Q. Footnote 11, Page 4, Schedule 1: Provide the dates of the orders and the time periods covered for the allowed returns on equity presented. Provide a copy of the decisions.

A. Table 1 provides the requested information relating to the current allowed returns on equity presented in Footnote 11.

Table 1
Allowed Returns on Equity

Jurisdiction	Allowed Return	Date of Order	Period
British Columbia	8.75%[1]	May 10, 2013	2013, 2014, 2015
Alberta	8.30%	March 23, 2015	2013, 2014, 2015
Ontario	9.30%[2]	November 20, 2014	2015
Quebec	8.90%[3]	March 5, 2013	2012, 2013
		May 16, 2014	2014, 2015
Nova Scotia	9.00%	December 21, 2012	2013, 2014

Copies of the decisions that established the referenced returns are provided as follows:

British Columbia	Attachment A
Alberta	Attachment B
Ontario	Attachment C
Quebec	Attachment D
Nova Scotia	Attachment E

[1] The 8.75% rate of return on equity in British Columbia is a benchmark return for FortisBC Energy, a natural gas utility. FortisBC, an electric utility, is allowed a rate of return on equity of 9.15% which is 0.40% higher than the benchmark.

[2] Electricity distributors can file evidence in individual rate hearings in support of different cost of capital parameters due to specific circumstances, but must provide rationale and supporting evidence for deviating from the Board's policy.

[3] The 8.90% rate of return on equity for Gaz Metro in Quebec was first established for 2012 and 2013 in an order on March 5, 2013. The 8.90% rate of return on equity was extended to include 2014 and 2015 in an order issued on May 16, 2014.

British Columbia

British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 1)
Decision, May 10, 2013

British Columbia Utilities Commission Generic Cost of Capital Proceeding (Stage 2)
Decision, March 25, 2014

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING
(STAGE 1)

DECISION

May 10, 2013

Before:

D.A. Cote, Commissioner/Panel Chair
R. Giammarino, Commissioner
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner

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EXECUTIVE SUMMARY

By Order G-20-12 on February 28, 2012, the British Columbia Utilities Commission (Commission) initiated the Generic Cost of Capital (GCOC) proceeding pursuant to section 82 of the *Utilities Commission Act* to review and determine among other things, the following:

- The setting of the appropriate cost of capital for a benchmark low-risk utility;
- The possible return to an automatic adjustment mechanism (AAM) for setting the return on equity (ROE) for the benchmark utility each year; and
- The establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt.

By Order G-48-12 on October 11, 2012, the Commission established the following:

- The proceeding will have two stages; Stage 1 will determine the cost of capital for the benchmark utility and Stage 2 will establish the cost of capital for other utilities as compared to the benchmark.
- Fortis Energy Inc. (FEI) in its pre-amalgamation state will serve as the benchmark utility for the GCOC proceeding; and
- An oral public hearing commencing on December 12, 2012, will be held to determine the cost of capital for the benchmark utility.

Fair Return Standard

The Fair Return Standard is foundational for cost of capital proceedings and has three requirements for a fair and reasonable return on capital: the comparable investment requirement, the financial integrity requirement, and the capital attraction requirement. The Commission Panel, consistent with previous decisions and the regulatory compact, confirms that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital. In the current proceeding, the Commission Panel has not considered the rate impacts of the revenue required to yield the fair return but has noted that by seeking an optimal capital structure and the opportunity cost of capital, the needs of customers are being served.

Contextual Issues

Three important issues were raised that were contextual in nature; the significance of past cost of capital decisions, the significance of decisions from other jurisdictions and the relevance of the disparity between “allowed” and “actual” ROE.

With respect to past cost of capital decisions and appropriate points of reference, the Commission Panel accepts that the 2009 Decision is a reasonable point of reference with respect to long-term risk as this is the most recent proceeding and has been used extensively by the parties. The Panel also remains open to looking back to the 2006 ROE Decision where appropriate.

With respect to reliance upon data from US jurisdictions, the Commission Panel has determined that it is appropriate to continue to accept the use of historical and forecast data but do not accept that US data should be considered to be the same or be given equal weight as data for Canadian utilities. Concerning Canadian jurisdictional decisions, the Panel acknowledges the importance of considering methodologies, approaches, and regulatory principles related to other jurisdictions’ decisions but does not accept the use of results and values for the purpose of calibration.

Concerning the relevance of disparity between FEI’s “allowed” and “actual” ROE, the Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from FEI’s positive track record. However, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management’s proactive approach. Additionally, the Panel is of the view that these differences are assessed in revenue requirement proceedings.

Capital Structure

In determining an appropriate capital structure for the benchmark utility, the Commission Panel considered FEI’s long and short-term risk, development of an optimal capital structure, credit ratings and metrics and experiences of other jurisdictions.

The Commission Panel is supportive of maintaining an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission Panel finds that reductions in long-term risk are warranted with respect to provincial climate and energy policies as well as the competitive position of natural gas relative to electricity. While acknowledging that there has been little change in short-term risk since the 2009 Decision, the Panel has determined that only minimal weight can be given to short-term risk as an impediment to earning a fair return. In consideration of both long and short-term risks, the Commission Panel has determined that a reduction in common equity ratio of 1.5 percent to 38.5 percent is appropriate. The Commission Panel considers a 38.5 percent common equity ratio reflects the reduced long-term risk, yet balances this against potential disruption caused by a significant weakening of credit metrics. The awarded common equity ratio falls within the upper end of the range of comparative utilities in other Canadian jurisdictions.

Return on Equity

The Commission Panel considered expert evidence on various model approaches to determine ROE. The Panel finds that the discounted cash flow model and the capital asset pricing model should be given equal weight in determining the ROE of the benchmark utility. No weight was given to the equity risk premium and comparative earnings models. The Commission has determined that an ROE of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the benchmark utility. The benchmark utility ROE will be effective January 1, 2013 and will be effective until December 31, 2015, subject to updating as a result applying the AAM formula.

Automatic Adjustment Formula

Consideration was given to re-instituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings, which had been eliminated in the 2009 Decision. In addition, consideration was given to the status of AAMs in other jurisdictions and what optional AAMs might be considered. The Commission Panel has determined that it is appropriate to re-establish an AAM formula noting that it better meets the FRS than giving no consideration to the market changes over the period between ROE proceedings. The Panel has directed that a two variable model considering changes to utility bond spreads and the long-term Canada bond yield be established to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

Cost of Capital – Small Utilities

Stage 1 of the GCOC proceeding considered the cost of capital for the benchmark utility, FEI. Stage 2 will assess the differences in short and long-term risk faced by regulated utilities in British Columbia other than FEI and their impact on the capital structure and ROE for these utilities. The Commission Panel has recommended that the utilities be separated into three groups, each of which will be handled separately. The Commission Panel has also made a number of determinations and findings with respect to the handling of the size factor as a business risk and deemed short and long-term debt interest rates.

1.0 INTRODUCTION

1.1 Background

The 2009 ROE Decision[1] (2009 Decision) was issued concurrently with Order G-158-09 on December 16, 2009. The Order set the return on equity for FEI, the benchmark utility in British Columbia, at 9.5 percent effective July 1, 2009, and the equity ratio at 40 percent effective January 1, 2010. Order G-158-09 also eliminated the AAM, which had been utilized to set the ROE for the benchmark utility annually. Since that Order, there have been no further adjustments to the ROE or capital structure of the benchmark utility.

This Decision for Stage 1 of the Generic Cost of Capital (GCOC) proceeding sets out:

- the new approved ROE and capital structure for FEI;
- the new automatic adjustment formula and the conditions under which it will be in effect; and
- the framework to review the cost of capital for small utilities.

Stating that changes have occurred in the financial markets since the 2009 Decision, the Commission, by Order G-20-12 dated February 28, 2012, initiated the GCOC proceeding pursuant to section 82 of the *Utilities Commission Act* (*UCA*) to review and determine, among other things, the following:

- the ROE and capital structure for a benchmark low-risk utility;
- the possible return to an AAM to set the ROE for the benchmark utility each year; and
- a deemed capital structure and deemed ROE for small utilities, particularly those utilities without short-term debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. The Order further divided the list of utilities regulated by the BCUC into Affected Utilities and Other Utilities. The Affected Utilities have been so designated given their active participation in previous ROE proceedings or their anticipated interest

[1] In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and capital Structure Decision, December 16, 2009.

in the GCOC proceeding as investor-owned utilities. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. The Other Utilities are so designated as they have not actively participated in previous ROE proceedings and they were not expected to file evidence in the GCOC proceeding.

On April 18, 2012, the Commission, by Order G-47-12, issued a final scoping document, which set out the purpose and scope of the proceeding. On April 19, 2012, the Commission issued a preliminary draft of the minimum filing requirements. Following submissions by Registered Interveners, the Commission issued Order G-72-12 on June 1, 2012, which set out the minimum filing requirements for those utilities expected to participate and a preliminary regulatory timetable. In an attachment to Appendix A to the Order, the Commission also placed on the record the terms of reference for a Survey of Cost of Capital Practices in Canada prepared by the Commission consultant, the Brattle Group (Brattle Report).

On October 11, 2012, following a procedural conference held on October 4, 2012, the Commission by Order G-148-12 established that in 2012, FEI in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding. The Order also established an oral public hearing to commence on December 12, 2012, to hear the cost of capital for the benchmark utility. In addition, it was determined that the proceeding will have two stages: Stage 1 establishing the ROE and capital structure for FEI the benchmark utility, and Stage 2, establishing a cost of capital for other utilities as compared to the benchmark utility.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

The Commission determined the purpose and scope of the GCOC proceeding in Order G-47-12, with certain outstanding matters such as the appropriate utility, which would serve as the benchmark utility, determined by Order G-148-12 dated October 11, 2012. The purpose and scope of this proceeding are as follows:

PURPOSE OF THE PROCEEDING

The main purposes of the GCOC Proceeding are:

I. to establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark return on equity (ROE) will be reviewed, and if required, adjusted on a regular basis;

II. to establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and

III. to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

SCOPE OF THE PROCEEDING

I. The appropriate cost of capital for a benchmark low-risk utility effective January 1, 2013. Cost of capital includes capital structure, return on common equity, and interest on debt.

II. Establishment of a Benchmark ROE based on a benchmark low-risk utility effective January 1, 2013 to December 31, 2013 for the initial transition year.

III. Whether re-establishment of an ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is accepted as a result of the GCOC Proceeding, it would be implemented January 1, 2014. If not, a future regulatory process will be set to review the ROE for a benchmark low-risk utility beyond December 31, 2013 on a regular basis.

IV. A generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility.

V. In certain circumstances, a methodology to establish a deemed capital structure and deemed cost of capital, particularly for those utilities without third-party debt. This would involve setting a methodology on how to calculate a deemed interest rate.

VI. In certain circumstances for those utilities that require a deemed interest rate, a methodology to establish a deemed interest rate automatic adjustment mechanism (Interest AAM). If warranted, the Interest AAM would be implemented for January 1, 2014. If not warranted, setting a future regulatory process on how the deemed interest for a benchmark low-risk utility would be adjusted in future years beyond December 31, 2013.

1.3 Regulatory Process

As noted previously, the Commission retained The Brattle Group to prepare a survey report on the Cost of Capital Practices in Canada. The Brattle Report, filed as Exhibit A2-3 on June 8, 2012, provides a description of the cost of capital estimation methods and the common approaches in implementing the results in Canadian jurisdictions. The Brattle Report was intended to provide context and background for the establishment of the cost of capital of a low-risk benchmark utility in B.C. All parties were provided with the opportunity to file Information Requests (IRs) on the Report.

In accordance with Order G-72-12, the following utilities filed minimum filing requirements:

- FEI, FortisBC Inc. , FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC (Whistler) Inc. (FEW),[collectively (FBCU)];
- Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. [collectively (PNG)]; and
- Corix Utilities (Corix).

The Industrial Customers Group of FortisBC Inc. (ICG) and the BC Utility Customers comprising the Association of Major Power Customers of BC (AMPC), the British Columbia Pensioners' and Seniors' Organization (BCPSO), and the Commercial Energy Consumers of BC (CEC) were active in the proceeding. Two rounds of IRs with respect to evidence filed by Affected Utilities and one round of IRs on evidence filed by Interveners took place.

The oral public hearing, including an *in camera* session on FBCU's confidential reports, took place over a period of seven days between December 12, 2012 and December 21, 2012. FBCU tendered five witness panels for cross-examination and Corix, BC Utility Customers, and the ICG each had one witness panel for cross-examination.

A list of procedural orders in the GCOC proceeding is included in Appendix A. A list of Appearances is included in Appendix B and Appendix C contains a list of witness panels that gave evidence. Appendix D contains the List of Exhibits. Appendix E contains a risk matrix used in a recent Commission decision with respect to a small utility that is Appendix B to Order C-1-13, Appendix F contains summary tables of ROE estimates by expert witnesses retained by the utilities and ratepayer groups, and. Appendix G is a list of acronyms.

1.4 Approach to Decision

The legal framework for determining a fair return for a regulated utility is called the "Fair Return Standard" and is discussed in Section 2.

There are a number of broader issues of importance, which were raised by this proceeding. These are contextual in nature and include the following:

- importance of past cost of capital decisions;
- consideration of decisions from other jurisdictions; and
- the relevance of the disparity between “allowed” and “actual” ROE.

These issues are discussed in Section 3 and provide the Commission Panel with a context to assist in reviewing and assessing the evidence.

Section 4 deals with an appropriate capital structure given FEI’s level of risk with consideration of credit ratings and metrics and decisions in other jurisdictions. Section 5 considers the appropriate ROE for the benchmark utility with a review of some of the key issues and models employed by the expert witnesses. Section 6 examines potential AAM models and whether there is justification to return to a reliance on such a mechanism. Section 7 considers issues related to cost of capital for small utilities, and Section 8 examines the need for financial models presented in proceedings such as this to have a sound theoretical basis.

2.0 LEGISLATIVE FRAMEWORK – THE FAIR RETURN STANDARD

2.1 Legislative Requirement

The enabling legislation for the BCUC, the *UCA*, provides that a public utility must not make, demand or receive:

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia;

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

A rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; or

(c) unjust and unreasonable for any other reason.[2]

The *UCA*, and other Canadian legislation delegating power to regulatory tribunals, follow what is known as the "Regulatory Compact." In general terms, the Regulatory Compact states that in exchange for an exclusive franchise to serve a defined area:

- a regulated utility must provide safe, reliable, non-discriminatory service to its ratepayers at cost-based rates as prescribed by the regulatory tribunal, and
- the regulatory tribunal must allow the regulated utility an opportunity to earn a fair return on its invested capital.

(Exhibit C4-9, p. 7; BCPSO Final Submission, p. 3)

The approach to determining a fair return on the cost of invested capital in a regulated utility has normally been referred to as the Fair Return Standard (FRS).

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[2] *UCA* sections 59 (1) (a) (b), 59(5), 60 (1) (a) (b) (i)

2.2 Elements of a Fair Return Standard

The Supreme Court of Canada decision in *Northwestern Utilities Ltd*. v. *Edmonton (City),* [1929] S.C.R. 186, (*Northwestern Utilities*) at pages 192-193 describes the FRS as follows:

> "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." (per Lamont J.)

The Brattle Report notes that the legal decisions, which provide the overarching principles of the FRS, do not prescribe how to determine comparability, how to estimate the cost of capital for the comparable companies, or how to apply those estimates when setting allowable rates. The cost of capital is the expected rate of return in capital markets on alternative investments of equivalent risk. The expected rate of return investors require is based on the risk-return alternatives available in competitive capital markets. In other words, the cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. (Exhibit A2-3, pp. 2-3)

On page 8 in the 2009 Decision, the Commission endorsed the National Energy Board's (NEB) articulation of the Fair Return Standard in NEB Decision RH-1-2008 where NEB stated:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - Be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - Enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)."

Ms. McShane, the expert witness for FBCU, submitted that the standards for a fair return arise from legal precedents and there are three requirements the utility must:

1. Earn a return on investment commensurate with that of comparable risk enterprises;
2. Maintain its financial integrity; and
3. Attract capital on reasonable terms.

According to Ms. McShane, the legal precedents make it clear that the three requirements are separate and distinct. The FRS is met only if all three requirements are satisfied. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8)

Dr. Laurence Booth, the expert witness for the BC Utility Customers, submitted that the definition of a fair rate of return was confirmed in *BC Electric* [*Railway Co. Ltd. v. Public Utilities Commission of B.C. et al ([1960] S.C.R. 837)*] when Mr. Justice Lamont adopted the definition of a fair rate of return, put forward in *Northwestern Utilities*.

Dr. Booth submitted that the definition in the *Northwestern Utilities* is referred to as an opportunity cost, in that the fair return is what could be earned by investing in similar securities elsewhere. Only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair, i.e., they will neither reward the owners with excessive profits, nor ratepayers by charging prices below cost. Dr. Booth further submitted that to any modern financial economist, Mr. Justice Lamont's definition of a fair rate of return as an opportunity cost means a risk adjusted discount rate or expected rate of return. (Exhibit C6-12, pp. 7, 8)

2.3 Application of the Fair Return Standard

The Commission Panel observes that the application of the FRS leaves room for disagreement, judgment and discretion. The methods relied upon by various regulators and practitioners therefore differ substantially. For example, while some regulators set rates by determining the weighted-average cost of debt and equity that the regulated company should be allowed to earn on its invested capital (as a whole), others determine separately the cost of equity and possibly the percentage of equity that should be allowed in the regulated company's capital structure.
(Exhibit A2-3, p. 2)

The Panel also notes the words of the Alberta Utilities Commission (AUC) on this subject related to conflicting evidence and applying judgment:

> "....the determination of a fair return on equity for Alberta utilities requires the assessment of three criteria: return on comparable investments, ability to attract capital and maintenance of financial integrity. As noted by Mr. Justice Rothstein in the TransCanada Pipelines decision cited above, the determination of the rate of return on equity for a regulated utility is difficult given that the correct answer is not readily apparent. This determination requires an expert tribunal to apply its judgment in assessing often conflicting evidence and to consider the differing interests and perspectives on risk of debt and equity investors. This exercise is even more complex in Canada, and in Alberta in particular, given the limited number of stand-alone utilities issuing debt and the lack of any utilities that issue equity directly to investors."[3]

The Commission Panel further notes the words of the Federal Court of Appeal's ruling in *TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149* on just and reasonable tolls. It quotes the *Northwestern Utilities* and states:

> "Tolls which reflect a fair return on capital will be just and reasonable to both the Mainline and its users.

It further states:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the point of view of the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring Mainline's costs are not overstated .... And, specific to this appeal, customers and consumers have an interest in ensuring that the Mainline's cost of equity is not overstated."
>
> (TransCanada Pipelines Ltd. v. National Energy Board, 2004 FCA 149, para. 33, 34)

[3] AUC 2009 Generic Cost of Capital Decision, November 12, 2009, p. 28

Submissions by Parties

None of the parties disagree with the Fair Return Standard as the applicable test. The Utilities and Interveners, however, disagree on how this test should be applied.

FBCU take the position that the overall rate of return allowed for FEI must be based on the utility's true cost of capital without compromising the legitimate cost of service to achieve lower rates in the short-run. FBCU submit that the combination of allowed ROE and capital structure should permit FEI to maintain credit ratings that are at a minimum in the "A" credit category in varying market conditions. This matter is further addressed in Section 4.5.

FBCU argue that a fair return is not synonymous with the lowest possible return. It pointed out that in the 2006 ROE Decision (2006 Decision),[4] the Commission had articulated that the "lowest possible" was not the appropriate test. Therefore, FBCU submit that the Commission should not rely on evidence on rate impacts and that the view of Dr. Safir, ICG's expert witness, that the outcome of a "fair return" should always favour the lower range is fundamentally inconsistent with the authorities on the FRS. (FBCU Final Submission, pp. 1, 7, 11-12)

The AMPC/CEC do not dispute the definition of the FRS based on the NEB Decision RH-1-2008 and endorsed by the Commission in the 2009 Decision. However, the AMPC/CEC disagree with FBCU's submission that the three requirements listed are the only factors to be considered when deciding what constitutes a fair return, with no consideration of the Commission's broader mandate to balance the interest of customers and regulated utilities. AMPC/CEC submit that when acting as the surrogate for competition, the Commission cannot and must not protect FEI from all business and financial risk by unnecessarily raising the ROE and common equity at the expense of customers; and the Commission must scrutinize whether the cushion FEI asks for is truly necessary to meet the FRS in light of its broader mandate to protect consumers. In Section 4.5 of this Decision, the Commission Panel discusses the application of the FRS and the role of credit metrics in the implementation of the FRS requirements.

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[4] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision and Order G-14-06, March 2, 2006.

According to AMPC/CEC, Dr. Booth's evidence shows that he recommended a fair return by applying the principle in the FRS that "only if the owners of a utility earn their opportunity cost will the returns accruing to them be fair." In addition, AMPC/CEC state that among other things, Dr. Booth checked his findings against numerous independent, reputable sources which confirmed that his estimates were reasonable. (AMPC/CEC Final Submission, pp. 5-7)

The BCPSO agrees with FBCU's characterization of the FRS and agrees that utilities are entitled to a competitive return as defined in the FRS' three tests regardless of the rate impact. However, BCPSO submits that it is not the same as to say that customer interests carry no weight in setting an appropriate deemed cost of capital as utility customers have an interest in ensuring that the utility's cost of capital is not overstated. BCPSO submit that a fair return is one that takes into account the right of utility customers to pay no more than a fair and reasonable charge for the service provided. Based on its logic, BCPSO submits that the evidence from Exhibit B1-42 which compares the rate impact of a 5 percent change in the equity ratio to a 50 and 100 basis point change in ROE is admissible; and furthermore, if the utility can be provided a competitive return with less rate impact, that option should be chosen. (BCPSO Final Submission, pp. 3-5)

ICG submits that the interests of customers should be paramount to those of the shareholders and reiterates Dr. Safir's testimony that where a range of competitive returns is available for evaluation, the outcome of a "fair return" should always favour the lower range presented. (ICG Final Submission, p. 3)

In Reply, FBCU submit that the Commission would err in accepting ICG's argument that regulation is simply to benefit customers. FBCU submitted that the Commission, in the 2009 Decision, had been explicit that it was not accounting for rate impacts in reaching its decision. (FBCU Reply, pp. 2-3)

Commission Determination

In previous decisions, the Commission concluded that the opportunity to earn a fair return must be provided to each regulated utility as a separate obligation from those service and financing requirements detailed in other sections of the *UCA*. For instance, on page 8 of its 2006 ROE Decision, the Commission said:

> "In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital."

The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility. This Decision reiterates the principle articulated in the 2006 ROE Decision and the 2009 Decision, and argued by FBCU on pages 7 to 9 in its Final Submission, that the Commission does not consider the rate impacts of the revenue required to yield the fair return. However, by seeking an optimal capital structure and the opportunity cost of capital we are serving the needs of the customer.

While this Commission Panel has not considered the rate impacts of the revenue required to yield the fair return *per se*, we are of the view that the capital structure of the utility should be set efficiently and, therefore, there is value in finding an optimal capital structure. Exhibit B1-42 provides comparative information on revenue requirements for FEI based on either a change in equity thickness or a change in ROE. The ICG submits that the Commission should reduce the ROE before reducing the capital structure of FEI. (ICG Final Submission, p. 4) In this regard, the Commission Panel finds the information on rate impacts as presented in Exhibit B1-42 useful. An optimal capital structure is discussed further in Section 4.4.

3.0 CONTEXTUAL ISSUES

This section considers important issues raised by this proceeding that are contextual in nature; they include:

- The significance of past cost of capital decisions;
- The relevance of US data and the significance of decisions from other jurisdictions; and
- The relevance of the disparity between "allowed" and "actual" ROE.

3.1 Past Cost of Capital Decisions

An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel's decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time. Each of these referenced areas will be discussed in turn.

Submissions by Parties

3.1.1 <u>Changes in Capital Markets</u>

Throughout this proceeding, the FBCU have relied upon and underlined the Commission's statement that changes have occurred in capital markets since the 2009 Decision was issued. They have taken the position that capital markets are similar (albeit for different reasons) to what they were in the fall of 2009 when the previous cost of capital proceeding took place. The FBCU have relied very heavily on the 2009 Decision as a reference point for the current proceeding and have provided comparisons between what they believe exists today as opposed to conditions which existed at the time of the 2009 Decision. FBCU have relied upon the opinion evidence prepared by two of their expert witnesses, Ms. McShane and Mr. Engen, which showed that many of the key indicators of conditions within capital markets are similar and in some cases worse than the same indicators reflecting capital markets late in 2009. FBCU maintain that the experts along with market indicators and Bank of Canada published information all suggest that equity capital markets in Canada are challenging and volatile and the market cost of equity has risen since 2009. In summary, FBCU maintain that current market conditions provide no basis for reducing FEI's overall return as argued by interveners. (FBCU Final Submission, pp. 1-2, 16-30)

ICG takes issue with FBCU on their choice of 2009 as an appropriate reference point and argue that a more appropriate reference point was the 2006 Decision. ICG submits that the 2009 Decision did not appropriately balance the interests of customers and shareholders and gave inappropriate weight to the interests of shareholders. Moreover, ICG submits that the 2009 Decision represented a significant departure from previous Commission cost of capital decisions. With respect to its Canadian peers, ICG points out that the weighted equity return component was materially lower (by 0.47) in 2005 through 2009 and materially higher (by 0.57) in the 2010 to 2012 period. ICG argues that the 2009 Decision should not be a point of reference for this decision given a steady decline in FEI's business risks since 2005. (ICG Final Submission, pp. 11-12)

BCPSO also takes issue with the use of the 2009 Decision as a reference point for this decision, expressing concern as to whether the capital market conditions comparator dates are consistent across the two proceedings. BCPSO submits that the current proceeding is forward looking with respect to capital conditions and snapshot-style evidence of past capital conditions is of limited value. In its view, the economic tests such as equity risk premium (ERP), comparable earnings (CE) and discounted cash flow (DCF) provide a better basis in assessing cost of capital stating that they "are more precise, forward looking, and can be made industry or company specific." The primary value of evidence relating to general market conditions lies in the trends it demonstrates. (BCPSO Final Submission, p. 6)

AMPC/CEC submit that regulators do not base a cost of capital decision on immediate circumstances only. They assert that the Commission will consider economic and financial conditions occurring since the last hearing and will also consider the outlook on a going forward basis. Referring to Mr. Engen's S&P/TSX Composite Index 10 Year Performance data, AMPC/CEC state that the difference now "is that the last few years have witnessed the market hold or increase ground it recovered, whereas in the lead up to the 2009 hearing, it had just suffered a dramatic crash." They further point out the FBCU argument that capital markets are similar to what they were in 2009 is in conflict with their own witnesses' (Ms. McShane and Dr. Vander Weide) DCF calculations, which have declined considerably since the close of evidence in the last hearing. (AMPC/CEC Final Submission, pp. 28-29; Exhibit B-1-9-6, FBCU Evidence, p. 14, updated in Exhibit B-1-49)

In Reply to ICG, the FBCU state that the choice of 2009 as a point of comparison is because that proceeding is where the Commission most recently assessed FEI's business risk. To disregard this in favour of the 2006 Decision because ICG preferred the outcome in FBCU's view is indefensible. (FBCU Reply, p. 21)

Concerning the AMPC/CEC's submissions regarding the inconsistency in capital markets being similar to 2009 and FBCU's witnesses' DCF calculations, the FBCU state the following:

- Mr. Engen's evidence relates to the overall capital market and trends in the market cost of equity which indicate the market cost of equity is higher today.
- Ms. McShane's and Dr. Vander Weide's DCF calculations relate to a narrow segment of the overall market and deal specifically with FEI's cost of equity. (FBCU Reply, p. 5)

3.1.2 <u>Changes in Long-Term Risk</u>

While there has been considerable disagreement with respect to relying upon 2009 capital markets as a reference point for comparison, there has been little concern raised by the parties with respect to using the 2009 Decision as a reference for changes in long-term risk. Both the FBCU and interveners have relied heavily on what has changed since 2009 and in some cases referred back to the period prior to the 2006 Decision as a source of comparison.

Commission Discussion

The Commission Panel accepts that many of the indicators reflecting the current state of the capital markets are similar to what they were in 2009. This, however, does not mean that the conditions under which the 2009 Decision was made are the same as they are today. As noted in Mr. Engen's evidence, the current period is characterized by concerns for a sustained US economic recovery, fears of an economic slowdown related to weak economic data from the US and the European Union and the European sovereign debt crisis, among other things. These are not at all descriptive of the period in latter 2009. (Exhibit B1-9-6, Appendix E, Engen Evidence, pp. 7-8) Moreover, as pointed out by AMPC/CEC, since that time markets have demonstrated a degree of stabilization in sharp contrast to the situation preceding the 2009 Decision which followed a dramatic crash. Therefore, while there are some similarities between the current period and late 2009, the Panel is of the view there are significant differences. By contrast, the markets, while maintaining volatility, have experienced a few years of comparative stability and the investor has been distanced from the financial conditions characterizing the period leading to the 2009 proceeding.

The Commission Panel is mindful that many of the key indicators of capital market conditions are similar to those of 2009 but does not consider them alone to be determinative in reaching a decision on the cost of equity. While considering changes in capital markets, pricing models some of which reflect the market outlook, are very important in reaching a determination on the appropriate rate of return in this proceeding.

The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

The Commission Panel does not accept ICG's argument that the 2009 Decision fails to appropriately balance the interests of customers and shareholders. In the view of the Panel, there is no value in re-examining the 2009 Decision nor is there evidence to support the need for doing so.

3.2 Consideration of Other Jurisdictions

Throughout the evidentiary portion of this proceeding there has been considerable reliance among the parties upon data and cost of capital decisions from both US and Canadian jurisdictions. The Commission Panel considers these separately as the issues related to each differ.

3.2.1 Relevance of US Data and Decisions

In the 2006 Decision, two issues related to reliance upon US data in cost of capital proceedings were dealt with by the Commission:

1) Opportunities exist for investors to commit capital on a global basis. The Commission Panel noted that there was considerable foreign exchange risk and was not convinced that the Federal Government's easing of foreign content in retirement portfolios was sufficient reason to raise the equity return of a utility.
2) The necessity of looking beyond Canadian data in measuring the risk premium. The Commission accepted the use of historical and forecast data for US utilities "when applied as a check to Canadian data; as a substitute for Canadian data when those data do not exist in significant quantity or quality; or as a supplement to Canadian data when Canadian data give unreliable results." (2006 Decision, p. 50)

In the 2009 Decision, the Commission accepted the use of historical and forecast data of US utilities as outlined in the 2006 Decision. In addition, the Commission supported the need for utilities to compete in a global marketplace and reiterated its acceptance of the use of historical and forecasting data. In the 2009 Decision, the Commission also noted the lack of relevant Canadian data and considered the potential for US gas utilities to act as a proxy in the determination of cost of capital and credit metrics. (2009 ROE Decision, pp. 15-16)

Submissions by Parties

In the current proceeding, the FBCU take the position that the Commission should find that US data remains useful and that US utilities can be appropriate comparators based on total investment risk. In support of this, they rely on the evidence of Ms. McShane and Dr. Vander Weide who make the following assertions:

- The operating, regulatory and business environments for US and Canadian regulated companies are generally similar.
- Capital markets in Canada and the US are significantly integrated and the cost of capital environment is similar.

In further support of their argument, the FBCU note that Dr. Safir acknowledged the integration of capital markets in his evidence and utilized US companies in his Capital Asset Pricing Model (CAPM) and DCF analysis. Further, the FBCU argue that Dr. Booth, in spite of his concern with the use of US data, conceded there was a high degree of integration between US and Canadian markets. (FBCU Final Submission, pp. 96-97)

AMPC/CEC's witness Dr. Booth raised two concerns with the use of US data:

- US financial markets exhibit greater risk than Canadian markets and have generated higher premia in the past.
- Regulatory implementation differs even though US and Canadian principles of regulation are the same.

(Exhibit C6-12, Dr. Booth Evidence, Appendix B, p. 106)

AMPC/CEC submit that there is ample support for Dr. Booth's assertion that US markets are riskier than those in Canada. They point out his evidence demonstrates that over the period 1926-2011, US returns showed greater volatility than Canadian returns and the risk premium was higher in the US than the equivalent in Canada. They further submit that during Ms. McShane's cross-examination, she agreed that a typical US utility could be viewed as higher risk than a Canadian one and point out that her report aligns with Dr. Booth's as it presents a historical risk premium of 4.7-4.8 percent for Canada compared to 5.5-5.7 percent for the US. (AMPC Final Submission, p. 46) Concerning the difference between Canada and the US with respect to the implementation of regulatory principles, AMPC/CEC state that the Commission in the 2009 Decision was cognizant of the danger of relying on US comparables and cites the following statement of the Commission Panel in that decision:

> "The Commission Panel agrees with Dr. Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short term, earn its allowed return than the Value Line US natural gas LDC enjoy." [emphasis added by AMPC/CEC]

Additionally, AMPC/CEC point to Dr. Booth's finding that Canadian utilities have higher bond ratings in spite of poorer financial ratios, which in his view reflects the importance bond rating agencies place on the differing regulatory approaches in Canada and the US. In summary, AMPC/CEC submit that the Commission should continue to approach US data based results with caution, adjusting them downward to reflect differences in financial and regulatory contexts between the two countries. (AMPC/CEC Final Submission, pp. 46-47)

FBCU argue that the evidence does not support a downward adjustment to US results and state the following:

> "Since the financial crisis, long term interest rates have been similar in Canada and the US across a broad range of bond types, equity market volatility has been virtually identical, and market risk premium surveys show virtual identical values." (FBCU Reply, p. 28)

None of the parties have suggested that the Commission should put no weight on US data and decisions.

Commission Determination

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

In making this determination the Commission Panel would like to be clear that while we accept there are similarities between the two jurisdictions, we do not accept that US data should be considered to be the same or necessarily be given equal weight as the data for Canadian utilities. Canadian investors considering US utility investments are subject to currency exchange risk that would not be the case with Canadian utility investments. Additionally, the US regulatory environment while similar is not identical to that of Canada. The 2009 Decision's reference to the array of deferral mechanisms resulting in greater certainty for the Canadian utility is just one example of potential differences between the jurisdictions. Moreover, Ms. McShane has acknowledged under cross-examination that the universe of US utilities is focused on vertically integrated utilities and, to the extent that there is a smaller number of Canadian investor-owned, vertically integrated utilities, the typical US utility could be viewed as higher risk than the typical Canadian utility. (T3:466-467) Therefore, in the view of the Commission Panel, the use of US data must be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist.

3.2.2 Consideration from other Canadian Jurisdictions

Throughout this proceeding the parties have chosen to utilize information and related decisions from other Canadian jurisdictions as support for the position they have taken on an issue. The Commission Panel notes that decisions in all jurisdictions result from the judgment of evidence specific to a region or a particular utility that in each case is unique. To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C.

3.3 Relevance of Disparity between "Allowed" and "Actual ROE"

3.3.1 Outline of the Issue

As described in Section 2.1, when setting a rate under the subsection 60 of *UCA,* the Commission must have due regard for, among other things, whether the rate is insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property. This standard does not mean, however, that a utility must be guaranteed its allowed return on equity. It simply means that a utility must be given an opportunity to earn this return. In any particular year, the actual ROE earned may be below or above the allowed ROE. The rates are set based on a forecast revenue requirement for the year, which includes a provision for the allowed ROE, grossed up for income taxes. The utility's actual performance during the fiscal year will determine how close the actual ROE will be to the allowed ROE.

Short-run risks in general relate to a utility's ability to annually earn its allowed return on equity. The issue for the Panel, therefore, is to determine the relevance of the difference of realized and allowed ROE. From the investors' perspective, this risk relates to the relative stability of year-to-year variations in earnings or cash flows and the value of those cash flows. Therefore, the Panel first has to assess the relevance of the disparity between "allowed" and "actual" ROE in relation to the question of whether FEI faces any short-run risks. FEI has a track record of generally achieving, and often exceeding, the allowed ROE in any particular year. Does this strong track record imply FEI having "no material short-run risk, or the risk of return on capital" as claimed by Dr. Booth? (T8:1464)

FEI's track record was explored extensively in the proceeding as shown below:

- From 2002 to 2011, there was only one year when the actual ROE was below the allowed ROE, whether assessed on a pre or post earnings sharing mechanism basis. This year was 2010, when 9.42 percent was achieved as compared to the 9.50 percent allowed, resulting in a net income variance of $1.2 million. (Exhibit B1-20, BCUC 1.95.1)
- A similar trend is also apparent from 1994 to 2001. (Exhibit B1-10, BC Utility Customers 1.2.1; Exhibit C6-12, pp. 27-29)
- FBCU stated that the data set used by Dr. Booth is largely from years in which a Performance Based Rate (PBR) mechanism was in place for FEI. During the PBR period, O&M and capital were set through a formula, not based on forecast spending. The PBR formula approach was designed to result in savings to be shared with customers, primarily from the operational consolidation of three separate utilities. The Commission–approved framework expressly anticipated earnings that were above the allowed ROE. FBCU argue that when the periods under PBR are excluded, the variances between FEI's achieved return and allowed ROE from 1994 to 2011 were not that significant. (FBCU Final Submission, p. 40; Exhibit B1-20, BCUC 1.96.1.1)
- For the PBR period 2004 to 2009, after sharing, the average ROE over the period is .67 percent over the allowed ROE. (Exhibit B1-32, Rebuttal Evidence, p. 3)

Submissions by Parties

FBCU submit that the relative consistency of utility sector earnings in Canada tends to suggest lower short-term risk than for non-regulated companies, but "is not synonymous with an absence of short-term risk." (FBCU Final Submission, p. 39)

ICG submits that the Commission Panel should not accept that consistent over-earnings can be explained by PBR, and that consistent over-earning is attributable to how effectively FEI manages the regulatory risk, which it claims is its largest risk, not how effectively FEI operates the utility. ICG further argues that one should think of over-earnings during the PBR period as a regulatory benefit that can be enhanced to provide increased earnings that exceed the Fair Return Standard, and that "…the historic returns suggest that FBCU have come to expect returns that exceed a fair return." (ICG Final Submission, p. 16)

AMPC/CEC first observe that FEI has not experienced any significant risk as "the shareholder has not cumulatively lost any money whatsoever since 1994." AMPC/CEC submit that "year after year, FEI continues to face very little short-run risk, such that this pattern of consistent overearnings is clearly a long-term phenomenon." (AMPC/CEC Final Submission, p. 9)

In Reply, FBCU submit "the similarly long track record among Canadian utilities of achieving or exceeding their allowed ROE suggests that Canadian regulators have long recognized that it is reasonable for a well-managed utility to be able to achieve its allowed ROE on a consistent basis." (FBCU Reply, p. 10)

Commission Determination

The Panel notes that FBCU did not explain why, even after allowance for the sharing mechanism, the over earnings have continued. For instance, in 2011 the actual ROE was 10.15 percent as compared to the 9.50 percent allowed. Consequently, the Panel observes a noteworthy asymmetry between allowed and actual ROEs that is apparent in the frequent occurrence of annual overearnings in contrast to very few years of under earnings.

In the view of the Panel, the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control costs for each test period.

The Commission Panel concludes that debt and equity investors, who in their risk assessment consider both long and short-term cash flows as well as risk of financial disruption, will derive some comfort from the track record of FEI. However, there is no evidence to suggest they are likely to make a major distinction between short-term and long-term risk. Accordingly, the relevance of disparity between allowed and actual ROE of FEI is entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.

4.0 CAPITAL STRUCTURE

4.1 Definition of Risk

Dr. Booth has described the most basic definition of risk as "the probability of incurring harm, which in a financial sense means losing money." Ms. McShane agreed with this definition noting that it was consistent with her own testimony which defined risk as the probability that the utility's future returns (including the return on and of capital) will fall short of returns that investors expect and require. Mr. Dall'Antonia put a finer point on it as he described a loss as not earning a fair return or more specifically, a loss is anything that is less than the allowed ROE. (Exhibit B6-12, Dr. Booth Evidence, p. 26; Exhibit B1-15, AMPC 1.4.1; T2:123-124)

The Commission Panel takes no issue with the basic definition of risk as provided by Dr. Booth. However, for this Decision, the Commission Panel views risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognizes the risk of potential financial disruption. We also accept the distinction outlined in both the 2006 Decision and the 2009 Decision where investment risk was described as comprising the sum of business risk, financial risk and regulatory risk.

Both Ms. McShane and Dr. Booth addressed business risk in terms of short-term and long-term risks, a distinction the Commission Panel considers appropriate. Each of these is discussed separately in Sections 4.2 and 4.3.

Dr. Booth has described short run utility risk as the risk of earning a return on capital and long run utility risk as the risk of earning a return of capital. (Exhibit C6-12, p. 25) Ms. McShane comments that both the capital structure and the ROE incorporate elements of long-term and short-term risks. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 39) The Commission Panel does not disagree with Ms. McShane but notes that long-term risk, which Ms. McShane outlines as being of primary importance to the utility investor, is primarily reflected in the equity structure determined for FEI considering the investors' ability to recover their invested capital. This is because if the underlying risk decreases, more debt can be issued; if it increases, the common equity ratio would increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: "The assessment of risks has a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

4.2 FEI's Long-Term Risk

In the 2009 Decision, eight factors that influenced FEI's long-term risk were identified. They were:

1. Provincial Government climate and energy policies;
2. The effect of aboriginal rights issues;
3. The competitive position of natural gas relative to electricity;
4. Percentage of new construction being captured by Terasen Gas Inc. (TGI);
5. Natural gas vs. Electricity in high density housing;
6. The impact of Alternative Energy Sources on TGI;
7. Changes in demand related to fuel switching; and
8. Use of natural gas per customer account.

FBCU has stated that the same risk factors are at play in the current proceeding, although they have been expressed and organized somewhat differently. (FBCU Final Submission, pp. 47-48)
For the purposes of examining the long-term risk of FEI, items 4 and 5 related to the capture rate of new construction and the energy choice for high density housing are combined under the more general heading "Customer Growth." Items 7 and 8 related to use per customer and fuel switching related demand are also combined under the new "Market Demand and Throughput" heading. In addition, two new factors which received little or no coverage in the 2009 proceeding are addressed: "Supply Risk" and "Regulatory Risk."

4.2.1 Provincial Government Climate and Energy Policies

In the 2009 Decision, the provincial government climate and energy policies of the previous few years played a significant role. During the period leading up to the proceeding, the provincial government published the "BC 2007 Energy Plan," introduced numerous pieces of legislation (principally in the area of greenhouse gas emissions reduction) and in 2008 implemented the BC Carbon Tax. In the 2009 Decision, the Commission was in agreement with TGI's position that the climate change legislation had created a level of uncertainty which did not exist during the 2005 hearing and stated that the change in government policy "will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity." (2009 Decision, pp. 36-38)

Submissions by Parties

The Commission Panel notes that there is considerable disagreement among the parties concerning the level of risk related to provincial government climate and energy policies. In the current proceeding, FBCU have ranked political risks in the number 2 risk category and submit that the risks associated with policy and legislation are equal to if not greater than in 2009. FBCU note that all of the legislation and policy relied upon by the Commission in the 2009 Decision remains in place and the introduction of the *2010 Clean Energy Act (CEA)* has had the following impacts:

- It has precluded natural gas utilities from using incentives to promote fuel switching (electricity to gas).
- It has required the Commission to account for enumerated energy objectives in the course of considering certain types of applications.

(FBCU Final Submission, pp. 53-56)

Both BCPSO and AMPC/CEC submit that conditions are far more favourable today and the resulting political risks are much lower today than TGI portrayed in 2009. In support of these submissions, they point to a number of factors:

- the lack of plans to increase the carbon tax;
- the introduction of the BC Natural Gas Strategy and its support of natural gas as a transportation fuel; and
- a collapse of the Western Climate Initiative and lack of progress on emissions-trading initiatives.

(BCPSO Final Submission, pp. 15-16; AMPC Final Submission, pp. 22-23)

Commission Determination

The Commission Panel finds that the risks related to provincial government climate and energy policy are less significant when compared to the period leading up to the 2009 Decision. At the time of the 2009 proceeding, there was considerable concern and uncertainty related to provincial energy policies, how they would be shaped in the future and what impact this would have on Terasen's gas utilities. In addition, the Commission placed importance on the Nyboer Report as reflected in the following statement:

> "In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers." (2009 Decision, p. 37)

The Commission Panel does not consider the current environment to be as threatening to FEI as it was perceived to be in the period leading to the 2009 Decision. As BCPSO points out, there are no plans to raise the carbon tax beyond the current $1.50 per GJ level and as AMPC/CEC reports, the Western Climate Initiative has collapsed and emission trading has become a dormant issue. These all reflect a less threatening current environment and with it, a lessening of risk associated with provincial government climate and energy policies.

4.2.2 Aboriginal Rights

In the 2009 Decision, the Commission Panel acknowledged that risks posed by First Nations did not exist previously and to the extent that they were currently perceived, represented an increase in risk over natural gas local distribution companies operating in other provinces. However, the Commission did not consider that risks posed by First Nations cast doubt over Terasen Gas Inc.'s "ability to earn a return on or of its capital." (2009 Decision, p. 37)

Submissions by Parties

FBCU acknowledge that aboriginal rights issues, which they rank in category 2, are much the same now as they were in 2009 and note that this issue was not addressed by the parties in IRs or at the hearing. (FBCU Final Submission, p. 49)

BCPSO argue the amount of aboriginal rights risk should be reduced relative to 2009, given the FBCU experience and understanding of aboriginal rights and title claims resulting from First Nation consultations tied into CPCN Applications. (BCPSO Final Submission, p. 17)

AMPC/CEC submit that this risk remains unchanged from 2009 where it was given no weight and this remains appropriate. (AMPC/CEC Final Submission, p. 24)

Commission Determination

The Commission Panel agrees with the FBCU and AMPC/CEC and find that there is no evidence to suggest that there has been a significant change to risk associated with aboriginal rights based on the evidentiary record of this proceeding. We also concur with the 2009 Decision that the risk associated with aboriginal rights has little impact on the FEI's ability to earn a return.

4.2.3 Competitive Position of Natural Gas Relative to Electricity

The competitive position of natural gas to electricity is an existing risk which bears scrutiny at each cost of capital proceeding. In the 2009 Decision, the Commission Panel took note of the interveners' position that the risk related to the competitive price of natural gas and electricity had diminished since 2005. However, the Panel considered that the competitive edge which existed was dependent on too many significant variables to be considered permanent. (2009 Decision, p. 36)

Submissions by Parties

The FBCU acknowledge that natural gas prices have fallen but submit that this occurred prior to the 2009 Decision and take no issue with the fact that the development of shale gas is a "game changer" or that there has been an increase in electricity prices. They do take issue with Dr. Booth's conclusion that long-term business risk has declined since 2009 and argue that his reliance on considerations related to cost-effectiveness paints an incomplete, distorted view of FEI's overall competitive position. FBCU make the following arguments in support of their position:

- Natural gas prices fell substantially prior to the 2009 hearing due to shale gas development and this was reflected in the evidentiary record leading to the 2009 Decision.
- Volatility in natural gas prices affect natural gas to electricity competitiveness and has increased due to the suspension of hedging instrument tools resulting from the 2011 Price

Risk Management Decision (PRMP Decision).[5] Looking ahead to 2017 there is a wide potential price range for natural gas based on the AECO Forward Curve. (see Figure 2 below)

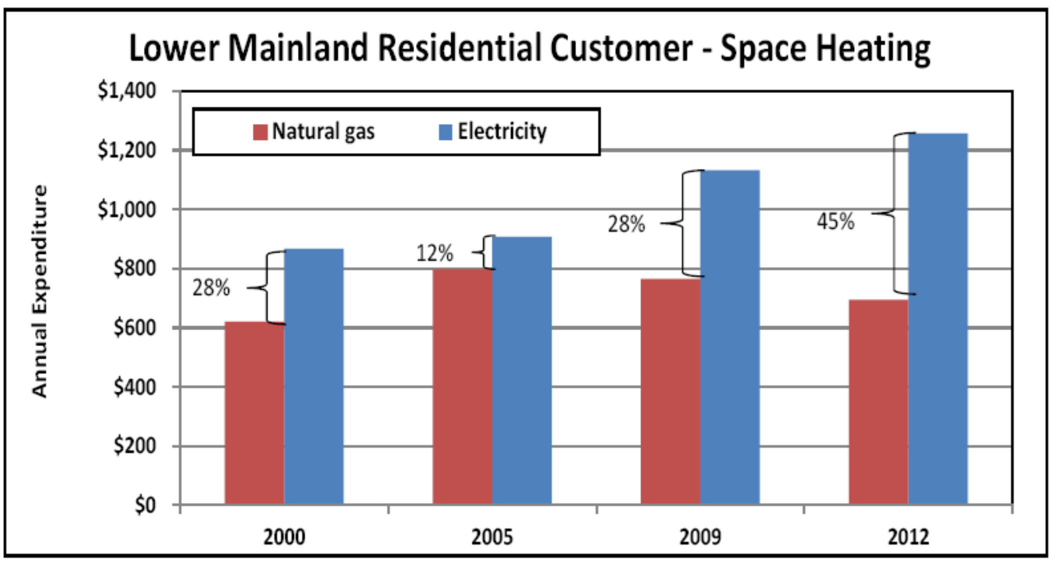
- The price of the natural gas commodity has decreased but the delivered cost of natural gas remains almost the same as 2009.
- Higher capital costs for natural gas heating materially diminish the operating cost advantage of natural gas over electricity.
- Non-price factors such as the desire to create a smaller carbon footprint have resulted in more customers being willing to adopt lower carbon and renewable energy sources.

(FBCU Final Submission, pp. 57-71)

ICG, relying on Figure 1 below, argues that there has been a significant improvement with respect to cost competitiveness between natural gas and electricity since both the 2005 and the 2009 proceedings.

Figure 1: Estimated Annual Expenditure

Figure 1: Estimated Annual Expenditure for FEI Lower Mainland Residential Customer – Natural Gas and Electricity for Space Heating



(Source: Exhibit B1-11, FBCU Response to BC Utility Customers, 1.4.2)

ICG contends that shale gas has been a game changer for natural gas prices, which has resulted in a "seismic" shift in the competitiveness of natural gas versus electricity. (ICG Final Submission, p. 11)

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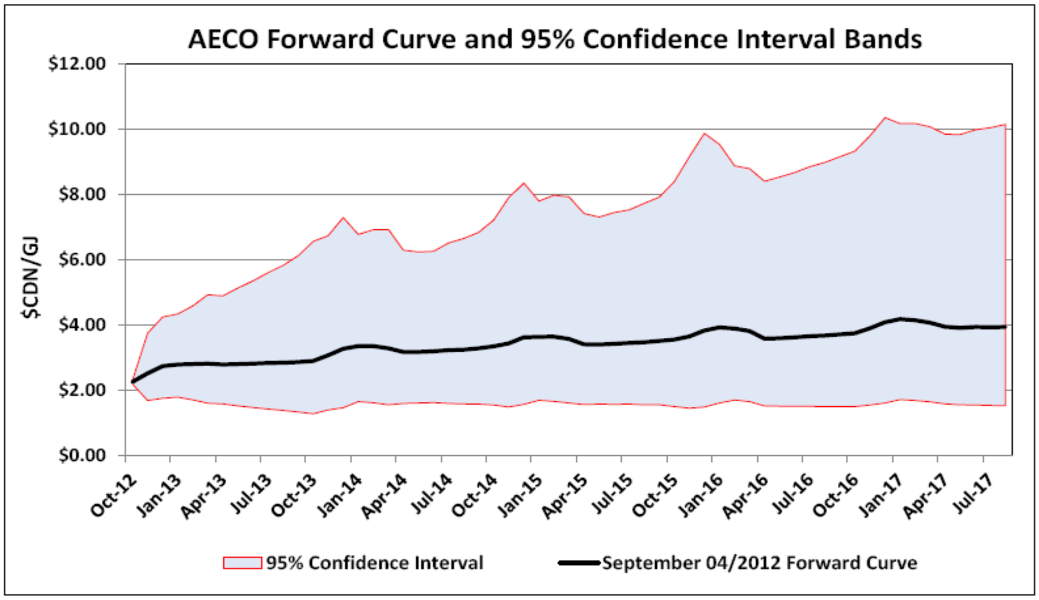
Figure 2: AECO Forward Curve



(Source: Exhibit B1-20, BCUC 1.105.1)

BCPSO notes that there has been no change in FBCU's rating of capital cost and it is the same as in 2009. It argues there is no evidence that the effect of higher capital costs will offset any competitive gain made through lower commodity prices. Further, BCPSO submits that the AECO Forward Curve relied upon by FBCU demonstrates only an increasing level of price uncertainty over time, not volatility. BCPSO also takes issue with the FBCU claim that there is effectively no reduction in the customers overall bill. The important comparison is not natural gas against itself but against electricity, and this comparison is very favourable to FEI. (BCPSO Final Submission, pp. 9-10)

AMPC/CEC state that price is a key determinant of natural gas competitiveness and deserves the greatest weight when considering changes to FEI's business risk. In answer to FBCU's claim that the delivered cost of natural gas is similar to 2009, AMPC/CEC argue that prices are at or near a ten-year low and by FBCU's evidence (in Figure 3 below) are lower than 2009 and even more so when compared against 2005. (AMPC/CEC Final Submission, pp. 11-13)

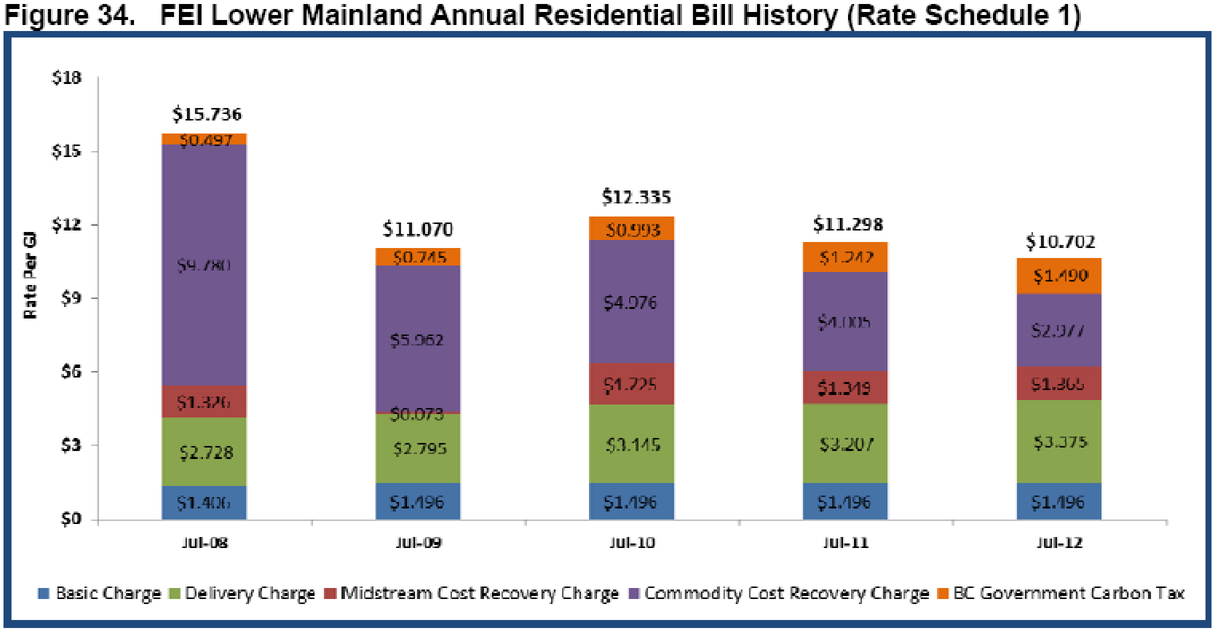
AMPC/CEC assert that the volatility is manageable through options, including equal payment plans and deferral accounts which FEI currently uses. AMPC/CEC notes than in addition to these options, FEI is proactive in communicating the natural gas cost advantage relative to other sources.

AMPC/CEC also submit that a telling point with regard to competitiveness is how it compares to electricity. They assert that FBCU's response to AMPC/CEC 1.4.2 (Exhibit B1-15) outlines the savings of natural gas over electricity for space heating (and to a lesser extent water heating) and demonstrates a trend that continues to widen. In their view, this information demonstrates that FEI is the beneficiary of both a reduction in gas prices and rising BC Hydro rates. (AMPC/CEC Final Submission, pp. 11-16)

In Reply, FBCU argue that using November 2009 rather than July 2009 is a more appropriate point of comparison and represents a variance of less than 3 percent. They also point out that this difference has been insufficient to drive behavioral changes in new and existing customers. (FBCU Reply, p. 14)

Figure 3: Delivered Cost of Natural Gas

Figure 34. FEI Lower Mainland Annual Residential Bill History (Rate Schedule 1)



(Source: Revised Exhibit B1-9-6, Appendix H, p. 51, Figure 34)

Additionally, FBCU state that they have not suggested that there is an increase in price volatility, but rather they have fewer tools to deal with it. Overall, FBCU submit that commodity price volatility is a risk factor which remains undiminished since 2009. (FBCU Reply, pp. 14-15)

Commission Determination

The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk. **The Commission Panel finds that there has been some reduction in the level of risk associated with the competitive position of natural gas as compared to electricity.** It is difficult to reach any other conclusion given there has been a reduction in the total billing costs while over the same period the cost of electricity has risen regardless of the timeline one chooses for comparison. The evidence relied upon by the interveners in Figure 1, which details the growing variance between natural gas and electricity, is persuasive and it is unlikely that a price conscious customer would move away from natural gas in these circumstances. Looking ahead, and relying upon the information in Figure 2 above, the Panel notes that in spite of the range considered to fall under the 95 percent interval band, the September 4, 2012 AECO Forward Curve projects relatively stable natural gas commodity costs looking out to 2017. While hardly definitive, this does point to some level of stability over the next few years.

Notwithstanding these favourable conditions, the Commission Panel does place some weight on the lack of change in the purchasing behaviour of new and existing customers. In our view, some of this relates to the higher capital costs required to convert to or install natural gas service and the move to multi-family dwellings, which is discussed in Section 4.2.4.

FBCU state that price volatility is a risk factor that remains undiminished since 2009. Based on the evidentiary record we agree. However, we are not in agreement with the assertion that FEI have fewer tools to manage volatility. In the PRMP Decision, the Commission Panel offered a number of suggestions or options FEI may wish to consider. Included among these was offering the PRMP program to existing customers on a permission basis. There is no evidence before the Panel to indicate any action that FBCU has taken to bring alternatives forward.

4.2.4 Customer Growth

Submissions by Parties

FBCU note that a continuing trend has been its lower capture rate on new construction and reports a decline in the rate of net residential customer additions when 2011 is compared against 2007. In addition, the FBCU submits that new customer usage is roughly half what it used to be and therefore, the trend that existed in 2009 has not changed. FBCU states that this trend is closely associated with growth of multi-family dwellings in BC, a market where FEI has low penetration driven by unfavourable installation economics. This shift toward multi-family dwellings means that FEI's capture rate will further decline over time. (FBCU Final Submission, pp. 50-51; Exhibit B1-9, Appendix H, pp. 33-37)

AMPC/CEC point out that in spite of the challenges faced by FEI in growing customers, its total customer base continues to grow. The number of residential customers grew by 8 percent over the period 2005-2011 and the number of commercial customers grew by 5 percent over the same period while there was some decline in the number if not the consumption of industrial customers. (AMPC/CEC Final Submission, pp. 16; Exhibit B1-11, BCUC 1.4.4)

Commission Determination

The Commission Panel notes that the circumstances related to unfavourable installation economics and the shift toward multi-family dwellings existed at the time of the 2009 Decision. In spite of this, the total number of customers continues to grow if not the market share of potential new customers. **Therefore, the Commission Panel finds that there is no persuasive evidence to suggest there has been a shift in risk related to customer growth.**

4.2.5 Impact of Alternate Energy Services on FEI

Submissions by Parties

FBCU state that the "adoption of energy forms produced in combination with newer technologies represents a challenge to FEI's core business for providing natural gas for space and water heating." The recent number of energy projects approved serves to demonstrate the momentum behind alternative energy which FBCU rate in the number 2 risk category. In FBCU's view, the growing consumer awareness of alternative energy and its green attributes and increasing cost effectiveness demonstrate the importance of this risk factor for FEI. (FBCU Final Submission, p. 52; Exhibit B1-9, Appendix H, p. 28)

AMPC/CEC argue that this represents double counting and there is no evidence to suggest that there is more risk posed by alternative energy to FEI than that which existed in 2009. Further, they argue that the new transportation technology will result in improved prospects as it allows natural gas to replace diesel in heavy trucking thereby increasing natural gas demand in the future. (AMPC/CEC Final Submission, p. 18)

Commission Determination

The Commission Panel notes that the impact of AES sources on FEI is not a new risk. However, we do acknowledge that in the three years since the 2009 proceeding, there has been greater momentum behind alternative energy forms and the adoption of new technology related to them. Therefore, the Panel is mindful that there is the potential for an increase in risk related to AES but, given that much of this risk has been accounted for in reference to FBCU's share of multi-family dwellings, it is difficult to quantify.

4.2.6 Market Demand and Throughput

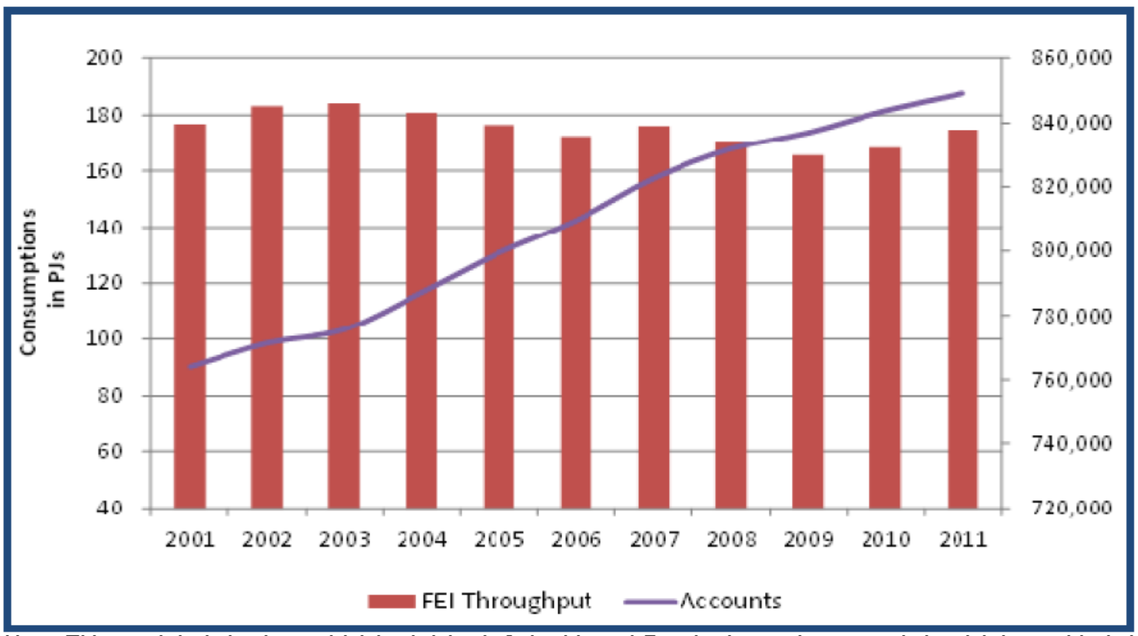
Submissions by Parties

The FBCU state that FEI's use per customer (UPC) for both new and existing customers has been declining; this trend, based on a Conservation Potential Review Study, is expected to continue until 2030. Contributing to this decline are a variety of factors including technological advances and energy efficiency improvements. In addition, the decline in UPC can, in part, be attributed to increased efficiency standards, better building envelopes and a move to smaller dwellings. Further, FBCU state that new construction research since the 2009 hearing shows that natural gas has been increasingly used as a secondary fuel source in new homes rather than the primary source. The FBCU state that there is no reason to believe the drivers behind these market trends will cease. (FBCU Final Submission, pp. 52-53; Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

ICG states that Exhibit B1-41 shows that there has been no decline in system throughput since 2009. In addition, ICG asserts that there is an upward trend in industrial throughput, which is reflective of lower natural gas prices over the same period. Given this recent trend, ICG argues that the Commission should not accept the FBCU's 2013-2016 lower industrial throughput evidence and conclude that business risks are in fact lower than in 2009. (Exhibit B1-41, Undertaking No. 6, p. 3; ICG Final Submission, pp. 7-9)

BCPSO notes that the Commission acknowledged the risks related to throughput in its 2009 Decision and, as a result, they are not new. BCPSO, like AMPC/CEC, further submit that based on graphical information in Figure 4 below, the trend of declining throughput has reversed itself in 2009 and has increased each year since. (BCPSO Final Submission, pp. 13-14)

Figure 4: FEI's Total Throughput (Normalized Demand vs. Customer Accounts)



Note: This graph includes Lower Mainland, Inland, Columbia and Revelstoke service areas. Industrial demand includes both sales and transportation volumes.

(Source: Exhibit B1-9-6, Section H, p. 9)

AMPC/CEC submit that the evidence presented by FBCU shows that both commercial and industrial UPC has increased since 2009, while residential UPC has decreased only marginally.

AMPC/CEC further submit that as the Commission considers the issue of declining UPC, it should consider two points:

- The residential throughput would have to decrease by 83 percent in 2012 to drive its distribution margin to a level equal to BC Hydro Tier 2 Rates; and
- The negative trend related to the creation of energy efficiency is no different than that faced by BC Hydro.

AMPC/CEC argues that these energy trends are not new and there is only risk if they affect the utility's ability to earn a fair return which, in their view, is not supported by the evidence on the record. (AMPC/CEC Final Submission, pp. 16-18)

In Reply, FBCU submit that revenues related to increased throughput are largely unaffected due to the structure of industrial contracts that only generate additional revenue if consumption exceeds an agreed upon level. Therefore, the declines in residential and commercial UPC continue to have a disproportionate impact on FEI. FBCU also point out that AMPC/CEC's reliance on Tier 2 rates is inappropriate. In addition, they argue that the AMPC/CEC's position is based on the view that existing customers will not leave natural gas until there is no longer a price advantage. FBCU state that this assumption is unwarranted given recent research that people are less committed to natural gas, irrespective of price. (FBCU Reply, pp. 16-17)

Commission Determination

The Commission Panel finds that there is insufficient evidence to support a finding that there has been a shift in risk related to market demand and throughput.

The Commission Panel notes that the decline in UPC and overall throughput were issues raised in the 2009 proceeding. Based on the evidence in this proceeding, it is apparent that the overall throughput has increased since 2009 and UPC, while decreasing overall, has increased for both commercial and industrial customers. In the view of the Panel, these are all positive but not conclusive signs.

The Commission Panel places little weight on the FBCU submission that the increased throughput has not resulted in increased revenue due to the structure of industrial contracts. Notwithstanding our understanding that industrial contracts are subject to competitive negotiations, in our view, FBCU nonetheless has some control over the structure of and risks related to the contracts it negotiates.

The Commission Panel does not consider the research indicating existing customers are less committed to natural gas in spite of the price advantage to be persuasive. The Panel notes that much of the research referred to in this context was related to AES options, which have been considered as part of the growth of multi-family dwellings addressed in Section 4.2.4.
(Exhibit B1-9-6, Appendix H, FBCU Evidence, pp. 32-35)

4.2.7 Supply Risk

Submissions by Parties

FBCU's position is that BC's shale deposits do not guarantee a reliable supply of natural gas at reasonable prices. Due to the higher cost of development relative to other areas and a lack of infrastructure for resource development and market connection, FBCU state that growth of production in northeastern BC has stopped and there is risk of current levels declining. This is in contrast to developments like the Marcellus Formation in the northeast part of the continent that is thriving. FBCU submit that this leads to the possibility of stranded resources or, at a minimum, higher market prices and an expansion of access infrastructure to encourage expansion of BC's shale gas resources.

FBCU also submit there is a lack of new development of infrastructure to move gas to FEI's service territory. They argue that the development of gas transmission infrastructure projects connecting BC sources with Alberta and Eastern markets, combined with the potential for LNG exports, could change the historical pricing relationship between BC supply and Alberta production leading to higher consumer prices in the future. (FBCU Final Submission, pp. 60-61)

AMPC/CEC describe the potential for stranded resources in northwestern BC as nonsensical. They submit that the impact of shale gas development on prices was not recognized, as it was not mentioned in the 2009 Decision. They also refer to the following statement of Ms. Des Brisay in the current proceeding:

> "What was not fully understood is how low the cost could be in terms of how we produced that resource, and that's really where we have seen the shifting of the curve has been as we have a better understanding of the economic feasibility of the development of shale gas reserves in different parts of North America."
> (T2:161)

Therefore, AMPC/CEC argues the existence of reserves may have been known in 2009, but the understanding of the economic feasibility of development has shifted since then. (AMPC/CEC Final Submission, p. 19)

AMPC/CEC submit that any weight the security of supply factor deserves pales when compared to the availability of supply. The Commission Panel notes they did not comment directly on the potential change to the historic pricing relationship between Alberta and BC. (AMPC/CEC Final Submission, pp. 18-20)

As noted previously, FBCU acknowledge that shale gas has been a "game changer" and that supply risk has declined. They did make the following points:

- There was knowledge of natural gas reserves prior to the 2009 proceeding.
- The price of natural gas must be higher (leading to higher rates) before supply will be extracted.
- FEI's ability to access cost effective supply could be challenged as there are competing markets for natural gas.

FBCU argue that it is the factors affecting demand for delivered natural gas, not energy supply considerations, that are the key supply risk for FEI. (FBCU Reply, pp. 19-20)

Commission Determination

The Commission Panel finds that there has been a decrease in the risk associated with the supply of gas but an increase in the risk associated with access to this gas at low prices. Balancing the two, there has been no material change in the level of risk related to energy supply.

The Commission Panel accepts the statement of Ms. Des Brisay as informative and a reasonably accurate reflection of where matters stood at the time leading up to the 2009 Decision. There is clearly no disagreement among the parties with respect to the existence of adequate supply of natural gas and FBCU have conceded that the actual supply risk has declined. Therefore, the issue is not whether natural gas will be available but whether sufficient natural gas will be available at the low commodity price levels that the consumer has come to expect. To this end, FBCU have laid out a number of facts and potential scenarios which they argue will have a significant impact on the supply of low cost natural gas. None of the interveners have challenged this information except AMPC/CEC who characterized the potential stranding of assets as "ludicrous."

In our view, the potential for some of FBCU's concerns to become a reality cannot be dismissed. The stability of the current environment remains uncertain, as does the magnitude of future development of the LNG business. Until this has been determined, the continuity of current low price levels for natural gas will be at some risk. However, the risk of supply to the extent that it existed, has abated and shifted to the risk associated with maintaining existing commodity price levels with no resulting increase in overall risk.

4.2.8 Regulatory Risk

Submissions by Parties

FBCU has ranked regulatory risk as their highest risk area with a number of factors in the "higher risk" category. In assigning this weighting, FBCU states that FEI is dependent on regulatory approvals that determine its revenue requirements, cost of service recovery and approval of investments. FBCU submit that the pace of change in the energy policy and environment has increased at a time when the Commission's role in implementing and applying policy has expanded. This has contributed to increased uncertainty in the regulatory environment and added process as compared to 2009. (Exhibit B1-9-1, Section H, pp. 5-6)

BCPSO points out the FBCU witnesses have confirmed that the regulatory environment is predictable and stable and regulatory risk should not be viewed as its number one risk factor. (BCPSO Final Submission, pp. 14-15)

AMPC/CEC questions the FBCU ranking of regulatory risk as there is no compelling evidence to suggest that FEI faces greater regulatory uncertainty than it did in 2009. (AMPC/CEC Final Submission, pp. 10, 20)

In Reply, FBCU acknowledge that the relative stability and predictability of the BC regulatory framework reduces regulatory risk. However, they point out that the breadth of the Commission's influence on FEI's business is undeniable and individual decisions can have significant implications for FEI particularly in the short-term. While they identify "regulatory risk as being 'higher,' any change since 2009 was not material to FEI's overall risk." (FBCU Reply, p. 12)

Commission Determination

The Commission Panel finds that there has been no material change in the level of risk associated with regulatory risk.

The Commission Panel accepts that the BC regulatory framework has a significant influence on FEI's business and that individual decisions can have significant implications for FEI. However, we agree with the parties that argue there has not been a material change since the 2009 Decision.

4.3 FEI's Short-Term Risk

There are two issues that must be considered by the Commission Panel with respect to short-term risk. The first is whether there has been a change in short-term risk since the 2009 Decision. The second is how much of FEI's short-term risk has been mitigated and, as a result, how much of the remaining risk must be considered. In the view of the Commission Panel, this will be determinative as to the level of weight to be placed upon the short-term risk in this proceeding. FBCU has expressed disagreement with the need to determine the level of short-term risk in reply to BCSPO submissions:

> "The Commission need not attempt to characterize or quantify FEI's short-term risk to determine a fair return for FEI. The question requiring a determination is the extent to which FEI's short-term risk has changed since 2009." (FBCU Reply, p. 9)

The Commission Panel disagrees. There are many measures of risk. The overall level of risk may not have changed substantially but one needs to consider the individual risk elements and their weighting. These may have changed and therefore, not considering them may be a mistake.

4.3.1 Change in Short-Term Risk

Submissions by Parties

The FBCU submit that short-term risk is essentially the same as in 2009. (FBCU Final Submission, p. 45)

Both FBCU and the interveners have focused their submissions on two areas in examining short-term risk:

- FEI's record of generally being able to earn its allowed ROE; and
- The amount of risk mitigation provided by deferral accounts.

Matters related to FEI's history of typically earning its ROE were dealt with in Section 3.3, where it was determined that actual earnings versus approved earnings history is more appropriately a matter for consideration in revenue requirements proceedings.

Concerning the use of deferral accounts, FBCU submit that "FEI's ability to manage short-term risk with deferral accounts is a function of the portion of the overall revenue requirement covered by deferrals, irrespective of the number of accounts providing that coverage." They also submit that there has been no material change in the collective scope of deferrals having an effect on earnings volatility. In the view of FBCU, their evidence on deferral accounts shows that the percentage of revenue requirements covered by deferral accounts has decreased and has resulted in a credit to customers. (FBCU Final Submission, pp. 38-45)

AMPC/CEC acknowledge that some of the additions in deferral accounts since 2009 are a reflection of accounting changes, but submit that three new accounts (Compliance to Emission Regulation Account, Customer Service Variance Account and Depreciation Variance Account) are significant. They further submit that while the new accounts may not represent a monumental change, they are an indication of FEI's ability to obtain such accounts. Therefore, this risk factor is lower today than in 2009. (AMPC/CEC Final Submission, p. 22)

BCPSO agrees with the submissions of AMPC/CEC and submits that the addition of the three new accounts demonstrates the Commission's willingness to mitigate the impact of short-term uncertainties. It concludes that the new accounts indicate short-term risk is no greater and likely less. In sum, BCPSO submit that short-term business risk is lower than in 2009. (BCPSO Final Submission, pp. 8-9)

FBCU, in reply, assert that the submissions of AMPC/CEC are at odds with the evidence of their witness, Dr. Booth, "who admitted that FEI risk hadn't changed "in the slightest."" The Commission Panel notes that Dr. Booth (T8:1475) was referring to ROE and not overall risk. FBCU conclude that short-term risk when compared to risk faced by its peers in other jurisdictions, remains unchanged. (FBCU Reply, p. 9)

Commission Determination

The Commission Panel, after reviewing the evidence, finds that there has not been a material change to FEI's short-term risk since the 2009 Decision. However, to the extent that there have been additional deferral accounts added, there is a greater ability to mitigate short-term risk. The Commission Panel agrees with BCPSO that the Commission's approval of the new deferral accounts demonstrates a willingness on the part of the Commission to mitigate the impact of uncertainty. However, in the Panel's view it is not important how the deferral account came to be. It is the effect. Therefore, the fact that the Depreciation Variance Account was ordered by the Commission, as noted by FBCU, in our view, is immaterial. More important is the fact that the deferral account now exists, as it reduces the risk associated with unforeseen variances in depreciation amounts.

4.3.2 Magnitude of Short-Term Risk

The second question to be considered by the Commission Panel with respect to short-term risk relates to the level of mitigation which has or could be applied against short-term risk. Much of the evidence related to this was focused on the use of deferral accounts which we explore below.

Revenue Related Deferral Accounts

The FBCU consider the overall risk for residential and commercial sales to be moderate and have assessed the risk of industrial sales to be high.

In 2011, residential and commercial sales accounted for 87.9 percent or $485.4 million of the total delivery margin revenue of $552.3 million. FBCU are protected for changes in use per customer for residential and commercial sales through the Rate Stabilization Adjustment Mechanism (RSAM). In assessing these risks as moderate, FBCU point out they are not protected for any differences in actual and forecast number of new customers in a given test period. The Commission Panel notes that impact of any variance in customer additions is likely to be minor, given the relatively small number of new customer additions as a function of the existing customer base. **Given the relatively heavy reliance on existing customers for most of the revenue and the existence of the RSAM, the Commission Panel finds the short-term risk related to residential and commercial sales to be low rather than moderate as suggested by FBCU.**

Industrial sales account for 12.1 percent or $66.8 million of the delivery margin revenue in 2011. FBCU assess the risk as high in this area because there are no deferral accounts utilized with this customer group. (Exhibit B1-20, BCUC 1.96.1)

In reviewing the submissions, the Commission Panel notes the following statement made by FBCU in reply to AMPC/CEC submissions: "Increased consumption by industrial customers only generates additional revenue if the consumption **exceeds a customer's fixed contract demand** (i.e., the 'take or pay' volume)." [emphasis added] Notwithstanding the impact on revenue as addressed in this statement, it appears to the Panel that the lack of deferral accounts in the industrial category is because there is no need as this area is run on a contract basis with a reliance on "take or pay" contracts. (FBCU Reply, p. 16) It is therefore evident that potential risk is mitigated to a large extend by the existence of such contracts. **For these reasons, the Commission Panel finds that a "high" risk rating for industrial sales is inappropriate and a moderate to low rating is more appropriate to the level of risk.**

Expense Related Deferral Accounts

Table 1 of the FBCU response to BCUC IR 1.96.1.1 indicates that in 2011, 75.3 percent ($1,160.7 million) of the FEI revenue requirement or 31.0 percent ($171.1 million) of the Revenue Margin Delivery Requirement was covered by way of deferral accounts. Overall, the single biggest expense item was cost of gas, which at $989.6 million is 100 percent covered by deferral mechanisms.

FBCU's Operation and Maintenance (O&M) Expense totalled $184.6 million. Of this, approximately 9 percent encompassing Pension & OPEB Variance, Insurance Variance and BCUC Levies Variance Deferral is covered by deferral accounts. FBCU rates the overall risk of O&M Expense as high citing the small portion covered by deferral accounts in explanation.

The Commission Panel also notes that of the remaining revenue requirements categories, Property and Sundry Taxes ($50.2 million), Financing Costs ($108.5 million) and Depreciation and Amortization ($99.9 million) are at or near 100 percent deferral account protection levels.
(Exhibit B1-24, BCUC 2.182.1; Exhibit B1-20, BCUC 1.96.1)

The most significant area not covered to a large degree by deferral accounts is O&M Expenses. O&M Expenses are also an area where there is a history of under spending approved O&M amounts. Under cross-examination, Mr. Dall'Antonia explained that risks at the start of each test year are the same and the success of managing within budgets can be attributed to management's experience and being sound managers. (T3:344) While the Commission Panel does not take issue with Mr. Dall'Antonia's comments, we are of the view that in addition to this, FEI has a broad range of options available to it to manage O&M budgets effectively. For example, many of the initiatives in an approved O&M plan can be postponed for short periods or in some cases not implemented within the test period. This could include items such as routine maintenance, new staff additions, replacement of staff vacancies or delaying of new programs or initiatives. This may, in part, account for the fact that O&M expenditures were less than forecast in 8 of the last 9 years. (Exhibit B1-24, BCUC 2.182.1) Therefore, in the view of the Commission Panel, this is an area where FEI has a high degree of control. **Accordingly, the Commission Panel finds that a high risk rating for O&M expenses is not appropriate and a moderate to low rating is more reflective of the risk FEI faces.**

Another area with a high risk rating due to limited use of deferral accounts is Other Operating Revenue which encompasses things like late payment charges, NSF cheques, and connection charges. This item has been in the $20 to $25 million range over the last nine years, which is a relatively small part of revenue requirements. However, as outlined in Undertaking No. 8, there have been consistent negative variances (meaning revenues were less than approved) in the $2 million range for all but the most recent completed year. (Exhibit B1-24, BCUC 182.1; Exhibit B1-20, BCUC 1.96.1; T2:293-294; Exhibit B1-43)

The Commission Panel acknowledges that many of the Other Operating Revenue areas are less predictable and controllable in nature and most items are not covered by deferral accounts. Therefore, the Commission Panel finds that a high risk rating is appropriate.

Commission Determination

Given our findings with respect to revenue risks and risks in expense areas not covered by deferral accounts, the Commission Panel is not persuaded that on balance FEI faces significant short-term risks to its achieving its allowed ROE in a given test period. While including items that are less predictable or controllable, the Other Operating Revenue item generally shows a consistent pattern of under earning revenues. However, their impact on the total revenue requirements is relatively small. **Therefore, acknowledging that there has been little change in short-term risk since the 2009 Decision, the Commission Panel has determined that only minimal weight can be given short-term risk as an impediment to earning a fair return.**

4.4 Developing an Optimal Capital Structure

An important component of the Panel's task is to determine an allowed capital structure. This section is devoted to the discussion of the evidence presented that relates to the capital structure decision and presents the Commission Panel's findings. In this section, we set out the context within which this evidence has been considered.

4.4.1 Capital Structure and the Fair Return Standard

Background on the role of capital structure on the cost of capital is provided in the Brattle Report, which recognizes that "underlying asset risk in each company is typically divided between debt and equity holders – making them derivatives of the underlying asset return." In addition, the result of a specific capital structure is a particular Weighted Average Cost of Capital.

$$WACC = r_d(1 - T_C).\frac{D}{V} + r_E\frac{E}{V}$$

where: r_d = market cost of debt; r_E = market cost of equity; T_C = corporate income tax rate; D = market value of debt; E= market value of equity; and V = the market value of the firm (i.e., V= D+E).

(Exhibit A2-3, pp. 38-40)

This cost of capital reflects the equity risk and the debt risk, both of which in turn reflect both operating and financial risk, as well as the tax advantage of debt.

The integration of the capital structure decision with the ROE decision is recognized in the argument of AMPC/CEC:

> "Capital structure is important for two main reasons: (1) the cost of equity is higher to reflect the greater risk of investing in shares as opposed to bonds, and (2) the cost of debt (interest) is tax deductible, whereas the cost of equity (dividends) is paid out of after-tax income. Consequently, equity is substantially more expensive than debt. . . . FEI's customers have a right to expect that its capital structure will be efficient and the common equity component will reflect the real risks equity shareholders are exposed to." (AMPC/CEC Final Submission, p. 32)

Ms. McShane submits that the inter-dependence between capital structure and ROE is largely based on the FRS with its three requirements i) the ability to attract capital on reasonable terms, ii) maintenance of financial integrity; and iii) comparability of returns. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 34)

These considerations translate into a focus on credit metrics and the need to maintain a particular credit rating. The FBCU does, however, discuss at length the possible disruptions that might take place if FBCU experienced a rating downgrade. AMPC/CEC submit that FBCU's credit metrics are not weak and that a 35 percent common equity ratio (as compared to its existing 40 percent ratio) "is entirely consistent with the objective of maintaining FEI's existing credit rating." (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 35-37; FBCU Final Submission, pp. 12-15; AMPC/CEC Submission, pp. 32, 34-36)

4.4.2 Commission Panel Discussion

The Commission Panel accepts the view put forth by AMPC/CEC that the capital structure should be set efficiently. The Panel also notes that debt comes with advantages, primarily the deductibility of interest payments from taxes.

At the same time, the Commission Panel recognizes the argument made by FBCU that the excessive use of debt could disrupt the operations of the company by making it difficult to finance the ongoing operations.

The Commission Panel accepts, therefore, that there are both expected benefits and expected costs associated with the use of debt. The task faced by the Panel is to determine the 'optimal' capital structure, one that is efficient in reducing the total or WACC through the use of debt without creating potential financing disruptions that could offset these benefits to the point where the net benefit is reduced.

The discussion of the capital structure evidence and determination found in this section reflects the Panel's desire to find an efficient or optimal capital structure. In doing so it applies the following principles to guide its analysis:

1. While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of the attendant costs and benefits.
2. The long-run risks discussed by all parties are important considerations in determining an optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management. Since the concern is with financial disruption, both diversifiable and non-diversifiable risks must be recognized in assessing the risk of financial disruption.
3. The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility. It is in this sense that the Panel agrees with FBCU's view that FEI is not a diversified investor. (FBCU Final Submission, pp. 130-131) As discussed in Section 5, however, this does not imply that the Panel accepts this view with regard to the ROE.

4.5 Credit Ratings and Metrics

An important issue for the Commission Panel is to determine how important it is for FEI, as the benchmark utility, to maintain an "A" category credit rating among credit agencies. Credit ratings are important indicators of potential financial disruption as discussed in Section 4.4. A lowering of credit agency ratings raises concerns about the cost of debt and access to the credit market at reasonable cost. Therefore, there are clearly advantages of maintaining an ROE and capital structure which will allow for existing credit agency ratings to be maintained. However, the Commission Panel must consider whether there is a point where maintenance of a particular credit rating may result in a capital structure or ROE that is suboptimal in the circumstances. In such instances, what importance should the Commission Panel place on the maintenance of a credit rating and at what additional cost?

Presently, FEI is rated by Moody's and DBRS, with Moody's providing the lower credit rating at A3, which is just one level above a Baa rating. DBRS provides a slightly higher A rating, which is comparable to a Moody's A2 rating. (Exhibit B1-58) The Moody's rating is considered to be more vulnerable to a downgrade due to weaker credit metrics, which, with further deterioration and a less predictable and supportive regulatory environment, could result in a drop to the Baa rating. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 59) This Baa rating could reduce the financial integrity of FEI by reducing its ability to maintain credit and access capital on as reasonable terms as an A3 rating.

The Commission determined in the 2009 Decision that Moody's rating should be the focus of attention because it was the lower in the group, and that the Moody's A3 rating should be maintained with a margin of cushion to ensure the financial integrity of FEI. (2009 Decision, p. 15)

None of the interveners took the position that FEI's 'A' rating should be jeopardized. AMPC/CEC submit that a reduction of the ROE to 7.5 percent at the existing 40 percent equity ratio would still leave FEI with strong credit metrics, including a cash flow coverage ratio of 2.67, and that a combined ROE reduction to 7.5 percent and lower equity ratio to 35 percent would leave FEI with a 2.35 ratio, which would still be above Moody's stated threshold of 2.3 to maintain the A3 rating. (AMPC/CEC Final Submission, pp. 35-36)

FBCU state that their current credit metrics are already weak for the existing rating and that the combined reduction in ROE and equity ratio as suggested by AMPC/CEC would not allow it to have a margin of comfort. (FBCU Final Submission, p. 15) FBCU also state that Moody's assessment of regulatory support had already weakened because of BC provincial energy policy. (T3:366) FBCU further state that under the Trust Indenture, Dr. Booth's recommendation would result in a coverage ratio of approximately 1.97. (FBCU Final Submission, p. 77)

Ms. McShane noted that the importance of 'A' category credit ratings arises from two factors: market access and cost. With respect to market access, Ms. McShane testified that regulated issuers can at times be closed out of the market if they have less than an 'A' category rating. Ms McShane further testified that "during the period June 2008 to January 2009, there was not a single issuer without at least one "A" credit rating who was able to issue long term debt <u>on any terms</u> in the Canadian market." With respect to cost, Ms. McShane states that in addition to market access issues, a rating downgrade would result in a cost increase to additional debt the company needs to raise. Further, it will also affect all of the utilities' outstanding debt as the increased cost of new debt will increase the required yield on existing debt and reduce the value of that debt. This higher cost of debt to the utility results in a higher cost of debt for ratepayers.
Ms. McShane further submits that institutional investors continue to have limits upon the amount of 'sub A' category debt they are able to hold or are restricted from holding Baa/BBB debt at all. This underscores the importance of 'A' credit ratings given the relatively small size of the Canadian market for Baa/BBB debt. (Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 35-37)

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36**)**

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

4.6 Other Jurisdictions

There is general agreement among the parties that the major natural gas utilities in Canada should serve as comparables for FEI for the purposes of assessing FEI's capital structure. This group which includes ATCO Gas, Union Gas, Enbridge Gas Distribution and Gaz Metro was used extensively throughout the proceeding as comparators. Dr. Booth also identified Nova Scotia Power Inc. as a reasonable comparator, being a province-wide integrated electric utility.

The equity thickness ratios of the comparator group of utilities are listed below in Figure 5. The equity ratios of the Canadian comparator group range from 36 percent to 39 percent in contrast to Dr. Booth's recommended equity ratio of 35 percent and FEI's current equity ratio of 40 percent:

Figure 5: Canadian Comparative Utility Equity Ratios

Company	Equity Ratio (%)
FEI	40.00
Dr. Booth on FEI	35.00
ATCO	39.00
Union Gas	36.00
Enbridge Gas Distribution	36.00
Gaz Métro *(*Quebec)*	38.50

(Source: FBCU Final Submission, p. 78)

While there is common agreement as to comparable gas utilities, there is considerable disagreement among the parties as to what these comparables suggest about FEI's required common equity ratio. (FBCU Final Submission, p. 78)

4.6.1 FEI Risk Level Relative to Alberta and Ontario Utilities

FBCU submit that the Commission should find that FEI faces higher long-term risk than natural gas distribution utilities in Alberta and Ontario for the following reasons:

- Alberta and Ontario marketplaces are more favourable from the perspective of supply and infrastructure for natural gas, overall marketplace liquidity, the number of storage facilities and pipeline companies that operate in the regions, and overall gas flows;
- Electricity costs in Alberta and Ontario are not heavily influenced by low embedded costs of "heritage hydroelectricity;"
- Eastern based utilities, by virtue of their proximity to the Marcellus Formation, have seen greater benefits from shale gas than FEI;
- The growing prevalence of multi-family dwellings in BC. The FBCU note that in a hearing before the Alberta Utilities Commission in 2011, Dr. Booth described this "condification" as a "significant competitive pressure;" and
- Government policy and legislation is a long-term risk factor for FEI. Among the provinces, BC is at the forefront of GHG reduction initiatives.

(FBCU Final Submission, pp. 77-81)

FBCU point out that regardless of the analysis relied upon by Dr. Booth, his approach ended up recommending a 35 percent common equity ratio for all Canadian Utilities excepting Gaz Metro. (Exhibit C6-12, AMPC/CEC Evidence, Dr. Booth Evidence, p. 43) In this instance, FBCU had the following concerns with the analysis leading to his recommendation of 35 percent:

- Absent from the comparison was ATCO Gas which was the highest comparator at a 39 percent common equity ratio. FBCU notes that Dr. Booth puts ATCO Gas in the same risk category as FEI and perhaps a little riskier.
- There was no reference to Gaz Metro's deemed preferred shares in his portraying them as having a common equity ratio of 38.5 percent. This effectively understated Gaz Metro's effective deemed common equity ratio.

(FBCU Final Submission, pp. 77-82)

AMPC/CEC submit that all of the comparators have common equity ratios that are below the current 40 percent common equity ratio of FEI. They also concede that at 38.5 percent, Gaz Metro is at the top of the range. However, they submit that Gaz Metro is in a far more difficult and risky climate than FEI, given FEI's advantage over electricity is 5 times as great as that of Gaz Metro. AMPC/CEC conclude that a common equity that is the same or greater than Gaz Metro's 38.5 percent would be unreasonable on comparative terms. (AMPC/CEC Final Submission, pp. 33-34)

FBCU submit that neither BCSPO nor AMPC/CEC made any attempt to reconcile the inconsistencies in the comparative analysis among Canadian utilities' capital structures. FBCU further submit that Dr. Booth's submission "that ATCO Gas risk was in the same risk bucket or slightly less risky than FEI" is significant because it suggests that the 40 percent common equity ratio for FEI is justified as ATCO has a 39 percent common equity ratio. (FBCU Reply, pp. 24-25)

Commission Determination

The Commission Panel has previously considered this matter in Section 3.2. The Panel has considered the common equity ratio decisions of other Canadian jurisdictions. **However, because each province is different in terms of its levels of regulatory protection and each utility has its own set of unique circumstances which are only minimally covered in the record of this proceeding, the Commission Panel has determined that only limited weight is to be given to the outcomes of proceedings in other Canadian jurisdictions.** Accordingly, evidence related to the equity ratios of other jurisdictions is used as a reference point only in determining whether FEI's is in an appropriate range.

4.7 Capital Structure – Commission Determination

The Commission Panel has determined that a common equity ratio of 38.5 percent is appropriate for FEI effective January 1, 2013.

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009.

The Commission Panel notes that the 2009 Decision put considerable emphasis on the uncertainty created by climate change legislation that did not exist during the previous cost of capital proceeding. In addition, the 2009 Decision acknowledged the change in the competitive position of natural gas versus electricity but concluded that there were too many variables at play for this to be considered permanent. The Panel's finding that there is lower long-term risk related to both of these factors since 2009 is indicative of a reduction in overall risk to FEI which needs to be reflected in the common equity ratio.

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

Considering the discussion of optimal capital structure in Section 4.3, the Commission Panel notes that the reduction in common equity ratio to 38.5 percent is reflective of reduced long-term risk and yet balances this against potential disruption caused by a significant weakening of credit metrics.

With respect to credit ratings and metrics, the Commission Panel notes that considerable concern has been raised concerning FEI's credit metrics. In Section 4.4 we found the evidence supportive of maintaining an "A" category credit rating but not at all costs.

The Commission Panel notes that the 38.5 percent equity ratio awarded FBCU in this proceeding falls within the upper end of a range of comparative utilities in other Canadian jurisdictions and considers it to be reasonable on a comparative basis.

FEI is to file within 30 days of this Decision and the accompanying Order G-75-13 a document setting out how and when it will implement the change to its capital structure.

5.0 RETURN ON EQUITY

5.1 Key Issues

The Commission Panel is of the view that an important consideration in this proceeding is the determination of a return that provides investors with the opportunity cost of their investments. The Brattle Report recognizes and elaborates on this fundamental principle:

> "[The cost of capital is] Defined as *the expected rate of return in capital markets on alternative investments of equivalent risk,* it is the expected rate of return investors require based on the risk-return alternatives available in competitive capital markets. Stated differently, the cost of capital is a type of opportunity cost: . . ." (Exhibit A2-3, pp. 2-3)

However, even if one accepts the concept of the opportunity cost as a foundation of a Return on Equity determination, a remaining challenge is that risk and expected return of the relevant 'alternative investments of equivalent risk' are in the eyes of investors who have access to well functioning capital markets. These expectations are not directly observable to Panel members or to parties in this proceeding who provide evidence for the Panel to consider. Instead, estimates of investors' expectations are based on data that are interpreted through *models* of competitive capital markets. The Panel finds an observation offered in the Brattle Report to be instructive:

> "It is useful to recognize explicitly at the outset that models are imperfect. All are simplifications of reality and this is especially true of financial models. Simplification, however, is also what makes them useful. By filtering out various complexities, a model can illuminate the underlying relationships and structures that are otherwise obscured." (Exhibit A2-3, pp. 3, 5-6)

The evidence presented to the Panel was based on a large variety of specific models that fall into four broad classes: (i) DCF models; (ii) CAPM (iii) ERP models and (iv) CE models. Within these four classes are numerous specific implementations that vary in structure, assumptions, and the data from which they were estimated. For instance, there are multiple DCF models with multiple estimates of the appropriate opportunity cost of an equity investment in the Benchmark Utility FEI. The estimates of the investor's opportunity cost of equity, summarized in Appendix F to this Decision, range from 6.15 percent (Dr. Safir CAPM) to 11.50 percent (Dr. Vander Weide's FRP model.

The models and approaches used by the expert witnesses in this proceeding to estimate the ROE are summarized in Tables included in Appendix F of this Decision.

The key issue then in the determination of the appropriate ROE is assessing how much weight to give to each of these models and their estimates. In turn, the weight given to each estimate depends on a judgment of the validity of the conceptual base of the four broad model classes and a judgment of how reasonable the model inputs are. The Panel has based this judgment, as much as possible, on the objective of determining the opportunity cost of equity.

The Panel finds that the two most compelling frameworks for assessing the cost of equity are the DCF model and the CAPM. These models have well understood theoretical bases and explicitly recognize the opportunity cost of capital. Accordingly, these two models are given equal weight in determining the allowed ROE. As discussed in Sections 5.4 and 5.5, the ERP models (with the exception of Ms. McShane's CAPM based equity risk premium) and comparable earnings model are not based on compelling foundations. Furthermore, model inputs and estimates are largely *ad hoc* and assessments of the validity of these inputs and estimates are based on subjective evaluations with minimal logical guidance. Consequently, both the ERP and CE approaches are given no weight in the Panel's determination of the appropriate ROE for the benchmark utility.

5.2 The Capital Asset Pricing Model

The CAPM is based on consideration of individual investors making portfolio decisions in a well functioning capital market. As such, it is a model of the shareholders who own the shares of the firm. Of all the models used to present evidence to the Panel, we consider that the CAPM provides the underpinnings of investor choice in greatest detail.

The CAPM is based on portfolio theory, a theory that answers the question: If an investor wishes to achieve a particular rate of return and is able to invest in a large set of securities, what investment strategy will deliver the target expected return at lowest possible risk? (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 78) The somewhat surprising answer given by portfolio theory is that all investors will hold a combination of two mutual funds; one made up of all risky securities available, referred to as 'the market portfolio' and the second made up of risk free securities. In contrast to intuition, individual risk aversion will not determine which specific securities to invest in but will determine how much of an investor's wealth will go in the market portfolio and how much will go into risk-free securities. A more risk-averse individual will hold less of their wealth in the market portfolio and more in treasury bills than a less risk-averse individual.

The result that investors will hold well diversified portfolios instead of individual stocks provides great guidance in elaborating on the seminal Supreme Court of Canada decision of *Northwestern Utilities* that the allowed return on capital is to be comparable to the return that would be earned on "... the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise." (Exhibit A2-3, p. 2) The CAPM tells us that these 'other securities' are not other comparable firms but are instead comparable portfolios that combine the market and the risk free rate.

The Commission Panel notes that the reason investors are better off holding a mutual fund instead of picking individual stocks is diversification. Diversification builds on another bit of intuition: don't put all your eggs in one basket. As The Brattle Report states:

> "…when security returns are positively correlated (i.e., have a tendency to move in the same direction, to some degree), trade in capital markets allows investors to reduce their total risk exposure by holding portfolios, which serve to diversify the risk of the individual securities. Diversification permits investors to obtain lower variance for a given expected return or a higher expected return for a given level of variance, where variance of returns over time is a measure of risk."
> (Exhibit A2-3, pp. 6-7)

Since diversification is a driving force in investor's decisions, leading them to hold broadly diversified portfolios, when they consider the value of an individual stock they do not consider the total risk of the stock in isolation. They instead consider the amount of risk the stock will add to the risk of the mutual fund, recognizing the effect the stock has on the total diversification achieved. The amount of risk that remains after the benefits of diversification is referred to as non-diversifiable or systematic risk. The measure of the systematic risk is called beta. (Exhibit A2-3, pp. 6-7; Exhibit C4-9, p. 9; Exhibit B1-9-6, Appendix F, p. 88)

The CAPM builds on portfolio theory by providing a risk return relationship that recognizes beta as the risk measure. The theoretical foundation and the formulation of the CAPM is discussed in the evidence of Dr. Safir (Exhibit C4-9, pp. 8-11) and in the Brattle Report, which states:

> "The presence of a market underlies the "opportunity cost" interpretation of cost of capital – by investing in a security A, an investor foregoes (some) investment in an alternative, "comparable risk," investment B obtainable through the market." (Exhibit A2-3, p. 6)

The opportunity cost of an investment is based on the return on a risk free investment, which is the risk free rate. To this is added a 'risk premium'. In turn there are two parts to the risk premium. The first is the extra return that would be earned by holding the market portfolio on its own instead of the risk free security. The expected return on the market is denoted r_m and the risk premium over the risk free return, r_f, is denoted by (r_m - r_f). This is referred to as the 'the market price of risk' or the 'market risk premium'. The second component of the risk adjustment is beta which adjusts the market risk premium to account for the degree to which the individual stock contributes to the market risk; low beta stocks contribute less than average and earn less than the market rate, high beta stocks earn more.

The advantage of the CAPM is that it distils the complex interactions among risk averse investors trading with each other to a simple equation with three parts:

$$r_e = r_f + (r_m - r_f)\beta$$

where r_e is the opportunity cost of equity.

So, to estimate the investor's opportunity cost requires an estimate of the risk free return, the market risk premium and the beta. In spite of the CAPM's strong theoretical underpinnings, the estimation of these model inputs presents challenges as outlined in the Brattle Report (Exhibit A2-6, pp. 16-25) and in the evidence of Ms. McShane. (Exhibit B1-9-6, Appendix F, pp. 67-70) The challenges include the role to be played by the US data in the analysis.

The Panel recognizes the growing importance of US and indeed global securities in the portfolios of Canadian investors as pointed out in the evidence of Mr. Engen and of Ms. McShane. (Exhibit B1-9-6, Appendix E, pp. 11, 43-50; Appendix F, pp. A-14, A-15) The Panel also recognizes that none of the evidence was based on data related to global portfolios held by investors; for instance, market portfolios were defined as either the Canadian or US market separately and none of the evidence dealt with an integrated global portfolio. Furthermore, currency risk was not considered nor was the magnitude of foreign ownership of FEI. The evidence presented includes CAPM estimates on either US or Canadian data. In light of these concerns with respect to the lack of a complete global perspective and the potential for risk (including currency risk), the Panel concludes that the more appropriate of these two perspectives is that of the Canadian based CAPM. Therefore, the Panel places greater weight on Canadian based CAPM estimates.

The Panel received a great deal of evidence on various estimates of the following three inputs.

(1) The Risk Free Rate, r_f

Evidence submitted to the Panel indicates that, at the time of filing, returns available to Canadian investors on long-term Government of Canada default free bonds were in the 2.6 to 3 percent range. (Exhibit B1-9-6, Appendix F, p. 77; Exhibit C6-12, pp. 53-71) Although this return was available to investors and therefore seems to meet the requirement of an opportunity cost, all of the experts submit that the appropriate opportunity cost is better measured by the *forecasted* yield on a long-term risk free instrument and that in some cases even this estimate should be adjusted.

Estimates of the risk free return available to investors, based on forecasted long-term Government of Canada Bond Yields, range from a low of 2.95 percent estimated by Dr. Vander Weide (Exhibit B1-9-6, Vander Weide Evidence Appendix G, p. 35) to a high of 4.0 percent by Ms. McShane and Dr. Safir. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 77; Exhibit C4-11, BCUC 1.4.1) Dr. Booth submitted that 3.0 percent was the forecasted yield on long-term Government of Canada Bonds but he considers forecast long Canada bond yields of 3.0 percent to be "well below any 'equilibrium' yield since they are only 1% above the forecast inflation rate and mean locking in a negative real yield for a typical taxable investor." (Exhibit C6-12, p. 60) Dr. Booth testified in cross-examination that:

> "…we do have foreign official flows of money coming into Canada because we are a triple A rate country and they are basically buying Canadian government bonds, pushing up prices, pushing down yields, and pushing them down to a value that I do not think reflects the proper trade-off between risk and return by "an ordinary private investor" making these decisions." (T8:1516)

Accordingly, Dr. Booth adds 0.8 percent to the 3 percent to recognize the alternative, and to arrive at his "Base adjusted LTC forecast" of 3.8 percent. (Exhibit C6-12, pp. 84-85, 93; Exhibit C6-15, BCUC 1.30.3)

In summary, the evidence presented seems consistent in stating that the current rates available on risk free government securities is between 2.6 percent and 3 percent. However, the Panel also agrees with the experts that current monetary policy is historically unusual and subsequently results in the possibility of a higher effective risk free rate. **Therefore, the Panel determines that the estimate of 3.8 percent for the risk free rate is reasonable, corresponds to Dr. Booth's estimate, and is within the relatively narrow range of estimates presented by all experts.**

(2) Market Risk Premium (r_m - r_f)

Estimates of the market risk premium range from 5 percent to 6 percent according to Dr. Booth (Exhibit C6-12, Appendix B, p. 16) to a high of 7.5 percent submitted by Ms. McShane. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 98) The basic estimation methodologies used by all experts were similar in that they were based on historical data on market returns and returns on risk free securities. They differ in some important details.

Ms. McShane bases her estimate on the average return on an investment in the market and shows, in Table 10, page 80 of her evidence that the average return on equities in Canada over the 1924-2011 period is 11.4 percent. From this number, Ms. McShane subtracts the *current* forecasted long-term Government of Canada Bond yield of 4 percent to arrive at her 7.5 percent estimate of the risk premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 87) The Commission Panel understands that it is typical to base the risk premium on the average historical difference between the return on the market and the risk free rate. It is our understanding that this approach is to deal with, among other things, the fact that historical market returns and historical bond yields reflect historical inflation while current returns reflect current inflationary expectations. This is an especially important consideration in the current environment where inflationary expectations are at a historically low level. (T3:483-485; T5:713-715)

To illustrate our concern with the approach used by Ms. McShane, the Commission Panel notes that there are times in the last 30 years where this approach would have yielded a very small or even negative risk premium. For instance, Schedule 2 of Ms. McShane's evidence reports that the yield on Long-term Canadian Government bonds in 1990 was 10.69 percent. If this was subtracted from the average market return it would have yielded an unreasonably low market premium. (Exhibit B1-9-6, McShane Evidence, Appendix F, Schedule 2, p. 1; T8:716-717)

Ms. McShane was asked if she could provide a single reference to a textbook or Journal article that advocated using her approach. Her response was that she 'probably could not' (T5:717-718). Accordingly, the Panel gives no weight to the risk premium estimate of 7.5 percent provided by Ms. McShane.

Dr. Booth provides evidence that the historical risk premium is between 5 percent and 6 percent. He adjusts this range for 'Operation Twist' to obtain a risk premium estimate of 5.8 percent to 6.8 percent with a midpoint of 6.3 percent. (Exhibit C6-12, p. 93) Operation Twist refers to monetary policy intended to influence returns at various maturities including long maturities.

Dr. Booth provides two tests of the robustness of his estimate. One robustness test is to compare his estimate of the market risk premium with expectations used by FEI in assessing its defined benefit pension liability. Dr. Booth takes the expectation of market return of 7 percent, provided by FEI's consultants, and converts this geometric return to an arithmetic return. From this, Dr. Booth infers that FEI has, for purposes of valuing its pension liability, accepted an expected market return of 9 percent. Based on this he concludes, on page 93 of his evidence, that "[a]s a result, FEI's data seems consistent with a market risk premium of about 6.2%." In their Final Submission, FBCU submit that the Panel should not rely on data used in assessing pension liabilities. FBCU assert that, since actuaries provided the data, they naturally reflect a conservative bias. FBCU cited its witness Ms. McShane, who stated that pension fund managers and actuaries "... have absolutely no incentive to be anything but very conservative because they have a lot on the line. A pension fund needs to be able to assure that it has funds available to pay its retirees." (FBCU Final Submission, p. 151)

The Panel does not accept the assertion that the actuarial expectations are conservatively biased and should be rejected. Actuaries are charged with fairly assessing pension plan liabilities. The Panel finds, therefore, that this robustness test is indeed helpful in assessing the risk premium.

In a second robustness test, Dr. Booth uses the DCF model to estimate an expected return on the entire market. The resulting estimate is 9.3 percent and Dr. Booth notes that this is very close to the expectation held by FEI's own actuaries. (Exhibit C6-12, Booth Evidence, p. 86) This is a forward looking estimate of the market return so that a forward looking risk free investment can be used to compute the risk premium. Since Dr. Booth concludes in his first robustness test that a 9 percent market return implies a 6.2 percent risk premium, his estimates of 9.3 percent for the market suggests a market risk premium of about 6.5 percent.

FBCU argue that the DCF cannot be used to assess the market as a whole. (FBCU Reply, pp. 29-30) The Panel disagrees with this assertion. Although the model is typically illustrated and applied to a single company, the logic of investors setting prices based on expected cash flows applies equally to a mutual fund or portfolio of shares. The Panel, therefore, does not agree that this approach cannot be taken to estimate the expected return on the market. The Panel therefore finds the DCF based estimate of forward-looking market returns to be helpful as a check.

Other estimates of the risk premium were also in the range of 5.96 percent (Dr. Safir's Canadian estimate, Exhibit C4-9, p. 12, Table 1) to 6.6 percent. (Dr. Vander Weide's estimate, Exhibit B1-9-6, Appendix G, p. 38) **Given the preceding discussion, the Commission Panel accepts a market risk premium of 6.4 percent as it is within reasonable forecasts presented.**

(3) Betas

Evidence on the beta estimates is largely based on a standard approach of regressing returns from comparable firms on market returns. Since FEI does not have traded equity, estimates of beta must be based on comparable firms. In the evidence submitted, the set of comparable firms include Canadian firms as well as, in some cases, US-based firms.

Dr. Vander Weide submits a beta estimate of 0.92 based on the historical ratio of the average utility risk premium to the S&P risk premium. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 42) Aside from the fact that this is a beta estimate for US Utilities (T6:1092), the method differs significantly from the more commonly accepted method(s) of calculating a beta estimate as set out in the Brattle Report (Exhibit A2-3, pp. 15-16), and as calculated by the other witnesses in the proceeding. Accordingly, the Panel places no weight on this beta estimate.

The other beta estimates submitted range from a low of .36 by Dr. Safir for his Canadian CAPM estimate (Exhibit C4-9, pp. 12, 15), to a high of 0.65-0.70 by Ms. McShane. (Exhibit B1-9-6, pp. 97-98) Dr. Booth provides an intermediate estimate of 0.45-0.55. (Exhibit C6-12, Appendix C, p. 14) All estimates begin with a regression of returns of the comparator firm on market returns with the 'raw beta' being the slope coefficient of the regression.

The differences among estimates largely result from adjustments that are made to the raw betas. Empirical evidence indicates that the regression based beta estimates seem to understate the betas of low risk firms and overstate the betas of high risk firms. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 96; Appendix A to Ms. McShane's Evidence, pp. A-21-26; Exhibit B1-9-6, Appendix G, p. 41) Since, by construction, the beta of the market is one, the adjustments are intended to bring the estimated beta's closer to one. To accomplish this, Ms. McShane contends that it is appropriate to adjust utility betas towards the market average of 1.0. (Exhibit B-19-6, McShane Evidence, Appendix F, p. 96) Both Dr. Booth and Dr. Safir, on the other hand, contend that the adjustment should be to the utility average beta that is in the range of 0.5 - 0.6. (Exhibit C6-12, Booth Evidence, p. 71; Exhibit C4-9, Safir Evidence, p. 15)

None of the evidence presented revealed the actual bias in beta estimates; instead the experts assert a particular adjustment. In cross-examination Ms. McShane acknowledges that utility betas may indeed not trend towards one.

Mr. HOBBS: And because regulation protects companies, isn't it also true that you would not expect betas for utilities to ever trend towards 1?

Ms. McSHANE: To trend towards 1. I guess I don't disagree with that. I never said that they would. (T4:549)

Similarly, in cross-examination at T6:1073, Dr. Vander Weide says*:*

DR. VANDER WEIDE: Yes. And I readily recognize that betas for utilities don't adjust toward 1.0.

In their Reply, FBCU argued:

> "Ms. McShane's relative risk adjustment of 0.65-0.70 for a benchmark utility, based partly on adjusted betas, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 55% of the risk premiums achieved on the equity market portfolio. That experience is consistent with the empirical evidence that lower (higher) beta stocks generally have achieved higher (lower)

> returns than the CAPM and beta would have predicted. It is not logical to conclude that, based on that experience, utility investors now only expect to achieve an equity risk premium that is 45% to 55% of the equity market risk premium (or Dr. Safir's lower 36%) simply because utility share price movements have not exhibited a high degree of correlation with price movements in the overall equity market." (FBCU Reply, p. 35)

An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.

5.2.1 Adjustments to the CAPM

A number of experts raised concerns about the validity of the simple 'single factor' CAPM. The term single factor refers to the reliance of the prediction of the model on only the market portfolio, the factor implied by the theory. Ms. Ahern introduced in evidence a summary article that shows how other factors such as firm market capitalization (size) and market-to-book ratios can provide added explanatory power to the single factor CAPM. (Exhibit B2-7, Evidence of Ms. Ahern, pp. 13-14; Exhibit B2-7, Attachment PMA-1, Exhibit PMA-9)

The CAPM is by far the most widely studied asset-pricing model and it is not surprising that more is known about its empirical performance than other asset pricing models. This evidence also implies that improved performance can be achieved by including these well-studied extensions of the model. The Panel notes, however, that none of the experts relied on the extensions as found in the literature findings in dealing with the shortcomings of the single factor CAPM. (Ms. McShane, T5:720-722); Dr. Vander Weide, T6:1102-1108; Dr. Safir, T7:1259-1262; Ms. Ahern, T7:1355-1357; Dr. Booth, T8:1658-1663) Instead, the evidence presented by different experts responded to the relatively poor empirical performance of the CAPM in a number of *ad hoc* ways.

Dr. Vander Weide's response to the weak empirical performance of the CAPM is to place no weight on CAPM estimates even though he provides estimates himself. In cross-examination, however, Dr. Vander Weide testified that he did not attempt any standard adjustments to the CAPM that might improve performance. For instance, he did not adjust for the importance of international markets to Canadians, he did not adjust for changes in capital structure and he did not study the ability of a multi factor model to capture returns. (T6:1108-1111) As a result, the Panel does not accept Dr. Vander Weide's response to the relatively poor performance of the CAPM and continues to place weight on the model.

Ms. McShane and Dr. Booth both attempt to improve the performance of the CAPM by adding empirical analysis in order to augment the basic model. Dr. Booth is clearest in his objective when he states: "I regard this sort of adjustment as converting the CAPM into a conditional CAPM where the CAPM holds conditional upon the state of the financial markets." (Exhibit C6-12, p. 81)
Dr. Booth testified that an academic literature exists that supports the analysis of a conditional risk premium and his credit spread adjustment is consistent with that literature. (T8:1659)
Ms. McShane does not provide the same link to the academic literature and acknowledged, in cross-examination, that her work is along the lines of a multi factor CAPM. (T5:718-720)

The Commission Panel appreciates the efforts of the experts to recognize and deal with the shortcoming of the single factor CAPM. The evidence suggests there are two main thrusts to this effort: i) improving the estimate of the risk premium by conditioning on the current state of the capital markets; and ii) improving estimates of the risk return relationship by adding the factors to the single factor CAPM. Notwithstanding the efforts, the Commission Panel finds that we are not able to assess the validity of the extensions to the single factor CAPM that were presented as there is insufficient evidence involving the use of multi-factor models in this proceeding. The experts expressed reluctance to include other potential extensions to the CAPM that they thought were too complex. This is further addressed in Section 8.

In this regard, the Panel agrees more generally with the specific concern of ICG who argues that in Ms. McShane's CAPM based ERP, she "…makes an adjustment to the market risk premium of approximately 100-150 basis points because in her opinion market risk premium are in fact correlated with the risk free rate." ICG cites Dr. Safir as characterizing the adjustment as arbitrary and not in keeping with the CAPM model. ICG submits that before the Commission Panel accepts this adjustment there must be very strong evidence to support it. In the absence of such strong evidence, the CAPM specifications should not be changed. ICG goes on to say that: "The evidence regarding the correlation (inverse relationship) between the market risk premium and the risk free rate is in fact just that, it is a subjective judgement, with at best, very limited evidence in support of Ms. McShane's proposed departure from the CAPM model." (ICG Final Submission, p. 19)

In support of its argument that there is limited evidence in support of Ms. McShane's adjustment ICG submits that her evidence in support of a relationship between the market risk premium and the risk free rate is presented on a cumulative basis. It argues that when the same data is provided on a non-cumulative basis the US risk premiums do not follow income returns in the manner she suggests (Exhibit B1-53, Undertaking No. 14) and in some instances the data support the opposite conclusion to that observed by Ms. McShane.

Rather than relate the models presented in this hearing to the academic literature, as presented by Ms. Ahern for instance, the extensions seem to be somewhat *ad hoc* leading to the sort of concerns raised by ICG. There is no evidence, therefore that the models present were not the result of a "fishing expedition." That is, the Panel does not know if other adjustments or specifications would produce different results and we cannot assess whether other non-reported specifications should logically be ignored. In the absence of persuasive evidence that these are of value, the Panel is content to consider simple single factor models. At this time the Panel is not persuaded that the specific model extensions that are presented are valid and hence places no weight on them. However, the Panel recommends that in the future improvements in the model can also be brought into evidence, but the evidence should then include both the model extensions as well as a basis on which to judge the validity of the extensions.

5.2.2 CAPM Based Estimate of ROE

Summarizing the discussion above, the Commission Panel has applied the required judgment and accepts the CAPM estimate at 7.64 percent. This reflects a risk free rate of 3.8 percent, a risk premium of 6.4 percent, and a beta of 0.6.

5.3 Discounted Cash Flow Approach

The basis of the DCF approach is the principle that in a competitive market investors who purchase securities are essentially bidding for expected future cash flows that the security entitles them to. Competition implies that investors search for 'good deals', ones that offer the lowest price for a particular cash flow of a particular risk. The higher the price paid, the lower the expected return, so, in an attempt to improve their lot, investors search for securities that trade at a low price generating a high expected return. In their quest for high returns, they are willing to pay a price up to a level that would make the purchase at least as good as the next best alternative, i.e. equal to their opportunity cost. Of course, in a competitive market, other investors are also looking for good deals and, as a result, competition ensures that observed prices generate returns equal to the opportunity cost.

The theory implies that if one can observe prices and expected cash flows one can infer the investor's opportunity cost. The DCF model applies this logic to equity investment in order to infer the opportunity cost of equity. It is assumed that cash flows to investors consist of dividends and that stock prices reflect investors' expected dividends and the opportunity cost of the investment. If we observe prices of equity and estimate all future dividends that the equity gives title to, then one can infer the opportunity cost of equity. (Exhibit A2-3, pp. 26-29; Exhibit B1-9-6, McShane Evidence, Appendix F, Appendix C, p. C-1)

An attractive feature of the DCF model is that it assumes, unlike the CAPM, that investors hold realistic investment horizons; both short and long-term investors estimate all dividends that the firm will provide over its lifetime. As with the CAPM, a significant disadvantage to the Commission is that for FEI none of the inputs, for example, price, dividends, or opportunity cost, are directly observable. The equity of the benchmark utility is held by Fortis Inc. and not actively traded. Therefore, future dividends are in the eye of the beholder as is the opportunity cost of capital. As a result, the opportunity cost estimate rests entirely on inferences that are commonly based on comparable firms. Not only should these firms be comparable, they should also have actively traded equity, and a source for estimating expected dividends.

Simplifying assumptions make the task of estimating dividends easier and the evidence submitted was all based on one of two simplifications or models. The 'Perpetual Constant Growth' model assumes that investors estimate the next dividend to be paid by the company and a single rate at which dividends will grow in perpetuity. The validity of the constant growth model is reduced when the estimated growth rate comes close to the opportunity cost (as this implies an extremely large stock price) and the model is invalid if the expected growth rate is greater than or equal to the opportunity cost of equity. The second model, 'the multi-stage growth' model, also requires an estimate of the next dividend to be paid but then allows investors to see multiple stages of constant growth; for example, the investor might expect growth of 4 percent for the next five years, 3 percent for the 5 years after that, followed by a constant perpetual growth rate of 2 percent starting

11 years hence. Although the long-term perpetual growth stage must meet the same growth restrictions as the constant growth model, the earlier stages are not restricted in this way. Therefore, multi stage growth models allow considerable more flexibility in dealing with growth forecasts. The Commission Panel has considered DCF-based ROE estimates presented by Ms. McShane, Dr. Vander Weide, and Dr. Safir.[6] Dr. Booth's DCF estimate for the market as a whole was used as a check on his CAPM estimate and is discussed with that estimate previously in Section 5.2.

1) Ms. McShane's estimates

Ms. McShane provides five different estimates with ROE estimates based on the DCF model. The estimates range from 8.6 percent to 11 percent. The estimates were variously based on 12 US Utilities or 5 Canadian utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 113) FBCU submit that: "The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%)." (FBCU Final Submission, pp. 105-107) The FBCU also point out that Ms. McShane relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations, minimizing the need to superimpose on the analysis her own subjective view of growth expectations. (FBCU Final Submission, p. 106) Ms. McShane recognizes, however, that the forecast period for analysts' long-range earnings and dividend forecasts is typically three to five years over a business cycle (Exhibit B1-9-6, Appendix F, Appendix C, p. C-4), and that extending these forecasts into perpetuity in the constant growth model can overstate expected return. (T4:664-665)

2) Dr. Vander Weide's estimates

Dr. Vander Weide only presents evidence based on a constant growth DCF and only for a sample of US Firms. He relies on I/B/E/S Thomson Reuters Mean Growth forecasts to estimate dividend growth. Dr. Vander Weide's application of the DCF model to his comprehensive group of utilities produced a result of 10.3 percent, and to his smaller group of utilities, 10.0 percent, including 0.50 percent for flotation costs. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, pp. 27-31; Exhibits

[6] Dr. Booth employed a Constant Growth model but only to estimate the market wide expected return. This was used as a check on his CAPM estimate and so is not included in this discussion.

6 and 7 of his evidence) The FBCU submit that "…Dr. Vander Weide's DCF estimates are reasonable and should be given significant weight." (FBCU Final Submission, p. 108)

3) Dr. Safir's estimates

Dr. Safir uses a two stage DCF model to develop two estimates; one of 8.99 percent based on 5 Canadian firms and one of 8.86 percent based on a sample of 18 US utilities, before adding flotation costs amounting to 5 percent of the initial ROE estimates. (Exhibit C4-9, pp. 24-26, and Schedules 3 and 4)

Commission Panel Discussion

The Brattle Report observes: "The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence unlikely to correspond to reality." Elsewhere the report is more specific: "The major source of debate for the DCF model is determining the dividend growth rate, particularly for the long-term. There is generally no publicly available data on forecast growth rates for periods longer than 5 years." (Exhibit A2-3, p. 30)

The FBCU urges the Panel to give the DCF considerable weight, while the AMPC/CEC submits that "a DCF analysis can provide a helpful "check" on CAPM estimates, but the Commission should be cautious not to rely too heavily on it." (FBCU Final Submission, p. 89; AMPC/CEC Final Submission, p. 41)

The Commission Panel is of the view that, notwithstanding the concerns expressed about the approach, considerable weight should be given to the DCF but also accepts that caution should be used in assessing the growth estimates presented. A number of specific concerns arise with respect to the evidence presented:

a) **Reliance on analysts' short-term forecasts as the long run forecasts in constant growth formulas**:

This reliance appears in the single stage models presented by Ms. McShane and Dr. Vander Weide. For instance, Ms. McShane's estimate based on Canadian comparable firms assumes perpetual dividend growth of 7.5 percent. Since this is larger than her estimate for long run GDP growth of 4.3 percent, Ms. McShane seems to imply that FEI will grow to be an increasingly larger segment of the economy. This is inconsistent with the evidence presented in Appendix F of her testimony where she enumerates many reasons why consumers, both residential and commercial, will migrate from natural gas to other sources. Similarly, Dr. Vander Weide's estimates of the cost of capital use short-term analysts' forecasts to estimate the constant growth model. Similar to Ms. McShane, the resulting implication is that FEI will become a larger component of the economy over time, a conclusion that seems inconsistent with FEI's submissions regarding a shrinking market share and falling customer capture rates. (FBCU Final Submission, p. 53) We also note that Dr. Vander Weide included firms whose growth rate exceeded his estimate of the cost of equity in his comparable firms. As noted above, such a growth rate is inconsistent with the DCF constant growth model yet were included in his sample without adjustment. This calls into question the DCF estimates presented by Dr. Vander Weide.

The Panel finds that the use of analysts' forecasts is more consistent with the multi-stage models where the analyst forecasts can inform the early stage and longer term forecasts, such as of GDP growth, can inform later stages.

b) **Reliance on comparable firms operating in the US**:

The AMPC/CEC submits that the use of US based comparable firms renders DCF estimates of limited value. In their submission, AMPC/CEC cites Dr. Booth as follows:

> "[In the past] we had lots of pure play utilities in Canada, where you could do a DCF. In particular, all the local telephone companies were still regulated by the CRTC on a rate of return rate based method, and we had Island Telephone traded, Maritime Tel traded, NewTel traded, Bruncor Traded, Bell Canada traded, B.C. Tel traded. So we had a lot of traded rate of return regulated utilities that we could actually do DCF tests on. Unfortunately, they don't exist anymore." (T8:1493-1494)

While the Commission Panel concurs with the concern about comparability of US based firms, it also agrees with the argument of FBCU that, given the paucity of comparable Canadian firms, also recognized by Dr. Booth, augmenting Canadian data with US firms is appropriate. (FBCU Final Submission, p. 94) The Panel also recognizes the need for careful informed judgment in adjusting the US based estimates to reflect differences in the respective environments.

c) **Analysts' forecast bias**:

Given the heavy reliance on the forecasts of equity analysts, the AMPC/CEC submit that analyst bias may inflate DCF ROE estimates. (AMPC/CEC Final Submission, p. 59) FBCU argues that analysts' forecasts for utilities are not biased. (FBCU Final Submission, p. 111) The Brattle Report notes that studies have shown that analysts' forecasts are likely to be more accurate in utilities than in other sectors and bias is likely to be less in utilities than other sectors. (Exhibit A2-3, pp. 28-29)

The Panel finds that there is reason to be cautious of potential analyst bias in the utility sector. The expert testimony at this time does not, however, convince the Panel that an adjustment for analyst bias should be made. The Panel expects that future hearings will be informed of the latest research on bias in the analyst's reports on the utility sector.

Overall Assessment

The Commission Panel finds that the constant growth DCF models presented have growth assumptions that render the estimates questionable given the discussion above. Therefore, we place little weight on the submitted estimates that are based on the constant growth DCF. The estimates that the Panel found most helpful are Ms. McShane's multi-stage estimates in the range of 8.6 percent to 9.2 percent and Dr. Safir's estimates of 8.86 percent to 8.99 percent (two-stage). (Appendix F) Applying the appropriate judgment required, **the Commission Panel accepts an 8.9 percent DCF based estimate of the opportunity cost of equity.**

5.4 Equity Risk Premium Models

5.4.1 Introduction

FBCU's witnesses Ms. McShane and Dr. Vander Weide each provided results from various models, classified as equity risk premium models. Ms. McShane provided the results of three different 'types' of ERP models, comprising numerous estimates. Dr. Vander Weide used two types of ERP models, which he termed "Ex-Ante" and "Ex-Post" risk premium tests, and used two different samples for each of the two types of tests. None of the other witnesses relied on the ERP.

The Brattle Report summarizes the form and some of the issues concerning ERP models. According to the report, the ERP is frequently implemented using either a historical estimate of the risk premium or a forward-looking or expected risk premium. It notes that the historical risk premium is commonly estimated as the historical spread between equity and debt returns, so the primary choices for the analyst become which equity returns and debt instrument to use as well as the sample period over which the estimate of the spread (i.e., the risk premium) is to be based. The Brattle Report states that it is important that the analysis is consistent in its choice of a debt instrument to determine the cost of debt and that used to determine the risk premium. It also notes that the realized risk premium is highly dependent on the time period over which it is estimated, so that choice is also important. (Exhibit A2-3, p. 31)

The Brattle Report states that the forward-looking model requires that the analyst determine a proper measure of the cost of debt and how to estimate the expected risk premium. It says that because the yield to maturity of an investment grade bond serves as a proxy for the expected return, yield to maturity measures are natural candidates for the expected bond cost. However, determining the expected equity return is more difficult and requires the reliance on an estimation technique. It notes that it is common to rely on DCF models to determine the risk premium in the forward-looking version of the model. (Exhibit A2-3, pp. 31-32)

5.4.2 Discussion of the ERP Method and Results

The Brattle Report states that the risk premium model is a derivative of the CAPM so the comments that apply to the CAPM also apply to the Risk Premium Model, but that "…the Risk Premium Model does not have the same level of theoretical support. The tie between theory and implementation is weakened because the interest rate in the Risk Premium Model is not necessarily equal to the risk-free rate and the risk premium is not explicitly based upon the product of the investment's beta and the MRP." (Exhibit A2-3, p. 33) Moreover, there is a concern that the historical risk premium approach to the ERP assumes that a historically realized risk premium is an appropriate measure for expected returns, but that over any given period, especially short periods, realized returns can differ substantially from expected returns. (Exhibit A2-3, p. 31)

A strength of the model identified in the Brattle Report is that the information on which the model relies is auditable. However, it notes that because inflation and other factors that are not directly related to the cost of equity capital may affect bond yields, the model will not necessarily produce like results for like conditions. It further states that the implementation of the model largely determines its ability to capture the systematic risk of companies, noting that, unless a forecasted return for relevant companies is used, the model will be unable to estimate reliably the cost of capital across different economic conditions. (Exhibit A2-3, pp. 34)

Commission Determination

The purpose of a rate of return model is to provide structure to the discussion of 'what a fair rate of return is.' Models used to assess this question provide structure and clarity and, in turn, a basis for the data to consider the appropriate interpretation to give it and the estimates.

The lack of a strong theoretical footing for ERP, as noted in the Brattle Report, may explain the large number of ERP estimates submitted to the Panel and the potentially intractable discussion of the merits of the models. There is simply little to help focus the analysis and as a result many models can be submitted as 'true' even though there is little on which to judge the validity of the submission.

The large number of estimates along with the absence of a compelling framework raises the following reservations about the estimates and indeed about the entire approach:

1. The models combine elements of the CAPM and the DCF with other ad hoc adjustments. Since evidence was presented on both the CAPM and DCF, it is not clear what is added by looking at these alternatives.

2. While it is not clear what is gained through these ERP models, it is clear that clarity is lost. In particular, the assumptions used in various estimates are difficult to evaluate. Ms. McShane, for instance, uses return estimates based on a sample of US firms with the 30-year Canada Bond rate in some estimates of the risk premium but in others uses 30-year A-rated utility/government bond yield spreads. (Exhibit B1-9-6, Appendix F, p. 99) Similar ad hoc assumptions are also found in Dr. Vander Weide's analysis. For instance, AMPC/CEC point to Exhibit C6-21 to demonstrate that if bond returns rather than bond yields were used in the analysis, the average Ex-Post risk premium for utilities would be approximately 4.47 percent or 2.3 percent less than Dr. Vander Wiede's estimate. Consequently, the AMPC/CEC argues that the Ex-Post estimates of Dr. Vander Weide must be ignored or if not ignored, then reduced by 2.3 percent. However, FBCU state that it is appropriate to use bond yields as the true risk-free rate. It is not clear, however, why the risk free rate is not estimated using a risk free return.

   Again, while judgment is always needed to evaluate estimates, without a theoretical base, there is no consistent way in which these differences of opinion can be assessed.

3. Since the model variations are ad-hoc they are subject to the concern that they may be subject to a "fishing' expedition" criticism. In contrast, while we can obtain various results from the CAPM or DCF models by changing parameters such as the risk premium in the CAPM or the growth rate in the DCF, the reasonableness of the selected parameter can be questioned.

Given these concerns along with the fact that there is ample evidence on both CAPM and DCF based estimates, the Panel places no weight on the ERP estimates submitted.

5.5 Comparable Earnings Approach

The Brattle Report states notes that the CE method is one of the traditional approaches to the cost of capital estimation, but that it does not have a financial economics foundation or strong theoretical basis. The report states that the legal decision, *Federal Power Commission et al v. Hope Natural Gas Co.,*[7] which stated that the return to the equity owner should be commensurate with returns on investment in other enterprises having corresponding risks, is often cited in the use of comparable earnings, but that neither the Canadian nor the US Supreme Courts has identified any specific methodology to determine a "fair return." (Exhibit A2-3, pp. 11, 36) The Commission Panel observes that much has been learned about financial economics since 1944. In particular, the notion of a comparable investment has been carefully cast in terms of investments in portfolios of

[7] 320 U.S. 591 (1944); 64 S. Ct. 281; 88 L.Ed. 333 (1944) U.S. Lexis 1204

comparable risk since portfolios are more efficient in achieving any expected return than is a single security.

The CE method requires the use of a sample of unregulated companies as comparators, since the use of regulated companies to estimate the comparable cost of capital would be circular. The Brattle Report notes that because the comparable companies are unregulated entities, it is necessary to adjust for any risk differences between the sample companies and the target company, and because the estimates from the model do not come from regulated companies or activities, the method does not recognize the regulatory context in which the cost of capital is being applied. (Exhibit A2-3, pp. 35, 38)

The Brattle Report states that a major issue with the comparable earnings method is whether realized book returns are a good proxy for the return that investors expect going forward and notes that it is a backward looking measure with no consideration of current market conditions. (Exhibit A2-3, pp. 36-37)

Ms. McShane submits that the fair return standard "…is only satisfied if the utility can attract capital on reasonable terms and conditions, its financial integrity can be maintained ***<u>and</u>*** the return allowed is comparable to the returns of enterprises of similar risk. The BCUC has recognized that the comparable return requirement is distinct from the capital attraction standard…." (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 8) [emphasis in the original] In her view, the comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard and it is critical that the regulator recognize the comparable returns standard when setting a fair return. (Exhibit B1-9-6, Mc Shane Evidence, Appendix F, p. 114)

Ms. McShane submits that the comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values.

Ms. McShane arrived at her comparable earnings estimates based on the earnings on book-value of 21 unregulated Canadian companies from 2004-2011. (Exhibit B1-9-6, Appendix F, pp. 113-116) She arrives at the following result: "To recognize the unregulated companies' higher risk, a downward adjustment of 125 to 150 bps to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%." (Exhibit B1-9-6, Appendix F, p. 116)

To complete her comparable earnings estimate, she assesses the need for a market/book adjustment to the comparable earnings results. She submits that "[t]he similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies' returns on equity due to their market/book ratios." (Exhibit B1-9-6, pp. 116-17)

Dr. Booth submits that the average ROE increases when one starts adding low-risk firms to a comparable earnings sample and then progressively decreases as more risky firms are added, particularly after the lowest risk firms are added. He argues that: "…to get a high ROE from a sample of comparable earnings firms simply means coming up with "reasonable" screens to narrow down the sample and exclude those firms with significant losses. (Exhibit C6-12, p. 6)

He used book-value based estimates for Corporate Canada as a whole, using Statistics Canada reported earnings for the period 1987 to 2011 and the TSX composite for the same time period. He arrived at a CE estimate for the Canadian market of 9.3 percent, and says that "Like the overall stock market return this then needs to be lowered for the lower risk attached to regulated utilities." (Exhibit C6-12, Appendix E, pp. 3, 7, Schedule 2)

Dr. Booth submits that CE "…is totally unreliable unless a market to book adjustment is made which is rarely the case." (Exhibit C6-15, BCUC 1.39.0) He also submits that a "…market to book adjustment is needed since low risk firms usually have market power which is reflected in higher ROEs. It is incorrect to then allocate to a utility an ROE from a sample of firms that reflects market power when regulation is designed to remove this market power." (Exhibit C6-15, BCUC 1.67.1)

Dr. Booth also says that a problem with looking at past ROEs is that they are earned on historic accounting book equity that does not reflect what can be earned on investments today. (Exhibit C6-12, Appendix E, p. 5)

The AMPC/CEC argues that the Commission should place little or no weight on the comparable earnings test. (AMPC/CEC Final Submission, pp. 38, 60)

Dr. Safir used two market-value based estimates: one for the same Canadian sample of 21 companies used by Ms. McShane; the other based on a sample of 31 US companies in the consumer goods, industrial goods or service sectors using the same sample selection criteria as Ms. McShane used for her Canadian sample. (Exhibit C4-9, pp. 28-29)

Dr. Safir calculated his comparable earnings estimates "…using net income and market value of equity…." He submits that because his comparable earnings estimates were calculated using market-based values instead of book value, they more accurately capture the conditions in the current capital markets in which the benchmark firm would be competing for capital. He goes on to say that his method accounts for factors such as inflation, since both the net income and the stock prices will reflect the level of inflation occurring at the time these numbers were reported and that "[b]ook value-based calculations of comparable earnings will not account for inflation." (Exhibit C4-9, p. 30) Using his market-value based method of calculating CE Dr. Safir arrived at estimates of 6.85 percent for his Canadian sample and 5.81 percent for his US sample. He submits that the Canadian estimate should be given twice the weight of his US estimate and arrives at a weighted average estimate of 6.50 percent. (Exhibit C4-9, p. 33)

Dr. Vander Weide did not provide a CE estimate.

Commission Determination

The fundamental issue regarding the CE test is its lack of a basis in financial economics. The approach requires a sample of unregulated companies of similar risk, but creating a sample of unregulated companies that are, and can be shown to be, of similar risk is difficult without a theoretical basis such as the CAPM or the DCF. Dr. Booth has pointed out the issues that arise when even 'reasonable' screens are used to eliminate companies from the entire universe of companies to create a sample. Moreover, the CE method is retrospective, whereas the ROE to be established for the benchmark utility is prospective.

In her evidence, Ms. McShane submits that: "The economic principle guiding the fair return is the opportunity cost principle." She also submits that one of the requirements of the FRS is that the return allowed is comparable to the returns of enterprises of similar risk and that it is critical that the regulator recognize the comparable returns standard when setting a fair return. She also states that the CE test is an implementation of the comparable returns standard and is to be distinguished from the cost of attracting capital standard. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 2, 8, 114)

During cross-examination a discussion on whether the comparable earnings test reflects an investor's opportunity cost concluded with the exchange below:

COMMISSIONER GIAMMARINO: But you would agree that in terms of an opportunity cost, it doesn't match up that closely to what we would consider the exact opportunity cost to the investor.

Ms. McSHANE: A: No, it is not an opportunity cost in the same sense that you were talking about. (T5:732-35)

The Commission Panel addressed the FRS in Section 2 and recognized that a fair or reasonable overall return on capital should be comparable to the return available from the application of the invested capital to other investments of like risk (comparable investment requirement). However, the Commission does not accept that this requirement means that it must use the comparable earnings method as a means of determining what return is required to meet the FRS. Modern finance theory has clearly established that comparable risk is assessed relative to a *portfolio* rather than a single stock. This is indeed the basis of the CAPM and other extensions of risk return modules. Searching for individual firms of comparable risk is consistent with this only if the comparison recognizes non-diversifiable risk as the relevant characteristic. This is exactly what is done when CAPM comparators are sought. But this is ignored when companies are considered comparable on dimensions other than systematic risk.

The preceding discussion highlights some of the serious problems the comparable earnings method contains as a means of determining the return required to meet the FRS. **Consequently, the Commission Panel places no weight on the comparable earnings results.**

5.6 Allowance for Financing Flexibility

Ms. McShane described financing flexibility allowance as intended to cover three distinct aspects: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the “fairness” principle (Exhibit B1-9-6, McShane Evidence, Appendix F, p. F-1). Flotation costs and financing flexibility adjustments are typically applied to the market-based cost of equity estimates, i.e., the CAPM and the DCF models.

Ms. McShane provided an allowance of 50 basis points for each of her market based tests in order to maintain the market value at a small premium to the book value. In the alternative, should the Commission rely only on the market-based tests, Ms. McShane proposed an allowance for financing flexibility at 1.0 percent. (Exhibit B1-20, BCUC 75.2.1)

Dr. Vander Weide provided an allowance of 50 basis points for flotation and financing flexibility. (Exhibit B1-9-6, Vander Weide Evidence, Appendix G, p. 35)

Dr. Booth provided an allowance of 50 basis points, stating that the market opportunity cost should be adjusted upwards to include issuing costs or a financial flexibility adjustment to make sure that shares can always be sold to net out the original cost included in the rate base, which is all that earns the fair ROE. He also noted that most regulators in Canada have allowed 50 basis points for these new issue costs (Exhibit C6-12, p. 8).

Dr. Safir referred to a survey of flotation costs, which determined them to be approximately 4.5 percent of the recommended rate of return. Based on the 4.5 percent, Dr. Safir applied 5 percent of the rate of return, an equivalent of around 32 to 40 basis points for his CAPM models and 47 bps for his DCF model, to reflect the marginally higher costs that would be faced by Canadian issuers either crossing the border to utilize the US market or in issuing in the smaller Canadian capital market. (Exhibit C4-9, pp. 16-18)

Commission Determination

The Commission Panel accepts the allowance for financial flexibility of 50 bps added to the CAPM and DCF tests in determining the fair ROE. As indicated in Section 5.5, the two market-based tests, CAPM and DCF are given equal weight in the determination of the allowed ROE for the benchmark utility.

With reference to Ms. McShane's proposed additional 50 bps if the CE test is not accepted, the Commission Panel is of the view that each test to estimate the fair return is applied separately to provide a different perspective and each test's results are not contingent upon the results of other tests. Therefore, the Commission Panel does not accept the conditional 50 bps in Ms McShane's alternative proposal.

5.7 Fair Return on Equity – Commission Determination

The Panel finds that the DCF and CAPM should be given equal weight in determining the ROE. Moreover, the Panel finds that CE and other ERP models have insufficient merit to be accorded any weight in the determination of the fair ROE. Considering the CAPM based estimate of 7.64 percent and the DCF estimate of 8.9 percent, the Panel concludes that the ROE, before adjustment for financing flexibility, of 8.25 percent is an appropriate base as it falls in the midpoint range of the two estimates. When an allowance for financial flexibility of 0.5 percent is added, the resulting ROE is 8.75 percent, to be effective January 1, 2013, provided for by Order G-47-12 and confirmed in Order G-187-12. **The ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula discussed and adopted in Section 6.**

FEI is to file within 30 days of this Decision and accompanying Order G-75-13 amended rate schedules in accordance with paragraphs 1 and 2 of Order G-75-13 as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013. FEI shall inform all affected customers of the final rates by way of customers notice.

6.0 AUTOMATIC ADJUSTMENT MECHANISM

6.1 Introduction

In 1994, the Commission determined that the Benchmark ROE was to be estimated annually by an Automatic Adjustment Mechanism (AAM).[8] This AAM was eliminated by Order G-158-09 issued concurrently with the 2009 Decision. In eliminating the AAM the Commission stated that: "... in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard." (2009 ROE Decision, p. 72)

One of the stated purposes of this proceeding was to review the possible return to an AAM for setting an ROE of the benchmark utility and examine potential AAM models. In this Section, the Commission determines that:

- Reinstituting an AAM formula for annually setting the ROE for a benchmark utility between proceedings is appropriate.
- A two-variable model AAM is to be instituted to set the benchmark ROE on an annual basis commencing in the 2014 calendar year for a period of two years.
- Implementation of the model will be subject to the actual long Canada bond yield meeting or exceeding 3.8 percent.
- The new formula will initially utilize the ROE of 8.75 percent as determined in Section 5.7.

6.2 Should the Commission Re-institute an AAM?

In considering re-instituting an AAM, the Commission Panel reviewed proposed AAMs to determine whether they would meet the Fair Return Standard or whether, as FBCU submit: "The Fair Return Standard is best met in intervening years until the next comprehensive cost of capital reviews by holding the ROE constant." (FBCU Final Submission, p. 153) In addition, the Panel examined the status of AAMs in other Canadian regulatory jurisdictions.

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[8] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd., -- Decision and Order G-35-94, June 10, 1994.

6.2.1 Status of AAMs in Other Canadian Jurisdictions

The Brattle Report surveyed the cost of capital practices in Canada including the formulas used to set the ROEs in Ontario and Quebec. (Exhibit A2-3, pp. 64, 72)

In the 2009 Decision, FBCU was directed to complete a study of AAM alternative formulas and report to the Commission. In compliance, FBCU filed the 2010 report, "A Review of Automatic Adjustment Mechanisms for Cost of Capital" prepared by Concentric Economic Advisers (Concentric). The 2010 Report provided an examination of the use of AAM formulas in other jurisdictions, contrasted these with alternatives and considered the merits of various approaches. While not recommending that a formula be adopted, Concentric identified attributes that should be considered if an AAM is adopted in the future. (Exhibit B1-9-6, Appendix I) In this proceeding, FBCU again engaged Concentric to provide an update of its analysis, which examined the use of ROE formulas in other jurisdictions. The update included the following observations with regard to Canadian jurisdictions:

- The Ontario Energy Board (OEB) continues to rely on its AAM which it modified in 2009. The modified formula is based on 50 percent of the change in forecast long-term Canada bond yields and 50 percent of the change in observed A-rated utility bond index over the 30-year Canada Bond yield.
- In Quebec the Régie de l'énergie (Régie) modified its previous formula in 2012 to incorporate 50 percent of the change in utility bond spreads in addition to the existing formula's 75 percent of change in government bond yields.
- In its December 2011 Decision, the AUC determined that the credit market remained volatile and therefore decided not to employ an AAM for 2012. The AUC indicated that it was not prepared to preclude a return to some form of formula-based AAM in future once the capital markets had stabilized.
- The Newfoundland and Labrador Board of Commissioners of Public Utilities, in June 2012, approved an 8.8 percent ROE (which was not set by formula) for Newfoundland Power stating that this was within a range of reasonable values. The Board did not disavow or abandon the formulaic approach for future rate proceedings.

Concentric has not changed its position on AAMs and stated that: "periodic rate hearings remain the only reliable method for the determination of utility ROE's." However, Concentric noted that Canadian regulators have recognized that a sole reliance on simple relationships to government bonds cannot be relied upon to estimate ROE. Concentric points out that both Ontario and Quebec have incorporated utility bond spreads in their formulas and notes that this mitigates one fatal weakness of past AAMs. Concentric views the two variable methodology utilized by Ontario as an improvement with a remaining concern being the lack of a specific link to the cost of equity , other than that conveyed by bond yields. (Exhibit B1-9-6, Appendix I, Concentric Update Report, pp. 1-4, 11)

The Commission Panel notes that both the OEB and the Régie formulas are variations of the model proposed by Dr. Booth and are discussed further in Section 6.2.2 below.

It appears that there is some acceptance by utility regulators in Canada of an AAM formula based on a two-variable model that uses the long-term Canada bond rate as a proxy for a risk free rate and a change in utility bond spreads as a proxy for credit risk. There is, however, reluctance in some jurisdictions to institute an AAM given the volatility of Canadian capital markets in recent years.

6.2.2 Submissions by Parties

AMPC/CEC

AMPC/CEC submit that the Commission abandoned the AAM in 2009 because it did not provide a fair return citing the following passage from the 2009 Decision: "the recent flight to quality has driven down the yield on long-term Canada bond yields, while the cost of risk has been priced upwards." Therefore, AMPC/CEC submit that the question for the Commission is, "what formula will allow it to return to an AAM, while ensuring that the results are fair in light of the current financial conditions and the conditions FEI might encounter going forward." (AMPC/CEC Final Submission, p. 62)

AMPC/CEC support a return to an AAM based on its contribution to regulatory efficiency because an AAM reduces the frequency of periodic ROE reviews. They note that FBCU have suggested that 3-5 years is a reasonable gap between comprehensive ROE reviews. AMPC/CEC points out that if the Commission agrees with this, an AAM would likely allow the reviews to be closer to five years rather than three, resulting in considerable efficiency benefits. (AMPC/CEC Final Submission, pp. 62-63)

Dr. Booth states that "The key problem with 'old' ROE adjustment models was that they *only* linked the ROE to the forecast long Canada yield. As a result, during the financial crisis the ROE formula indicated declining ROEs while at the same time the utility cost of debt was increasing. An enhanced ROE formula has to deal with this, which can be done by incorporating the credit market adjustment I have used in my direct ROE estimates." (Exhibit C6-12, pp. 97, 100)

Dr. Booth recommends "an ROE adjustment model where ROE adjusts by 75% of the forecast change in long Canada bond yields and 50% of the change in the credit spread. This would be subject to a minimum forecast long Canada bond yield of 3.80% … Similar models are in use by the Régie and OEB." (Exhibit C6-12, p. 3) Dr. Booth selects 3.80 percent as the "floor" stating that this "is the lowest rate consistent with a normal cyclical low." (Exhibit C6-12, pp. 97, 100)
AMPC/CEC argue that Dr. Booth's enhanced two variable ROE formula addresses the concern with the old ROE formula that during periods of financial crisis the allowed ROE and utility borrowing costs move in opposite directions. They argue that Dr. Booth's formula obviates FBCU's concern that the AAM won't work because of the current unusual business cycle. The proposed 3.8 percent floor acts like a fixed rate ROE until the long Canada bond yields return to normal, and it provides an adjustment mechanism for periods when conditions are more typical. (AMPC/CEC Final Submission, p. 64)

<u>ICG</u>

Dr. Safir believes that an AAM for a limited number of years is appropriate because "It is simply not economically efficient to revisit the entire ROE setting mechanism annually" and also states that "the AAM is administratively efficient, resulting in significant savings by avoiding costly, annual rate hearings." In Dr. Safir's view, AAMs that reference long-term bond rates, such as the one previously used by the BCUC, are good ways to account for near term influences that affect a fair ROE. (Exhibit C4-9, pp. 36-37)

ICG observes that during the interim years between periodic cost of capital proceedings an AAM formula is more likely to result in an ROE that meets the FRS than no formula. It submits that the Commission should establish an AAM similar to the one discontinued by the Commission in 2009 that referenced long-term bond rates with a three year effective period. It would differ from the previous Commission AAM in that it would use a five year average for the forecast long-term Canada bond yield. (Exhibit C4-9, pp. 36-38; ICG Final Submission, p. 32; T7:1187)

ICG concedes that a multiple factor model may be more likely to meet the FRS than a single factor model, but given that the single factor model has been tested over a long period, it has been recommended to the Commission. (ICG Final Submission, pp. 32-33)

BCPSO

BCPSO submits that an AAM is beneficial because it ensures that the benchmark utility will not operate for more than a brief period of time with a higher than required ROE and therefore supports reinstatement of an AAM. (BCPSO Final Submission, pp. 19-20)

FBCU

FBCU does not support the return to an AAM. FBCU's main concern with the AAM is that the basis upon which the annual ROE adjustments are being made may be suspect. They submit that an AAM relies on a formula with a limited number of inputs that could never capture the complex factors affecting ROE, and that an AAM likely relies on long Canada bond yields and corporate spreads, which are still affected by atypical market conditions. In addition, any formula relies on imperfect proxies. In their view, the application of the FRS requires a significant degree of analysis, market information, and judgment that evolve over time. Formula parameters are static and based on historic relationships and fundamental relationships may shift, leaving the formula out of touch with current market conditions. FBCU take the position that there is no formulaic way to assign a value or weighting to specific risk factors or utility/utility sector characteristics that would apply across multiple utilities and generate the appropriate cost of capital for each one. This is supported by Ms. McShane who submits that the Commission should continue to address the appropriate cost [of capital] on a case-by-case basis: "There is no 'one size fits all' cost that should be determined by means of an interest automatic adjustment mechanism." (FBCU Final Submission, p. 153-156; Exhibit B1-9-6, p. 33; Exhibit B1-9-6, McShane Evidence, Appendix F, p. 7)

FBCU prefer to have the allowed ROE and capital structure set through a traditional process and remain constant between the periodic (three to five year) formal reviews, subject to events occurring that bring the results out of alignment with the FRS, which could result in an unscheduled full review process. This is preferable to having updates made on a basis that the FBCU believe is suspect. (Exhibit B1-20, BCUC 2.113.1)

FBCU argue that there is no efficiency gain associated with implementing the AAM, if there are to be periodic reviews. FBCU further argue that the regulatory burden associated with periodic cost of capital reviews is the same as that associated with periodic reviews with annual formula-driven ROE changes in the interim. FBCU also argue the FRS is best met in the intervening years until the next comprehensive cost of capital reviews by holding the ROE constant. (FBCU Final Submission, pp. 153-156)

FBCU further submit that "The rationale for why the Commission discontinued the AAM remains valid today. Meeting the Fair Return Standard is not optional." FBCU state that "All of the experts agree that we are still experiencing unusually low interest rates, and the ability of any AAM to produce fair results is far from certain [when such conditions exist]." (FBCU Final Submission, p. 153)

With respect to the positions taken by Dr. Safir and Dr. Booth, FBCU make the following submissions:

1. FBCU submit that Dr. Safir is proposing to return to an AAM that has already been rejected by the Commission, with the only difference being the starting point for measurement of changes in the forecasted long Canada bond yields (i.e., the use of the five-year average forecast). They cite Ms. McShane's statement that there is an inverse relationship between long-term government bond yields and the utility risk premium. FBCU also argue that Dr. Safir's use of a five-year average forecast Canada bond yield as the base line in the formula is problematic because it suppresses ROEs despite increases in long Canada bond yields. FBCU submit that while this five year average is intended to compensate for present unusually low interest rates, it would be better to postpone consideration of a formula, rather than implement a "quick fix" that artificially suppresses the ROE. (FBCU Final Submission, pp. 159-160)

2. FBCU submit that the AAM proposed by Dr. Booth is biased downwards. FBCU notes that the current long Canada bond yield is well below the 3.8 percent that Dr. Booth employs as the floor, and points out that while he expects rates to increase, he does not expect the forecast to rise above the 3.8 percent for at least three years. FBCU submit that the combination of rock-bottom forecast yields and a slow rise in interest rates has two implications. First, rock-bottom interest rates means that further declines are not likely. Second, any increase in the forecast long Canada bond rate will not result in an increased ROE. In addition, FBCU submit that the cross-examination of Dr. Booth indicates that he expects credit spreads to fall while the long term Canada bond yield remains below 3.8

> percent, an expectation shared by Mr. Coyne. FBCU propose that the result of this will be a progressively lower benchmark ROE after 2013 if Dr. Booth's formula is employed. (FBCU Final Submission, pp. 160-161)

FBCU's position is that if the Commission requires an ROE AAM, it should seek to rectify the problems of the old formula. A new formula would address changes in the equity risk premium, and not solely changes in long Canada bond yields. Any adjustment factor would need to reflect sensitivity to change in bond yields to ROE. (Exhibit B1-9-6, pp. 27-29)

Corix

Corix submits that there is a continued flight to quality and a still increasing cost of risk, so an updated AAM is not appropriate at this time. (Exhibit B2-9, BCUC 1.2.1, p. 3)

6.3 Commission Determinations

6.3.1 Re-instituting an AAM

The Commission Panel does not take issue with FBCU's argument that an AAM formula with limited inputs cannot capture all of the complex factors affecting ROE and therefore, relies on imperfect proxies. However, at the same time, the Panel is of the opinion that the issue is whether the adoption of an AAM formula is better than the alternative, which is to do nothing as suggested by FBCU and Corix. In other words, while implementing an AAM formula may not be perfect, the question is whether it better satisfies the FRS than leaving the ROE static for a period of time or conducting frequent costly and time consuming ROE proceedings. The difficulty with leaving the ROE static over a three year or longer period is that financial markets continue to change and investors' needs continue to evolve. Therefore, in the view of the Commission Panel, implementing a mechanism to capture the impact of some of these changes is far superior to the alternative of doing nothing. Furthermore, as the AMPC/CEC submits, "if there are reasonable grounds to believe the mechanism is not producing fair results, the benchmark utility always has the option of asking for a review." (AMPC/CEC Final Submission, p. 64)

The Commission Panel does not disagree with FBCU's argument that the regulatory burden associated with periodic cost of capital reviews with or without an AAM is similar. However, we are of the view that the likelihood of a requirement for more frequent ROE proceedings is reduced by having in place an AAM formula. Thus, the Panel is persuaded that the application of the AAM has the potential to contribute to regulatory efficiency.

Therefore, the Commission Panel determines that re-instituting an AAM formula for annually setting the ROE of the benchmark utility between ROE proceedings is appropriate. Additionally, the Commission Panel finds the FRS is adequately met because implementing an AAM formula better meets the standard than taking no consideration of changes in the market over a three year period as suggested by FBCU. The AAM formula to be adopted and the timing of its use is addressed in Section 6.3.2.

6.3.2 Optional AAMs to be Considered

The Commission Panel acknowledges that interest rates have been atypical in recent years and have remained at historical lows. The historical AAM used by the Commission prior to 2009 relied exclusively on a single variable formula based on the long-term Canada bond yields as a proxy for risk free rates. This model was less than fully effective for utilities because the flight to quality kept interest rates abnormally low while the risk had been priced upwards. It could not assure that the FRS could be met in extended times of low interest rates.

As noted previously, Dr. Booth proposed a two-variable model that incorporates the traditional concept of tying the benchmark utility's ROE to the "risk free" long-term Canada bond yield, and also incorporates a credit market adjustment to reflect the relationship of ROE and credit risk within the utility sector. His model also utilizes a "floor" long-term Canada bond rate of 3.8 percent as the risk free proxy until such time as long-term Canada bond yields return to a more common level.

Concentric submits that any new AAM formula should address changes in the utility risk premium and not be based solely on changes to the long Canada bond yields. While it does not recommend a formulaic approach, it does provide several potential formulaic methodologies that could be used in British Columbia (Exhibit B1-9-6, Appendix I, 2010 Report, pp. 39-45)

In summary, possible options for re-instituting an AAM include:

- The single variable model used by the Commission prior to 2009 that was based on long Canada bond yields;
- The variety of approaches offered by Concentric (Exhibit B1-9-6, Appendix I, p. 11);
- Dr. Booth's two-variable model or a variation incorporating the long Canada bond yield, a floor level of long Canada bond yield to address the atypical low interest rates, and a metric to address credit spreads.

The Commission Panel recognizes the shortcoming of the single variable model used by the Commission prior to 2009 in that it fails to satisfy the FRS when interest rates continue at abnormally low levels. Accordingly, this model will not be considered.

While Concentric has explored a number of alternative formulas that could be used in British Columbia, the Commission Panel notes that none of these have been recommended by Concentric nor have they provided evidence as to their use and effectiveness in other jurisdictions. In addition, none of the interveners has expressed support for any of these. Given this lack of support and the lack of evidence to support their efficacy and relevance to British Columbia, the Commission Panel does not endorse any of the possible alternative AAMs explored by Concentric.

During cross-examination, Commission counsel asked Mr. Coyne of Concentric what advice he would give the Commission in terms of adjustments if the Commission were adopt an AAM similar to that of the OEB and the Régie. Mr. Coyne testified that a coefficient of 0.5 was a more accurate reflection of the historic relationship to long-term Canada bonds than 0.75. (T5:827)

Dr. Booth testified that he recommended 75 bps but that he could live with 50 bps and he did not believe that there would be a big impact. (T8:1622)

The Commission Panel is persuaded that a two-variable model similar to that proposed by Dr. Booth and currently utilized in Ontario is appropriate for application to the benchmark utility within British Columbia. (Exhibit C6-15, BCUC 1.44.5 attachment)

By utilizing the 50 percent adjustment of the change in the long-term Canada bond yield as a proxy for risk free rates, it recognizes the relationship between ROE and risk while moderating the level of change resulting from any volatility in the long-term Canada bond rate. In addition, by utilizing the 50 percent adjustment in the change in the utility bond spreads, it recognizes the relationship between credit risk and ROE in the utility sector and moderates volatility in utility bond spreads. And finally, by utilizing a 3.8 percent floor for the long Canada bond yield, it recognizes the atypical relationship between ROE and cost of risk in periods of unusually low interest rates. Further, the application of similar models within both Ontario and Quebec supports it usefulness and acceptance within other Canadian regulatory jurisdictions.

Given the advantages, the Commission Panel adopts a two variable model AAM to determine the benchmark ROE on an annual basis commencing in the 2014 calendar year. The AAM formula will operate until December 31, 2015. The implementation of the model is subject to conditions outlined in Section 6.3.3. The formula will initially utilize the 8.75 percent ROE as determined in Section 5.7 as the base ROE.

The formula to be used and the basic method to determine the changes in long Canada bond forecast and the changes in utility bond spread are provided as follows:

$$ROE_1 = Base\ ROE\ (8.75\%) + 0.50 \times (LCBF_t - BaseLCBF) + 0.50 \times (UtilBondSpread_t - BaseUtilBondSpread)$$

Where:
$LCBF_t$ is the Long Canada Bond Forecast for the test year, with a floor of 3.8 percent. The Base LCBF is 3.8%.

$UtilBondSpread_t$ is the average spread of 30 year A-rated Canadian Utility bond yields over 30 year Government of Canada bond yields and BaseUtilBondSpread will be determined.

6.3.3 Impact of a 3.8 percent Floor

FBCU has argued that the AAM proposed by Dr. Booth is biased downwards. The Commission Panel agrees that the potential for a downward bias does exist.

Dr. Booth has recommended that any change in the ROE be subject to a minimum forecast bond yield of 3.8 percent as this is the lowest rate which is consistent with a normal cyclical low. The Commission Panel accepts this as reasonable since it is the risk free rate for the CAPM ROE as determined in Section 5.2.

With respect to the two-variable AAM formula, Dr. Booth has acknowledged that as long as the long-term Canada bond yields are below 3.8 percent, the only variable that can affect ROE is the corporate utility bond spreads. FBCU submit that if the credit spread drops or tightens before long Canada bond rates are above 3.8 percent, the ROE will drop further from whatever the starting point is under his formula. Further, Concentric states that "a troubling aspect of Dr. Booth's proposed formula is that it sets a minimum floor LTC yield of 3.8 %, which will be applied for purposes of measuring year over year changes in the formula, but does not specify an objective bond forecast to reference for the starting point." (Exhibit B1-32, Concentric Rebuttal Evidence, Concentric Response to Interveners, p.4) The Panel notes that all parties seem to agree that long-term Canada bond yields are well below what would be considered a cyclical low and have been influenced by monetary policy. Therefore, it is reasonable to assume that the likelihood of an increase in the yields of long Canada bond is much more likely than a decrease. If this were to occur with no corresponding change in utility bond rates, the result would be a decrease in the credit spread and, consequentially, the ROE. Given that a rise in the long Canada bonds yields may be driven by monetary policy and not a change in market conditions, and there is no evidence to suggest there would be a corresponding change in utility bond rates, the Commission Panel accepts that a potential for downward bias exists. **To deal with this the Commission Panel directs that any change in ROE resulting from the AAM formula be subject to an actual long Canada bond yield of 3.8 percent being met or exceeded. Accordingly, the AAM formula will not be operative as long as the long Canada bond yield is below 3.8 percent.**

The Commission Panel has considered Concentric's submission that Dr. Booth did not specify an objective bond forecast to reference as a starting point. We are of the view that the potential for downward bias will continue if attention is not paid to setting appropriate base rates for the formula. Therefore, the Commission will seek submissions from the parties with respect to determining appropriate base levels and developing an effective methodology for deriving the inputs to the formula.

The Commission Panel understands that the conditions placed upon the implementation of the AAM formula may well result in the 8.75 percent ROE being in place for the term of this Decision ending December 31, 2015. However, in consideration of the FRS, the Panel is of the view that this is appropriate.

FEI is directed to file an application for the review of the common equity component and the ROE approved in Order G-75-13 by no later than November 30, 2015.

7.0 COST OF CAPITAL – SMALL UTILITIES

7.1 Introduction

When the Commission initiated the GCOC Proceeding, it identified the Affected Utilities, which included FEI and other FortisBC gas and electric utilities, PNG and Corix. These utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. In addition, the Commission identified Other Utilities that "may wish to participate in the GCOC Proceeding." This list included among others:

- Big White Gas Utility Ltd. and Sun Peaks Utilities Co. Ltd.;
- Central Heat Distribution Ltd.;
- Dockside Green Energy LLP;
- Hemlock Valley Electrical Services Limited; and
- River District Energy Limited (River District).

The recent emergence of thermal energy services (TES) in British Columbia has resulted in the creation, over the last few years, of a number of new on-site thermal energy systems and district energy systems, which are subject to the Commission oversight. For instance, FortisBC Alternative Energy Service Inc. (FAES), an affiliate of FEI and a wholly-owned subsidiary of FortisBC Holdings Inc. (FHI), now owns and operates or is proposing to develop the following regulated TES projects:

- Delta School District Number 37;
- Tsawwassen Springs Development;
- PCI Marine Gateway;
- TELUS Garden Thermal Energy System; and
- Kelowna District Energy System.

Key purposes identified by the Commission Panel in its Final Scoping Document were to establish:

(i) a method to determine the appropriate cost of capital for a benchmark low-risk utility in BC and how the Benchmark ROE will be reviewed and/or adjusted;

(ii) a generic methodology or process for determining each Affected Utility's cost of capital in relation to the benchmark utility's cost of capital; and

(iii) a framework for determining the appropriate cost of capital for other smaller utilities in the province.

Related to this framework, the scope of the proceeding included the following key activities:

(i) establish a generic methodology or process for each utility to determine its unique cost of capital in reference to the benchmark low-risk utility;

(ii) in certain circumstances, develop a methodology to establish a deemed capital structure and deemed cost of debt, particularly for those small utilities without third-party debt, which would involve setting a methodology on how to calculate a deemed interest rate.

(Exhibit A-3, Appendix B to Order G-47-12)

The Commission Panel also requested submissions regarding Stage 1 and Stage 2 review. The FBCU submitted it would be most efficient to break the process down into three groups which would be handled separately: one for the FBCU, a second for the PNG and a third for micro utilities including Corix and FAES and others. (Exhibit B1-22, pp. 10-11) By Order G-148-12, the Commission Panel directed that a Stage 2 will be added to this GCOC proceeding with the schedule to be determined prior to the end of Stage 1. (Exhibit A-21)

Transition to Stage 2

The purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by the Affected and Other Utilities as compared to the benchmark utility FEI. Based on this assessment the Panel will then determine how the risk differentials will impact the capital structures and the allowed ROE for these utilities.

The Panel acknowledges the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a single process to address cost of capital issues for TES systems, irrespective of the provider. This would include FEI and FAES's Thermal Energy Services, and similar systems to be operated by developers or providers like Corix. (Exhibit B1-9, p. 34) The Panel also notes the previously mentioned FBCU suggestion about dividing the Stage 2 process into three groups.

In anticipation of Stage 2, this section addresses issues related to the framework for determining the cost of capital for the smaller utilities, including all new small TES utilities. The appropriate method to determine interest rates for deemed debt will also be addressed. In this Decision, the definitions of “small utilities” and “micro utilities” are used interchangeably.

7.2 Framework for Establishing an Appropriate Cost of Capital – Equity Risk Premium

7.2.1 Is Size a Risk Factor in ROE and Capital Structure Determination?

Ms. Ahern, the expert witness for Corix states “it is conventional wisdom, supported by actual returns over time, that smaller companies tend to be more risky, causing investors to expect greater returns as compensation for that risk.” Ms. Ahern further explains that smaller companies, for instance, face more risk exposure to business cycles and economic conditions, both nationally and locally. Similarly, the loss of revenues from a few larger customers would have a greater effect on a small company than on a much larger company with a larger, more diverse customer base. Moreover, smaller companies are generally less diverse in their operations as well as experiencing less financial flexibility. (Exhibit B2-7, pp. 6-7)

Ms. McShane, the expert witness for FBCU states that in the assessment of investment risk, size has two dimensions that should be considered in determining a utilities common equity ratio and ROE:

1. A small utility does not have the opportunities to diversify its risks to the same extent as a larger utility. For example, assets are typically more concentrated in a limited geographic area, which limits operational flexibility.
2. Smaller utilities have fewer financing options, less institutional interest in acquiring their debt securities, issued debt would be relatively illiquid, and, if issued to third-parties would likely require stricter covenants than debt issued by large utilities.

Ms. McShane also points out that debt rating agencies often take size into account when rating companies and their debt issues. The impact of smaller size for rated utilities is frequently exhibited in lower debt ratings for these companies even in cases where their financial parameters are stronger than their larger peers. (Exhibit B1-9, Appendix F, p. 134)

PNG submits "there was little to no evidence submitted that suggested or countered that size was not a significant factor." While precedents and empirical studies exhibit a broad range of explicit company size adjustments (150-436 bps), which introduces a degree of subjectivity, PNG further submits that "Stage 1 evidence concerning size as an independent factor was relatively uncontested." (PNG Final Submission, p. 13)

7.2.2 Stand-Alone Principle

Both Ms. Ahern and Ms. McShane reaffirm the importance of the stand-alone principle, which is "a cornerstone of Canadian utility regulation with a history dating to at least 1978." (Exhibit B1-9, Appendix F, p. 10, B2-9, BCUC 1.4.7) Therefore, even if a small utility is owned by a larger parent company, there should be no impact on the determination of the small size utility ROE and capital structure. Each utility within the Commission's jurisdiction should be evaluated on a stand-alone basis.

Ms. Ahern further states there is ample academic evidence that investors demand greater returns to compensate for the lack of marketability and liquidity of the securities of smaller firms. She submits "it is the use of funds invested and not the source of those funds which gives rise to the risk of any investment." She refers to the text of Brealey and Myers, which notes "Each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put." (Exhibit B2-7, p. 7)

7.2.3 Academic Evidence of the Size Effect in Literature

In her filed evidence, Ms. Ahern provides additional examples of the academic literature, where the risk effects of a company's size on the investor required return is addressed:

Eugene F. Brigham, *Fundamentals of Financial Management:*

> A number of researchers have observed that portfolios of small-firms have earned consistently higher average returns than those of large-firms stocks; this is called "small-firm effect." On the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; what the small-

> firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of large firms.
>
> (Exhibit B2-7, PMA-3, p. 4)

Giacchino and Lesser, *Principles of Utility Corporate Finance:*

> In general, smaller firms face greater financial risk than do large firms... Generally, firm size is measured in terms of total capitalization (i.e., the market value of a firm's equity). Empirical studies have typically found that small firms typically have higher returns over the long run than larger firms. (Exhibit B2-7, PMA-4, p. 3)

Fama and French, in *"The Capital Asset Pricing Model: Theory and Evidence,"* *Journal of Economic Perspectives*, note that size is a risk factor which must be reflected when estimating the ROE:

> ...the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market returns and are priced separately from market betas. (Exhibit B2-7, PMA-5, p. 14)

Based upon this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect of size on the rate of return on common equity.

Marc Reinganum, *"A Possible Explanation of the Small Firm Effect,"* *The Journal of Finance:*

> While the OLS estimates seem to understate the betas of small firms, the excess returns not explained by the misestimation could easily exceed twenty percent per year on average. Thus, one can conclude with confidence that the small firm effect is still a significant economic and empirical anomaly. (Exhibit B2-6, PMA-6, p. 9)

From her academic research, Ms. Ahern concludes that:

- The specific, unique risks of the investment (e.g. utility) must be reflected in the rate of return; and
- The size of an investment (e.g. size of the utility) is one of those unique risk factors for which investors must be compensated. (Exhibit B2-7, pp. 10-11)

7.2.4 Empirical Evidence for the Risk Effects of a Company's Size on the Investor's Required Rate of Return

Studies on small size and returns have quantified the impact of a firm's small size on the required return based on an analysis of the relationship between betas and historical returns for companies of different sizes. Ms. McShane and Ms. Ahern state the analyses indicate that small companies tend to exhibit higher betas than larger companies. Two empirical studies reviewed by Ms. Ahern are:

Morningstar/Ibbotson Size Premium Study (Firm Size and Return)
Ibbotson SBBI – 2012 Valuation Yearbook

This study constructs decile (10) portfolios of the companies contained in the NYSE, AMEX and NASDAQ. Ms. Ahern suggests that the study can be used to determine the approximate risk premium due to size for a specific utility over the benchmark utility return. This is done by comparing the size premium appropriate for the decile in which the benchmark utility would fall based on the estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization.

	Decile	**Market Capitalization ($Millions)**	**Size Premium (%)**
Benchmark Utility	5	2,246 (average)	1.74
Micro-Cap	10	92	6.10
Size Premium			**4.36%**

(Exhibit B2-6, PMA-8, Table 7-1 and 7-5)

Duff & Phelps Size Study and Risk Study

The Size Study analyzes the relationship between equity returns and company size in a similar manner as the Morningstar Study. It could also be used to determine the magnitude of any necessary risk premium due to the size of a specific utility relative to the benchmark. In addition to presenting risk premia and size premia for 25 size-ranked portfolios using the traditional market capitalization measure, this study also considers seven other measures of company size, including book value of equity, 5-year average net income, market value of invested capital, total assets, 5-year average EBITDA, sales and number of employees. (Exhibit B2-7, PMA-9, p. 30)

The Risk Study is an extension of the Size Study. The main difference is that while the Size Study analyzes the relationship between size and return, the Risk Study analyzes the relationship between fundamental risk measures (based on accounting data) and return. These are called "fundamental" measures of a company risk to distinguish these risk measures from a stock market-based measure of equity risk such as betas. (Exhibit B2-7, PMA-9, p. 65)

Corix provided a calculation of the size risk premium for micro utilities over the benchmark based on the Duff & Phelps Study. This resulted in a 3.89 percent risk premium as opposed to the 4.36 percent size premium based on the Morningstar Study. (Exhibit B2-8, Attachment to BCPSO 1.1)

7.2.5 Regulatory Support for Size Premium

Ms. Ahern provided only one example of a jurisdiction which has adopted the size premium concept. She cites the Florida Public Service Commission (FL PUC), which adds for small water utilities a bond yield differential, a 50 bps private placement premium and a 50 bps small utility risk premium to the ROE based upon the index of natural gas utilities. Regardless, Ms. Ahern recommends that the size risk of each utility be measured in accordance with the Morningstar/Ibbotson and the Duff & Phelps studies. Specifically, Ms. Ahern states "all of these risk premium spreads should then be averaged and through the exercise of informed expert judgement, a determination of the appropriate risk premium to be added to the benchmark utility return on equity to reflect the size risk of the utility/project relative to the benchmark utility." (Exhibit B2-9, BCUC 1.12.1; Exhibit B2-8, BCPSO 1.2.1)

In responses to IRs and during cross-examination, Ms. Ahern made it clear that she is not recommending any particular amount of a size premium to be adopted by the BCUC but is simply providing testimony for the purpose of establishing a framework. (T6:1128) Similarly, Ms. Ahern states the 4.36 percent risk premium shown in the example would only represent the upper limit of a size premium above the allowed benchmark ROE due to small size. Where in the 10th decile, Corix or any of its projects fall needs to be evaluated to determine the exact risk premium it would propose. Corix stated it has not yet undertaken a comprehensive study of the appropriate size risk premium above the benchmark for each of its projects and indicated that such a study will be conducted in the next phase of the GCOC proceeding. (Exhibit B2-9, BCUC 1.13.2)

Ms. Ahern acknowledged that based on her experience the regulatory support for a specific size premium has been minimal and that ultimately any risk premium, whether it is linked to business risk in general or size specifically, is a matter of informed expert judgment. (T7:1278-1284) Further, Ms. Ahern could provide only seven cases out of over 200 regulatory proceedings where she has been involved that resulted in an allowed size adjustment. Yet, in a response to an undertaking, it appears that only two of those seven cases *specifically* reference “size” in the determination of the overall ROE and only one case granted a specific size premium. (Exhibit B2-14) Furthermore, the Panel notes that Ms. Ahern had recommended only modest size adjustments in the range of 25-50 bps in all those seven cases.

Ms. McShane concludes the empirical study findings indicate that small size is a factor that both debt and equity investors are concerned with, and which should be taken into account when evaluating ROEs and capital structures of individual utilities in British Columbia. (Exhibit B1-9, Appendix F, p. 136)

Commission Determination

Stand-Alone Principle

The Panel reaffirms the long history and importance of the stand-alone principle in Canadian utility regulation. The determinations on the benchmark ROE and capital structure in this Decision are based on this principle. Therefore, there is no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. These projects can represent either a “new” utility with a greenfield operation and no historical performance data or an existing facility being developed into a TES project. Each project needs to be considered individually and independently.

The Size Premium

The Panel has considered the evidence on record regarding the academic literature on the size effect as well as the empirical evidence for the risk effects of a company's size on the required rate of return. Noteworthy is the lack of regulatory support for the recognition of a small size risk premium. Finally, the Panel notes the requirement for on-going exercise of informed judgment by both the Commission and experts retained by the utilities, which was acknowledged by Ms. Ahern.

As a result, the Panel recognizes the academic literature and empirical studies seem to support the importance of size in explaining returns. At the same time, however, the evidence presented does not indicate how adjustment for size should be implemented.

Accordingly, the Panel determines that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. Utilities are encouraged to use other methodologies or approaches to justify their risk differential in relation to the benchmark. The Panel has not been sufficiently persuaded to put any weight to the empirical studies reviewed to date.

The Panel notes that the Commission developed a risk matrix that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. The "size" factor is one of the risk factors included in the matrix. **The Panel recommends that the small utilities use this risk matrix attached as Appendix B to Order C-1-13 of the TELUS Garden Decision[9] in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the benchmark ROE**. For convenience, the risk matrix is attached in Appendix E of this decision. Small utilities, other than TES, can modify this matrix to facilitate a similar comparison of their own short and long-term risks to those of FEI.

The Panel is cognizant of the on-going Phase 2 of the Alternative Energy Solutions (AES) Inquiry,[10] which involves development of a regulatory framework for dealing with small TES utilities. This evolving process will further influence the nature and content of future TES applications.

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9 Certificate of Public Convenience and Necessity Order C-1-13 and Reasons for Decision dated February 5, 2013, regarding FAES Telus Garden Thermal Energy Services

10 In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Solutions and Other New Initiatives

7.3 Guiding Principles for Setting Deemed Capital Structure and Deemed Debt

7.3.1 Determination of Deemed Capital Structure

The Commission deems an appropriate common equity ratio for the utility. The resultant debt ratio is simply the residual between 100 percent and the deemed equity ratio. However, the deemed component typically incorporates actual debt issues where rates can be objectively observed and determined. In some cases, the utility manages its actual financing to mirror the deemed debt/equity ratio.

Ms. McShane explains the actual debt issues may consist of issues that have been made directly into public markets; they may be private placement to third party institutions such as bank or insurance companies, or they may be non-arms length issues between a utility and affiliated company. In the latter case, there is a contract between the utility issuer (a legal entity) and the affiliated company, which specifies the terms and conditions of the loan, with rates that are based on market conditions. When the parent company issues debt, the subsidiary can enter into an arrangement with the parent for a specific portion of that debt issue, with the same terms as the third-party issue. Alternatively, the utility may enter into an arrangement with its parent for a debt issue that reflects the utility issuer's risk profile, funding requirements and market conditions at the time the issue is made, but is not tied to a specific third-party issue made by the parent. (Exhibit B-1-9-6, McShane Evidence, Appendix F, p. 121)

7.3.2 Criteria for Setting the Deemed Capital Structure

Ms. Ahern, the Corix expert, states that an appropriate deemed capital structure should:

- be reasonable relative to or consistent with the average capital structure of the particular utility industry;
- reflect the specific utility's unique risks, including its relative size;
- be consistent with bond rating agency metrics; and
- provide the opportunity for the utility to earn a reasonable and fair rate of return, given its unique risks, e.g., size etc.

(Exhibit B2-7, p. 19)

Ms. McShane provides general principles that should be observed when setting the ROE and common equity ratio for utilities, regardless of size:

- The combination of ROE and common equity ratio awarded to each utility in relation to the overall return adopted for the benchmark utility should reflect the level of that utility's business risk relative to that of the benchmark utility;
- The overall return awarded to each utility should be comparable, on a risk adjusted basis, to the overall return awarded to the benchmark utility;
- The capital structure, in conjunction with the ROE, should be adequate to permit the utility, on a stand-alone basis, to achieve investment grade debt ratings, with the caveat that some utilities many not actually have a credit rating; and
- There is a trade-off between equity ratio and ROE. For example, if a utility is not fully compensated for higher business risk than that of the benchmark utility through its common equity ratio, its ROE needs to be higher than the ROE granted to the benchmark utility. (Exhibit B1-9-6, p. 129)

7.3.3 When Is Deemed Debt Appropriate?

The FBCU state the deemed debt is appropriate for small utilities in cases where raising debt is inefficient. For example, a separate division or class of service within a larger regulated utility can contain a stand-alone project. Similarly, a regulated utility subsidiary/affiliate within a larger corporate organization can face circumstances where either:

(i) The high cost of debt issuance relative to the size of the issue makes the effective debt cost higher than it would be otherwise; or

(ii) The size of the utility precludes it from accessing appropriate debt terms.

The FBCU further state that the assessment as to whether deemed debt is appropriate and efficient should involve some judgment to ensure that the use of deemed debt is limited to circumstances where it is efficient to do so. Finally, FBCU state "it is reasonably clear that deemed debt would be appropriate for FEW (a separate legal entity), the Fort Nelson Division of FEI, and FAES." (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.1, 1.140.2)

7.3.4 Setting the Appropriate Deemed Debt Rate and Term

The FBCU state that deemed debt rates and duration should reflect the particular circumstances of each utility. Utilities for which a deemed cost of debt might be appropriate may have differing profiles; FEW, for instance, is not the same as one of FAES's TES projects or Corix's UniverCity project. The appropriate term of debt may also vary even among projects with a broadly similar risk profile. (FBCU Final Submission, p. 163; Exhibit B1-20, BCUC 1.140.2)

Ms. McShane submits as a general proposition that the term should reflect the long-term nature of the assets and offers the following additional considerations:

1. If the specific utility operations are backed by contractual arrangements, the length of the contract would be a relevant consideration in the determination of the term for the debt.
2. The higher the risk of the specific operation, the less their ability would be to obtain "real" debt on a long-term basis; i.e., on terms longer than 10 years. The term of the debt should reasonably reflect the limitations of what would reasonably be available to operations with a similar risk profile.
3. The appropriate term for the deemed debt also depends on the state of the capital markets.

Ms. McShane concludes that the individual utilities' circumstances may differ in terms of risk, the funding requirements and appropriate terms of debt. Accordingly, she recommends that the Commission continue to address the cost of deemed debt for each utility separately, on a case-by-case basis. In her view, there is no "one size fits all" cost mechanism. (Exhibit B1-9-6, pp. 123-124)

Commission Determination

Before addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission Panel wishes to reaffirm certain principles for the Stage 2 GCOC proceeding framework.

(i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

(ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;

(iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and

(iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

Related to the issue of deemed capital structure and deemed debt are two key questions that the Stage 2 GCOC proceeding must address more comprehensively:

1. Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
2. How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

7.4 Appropriate Portions of Short-Term and Long-Term Debt in the Deemed Capital Structure

In British Columbia, in some of the more recent TES Decisions, the Commission has considered deeming a portion of overall debt to short-term debt. To date no determination has been made to put this into effect. However, the Panel notes that the OEB has officially deemed a standard four percent proportion of short-term debt component for utilities under its jurisdiction for reasons that it outlined in its 2006 Decision:

(i) All utilities actually use some short-term debt;

(ii) Short-term debt is generally less expensive than long-term debt and provides greater financing flexibility; and

(iii) While actual short-term debt percentages may seem to be a more accurate approach, it is administratively challenging given the number of distributors regulated by the OEB.[11]

[11] OEB, Report of the Board on Cost of Capital and 2nd Generation incentive Regulation for Ontario's Electricity Distributors, December 20, 2006, pp. 9-10

In 2009, the OEB reaffirmed this practice for natural gas distributors as well. It also updated its methodology to estimate the deemed short-term debt rate. (Exhibit A2-21, Report of the Board on the Cost of Capital for Ontario Regulated Utilities, EB-2009-0084)

Ms. McShane states there is no single right answer to the question of what proportion of a deemed capital structure should be designated as short-term debt. She notes that annual fluctuations for individual utilities will reflect, among other things, the fact that utilities frequently use short-term debt as a bridge between long-term debt issues. Based on her filed evidence she further states that the average proportion of short-term debt to total capital for rated Canadian utilities has been approximately 1 percent to 2 percent. Her review of 2010 data for Ontario electricity distributors indicated that the average and median actual short-term debt ratios were at 2.9 percent and 0.4 percent respectively. (Exhibit B1-9-6, pp. 125-127)

Ms. Ahern states that conceptually the maturity of the debt capital should match the life of the assets being financed. But when the inclusion of short-term debt is optional, its inclusion should be based upon several criteria:

- If its use is sporadic and hence, volatile, it should not be included in the capital structure. However, if its use is consistent and especially at a significantly high level, it is likely financing rate base and possibly should be included;
- If its use is seasonal and self-liquidating, e.g., financing short-term inventories of natural gas in anticipation of heating season, it probably should not be included;
- If short-term debt is financing working capital, it should be included;
- If it is used as bridge financing until permanent financing can be put in place it should be included at the expected cost rates of that permanent financing; and
- If the short-term debt financing construction projects and if the Construction Work In Progress (CWIP) are included in rate base the short-term debt should be included. (Exhibit B2-7, pp. 23-24)

The FBCU provided information showing actual percentages of short-debt for FEI, FEI – Fort Nelson, FEVI, FEW, and FortisBC Inc. for the 2002-2012 period. While there has been significant fluctuation over the years, the average percentages for the period as a share of capital structure amounted to

5.28 percent, 8.58 percent, 10.77 percent, 13.10 percent and 5.27 percent for each respective utility. (Exhibit B1-24, BCUC 2.189.1, 2.189.2)

Commission Determination

The Commission Panel finds it as an accepted fact that all utilities use some short-term debt financing. The FBCU IR responses clearly support this. While there are varying reasons for its use, the evidence demonstrates that, on average, utilities always carry a small portion of short-term debt in their capital structure. The construction work in progress, due to its nature, is often financed by short-term debt.

Accordingly, the Commission Panel finds it reasonable and prudent to include a deemed component of short-term debt in the capital structure for all small utilities without third-party debt to reflect reality. To establish the percentage of short-term debt to be deemed, the Panel has considered testimony of Ms. McShane, FBCU IR responses and the OEB established practice in Ontario. **While acknowledging that there is no correct amount, the Panel concludes that a four percent component for deemed short-term debt provides a reasonable proxy as it is the midpoint of the range of actual short-term borrowing.**

7.5 Setting the Deemed Interest Rates

7.5.1 <u>Deemed Interest Rate for Long-Term Debt</u>

Parties acknowledge that there are at least three reasonable options for determining the deemed interest rate applicable to a small utility without third-party debt. These options are summarized below.

<u>FBCU Option 1:</u>

Step 1: Assign a credit rating on a stand-alone basis, and then obtain indicative quotes from investment dealers or banks based on the credit rating of a comparable proxy issuer. Using proxy companies that are engaged in the power sector or energy infrastructure can help to minimize subjectivity. The FBCU submit this approach is consistent with the stand-alone principle, and is how FEW has financed the debt component of its capital structure. (Exhibit B1-9, pp. 29-30; Exhibit

B1-20, BCUC 1.141.1, 1.141.5, 1.144.2) A reasonable deemed stand-alone rating for a small regulated utility appears to be in the range of BBB to BBB (low), with the deemed debt cost set on this basis. (Exhibit B1-9-6, McShane Evidence, Appendix F, p. 123; Exhibit B1-20, BCUC 1.147.1)

Step 2: Determine a Government of Canada (GoC) bond yield reflecting the proposed term of debt that could be either the 10-year or 30-year bond as the benchmark, or an interpolation of the two. The selected benchmark should reflect the long-term nature of utility assets, contractual terms and available debt terms. (Exhibit B1-9, p. 30)

Step 3: Determine the credit spread of a comparable corporate proxy issuer in similar industries or lines of business (e.g., regulated utility, power generation, energy infrastructure) at the same term to maturity as that selected as the benchmark GoC bond. (Exhibit B1-9, p. 30; Exhibit B1-24, BCUC 1.141.5.2; Exhibit B1-24, BCUC 2.188.2, 2188.3)

<u>FBCU Option 2</u>:

Ms. McShane identified an alternative approach to use the embedded cost of debt of the issuing entity as the deemed interest rate and allocate the deemed debt and interest rate based on an approved capital structure. Currently, FEI-Fort Nelson debt is deemed and the rate is the embedded cost of debt. (Exhibit B1-20, BCUC 1.141.1, 1.141.6) The FBCU submit that this is an administratively efficient way to allocate debt issued by a single regulated entity, allows the benefits of issuing all debt centrally to be shared, and provides a reasonable degree of assurance that the regulated entity raising the debt will be able to recover its actual incurred cost of debt. (Exhibit B1-20, BCUC 1.148.8)

<u>Corix Option</u>:

Corix supports FBCU's recommendation to apply one benchmark credit spread for small utilities to provide regulatory efficiency. To align with the proposed method, the benchmark credit spread would reflect the spread for BBB and BBB (low) rated debt relative to the underlying 10 year GoC bond yield and would reflect incremental risk of small utilities. Corix states that with the benchmark set for small projects, project stakeholders and interveners can then justify any variances from the benchmark depending on the risk exposure. (Exhibit B2-9, BCUC 1.26.3, 1.27.1, 1.46.5, 1.46.7, 1.46.11)

<u>Commission Staff Option</u>:

This option was raised in order to account for the scarcity of BBB-rated utilities in Canada that can be used as proxy, and for the possibility that utility ratings can be changed.

Step 1: Obtain the yield on an appropriate GoC bond as the benchmark.

Step 2: Assign a credit rating to the stand-alone utility/project based on an assessment of financial and business risk (e.g., BBB, other)

Step 3: Obtain the bond yield (credit) spread between GoC bond and a high grade utility (A or A low) and add it to the rate in Step 1.

Step 4 Add a premium, if required, to the credit spread in Step 3. This premium will be calculated as the credit spread between high grade utility bonds (A or A low) and utility bonds of the credit rating estimated in Step 2. The use of historical data (e.g., two most recent years) to have more data points could be considered. (Exhibit A2-43; Exhibit B1-20, BCUC 1.141.9; Exhibit B1-24, 2.188.6; Exhibit B2-9, BCUC 1.26.6)

The FBCU submits it is generally supportive of the Staff option but raised one concern. Ms. McShane cautioned that for any method involving the use of credit rating proxy companies, care should be taken to employ reasonable credit ratings. She re-emphasized that an appropriate credit for small utilities would be BBB to BBB (low), as the inherent risk of small size would preclude them from achieving higher ratings:. "As it is much more likely that the small utility would be BBB on a standalone basis, it makes sense to use a BBB yield as the benchmark to begin with rather than using A-rated proxies." (FBCU Final Submission, pp. 164-165; T5: 680-681)

Commission Determination

The evidence and Final Submissions suggest that setting the deemed interest rate is not a very controversial issue. However, each option reviewed has advantages and disadvantages. The Panel also notes that similar approaches have been adopted in number of recent TES Decisions. For example, BBB-rated proxies were used for the Delta School District Number 37 and Tsawwassen Springs projects.

The Commission Panel has already found that the cost of deemed long-term debt (rate and term) for each utility should be addressed separately on a case-by-case basis. Based on this the Panel recommends that on a go-forward basis the FBCU's Option 1 be used as a guideline for setting the deemed debt rate. The Panel is cognizant of the refinement proposed by Commission Staff to account for the scarcity of BBB-rated utilities in Canada that can be used as a proxy. Should this become a major issue in the future, the Commission can consider switching to use the Commission Staff Option as the guideline.

Because the deemed long-term debt by definition is set for a fixed term, the Panel finds that adjustments will not be necessary during the term of the loan. The only reason for a re-opener would be the situation where a small utility actually issues new debt. The impact of the rate change could be considered a subsequent revenue requirement review.

However, to allow some flexibility, the utilities will have an option to apply for a rate adjustment in accordance with the following reopener-criteria:

- **A measurable change in market conditions**
- **A measurable change in actual debt costs**

The Commission will consider each application for a rate adjustment on a case-by-case basis.

7.5.2 Deemed Interest Rate for Short-Term Debt

The FBCU state the basis for determining the deemed interest rate for short-term debt would be similar to that of long-term interest rate determination. It would be based on indicative credit spread quotes from investment dealers or banks using comparable proxy issuers plus a short-term benchmark yield. A common benchmark yield in Canada is the Canadian Dealer Offered Rate (CDOR). CDOR is the quoted benchmark that is used when a company issues short-term Bankers' Acceptances (BAs), which reflect the short-term benchmark rate plus the company's applicable credit spread. (Exhibit B1-9, p. 31) In response to IRs, the FBCU clarified that quotes from banks would be obtained based on indicated credit rating, not by individual proxy issuer. (Exhibit B-20, BCUC 1.44.2, 1.44.3)

Ms. McShane states that three-month BAs are also a common benchmark for establishing the cost of short-term debt for utilities. (Exhibit B1-9-6, McShane Evidence, Appendix F, pp. 127-128) In response to IRs the FBCU confirm that either the 3-month CDOR or 3-month BA rate is reasonable for setting the short-term rate. Regarding the indicative credit spread quotes, the FBCU state the following approach used by the OEB is reasonable: the OEB obtains up to six quotes from banks. If it obtains six quotes, it discards the highest and the lowest and uses the average of the remaining four. If less than four are obtained, it uses the average of all the quotes obtained. (Exhibit B1-20, BCUC 1.144.4) The FBCU submit that the OEB formulaic approach is an efficient and transparent way of estimating a deemed short-term debt rate. However, the FBCU stress that the OEB methodology is premised on a single debt rating, a short-term debt rating of R1-low, which generally corresponds to long-term credit ratings in the A category; i.e., higher than would be applicable to the small utilities. To overcome this problem, the FBCU suggest using a more reasonable short-term credit rating, one that would correspond to a BBB/BBB (low) on the long-term rating scale. (Exhibit B1-20, BCUC 1.144.5, 1.144.5.1)

Commission Determination

The Commission Panel recommends that small utilities use either the 3-month CDOR or 3-month BA rate as a basis and obtain 3-4 quotes to establish the credit spread for the purpose of setting the deemed short-term interest rate. Because it is highly unlikely that small utilities, especially the TES utilities/projects, will have frequent revenue requirement reviews, the Panel finds that there is no requirement for an annual adjustment mechanism. **The short-term rates are to be reset at the time of the revenue requirement review only.**

8.0 OTHER MATTERS

8.1 Reliance on Less Complex Financial Methodology

Expert witnesses in this proceeding expressed reluctance to use more complex models that could improve understanding and/or estimating the cost of equity. For instance, Ms. McShane states: "I think it's reasonable to try to capture these other factors. I know that it's been difficult to have regulators accept the Fama/French type models ..." (T5:721)

In response to a question from Commissioner Giammarino, Dr. Vander Weide expressed similar concerns:

> **COMMISSIONER GIAMMARINO:** "And [Fama/French] suggest that maybe the future is in an inter-tempo CAPM, that has multi factors. And that would allow for changes in the opportunities – the investments that are available to investors. Did you consider that as an alternative?" (T6:1103)
>
> **DR. VANDER WEIDE:** "That would certainly be an alternative, but from my years in testifying on the cost of capital, I have realized that there are two qualities that make a model present reasonable evidence. One is that it's -- you can estimate the inputs to the model reasonably well, and two, it has to be reasonably easy to understand. So that one can judge the model in the context where everyone doesn't have Ph.D.s in finance or economics. And once you get into dynamic capital asset pricing models, to me that's getting into a level that's too complicated for discussion in a public forum." (T6:1103)

Although Dr. Booth added a credit spread adjustment to his CAPM analysis, he also expressed a similar sentiment about adding further factors to his CAPM, as shown by the following exchange:

> **COMMISSIONER GIAMMARINO**: …there is sort of a well-established set of suspects. You've looked at one.
>
> **DR. BOOTH:** Correct.
>
> **COMMISSIONER GIAMMARINO:** So why not look at all?
>
> **DR. BOOTH:** Two reasons. First of all, with all due respect to the Commission, it's a question of getting things to the Commission in an understandable way through cross-examination. And KISS works. That a simple way of looking at these things, I think, makes sense. The only time,

> for example, I saw a company put forward the Fama French model was before the Gaz Métro. And the witness had a real tough time with the more complicated model. And the Régie was very reluctant to adopt a more complicated model.
>
> **COMMISSIONER GIAMMARINO:** Right.
>
> **DR. BOOTH:** So when you get down to conditioning, you're absolutely correct. You think about Chandrell and Ross, and you think about economic factors affecting security returns, you can go to more measures. Does the addition of more measures make the testimony more saleable to a Commission? And the answer to that is generally no. It may make it more saleable in an academic seminar but it's easier, I think, to pick on one thing that people can relate to – credit spreads – that was picked up in most of the hearings in 2009, which seems to make sense, and seems to be consistent with the academic literature, than to go through a more complicated model with term structure, yield parameters, dividend yields or other conditioning variables. So, I pick one, the credit spread. (T8:1658-59)

The Commission Panel accepts that evidence should meet some basic criteria. For example, expert witnesses must have confidence in their estimates; and the evidence must be understandable to the Panel, ideally for all parties involved. The Panel is, however, concerned that experts pay undue attention to prior assessments of the limits of what the Commission will understand and/or accept. While evidence put forward should be as helpful as possible to a Panel dealing with the difficult task of determining the appropriate rate of return and capital structure, it should reflect the expert's best judgment about the state-of–the-art methodology, which should in turn be presented in an understandable way.

It is the Commission Panel's opinion that the purpose of a cost of equity model is to provide structure to the discussion of 'what is a fair rate of return.' Models used to fulfill this purpose provide structure and clarity, and in turn provide a basis for determining the truth of any particular assessment. Models are abstractions and, by definition, imperfect representations. As a result, it is up to the Panel to decide how much confidence it should put in various models that have unrealistic assumptions and do not explain returns perfectly. The Panel must also understand where judgment needs to be applied to the output delivered by these models.

Specifically, in Section 5.2.1, the Panel identified some of the weaknesses related to the adjustments to the CAPM. In particular, the experts expressed reluctance to include additional potential extensions to the CAPM because they were perhaps "too complex" to the Panel. This in turn leaves open what results other extensions could imply. Similarly, in the beginning of Section 5.2 the Panel identified the lack of global perspective in assessing the investor's portfolio. A more clear set of principles, including a definition of FEI's investors' portfolios (i.e., Global, North American, Canadian) would have been valuable. Accordingly, the Panel invites more comprehensive evidence on these topics in the future.

The Commission Panel believes that one of the roles of the expert is to guide the regulator in evaluating the trade-off between the complexities of the structures needed to evaluate arguments versus the reliability of the structures. This trade-off is at the heart of cost of capital hearings. As this trade-off evolves constantly, the testimony should evolve with it.

8.2 FEI - The Benchmark Utility

Based on the evidence related to long and short-term risk before the Commission Panel we are in agreement with describing FEI as the "benchmark utility" rather than a "low-risk benchmark utility." While the Panel has determined that the level of risk is somewhat less in a number of areas than those which existed at the time of the 2009 Decision, there has been little change in many areas. Therefore, we are of the view that describing FEI as low-risk would not be appropriate. Accordingly, for the purposes of Stage 2 of the GCOC, FEI will be referred to as the benchmark utility. **The common equity component and the approved ROE in this Decision will serve as the benchmark cost of capital for any other utility in British Columbia that uses the benchmark utility to set rates.**

The issue as to whether FEI is a pure-play gas distribution received little direct attention beyond the October 4, 2012 procedural conference. However, the Commission Panel has considered the issue in the context of the level of throughput related to alternative energy initiatives. It appears that FEI's forecasted throughput related to alternative energy initiatives is relatively small. Under cross-examination, FBCU witness, Mr. Stout with reference to natural gas transportation initiatives stated:

> "...we forecast two and a half to three petajoules in 2017. I think even if you go to some volume that's in the 10 to 15 petajoule range, it's still less than 10 percent of the throughput of the system, say 5 to 10 percent of the total throughput". (T3:317)

Based on Mr. Stout's testimony, the Commission Panel accepts that FEI at this point in time is primarily a pure-play gas distribution utility.

While Stage 1 of the GCOC proceeding has been mainly concerned with determining an appropriate cost of capital for the benchmark utility, Stage 2 will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk. The Commission Panel considers that it is feasible that a stand-alone public utility may face overall business risks that are either higher, lower or the same as the benchmark utility.

The primary factors that have influenced FEI's long-term risk have been identified and addressed in Section 4.2. In addition, we have further identified and made determinations upon FEI's short-term risk. In Stage 2 of the GCOC, the public utilities, where appropriate, will be required to describe how they differ from the benchmark utility on these and any other risk factor as it relates to them. In addition, in Section 7.2.5 the Commission Panel has described a risk matrix (included in Appendix E) as a tool for the small utilities (especially the TES utilities) to further assist in justifying their case for an appropriate capital structure and risk premium.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

Original signed by:
____
D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:
____
R. GIAMMARINO
COMMISSIONER

Original signed by:
____
M.R. HARLE
COMMISSIONER

Original signed by:
____
L.A. O'HARA
COMMISSIONER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-75-13

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Generic Cost of Capital Proceeding

BEFORE: D.A. Cote, Commissioner/Panel Chair
M.R. Harle, Commissioner
L.A. O'Hara, Commissioner
R. Giammarino, Commissioner

May 10, 2013

O R D E R

WHEREAS:

A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third party debt;

B. Appendix C to Order G-20-12 divided public utilities into two categories for the purpose of the proceeding: "Affected Utilities" and "Other Utilities;"

C. FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc. and FortisBC Inc. (FortisBC)[collectively (FBCU)]; Corix Multi-Utility Services Inc. (Corix); and Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (PNG) registered as Affected Utilities. The British Columbia Hydro and Power Authority (BC Hydro) and the River District Energy (RDE) registered as Other Utilities;

D. Among the Interveners who registered for the proceeding, the Association of Major Consumers of BC (AMPC), British Columbia Pensioners' and Seniors' Organization (BCPSO), Commercial Energy Consumers (CEC) [collectively B.C. Utility Customers], and the Industrial Customers Group of FortisBC Inc. (ICG) actively participated;

E. By Order G-47-12 dated April 18, 2012, the Commission issued the Final Scoping Document for the proceeding. The Scoping Document sets out the purpose and the scope of the proceeding. Matters within the scope of the proceeding included, among others, the appropriate cost of capital and its effective date for a benchmark low-risk utility, the establishment of a benchmark ROE, the consideration of an automatic adjustment mechanism, and the deemed capital structure and deemed cost of capital for small utilities without third-party debt;

F. By Order G-50-12 dated April 19, 2012, the Commission, among other matters, set out the further procedural matters to be addressed in the proceeding and a Preliminary Minimum Filing Requirements (MFR) for Affected Utilities document. Parties were invited to make submissions on the Preliminary MFR for Affected Utilities by May 3, 2012, and on the allocation of Participant Assistance/Cost Awards (PACA), PACA eligibility, and/or the Draft Preliminary Regulatory Timetable by May 9, 2012;

G. By Order G-72-12 dated June 1, 2012, the Commission, among other matters, issued the Final Minimum Filing Requirements for Affected Utilities and the Preliminary Regulatory Timetable for the proceeding;

H. On June 8, 2012, the Commission released "A Survey of Cost of Capital Practices in Canada" prepared by The Brattle Group for the Commission (Brattle Report). Utilities and Interveners were provided with the opportunity to ask Information Requests on the Brattle Report;

I. By Order G-84-12 dated June 20, 2012, the Commission amended the Preliminary Regulatory Timetable, establishing, among other things, a Procedural Conference for October 2, 2012 and the commencement date for an oral hearing, if required, on December 12, 2012. The Procedural Conference was subsequently rescheduled to October 4, 2012;

J. At the Procedural Conference the Commission received, among others, submissions on the following items: (1) the appropriate benchmark utility for the determination of the generic cost of capital; (2) whether a Stage 2 for the purpose of determining an appropriate cost of capital for Affected and Other Utilities to immediately follow Stage 1 was desirable; (3) whether an oral phase was required and (4) the proposed timetable going forward;

K. By Order G-148-12 dated October 11, 2012, the Commission determined that : (1) FEI in its present pre-amalgamation state, would serve as the benchmark for the proceeding and whether FEI in 2012 is a pure play gas distribution utility would be determined following the hearing of further evidence; (2) a Stage 2 would be added to the proceeding with the schedule to be determined prior to the end of Stage 1; and (3) the review of the proceeding would continue by way of an oral hearing commencing on December 12, 2012;

L. By Order G-187-12 dated December 10, 2012, the Commission ordered that: (1) the current ROE and capital structure for FEI, the designated benchmark utility, and all regulated entities in B.C. that rely on the benchmark utility, except British Columbia Hydro and Power Authority, are to be maintained and made interim, effective January 1, 2013; and (2) any determinations of the premiums on the benchmark ROE and capital structure of regulated utilities that depend on the benchmark utility for rate setting will be made following the decision in Stage 2; M. The oral public hearing took place over a period of seven days between December 12, 2012 and December 21, 2012. A total of eight witness panels from FBCU and Interveners gave evidence;

N. FBCU, PNG, Corix, AMPC/CEC, ICG and BCPSO filed Final Submissions. FBCU filed a Reply Submission; and

O. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

.../3

NOW THEREFORE, the Commission orders as follows:

1. The common equity component appropriate for the benchmark utility, FEI, effective January 1, 2013 is 38.5 percent.

2. A Return on Equity (ROE) for the benchmark utility, FEI, is established at 8.75 percent effective January 1, 2013.

3. An Automatic Adjustment Mechanism (AAM) formula for annually setting the ROE of the benchmark utility between ROE proceedings is adopted commencing January 1, 2014. The AAM formula will operate until December 31, 2015. The implementation of the model will be subject to conditions outlined in the Decision.

4. FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015.

5. The common equity component and the ROE approved in Paragraphs 1 and 2 of this Order will continue to serve as the Benchmark cost of capital for any other utility in British Columbia that uses a Benchmark Utility to set rates.

6. Within 30 days of the date of this Order, FEI is to file:

    (a) a document setting out how and when it will implement the change to its capital structure;

    (b) amended rate schedules in accordance with paragraphs 1 and 2 of this Order as well as a proposal on the treatment of the refundable portion of the rates collected since January 1, 2013.

7. Small utilities without third-party debt are to include a deemed component of short-term debt of 4 percent.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of May 2013.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-1	G-20-12 (Feb 28, 2012)	• Stated purpose in establishing the GCOC proceeding • All regulated utilities determined to be applicants in this proceeding. Utilities are divided into "Affected Utilities" and "Other Utilities." • Issued initial regulatory timetable for registration of Utilities and Interveners and written submissions on the Preliminary Scoping Document
A-3	G-47-12 (April 18, 2012)	• Issued Final Scoping Document
A-5	G-50-12 (April 19, 2012)	• Issued preliminary Minimum Filing Requirements (MFR) • Issued preliminary regulatory timetable for written submissions on the MFR and the cost allocation of Participant Assistance/Cost Awards (PACA) and PACA eligibility
A-6	G-72-12 (June 1, 2012)	• Issued Final MFR • Determined the principles in the allocation of PACA costs and PACA cost eligibility • Considered expansion of the current proceeding by conducting the GCOC proceeding in two stages • Issued preliminary regulatory timetable for a Procedural Conference and Stage 1 of the GCOC proceeding. • Put on the record the terms of reference for the survey Report carried out by The Brattle Group
A-9	Order G-84-12 (June 20, 2012)	• Issued amended preliminary regulatory timetable

LIST OF PROCEDURAL ORDERS

Exhibit Number	Commission Order (Date)	Determinations
A-16 and A-17	Letter L-52-12 (September 13, 2012)	• Established the amended date and agenda for the Procedural Conference
A-22	G-148-12 (October 11, 2012)	• Determined that FEI in 2012 in its pre-amalgamation state, will serve as the benchmark utility for the GCOC proceeding • Determined that a Stage 2 will be added to the proceeding • Determined that review will take place by an oral hearing commencing on December 12, 2012
A-30	G-187-12 (December 10, 2012)	• Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013

LIST OF APPEARANCES

G. Fulton, Q.C.	Commission Counsel
L. Bussoli	Commission Counsel
M. Ghikas	FortisBC Utilities
T. Ahmed	FortisBC Utilities
M. Cheesman	Corix Multi-Utility Services Inc. (Corix)
J. Kennedy	Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.
R.B. Wallace, Q.C.	Association of Major Power Customers of B.C. (AMPC)
R. Hobbs	Industrial Customers Group of FortisBC Inc. (ICG)
L. Worth	British Columbia Pensioners' and Seniors' Organization (BCPSO)
E. Kung	British Columbia Pensioners' and Seniors' Organization (BCPSO)
T. Braithwaite	British Columbia Pensioners' and Seniors' Organization (BCPSO)
C. Weafer	Commercial Energy Consumers of British Columbia (CEC)
D. Craig	Commercial Energy Consumers of British Columbia (CEC)
J. Christian	British Columbia Hydro and Power Authority (BC Hydro)
B. Hobkirk	British Columbia Hydro and Power Authority (BC Hydro)
R. Hanson	River District Energy
J. Quail	Canadian Office and Professional employees' Union Local 378

E. Cheng Y. Domingo J. Tran B. Grant J. Fraser	Commission Staff
Allwest Reporting Ltd.	Court Reporters

LIST OF PANELS

FORTISBC INC., FORTISBC ENERGY INC., FORTISBC ENERGY (VANCOUVER ISLAND) INC., AND FORTISBC ENERGY (WHISTLER) INC.

PANEL 1 - COMPANY EVIDENCE

Roger A. Dall'Antonia	Vice President, Strategic Planning, Corporate Development and Regulatory Affairs (Panel Chair)
Douglas Stout	Vice President, Energy Solutions and External Relations
Cynthia Des Brisay	Vice President, Energy Supply and Resource Development
Michele Leeners	Vice President, Finance and CFO

PANEL 2 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

Kathleen C. McShane, MBA, CFA	President Foster Associates, Inc.

PANEL 3 - EXPERT OPINION ON AUTOMATIC ADJUSTMENT MECHANISMS

James M. Coyne	Concentric Advisors

PANEL 4 - EXPERT OPINION ON CAPITAL MARKETS

Aaron M. Engen	Managing Director BMO Capital Markets (Energy Infrastructure Group)

PANEL 5 - EXPERT OPINION ON A BENCHMARK FAIR RETURN

James H. Vander Weide, PhD	Duke University

CORIX MULTI-UTILITY SERVICES INC. (CORIX)

Pauline M. Ahern, MBA	Principal AUS Consultants

LIST OF PANELS

THE INDUSTRIAL CUSTOMERS GROUP OF FORTISBC INC. (ICG)

Andrew Safir, PhD	President Recon Research Corporation

THE ASSOCIATION OF MAJOR POWER CUSTOMERS (AMPC), THE COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC), THE BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO), COLLECTIVELY THE BC UTILITY CUSTOMERS

Laurence D. Booth, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 1

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated February 28, 2012 and Order G-20-12 – Establishing an initial Regulatory Timetable
A-2	Letter Dated April 17, 2012 – Response clarifying Union Gas's Intervener Status
A-3	Letter dated April 18, 2012 and Order G-47-2012 – Reasons for Decision and Final Scoping Document
A-4	Letter dated April 18, 2012 – Appointment of Panel
A-5	Letter dated April 19, 2012 - Order G-50-12 List of Further Procedural Matters
A-6	Letter dated June 1, 2012 - Order G-72-12 Issuing Preliminary Timetable, PACA costs, Final Minimum Filing Requirements for Affected Utilities
A-7	Letter dated June 6, 2012 - Request for Variance of Regulatory Timetable Order G-72-12
A-8	Letter dated June 8, 2012 – Commission Consultant's Survey Report
A-9	Letter dated June 20, 2012 – Order G-84-12 - Amended Preliminary Regulatory Timetable
A-10	Letter dated July 27, 2012 – Request for Comments on the Addition of a Panel Member
A-11	Letter dated August 22, 2012 – Appointment of Commissioner Mr. R. Giammarino
A-12	Letter dated August 31, 2012 – Information Request No. 1 to FortisBC Utilities
A-13	**CONFIDENTIAL** Letter dated August 31, 2012 – CONFIDENTIAL Information Request No. 1 to FortisBC Utilities
A-14	Letter dated August 31, 2012 – Information Request No. 1 to PNG

Exhibit No.	Description
A-15	Letter dated August 31, 2012 – Information Request No. 1 to Corix
A-16	Letter dated September 13, 2012 – L-52-12 Amending Regulatory Timetable
A-17	Letter dated September 27, 2012 – Agenda for Procedural Conference
A-18	Letter dated October 9, 2012 – Information Request No. 2 to FortisBC Utilities
A-19	**CONFIDENTIAL** Letter dated October 9, 2012 – CONFIDENTIAL Information Request No. 2 to FortisBC Utilities
A-20	Letter dated October 9, 2012 –Information Request No. 2 to Corix
A-21	Letter dated October 11, 2012 – Order G-148-12 and Reasons for Decision
A-22	Letter dated October 24, 2012 - Request to Access Confidential Material
A-23	Letter dated October 31, 2012 - Access to Confidential Material Response
A-24	Letter dated November 1, 2012 – Confidential Material Access to AMPC (Exhibit C6-11)
A-25	Letter dated November 16, 2012– Information Request No. 1 to ICG on Intervener Evidence
A-26	Letter dated November 16, 2012– Information Request No. 1 to AMPC on Intervener Evidence
A-27	Letter dated November 20, 2012 – Request for submissions
A-28	Letter dated December 3, 2012 – Oral Public Hearing Information
A-29	Letter dated December 5, 2012 – Opening Statements Clarification
A-30	Letter dated December 10, 2012 - Commission Order G-187-12 establishing the current ROE and capital structure
A-31	Letter dated February 14, 2013 – Commission Response to request for extension

Exhibit No.	**Description**
COMMISSION STAFF DOCUMENTS	
A2-1	Letter Dated February 28, 2012 - Commission Staff Filing British Columbia Utilities Commission letter dated November 28, 2011-Preliminary Notification of Initiation of Generic Cost of Capital Proceeding
A2-2	Letter Dated February 28, 2012 - Commission Staff Filing the Terasen Utilities (December 8, 2010) – Automatic Adjustment Mechanism Review
A2-3	Letter dated June 8, 2012 – Commission Staff Filing the Brattle Group Survey of Cost of Capital Practices in Canada
A2-4	Letter dated July 12, 2012 - Commission Staff Filing Response to AMPC Information Request to Commission Consultants
A2-5	Letter dated July 12, 2012 - Commission Staff Filing Response to FEU Information Request on the Consultants Survey Report
A2-6	Letter dated July 12, 2012 - Commission Staff Filing Response to Industrial Customer Group Information Request on the Consultants Survey Report
A2-7	Letter dated July 12, 2012 - Commission Staff Filing Response to BCOAPO Information Request to Consultants Report
A2-8	Letter dated July 12, 2012 - Commission Staff Filing Response to CEC Information Request to Consultants Report
A2-9	Letter dated July 13, 2012 – Commission Staff Filing BCUC Request for Proposal for a Survey of Canadian Cost of Capital Practice Report
A2-10	Letter dated August 31 2012 – Commission Staff Filing Behavior of the Firm under Regulatory Constraint by Harvey Averch and Leland L. Johnson
A2-11	Letter dated August 31 2012 – Commission Staff Filing Extract from Terasen 2005 and 209 ROE CAP Applications
A2-12	Letter dated August 31 2012 – Commission Staff Filing Extract from FEU 2012-13 Revenue Requirements Decision
A2-13	Letter dated August 31 2012 – Commission Staff Filing Extract from Bloomberg News (Report dated August 6, 2012)

Exhibit No.	Description
A2-14	Letter dated August 31 2012 – Commission Staff Filing Capital Structure - A Comparison
A2-15	Letter dated August 31 2012 – Commission Staff Filing Summaries of Reports and Notes from Recent Credit Rating Agencies and Investment Banks on FEI's Risk and Credit Metrics
A2-16	Letter dated August 31 2012 – Commission Staff Filing Extract from Washington Utilities and Transportation Commission Order 08 Decision
A2-17	Letter dated August 31 2012 – Commission Staff Filing Fitch Affirms National Fuel Gas' IDR at 'A'
A2-18	Letter dated August 31 2012 – Commission Staff Filing The City of Vancouver - District Energy Connectivity Standards Information for Developers
A2-19	Letter dated August 31 2012 – Commission Staff Filing City of Surrey – District Energy System By-law, 2012, No. 17667
A2-20	Letter dated August 31 2012 – Commission Staff Filing Extract from BCUC Information Request No. 2 to River District Energy Limited Partnership
A2-21	Letter dated August 31 2012 – Commission Staff Ontario Energy Board Report of the Board on the Cost of Capital for Ontario's Regulated Utilities December 11, 2009
A2-22	Letter dated August 31 2012 – Commission Staff Filing Ontario Energy Board Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012
A2-23	Letter dated August 31 2012 – Commission Staff Filing Summary of Reports from Recent Credit Rating Agencies and Investment Banks on PNG's Risks and Credit Metrics
A2-24	Letter dated October 9, 2012 – Commission Staff Filing Bradshaw et al. - Playing Favorites
A2-25	Letter dated October 9, 2012 – Commission Staff Filing CTA-Risk-Free Rate Determination
A2-26	Letter dated October 9, 2012 – Commission Staff Filing Exhibit A2-26 OEB Cost of Capital Parameter, May 1 2012

Exhibit No.	Description
A2-27	Letter dated November 16, 2012 - Commission Staff Filing Cost of Capital by Sector_NYU_Value Line Database
A2-28	Letter dated November 16, 2012 - Commission Staff Filing Gau, Thompson 2012 Capitalization Rate Study
A2-29	Letter dated November 16, 2012 - Commission Staff Filing Schaeffler and Weber-The Cost of Equity of Network Operators
A2-30	Letter dated November 16, 2012 - Commission Staff Filing TD-Long-Term Returns October 2012
A2-31	Letter dated November 16, 2012 - Commission Staff Filing Ashton et al- Analysts' Optimism in Earnings Forecasts
A2-32	Letter dated November 16, 2012 - Commission Staff Filing Understanding Corporate Bond Spreads Using Credit Default Swaps
A2-33	Submitted at Oral Hearing December 12, 2012 – Commission Staff Filing FEU 2012-2013 Revenue Requirements G-44-12 Compliance Filing
A2-33-1	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing page 1 of letter dated may 1, 2012 to BCUC from FortisBC, with two pages attached
A2-34	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Vancouver Sun Article Natural gas seen as green fuel
A2-35	Submitted at Oral Hearing December 13, 2012 – Commission Staff Filing Staff Witness Aid
A2-36	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing pages 7 to 10 from Standard & Poors Report
A2-37	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Long-Term Economic Forecast, TD Economics, September 18, 2012
A2-38	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Attachment 8.2(A), page 17 of 18, Results of Differences in Systematic Risk
A2-39	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Extract from Order No. 09-176 from Public Utility Commission of Oregon

Exhibit No.	Description
A2-40	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Rating Report, February 29, 2012 from DBRS
A2-41	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Document Headed Moody's Investors Service, Credit Opinion: FortisBC Energy Inc.
A2-42	Submitted at Oral Hearing December 14, 2012 – Commission Staff Filing Five-Page Document, First Page Headed Returns on Average Common Stock Equity for Sample of U.S. Utilities
A2-43	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Approaches to Estimating the Deemed Interest Rate for Long Term Debt
A2-44	Submitted at Oral Hearing December 17, 2012 – Commission Staff Filing Excerpt of FEI Kelowna DES CPCN Application
A2-45	Submitted at Oral Hearing December 17, 2012 – Document Headed Credit Rating and Equity Risk Premium
A2-46	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Weathering the Headwinds to Canada's Economic Growth 21 November 2012
A2-47	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Puget Sound Energy Inc.
A2-48	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Document Headed Power & Utilities Research, the One-Two Punch: Growth Combined with Attractive Yield
A2-48-1	Submitted at Oral Hearing December 18, 2012 – Commission Staff Filing Extract from BMO Capital Markets, page 11, Headed Power & Utilities
A2-49	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Ontario Energy Board, Report of Board, December 20, 2006
A2-50	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Extract from Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First
A2-51	Submitted at Oral Hearing December 19, 2012 – Commission Staff Filing Witness Aid Prepared by Commission Staff Entitled Informed Expert Judgment

Exhibit No.	**Description**
AFFECTED UTILITIES DOCUMENTS	
B1-1	**BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU)** Letter Dated March 15, 2012 – Notice of Registration
B1-2	Letter Dated March 21, 2012 – FBCU Submission on the Preliminary Scoping Document
B1-3	Letter Dated May 3, 2012 – FBCU Submission on Minimum Filing Requirements
B1-4	Letter Dated May 9, 2012 – FBCU Submission regarding Order G-50-12 Appendix A
B1-5	Letter Dated June 5, 2012 – FBCU Submitting Request for Variance of Preliminary Regulatory Timetable
B1-6	Letter Dated June 5, 2012 – FBCU Reply Submissions regarding Request for Variance of Preliminary Regulatory Timetable
B1-7	Letter Dated June 22, 2012 – FBCU Submitting Information Request regarding the Commission Consultant Survey Report
B1-8	Letter Dated August 2, 2012 – FBCU Submitting comments regarding the addition of a panel member
B1-9	Letter Dated August 3, 2012 – FBCU Submitting Evidence
B1-9-1	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 1 to 2
B1-9-2	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3A – Debt Investment Analyst Reports for FEI
B1-9-3	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Beacon to Credit Suisse
B1-9-4	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Section 3B – Equity Analyst Reports Macquarie to UBS

Exhibit No.	Description
B1-9-5	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendix A – Sections 4 to 11
B1-9-6	Letter Dated August 3, 2012 – FBCU Submitting Evidence Appendices B to J
B1-9-7	CONFIDENTIAL Letter Dated August 3, 2012 – FBCU Submitting Evidence CONFIDENTIAL Appendices
B1-10	Letter Dated September 24, 2012 – FBCU Submitting Response to BCPSO IR No. 1
B1-11	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – FBCU
B1-12	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – A. Engen
B1-13	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Concentric
B1-14	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – Dr. Vander Weide
B1-15	Letter Dated September 24, 2012 – FBCU Response to BC Utility Customers IR1 – K. McShane
B1-16	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – A. Engen
B1-17	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Concentric
B1-18	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 - Dr. Vander Weide
B1-19	Letter Dated September 24, 2012 – FBCU Response to ICG IR No.1 – K. McShane
B1-20	Letter Dated September 24, 2012 – FBCU Response to BCUC IR No.1
B1-20-1	CONFIDENTIAL Letter Dated September 24, 2012 – FBCU Confidential Response to BCUC IR No.1
B1-21	CONFIDENTIAL Letter Dated September 24, 2012 – FBCU Response to Confidential BCUC IR No.1

Exhibit No.	Description
B1-22	Submitted at Procedural Conference Letter Dated October 3, 2012 – FBCU Counsel's Oral Submissions
B1-23	Letter dated October 26, 2012 – FBCU Response to Confidentiality Request
B1-24	Letter dated October 29, 2012 – FBCU Response to BCUC IR No. 2
B1-25	CONFIDENTIAL Letter dated October 29, 2012 – FBCU Response to BCUC Confidential IR No. 2
B1-26	Letter dated October 29, 2012 – FBCU Response to BCPSO IR No. 2
B1-27	Letter dated November 2, 2012 – FBCU Comments regarding Confidential Material Access
B1-28	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to AMPC/BC Utility Customers on the Evidence of Dr. Booth
B1-29	Letter dated November 16, 2012 – FBCU Submitting IR No. 1 to ICG on the Evidence of Dr. Safir
B1-30	Letter Dated November 23, 2012 – FBCU Submission on Interim Rates Jan 1, 2013
B1-31	Letter Dated November 30, 2012 – FBCU Submitting Witness Panels and Direct Testimony
B1-32	Letter dated December 6, 2012 – FBCU Submitting Rebuttal Evidence
B1-33	Letter dated December 10, 2012 – FBCU Submitting Opening Statement
B1-34	Submitted at Oral Hearing December 12, 2012 – FBCU Written Opening Statement of Counsel
B1-35	Submitted at Oral Hearing December 12, 2012 – FBCU Revised: Exhibit B1-9-6, Appendix H, page 51, Figure 34
B1-36	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 1
B1-37	Submitted at Oral Hearing December 12, 2012 – FBCU Undertaking No. 2
B1-38	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 3

Exhibit No.	Description
B1-39	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 4
B1-40	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 5
B1-41	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 6
B1-42	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 7
B1-43	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 8
B1-44	Submitted at Oral Hearing December 13, 2012 – FBCU Undertaking No. 9
B1-45	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 10
B1-46	Submitted at Oral Hearing December 14, 2012 – FBCU Undertaking No. 11
B1-47	Submitted at Oral Hearing December 14, 2012 – FBCU Filing Testimony of Kathleen C. McShane Tab 2
B1-48	Submitted at Oral Hearing December 17, 2012 – FBCU Undertaking No. 12
B1-49	Submitted at Oral Hearing December 18, 2012 – FBCU Filing Testimony Figures Update
B1-49-1	Letter received January 3, 2013 – FBCU Filing Remaining Chart Updates
B1-50	Submitted at Oral Hearing December 19, 2012 – FBCU Filing 104 page Collection of Documents Used in Cross Examination of Dr. Booth
B1-51	Submitted at Oral Hearing December 21, 2012 – FBCU Filing Compendium of Extracts, First Page Entitled Fair Return for Terasen Gas Inc. (TGI) August 2009
B1-52	Letter received January 3, 2013 – FBCU Undertaking No. 13
B1-53	Letter received January 3, 2013 – FBCU Undertaking No. 14
B1-54	Letter received January 3, 2013 – FBCU Undertaking No. 15
B1-55	Letter received January 3, 2013 – FBCU Undertaking No. 16
B1-56	Letter received January 3, 2013 – FBCU Undertaking No. 17
B1-57	Letter received January 3, 2013 – FBCU Undertaking No. 18

Exhibit No.	Description
B1-58	Letter received January 3, 2013 – FBCU Undertaking No. 19
B1-59	Letter received January 3, 2013 – FBCU Undertaking No. 20
B1-60	Letter received January 29, 2013 – FBCU Undertaking No. 21
B1-61	Letter received January 29, 2013 – FBCU Undertaking No. 22
B1-62	Letter received January 29, 2013 – FBCU Undertaking No. 23
B1-63	Letter received January 29, 2013 – FBCU Undertaking No. 24
B1-64	Letter received January 29, 2013 – FBCU Undertaking No. 25
B1-65	Letter received January 29, 2013 – FBCU Undertaking No. 26
B1-66	Letter received January 29, 2013 – FBCU Undertaking No. 27
B1-67	Letter received January 29, 2013 – FBCU Undertaking No. 28
B1-68	Letter received January 29, 2013 – FBCU Undertaking No. 29
B2-1	**CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter Dated March 14, 2012 – Notice of Registration
B2-2	Letter Dated March 21, 2012 – Corix Submission on the Preliminary Scoping Document
B2-3	Letter Dated May 3, 2012 – Corix Submission on Minimum Filing Requirements
B2-4	Letter Dated May 9, 2012 – Corix Submission regarding Order G-50-12 Appendix A
B2-5	Letter Dated June 8, 2012 – Corix Submission on FBCU Request for Variance
B2-6	Letter Dated August 3, 2012 – Corix Submitting Comments Regarding the Addition of a Panel Member
B2-7	Letter Dated August 3, 2012 – Corix Submitting Evidence
B2-8	Letter Dated September 24, 2012 – Corix Submitting Response to BCPSO IR No. 1
B2-9	Letter Dated September 24, 2012 – Corix Submitting Response to BCUC IR No. 1

Exhibit No.	**Description**
B2-10	Letter Dated October 18, 2012 – Corix Submitting Response to BCUC IR No. 2
B2-11	Letter Dated November 23, 2012 – Corix Submission regarding A-27
B2-12	Submitted at Oral Hearing December 18, 2012 – Corix Filing Opening Remarks of Counsel for Corix Multi-Utility Services Inc., December 12, 2012
B2-13	Submitted December 24, 2012 – Corix Filing Undertaking Document Titled Before the Florida Public Service Commission
B2-14	Submitted December 24, 2012 – Corix Filing Undertaking Document titled Comparison of Business Risk Adjustments in Cost of Capital Testimony Filed by Ms. Pauline M. Ahern
B2-15	Letter received January 3, 2013 - Corix Filing Response to Undertaking
B3-1	**PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG)** Online Registration Dated March 16, 2012 – Notice of Registration
B3-2	Letter Dated March 21, 2012 – PNG Submission on the Preliminary Scoping Document
B3-3	Letter Dated May 3, 2012 – PNG Submission on Minimum Filing Requirements
B3-4	Letter Dated May 9, 2012 – PNG Submission Regarding Order G-50-12 Appendix A
B3-5	Letter Dated June 8, 2012 – PNG Submission Regarding Variance of the Regulatory Timetable
B3-6	Letter Dated August 3, 2012 – PNG Submitting Comments Regarding the Addition of a Panel Member
B3-7	Letter Dated August 3, 2012 – PNG Submitting Evidence
B3-8	Letter Dated September 24, 2012 – PNG Submitting Response to BCUC IR No. 1
B3-9	Letter Dated September 24, 2012 – PNG Submitting Response to BCPSO
B3-10	Letter Dated September 24, 2012 – PNG Submitting Response to AMPC, BCPSO and CEC
B3-11	Letter Dated November 23, 2012 – PNG Submission Regarding A-27

Exhibit No.	Description
B3-12	Letter Dated November 30, 2012 – PNG Submitting Comments regarding Witness Panels
OTHER UTILITIES DOCUMENTS	
B4-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter Dated March 12, 2012 – Notice of Registration
B4-2	Letter Dated March 21, 2012 – BCH Submission on the Preliminary Scoping Document
B4-3	Letter Dated May 3, 2012 – BCH Submission on Minimum Filing Requirements
B4-4	Letter Dated May 9, 2012 – BCH Submission Regarding Order G-50-12 Appendix A
B4-5	Letter Dated June 8, 2012 – BCH Submission Regarding variance of the Regulatory Timetable
B4-6	Letter Dated August 3, 2012 – BCH Submitting Comments Regarding the Addition of a Panel Member
B4-7	Letter Dated November 23, 2012 - BCH Submission Regarding A-27
B4-8	Letter Dated November 30, 2012 – BCH Submitting Comments Regarding Witness Panels
B5-1	**RIVER DISTRICT ENERGY (RDE)** Letter Dated March 12, 2012 – Notice of Registration
INTERVENER DOCUMENTS	
C1-1	**UNION GAS LIMITED (UG)** Letter dated March 5, 2012 – Request for Intervener Status by Patrick McMahon
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated March 15, 2012 – Request for Intervener Status by James Quail
C2-1-1	Letter dated March 20, 2012 – COPE 378 Submitting Intervention Supplementary Comments
C2-2	Letter dated April 19, 2012 - COPE 378 Submitting Updating Consultant details
C2-3	Letter dated June 26, 2012 - COPE 378 Submitting Updating Consultant Information

Exhibit No.	Description
C3-1	**SENTINEL ENERGY MANAGEMENT (SEM)** Online Registration dated March 20, 2012 – Request for Intervener Status by Jim Langley
C4-1	**INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated March 20, 2012 Via Email – Request for Intervener Status by Robert Hobbs and Brian Merwin
C4-2	Letter Dated March 21, 2012 – ICG Submission on the Preliminary Scoping Document
C4-3	Letter Dated May 3, 2012 – ICG Submission regarding the Preliminary Minimum Filing Requirements for Affected Utilities
C4-4	Letter Dated May 9, 2012 – ICG Submission Regarding Order G-50-12 Appendix A
C4-5	Letter Dated June 8, 2012 – ICG Submission regarding Variance of the Regulatory Timetable
C4-6	Letter Dated June 21, 2012 – ICG Submitting Information Request Regarding the Commission Consultant Survey Report
C4-7	Letter Dated August 31, 2012 – ICG Submitting Information Request No. 1
C4-8	Letter Dated October 24, 2012 - ICG Submitting Comments regarding Request for Confidential Information
C4-9	Letter dated November 5, 2012 – ICG Submitting Evidence
C4-10	Letter dated November 6, 2012 – ICG Submitting Confidential Undertakings
C4-11	Letter dated November 30, 2012 – ICG Submitting Responses to Information Request No. 1
C4-12	Letter dated November 30, 2012 – ICG Submission Regarding Exhibit A-27
C4-13	Submitted at Oral Hearing December 12, 2012 – ICG Opening Comments
C4-14	Submitted at Oral Hearing December 14, 2012 – ICG Filing Tab 2 Testimony of Kathleen C. McShane
C4-15	Submitted at Oral Hearing December 17, 2012 – ICG Filing Opening Statement of Dr. Andrew Safir

Exhibit No.	Description
C4-16	Letter dated January 14, 2013 – ICG Submitting Undertakings
C4-17	Letter dated January 25, 2013 – ICG Submitting Dr. Lawrence Booth Undertaking No. 2
C5-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** (previously BC Old Age Pensioner' Organization *et. al*.) **VIA EMAIL -** Letter Dated March 20, 2012 – Request for Intervener Status by Leigha Worth, Tannis Braithwaite and Bill Harper
C5-2	Letter Dated March 21, 2012 – BCOAPO Submission on the Preliminary Scoping Document
C5-3	Letter Dated May 3, 2012 – BCOAPO Submission on Minimum Filing Requirements
C5-4	Letter Dated May 9, 2012 – BCOAPO Submission Regarding Order G-50-12 Appendix A
C5-5	Letter Dated June 8, 2012 – BCOAPO Submission Regarding Variance of the Regulatory Timetable
C5-6	Letter Dated June 22, 2012 – BCOAPO Submitting Information Request Regarding the Commission Consultant Survey Report
C5-7	Letter dated July 23, 2012 – BCOAPO Submitting Notice of Name Change to British Columbia Pensioners' and Seniors' Organization (BCPSO)
C5-8	Letter Dated August 3, 2012 – BCPSO Submitting Comments Regarding the Addition of a Panel Member
C5-9	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to Corix
C5-10	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to FBCU
C5-11	Letter Dated August 31, 2012 – BCPSO Submitting Information Request No. 1 to PNG
C5-12	Letter Dated October 9, 2012 - BCPSO Submitting Information Request No. 2 to FBCU

Exhibit No.	**Description**
C5-13	Letter Dated October 9, 2012 - BCPSO Submitting Contact Update
C5-14	Letter Dated November 30, 2012 - BCPSO Submission Regarding Exhibit A-27
C5-15	Submitted at Oral Hearing December 17, 2012 – BCPSO Filing Business Spectator Document
C6-1	**ASSOCIATION OF MAJOR POWER CUSTOMERS OF BC (AMPC)** Letter Dated March 20, 2012 – Request for Intervener Status by Richard Stout and Lloyd Guenther
C6-2	Letter Dated May 2, 2012 – AMPC Submitting Contact Update
C6-3	Letter Dated May 3, 2012 – AMPC Submission on Minimum Filing Requirements
C6-4	Letter Dated May 9, 2012 – AMPC Submission Regarding Order G-50-12 Appendix A
C6-5	Letter Dated June 8, 2012 – AMPC Submission Regarding Variance of the Regulatory Timetable
C6-6	Letter Dated June 22, 2012 – AMPC Submitting Information Request Regarding the Commission Consultant Survey Report
C6-7	Letter Dated August 3, 2012 – AMPC Submitting Comments Regarding the Addition of a Panel Member
C6-8	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU
C6-9	Letter Dated August 31, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Information Request No. 1 to FBCU on Mr. Engen’s Evidence
C6-9-1	Letter Dated September 23, 2012 – Filing on behalf of BCUC Utility Customers AMPC/BCPSO/CEC Corrected Information Request No. 1 to FBCU on Mr. Engen’s Evidence
C6-10	Letter Dated October 22, 2012 - AMPC Filing a Request for Confidential Information
C6-11	Letter Dated October 31, 2012 - AMPC Submitting Comments regarding Access to Confidential Information
C6-12	Letter dated November 5, 2012 – AMPC Submitting Evidence

Exhibit No.	**Description**
C6-13	Letter dated November 5, 2012 – AMPC Submitting Confidential Undertakings
C6-14	Letter dated November 30, 2012 – AMPC Submission regarding Exhibit A-27
C6-15	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to BCUC
C6-16	Letter dated November 30, 2012 – AMPC Submitting Responses to Information Request No. 1 to FBCU
C6-17	Submitted at Oral Hearing December 12, 2012 – AMPC Filing BC Natural Gas Strategy Fueling BC's Economy for the Next Decade and Beyond
C6-18	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 17d
C6-19	Submitted at Oral Hearing December 14, 2012 – AMPC filing AUC 2011 GCOC IR Responses CAPP McShane ROE Attach 21 i
C6-20	Submitted at Oral Hearing December 17, 2012 – AMPC filing Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding Direct Testimony of James M. Coyne
C6-21	Submitted at Oral Hearing December 18, 2012 – AMPC Filing Witness Aid Prepared by BC Utilities Customers
C6-22	Submitted at Oral Hearing December 19, 2012 – AMPC filing Dr. Booth's Opening Statement
C6-23	Letter dated January 18, 2013 – AMPC Submitting Dr. Booth Undertaking No. 1
C6-24	Letter Dated February 14, 2013 – AMPC Submitting Extension Request
C7-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** Letter Dated March 20, 2012 – Request for Intervener Status by Christopher Weafer
C7-2	Letter Dated May 9, 2012 – CEC Submission Regarding Order G-50-12 Appendix A
C7-3	Letter Dated June 8, 2012 – CEC Submission Regarding variance of the Regulatory Timetable

Exhibit No.	Description
C7-4	Letter dated June 25, 2012 – CEC Submitting Information Request Regarding the Commission Consultant Survey Report
C7-5	Letter Dated August 3, 2012 – CEC Submitting Comments Regarding the Addition of a Panel Member
C7-6	Letter dated November 9, 2012 – CEC Submitting Confidential Undertakings

INTERESTED PARTY DOCUMENTS

D-1	**AT BUSINESS CONSULTING (ATB)** Online Registration dated May 9, 2012 – Request for Interested Party Status by Anastasios Tsalamandris

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
	Capital structure (debt/equity ratio)	60/40 (actual)	60/40 (actual)	60/40 (actual; proposed)		60/40 (actual)	Deemed 60/40	Deemed 60/40	Deemed 60/40
	Equity Risk Premium	N/A	0 bps (approved)	50 bps (proposed)		50 bps (approved)	50 bps (approved)	100 bps (approved)	50 bps (approved)
1	Technology risk/system performance risk associated with chosen technologies	Natural Gas: proven technology	Geo-exchange loop field system and heat recovery with high efficiency natural gas boilers equipment	Recovered waste heat from TELUS Data Centre with peaking and redundant backup heat supplied by Centre Heat Distribution Ltd.: low risk	Slightly higher for PCI / TG than FEI NG	High efficiency condensing boilers: proven technology; Ground source heat pumps; less established technology	Natural gas boilers proven technology	Biomass Gasification innovative technology; Natural Gas boilers; proven technology (while DGE not yet on biomass, the Commission approved the technology)	Natural Gas: boiler: proven technology

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ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
2	Fuel Risk cost and availability	Natural gas: Low-medium	Low risk: free energy from ground and heat recovery, but cost risk for electricity used to operate heat pumps and TES equipment, and for natural gas for supplementary heat and peaking	Data Centre that supplies waste heat is assumed to be available throughout the 20 year term of the analysis: low risk Data Centre ceases operation	Lower for PCI / TG than FEI NG	Natural gas and electricity: Low-medium; Heat from ground: low (some energy cost risk in electricity costs to operate GSHPs)	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant	Biomass: medium-high; natural gas; low-medium	Natural gas fuelled energy centre: low medium Alternative renewable energy source: not approved yet and thus not relevant
3	Customer Base (e.g., diversity, certainty, growing, declining)	Established and diverse customer base but very slow growth	Greenfield utility four types of customers	Not large customer base or significant diversity: low risk	Higher for PCI / TG than FEI NG (NG has much greater diversity)	Established customer: low risk	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out	Greenfield utility: uncertainty related to timing of full build out
4	Default risk of customer	Minimal	Minimal	Minimal	Similar for PCI / TG as for FEI NG	Minimal as SD has budget constraints as well	Minimal	Minimal	Minimal

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
5	Property development risk	Medium to high: there are competing energy options	Low risk: all customers bound by agreement	Majority of tenants committed but customers can still leave: low risk	Lower for PCI / TG than FEI NG	None, as not a new development	Low: phased approach to capital deployment	High: build first approach to capital deployment	Low: phased approach to capital deployment
6	Developer / customer connection risk	Medium to high: due to building stock changes and competitive energy sources	Low Risk: customers will connect on occupancy	Low Risk: customers will connect on occupancy	Lower for PCI / TG than FEI NG	Low, as one known customer with existing sites	Low: mandatory connection	Low: mandatory connection	Low: mandatory connection
7	Load Forecast Uncertainty	Minimal in the short term, as mature utility with deferral account; somewhat higher in the long term	Inherent uncertainty in load forecast	FAES proposes to take forecast risk on actual energy throughput versus forecast for 5 year period: Low-medium	Higher for PCI / TG than FEI NG	Low, as established energy load	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast	Inherent uncertainty in load forecast

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
8	Utility size	Large and mature utility	Project is carried out by a separate corporate entity, Small development specific utility	Project is carried out by separate corporate entity, Small development specific utility	Higher for PCI / TG than FEI NG	Project is carried out by separate corporate entity	Small development specific utility	Small development specific utility	Small development specific utility
9	Initial Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
10	Future Construction cost risk	Depends on the nature of the individual project	Depends on nature of the individual project	Depends on nature of the individual project	Similar for PCI / TG as for FEI NG	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project	Depends on the nature of the individual project
11	Operating cost risk	Minimal as revenue requirement application to recover costs	Minimal as mechanism in place to recover costs	Low-medium risk as deferral accounts do not cover all O&M variances between forecast and actual	Higher for TG, similar for PCI relative to FEI NG	Minimal as mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs	Minimal as a mechanism in place to recover costs

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
12	Public Acceptance Risk	Medium as natural gas is an established and widely used technology but public perceives it as less than clean	Low as seen as green alternative	Low	Lower for PCI / TG than FEI NG	Low as seen as green alternative	Low as seen as a green alternative	Low as gasification technology part of approval process for the development and already selected at the time of the CPCN application	low as seen as a green alternative
13	Fixed/Variable rate design	15% fixed/85% variable	~~100% variable~~ Rate Design Not Approved	100% variable (volume rate)	Higher for TG, relative to FEI NG PCI Rate Design not Approved	100% variable	60% fixed/40% variable	50% fixed/50% variable	66% fixed / 34% variable

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
14	Levelized approach to rates	No	~~Only in first three years then transition to cost of service~~ Rate Design not Approved	The rates charged for the first five years have been mutually agreed upon using a benchmark based on BC Hydro RIB Step 1 and Step 2	Slightly higher for TG, relative to FEI NG PCI Rate Design Not Approved	No, transitional market rate and deferral account	Yes	Yes	Yes
15	Financial risk	Low-medium: appropriate standalone financing structure for capital markets	Medium (similar to DSD)	Forecast risk and rates fixed for first five years (other than one-time adjustment for GCOC changes) impacts financial risk: medium risk justifies 50 bps on FEI utility benchmark	Higher for PCI / TG than FEI NG	Medium	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility	Low-medium: subsidiary of parent utility

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	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
16	Competitive challenges	Competitive with electricity and competition from alternative energy providers	Other TES providers and electricity	Other TES providers and electricity	Lower for PCI / TG than FEI NG	Other TES providers and electricity	Other utilities and electricity	Other utilities and electricity	Other utilities and electricity
17	Provincial climate change and energy policies	Encourage reduction of fossil fuels usage to reduce GHG emissions and lower energy use.	Favourable government policies	Favourable government policies	Lower for PCI / TG than FEI NG	Favorable govt. policies	Favourable govt. policies	Favourable govt. policies	Favourable govt. policies
18	Regulatory uncertainty	Low to medium: uncertainty exists for service offerings within the natural gas class of service.	Medium risk: New, uncertainty, scrutiny and not streamlined Rate Design Denied as Applied	Medium risk: New, uncertainty, scrutiny and not streamlined	Higher for PCI / TG than FEI NG	Medium risk: new, uncertainty, scrutiny and not streamlined	Medium risk: New, uncertainty, scrutiny, alternative energy centre not yet approved	Medium risk: New, uncertainty, scrutiny	Medium risk: New, uncertainty, scrutiny

ORDER C-1-13
ATTACHMENT B

	Risk Factor	FEI Natural Gas Class of Service (1)	FAES PCI Marine Gateway Project (2)	Telus Garden (3)	PCI Marine / Telus Garden Vs. FEI NG Class of Service (4)	FEI Delta School District (5)	Corix UniverCity (6)	Dockside Green Energy (7)	River District Energy (8)
19	Business Development Risk	Minimal	Low – deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) [Shareholder ultimately at risk for the TESDA]	FAES has agreed to purchase the TGTES from the Partnership upon commissioning for actual construction cost of $7.9 million up to a maximum of 30% above the $7.9 million estimate	Higher for PCI / TG than FEI NG	Low: deferring business development costs increases risk of non-recovery. (PCI BCUC IR 1.41.1) [Shareholder ultimately at risk for the TESDA)	High as part of overhead costs	High as part of overhead costs	High as part of overhead costs

COST OF CAPITAL ESTIMATION MODELS AND KEY INPUTS

DISCOUNTED CASH FLOW MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
McShane	Constant Growth	12 US utilities	4.9% - Average of consensus earnings forecasts from Bloomberg, Reuters, ValueLIne and Zacks.	9.3	McShane Evid, Table 30, p. 113; App. C, and Schedule 19
	Constant Growth	5 Can utilities (incl. Fortis Inc.)	7.5% - Reuters L-T EPS forecasts	11.0	McShane Evid, Table 30, p. 113 and Schedule 22
	Sustainable Growth	12 US Utilities	4.4% - Avg of sustainable growth rates for US utilities derived from Value Line forecasts of ROEs, earnings retention rates and earnings growth from external financing.	8.7	McShane Evid, Table 30, p. 113 and Schedule 20
	Three Stage Model	5 Can utilities (incl. Fortis Inc.)	Stage 1 (yrs 1-5) - Reuters L-T EPS forecasts: 7.5% Stage 2 (yrs 6-10)- Avg of stages 1 and 3: 5.9% Stage 3 (yrs 11+)-GDP growth: 4.3%	8.6	McShane Evid, Table 30, p. 113 App. C and Schedule 23
	Three Stage Model	12 US utilities	Stage 1 (yrs 1-5) - Avg of all EPS forecasts: 4.9% Stage 2 (yrs 6-10) - Avg of stages 1 and 3: 4.9% Stage 3 (yrs 11+) - GDP growth: 4.9%	9.2	McShane Evid, Table 30, p. 113 and Schedule 21
	Mid-point of range	Canadian sample		9.8	McShane Evid. p. 113
	Mid-point of range	Both samples		9.4	McShane Evid. p. 113
			Bare bones Cost of Equity estimated at 9.4% and add Financing Flexibility Adjustment of 0.5%	9.9	

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Vander Weide	Quarterly DCF model	Comprehensive group of 32 US utilities	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.8	VdW Evid, p. 28 – 30 and Exhibit 6
		Small group of 19 US utilities (subset of large group)	Range: 3.15% to 9.75% I/B/E/S Thomson Reuters mean growth forecasts	Range: 7.4-14.6 Avg: 9.5	VdW Evid, p. 28 – 30 and Exhibit 7
			Bare-bones cost of equity for the Comprehensive Model 9.8% plus Financing Flexibility	10.3	
			Bare-bones cost of equity for the Small Utilities Model 9.5% plus Financing Flexibility	10.0	
			Summary of results from DCF	10.15	

Booth		All of Canadian market	Growth rate range 4.7% - 6.1% based on multiplying corporate Canada ROEs since 1987 times retention rates.	9.3	Booth Evid., p. 94 & App D, p. 9-10
		US market – S&P 500	Growth rate range of 6.79% - 7.97% based on multiplying the average and median values respectively for S&P 500 ROEs since 1977 times the current dividend yield	Calculated range: 8.93-10.01. Adjusted range: 9.5-10.5	Booth Evid., App D, p. 10-13 (Note disc. of analyst forecasts at p. 14-17.)

...DCF MODELS

Analyst	Model Sub-type	Sample	Growth Estimate	ROE est. (%)	References
Safir	Two-stage model	Canadian Sample - 5 Can. utilities (incl. Fortis)	Stage 1 (analyst forecasts)- 7.49%; Stage 2 (GDP growth) – 4.49% Weighted average (33/67): 5.49%	8.99	Safir Evid, p. 24-26, and Schedule 3
	Two-stage model	US Sample – 18 US utilities	Stage 1 (analyst forecasts) - 5.50%; Stage 2 (GDP growth) – 4.57% Weighted average (33/67): 4.88%	8.86	Safir Evid,p. 24-26, and Schedule 4
			ROE Adjusted by Flotation Costs at 5% for Canadian sample	9.46	Safir Evid. p. 26
			ROE Adjusted by Flotation Costs at 5% for US sample	9.33	Safir Evid. p. 26

CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	See her Risk-Adjusted Equity Risk Premium Model					
Vander Weide	N/A – Vander Weide recommends placing no weight on CAPM results	2.95% forecast yield to maturity on L-C bonds	6.6% - Ibbotson SBBI estimate of risk premium on market portfolio – diff. between arithmetic mean return on S&P 500 vs. income return on 20-year Treasury bonds. (1937-2012)	0.73 – Average Value Line beta for his large proxy US utility group.	8.27 (including financial flexibility)	Vander Weide Evid, pp. 38-44; Exhibits 12 to 15
				0.92 – historical ratio of the average utility risk premium to the S&P risk premium	9.52 (including financial flexibility)	
Booth	Simple CAPM estimate	3.00% (Base adjusted LTC forecast)	Range: 5.0 – 6.0%	Range: 0.45-0.55	Range: 5.75-6.80, including 0.50 flotation cost allowance	Booth Evid, p. 74 & 75; App. B (MRP), p. 16, App. C (beta est), pp. 10-14
	Adjusted CAPM (Simple CAPM plus 0.40 for credit spread and 0.80 for Operation Twist.	3.80% (Base adjusted LTC forecast)	Same as above	Same as above	Range: 6.95 to 8.00 (2013) 7.00 -8.00 Including flotation cost allowance	Booth Evid, p. 85, 93-94 (adjustments); other values same as above.
				Point estimate for CAPM	7.5	Booth Evid. p. 95

...CAPITAL ASSET PRICING MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
Safir	Canadian CAPM	4.00%	5.96% (Total mkt. return minus the est annual long bond income return (both 1924-2010)	Adjusted beta: 0.36 (weighted 0.67 raw + 0.33 mkt tendency) Calculated raw beta (Sched 1): 0.25 Long-run mkt tendency beta (Schaeffler & Weber survey): 0.58	6.15	Safir Evid. p. 12-15 and Schedule 1
	US CAPM	4.50%	6.62% (Total mkt. return minus the est annual long bond income return (both 1926-2011)	Adjusted beta: 0.48 (weighted 0.67 raw + 0.33 market tendency) Calculated raw beta (Schedule 2): 0.43 Long-run market tendency beta (Schaeffler & Weber survey): 0.58	7.68	Safir Evid. p. 18 and Schedule 2
				Adjusted by flotation cost allowance of 0.32% for the Canadian ROE estimate	6.47	Safir Evid. p. 12
				Adjusted by flotation cost allowance of 0.40% for the US ROE estimate	8.08	Safir Evid. p. 18

EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
McShane	Risk-adjusted ERP (variant of CAPM)	4.0% (forecast 30 yr Long-Can bond yield)	7.25-7.5% (based on bond income returns < 8.0%; table 12, pp. 82, 98 of her evid)	0.65-0.70 adjusted (0.65 based on Bloomberg adjusted betas for 5 Can utilities or raw beta for TSX utilities index adjusted per Bloomberg (.67 raw+0.33; see McShane evid. p. 97. For upper end of range see table 21, p. 98)	Range: 8.9-9.1% Est. 9.0%	McShane Evidence, p. 98
	DCF Based ERP Models: 1998-2012 Q1 US Sample					
	Constant Growth – Single variable (L-C bond rate)	4.0% (forecast 30 yr L-C yield)	5.7% at 4.0% risk free rate (see table 22, p. 100)	N/A	9.7%	McShane evid. p. 99-101
	3-stage growth - single variable	4.0%	5.7 or 5.8% at 4.0 risk free rate (apparent inconsistency between tables 24 and 25)	N/A	9.7	McShane evid p. 99-105
	Constant Growth – two variable (L-C bonds and 30 year A-rated utility yield spreads)	4.0%	5.5%	N/A	9.5	McShane evid at pp. 102-105, esp. table 25.
(cont….)	3-stage growth – two variable	4.0%	5.6%	N/A	9.6	McShane evid at pp. 102-105, esp. table 25.

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Market Risk Premium	Beta Estimate	ROE est. (%)	References
	DCF Based ERP Models: 1998-2012Q1 US Sample (continued from previous page)					
	Quarterly US utility ROE's as proxy for utility cost of equity – single variable	4.0%	6.2%		10.2 (McShane gives no weight)	McShane evid at pp. 102-105, esp. table 25
	Quarterly US utility ROE's– two variable	4.0%	6.1%		10.1 (no weight)	McShane evid at pp. 102-105, esp. table 25
McShane (cont. from previous page)	Constant Growth over A-rated bond	5.35% (4.0% L-C bond yield + 135 bp)	4.0		9.4	McShane evid at p. 105, table 26
	3-stage growth over A-rated bond	5.35% (as above)	4.2		9.6	McShane evid at p. 105, table 26
	Allowed ROEs over A-rated bond	5.35% (as above)	4.8		10.2 (no weight)	McShane evid at p. 105, table 26
	Summary of results DCF based results	4.0%% (f'cast L-C bond yields) or 5.35% (A-rated utility bond yields	Range of regression results		9.4 – 9.7	McShane Evid. p. 106
(cont…)			Bare bones Cost of Equity (mid-point)		9.6	

…EQUITY RISK PREMIUM MODELS

Analyst	Model Sub-type	Risk Free Rate	Equity Returns	Bond Inc. Returns	Utility Risk Premium	Change in Bond Yield/Ret	Change in Util Risk Pr.	Utility Equity Risk	ROE est. (%)	References
McShane (cont. from previous page)	Historic Utility ERP- Can utilities (1956-2011)	4.0%	12.1%	7.3%	4.8%	-3.3%	+1.6%	6.4%	10.5 (based on all 3 Historic Utility ERP tests)	McShane Evid. pp. 106-108
	Historic Utility ERP- US Gas Utilities (1947-2011)	4.0%	11.9%	5.9%	6.0%	-1.9%	+1.0%	7.0%		McShane Evid. pp. 106-108
	Historic Utility ERP- US Elec Utilities (1947-2011)	4.0%	11.0%	5.9%	5.1%	-1.9%	+1.0%	6.2%		McShane Evid. pp. 106-108
	Summary of All Risk Premium Tests	Risk-Adjusted Equity Market							9.0	McShane Evid p. 109, table 29
		DCF-based							9.6	
		Historic Utility							10.5	

			Stock Returns	Avg Bond Yields	Risk Premium	Expected bond yield		
Vander Weide (cont…)	Ex-Post Risk Premium	S&P/TSX Utilities: 1956-2011	11.99%	7.33%	4.7%	N/A	N/A	Vander Weide Evid, pp. 32-35, 44; and Exhiibits 8 & 9
		BMO Utilities: 1983-2011	16.01	7.24	8.8%	N/A	N/A	
		Average risk premium of the two samples			6.7%	2.95%	10.15 (rounded to 10.2% (incl. 0.5% flotation	

…EQUITY RISK PREMIUM MODELS

Analyst	Model sub-Type	Sample Group and Period	DCF Growth rate	Risk Prem.	Risk Free Rate	Roe est. (%)	References
Vander Weide (cont. from previous page)	Ex-Ante Risk Premium	Natural Gas group selected from S&P nat. gas companies	DCF growth rate and analysis by individual company from I/B/E/S forecast of earnings growth for each month. (Exhibits 10 & 11)	8.0%	2.95%	11.5 (incl flotation)	Vander Weide Evid. pp. 35-38 and App. 3, Exhibits 10, 11 and 24
		Moody's group of 24 Electric utilities.		7.5%	2.95%	11.0 (incl flotation)	
Booth	N/A						
Safir	N/A						

COMPARABLE EARNINGS TESTS

Analyst	Model sub-Type	Sample Group and Period	ROE est. (%)	References
McShane	Book-value based	21 Canadian unregulated companies: 2004-2011 (incl downward adjustments of 125 to 150 bps)	Range: 11.0-12.0 Est: 11.5	McShane Evid, pp. 113-117, 119 and App E.
Vander Weide	N/A		N/A	
Booth	Book-value based	Corporate Canada (Statistics Canada reported earnings): 1987-2011, and TSX composite for the same period	Market ret: 9.3	Booth Evid. p. 93 and App. E, Schedule 2
Safir	Market-value based	Canadian sample: same 21 Canadian Companies as used by McShane: 2004-2011	6.85	Safir Evid. pp. 28-35 and Schedules 5 and 6
	Market-value based	US Sample: 31 US companies in the consumer goods, industrial goods or service sectors using same selection critiera as McShane used for her Canadian sample: 2004-2011.	5.81	
	Weighted average giving Canadian results twice the weight of the US results		6.50	

SUMMARY OF ROE RECOMMENDATIONS

Analyst	Method	Model Sub-Type	'Bare-bones' Cost of Equity"	Financing Flexibility Adjustment	ROE est. (%)	References
McShane	DCF		9.4%	0.50%	9.9	McShane Evid. pp. 6 and 119
	Risk Premium	Risk-Adj Equity Mkt	9.0%	0.50%	9.5	
		DCF-based	9.6%	0.50%	10.1	
		Historic Utility	10.5%	0.50%	11.0	
	Comp. Earning		N/A	N/A	11.5	
VanderWeide	DCF		9.5%	0.5%	10.15	Vander Weide Evid. p. 44 and Exhibit 7
	CAPM	Calulates ROEs (incl. flotation allowance) of 8.27% and 9.52% but gives the CAPM results no weight			N/A	Vander Weide Evid. p. 44 and Exhibits 12 and 13
	Risk Premium	Ex-Post RP	9.65%	0.50%	10.15 (10.2)	Vander Weide Evid. pp. 35, 38 and 44, and Exhibits 8, 9, 10, 11 and 24
		Ex-Ante RP (average of Natural Gas and Elec. Samples	10.75%	0.50%	11.25	
Booth	Discounted Cash Flow	All of Canadian market	9.28% for the market as a whole		N/A	Booth Evid. p. 93-94 and App. D, pp. 9-10
		US market – S&P 500	9.5% - 10.5% for the US market		N/A	
	CAPM	Adjusted for credit spread and Operation Twist	6.95-7.50%	0.50%	7.50	Booth Evid. pp. 93-94
	Comp. Earning	Market Returns	9.3% for Corporate Canada (StatsCan)		N/A	Booth Evid, p. 93-94; App. E, pp. 2-7
Safir	DCF	Canadian Sample	8.99%	0.47%	9.46	Safir Evid, p. 26
		US Sample	8.86%	0.47%	9.33	
	CAPM	Canadian Sample	6.15%	0.32%	6.47	Safir Evid. p. 12
		US Sample	7.68%	0.40%	8.08	Safir Evid. p. 18
		Weighted average	N/A	N/A	7.01	Safir Evid, p. 19
	Comp Earning	Market value based results; wighted avg of Can and US results			6.50	Safir Evid. p. 33

LIST OF ACRONYMS

AAM	Automatic Adjustment Mechanism
AECO	Alberta’s gas trading price
AES	Alternative Energy Services
AMPC	Association of Major Power Consumers
AUB	Alberta Utilities Commission
B	Beta
BA	Bankers’ Acceptances
BCPSO	British Columbia Pensioners’ and Seniors’ Organization
BCUC	British Columbia Utilities Commission
BC Utility Customers	Collectively AMPC, BCPSO, CEC
bps	Basis points
CAPM	Capital Asset Pricing Model
CDOR	Canadian Dealer Offered Rate
CEC	Commercial Energy Consumers of B.C.
CEA	Clean Energy Act
Concentric	Concentric Economic Advisers
CPCN	Certificate of Public Convenience and Necessity
DCF	Discounted Cash Flow
ERP	Equity Risk Premium
FRS	Fair Return Standard
FBCU	FortisBC Utilities
Fl PUC	Florida Public Service Commission

LIST OF ACRONYMS

GCOC	Generic Cost of Capital
GJ	Gigajoule
ICG	Industrial Customers Group of FortisBC Inc.
LCBF	Long Canada Bond Forecast
NEB	National Energy Board
O&M	Operation and Maintenance
PBR	Performance Based Ratemaking
PNG	Pacific Northern Gas
PRMP	Price Risk Management Plan
OEB	Ontario Energy Board
ROE	Return on Equity
r_m	Expected return on the market
r_f	Risk free rate
$r_m - r_f$	Market risk premium
r_e	Opportunity cost of equity
Régie	Régie de l'Energie
TES	Thermal Energy Services
Terasen, TGI	Terasen Utilities, Terasen Gas Inc.
UCA	Utilities Commission Act
UPC	Use Per Customer

IN THE MATTER OF

BRITISH COLUMBIA UTILITIES COMMISSION

GENERIC COST OF CAPITAL PROCEEDING
(STAGE 2)

DECISION

March 25, 2014

Before:

D.A. Cote, Commissioner/Panel Chair
L.A. O'Hara, Commissioner
C. van Wermeskerken, Commissioner

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EXECUTIVE SUMMARY

This Stage 2 Decision addresses cost of capital awards for all utilities as compared to the established Benchmark, FortisBC Energy Inc. (FEI). Order G-75-13 issued on May 10, 2013, determined the Stage 1 Benchmark cost of capital. In that ruling, the British Columbia Utilities Commission established the common equity ratio and return on equity (ROE) for the Benchmark at 38.5 percent and 8.75 percent respectively. It also reinstated a reliance on an Automatic Adjustment Mechanism (AAM) formula for annual ROE adjustments subject to the long Canada bond yield of 3.8 percent being met or exceeded.

The Stage 2 proceeding was set to determine what individual circumstances apply to each utility in comparison to the Benchmark in setting the debt/equity ratio and allowed ROE. To do this, the Commission Panel is to compare each utility to the Benchmark and determine the level of difference in circumstances with particular attention to differences in risk. Stage 2 was categorized under three groups:

- **Group 1:** The FortisBC Utilities comprised of FortisBC (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Inc. (FBC);
- **Group 2:** Pacific Northern Gas Ltd. (PNG) companies comprised of PNG-West, PNG (N.E.) Fort St. John/Dawson Creek (FSJ/DC) and PNG (N.E.) Tumbler Ridge (TR); and
- **Group 3:** The Companies comprised of Corix Utilities Inc. (Corix), Central Heat Distribution Limited (Central Heat), and River District Energy Limited Partnership (RDE) as well as FortisBC Alternative Energy Services Inc. (FAES).

The Stage 2 proceeding was reviewed by way of written hearing and relied upon a number of determinations in the Stage 1 proceeding that had application. These included the use of Canadian vs. US data, the weight placed on decisions from other Canadian jurisdictions, the importance of credit ratings and related metrics, and reliance upon the stand-alone principle.

Contextual Issues

Prior to making determinations on the Stage 2 utility applications the Commission Panel addressed a number of contextual issues. Key among these are the following:

Basis for Comparing Against the Benchmark Utility

The Commission Panel determined that the primary reference point for the Stage 2 proceeding is FEI, the Benchmark as assessed in the period leading to the Stage 1 Decision. Additionally, the Panel finds that evidence related to previous cost of capital decisions will also be considered but only in those cases where the information contributes to a more complete evidentiary base.

Need for a Minimum Default Capital Structure and Risk Premium

The Commission Panel is persuaded that Thermal Energy Services (TES) projects "are more similar than different" and for regulatory efficiency a default structure is appropriate. A minimum default capital structure and equity risk premium is set for all TES Stream B projects with a capital cost in excess of a minimum threshold of $500,000 and below a maximum of $15,000,000.

Small Firm Effect- Applicability of Ms. Ahern's Evidence

There has been a great deal of empirical research into what has been termed the small firm effect. The Commission Panel is not persuaded that the Companies' expert Ms. Ahern's use of this empirical research has application to the Stage 2 proceeding. Therefore, the Panel gives no weight to Ms. Ahern's framework for determining the cost of capital for small utilities. However, small size factors will be considered among a range of business and financial risks that utilities face.

TES Projects –What is Being Regulated

It was determined that the timeline for the consideration of risk must begin when the project proponent is seeking equity funding and must encompass risks associated with efforts to secure agreements to initiate TES projects. A second phase of risk assessment begins when a project comes on stream following a utility successfully competing for a project in the market. The Panel has determined that Stage 2 will consider all risks faced by a project investor over the business development, construction and operational phases.

The determinations related to these contextual issues have provided guidance to the Panel on how to consider the evidence in making individual Stage 2 utility cost of capital decisions.

Cost of Capital – Stage 2 Utilities

FortisBC (Vancouver Island) Inc. and FortisBC (Whistler) Inc.

The Commission Panel has determined that an equity ratio of 41.5 percent and an equity premium of 50 basis points (bps) for FEVI and an equity ratio of 41.5 percent and an equity premium of 75 bps for FEW is appropriate effective January 1, 2013.

As compared to the Benchmark, the Panel places significant weight on the small service areas and less diverse customer and economic bases for both FEVI and FEW. Minimal weight has been applied to supply and competition risks for both utilities but consideration has been given to the importance of maintaining current credit ratings for FEVI in determining an appropriate equity ratio. An additional 25 bps was awarded FEW in recognition of risks related to its small size.

By Order G-21-14 dated February 26, 2014, and accompanying Decision, the Commission approved the amalgamation of FEI, FEVI and FEW subject to confirmation that the Lieutenant Governor in Council has consented to the amalgamation and that it has been effected. Relying upon the Commission's recommendations in the Amalgamation Reconsideration Decision, the Commission Panel has determined that once amalgamation has been effected, the capital structure and ROE for the amalgamated utility will be the same as FEI, the Benchmark.

FortisBC Inc.

The Commission Panel has determined that an equity ratio of 40 percent and an equity risk premium of 40 bps are appropriate for FBC effective January 1, 2013.

The evidence supports the finding that FBC faces additional price competitiveness risk as compared to the Benchmark and there is some additional risk related to small size. However, the Commission Panel finds no substantial difference in supply risk in comparison to the Benchmark and in regard to operational risks, there was no basis on which to establish the potential impact of any differential in risk which may exist. Concerning the equity risk premium, the Panel is satisfied that maintenance of the current 40 bps premium is justified but is not persuaded that FBC has made a case for further differential as compared to the Benchmark.

PNG Utilities

Approved common equity ratios and equity risk premiums for PNG are as follows:

PNG-West:	Common equity ratio:	46.5 percent
	Equity risk premium:	75 bps
PNG (N.E.)-FSJ/DC:	Common equity ratio:	41.0 percent
	Equity risk premium:	50 bps
PNG (N.E.)-TR:	Common equity ratio:	46.5 percent
	Equity risk premium:	75 bps

The Commission Panel placed significant weight on PNG-West's issues with customer growth, market demand and throughput. PNG (N.E.)-TR was considered to have similar risks to those of PNG-West but the Panel placed greater weight on factors related to size as well as difficulties with supply than those of customer growth, demand and throughput. The evidence related to credit ratings and the desire to maintain a credit rating higher than non-investment grade for all PNG utilities also received some weight. The additional 25 bps equity risk premium for PNG-West and PNG (N.E.)-TR reflects the difference in short term risk between the PNG utilities as well as in comparison to the Benchmark.

In consideration of PNG's unique set of circumstances the Commission Panel has assessed the business risks which exist today and little weight was placed on the potential for change to these risks in the future. Given the potential for development of the Liquefied Natural Gas industry and other initiatives and their impact on PNG's business risk, the Panel has directed the PNG utilities to include an updated business risk assessment in all future revenue requirements applications.

TES Utilities

The Commission Panel has established a minimum default structure of 42.5 percent common equity and a default equity risk premium of 75 bps for all regulated TES projects. However, the project proponent retains the right to submit evidence in support of a higher risk premium than the default premium.

Specifically, the 42.5 percent equity ratio and 75 bps equity risk premium default structure was set for the FAES Kelowna District Energy System project and the Companies' projects inclusive of UniverCity at Burnaby Mountain and River District Energy Partnership. Dockside Green's equity ratio has been set at 42.5 percent and it equity risk premium at 100 bps based on its unique set of risks. Central Heat Distribution Limited was also awarded the 42.5 percent equity ratio and 75 bps equity risk premium, but only as transitional amounts. The Commission Panel directs Central Heat to file within next 12 months either a 2016 or multi-year revenue requirement application with the Commission reflecting a new business plan with a comprehensive justification for the equity thickness and equity risk premium.

1.0 INTRODUCTION

1.1 Background

The British Columbia Utilities Commission (Commission, BCUC) issued Order G-20-12 on February 28, 2012, to initiate the Generic Cost of Capital (GCOC) proceeding. The Order was issued pursuant to section 82 of the *Utilities Commission Act* (Act, UCA) to review and determine, among other things, the following:

- The Return On Equity (ROE) and capital structure for a benchmark low-risk utility;
- The possible return to an Automatic Adjustment Mechanism (AAM) to set the ROE for the benchmark utility each year; and
- A deemed capital structure and deemed ROE for small utilities, particularly those utilities without third party debt.

Order G-20-12 established that all public utilities would be considered applicants in the GCOC proceeding and included a preliminary scoping document, which set out a list of matters to be examined and determined within the proceeding. Order G-148-12 established that FortisBC Energy Inc. (FEI) in its pre-amalgamation state would serve as the benchmark utility (Benchmark) for the GCOC proceeding. It was determined that the proceeding would have two stages: Stage 1 to establish the ROE and capital structure for the Benchmark, followed by Stage 2 establishing a cost of capital for other utilities as compared to the Benchmark.

The intent of this approach as well as the relationship between the Stage 1 and Stage 2 proceedings are outlined in the following.

1.1.1 Purpose of the GCOC Proceeding

The GCOC proceeding was initiated specifically:

I. To establish a method to determine the appropriate cost of capital for a benchmark low-risk utility in British Columbia, commencing January 1, 2013, and to establish how the Benchmark Return on Equity (ROE) will be reviewed, and if required, adjusted on a regular basis;

II. To establish a generic methodology or process on how to establish each utility's cost of capital based on the cost of capital for a benchmark low-risk utility; and

III. To establish a framework for determining the appropriate cost of capital for other smaller utilities in the province.

(Stage 1 Decision, pp. 2-3)[1]

On May 10, 2013, the Commission rendered the Stage 1 Decision. Some of the key determinations made with reference to the Benchmark include the following:

I. A common equity ratio of 38.5 percent and a debt ratio of 61.5 percent is to be applied to the Benchmark. (Equity thickness as a percentage of total capital, debt/equity ratio of 61.5/38.5 also used interchangeably)

II. The return on equity of 8.75 percent inclusive of a 0.50 percent allowance for financial flexibility is appropriate for the Benchmark. This was effective January 1, 2013, and will remain until December 31, 2015, subject to annual adjustment as a result of applying an automatic adjustment mechanism (AAM) formula.

III. The AAM for determination of the benchmark ROE on an annual basis was established. Implementation of the AAM will be subject to an actual Canada bond yield of 3.8 percent being met or exceeded. Therefore, the AAM formula will not be in effect as long as the long Canada bond yield is below 3.8 percent.

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

In addition, the Commission determined that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to. The Commission was not sufficiently persuaded to put any weight to the empirical studies reviewed to date. Utilities were encouraged to use the Commission developed risk matrix as a tool. However, utilities were free to use other methodologies or approaches to justify their risk differential in relation to the Benchmark.

It is noteworthy, that at the outset it was not clear what the appropriate benchmark utility should be. For instance, the Commission raised a concern whether some of the new business initiatives being undertaken by FEI have already been recognized by the financial markets; and whether amalgamation will impact its risk profile. Ultimately, the Commission believed that one of the main reasons to establish a benchmark utility is to provide a stable point of reference against which other utilities can be measured and compared to over the longer term. To facilitate such comparison, the Commission was of the view that the benchmark utility should as closely as is reasonable represent a mature, stable "pure play" gas distribution utility. (Stage 1, Exhibit A-17) In summary, FEI now is the Benchmark, but is no longer described as a low-risk utility.

1.2 Stage 2 Proceeding

The main purpose of Stage 2 is to determine what individual circumstances apply to each utility compared to the Benchmark, in setting the overall return on investment (debt/equity ratio and allowed ROE). In doing so, the Commission Panel must compare each utility to the Benchmark and assess whether there are any differences in circumstances between the two, particularly with respect to risk. If there are differences, the Commission Panel must determine how these differences should be reflected in the debt/equity ratio and equity risk premium. If there are no significant differences, the equity/debt ratio and risk premium should be the same as those of the Benchmark. Accordingly, the Commission Panel must:

1. Assess the risks for each utility as compared to FEI, the Benchmark; and
2. Quantify the risk of each utility as compared to the Benchmark in:
    a. allowed equity thickness (equity component in capital structure); and
    b. allowed equity risk premium.

The process relevant to Stage 2 of these proceedings can be summarized as follows.

1.2.1 Key Participants

Utilities that filed evidence were:

- **Group 1:** The FortisBC Utilities (FBCU) comprised of FortisBC Energy Inc. (FEI),[2] FortisBC (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Inc. (FBC);
- **Group 2:** Pacific Northern Gas Ltd. (PNG) companies comprised of PNG-West, PNG (N.E.) Fort St. John/Dawson Creek (FSJ/DC) and PNG (N.E.) Tumbler Ridge (TR); and
- **Group 3:** The Companies comprised of Corix Utilities Inc. (Corix), Central Heat Distribution Limited (Central Heat), and River District Energy Limited Partnership (RDE) as well as FortisBC Alternative Energy Services Inc. (FAES).

The only Interveners were the British Columbia Pensioners' and Seniors' Organization et al. (BCPSO) and the Industrial Customers Group of FortisBC Inc. (ICG).

1.2.2 Regulatory Process

By Order G-77-13, the Commission confirmed that the Stage 1 record would form part of the Stage 2 record (Exhibit A-35). Stage 2 evidence was reviewed by way of a written hearing. A list of Procedural Orders is provided in Appendix A.

[2] FEI is not an applicant utility in Stage 2.

On December 10, 2012, Order G-187-12 established the currently allowed ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility to establish rates, except British Columbia Hydro and Power Authority (BC Hydro), as interim effective January 1, 2013. Any determinations on the premia for the regulated utilities over the Benchmark ROE and capital structure will be made in Stage 2.

1.3 Guidance from Stage 1 Determinations

Within the Stage 1 Decision there were a number of determinations made which have application in the Stage 2 proceeding. Among these are the following:

1.3.1 Use of Canadian vs. US Data

The Commission, in keeping with previous decisions, accepted that Canadian utilities need to be able to compete in a global marketplace and be allowed a return for them to do so. In addition, the Commission accepted that the amount of Canadian data upon which to rely continues to be limited. Therefore, it was recognized there may be times when natural gas companies operating within the US may prove to be a useful proxy in determining the cost of capital. Accordingly, it was determined that continuing to accept the use of historical and forecast data for US utilities and securities as outlined in the 2006 Decision[3] and again in the 2009 Decision[4] is appropriate.

1.3.2 Consideration of Other Canadian Jurisdictions

In Stage 1 many of the parties chose to utilize information and related decisions from other Canadian jurisdictions to support positions they had taken on an issue. The Commission Panel in its

[3] In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism Decision, March 2, 2006 [hereinafter 2006 Decision].

[4] In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision, December 16, 2009 [hereinafter 2009 Decision].

Stage 1 Decision noted that decisions in all jurisdictions result from the judgement of evidence specific to a region or a particular utility that in each case is unique and stated the following:

> "To the extent that the ROE and equity thickness of a specific utility in another jurisdiction can be used as a comparator, we are open to considering it if it helps inform our decision. However, considerable reliance on decisions from other jurisdictions in our view would lead to circularity that would ensure that only the status quo is maintained -- perhaps at the risk of common sense. The Commission Panel acknowledges the importance of considering the methodologies, approaches and regulatory principles related to other jurisdictions' decisions. However, we do not accept that it is appropriate for results and values to be used for the purpose of calibration in B.C."
>
> (Stage 1 Decision, p. 20)

1.3.3 Credit Ratings and Metrics

The Commission Panel acknowledged that ongoing access to debt capital at an attractive price is of benefit to the shareholder and possibly the customer. The Commission stated that it would continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Commission supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard. The Commission found that maintenance of a credit rating (in the case of FEI, an "A" rating) is desirable but not at all costs. (Stage 1 Decision, p. 50)

1.3.4 Stand-Alone Principle

In its Stage 1 Decision, the Commission acknowledged the long history and importance of the stand-alone principle in Canadian utility regulation. The Panel found no reason to deviate from this principle even in the case of small utilities or projects whether or not they are part of a larger utility. This included either a "new" utility with a greenfield project and no historical performance data or an existing facility being developed into a thermal energy services (TES) project. As stated in the Decision: "Each project needs to be considered individually and independently." (Stage 1 Decision, p. 100)

1.3.5 Use of the Commission Risk Matrix

The Stage 1 Decision made reference to the risk matrix developed by the Commission that has been used in various small TES utilities proceedings to evaluate overall risk of a given project. It was recommended that the small utilities use this risk matrix in the Stage 2 proceeding and for future projects to justify their case for the appropriate capital structure and risk premium over and above the Benchmark ROE. It was further recommended that small utilities, other than TES, could modify the matrix to facilitate comparisons of their individual short and long-term risks to those of FEI. (Stage 1 Decision, p. 101)

1.3.6 Principles for Stage 2 Framework

In addressing the issue of short-term and long-term debt in the deemed capital structure and the methodology for determining a deemed interest rate, the Commission reaffirmed certain principles for the Stage 2 GCOC proceeding framework.

(i) The general principles and criteria outlined by the Corix and FBCU experts for setting the capital structure for any utility in general and the deemed capital structure specifically for the small utilities are accepted as they are consistent with the principles adopted for setting the benchmark ROE;

(ii) Deemed debt is appropriate for small utilities in cases where raising debt is inefficient;

(iii) Deemed debt rates and duration should reflect the particular circumstances of each utility. Accordingly, the Commission should continue to address the cost of deemed debt for each utility separately on a case-by-case basis; and

(iv) Risk assessment of small utilities, especially the TES projects, must include consideration of rate setting mechanisms, deferral account treatment, length of term and the overall risk/reward equation.

(Stage 1 Decision, pp. 104-105)

The Commission also raised two questions to be addressed more comprehensively in Stage 2:

- Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular small utility or project?
- How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

(Stage 1 Decision, p. 105)

1.4 Approach to the Decision

Prior to discussing the attributes of the individual applications of the Stage 2 utilities, the Commission Panel has addressed a number of broader questions and issues related to this Decision in Section 2, Context and Issues. Determinations related to these contextual issues provides direct guidance to the Panel with respect to how it will consider the evidence.

Following a discussion of these issues the Commission Panel has reviewed the applications of the applicant utilities in Section 3.0. Finally, Section 4.0 addresses Other Matters resulting from the cost of capital determinations.

2.0 CONTEXTUAL ISSUES

2.1 Basis for Comparing against the Benchmark Utility

As noted in Section 1.1.1, one of the purposes of the GCOC proceeding was to create a methodology or process on how to establish each utility's cost of capital based on the cost of capital for the Benchmark. The Stage 1 proceeding established the cost of capital for the Benchmark. The Stage 1 Decision outlined that Stage 2 of this proceeding "will be primarily concerned with business risk assessment relative to the benchmark. More specifically, public utilities will be called upon to provide evidence as to how they differ from FEI with respect to business risk." Given that the Benchmark is no longer considered to be low risk, the Commission noted that business risks faced may be either higher, lower, or the same as FEI, the Benchmark.

In the Stage 1 Decision the issue arose as to the appropriate reference point from which to compare the level of change in FEI's long-term risk. The Commission, noting that the 2009 Decision was the most recent proceeding, accepted that the period leading up to it was a reasonable reference point although the 2006 Decision could be used where appropriate. Based on these reference points, the Commission made its Stage 1 determinations. (Stage 1 Decision, p. 16)

In this, the Stage 2 proceeding, the appropriate reference point has been raised again. Specifically, the question has arisen as to whether an appropriate reference point for this proceeding is the Benchmark as established in Stage 1 as advocated by some parties. In the alternative, some have held that the appropriate point of reference is the 2009 ROE proceeding as it was in Stage 1 or even some earlier point in time.

2.1.1 Positions of Utilities

FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

Based on their submissions, FEVI and FEW seem to have used a combined approach relying in some cases on a first principles approach or a comparison against the Benchmark as defined in the Stage 1 proceeding and in others, as compared against the FEI in prior decisions. In FEVI's and FEW's application in Stage 2, business risk relative to the Benchmark was assessed in two ways: the business risk relative to the current Benchmark and as changes in their risk profile since 2009. Their expert, Ms. McShane described the focus for this proceeding as "how FEVI's and FEW's current business risks compare to those of FEI and whether there has been any material change in the relative business risks of FEVI and FEW as compared to FEI since 2009." (Exhibit B1-71, Appendix B, Ms. McShane's Evidence, p. 7)

FortisBC Inc.

The approach taken by FBC relies primarily on the current Benchmark as a reference for comparison. It states in evidence that the last time the Commission performed a comprehensive review of FBC's common equity risk premium ratio and equity was during its 2005 revenue requirements application when the common equity ratio of 40 percent and risk premium of 40 basis points was reaffirmed.[5] (Exhibit B1-72, Evidence, p. 1) FBC's expert witness, Ms. McShane, described her focus or approach in this proceeding as providing "an overview of FBC's business risk, and where possible or relevant, a comparison with FEI, the benchmark utility, inasmuch as the Commission's focus in Stage 2 is a review of all other utilities against the benchmark utility." (Exhibit B1-72, Appendix B, Ms. McShane's Evidence, p. 11) In addition, Ms. McShane submits that a first principles approach is appropriate for FBC, and less so for FEVI and FEW because the Commission has not comprehensively evaluated FBC's business risks since 2005, more than eight years ago. (Exhibit B1-84, Rebuttal Evidence, pp. 1-2)

[5] In the Matter of FortisBC Inc., 2005 Revenue Requirement Application (RRA), 2005-2014 System Development Plan, 2005 Resource Plan, Decision, May 31, 2005 [hereinafter 2005 RRA Decision].

The evidence of ICG's expert witness, Dr. Safir, is that the differential risk between FBC and the Benchmark had narrowed thereby justifying a reduction in equity thickness and equity risk premium. FBC asserts that Dr. Safir's evidence is flawed. FBC submits that one of the fundamental problems with Dr. Safir's analysis is that it is based on the assumption that the pre-Stage 1 differential was the product of the Commission's assessment of FBC's business risk in relation to Terasen Gas Inc. (now FEI) in 2009. FBC stresses that the regulatory chronology shows that the business risk differential was last assessed in 2005 and the differential in common equity ratios between FBC and the Benchmark disappeared in 2009 because of the Commission's determinations with respect to Terasen Gas Inc. (TGI) alone. When it was last assessed as part of FBC's 2005 revenue requirement application (RRA), the Commission's 2005 RRA Decision approved a 40 percent common equity ratio that was 7 percent higher than the Benchmark's equity thickness at the time. FBC also submits that in the 2009 Decision relied upon by Dr. Safir, FBC was not an applicant nor did it submit evidence. FBC notes that Dr. Safir's "general approach would be reasonable if the Commission had considered FBC's relative business risk and allowed return in 2009, but it hadn't" (FBC Final Submission, pp. 39-41).

In Reply, FBC submits that a "first principles" assessment is appropriate given the passage of time since 2005 but nonetheless, it has provided evidence to permit the Commission to use 2005 as a point of reference (FBC Reply, p. 3).

Pacific Northern Gas Utilities

PNG, like FBC relies on FEI in its current state as the reference point for comparison. Ms. McShane, also an expert witness for PNG, submits that "In Stage 1 of this proceeding, I assessed the principal areas of business risk facing the benchmark utility, FEI, focusing on whether there had been any material changes since the 2009 ROE Decision. For purposes of Stage 2, as regards the PNG utilities, the focus is on how their current business risks compare to those of FEI." (Exhibit B3-14, Appendix B, p. 11)

The position taken by PNG is captured by the following: "comparing PNG as it stands today to its circumstances as of past PNG decisions effectively eliminates the 'generic' position of this proceeding in that it becomes solely an exercise of defining PNG's absolute risks rather than examining those risks relative to the Benchmark. PNG submits that this would represent a very different methodology from what was specified by the Commission and would have resulted in PNG presenting its evidence in a different manner." (PNG Final Submission, p. 2)

In response to BCPSO's Final Submission on PNG's changing risk over time, PNG submits that "the appropriate approach, as stated by the Commission in its Stage 1 Decision, is to conduct an assessment of the differences in the short and long-term risk faced by PNG as compared to the Benchmark." It submits that the risk assessment should be from first principles, based on the extensive evidence filed in the proceeding. (PNG Reply, p. 3)

Thermal Energy Services Utilities

This is the first instance where small TES utilities are reviewed for their common equity ratios and cost of equity before the Commission and, therefore, with the possible exception of Central Heat, the change in risk over a time period between the cost of capital proceedings is generally not applicable.

The Companies submit that the Commission should not consider itself bound by the past decisions on individual TES utility cost of capital issues where the issues have not been examined in depth (the Companies Reply, p. 2). The Companies submitted that setting the return on equity and capital structure for a "benchmark low-risk" utility in Stage 1 established a reference point against which other utilities could be compared (Exhibit B2-17, p. 3).

FAES provided evidence to compare: (a) the corporate position of FAES as a corporate entity relative to FEI, and (b) a comparison of the relative business risk of TES projects, once installed, to the benchmark utility (Exhibit B-6-2, p. 2).

2.1.2 Submissions by Interveners

British Columbia Pensioners' and Seniors' Organization et al.

BCPSO takes the position that the difference in prospective risk at the present time between FEI and the utility being assessed in Stage 2 is the only relevant consideration. Changes in risk between the present and previous periods were used to assess the Benchmark's business risk. In Stage 2 these are not relevant to providing an assessment of the level of risk applicable to an individual utility except to assist in the assessment of the difference in prospective risk between the utility and the Benchmark at the present time. (BCPSO Final Submission for FEVI and FEW, p. 1)
While maintaining this approach for FBC and PNG, BCPSO also submits that for FBC it may be necessary to rely more heavily on comparisons between 2005 and the present, and on comparisons with other integrated electrical utilities because of decreased similarity between FBC and FEI as the Benchmark. (BCPSO Final Submission for FBC, p. 2)

Industrial Customers Group of FortisBC Inc.

ICG is a customer in FBC's service area and its primary interest in this proceeding is with FBC.
ICG submits that the Commission Panel should not accept the submissions of FBC. Instead ICG has taken the position that the Panel should consider the 2009 Decision as an important point of reference with particular emphasis on the equity component. Its witness, Dr. Safir, states that since 2009 the relative risk between FBC and the Benchmark has decreased slightly and consequently FBC should be granted the same equity ratio as the Benchmark and a slightly reduced equity premium. He further states that "In the 2009 cost of capital proceeding for the Terasen/FortisBC gas utilities, the Commission confirmed that FEI/TGI would continue as the benchmark utility. The Commission left intact its previous ruling that FBC's equity ratio would remain at 40% and that the utility would continue to receive a risk premium to its ROE of 40 basis points. This was determined by the Commission to be a fair premium relative to the benchmark." (Exhibit C4-22, pp. 5, 14; ICG Final Submission, p. 6)

It thus appears that the basis for the position taken by ICG is its belief that the Commission, in the 2009 Decision, had fully considered the relative risk that existed between FBC and the Benchmark in making its determinations. This seems to be confirmed by the following ICG statement "it must be presumed that the Commission Panel that issued the 2009 Decision knew all the circumstances surrounding the capital structure of the utilities that might be affected by the decision. In particular, it must be presumed that the Commission Panel that issued the 2009 Decision considered the cost of capital of FBC established by Order G-193-08." (ICG Final Submission on FBC, p. 5)

Commission Determination

As noted earlier in this Section, the Stage 1 proceeding determined the cost of capital for the Benchmark. The Stage 2 proceeding is designed to have utilities other than FEI provide evidence comparing their business risks to those of the Benchmark for which a comprehensive cost of capital proceeding has only recently been concluded. It seems illogical that the Commission Panel would choose to minimize the importance of evidence in the most recently completed cost of capital proceeding and choose to put more weight on the results of a proceeding which was conducted four years previously and was based on evidence which is not part of this evidentiary record. Therefore, the Panel is in agreement with FEVI, FEW, FBC, PNG and BCPSO that setting the cost of capital for FEI also established a reference point from which to compare other utilities. **Accordingly, the Commission Panel has determined that the primary reference point for the Stage 2 proceeding will be FEI, the Benchmark as assessed in the period leading to the Stage 1 Decision.**

In determining that the current Benchmark will be the primary point of reference, the issue arises as to whether any weight should be given to reference points related to other previous decisions. In reviewing the evidence, the Commission Panel acknowledges that there are some instances where comparisons against previous decisions for the applicant utility may provide further background, clarity and a broader evidentiary base. In some cases the elimination of evidence related to comparisons against previous decisions would leave some areas less than fully explored. **Therefore, the Commission Panel finds it appropriate to consider evidence related to previous cost of capital decisions but only in those cases where the information contributes to a more complete evidentiary base.**

ICG has made arguments with respect to FBC and whether it is appropriate to consider the 2009 Decision as a reference point. The Panel will address this issue further in Section 3.2 in assessing the cost of capital for FBC.

2.2 Common Equity Ratio and Cost of Equity Quantification Methodology

The Stage 1 proceeding included extensive evidence on cost of capital theory and suggested capital structures and ROE for the Benchmark. The FBCU (on behalf of FEI) put forward expert opinions from Ms. McShane, Mr. Engen, Dr. Vander Weide and Concentric Energy Advisors. Intervener evidence included expert opinions from Dr. Booth and Dr. Safir. That evidence was thoroughly tested in information requests and in cross-examination at the oral hearing. The Stage 1 Decision on the appropriate capital structure and cost of equity for the Benchmark utility included detailed analyses of the experts' opinions, including determinations on the various risk factors and how they had changed since the last cost of capital hearing in 2009. All parties agreed that the determination of appropriate capital structures and ROEs requires a high degree of judgement by the Commission since there is no consensus on the validity of the theoretical models or agreement on the input factors.

In considering the Stage 2 hearing format and content required to establish appropriate equity ratios and equity risk premiums for the remaining utilities in BC compared to that established for the Benchmark, the Commission held a procedural conference on April 25, 2013. The ensuing Order and Reasons for Decision included the following statement: "We agree with FBCU that Stage 2 is primarily concerned with business risk assessment which is tangible and does not require an oral examination." (Order G-77-13 with Reasons for Decision, p. 4) To put it another way, the stated purpose of the Stage 2 proceeding is to assess the differences in short and long-term risk faced by utilities, as compared to the Benchmark.

In addition to providing evidence on the various business risks of each utility in reference to the Benchmark, the FBCU and PNG utilities also included expert evidence from Ms. McShane on the cost of equity and capital structure for those utilities. The evidence of Ms. McShane might be characterized as additional perspectives on the reasonableness of her conclusions. She includes a submission on the principles that should apply to establishing a fair capital structure and ROE, her assessment of business risk comparisons, the implications of the rating agencies opinions, beta differentials, size premiums, and allowed capital structures and ROEs of utilities she considers comparable. All of this information can be helpful in informing the Commission Panel of the relative risks of these utilities to the Benchmark.

At issue in this Section specifically are the additional perspectives Ms. McShane provided on capital structure theory and beta differential analysis and their implications on the cost of equity.

For the capital structure theory analysis, Ms. McShane referred to three theoretical approaches that could be used to quantify the range of impact of a change in financial risk, or the common equity ratio, on the cost of equity (Exhibit B1-71, Appendix B, p. 25; Exhibit B1-72, Appendix B, p. 25; GCOC Stage 1 Exhibit B1-9-6, Appendix F). These can be summarized as follows:

Approach 1 is based on the theory that the overall after-tax cost of capital and the pre-tax cost of capital do not change materially over a relatively broad range of capital structures. This approach effectively assumes that the benefit of the deductibility of interest expense for corporate income tax purposes, which would tend to lower the overall cost of capital, is offset by personal income taxes on interest.

Approach 2 is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. This approach does not account for any of the factors that offset corporate income tax advantage of debt, and including the costs of bankruptcy/loss of financial flexibility, the impact of personal income taxes on the attractiveness of issuing debt, and the flow-through of the benefits of interest expense deductibility to ratepayers. Therefore, Ms. McShane states the results of applying the second approach will overestimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

Approach 3 assumes for utility cost of capital purposes that the corporate income tax rate is zero. The underlying premise is that the benefits of the corporate tax deductibility of interest accrue to rate payers in regulated companies, not shareholders, as is the case with unregulated companies. As with the first approach, Ms. McShane states the overall cost of capital remains unchanged as the capital structure changes. However, since the cost of capital contains no income tax component, the impact on the cost of equity due to changing leverage is less than in the presence of corporate income tax and interest deductability.

Ms. McShane concludes that while it is impossible to state with precision whether, within a reasonable range of capital structures, raising the debt ratio decreases the overall cost of capital or leaves it unchanged, in all cases an increase in financial risk will be accompanied by an increase in the cost of capital.

Table 2.1 below shows the adjustments recommended by Ms. McShane to the cost of equity required under each of the three approaches to recognize the difference in financial risk between the proposed equity ratio for FEVI and the 48 percent equity ratio that represents the mid-point of the range of benchmarks.

Table 2.1

Equity Ratio		Basis Point Adjustment to ROE for Change in Common Equity Ratio Based on Approach:		
Mid-Point of Range of Benchmarks	FEVI Recommended	1: 26% tax rate	2: 26% tax rate	3: 0% tax rate
48%	43.5%	60	40	50

Source: Exhibit B1-71, Appendix B, p. 26

The estimated risk premium for FEW based on this approach is similar to that for FEVI. The estimated difference in the cost of equity between the recommended equity ratio of 45 percent and 50 percent equity ratio is approximately 55 basis points (Exhibit B1-71, Appendix B, p. 27).

Table 2.2 below shows the adjustments to cost of equity required under each of the three approaches for FBC to recognize the difference in financial risk between equity ratios of 40 percent and 45 percent.

Table 2.2

Equity Ratio		Basis Point Adjustment to ROE for Change in Common Equity Ratio Based on Approach:		
Equity Ratio for FEI Debt Ratings	FBC Recommended	1: 26% tax rate	2: 26% tax rate	3: 0% tax rate
45%	40%	70	50	60

Source: Exhibit B1-72, Appendix B, p. 27

In her beta differential analysis, Ms. McShane used likely beta differentials of the Benchmark and the utilities to estimate reasonable equity risk premiums. Ms. McShane described it as a potential approach. This approach allows Ms. McShane to recommend equity risk premiums by comparing the betas of utilities to the Benchmark beta of 0.60 used in the Stage 1 Decision. She summarized her beta analysis and qualified it to recognize that betas can vary significantly and there is a range of views on how utility betas should be adjusted. (Exhibit B1-71, Appendix B, pp. 28-32, and similar evidence for other FortisBC and PNG utilities)

In her evidence, Ms. McShane selected a sample of US and Canadian electric and natural gas utilities to gauge the likely differentials in betas. The steps involved adjusting the raw betas to a market mean beta of 1.0, relevering the betas to isolate differences due solely to differences in business risk, and assigning the Benchmark utility as well as the Stage 2 utilities to proxy sample categories that are grouped by credit ratings.

The Commission did not receive alternative theoretical evidence from Intervener experts. One relevant information response is in response to BCUC informations requests (IRs) 1.29.1 and 1.29.2 (Exhibit B3-15) where Ms. McShane cannot assign a level of statistical confidence to her betas due to “an unavoidable degree of imprecision” and she acknowledges that betas can vary widely not only due to estimation methodology, but also due to both differences that are observed from period to period and to the manner in which betas are adjusted. This degree of variation is widely recognized, as is the need to apply expert judgement to inherently noisy data.

Commission Determination

The Commission Panel notes that there are insufficient data to support the conclusions made by Ms. McShane regarding her quantification methodology. However, the Panel will not reject this theoretical evidence and will use it as a check against the more direct evidence on business risk factors. The Panel notes that the appropriateness of Ms. McShane’s assumptions, calculations and recommendations went largely untested in IRs. Furthermore, the Commission Panel did not receive alternative theoretical evidence from Intervener experts or suggestions on how they should be applied to the subject utilities. The evidence is of limited value because the assumptions are not altogether clear; and her findings indicate a large range of possible capital structures and equity risk premiums.

The Panel notes that Ms. McShane's beta analysis approach involved assumptions at every step: sampling of utilities, adjusting the raw betas, relevering the betas based on an assumed universe average equity ratio. These assumptions have no support and her use of adjustment methods, for example, adjusting raw betas to a market mean beta of 1.0, has been cautioned against in the Stage 1 Decision. (Stage 1 Decision, pp. 62-64) In her approach to relevering betas, there is little support put forward by any parties on the assumptions used. Therefore, while the Panel finds Ms. McShane's additional perspective to be an interesting approach to quantify the reasonableness of her conclusions, they are of limited value. The Panel gives little weight to the results and her conclusions.

The Commission addressed the topic of developing an optimal capital structure at length in the Stage 1 Decision. In doing so, it applied the following principles to guide its analysis:

- While credit ratings are important indicators of the risk of disruption, a particular rating is not in and of itself the definition of an efficient capital structure. Possible ratings downgrades are important but must be considered in terms of attendant costs and benefits.
- The long-run risks are important considerations in determining the optimal capital structure. They indicate operating uncertainties that can cause financial distress and the possible attendant disruption and distraction of management.
- The stand-alone principle implies that the risk of disruption due to financial distress is assessed within the context of the risks to the benchmark utility.

(Stage 1 Decision, pp. 46-50)

In this Decision, the Panel will put primary emphasis on the evaluation of comparative business risks of the Stage 2 utilities to the Benchmark, FEI. However, given that the Panel must exercise informed judgement in determining a fair ROE and capital structure we will acknowledge the value of Ms. McShane's quantification methodologies even though our emphasis will be on the relative business risk evaluation.

The Panel will continue to rely on the approach adopted by the Commission in the 2009 Decision and the Stage 1 Decision regarding the reflection of various business risks. Specifically, the Panel will endeavour to reflect long-term risks primarily in the common equity thickness while the shorter term risks will be reflected in the allowed return on equity. This approach reflects consideration of utility investors' ability to recover their invested capital. The Panel notes that if the underlying risk decreases, more debt can be issued; conversely, if it increases, the common equity ratio would have to increase resulting in less debt. Therefore, as pointed out in the 2009 Decision: "The assessment of risks has a significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes."

2.3 Impact of TES Framework Decision

2.3.1 Background

On December 27, 2012, the Commission issued its Report on the Inquiry into Alternative Energy Solutions (AES Report),[6] which among other things tasked Commission staff with conducting consultation with stakeholders on a scaled regulatory framework for thermal energy services (TES).

The scaled regulatory framework was to be developed in accordance with the Principles and Guidelines set out in Section 2 of the AES Report. Some of the key principles stipulated that the least amount of regulation to protect the ratepayer should be used, the benefits of regulation should outweigh the costs, and that TES utilities be encouraged to pursue market-based pricing mechanisms to increase efficiency, reduce costs and enhance performance as contemplated by section 60(1)(b) of the UCA. The Report further found that "economic regulation of Discrete Energy Systems is not warranted given the lack of natural monopoly characteristics and the lack of a need for consumer protection in light of the presence of a functioning competitive market place."

[6] In the Matter of FortisBC Energy Inc. Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives Report, December 27, 2012 [hereinafter AES Report].

After developing a "straw-man" document describing the proposed framework, starting in May 2013, the Commission staff held two consultation workshops with stakeholders and received two rounds of submissions on the proposed framework. On August 28, 2013, the Commission established a written hearing process for review of the proposed Regulatory Framework, which also included an exemption from regulation for certain Thermal Energy System Utilities (TES Framework).

On December 31, 2013, the Commission issued Order G-231-13A, which brings significant additional certainty to the regulation of TES utilities. The Commission Panel summarized its findings as follows.

1. The Panel approves the Stream A exemption proposed by staff subject to the following changes:

    - All projects below a "minimum threshold" should be exempt from Part 3, except for sections 42 and 43 of the UCA. This is referred to as the "Micro TES" exemption.
    - The Stream A regulatory model should apply to all on-site TES systems with a capital cost in excess of the "minimum threshold" and below a "maximum threshold."
    - The "maximum threshold" should be set initially to $15 million. Parties are invited to provide submissions regarding the quantum of the "minimum threshold."
    - The "maximum and minimum thresholds" should be subject to change as determined by the Commission following a hearing.
    - The Stream A regulatory model should include exemption from sections 45 and 61 of the UCA, in addition to the proposed exemption from sections 44.1, 59 and 60.
    - All other TES Systems are subject to the Stream B regulatory model, including CPCN requirements and rate approval.

2. The Panel approves the exemption, as proposed by staff, where the Strata Corporation is the Provider of TES.

3. The Panel will make determinations on the following further aspects of the TES framework in a subsequent decision:

    - Registration processes, forms, procedures and fees.
    - Capital Reserve Fund requirements for Stream A and Stream B TES Systems.
    - Reporting requirements for Stream A and Stream B TES Systems.

The TES Framework Decision will become effective upon approval of the Lieutenant Governor in Council. (Appendix A to G-231-13A, pp. 5-6)

2.3.2 Implication of the TES Framework to the GCOC Proceeding

The TES Framework Decision acknowledges that public utility regulation is only necessary when the competitive market is insufficient to protect the public interest, and has therefore approved the scaled down light-handed regulation for TES systems to encourage the growth of the TES market. In their submissions, FAES and the Companies expressed concern over the high regulatory risk of TES projects. Now that the Framework has been approved, subject to receipt of the Order in Council exemptions, there is more regulatory certainty and context, which lays the foundations for the subsequent equity risk premium and equity thickness determinations to follow in this Stage 2 Decision.

A further description of the Stream A and Stream B models follows:

Stream A Regulatory Model

This model will apply to all on-site TES Systems with a capital cost in excess of a “minimum threshold” of $500,000 and below the “maximum threshold” of $15 million as outlined in the Commission’s Final Report on the Proposed Micro Thermal Energy System Exemption Limit and Stream B Extension Test of March 6, 2014. This model includes exemption from sections 44.1, 45, and 59-61 of the UCA. By providing for complaint only regulation, Stream A enables TES providers and their customers to negotiate contract terms they find appropriate. There will be no initial Commission review of the contracts or rates for Stream A Systems. Accordingly, there will be no determination made as to the rates being just and reasonable, which in turn means that this Stage 2 Decision is not relevant for Stream A projects.

Furthermore, the ‘regulatory compact,’ which is related to the Commission’s mandate to approve rates with utilities being granted a reasonable return on their investment, does not apply in Stream A. By using alternative rate setting mechanisms such as long term agreements or performance based rates, the utilities have an opportunity to earn higher than a regulated return for their TES projects.

For further clarity, the TES Framework Panel noted that “Stream A Systems will be exempt from rate regulation, and consequently regulate cost of service rates. ... There will be no approval of capital expenditures through the issuance of a CPCN, no notion of a regulated return on the equity deployed in the TES and no rate base on which to base that return.” (Appendix A to G-231-13A, p. 30)

Accordingly, the Stage 2 proceeding is not applicable to Stream A type TES projects.

Stream B Regulatory Model

All other TES systems are subject to the Stream B regulatory model, including Certificate of Public Convenience and Necessity (CPCN) requirements and rate approval. It should be noted, however, that even for Stream B Systems, alternatives to cost-of-service based rates may turn out to be more appropriate rate setting mechanisms. Examples of other forms of rate setting include cost recovery basis, avoided costs, business-as-usual competitive rate, with inclusion of a profit margin or a percentage management fee, provision for a take-or-pay clause etc. To emphasize the focus on other mechanisms, the TES Framework Decision also stipulates that should a Stream B TES System

proponent propose a regulated cost-of-service rate setting mechanism, it must provide justification in its rate application as to why other rate setting mechanisms are not feasible or desirable.
In summary, the TES Framework Decision remains true to the spirit of the AES Report. This means that in the projects to come forward, the cost-of-service rate setting methodology should be viewed as the method of last resort. It follows that the Panel in this Decision will only determine equity risk premiums and equity thickness for Stream B TES projects that have or will be approved with the regulated return/traditional cost-of-service rate setting mechanism.

2.4 Need for a Minimum Default Capital Structure and Risk Premium

Given the growing number of TES projects and the potential for significant growth in the number of regulatory proceedings, both FAES and the Companies are in support of the Commission setting a minimum default cost of capital for TES projects. The case made for this approach is based on consideration of both the defining features of TES projects and the regulatory efficiency. FAES and the Companies made submissions in support of a default structure and have provided their respective positions as to an appropriate capital structure and the equity risk premium. This section addresses the need for a default equity thickness and risk premium in principle, whereas the quantum requested is discussed in Section 3.4.

FAES states that the defining features of TES projects – small size and lack of diversity – permit the Commission to establish a minimum default common equity ratio and risk premium for all non-exempt TES projects, subject to FAES bringing forward evidence establishing a risk profile higher than the risk reflected in the default standard. FAES considers the minimum default to be recognition that typically TES projects as a group will have more similarities than differences and can be expected to have a similar ROE and capital structure. FAES further states this approach is reasonable and efficient as it recognizes the overriding similarities and avoids the necessity of re-litigating ROE and capital structure for each TES project. (Exhibit B6-2, p. 1; Exhibit B6-3-1, BCUC-FAES 1.2.2; Exhibit B6-5, BCUC-FAES 2.32.1; FAES Final Submission, p. 15)

The Companies state that the regulatory burden of setting capital structure and return on investment for TES projects is disproportionate to the relative size of the utility if the traditional regulatory approach is followed. Furthermore, the Companies state that the risk of regulatory burden frustrating the TES market can be mitigated by lowering the regulatory barrier to facilitate small utility participation and growth in the TES market. The Companies provided evidence which suggests a set of default financial parameters for small utilities that, they state, is "fair and is directionally closer to the actual market conditions." In addition, in the Stage 1 proceeding, Corix already suggested that the Commission adopt a generic approach to setting a deemed capital structure, ROE and debt rates. (Exhibit B2-17, pp. 4-5; the Companies Final Submission, pp. 1, 3-4)

As discussed in Section 2.3.1, the Commission issued Order G-231-13A and Reasons for Decision on December 31, 2013, and found that the public interest is served in certain circumstances by providing exemptions from certain provisions of the UCA. In accordance with this, the Commission has sought approval from the Lieutenant Governor in Council (LGIC) for such exemptions. The effect of these exemptions when approved will be to greatly reduce those instances where regulation is a requirement for TES projects. The requirement for regulation would be restricted to District Energy TES systems and on-site TES systems not otherwise excluded from the public utility definition. Where regulation is required, approvals would be through a streamlined CPCN and Rate Application process.[7]

Commission Determination

Given the proposed exemptions, the question is whether a need for a minimum default structure remains. The exemptions before the LGIC have greatly reduced the number of projects which must be regulated and only those where the public interest is at risk are required to be regulated. Where regulation is required, more light handed streamlined processes will reduce the regulatory burden and facilitate the approval process.

[7] TES Framework proceeding, Exhibit A-4, Appendix A, pp. 8-9.

The Commission Panel notes that the TES business is small and in its early stages and will continue to grow and evolve over time. Looking ahead, there will likely be many new issues as yet unknown that will need to be addressed. Because of this, it might be premature and difficult to establish a reasonable minimum default structure for TES projects that could be relied upon by the Commission on a go-forward basis. Nonetheless, the Panel finds that the Commission raised some expectations in Order G-47-12 by stating that one of the purposes of the GCOC is "to establish a framework for determining the appropriate cost of capital for other smaller utilities in the province." The Panel also agrees with the submissions of the Companies that the regulatory burden should not be disproportionate to the relative size of the utility.

In summary, after having reviewed the evidence on risks faced by TES projects and their proponents, the Panel is persuaded by FAES and the Companies' submission that TES projects as a group "are more similar than different" and that regulatory efficiency calls for a default structure at this point in time. **Accordingly, the Commission Panel, in Section 3.4, sets a minimum default capital structure and equity risk premium for Stream B TES projects.** Should a Stream B TES project possess risk characteristics that overall are higher than those implicit in the default TES, the project proponent can bring forward the related evidence and make its case. While it is unlikely that any project proponent would bring to the Commission an application to lower the cost of capital, a potential customer of a low risk Stream B TES project can always have recourse by bringing a complaint to the Commission to raise this issue.

2.5 Small Firm Effect – Applicability of Ms. Ahern's Evidence

In the Stage 1 Decision, consideration was given to the impact of firm size on the determination of an appropriate ROE and capital structure. In the Stage 1 proceeding, Ms. Ahern, the expert for Corix Utilities, submitted evidence in support of the establishment of a framework for determining the cost of capital for small utilities. Ms. Ahern asserted "it is conventional wisdom, supported by actual returns over time that smaller utilities tend to be more risky, causing investors to expect greater terms as compensation for that risk." Ms. Ahern also stated that smaller companies are less diverse and face higher risk to business cycles and economic conditions. In addition, the loss of a few customers has more impact on a smaller firm than a larger firm with a more diverse customer base. (Exhibit B2-7, pp. 6-7)

In the Stage 1 proceeding, Ms. Ahern relied upon evidence of two empirical studies which in her view have direct application to utility cost of capital proceedings; the Morningstar/Ibbotson Size Premium (SBBI) (Ibbotson SBBI-2012 Valuation Yearbook) and the Duff &Phelps (D&P) Size Study and Risk Study. She states that the Morningstar/Ibbotson study can be used as a means to determine the size risk premium for a given utility over the benchmark utility. This is done by "comparing the size premium appropriate for the decile in which the benchmark utility would fall based upon estimated market capitalization with the size premium appropriate for the decile in which the specific utility would fall based on market capitalization." The D&P study analyses the relationship between equity returns and company size in a similar manner and can also be used to determine size risk premium of a specific utility against the benchmark. D&P's Risk Study is described as an extension of the Size Study in that it analyses the relationship between fundamental risk measures based on accounting data and return. Based on the studies, Ms. Ahern has concluded that specific, unique risks of a utility investment must be reflected in the rate of return; and the size of an investment (or a utility) is one of those unique risk factors for which investors need to be compensated. Under cross-examination in Stage 1, Ms. Ahern acknowledged that regulatory support for these data in regulatory proceedings has been minimal. (Exhibit B2-7, Ms. Ahern's Evidence, pp. 10-11, 15-16; Exhibit B2-7, PMA-9, pp. 30, 65; T7:1278-1284)

In the Stage 1 Decision, this evidence was considered. While noting the lack of regulatory support for a small size risk premium, the Commission also commented on the need for an on-going exercise of informed judgement by both the Commission and experts retained by the utilities. The Commission acknowledged that the academic literature and empirical studies seem to support the importance of size in explaining returns but noted that the evidence did not indicate how adjustment for size should be implemented. The Commission was not sufficiently persuaded to put any weight on the empirical studies and determined that the small size factor should be further considered in the Stage 2 proceeding, but only as one of the many business and financial risks small utilities or projects are exposed to.

In Stage 2 Ms. Ahern has provided her estimates of specific risk adjustments based on size for Corix, Central Heat and RDE relying upon updated versions of the SBBI and D&P studies which were used in Stage 1. Based on the same methodology used in Stage 1, Ms. Ahern estimated the appropriate range of size-related premiums to be the following:

Table 2.3

	D&P	**D&P**
	Company-Specific	
	Interpolated Premium	**Portfolio-Specific Premium**
DGELLP:		
Range of D&P Size Premiums	5.69% - 9.73%	2.60% - 5.32%
SBBI Size Premium		5.19%
UniverCity:		
Range of D&P Size Premiums	6.45% - 10.05%	2.60% - 5.32%
SBBI Size Premium		5.19%
Central Heat Distribution Limited:		
Range of D&P Size Premiums	4.19% - 7.74%	2.41% - 5.32%
SBBI Size Premium		5.19%
River District Energy Limited Partnership:		
Range of D&P Size Premiums	5.88% - 9.01%	2.60% - 5.32%
SBBI Size Premium		5.19%

Source: Derived from Exhibit B2-20, p. 2

Both the SBBI and D&P studies rely upon major US stock exchange companies for their portfolio of companies (Exhibit B2-17-1, PMA 1, p. 2; PMA 2, p. 13).

In calculating the D&P range of size premiums and the SBBI size premium for the utilities of the Companies, Ms. Ahern appears to have applied a similar approach as the studies she has relied upon. Her approach places the benchmark utility in a decile that is made up of the sample of US electric and gas utilities used by Ms. McShane in Stage 1. In using Ms. McShane's sample she states: "The size premiums specific to DGELLP must be subtracted from those relative to Ms. McShane's proxy group, because the benchmark is based upon the proxy group." It therefore appears that Ms. Ahern's calculations result from a comparison of a sample of US electric and gas utilities, which serves as proxy for the benchmark. The information in PMA 3-6 seems to confirm this. (Exhibit B2-17-1, pp. 4-7)

Ms. McShane, the expert for FAES, has taken a similar position to that of Ms. Ahern as to the small firm effect. She relies on a number of studies to support her position. One such study states:

> "A number of researchers have observed that portfolios of small firms' stocks have earned consistently higher average returns than those of large firms' stocks; this is called the "small-firm effect. On the surface, it would seem to be advantageous to the small firm to provide average returns in the stock market that are higher than those of large firms. In reality, however, this is bad news - what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on the stocks of otherwise similar large firms. Therefore, the basic cost of equity capital is higher for small firms."
>
> (Exhibit B6-2, FAES Evidence, Appendix B, McShane's Evidence, pp. 15-16)

However, Ms. McShane differs from Ms. Ahern in that her estimates take into consideration the differences in environments in which publicly traded firms operate and that regulated companies are afforded greater protection than unregulated companies. Ms. McShane notes that once FAES has competed for a project and it's constructed, it is afforded protection not available to the unregulated firms that would comprise the majority of the firms in the Ibbotson analysis.
Ms. McShane concludes that size premia applied to very small TES utilities, while relevant, are smaller than those that could be applied to companies operating in fully competitive markets. In support of this conclusion, she submits that the Ibbotson studies demonstrated that small utilities

(i.e., publicly traded gas, electric and sanitary) have achieved returns that are approximately 1.5 and 3.0 percentage points higher on a compound and arithmetic average basis respectively, than those of large utilities. (Exhibit B6-2, FAES Evidence, Appendix B, Ms. McShane's Evidence, pp. 17-18; Exhibit B6-3-1, BCUC-FAES 1.29.2 (Ms. McShane) further clarified this aspect of her evidence in the response to Exhibit B6-3-1, BCUC-FAES 1.30.2 (Ms. McShane))

BCPSO expresses concern with some of Ms. Ahern's assumptions regarding the calculation of risk premium ranges. BCPSO points out that FEI, rather than the average of Ms. McShane's sample of US electric and gas utilities, is the appropriate gauge from which to calculate differences in return. Had this been used, BCPSO submits that the low end of the range for the D&P risk premium would have been substantially lower. (BCPSO Final Submission, pp. 4, 7)

Commission Determination

The Commission Panel acknowledges that there has been a great deal of empirical research into what has been termed the small firm effect. Among these, the SBBI and D&P studies have explored the development of models designed to relate firm size factors with the determination of an appropriate risk premium for a given company as compared to others of different size. Both of these studies relied upon the results of a large group of US companies encompassing most of the major US stock exchange companies. There is no evidence to suggest that Canadian companies have been included in these studies.

The question the Commission Panel must address is whether Ms. Ahern's application of this research in establishing a framework for determining the cost of capital for small utilities has application in this proceeding and if it does, what weight should be placed upon it. After consideration of the evidence put forward by the Companies, the Commission Panel is not persuaded that the empirical studies as used by Ms. Ahern has application in the Stage 2 proceeding. Our reasons for this follow.

Individual Categories of Business vs. the Universe of US Stock Exchange Companies

The approach taken by Ms. Ahern implies that with respect to size, all businesses are the same and the results of the larger sample of US stock exchange companies are reflective of those in each of the business categories making up that larger sample. Thus, an investor considering a small firm in the high tech industry would assess the same level of risk and have the same return expectations as an investor considering a small utility. Put more simply this could be interpreted to mean that high tech stock purchase risks are comparable to utility stock purchase risks.

Ms. Ahern has presented no evidence to support the position she has taken regarding the validity of applying the results of the empirical studies for the broader US stock exchange companies to the Canadian or US utility industry. The Commission Panel is of the view that business environments differ among categories of business as do investor assessment of risks and expectations of returns. Ms. McShane makes this point as she submits that the estimates she has prepared take into account environmental differences in which relevant firms operate. As noted, Ms. McShane points out that there is a significant difference between the protections offered regulated companies, which leads to her conclusion that the size premia applicable to very small TES utilities are smaller than those which would be applied to those companies in a fully competitive market. The Commission Panel agrees with Ms. McShane as the regulatory compact and the fair return standard are just two examples of the protection afforded regulated companies. In addition, the Panel has noted that Ms. McShane has reported results of an earlier Ibbotson study which demonstrated that returns for a group of small utilities varied by approximately 1.5 percent on a compound basis. This further casts doubt on the validity of Ms. Ahern's conclusions.

Reliance Upon a Sample of US Gas and Electric Utilities

As stated previously, Ms. Ahern relies upon a sample of US gas and electric utilities (used by Ms. McShane in Stage 1 as a basis for her calculations). The Commission Panel has two concerns with Ms. Ahern's choice of comparator. First, Ms. Ahern has made no effort to justify the use of this sample as being representative of the Canadian market and her calculations have in no way been adjusted to account for this omission. As stated in the Stage 1 Decision and in Section 2.3 of this Decision, "US data needs to be considered on a case by case basis and weighed with consideration to the sample being relied upon and any jurisdictional differences which may exist." Second, the sample she has relied upon serves as a proxy for the Benchmark. No evidence has been presented to justify the use of a proxy of US companies rather than FEI, which is the Benchmark. This point was raised by BCPSO who submits that the appropriate approach "would have been to calculate the differences in return as between a utility comparable in size to FEI versus the size of the various TES utilities." BCPSO further submits, based on the Companies response to BCPSO IR 1.3, that the "resulting range of results is somewhat lower for both SBBI and D&P studies across virtually all size metrics." (BCPSO Final Submission, p. 7) The Panel notes that the Companies did not respond to this in reply.

While the SBBI and D&P studies in support of the small firm effect are not at issue in this proceeding, Ms. Ahern's use and their application of the studies are very much at issue. For all the foregoing reasons, the Commission Panel finds that no weight should be given to Ms. Ahern's framework for determining the cost of capital for small utilities. Despite giving no weight to Ms. Ahern's framework, we still consider that the business world has generally accepted that there is greater risk in being small. Therefore, small size as a factor will still be considered in our Stage 2 utility cost of capital determinations but as one of a number of related factors. Factors such as diversity of customer and economic base, concentration of assets and differences in service areas all of which may be related to small size will be considered among a range of business and financial risks utilities are exposed to.

2.6 TES Projects – What is Being Regulated?

To provide further clarity for the discussion and determinations to follow, this section will define at the outset what is being regulated in the case of TES projects.

Utility, Person, Project or System

The Commission, in its communications regarding the Stage 2 proceeding, identified the Group 3 utilities as micro utilities engaged in thermal energy services (Exhibit A-33). FAES states it develops and operates TES projects (Exhibit B6-2, p. 1). The Companies state they provide thermal energy services throughout the province and that in most cases the Companies' projects are regulated as "public utilities" under the UCA. In the case of Corix, however, some of its projects are not regulated under the UCA (Exhibit B2-17). The TES Framework Decision also addressed the confusion related to references of a person, utility, project or a system. This confusion arises because the UCA defines a public utility as a person providing, in this case, certain thermal energy related services. The Framework Panel noted that the proposed exemptions were based on the characteristics of a particular TES system (project) and not the person providing those services.

The Commission Panel acknowledges the Corix description of owning both regulated and unregulated projects. However, it is unclear as to the current status of FAES in this regard. In any case, the Commission Panel in this Decision considers Corix and FAES as corporate entities that contain numerous TES projects under their umbrellas. For the purposes of this Decision, the Panel will make determinations related to individual TES projects, defined as public utilities under the UCA.

What Entity Faces the Financial Risk?

The Commission Panel notes that among the applicants in the Group 3 utilities, there does not appear to be a common agreement as to the entity being regulated or how risk will be assessed in determining an appropriate cost of capital for utilities within this group. More specifically, this relates to whether the risks associated with an entity financing individual TES projects should be considered in determining a cost of capital for one of its utility projects. Therefore, the question becomes whether the Commission is assessing the cost of capital for the operator of the TES utility project or the project itself. Furthermore, a crucial determination at the outset involves deciding whether the Stream B utility in consideration should be compensated for the business developmentrisks during the early stages before the project comes to fruition.

FAES appears to have taken the position that the cost of capital to be determined is for the operator of the utility rather than the project utility itself. This is evident in the following:

- From the perspective of FAES as the entity financing individual TES projects, the company faces similar competitive pressures to FEI from other energy sources. Unlike FEI, which is a natural gas monopoly within its defined service territory, FAES also competes with other TES entities to construct TES projects. A small entity competing in a highly competitive energy market, by definition, faces higher risk.
- Once constructed, each TES project operates as a very small utility. Although there are differences among TES projects, the defining characteristics of all TES projects are that they are exponentially smaller and less diverse than FEI, are greenfield operations, and by their very nature face financing challenges. (Exhibit B6-2, FAES Evidence, p. 1)

FAES states that the additional risk to FAES in competing with other TES providers to construct and operate a project is one that is not material for FEI which is large, established and has a well-defined service territory. FAES points out that it is only once it has successfully competed for the market, thus winning a greenfield utility, that a more direct comparison with the benchmark utility is possible. (Exhibit B6-2, FAES Evidence, Appendix A, p. 1)

Corix states that Corix Utilities is financed through a combination of debt and equity with debt financing being provided through Corix' consolidated credit facilities. Corix is a private, investor-owned company, which provides propane, gas, water and electricity utility deliveries to various communities within BC. The Companies state small utilities often operate in a competitive environment where customers have many energy choices, including their service provider should they choose TES. The TES market is an emerging market that provides service to customers on a small scale using many different applications of both existing and new technologies. Furthermore, the Companies state that due to the local nature and smaller size of TES energy projects, the TES market has much lower economic barriers to entry than the natural gas distribution market, and is best served when competition is encouraged. In addition to competing on the basis of price or quality of service, TES projects also compete on the basis of environmental qualities of their service. In summary, the Companies state the competitive efforts including innovative technologies entail a very different risk profile than that of a conventional utility business characterized by a natural monopoly with a large, captive customer base. "As a result, the return that investors expect to receive on an investment in small utilities is higher than an investment in the benchmark utility." (Exhibit B2-17, pp. 3-4, 13-15)

River District Energy's development and net operations are 100 percent funded by its parent, Wesgroup Properties Limited Partnership (Wesgroup).

The Companies state that customers who make the decision to consider an alternative to traditional heating options typically issue a request for proposals, which generally result in several bids from competing TES service suppliers. (Exhibit B2-17, p. 29)

Commission Determination

In the Stage 1 Decision, the Commission viewed the overall risk as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations. In addition, the Panel recognized the risk of potential financial disruption and accepted the distinction outlined in the 2006 and 2009 Decisions where investment risk was described as comprising the sum of business risk, financial risk, and regulatory risk. (Stage 1 Decision, p. 24)

The Stage 2 Panel also accepts the above description of risk and further reaffirms the principles of the Stage 1 proceeding that should be respected when establishing the cost of capital in general, and the capital structure and equity risk premium for TES projects, specifically:

- The stand-alone principle;
- Fair Return Standard;
- Compatibility of capital structure and overall return with business risks;

- Ability to attract capital on reasonable terms and conditions;
- Maintenance of financial integrity; and
- Comparability of returns with similar enterprises.

These principles were also articulated by FAES' expert, Ms. McShane. (Exhibit B6-2, Appendix B, pp. 3-4)

To find answers to the questions that have been posed, the Commission Panel must consider who is the investor in these TES projects. In practical terms, the investors in the existing projects have been identified and include entities such as Corix, FAES and Wesgroup. Consistent with this analogy, the investor in FEI is its parent, Fortis Inc. However, the Fair Return Standard, which arises from legal precedents, requires that a utility must (i) earn a return on investment commensurate with that of comparable risk enterprises; (ii) maintain its financial integrity; and (iii) attract capital on reasonable terms. Consistent with this standard and the stand-alone principle, the entire focus of the Stage 1 proceeding was on FEI and its investors' perception of FEI risk profile even though one can invest in FEI only via Fortis Inc. shares. The fact that FEI issues debt and, therefore is the subject of credit rating reports, is an actual test of the reasonableness of its capital structure.

In the case of TES projects, due to their small size, even the debt component is deemed as the TES projects are too small to issue actual debt. Regardless, as described above, this Decision must consider the risks faced by current and future investors in thermal energy services. Therefore, the timeline for this consideration must begin at the stage when a project proponent is seeking equity funding, by way of seed money from an angel investor, private equity funds, a property developer, an existing utility, etc. This in turn involves assessing first any risks associated with efforts to secure agreements to initiate TES projects. The second phase of risk assessment begins once an individual project, as a stand-alone entity, becomes a utility after successfully competing in the market for the project. **Accordingly, the Stage 2 Decision considers all risks faced by a Stream B TES project investor, which include the business development, construction and operation phases.**

2.7 Use of the Risk Matrix

To evaluate the overall risk of a given TES project, the Commission has developed a risk matrix for use in small TES utility proceedings. In Stage 1, the Commission recommended that small TES utilities use this risk matrix in Stage 2 as an aid in justifying a risk premium and capital structure in comparison with the benchmark utility. The Commission also encouraged other small utilities to modify the matrix to facilitate a similar comparison. (Stage 1 Decision, p. 101)

A number of utilities took issue with the recommendation of the Commission to utilize the risk matrix.

The Companies submit that the Commission's risk matrix with 19 risk factor comparisons is not an effective tool to assess small utility profiles. They recommend that the process should be more simplified with appropriate weight given to utility size, the factor they consider to be the most important determinant of small utility risk. The Companies point out their concerns as follows and suggest a modified approach for each:

- The current list of 19 risk factors overlaps yet each factor appears to receive equal weighting. They suggest that a reduction in the number of risk factors will result in a more focused and accurately weighted risk profile.
- Because regulation provides a surrogate for competitive market pressures, the Commission should rely on objective data that quantifies the market indicators. In doing so the Commission should evaluate utility risk and financial risk separately.
- To date, the Commission has placed a de facto limit of 100 basis points (bps) that ignores the risk profile differences between most small utilities and the benchmark. The Companies propose the Commission expand the spread beyond 100 bps.

(the Companies Final Submission, pp. 4-5)

FAES notes its experience in previous proceedings where the Commission has relied upon a 20-factor risk matrix and has expressed concerns about this approach in both past and in the current proceeding. While acknowledging that there is value to using a risk matrix as a tool to summarize utility characteristics in terms of risk factors, FAES raises the following concerns:

- If the matrix is interpreted as a checklist, dominant factors like size and diversity could be given equal weight to other less dominant factors on the list.
- The 20 point risk matrix implies a degree of precision in a projects cost of capital that is not warranted.

In summary, FAES submits that the risk matrix approach has provided little value in setting out its evidence and should not be a requirement in future proceedings. In the event the Commission continues to use the risk matrix, FAES recommends that the Commission should acknowledge that it does not imply weightings for any particular factor or that differences among TES projects do not translate into differences in cost of capital. (FAES Final Submission, pp. 11-12; Exhibit B6-5, BCUC 2.39.1)

BCPSO takes a more holistic view of the risk matrix and submits it is a framework that all utilities can use in distinguishing their risk in comparison to the benchmark. In its view "It should be open to utilities to identify those areas in which their risk differs from that of the benchmark utility." Therefore, risks that are not spoken to or identified can be considered to have no difference in risk to that of the benchmark. BCPSO argues that as long as it can be justified on a rational basis, and eases the process of assessment and presentation, it should be open to utilities to determine their own groups of risks. Accordingly, BCPSO takes no issue with the Companies approach to simplifying the risk matrix but leave it open for other utilities to group the risk factors differently if they so choose. (BCPSO Final Submission, pp. 2-3)

Commission Determination

There does not appear to be any disagreement among the parties with respect to the purpose of the risk matrix although there does appear to be a level of anxiety regarding its application. In the view of the Commission Panel much of the problem is related the parties' understanding of how the risk matrix will be used and how results are to be interpreted. There appears to be much concern regarding the weighting of each factor and whether appropriate weight will be applied to what some utilities consider to be the key factors of size and diversity. This seems to place the risk matrix in the context of being viewed as a formulaic approach to cost of capital, which yields a specific result. As outlined previously, FAES raised this concern in its submissions by pointing out that the degree of precision implied by the Commission risk matrix with respect to TES projects' cost of capital is not warranted. BCPSO, on the other hand, seems to consider the risk matrix as a tool providing a level of guidance to the utility that also allows complete flexibility as to how it is to be used.

The Commission Panel considers the risk matrix to be a useful tool to assist utilities in capturing the scope of risks that a utility may face. In our view it does not address specifically the level of importance accorded a particular risk or whether it is appropriate in a given circumstance to combine certain risk factors. Therefore, the Panel recommends that in future proceedings it is appropriate to continue to use the risk matrix for the purposes of identifying and describing risks or categories of risks. However, for purposes of clarity, the Panel provides the following guidelines regarding its use:

- Utilities are free to use some or all of the risk factors and are free to group them as they deem appropriate.
- The Commission has no predetermined weighting for any of the risk factors. However, utilities are free to weight factors or groups of factors and base their submissions on those weightings.
- Any weight to be placed on a specific risk factor or group of factors will, at the discretion of the Commission Panel, be determined on a case-by-case basis in each proceeding.

- The risk matrix is not to be considered a formulaic approach with a specific outcome.
- Any comparisons among utilities will be made to aid in maintaining inter utility consistency. Such comparisons will be used as a check only with the primary source of comparison being the Benchmark.

In continuing to support the use of the risk matrix, the Commission Panel would like to be clear that it is viewed as a tool only. In making cost of capital decisions, the Commission will continue to rely on exercising its judgement based on all of the evidence before it. In the course of its deliberations, if a Commission Panel is persuaded that a risk premium in excess of 100 bps is warranted to meet the fair return standard, it is not bound by any limitations or a de facto limit.

3.0 COST OF CAPITAL – STAGE 2 UTILITIES

Commission Order G-77-13 issued on May 13, 2013, set out the review of Stage 2 of the GCOC proceeding with all the utilities in Stage 2 separated, for practical reasons, into three groups:

Group 1: FBCU: FEVI, FEW and FBC.
Group 2: PNG Utilities.
Group 3: Corix, FAES and other small TES utilities.

In the following sections, the short and long-term business risks of each utility is examined relative to FEI, the Benchmark with some consideration of past decisions as outlined in Section 2.1. Based on this, the Commission Panel has determined the allowed ROE and deemed capital structure for each utility. Where appropriate, the determinations on contextual issues from Section 2.0 has been relied upon to provide guidance to the cost of capital determination process.

3.1 Group 1 Utilities - Gas

FortisBC (Vancouver Island) Inc. and FortisBC (Whistler) Inc.

Introduction

FEVI and FEW filed evidence in a joint document that outlines the current assessment of their respective business risks relative to the Benchmark utility (Exhibit B1-71, Evidence of FEVI and FEW, pp. 1-12).

In the 2009 Decision, the risk premiums for FEVI (formerly known as Terasen Gas (Vancouver Island) Inc.) and FEW (formerly known as Terasen Gas (Whistler) Inc.) were set at 50 bps above the Benchmark FEI. The allowed equity thickness for both entities was 40 percent.

In the current proceeding a 43.5 percent common equity with an ROE risk premium of 50 bps is proposed for FEVI, a 45 percent common equity with an ROE risk premium of 75 bps is proposed for FEW. The currently allowed levels, those applied for as well as the Intervener proposal, are summarized below for ease of comparison.

Table 3.1
Summary of Capital Structure and Equity Risk Premiums (ERP)

	Current		**Requested by FEVI/FEW**		**Proposed by Intervener (BCPSO)**	
	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)
FEVI	40	50	43.5	50	40-42	50
FEW	40	50	45	75	40-42	50
Benchmark	38.5	0	n.a.	n.a.	n.a.	n.a.

In support of their respective positions, FEVI and FEW assert that they have higher risk than the Benchmark in the following areas:

- Smaller Service Area and Less Diverse Customer and Economic Base;
- Less Competitive;
- Greater Supply Risk.

FEVI and FEW note that historically, the Commission has consistently determined that FEVI and FEW risks are higher than those of the Benchmark. The two utilities further assert that their evidence and that of Ms. McShane is that FEVI and FEW continue to face higher business risk. This is further corroborated in the case of FEVI by its lower credit ratings. (FEVI and FEW Final Submission, pp. 4-5)

Ms. McShane recommends deemed equity ratios for FEVI and FEW of 43.5 percent and 45 percent, respectively. Her conclusions are based on the following:

- Both FEVI and FEW face higher business risk than FEI and FEW faces risks higher than FEVI. This is supported by both Moody's and DBRS debt ratings and related opinions which support the conclusion that the FEVI higher business risk points to a ratio higher than 40 percent.
- Moody's June 2013 Credit Opinion on FEVI indicates an equity thickness of over 40 percent is needed to maintain credit metrics.
- There has historically been a 5 percentage point difference in equity ratios of FEVI and FEW compared to FEI.
- Differences between allowed common equity ratios of small and large Canadian utilities indicates a 45 percent ratio for both utilities.
- US gas utilities are appropriate benchmarks and point to equity ratios in the 50 to 52 percent range for FEVI and FEW.

In addition, Ms. McShane recommends a 50 bps equity risk premium for FEVI and 75 bps equity risk premium for FEW. She bases this on the following:

- With no material change in the relative risk between the utilities, a 50 bps premium is equal to the most recently approved risk premium over FEI and remains reasonable.
- At recommended common equity ratios there is a need for equity risk premiums relative to FEI's ROE to recognize higher business risks for FEVI and FEW. Premiums of 50 bps are indicated at recommended equity ratios.
- Differences in the Commission's attributed beta to FEI in Stage 1 and betas of higher risk utilities support risk premiums of 50 bps for FEVI and 75 bps for FEW.
- Available data on size premia for small utilities like FEVI and FEW indicate that proposed premiums are conservative

(Exhibit B1-71, Appendix B, Ms. McShane's Evidence, pp. 1-3)

BCPSO states that it agrees that both FEVI and FEW face greater business risk than FEI. Accordingly, BCPSO submits that it supports an equity thickness in the range of 40 percent to

42 percent for FEVI and FEW with a ROE premium in the range of 50 basis points. In reaching this conclusion, BCPSO submits that this will produce credit metrics to allow FEVI to avoid a ratings downgrade.

As noted in Section 2.1, the Commission Panel has determined that the primary point of comparison will be against the Benchmark. Comparisons against prior Decisions will be considered secondarily. In addition, the Panel notes that Order G-21-14 and the accompanying Reasons for Decision issued on February 26, 2014, for the FortisBC Energy Utilities Application for Reconsideration and Variance of Order G-26-13 concerning Common Rates, Amalgamation and Rate Design is a consideration. This will be addressed in Section 4.2.

Risk Assessment

3.1.1 Smaller Service Area and Less Diverse Customer and Economic Base

FEVI and FEW Positions

FEVI and FEW state that they are significantly smaller natural gas distribution utilities than the Benchmark in terms of service area, customers, rate base and revenues. FEVI is approximately 1/8 the size of FEI at 100,000 customers and serves far fewer communities than the Benchmark, while FEW is considerably smaller with only 3,000 customers and is confined to a single community. FEVI and FEW assert that the concentration of assets within a small service area makes it more difficult for them to diversify risk relative to FEI (Exhibit B1-71, Appendix A, Evidence of FEVI and FEW, pp. 3-8). While having a smaller rate base than FEI, the rate of asset growth is higher. The FEVI average annual growth of rate base of FEVI is 13.5 percent from 2009 to 2012, and the FEW average annual growth in rate base is 9.8 percent. This compares to a much smaller growth of rate base for FEI at 3 percent over the same period. (Exhibit B1-79, BCUC 2.29.1)

In terms of customer profile, FEVI and FEW submit that they have less diverse economic and customer bases than the Benchmark. The less diverse customer base, and the concentration of customers in particular industry segments, make FEVI and FEW subject to greater throughput and revenue risks in response to events that affect specific customers and industries. FEVI submits that its throughput is largely dependent on industrial customers, mainly the Vancouver Island Gas Joint Venture (VIGJV) in the pulp and paper industry and the BC Hydro – Island Generation. These two customers account for 61 percent of FEVI's total demand and 16 percent of its total delivery margin. FEVI submits that there is risk associated with both of these customers. BC Hydro can terminate its service agreement on 24 months' notice as early as November 2015 and a recent change in use has led to a 20 percent reduction in firm demand charges. Further, the VIGJV contract expires in 2017 and there is uncertainty around requirements beyond that date.

FEW states that the majority of its delivery margin is derived from the commercial sector and is largely focused on tourism, which is cyclical and dependent upon discretionary income. This, they note, was recognized in the FEW 2009 Decision where the Commission stated that FEW "lacks the diversity of service area and customer base enjoyed by the benchmark low risk utility."[8] FEW asserts that investors, in making longer term decisions, must consider the risk of customer failure when the cycle hits a low point. FEVI and FEW state that with respect to the cost of capital, the important thing to consider is the forward looking risks associated with a service area. (Exhibit B1-71, Evidence of FEVI and FEW, Appendix A, pp. 3, 7-10; FEVI and FEW Final Submission, pp. 7-11; Exhibit B1-76, BCUC 1.8.1, 1.9.1)

FEVI and FEW contend that their smaller service area and smaller utility size means they are riskier than the Benchmark. Their expert, Ms. McShane, seems to agree with this and states that having physical assets concentrated in a limited geographic area contributes to a higher business risk profile. (FEVI and FEW Final Submission, p. 5) FEVI and FEW submit they have a much higher rate

[8] In the Matter of Terasen Gas (Whistler) Inc. and an Application for 2009 Revenue Requirements and for a Return on Equity and Capital Structure Decision, April 7, 2009 RRA Decision [hereinafter TGW 2009 RRA Decision].

base per customer than FEI, and are reliant on a smaller number of customers to generate revenue. (FEVI and FEW Final Submission, pp. 6-9; Exhibit B1-71, Appendix B, p. 8)

BCPSO Position

BCPSO considers compact utilities to have significant advantages and rejects the idea that it necessarily follows that operating in a small service area results in greater risk. BCPSO argues small utilities require less infrastructure to serve the same load, resulting in a lower rate base and cost of service relative to their more widely dispersed counterparts (BCPSO Final Submission for FEVI and FEW, p. 2).

BCPSO acknowledges that FEVI and FEW have a smaller customer base and rate base per customer than FEI. However, it asserts this is a forward looking exercise and one advantage held by FEVI and FEW is their higher customer growth rates (BCPSO Final Submission for FEVI and FEW, p. 2).

BCPSO submits that there seems to be improvement with respect to FEVI's industrial customer base. The VIGJV has increased its demand to 12 TJ/day effective November 1, 2012 from 8 TJ/day since August 2008. While acknowledging that a downturn in the pulp and paper industry could come any day, the trend is toward improving conditions. Further, BCPSO does not see the BC Hydro - Island Generation as a high risk customer pointing out that its Island Generation contract is renewed to 2022 and FEVI has acknowledged that there has been no indication that BC Hydro intends to terminate its transportation agreement. In addition, BCPSO asserts that FEVI is in a good position to increase its industrial customer base with the proposed Pacific Energy Corporation (PEC) export facility and note that it appears increasingly likely the facility will be built (BCPSO Final Submission for FEVI and FEW, p. 3).

<u>FEVI and FEW Reply</u>

FEVI and FEW question BCPSO's assertion regarding infrastructure requirements to serve the same load and argue that it costs FEVI and FEW more to deliver each gigajoule (GJ) of throughput (hence the higher delivery rates than FEI). A higher rate base per customer means that to recover their invested capital, FEVI and FEW must be more reliant on each customer and competitive risk related to high delivery rates is increased (FEVI and FEW Reply, p. 3).

FEVI and FEW submit that while BCPSO's calculation of growth rate is correct, the absolute number of FEVI and FEW customers is very small and the calculated growth percentages are still low. They note that there is little to distinguish among the growth rates of FEI, FEVI and FEW (FEVI and FEW Reply, p. 4).

Concerning the long-term risk arising from having customers in highly cyclical industries, FEVI and FEW assert that long term risk is not related to an industry's position in the economic cycle. FEVI and FEW further argue that while BCPSO seems to acknowledge that the future is more important than the present from an investment perspective, it departs from this in its assessment of risk associated with VIGJV and BC Hydro – Island Generation. They point out that the VIGJV's current demand is related to the pulp and paper industry today and the long-term risk is more related to long-term requirements and mill closures (FEVI and FEW Reply, p. 5).

FEVI considers the PEC project to be uncertain and argues it is inappropriate for the Commission to place any material weight on the project during its business risk assessment. FEVI submits that the PEC project, should it proceed, is properly a consideration for the next cost of capital proceeding (FEVI and FEW Reply, pp. 6-7).

Commission Determination

The Commission Panel considers the risks related to the smaller service areas and a less diverse customer and economic base to be important determinants. **The Commission Panel finds that both FEVI and FEW face additional business risk, which are deserving of significant weight when compared to FEI with respect to their service area size and its diversity.**

The Panel acknowledges that there is additional business risk associated with FEVI and FEW having fewer options available to diversify their risk in what are relatively small service areas when compared to FEI. The growth rate of rate base as compared to FEI and the higher rate base per customer and its impact on rates are also considerations contributing to higher risk. BCPSO submits that this is offset by FEVI's and FEW's higher customer growth rate in comparison with FEI. The Panel notes that the difference in growth rates between the utilities is small and places minimal weight on it given the lack of materiality.

A significant factor related to rate base growth rates is the fact that they were largely driven by FEVI's Mt. Hayes project and the FEW's pipeline which was completed in 2009. These, while significant, were "one off" projects which are not necessarily representative of what will occur in the future.

The less diverse customer base and concentration in limited industry segments is also a consideration as evidenced by FEVI's reliance on two major customers, VIGJV and BC Hydro, for 61 percent of their total demand. Likewise, FEW is dependent on tourism for 70 percent of its total demand and 68 percent of its margin (Exhibit B1-71, Appendix A, p. 11). While the Panel acknowledges the cyclical nature of both of these market areas, we are not persuaded that a case has been made that either utility faces undue stress in the future. With respect to BC Hydro and VIGJV (which has increased its consumption in recent years), FEVI has presented no evidence as to what either of these customers intends to do in the future noting only that they have options when contracts expire. With respect to FEW the Panel takes a similar view. While the Panel accepts these are risks that must be considered, we are not persuaded as to the probability of these events occurring. Consideration of the potential PEC project can be viewed through the same lens. While there is a possibility that the PEC project may proceed, as noted by BCPSO, there is no firm evidence as to the probability or the materiality.

FEW and FEVI assert that investors must consider the risk of customer failure during a low cycle. The Panel notes that given the recent difficult economic period, it would not be unreasonable for investors to take guidance from the recent past in determining the level of cyclical risk they may face with an investment in the Whistler area.

3.1.2 Competition Risk

FEVI and FEW Positions

FEVI and FEW submit that their burner tip rates are higher than the Benchmark. More importantly, their new space and water heating burner tip rates are higher as compared to Tier 2 electric equivalent rates when upfront capital costs are taken into account. FEVI and FEW submit that along with FEI they must compete against BC Hydro "postage stamp" electricity rates. However, they argue that they continue to face much higher effective per gigajoule natural gas delivery rates than the Benchmark. In their view, the differences between the Benchmark and FEVI and FEW in this regard are significant. While FEI enjoys a favourable advantage against the cost of electricity, FEVI and FEW customers face higher energy costs than customers with electric heat. FEW and FEVI argue that this differential makes it challenging for builders and developers to make a case for choosing gas equipment over electricity. (Exhibit B1-71, Appendix A, Evidence of FEVI and FEW, pp. 16-17; FEVI and FEW Final Submission, pp. 11-12)

In addition, FEVI submits that the impact of the loss of royalty revenues has been significant. Because of this, its rates are currently insufficient to recover costs. Consequently, FEVI anticipates a further increase in rates once the amounts remaining in the Revenue Surplus Deferral Account

(RSDA) are depleted. FEVI also points out that loss of the royalty revenues has further competitive impact in that they formerly acted as a hedge on volatility which is no longer there.

In consideration of this evidence, FEVI and FEW submit that the Commission should find that they face greater price risk than FEI. (Exhibit B1-71, Evidence of FEVI and FEW, Appendix A, p. 3; FEVI and FEW Final Submission, pp. 13-14)

BCPSO Position

BCPSO does not disagree with the assertion that FEVI and FEW delivery rates are higher than those of FEI or that natural gas is less price competitive relative to electricity than is the case in FEI's service area. However, BCPSO disagrees with the assertion that FEVI and FEW are facing higher energy costs than customers with electric heat. BCPSO submits that the majority of customers with electric space and water heat take Tier 2 energy, which is therefore, a better comparator than Tier 1 energy. In addition, BCPSO asserts that the information in the response to BCUC IR 2.30.2 "appears to indicate that gas is cost competitive with tier 1 electricity when total bill charges are factored in" (BCPSO Final Submission for FEVI and FEW, pp. 4-5).

BCPSO also notes the significant increases in BC Hydro rates announced by the Minister of Energy in November 2013, and asserts there is no indication that rates for natural gas will rise as quickly. They further submit that FEVI's projection for rates following the depletion of the RSDA sometime after 2020, as outlined in response to BCUC IRs 1.11.3 and 2.34.2 [sic], indicate the impact on rates will be far less than that announced for BC Hydro. They state that "...even under the most pessimistic forecast, BC Hydro rate increases will come sooner and will be a greater percentage increase than any rate increases anticipated by FEVI." (BCPSO Final Submission for FEVI and FEW, p. 5)

BCPSO also submits that the withdrawal of royalty revenue is not a legitimate issue “affecting shareholders or the ability of FEVI to raise capital when the RSDA balance will not be depleted for a decade.” (BCPSO Final Submission for FEVI and FEW, p. 5)

With respect to FEW, BCPSO notes that the 2009 conversion to natural gas made FEW much more cost competitive relative to BC Hydro than was previously the case. (BCPSO Final Submission for FEVI and FEW, p. 5)

<u>FEVI and FEW Reply</u>

FEVI and FEW submit that BCPSO takes no issue with respect to FEVI and FEW delivery rates being higher than FEI thereby making them less competitive relative to electricity. FEVI and FEW assert that “[T]he relevant evidence for the Commission’s Stage 2 assessment of competitive risk is that FEVI/FEW’s service is less competitive vis a vis electricity than the benchmark utility, a fact which BCPSO concedes.”

FEVI takes issue with BCPSO downplaying the loss of royalty revenues as an additional risk. It submits that this was recognized by the Commission as a risk not faced by the benchmark utility in the 2009 Decision. FEVI submits that the depletion of the RSDA is well within the time horizon of long term investors (FEVI and FEW Reply, p. 8).

Concerning the competitiveness of FEW, the utility relies on the Terasen Gas (Whistler) Inc. 2009 RRA Decision which states the following: “supply risk may be reduced following conversion, its business risk will have increased by virtue of the fact that its rate base will have doubled as a result of the conversion while its customer base remained largely unchanged.” FEW submits that the Commission should not double count the effects of conversion (FEVI and FEW Reply, p. 9).

Commission Determination

There seems to be agreement among FEVI and FEW and BCPSO as to delivery rates being higher in FEVI and FEW service areas than in that of FEI and that vis-à-vis electricity, FEI holds a cost advantage over FEVI and FEW. The Commission Panel also acknowledges these facts. However the question we must consider is what level of weight is appropriate to place on these differences.

FEVI and FEW submit their burner tip rates, in addition to being higher than FEI, is also higher as compared to BC Hydro Tier 2 equivalent rates when upfront capital costs are taken into account. They argue that because of this, builders and developers have difficulty making a case for gas equipment over electricity. The higher cost related to installing natural gas space and water heating as opposed to electric heat was raised in Stage 1 and has been a subject in previous cost of capital proceedings and applies equally to all gas utilities. Notwithstanding this, the Panel notes that in most cases, a builder must consider installation costs as they relate to the construction costs and they must weigh the cost of options against customer requirements. Therefore, the cost of energy is separate and combining the capitalized cost with the energy cost clouds the issue and is inappropriate. Eliminating capitalized costs from the cost of natural gas results in both FEW and FEVI rates being substantially lower vis-à-vis electricity Tier 2 rates. The question then becomes one of magnitude and the Commission Panel considers that while FEI holds an advantage in differential, the costs of energy in FEVI and FEW are still favourable.

FEVI submits that the impact of the loss of royalty revenues has been significant pointing out that rate increases will result following exhaustion of the RSDA sometime in 2022. FEVI states that "based on the change in the commodity price, all else equal, the RSDA is forecast to be fully depleted by 2022." (Exhibit B1-79, BCUC 2.34.3) The Commission Panel considers a timeframe spanning 8 or 9 years to be considerable even from the point of view of a forward looking investor. Moreover, the Panel notes that as BCPSO argues, the projected increases are relatively modest following depletion of the RSDA and, as announced by the Minister of Energy, the cost of electricity will be rising in the near term. Add to this the fact that amalgamation of the three utilities has been reconsidered in a concurrent proceeding and the proposal concerning the risk that FEVI and FEW's market will be less competitive in the future against electricity becomes difficult to accept.

The Commission Panel finds that FEVI and FEW face some additional risk due to differences in rates vis-à-vis electricity compared to FEI. The Panel also finds that natural gas rates are likely to continue to maintain a competitive advantage over electricity and therefore places minimal weight on this factor.

3.1.3 Supply Interruption Risk

FEVI and FEW Positions

FEVI and FEW face natural gas supply issues similar to that of FEI since the three utilities all source their gas requirements in the same market. FEVI and FEW rely upon FEI's coastal transmission system to obtain natural gas and thus have similar infrastructure constraints to transport natural gas to the Lower Mainland. However, FEVI and FEW are downstream of the FEI coastal transmission system. For its supply, FEVI is dependent on a single high pressure pipeline system that includes marine crossings, traverses rugged terrain and interconnects with the coastal transmission system. FEW is served by a single pipeline lateral that interconnects at Squamish with FEVI's system. A disruption on this pipeline lateral would disrupt service to FEW's entire customer base. (Exhibit B1-71, Appendix A, FEVI and FEW Evidence, pp. 3-4)

FEVI and FEW argue that the Commission should find they have greater supply risk based on the following:

- Being downstream of FEI increases risk.
- FEI's load centres are throughout its service territory with various means to access supply while FEVI and FEW load centres are at the end of a radial pipeline.
- The pipelines on which they rely cross challenging terrain.

- Although total failure of the twinned submarine crossings on FEVI's is a small probability, there is additional risk associated with the challenge of making repairs to maintain uninterrupted service.
- FEW lacks any on-system storage to deal with emergencies.

BCPSO Position

BCPSO submits that FEVI and FEW have slightly higher supply risks than FEI. However, it does not agree that this is a significant business risk factor affecting the smaller utilities' cost of capital. In support of its position, BCPSO submits the following:

- It is unlikely that both of FEVI's submarine crossings will be disabled at the same time.
- While two LNG tankers cannot fully backstop a complete FEW supply failure, a second LNG tanker was added to the fleet in November 2010 mitigating the damage if a supply failure were to occur.
- The Mt. Hayes LNG facility came online in April 2011, which reduced the supply risk of both FEVI and FEW.

(BCPSO Final Submission for FEVI and FEW, p. 6)

FEVI and FEW Reply

In response to BCUC IR 2.36.1, FEVI and FEW submit that the mitigation activities are only available for the management of short-term supply interruptions, and not capable of relieving long-term supply interruption. FEVI and FEW submit the answer to BCPSO's argument is twofold. First, FEI's LNG tankers are insufficient to replace a pipeline and meet FEW's demand, even on a short-term basis. Second, the role of Mt. Hayes in helping to manage supply interruptions should not be considered a new development as it was already known in 2009 when the Commission last determined FEVI's and FEW's cost of capital (FEVI and FEW Reply, p. 9).

Commission Determination

The Commission Panel finds that there are additional supply interruption risks faced by FEVI and FEW when compared to the Benchmark but they are marginal. Therefore, the Panel places minimal weight on this factor.

The Commission Panel agrees with BCPSO with respect to the likelihood of both of FEVI's submarine crossings being disabled concurrently. We acknowledge that there is a remote possibility but the probability is very low. The Panel acknowledges that both FEVI and FEW load centres are at the end of a radial line which results in some increased risk and FEW's lack of on-system storage. However, FEVI and FEW did not provide evidence to establish the level of probability related to such an occurrence or examples of where these types of issues proved to be a problem in other jurisdictions.

The Panel does not disagree that the role of Mt. Hayes in the management of supply interruption was known when FEVI's last cost of capital was determined. However, we note that the backstopping capability of Mt. Hayes has reduced FEVI's absolute risk. A similar capability does not exist for FEW.

Other Considerations

3.1.4 Credit Rating Outlooks of FortisBC Energy (Vancouver Island) Inc.

FEVI Position

FEVI has relied upon debt ratings and related opinions by both Moody's Investor Services (Moody's) and Dominion Bond Rating Services (DBRS) to support their conclusion that FEVI is of higher stand-alone business risk than FEI and that FEVI's higher business risk points to an equity ratio higher than the existing 40 percent (FEW is not rated). The current Moody's rating for FEVI is A3. However, FEVI notes that Moody's issued a press release in June of 2013, indicating that it had changed the outlook for all FortisBC utilities from "stable" to "negative." FEVI states that "Moody's cited the "severely weak" financial metrics at current rating levels and the recent Stage 1 Decision that further weakened the credit metrics of the utilities." This was followed by the June 26 Credit Opinion for FEVI, FEI and FBC. In it Moody's considers FEVI's high cost of service and small size and recent developments regarding the phase-out of royalty revenues and the denied amalgamation application as factors underscoring a need for additional regulatory support in maintaining credit metrics. Moody's states later in its report that "the degree of BCUC regulatory support may not be of sufficient strength to support FEVI's A3 unsecured rating..." Based on this FEVI submits that the potential for a credit rating downgrade is of immediate concern and should be a consideration for the Commission in determining the appropriate capital structure and risk premium. With respect to DBRS, FEVI reports that its rating for FEVI is already two notches lower than the FEI rating, supporting the position that FEVI is of higher overall risk than FEI. (Exhibit B1-71, pp. 10-11; FEVI and FEW Final Submission, p. 19; Exhibit B1-71, Appendix B, Ms. McShane's Evidence, p. 22; Exhibit B1-71, Appendix D, Moody's Credit Opinion: FortisBC (Vancouver Island) Inc.)

<u>BCPSO Position</u>

BCPSO submits that while it is preferable for FEVI to avoid a ratings downgrade, it does not support going beyond what is required by the fair return standard to ensure this result. BCPSO observes that Moody's appears to have assumed that FEVI's ROE will be stepped down in accordance with FEI. In addition, it submits that this is also true of DBRS. The DBRS Credit Opinion of June 11, 2013, seems to support this. DBRS further commented that while the current cost of capital is under review for FEVI, it does not expect the decision to have a material effect on the company's earnings and cash flow. (BCPSO Final Submission for FEVI and FEW, p. 8)

<u>FEVI Reply</u>

FEVI argues that BCPSO's conclusion is based on the erroneous assumption that if it's recommended equity ratio (40-42 percent) produced credit metrics similar to 2012 metrics, a downgrade would not occur. FEVI states that this ignores the fact that its rating, based on 2012 metrics, was Baa1 as shown in Moody's June 2013 Credit Opinion. (FEVI and FEW Reply, p. 10)

Commission Determination

The Commission Panel has considered the evidence submitted by the parties. **The Panel finds it appropriate that it continue to be guided by its Stage 1 finding as discussed in Section 1.3 of this Decision and considers the maintenance of current credit ratings to be desirable but only to the extent that doing so does not go beyond what is required by the Fair Return Standard.**

3.1.5 Commission Cost of Capital Determination

The Commission Panel determines that an equity ratio of 41.5 percent and an equity risk premium of 50 bps for FEVI and an equity ratio of 41.5 percent and an equity risk premium of 75 bps for FEW is appropriate effective January 1, 2013.

Both FEVI and FEW acknowledge that many of the risks they face are the same as those faced by FEI and the level of business risk to the three utilities on many of the identified risk factors is not materially different (FEVI and FEW Final Submissions, pp. 4-5). The key area where FEVI and FEW identified business risk differs from that of the Benchmark is on the following factors:

- The size of service area;
- The less diverse customer and economic bases;
- Challenges with energy price competitiveness; and
- Risks related to supply security.

The Commission Panel has considered the evidence and submissions related to each of these risk areas in conducting its risk assessment. The small service areas and the less diverse customer and economic bases for both FEVI and FEW pose additional business risk deserving of significant weight when compared against the Benchmark. In addition, there is some additional business risk related to competition with electricity when rates were compared with the Benchmark. However, both FEVI and FEW had lower rates when compared with BC Hydro Tier 2 rates. Given this competitive advantage and no evidence of a future change in circumstance, the Commission Panel places minimal weight on risks associated with competition. A final consideration is the risk of supply interruption. It is acknowledged that there are additional supply risks faced by FEVI and FEW when compared to the Benchmark but these are marginal and again the Panel has awarded them only minimal weight.

The Commission Panel has considered the evidence of Ms. McShane along with the evidence related to credit ratings.

There is no way to predict how rating companies will react to this Decision. However, the Commission Panel acknowledges the importance of maintaining current credit ratings and has given this factor some weight in reaching our overall cost of capital determination.

With respect to Ms. McShane's evidence, the Commission Panel is in agreement that FEVI and FEW face a higher level of business risk than the Benchmark. This is the basis for awarding the higher equity ratio of 41.5 percent for both utilities. With respect to equity risk premiums, the Commission Panel has awarded FEVI and FEW risk premiums of 50 bps and 75 bps, respectively. Historically, both FEVI and FEW have had a 50 bps equity risk premium compared to the Benchmark. Given the higher level of business risk, Ms. McShane's expert opinion in support of the premiums, and the support from BCPSO, the Commission Panel is not persuaded there is any justification to reduce these premiums.

Further consideration was given to the fact that FEW faces overall somewhat higher business risk than FEVI and to FEW's small size in comparison to both FEVI and the Benchmark as key factors in awarding the additional 25 bps risk premium for FEW. The higher risk premium is also justified by the identical equity ratios granted to both FEVI and FEW.

3.2 Group 1 Utilities – Electric

FortisBC Inc.

Introduction

FBC is a fully integrated electric utility and is the owner and operator of hydroelectric generating plants, high voltage transmission lines and a distribution asset network in the southern interior of BC. FBC's service area is comprised of 1,400 km of transmission lines and 5,369 km of distribution lines serving directly or indirectly over 160,000 customers. (Exhibit B1-72, Appendix A, p. 5)

The most recent full review of FBC's capital structure and equity risk premium was undertaken as part of the 2005 FBC RRA proceeding. At that time, the common equity ratio of 40 percent and equity risk premium of 40 bps from previous decisions were reaffirmed. In the 2009 Decision, the Commission Panel responded positively to FBC's request for "an order of the Commission maintaining the current regulatory framework in British Columbia whereby TGI's ROE is established as the Benchmark ROE for utilities in British Columbia, including FBC, as previously ordered by the Commission in Order G-14-06" by noting that there was no evidence suggesting that its use was not in the public interest.[9] FortisBC was an intervener in that proceeding.

As indicated in Table 3.2, FBC proposes a 40 percent common equity ratio with an ROE risk premium of between 50 and 75 bps. The table also shows the currently allowed amounts and those proposed by Interveners.

[9] 2009 Decision pp. 79-80.

Table 3.2
Summary of Capital Structure and Equity Risk Premiums (ERP)

	Current		Requested by FBC		Proposed by Interveners	
	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)
FBC	40	40	40	50 - 75	40 (BCPSO) 38.5 (ICG)	40 (BCPSO) 30 (ICG)
Benchmark	38.5	0	n.a.	n.a.	n.a.	n.a.

FBC, in support of its proposal, states that its risks are higher than that of the Benchmark in the following areas:

- Smaller Size, More Concentrated Assets and Less Diverse Customer and Economic Base;
- Energy Price Competitiveness;
- Supply Risk;
- Operating Risk; and
- Financial Risk Related to its Credit Profile.

FBC and FEI operate in substantially the same financial, regulatory, policy, operating and business environment. Therefore, FBC states it can be directly compared without revisiting the determinations made in respect of the Benchmark. (Exhibit B1-72, p. 2; Appendix A, pp. 1-2)

Ms. McShane, FBC's expert witness, states that FBC's common equity ratio "...should, in conjunction with the returns allowed on various sources of capital, provide the basis for strong investment grade credit ratings." She recommends that a 40 percent common equity ratio is reasonable and bases this on a number of factors including the following:

- FBC faces higher business risk than the Benchmark.
- FBC's existing 40 percent common equity ratio is at the lower end of the range based on her assessment of FBC's relative position on the Canadian electric utilities business spectrum.
- At the current ratio FBC has only been able to attain split credit ratings; one that is in the Baa/BBB category and one in the A category.
- Recent and expected credit metrics are not materially stronger in the context of the minimums cited by Moody's as a potential trigger for a downgrade.
- Any reduction in the equity ratio which has been stable since 1996 may be regarded by Moody's as reduced support for FBC's regulatory framework resulting in a relatively high risk of a downgrade.

In addition, Ms. McShane has recommended a 50-75 bps equity risk premium for FBC based on the following:

- FBC's lower debt ratings indicate that at the recommended 40 percent common equity ratio an equity risk premium over the Benchmark of no less than 50 bps is reasonable.
- Differentials between the Benchmark beta attributed by the Commission and those of utilities with similar total risk to that of FBC indicate that an equity risk premium of 50-75 bps is reasonable.
- The size differential between FBC and the Benchmark indicate an equity premium for FBC of 50-75 bps is conservative.

(Exhibit B1-72, Appendix B, pp. 1-3)

BCPSO states, "it is reasonable to conclude the FBC's overall business risk is greater than FEI's." However, BCPSO is of the view that FBC may have overstated the degree of risk differential in its comparisons against the Benchmark. BCPSO concludes that the BCUC should approve a maximum common equity ratio of 40 percent and an equity risk premium of 40 bps over the Benchmark. (BCPSO Final Submission, pp. 7, 11)

ICG has relied on past decisions in reaching its conclusions on the appropriate cost of capital for FBC. ICG submits that the 38.5 percent equity ratio for the Benchmark should be the same for FBC and the equity premium should be reduced to 30 bps.

In Section 2.1, the Commission Panel discussed ICG's use of 2009 as a reference point. The Panel notes that ICG has based their approach on its assumption as to the intent of the Commission in the 2009 Decision. Given the importance of this distinction, the Panel will address this matter prior to examining the positions of the parties with respect to the various risks faced by FBC.

As noted in Section 2.1, ICG takes the position that an appropriate reference point for comparison of FBC with the Benchmark is the 2009 Decision rather than the Stage 1 Decision. This is based on its view that the Commission Panel in the 2009 Decision had made its decision on the Benchmark with full consideration of the relative risks that existed between FBC and TGI. Thus, in effect, the Commission, in establishing a 40 percent equity ratio for the Benchmark had done so with the intent that a similar equity ratio should apply to FBC as should a 40 bps equity premium.

Commission Determination

The Commission Panel rejects the submission of ICG that the Commission, in the 2009 Decision, had considered the relative risks that existed for FBC as compared to the Benchmark. The 2009 Decision was established in response to an application collectively from TGI, TGVI and TGW concerning their cost of capital. Accordingly, there was a robust evidentiary record concerning TGI in that proceeding. This was not the case for FBC as it was not an applicant nor did it file evidence in the proceeding.

The Panel notes that ICG has submitted no evidence in support of its position to suggest that the Commission, in the 2009 proceeding had considered whether, on a comparative basis, the risks faced by FEI and FBC were the same or to what extent they may have differed. Therefore, the

Commission Panel accepts the approach taken by FBC in this proceeding, which relies upon the Benchmark as defined in Stage 1 as the primary reference point.

Risk Assessment

3.2.1 Smaller Size with More Concentrated Assets and Less Diverse Customer and Economic Base

FBC Position

FBC submits that its smaller size, higher rate base per customer and higher concentration of assets results in increased risk relative to the Benchmark. In addition, FBC considers that its less diverse customer and economic base in comparison to FEI are two further factors leading to an elevated level of risk.

FBC further submits that it serves a much smaller service area, with less than one-third the number of communities and, on a proportional basis, is far more rural than the Benchmark. In addition, rural economies are less diverse and as a utility, FBC is more dependent on fewer industries than is FEI and this lack of geographic diversity contributes to its business risk. FBC also contends that because its assets are concentrated in a limited geographic area, negative events can have a greater impact on earnings and viability and there is greater potential for an event that affects most or all of its service territory. According to FBC, because its rate base per customer is significantly higher than that of the Benchmark, customer losses resulting from localized events has a larger impact on average on its ability to recover its invested capital.

FBC has a smaller customer base than FEI with an approximate total of 163,000 direct and indirect customers although the customer profile is similar in that the majority are in the residential sector. The difference in customer profile is greatest in the wholesale sector, which accounts for 22 percent of the utility load representing $32 million in revenue. The loss of this customer base would result in an increase of 5 percent for the remaining customers. A further consideration is the portion of industrial load attributable to a low number of customers. If the largest 10 industrial customers chose to discontinue taking service, it would result in the loss of $14 million and a 2 percent rate increase for the remaining customers.

FBC states that as a general principle, the impact of a downturn or failure of an industry is more likely to have a material impact on a utility's customer base when it is dominated by a small number of industries. Eight out of 10 of its largest customers are in the forestry industry and account for well above 50 percent of total industrial load and revenue. FBC asserts that the forestry industry is sensitive to many factors including the strength of the Canadian dollar, the strength of the US and Pacific Rim economies and other more local factors such as strikes or trade disputes. In addition to the impact on the industry itself, such factors resulting in a longer-term downturn or decline also have secondary effects on the local economy reliant on those employed in those industries. FBC reports that the forestry industry is currently struggling due to slow domestic and US demand for Canadian lumber products and issues related to the mountain pine beetle infestation, and it expects this to continue. Since 2005, forest industry trends have contributed to the significant drop in demand from the industrial customer group. (Exhibit B1-72, Appendix A, pp. 5-11; Exhibit B1-72, Appendix B, p.11; FBC Final Submission, pp. 8-14)

<u>BCPSO Position</u>

With respect to size, BCPSO observes that while FBC is smaller in size than FEI on major parameters, there is no evidence to suggest that the relative risk has changed since 2005. It also notes that FBC, unlike the Benchmark, is not suffering from declining use per customer (UPC) as its load since 2005, has been relatively flat. Further, while FBC states that a significant portion of its load is related to a small number of customers, BCPSO notes it has not indicated how this has changed since 2005.

In addition, BCPSO makes the following assertions:

- The evidence suggests that customer concentration risk relative to wholesale customers has gone down since 2005 while that associated with industrial customers remains unchanged.
- For residential customers, there has been steady growth in UPC since 2001 in contrast to the gas utilities where it has declined.
- Implementation of the "advanced metering program should improve reliability and reduce costs, both of which will assist FBC in retaining customers."

(BCPSO Final Submission for FBC, pp. 3-4)

<u>ICG Position</u>

ICG states that FBC "argues that wholesale and industrial sales risk has not changed since 2009." ICG asserts that there was significant change to FBC's customer composition as a result of the City of Kelowna purchase and, as a result of the transaction, its customer base has grown and there are increased economies of scale. ICG notes that Ms. McShane's evidence did not address this transaction but its expert witness, Dr. Safir, observes that there are now many individual customers from what was a single large wholesale customer. The result of this change has been to reduce the expected variability in revenues due to the unlikelihood that all new customers would leave FBC simultaneously.

<u>FBC Reply</u>

FBC submits that there appears to be no challenge from Interveners as to it being a smaller utility and because of this, it has increased risk relative to the Benchmark. Regarding BCPSO's submissions with respect to UPC as compared to FEI and its relatively flat load, FBC points out that neither of these points represents change in FBC's business risk compared to the Benchmark.

FBC does take issue with ICG's submission regarding the City of Kelowna and asserts that while there is a directional impact on customer diversity, there has been no material change in business risk. In support of this, FBC points to the evidence of Ms. McShane who makes, among others, the following points:

- In terms of load served the transaction was neutral.
- From a size perspective it was immaterial and the effect was similar to incurring a couple of larger capital expenditures.
- Even with the transaction, FBC's rate base per customer is higher than in 2009 and since then has outpaced FEI's growth on a per customer basis by 2:1.

(Exhibit B1-73, BCUC 1.10.9; Exhibit B1-81, BCUC 2.34.1; FBC Reply, p. 8)

Regarding BCPSO's comments about the improvement in forestry in recent years, FBC disagrees and submits that investors making long-term investments look beyond current circumstances.

Commission Determination

While FBC is smaller than the Benchmark, it is nonetheless a sizable entity with many customers. In the Commission Panel's view, the more relevant factor is business risk associated with FBC's reliance on a relatively small wholesale and industrial customer base and its overall reliance upon the forestry industry. We acknowledge the cyclical nature of the forestry industry and its sensitivity to many external factors both internationally and local. However, we also note that this is not a unique circumstance as many industries face similar issues. Rather, what separates FBC from the Benchmark is its heavy reliance on one industry. This lack of wholesale and industrial diversity is a factor the Panel considers to be relevant and worthy of some weight. On the other hand, the Panel notes that FBC did not refute the BCPSO submission as to the improvement in the forestry industry in recent years. Instead it chose to comment upon the longer view taken by investors. The Panel notes that the recent results appear to at least be moving in the right direction and should not be dismissed.

The Commission Panel also considers the City of Kelowna electric distribution system purchase to be directionally positive in reducing business risk. As pointed out by Dr. Safir, it seems to eliminate the possibility of losing all of the customers that may have occurred previously. We recognize that that the transaction was not exceedingly large and neutral in terms of load but it does reduce risk of customer loss that potential long-term investors may be concerned with.

Taking all of these factors into consideration, the Commission Panel finds that FBC does face more risk than the Benchmark with respect to size related issues such as concentrated assets, and the lack of diversity in both its customer and economic base and the Panel places some weight on this difference.

3.2.2 Energy Price Competitiveness

FBC Position

FBC submits that one of the primary factors contributing to FBC's elevated business risk relative to the Benchmark is competitive risk. It cites the importance placed on this by the Commission in the Stage 1 Decision: "The Commission Panel considers price, because of the importance placed on it by the consumer, to be a key determinant and deserves significant weight when considering changes to FEI's risk." FBC considers that the evidence demonstrates that its business risk related to energy prices is higher than the Benchmark. (FBC Final Submission, pp. 6-7, 14; Stage 1 Decision p. 32)

FBC states that low natural gas prices and rising FBC electricity rates make it more difficult for it to compete on the basis of price across all customer classes.

For residential and commercial heating load, FBC competes with natural gas, alternative technologies and, in some cases, BC Hydro. The primary competition is natural gas. Approximately one-third of its residential sales are for space and water heating, making competition for heating load an important determinant of its overall business risk. Natural gas commodity costs are currently low, resulting in lower operating costs and competitive advantage. At the same time FBC's rates for residential customers are significantly higher than BC Hydro's residential rates. This rate differential becomes a factor in underdeveloped regions within FBC's service area that are adjacent to BC Hydro's service area. Where this exists, customers have an option as to which electricity provider they choose. FBC must also compete along with the Benchmark with alternative energy technologies such as source heat pumps and other forms like solar and wind are gaining viability as technology improves and costs decrease. Over the longer term FBC expects technical change to increasingly create competitive alternatives. (Exhibit B1-72, pp. 15-19; FBC Final Submission, pp. 14-15)

FBC states that wholesale and industrial customers have options that would allow them to discontinue their contract for service with reasonable notice. These include self-generation, purchasing electricity on the open market or taking service from BC Hydro through its Open Access Transmission Tariff (OATT). Further, in addition to two industrial customers with generation, others have explored generation opportunities in recent years.

Looking ahead, FBC notes that it will continue to face upward rate pressure due to the necessity of investing in infrastructure. In the utility's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, annual capital costs of $60-$70 million per year are forecasted. FBC states that the required capital for sustainment projects along with expenditures for infrastructure upgrades will result in it spending more on capital as a proportion of rate base than the Benchmark. (Exhibit B1-72, pp. 15-19; FBC Final Submission, pp.14-17)

BCPSO Position

BCPSO states that FBC is not suffering from declining UPC as the evidence indicates there has been steady growth since 2001. This compares favourably to the declining use by customer experienced by gas utilities. In addition, FBC enjoys a new home heating capture rate of 57 percent since 2006.

BCPSO submits that there is no evidence that any wholesale customer has indicated it will leave FBC in favour of an alternative energy source. Further, the responses to BCUC IR 1.9.2 and BCPSO 1.3.3 indicate that FBC is not aware of any FBC customers planning to purchase electricity on the open market. Therefore, while this may represent a theoretical risk, it is not imminent and so far customers have not elected to purchase from BC Hydro at lower rates.

BCPSO also submits that BC Hydro rates are under considerable upward pressure and the announced 16 percent increase over two years will impact FBC rates by 2 percent. BCPSO argues that FBC appears to be minimizing the impact that rising BC Hydro prices will have on its competitiveness with that utility and focusing on the impact of these increases on FBC prices only. In addition, it points out that existence of open access and options for customer choice were risks that were flagged in 2005. While these risks exist, BCPSO argues they are overstated as they have existed since 2005 and have yet to materialize. (BCPSO Final Submission for FBC, pp. 4-5)

<u>ICG Position</u>

Dr. Safir states that to some extent he agrees that FBC has greater business risk than FEI due to competition from alternative forms of energy noting the effect that shale gas has had on the price of natural gas. Dr. Safir states that the offset for this is the development of the LNG market which will increase the demand for the commodity and limit the extent to which prices will decline. (Exhibit C4-22, p. 21)

ICG did take issue with Ms. McShane's submission attributing the improved position of natural gas versus electricity as the reason the Commission concluded that FEI's common equity ratio should be reduced. ICG argues that the competitive position of natural gas versus electricity alone cannot be considered a reason for increasing either the equity component or ROE of FBC from the benchmark equity component and ROE. (ICG Final Submission, p. 11)

ICG also addresses the risk identified by FBC concerning its wholesale and industrial customers choosing alternative forms of supply. ICG notes one of FBC's largest customers, Zellstoff Celgar (Celgar), has expended considerable effort and resources dealing with what are described as unresolved issues. In its view, this expenditure of effort should leave no doubt that electric utility service rates remain attractive to industrial customers. (ICG Final Submission, pp. 11-12)

FBC Reply

FBC submits that the key fact for assessing competitive risk in the residential sector is that FBC rates are facing considerable upward pressure at a time when natural gas rates at the burner tip are relatively low.

FBC addresses BCPSO's reliance on a retrospective approach and states that business risk can only be assessed prospectively. FBC also takes issue with BCPSO's characterization that the risk of Industrial customers leaving is not imminent pointing out that the Commission has always given the greatest weight to longer term business risks. With respect to BCPSO's comments regarding competitiveness with BC Hydro, FBC submits that its primary competition in the Residential and Commercial markets is from competing energy forms such as natural gas and alternative energy, as opposed to direct competition with BC Hydro. (FBC Reply Submission, pp. 9-11)

In consideration of ICG's comments regarding the potential for Celgar to leave the system, FBC submits that "[g]iven that energy costs are a significant operating cost for industrial customers, one can reasonably expect industrial customers to consider all options available to them to reduce costs." FBC also submit that ICG is at pains in its submissions to downplay the significance of lower natural gas prices and speculates this is attributable to lower gas prices improving FEI's competitive position compared to electricity utilities.

Commission Determination

The Commission Panel finds that the evidence supports FBC facing additional risk due to competitive pricing factors when compared with the Benchmark. The primary reason for this is the fact that relative to the price of electricity, natural gas is less expensive, which is important in that the service areas of FBC and FEI overlap to a large degree (Exhibit B1-72, Appendix A, p. 19). The Panel notes that this was not contested by any of the parties.

The Commission Panel notes the evidence of Dr. Safir who points out that the demand and hence the price of natural gas may be affected by the development of the LNG business. While this may indeed be the case, there is no evidence to support the view that natural gas prices will increase in the future or will be directly affected by development of the LNG business.

The Commission Panel acknowledges that there are wholesale and industrial customers that have options available to them allowing them to discontinue their service. The question is whether it is probable that such an event will occur. As noted by BCPSO, there were no recent examples where this has occurred or where it is expected to occur. The Panel accepts that the risk continues to exist but is not persuaded that there is a probability of such customer loss occurring. The Panel notes ICG's comments on behalf of a major customer and FBC's response that if there is the potential for savings that industrial customers will consider all options. The Commission Panel agrees with FBC but notes that it cuts both ways. The fact that Celgar has remained a customer indicates that Celgar has not determined it is in its best interest to pursue other options. **Hence, the Commission Panel places minimal weight on this risk.**

3.2.3 Energy Supply Risk

FBC Position

FBC submits that with respect to energy supply it faces greater risk overall compared to FEI. It describes energy supply risk as being made up of two elements:

- The business risk associated with relative long-term availability of natural gas for FEI verses electricity for FBC.
- The business risk related to supply interruption and replacement costs.

FBC submits that in general the circumstances regarding the availability of supply are similar for FBC and FEI. Supply risk for FBC has been mitigated to a degree by long-term capacity agreements but this is offset by price risk concerns with future rate increases related to the BC Hydro Power Purchase Agreement (PPA) and open market pricing. FBC describes its supply risk related to availability as 'fairly low.'

FBC currently generates 45 percent of its energy and 30 percent of its capacity from hydro generating plants it owns. In addition, it has long-term agreements for energy supply with BC Hydro and Brilliant Power Corp. and a long-term capacity agreement for power from the Waneta Expansion (WAX) project expected to go into service in 2015. Collectively, these projects are sufficient to cover capacity requirements for the next 10 years. Like FEI, FBC faces supply interruption risk associated with transmission systems that it either owns or to which it connects. However, there is increased risk for FBC relative to FEI due to the potential for failure of one of its generating plants each of which must be on line if it is to obtain its entitlements under the Canal Plant Agreement. If equipment failure occurs the utility faces a potentially higher cost of purchasing replacement power on the open market. FBC submits that this has occurred three times in recent years. It also notes that in addition to these replacement costs, it is exposed to potential penalties, additional Mandatory Reliability Standards compliance costs or litigation costs resulting from the potential for claims by its customers. Because of this, FBC considers its supply risk to be higher than the Benchmark. (Exhibit B1-72, pp. 19-20; FBC Final Submission, pp. 18-22)

FBC takes issue with Dr. Safir's evidence with respect to vertical integration and his view that it lowers business risk. FBC states that the evidence related to supply interruption risk and the potential impacts of this fully answer Dr. Safir's arguments on vertical integration. In addition, on this subject, FBC submits the following:

- Vertical integration increases business risk. FBC relies upon Ms. McShane's evidence that there is a common view among the rating agencies that integrated utilities are more risky than distribution utilities.
- Dr. Safir has misinterpreted the studies he cites and misapplies the results as finding that a vertically integrated business is less risky and that "the sum of its individual parts in a portfolio of investments is fundamentally different from a finding that a vertically integrated electric utility is less risky than a natural gas LDC like FEI."

(FBC Final Submission, pp. 22-24)

<u>BCPSO Position</u>

BCPSO submits that FBC's final submissions requesting the Commission to find that the utility's energy supply risk is higher than FEI is quite different than its earlier evidence, which concluded that both utilities had similar energy supply risk profiles. BCPSO states that the reason for this is that FBC's evidence speaks to the higher number of energy supply contracts compared to the Benchmark. These contracts mitigate some of the risk, lead to a lower energy price risk than FEI and when considered, the supply risk for the two utilities is similar.

Worthy of note is FBC's answer to BCUC IR 1.16.8 which cites Moody's statement that "FBC's hydrology risk is substantially mitigated by the Canal Plant Agreement." BCPSO states that FBC believes this statement would apply equally to the WAX capacity available and considers that this agreement has improved its business risk related to its ability to meet its capacity requirements. (BCPSO Final Submission for FBC, p. 6)

ICG Position

ICG submits that the WAX Capacity Exchange (WAX CAPA) and the BC Hydro PPA are two significant supply risk changes since 2009. ICG state that "the record on WAX CAPA is clear: the WAX CAPA reduces supply side risks for FBC, provides the shareholder with a higher than regulated return, and transfers the risk of surplus sales from the new facility to customers." ICG asserts that given this "FBC proposes to deny customers the benefit of the lower cost of capital attributable to the WAX CAPA." ICG submits that the Commission Panel should give weight to the views of customers by reducing the cost of capital thereby providing customers with some relief.

ICG acknowledges that at the time of final submission the BC Hydro PPA was before the Commission and observes the following; there is a new PPA that both parties have agreed to, it provides certainty for all stakeholders, and in 2009 there was uncertainty considering the renewal of this agreement. As this represents 34 percent of power purchase expenses, ICG submits that this is a most significant variable and will reduce the supply risk of FBC as compared to 2009.

ICG urges the Commission to reject FBC's evidence that power supply risk has not changed materially since the 2005 RRA. (ICG Final Submission, pp. 12-13)

ICG denies that Dr. Safir said, as suggested by FBC and Ms. McShane, that FBC warrants a smaller risk premium because it is vertically integrated. Further, ICG disagrees with FBC's argument that because the FBC vertical integration involves ownership of generation assets, which individually tend to be more risky than electricity transmission and distribution, that FBC is therefore more risky than FEI with regards to supply. To ICG "[t]he process of vertical integration is akin to compiling a portfolio" and having a diversified portfolio is less risky than owning a single entity. The point being made by Dr. Safir was that an integrated utility is not necessarily a higher risk than one that is not integrated.

ICG also submits that the assumption that FEI's supply risk is lower than FBC's because FEI receives its supply through the market is economically untrue. It asserts that FBC's analysis ignores that FEI's supply risk profile is influenced by risks of pipeline failures because FEI receives most of its supply from outside pipelines. (ICG Final Submission, pp. 17-18)

FBC Reply

FBC considers certain parts of the ICG submissions regarding WAX CAPA to be beyond the scope of this proceeding as the task in Stage 2 is to assess FBC's business risk. FBC notes that while the ICG may not be in favour of the WAX CAPA, the Commission has already determined it to be in the public interest and in doing so accounted for the greater rate impacts in the early years. In its view, the ICG argument requesting denial of a return that reflects the appropriate level of FBC's business risks is not in keeping with the fair return standard.

FBC does not disagree with the fact that the BC Hydro PPA renewal and the Wax CAPA have reduced its supply risk in terms of supply availability but assert that this was already low. The key issue for FBC is the risk associated with supply interruption and the resulting price or reliability consequences. In the view of FBC, ICG failed to address the following evidence referenced in final submissions:

- The fact that it is an electric utility in and of itself affects interruption risk as compared to the Benchmark.
- There remains price risk uncertainty due to future rate increases related to the BC Hydro PPA and prices on the open market affecting rates.
- Supply interruption risk is higher than FEI resulting from having owned and contracted generation within its service area.

FBC also notes that while both utilities have risks associated with getting the commodity to where it can be used, FBC's transmission is above ground and more exposed than that of FEI. Further, in the event of interruption, FBC's ability to serve load is effected, as it has no access to storage. (FBC Reply, pp. 14-15)

Concerning vertical integration, FBC submits that according to the Capital Asset Pricing Model (CAPM) "since risk can be reduced by diversification, investors should not expect to be compensated for unsystematic risks or company-specific risks that they can diversify away by investing in a portfolio of assets." Therefore, an investor's expected return on an asset within a portfolio is a reflection of whether the investor is able to diversify and represents the assets marginal contribution to the portfolio's systematic risk. Based on this, FBC notes that if a higher systematic risk entity is added to the portfolio the risk of the portfolio will increase. Therefore, in the case of FBC, the portfolio is riskier when higher risk generation assets are added to lower risk transmission and distribution. (FBC Reply, p. 15)

Commission Determination

With respect to availability of supply, FBC has acknowledged there is little difference compared to the Benchmark and describes availability risk as 'fairly low.' Neither ICG nor BCPSO took issue with this characterization nor does the Commission Panel. The remaining issues are concerned with whether there is a risk differential between an integrated generation, transmission and distribution utility such as FBC and one like FEI that is transmission and distribution only.

With respect to vertical integration, the Commission Panel accepts FBC's submission that adding a higher systematic risk entity to a portfolio will raise the risk of that portfolio. However, the question remains as to whether the generation assets add risk to FBC and if they do, whether this risk is higher or lower than that of the Benchmark. FBC has made the case that business risk has increased due to the risk that one of its generating plants will fail resulting in the need to purchase power immediately on the open market at potentially higher prices. The Commission Panel accepts that there may be instances where such an event may occur and would result in a higher supply cost risk. However, in considering whether this potential risk might also exist for FEI, the Panel notes that a similar position was taken by FBCU in the Stage 1 proceeding with respect to risks associated with the BC shale deposits not guaranteeing a reliable supply of natural gas at reasonable prices. The Commission in Stage 1 accepted FBCU's position that the current environment is uncertain and stated that "[u]ntil this has been determined, the continuity of current low price levels for natural gas will be at some risk." It therefore appears that both FBC and FEI face risks that have the potential to drive higher commodity prices.

Accordingly, the Commission Panel finds that the risks faced by FBC with respect to supply do not differ significantly from those faced by the Benchmark. In the view of the Panel both utilities have similar access to the respective commodities and both face potential challenges which could impact commodity pricing.

3.2.4 Operating Risk

FBC Position

FBC takes the position that as a vertically integrated electric utility, it faces greater operational challenges and risks as compared to the Benchmark. These include risks related to the integrity of its older generation, transmission and distribution assets, the presence of polychlorinated biphenyls (PCBs) in transformers and substations, the risks associated with an above-ground infrastructure and the radial configuration of the system.

FBC's four hydroelectric generating plants represent 17 percent of its rate base and the majority of its generation assets are over 80 and some are over 100 years old. FBC points out that it is maintaining these assets and, in spite of refurbishing 11 of its 15 generation plants, it remains exposed to risks related to events that cause failure. FBC submits that the advanced age of some of these generation assets in relation to their end-of-life expectations results in the risk of increased deterioration. FBC also states that its distribution and transmission assets are on average older than FEI's noting that a higher portion of FEI's assets have been installed in the past 30 years. As stated previously, FBC also has predominately above-ground assets that are exposed to extreme weather and the potential for outside interference and conductor theft to compromise asset integrity.

Another risk relates to PCBs. Significant portions of FBC's station assets and pole top transformers have PCBs and by government regulation, must be removed by 2025. In the meantime, a release of significant PCBs gives rise to the possibility of penalties including fines.

FBC also contends that because it has a radial configuration of its system, it faces higher risk than the Benchmark. Because of this, the implications of operational failure are more far-reaching and often result in a corresponding outage to customers where no alternative transmission paths are available. Additionally, because the system is radial such transmission can be widespread and lengthy. By contrast, an interruption of FEI's transmission network does not necessarily result in a corresponding outage to customers. (Exhibit B1-72, Appendix A, pp. 22-27)

<u>BCPSO Position</u>

BCPSO states that the identified risks related to generation are being well managed and note that 11 of 15 generating units have been refurbished and plans are underway for the remaining four units. Citing the answer to BCPSO IR 1.2.2, BCPSO points out that hydroelectric generation tends to be less risky than fossil fuel generation and it believes that FBC has lower risk because of the Canal Plant Agreement.

BCPSO notes FBC's submission that on average its assets are older but it adds that there is nothing in the record to suggest this was not the case in 2005. While not addressing FBC's operational submissions directly, BCPSO point out that it is also worth noting that electricity is at lower risk from provincial GHG emissions policy and bears less risk due to the universal need for electricity and the cost of moving away from electrical space and hot water heating to natural gas. (BCPSO Final Submission for FBC, pp. 6-7)

ICG Position

ICG made no submissions specific to FBC's operating risks.

FBC Reply

FBC states that the submissions of BCPSO miss the mark. With respect to the age of the FBC assets, the appropriate response was not whether FBC or the Benchmark properly managed the risks but whether the risks faced by FBC are greater than those faced by the Benchmark. With respect to comments related to the percentage of FBC's rate base being in generation and the risks of hydroelectricity versus fossil fuel generation, the relevant comparator is with FEI. No such comparison was made.

Commission Determination

The Commission Panel accepts that there is clearly a difference in some of the operational risks that are faced by FBC as opposed to those faced by the Benchmark.

- FBC has generation assets while FEI has none.
- FBC's assets are older than those of FEI and faces challenges related to PCBs that do not exist for FEI.
- FBC with its radial configuration has fewer options in the event of a problem leading to system outages than does FEI.

What is less clear is how these identified risks relate to the risk of losing business or discouraging a potential investor. In other words what are the implications of having these risks?

In the Stage 1 Decision, the Commission defined risk "as the probability that future cash flows will not be realized or will be variable resulting in a failure to meet investor expectations." (Stage 1 Decision, p. 24)

In its evidence, FBC raised these risk issues yet did not clearly connect them to the probability of them occurring or their impact on future cash flows. Therefore, it is difficult to assign any weight to operational risk as a factor in determining FBC's cost of capital.

Accordingly, the Commission Panel finds that although there are differences in operational risk between FBC and the Benchmark there is no basis upon which to establish the potential impact of these differences. Accordingly, the Commission Panel gives these operational risks limited weight.

Other Considerations

3.2.5 Credit Ratings

FBC Position

FBC states that its rating agencies, Moody's and DBRS have raised concerns with the potential impact of the GCOC proceeding on its credit ratings. FBC is concerned that reducing its equity thickness or its allowed ROE increases the risk of a ratings downgrade. This would increase the Company's cost of debt and restrict its access to financing. It asserts that the requested cost of capital requirements is, in part, justified in response to the possible downgrades.

As noted in Section 3.1.4, Moody's changed the outlook for all FBCU utilities from "stable" to "negative." With respect to FBC, Moody's on June 26, 2013, issued a credit opinion on FBC at Baa1 (negative). Moody's commented that the weak financial metrics may get worse following the recent Stage 1 Decision. FBC submits that Moody's summary table from its Credit Opinion shows that FBC is borderline investment/non-investment grade on Financial Strength and its indicated rating from the methodology grid is one notch (Baa2) lower than its actual rating. FBC states that

"Moody's June 2013 Credit Opinion concludes that a downgrade could occur if FBC's CFO pre-WC metric remains around 10 %, or Moody's concludes that the Commission has become less supportive."

FBC submits that DBRS, the higher of the two credit agencies with respect to ratings, in its March 25, 2013 opinion was clear that FBC's credit profile could be weakened by any material change in ROE or deemed equity from the GCOC proceedings that may negatively affect cash flow or earnings. This opinion was issued prior to the Stage 1 Decision. Given that this decision will impact FBC's earnings and cash flow, FBC concludes that a DBRS downgrade is not out of the question. (Exhibit B1-72, pp. 7-8; FBC Final Submission, pp. 54-56)

On a related matter, FBC submits that it's "ability to issue long-term debt is restricted by an "Earnings Coverage Test" covenant that exists pursuant to the trust agreements for certain of its outstanding debentures." A decrease in allowed ROE or equity thickness combined with rising interest rates and low taxes could impact FBC's liquidity arrangements negatively. (FBC Final Submission, pp. 57-58)

<u>BCPSO Position</u>

BCPSO submits that FBC only considered the implications of implementing a capital structure similar to that of the Benchmark based on past performance. FBC's response to BCPSO IR 1.18.1 indicates that if it were granted a 40 percent equity thickness and a 40 bps risk premium again based on past performance, it would be sufficient to maintain the current credit ratings. BCPSO also submits that based on the response to BCUC IR 2.29.2, there will be virtually no improvement in average results if the equity premium were to be raised to 70 bps.

ICG Position

Dr. Safir asserts the evidence indicates that FBC would still be able to raise capital on reasonable terms because a downgrade to a BBB(high) rating would still allow FBC to maintain its financial integrity. To support this assertion, Dr. Safir relies upon two long-term bonds, one issued by FEI and one by FBC during the 2006 to 2010 period where FEI had a lower credit rating.
Dr. Safir notes that the market price for FBC was only marginally lower than for the higher rated FEI. (Exhibit C4-22, p. 27; ICG Final Submission, p. 21)

Concerning the Earnings Coverage Test covenant, ICG states that the interest coverage was 2.64 in 2012 and a review of various SEDER filings for FBC through 2013 indicate earnings coverage ratios varied from 2.47 to 2.53. ICG notes that the trust deed agreement restriction was 2.0 for FEI. (ICG Final Submission, p. 23)

FBC Reply

FBC disagrees with ICG's conclusion that the costs of a lower credit rating can reasonably be expected to be in the order of 10 basis points. In FBC's view to examine bond yield spread differentials over more normal market conditions and extrapolate this to mean that the impact of a downgrade will be small is not meaningful. During difficult economic periods there is a flight to quality as evidenced by the 90 bps between the two utilities in January 2009. FBC asserts that it did not attempt to raise debt during the worst of the recent financial crisis and notes that access to capital is of equal importance during adverse market conditions. Further, FBC notes that ICG did not address Ms. McShane's evidence raised in the Final Submission that during the period from June 2008 to January 2009 there was no issuer (without at least one "A" rating) of long term debt on any terms in the Canadian market.

FBC characterizes ICG's comparison of FBC's actual historic coverage ratios to a Trust Indenture Minimum as simplistic and states it does not take FBC's debt financing requirements into account.

It therefore provides limited insight into the constraints on its ability to issue long term debt in the event ICG's recommendations were adopted.

Commission Determination

The Commission Panel has considered the evidence submitted by the parties. In Section 3.1.4, the Panel determined it appropriate that it continues to be guided by its Stage 1 finding as discussed in Section 1.3.2 of this Decision. The maintenance of current credit ratings is desirable but only to the extent that doing so does not go beyond what is required in the Fair Return Standard. We have no reason to vary this.

3.2.6 Short Term Risks and Deferral Accounts

ICG Position

ICG notes that FBC has consistently achieved ROE amounts in excess of those approved and assert that because of the use of deferral accounts, business risks are by and large borne by the customer. ICG submits that in FBC's last revenue requirements decision[10] the Commission approved the establishment of the Power Purchase Expense Deferral Account. This captured any risk with regards to future power purchase costs. In addition, since 2009, the Revenue Deferral Account has been in place and together these two deferral accounts manage utility risks by transferring what were formerly FBC risks to customers. In ICG's view, the fact that these risks are now borne by the customer results in the narrowing of differential risk with the Benchmark and justifies a lower risk premium. (ICG Final Submission, pp. 17-18)

[10] 2012-2013 Revenue Requirements Application and Review of Integrated Systems Plan Decision, August 15, 2012, p. 116).

FBC Position

FBC states that ICG overplays the significance of the deferral accounts as well as the ROE track record and makes the following comments:

- Achieving its ROE is not a distinguishing factor because FEI's record is similar.
- The introduction of the deferral accounts were predated by its ROE performance and deferral accounts do not address underlying business risk.
- It would be inconsistent for the Commission to give significant weight to FBC's increase deferral account coverage as no significant weight was given to FEI's lack of change in short-term risk in the Stage 1 Decision.
- The percentage of FBC's revenue requirement currently covered by deferral accounts is lower than in 2005.

Commission Determination

The Commission Panel agrees with FBC with respect to FBC's performance on ROE being similar to that of the Benchmark in that both have consistently earned higher than allowed amounts. The Panel also notes that in Stage 1 it was determined that actual earnings versus approved earnings history is a matter for revenue requirements and should have no bearing on the cost of capital. However, in the view of the Commission Panel, this determination cannot be interpreted to mean that the use of deferral accounts does not impact a utility's ability to earn or exceed its approved ROE.

FBC, relying upon evidence in BCUC IR 2.46.2, takes the position that the amounts covered by deferral accounts are reduced from amounts covered in 2005. The Commission Panel notes that the comparative point of 2005 was a Performance Based Ratemaking (PBR) period and there is no evidence on the record of this proceeding that assists in determining how this may have affected any comparison between the two time periods. Further, this comparison is for FBC over time and does not address any differences which may exist between FBC and the Benchmark.

FBC has requested an increase in its risk premium from the 40 bps that has been in place for a number of years. In the view of the Commission Panel, the addition of deferral accounts can serve to mitigate short-term risk. It would not be reasonable to take the position that the addition of these deferral accounts has significantly reduced the level of short-term risk relative to the Benchmark. However, it would be equally unreasonable to ignore the effect of significant deferral account additions on FBC's short-term risk. Therefore, given the addition of these new deferral accounts and their impact on the reduction of risk, the Commission Panel considers the 10 to 35 bps additional risk premium requested by FBC to be more difficult to justify.

3.2.7 Commission Cost of Capital Determination

The Commission Panel has determined that an equity ratio of 40 percent and an equity risk premium of 40 bps for FBC is appropriate effective January 1, 2013.

While acknowledging that there are areas where its business risks are similar to the Benchmark, FBC outlined a number of key areas of risk that, in its view, differed from FEI. These included smaller size, more concentrated assets and less diverse customer and economic bases, energy price competitiveness, supply risk, operating risk and financial risk related to its credit profile. The Commission Panel has reviewed the evidence from the parties related to each of these areas in reaching its overall risk assessment. The evidence supports the findings that FBC faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk. In addition, the Commission Panel has considered the observations of BCPSO that electricity is at lower risk from provincial GHG emissions policy as well as the difficulty and costs associated with moving from electrical space and hot water heating in favour of natural gas (BCPSO Final Submission, p. 7). The matters were raised in Stage 1 and soften the impact of some of the factors raised by FBC in support of the level of differential in business risk between it and the Benchmark.

The Commission Panel has considered the evidence concerning credit ratings and Historic Trust Indenture Minimum and noted the desirability of maintaining current credit ratings but only to the extent that it does not go beyond what is required by the fair return standard. Concern for credit weightings has been given consideration and some weight in reaching our overall cost of capital decision for FBC.

The Commission Panel agrees with Ms. McShane's overall assessment that FBC faces a higher level of business risk than the Benchmark. This higher level of risk is the basis for our support of the recommendation of maintaining the equity ratio at its present level of 40 percent. With respect to the equity risk premium, the Commission Panel is not persuaded that FBC has made a case for a further differential in short term risk as compared to the Benchmark. Further, the Panel has considered Ms. McShane's evidence concerning FBC's debt ratings, the size differential between FBC and the Benchmark and the differences in the beta of the Benchmark as compared to other utilities of similar overall risk and finds that the current 40 bps risk premium is not significantly out of the range which would be considered reasonable. Moreover, the Panel notes that FBC's answer to BCUC IR 2.29.2 suggests that increasing the risk premium to 70 bps will have little impact on credit metrics. Finally, the Panel has considered the impact of BC Energy Policy, which favours electricity, and the fact that this along with the high cost of conversion from electricity to gas all serve to soften some of the long and short term risk faced by FBC. **Therefore, the Commission Panel finds that maintaining a 40 bps equity risk premium is both reasonable and appropriate.**

3.3 PNG Utilities

Introduction

The PNG utilities are made up of PNG-West, PNG (N.E.) Fort St. John/Dawson Creek (FSJ/DC) and PNG (N.E.) Tumbler Ridge (TR). PNG-West, the largest utility, encompasses the transmission and distribution system in the west-central portion of northern British Columbia from Summit Lake, BC to the west coast of the province. PNG (N.E.)-FSJ/DC Division includes the distribution system in the FSJ and DC service areas in northeastern BC. PNG (N.E.)-TR Division, the smallest utility, is made up of the distribution system and gas processing plant in the Tumbler Ridge service area in northeastern BC.

As presented in Table 3.3, PNG is proposing the following equity ratios and equity risk premiums for the three utilities:

- PNG-West's common equity ratio to be increased from 45 percent to 50 percent and that PNG-West's equity risk premium be increased from 65 to 100 bps above the Benchmark.
- PNG (N.E.) FSJ/DC's common equity ratio to be increased from 40 percent to 45 percent and that its equity risk premium be increased from 40 bps to 75 bps.
- PNG (N.E.) TR's common equity ratio to be increased from 40 percent to 50 percent and that its equity risk premium be increased from 65 bps to 100 bps.

Table 3.3
Summary of Capital Structure and Equity Risk Premiums (ERP)

	Current		**Requested by PNG**		**Alternative Proposals by Intervener (BCPSO)**	
	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)
PNG-West	45	65	50	100	(A) 43.5 (B) 45	(A) 65 (B) 140
PNG (N.E.) FSJ/DC	40	40	45	75	(A) 38.5 (B) 40	(A) 40 (B) 115
PNG (N.E.) TR	40	65	50	100	(A) 38.5 (B) 40	(A) 65 (B) 140
Benchmark	38.5	0	n.a.	n.a.	n.a.	n.a.

PNG submits that it has been and remains the riskiest utility in Canada. PNG states that its proposed capital structure ratios are based on a number of factors including:

- Its best judgement of what is required to maintain PNG's financial integrity given its business risks.
- The evidence of its expert, Ms. McShane.
- It reflects the higher equity ratio PNG has maintained to retain an investment grade rating.

PNG submits that it has relied upon Ms. McShane's analysis to determine its appropriate equity risk premium. (PNG Final Submission, p. 35; Exhibit B3-14, pp. 29, 41)

Ms. McShane's recommended common equity ratios for PNG-West, PNG (N.E.)-FSJ/DC, and PNG-TR of 50, 45 and 50 percent respectively. Her recommendations are based on the following:

- The PNG utilities face higher business risk than the Benchmark.
- PNG will be able to maintain and possibly improve its investment grade debt rating. DBRS requires PNG maintain a debt/capital ratio of approximately 50 percent to maintain its investment grade rating.
- If deemed capital structures do not equate to the amounts required for an investment grade rating, PNG will be unable to earn its ROE.
- The recommended ratios will reasonably reflect the relative business risks for the utilities and is close to the DBRS required equity ratio.

In addition, Ms. McShane has recommended an equity risk premium for PNG-West and PNG (N.E.)-TR of 100 bps and a 75 bps premium for PNG (N.E.)-FSJ/DC. She has based this on the following:

- They are consistent with the DBRS conclusion that PNG's allowed ROE is low relative to its business risk.
- The beta analysis conducted by Ms. McShane supports the risk premiums.
- Data on size premiums indicate that recommended risk premiums are conservative.

(Exhibit B3-14, Ms. McShane's Opinion, pp. 2-3)

BCPSO acknowledges that PNG faces greater business risks than the Benchmark but notes that this has been reflected in the PNG utilities current equity ratios and risk premiums. BCPSO further states that in comparison to 2009, riskiness relative to the Benchmark has remained largely unchanged. This being considered, BCPSO takes the position that the equity ratio for PNG-West, PNG (N.E.)-FSJ/DC, and PNG (N.E.)-TR should be 43.5, 38.5 and 38.5 respectively and the equity risk premium should be 65, 40 and 65 bps respectively. (PNG Final Submission, p. 9)

Risks Assessment

PNG presents its evidence as a consolidated entity where risks affect all of the individual regulated utility divisions, on an equal basis, except in circumstances where there are significant differences between the utilities. (Exhibit B3-14, p. 4) To compare its overall business risk to the Benchmark, PNG has assessed seven risk categories providing an impact and probability assessment and a probability weighted ranking. These are summarized in Tables 3.4, 3.5 and 3.6 which follow.

PNG-West Division serves customers in 11 municipalities close to its transmission lines, which traverses B.C. from the Westcoast Energy system mainline interconnection near Summit Lake to Prince Rupert. The total population of the service area is under 100,000. (Exhibit B3-14, Ms. McShane's Opinion, p. 11)

Table 3.4 PNG-West Risk Ranking

Table 2 - PNG West Probability Weighted Impact

PNG West Risk Ranking by Probability Weighted Impact

Risk Category	Impact (1)	Probability (2)	Prob. Weighted Ranking (3)
Other (operating and size)	4 - High	5 - Very High	1
Demand and Throughput	4 - High	3 - Moderate	2
Competitive Position	3 - Moderate	4 - High	3
Regulatory	5 - Very High	2 - Low	4
Customer Growth	3 - Moderate	3 - Moderate	5
Aboriginal Rights	3 - Moderate	2 - Low	6
Supply Risks	3 - Moderate	2 - Low	7

(1) Impact defined as the potential magnitude of a significant adverse impact on PNG's returns
(2) Relative probability of a significant adverse occurrence
(3) Based on result of both Impact and Probability scores

Source: Exhibit B3-17, BCUC 2.3.1

The highest weighted risks identified for PNG-West are operating and size, demand and throughput, competitive position and regulatory.

PNG(N.E.) FSJ/DC is a small town utility in the heart of the natural gas producing region of B.C. with extensions to nearby hamlets. This division has been a very stable small utility for decades and offers the lowest residential delivered rate for natural gas ($7.64/GJ) in the Province. (Exhibit B3-14, p. 6)

Table 3.5 – PNG (N.E.)-FSJ/DC Risk Ranking

Table 4 – FSJ/DC Probability Weighted Impact

FSJ/DC Risk Ranking by Probability Weighted Impact

Risk Category	Impact (1)	Probability (2)	Prob. Weighted Ranking (3)
Other (operating and size)	4 - High	5 - Very High	1
Demand and Throughput	4 - High	3 - Moderate	2
Regulatory	5 - Very High	2 - Low	3
Customer Growth	3 - Moderate	3 - Moderate	4
Competitive Position	3 - Moderate	2 - Low	5
Aboriginal Rights	2 - Low	2 - Low	6
Supply Risks	2 - Low	2 - Low	7

(1) Impact defined as the potential magnitude of a significant adverse impact on PNG's returns
(2) Relative probability of a significant adverse occurrence
(3) Based on result of both Impact and Probability scores

Source: Exhibit B3-17, BCUC 2.3.2

PNG (N.E.)-FSJ/DC highest weighted risks are operating and size, demand and throughput, customer growth and regulatory.

Tumbler Ridge is a very small town that was settled in the 1980's as a service town to the NE coal development and included an underground gas grid utility. As the coal industry went into decline and closure, TR faced a bleak future since it is located in such a remote area. Some oil and gas development has supported the remaining community. Although TR is able to source its gas supply locally, most of the gas production in the area is very sour and is not processed until it is delivered to a processing plant outside of the area before delivery to its customer base of just over 1,200 and its sole industrial customer Canadian Natural Resources Limited (CNRL). PNG (N.E.)-TR purchases its gas from some less sour wells owned by CNRL but there is concern that those wells are becoming depleted. These factors, along with an aging gas processing plant that cannot be economically replaced, add to the risks and strains faced by PNG. (Exhibit B3-14, p. 26)

Table 3.6 – PNG (N.E.)-TR Risk Ranking

Table 6 – Tumbler Ridge Probability Weighted Impact

Tumbler Ridge Risk Ranking by Probability Weighted Impact

Risk Category	Impact (1)	Probability (2)	Prob. Weighted Ranking (3)
Other (operating and size)	5 - Very High	5 - Very High	1
Demand and Throughput	4 - High	4 - High	2
Supply Risks	4 - High	3 - Moderate	3
Customer Growth	3 - Moderate	4 - High	4
Regulatory	5 - Very High	2 - Low	5
Competitive Position	3 - Moderate	3 - Moderate	6
Aboriginal Rights	2 - Low	2 - Low	7

(1) Impact defined as the potential magnitude of a significant adverse impact on PNG's returns
(2) Relative probability of a significant adverse occurrence
(3) Based on result of both Impact and Probability scores

Source: Exhibit B3-17, BCUC 2.3.2

PNG (N.E.)-TR's highest weighted risks are operating and size, demand and throughput, supply and customer growth and regulatory.

Some of the categories utilized by PNG in its submissions have been combined in the discussion as follows.

3.3.1 Operating, Size and Supply Risks

PNG presented its size measurement factors and data comparisons with the Benchmark based on absolute as well as on a per customer basis (Exhibit B3-15, BCUC 1.20.1). The consolidated PNG rate base is 6.4 percent of the benchmark comprising PNG-West at 4.7 percent and the consolidated PNG (N.E.) at 1.7 percent.

PNG-West

PNG describes PNG-West size and operating risk as higher than the Benchmark. PNG describes PNG-West as about one-twentieth the size of the Benchmark and in comparison to FEI it "operates in a northern, mountainous and generally harsher environment, where the company's assets are subject to significant weather, geographic and geologic factors." These factors can be a cause of significant operating volatility and are reflected in increased costs of operating and maintaining a safe, reliable and efficient pipeline. PNG points out that both operating and capital cost are borne by fewer customers resulting in greater significance attached to customer losses relative to the Benchmark. Further, as noted by Ms. McShane, "the impact of smaller size for rated utilities is frequently exhibited in lower debt ratings despite financial parameters that are stronger than their larger peers" (Exhibit B3-14, p. 26; Exhibit B3-14, Ms. McShane's Opinion, p. 13; PNG Final Submission, pp. 5-6).

PNG, in assessing PNG-West's gas supply risk rates it slightly higher than the Benchmark due to having only one access point for all its gas supply. By contrast, the Benchmark has the Southern Crossing pipeline as an alternative supply source. PNG also cites its generally harsh operating environment as a factor noting that there is a greater potential for an event and access and repair can be more difficult (Exhibit B3-14, p. 26, Ms. McShane's Opinion, p. 17; PNG Final Submission, p. 18).

PNG (N.E.) Fort St. John/Dawson Creek

PNG describes the FSJ/DC Division as having higher risk than the Benchmark with respect to operating and size risk. PNG asserts that the FSJ/DC Division at approximately one-fiftieth the size is multiple orders of magnitude smaller than the Benchmark. Further, because of the smaller size, the impact of adverse events can create greater disruption and, due to its non-diversified customer base, it has fewer resources to deal with such occurrences. In addition, the small size of the communities within the service area limits FSJ/DC's access to services and trades and it is forced to compete for relatively scant resources with the gas industry. PNG states that this is much different than the situation faced by the Benchmark and that these factors increase the cost of operating and maintaining a safe, reliable and efficient utility system. (Exhibit B3-15, BCUC 1.20.1; PNG Final Submission, pp. 20-21)

PNG describes the FSJ/DC Division supply risks to be slightly higher than the Benchmark. FSJ/DC is located in the heart of the production region and PNG notes that if curtailment of long term development of the area were to occur, the lack of access to gas would severely affect its competitive advantage (PNG Final Submission, p. 25).

PNG (N.E.) Tumbler Ridge

PNG states that the TR Division faces much higher operating and size risks than the Benchmark. The TR Division operates in a northern mountainous area characterized by a harsher environment and its assets are subject to significant weather, geographic and geologic factors. TR is a small remote community, with a customer base of just over 1,200, a size similar to some of the "micro-utilities" (i.e., small TES utilities). The small size means the TR division, like the FSJ/DC Division has limited access to services and faces the risk of competing for relatively scarce resources with the oil and gas industry. This is a situation that is much different than the Benchmark (PNG Final Submission, pp. 27-28).

PNG rates the TR risk related to supply to be much higher than the Benchmark. The area is served by gas supply from nearby CNRL wells and processed by PNG's gas plants before usage by customers. Of concern to PNG is the TR division's reliance on these wells, which are depleting, and the increasingly sour content of the gas. In addition, CNRL's own usage effectively limits gas supply availability to the TR Division's other customers and there are no alternative economically accessible pipeline quality gas sources available. As a means of partially mitigating this risk, in July 2013, PNG (N.E.) applied to the Commission for a Certificate of Public Convenience and Necessity (CPCN) to acquire, construct, own and operate a compressed natural gas virtual pipeline between the communities of Dawson Creek and Tumbler Ridge. (Exhibit B3-14, pp. 25-26; Exhibit B3-15, BCUC 13.3-13.4)

PNG believes that even if the virtual pipeline is put in place, the greater level of operational complexity will continue to result in greater supply risk than the Benchmark (PNG Final Submission, p. 30).

BCPSO Position

BCPSO does not dispute that PNG's experiences higher operating and size specific risks as compared with the Benchmark. However, in BCPSO's submission, those risks have not changed since 2009. Similarly, the size differential between the two has not changed and BCPSO points out that the growth in PNG (N.E.) likely exceeds that of FEI (BCPSO Final Submission for PNG utilities, pp. 4-5).

With respect to supply risk, BCPSO views PNG's being the same or lower than it was relative to FEI in 2009. BCPSO considers that PNG's relative proximity to much of the shale supply in BC "is not only driving growth, particularly in the NE division, but ensures that the supply is accessible, whether production growth continues or not." (BCPSO Final Submission for PNG utilities, p. 9)

PNG Reply

PNG submit that with respect to what it refers to as Other Risks (operating and size risks) BCPSO's arguments are either unsubstantiated or based on a comparison of PNG's position in 2013 relative to 2009 with no reference to current position of PNG to the Benchmark. Therefore it is not relevant.

Commission Determination

The Commission Panel finds that all of the PNG utilities face additional business risk deserving of some weight when compared to FEI with respect to operating, size and supply risks.

The Commission Panel accepts that PNG's small size and operating environment creates challenges and limits its ability to diversify its risks when compared with the Benchmark. In addition, the Panel accepts that the extremely harsh environment where the PNG utilities operate is also more challenging than that of the Benchmark. This is especially true of PNG (N.E.)-TR, the smallest and most isolated of the communities. However, as argued by BCPSO, the Panel notes that these are not new risks and they have not changed markedly in recent years.

With respect to supply risk there is no disagreement from the Panel regarding the challenges that PNG (N.E.)-TR currently faces with respect to the quantity and quality of available gas. Among the PNG utilities PNG (N.E.)-TR faces the most serious challenges with regard to supply risk. However, we must consider that PNG has taken steps to develop a means to mitigate this risk through its application for a virtual pipeline. The eventual approval of the application may not remove all of the additional risk but the TR Division will have options.

With regard to PNG-West and PNG (N.E.) FSJ/DC supply risk, the Panel is not persuaded that it differs substantially from that of the Benchmark.

3.3.2 Customer Growth, Market Demand and Throughput Risk

PNG-West

PNG states that the evidence indicates that it has much higher risk with regards to customer growth than the Benchmark. PNG-West has experienced negative customer growth for nine consecutive years covering the 2003 to 2012 period. In total, this amounts to close to a 10 percent decline in overall accounts over this period. PNG asserts that this is very different from the experience of the Benchmark, which has experienced steady growth in the number of customer accounts. PNG considers that if proposed LNG projects do not move ahead in a timely manner, it is doubtful that population growth will occur in its service area. (Exhibit B3-14, p. 11; Exhibit B1-9-6, Section H, p. 9; PNG Final Submission, pp. 15-16)

PNG-West submits that it faces much higher risk than the Benchmark with respect to market demand and throughput. PNG-West's total system throughput has declined by 87 percent over the 2003-2012 timeframe. A significant part of this is related to the loss of a major customer, Methanex. Notwithstanding this loss, a 42 percent decline continued over the 2006-2012 timeframe following the loss of Methanex. In PNG's view, this demonstrates the level of volatility that it faces and the detrimental impact of the loss of a single large customer. PNG provides a further example of this susceptibility, where in 2010 it lost the West Fraser Kitimat linerboard mill as a customer. Over the past ten years, PNG-West has experienced year-over-year declines of greater than 10 percent on at least four occasions, which is extremely atypical for the traditionally stable gas distribution industry. PNG submits that the Benchmark had not experienced these types of declines during the 2001-2011 time-period and had not faced a 10 percent decline in annual throughput in its entire history. (Exhibit B3-14, p. 14; PNG Final Submission p. 7)

Regarding business outlook, PNG has updated its evidence on a potential large industrial customer in the Burns Lake area. The customer informed PNG that it has recently reprioritized its capital spending plans and is not going forward with its proposed natural gas conversion project although it may revisit its decision in mid-2014. PNG submits that if the customer were to move forward with the project, "a contract would likely not be signed until the third quarter of 2014 with service not expected until 2015 at the earliest." (Exhibit B3-16-1, revised BCUC 10.2)

With reference to new LNG contracts, PNG remains optimistic regarding various initiatives but notes that none of the potential customers has made a final investment decision. In addition, PNG has updated its evidence with the information that Douglas Channel Energy Partners (DCEP), which has contracted to take up to 80 mmcf/day of PNG-West's existing transportation capacity (representing approximately 70 percent of PNG-West's total capacity), is now in CCAA proceedings. While PNG submits that it is hopeful that DCEP will be able to successfully restructure its affairs, there is no assurance that such a restructuring will take place. (PNG Final Submission, p. 7; Exhibit B3-16-1, revised BCUC 1.10.2)

PNG submits that the potential Burns Lake customer and DCEP are indicative of the various risks PNG-West faces on an on-going basis. (PNG Final Submission, pp. 8-9)

PNG (N.E.) – FSJ/DC

PNG's view is that PNG (N.E.)-FSJ/DC faces a slightly higher level of risk than the Benchmark with respect to customer growth. FSJ/DC has had a more positive growth trend than PNG-West. This is primarily due to the population impact within the Fort St. John and Dawson Creek service areas resulting from the economic activity associated with the natural gas extraction industry (Exhibit B3-14, p. 11).

PNG submits that in contrast to the Benchmark, the growth experienced by FSJ/DC is primarily reliant on a single cyclical industry and is due to an increase in gas exploration in its service area. In its view, an extended downturn in the oil and gas industry could reduce the level of growth and subject FSJ/DC to significant future customer losses. PNG further points out that because it is relatively small, a small number of new households can potentially distort its overall growth figures. PNG is hopeful that LNG growth will eventually occur but there has yet to be any final investment decisions with respect to LNG projects. (Exhibit B3-15, BCUC 9.1; PNG Final Submission, p. 23)

PNG submits that the market demand and throughput risk faced by FSJ/DC is higher than the Benchmark. PNG attributes the lack of customer diversification, small service area, and single industry focus within the FSJ/DC customer base in its description of the division's more negative and more volatile throughput trend compared to the Benchmark. At the same time, PNG concedes that FSJ/DC has not exhibited the same magnitude of declines in throughput as PNG-West. PNG describes FSJ/DC Division as more reliant on its residential and small commercial base and more exposed to the risk of continuously declining UPC levels, which has been far greater than the Benchmark. Specifically, FSJ/DC's 2000-2013 normalized residential UPC has declined by approximately 26 percent in comparison to a 10 percent decline in the Benchmark's UPC over a similar period. FSJ/DC's small commercial UPC results are similar in that a 24 percent decline over this same period are in contrast to an actual increase in the Benchmark's commercial UPC. (Exhibit B3-14, pp. 16-17; PNG Final Submission, p. 22)

FSJ/DC's total system throughput was 4,916 TJ in 2009 compared to 4,398 TJ in 2012, representing a net decline of 10.5 percent. PNG submits that the market prospects for FSJ/DC have not improved, particularly when compared to the Benchmark (PNG Final Submission p. 21).

PNG (N.E.)-TR

PNG describes the level of customer growth of PNG-TR to be similar to that of the Benchmark but it faces higher risk. PNG submits that while the overall number of customers has increased, the average is less than 1 percent per year, and because of the exceptionally small base, the absolute increase in customers has been minor. Further, PNG asserts that its reliance on a single cyclical industry is in contrast to the Benchmark, which is large and well diversified (PNG Final Submission, p. 31).

PNG is of the view that the risks related to demand and throughput are higher than those of the Benchmark. PNG describes its TR division as a small size utility with reliance on a single large industrial customer, CNRL, representing over 80 percent of its throughput volume and approximately 25 percent of its margin. As a result, a change in the demand level of this one customer will effectively lead to a change in total throughput levels. (Exhibit B3-14, pp. 19- 20)

PNG submits that it is actively seeking methods to not only reduce the level of supply risk but also potentially stimulate additional demand via a CNG or “virtual pipeline” strategy. This should also help to alleviate a portion of the Tumbler Ridge Division’s reliance upon CNRL (PNG Final Submission, p. 29).

BCPSO Position

BCPSO agrees that PNG-West has experienced challenges in customer growth and notes that this is not a new trend. In its view, the relative risk to PNG-West is the same or better than it was in 2009. BCPSO consider the growth of FSJ/DC to be similar to that of the Benchmark citing the oil and gas boom as the cause (BCPSO Final Submission, p. 8).

While it does not dispute the decline of 87 percent from 2003-2012, BCPSO disagrees with the timeframe PNG put forward in its evidence when describing the market demand and throughput risk. In the view of BCPSO, the 2003-2012 timeframe is not an appropriate comparator when determining PNG’s relative decline compared to FEI. It submits that the loss of Methanex in 2005 accounts for the majority of that decline and has been accounted for in the 2009 Decision (BCPSO Final Submission, p. 5).

BCPSO submits that “FSJ/DC has not experienced near the magnitude of decline as PNG-West, and indeed saw an increase of 3.6% in 2012.” Furthermore, it takes the position that the decline in throughput is offset by the improved outlook both in the PNG NE territory and the potential improved outlook for PNG due to potential LNG projects. While BCPSO accepts there is a degree of uncertainty remaining, PNG’s position relative to FEI is the same or better in 2013 than it was in 2009 and that should be reflected in determining the overall business risk (BCPSO Final Submission for PNG utilities, p. 5).

PNG Reply

PNG states that BCPSO's arguments concerning demand and throughput risks are not supported by evidence and are compared against 2009 with no reference to the current position of PNG relative to the Benchmark (PNG Reply, p. 5).

Commission Determination

The Commission Panel finds that PNG-West faces significantly more risk than the Benchmark with respect to customer growth, market demand and throughput risk and these factors are deserving of weight. While PNG (N.E.)-FSJ/DC and PNG (N.E.)-TR face risks that are greater than the Benchmark on these factors, they are less than those faced by PNG-West. The Commission Panel awards only limited weight to PNG (N.E.)-FSJ/DC and PNG (N.E.)-TR and moderate weight to PNG-West.

The Commission Panel accepts that PNG-West has and continues to have significant challenges with customer growth and its impact on demand and throughput. The Panel acknowledges that this situation is not new and has existed for some time. However, to deny the fact that the challenges faced by PNG-West are significant would not be reasonable and justifies the moderate weight given relative to the Benchmark. The Panel also acknowledges that there is great potential in the LNG market, which could significantly change the situation for PNG-West. However, there are no firm contracts in place for new customers and some LNG initiatives with potential are less certain. Therefore, while placing some weight on the potential for future development, the Commission Panel remains cautious about the future.

The challenges faced by PNG (N.E.)-TR while different than those of PNG-West are still significant. While enjoying some growth in recent years, the small customer base and reliance on one industry are risks that have not dissipated. The heavy reliance on CNRL as its largest customer and the potential for demand shifts creates business risk. It is too early to determine the impact of the virtual pipeline strategy on attracting potential customers but the Panel considers this a positive development. The Panel acknowledges the conditional CPCN granted by Order G-4-14 on March 5, 2014.

The Commission Panel notes that PNG (N.E.)-FSJ/DC has experienced a more positive growth trend due to increasing economic activity related to the natural gas industry and has not experienced the magnitude of declines in throughput as has PNG-West. In addition, the future does hold some potential for further growth if LNG projects become a reality. However, this is tempered by the fact that the FSJ/DC Division is reliant on one industry that is cyclical and there remains the risk of a downturn with significant impact.

3.3.3 Competitive Position of Natural Gas

PNG-West

PNG states that the evidence indicates that PNG-West has much higher risk with regards to its competitive position than the Benchmark. PNG-West differs substantially from the Benchmark with regards to competitiveness of gas versus electricity for space heating because of the much smaller differential in rate advantage over electricity. This leads to less ability to offset higher initial capital costs for natural gas in comparison with electricity. In addition, due to PNG's smaller customer base and relatively large service area, PNG's delivery rates have historically been, and are expected to remain, substantially higher than those of the Benchmark. (Exhibit B3-14, p. 5)

Ms. McShane states that the differential in delivery rates between PNG-West and FEI "...means that irrespective of the change in natural gas prices or electricity prices, it will continue to face significantly higher price competitive risks than the Benchmark utility" (Exhibit B3-14, Ms. McShane's Opinion, p. 14).

PNG states that PNG-West's customers have seen a significant decline in the commodity cost of gas over the past several years. However, the delivered charge to residential customers is nearly twice that of FEI ($16.04/GJ vs $8.80/ GJ). In addition, noting that PNG-West's delivered cost of gas is now approximately 30 percent below that of electricity, PNG considers that a return to 2008 level gas prices would effectively result in the disappearance of any operating cost advantage. (PNG Final Submission pp. 9-11)

PNG (N.E.)-FSJ/DC

PNG submits that FSJ/DC Division face competitive risk equal to the Benchmark. FSJ/DC Division is located within BC gas exploration and production sector. The presence of local (low-cost) gas, combined with virtually no transmission requirements, has allowed FSJ/DC's customers to enjoy competitive rates versus electricity for an extended period of time. The residential rate for FSJ/DC is $7.64/GJ compared to $8.80 for FEI. PNG submits that despite the competitive advantage, it has not led to significant customer growth; moreover, more efficient appliances and insulation/home construction have resulted in lower UPC which has declined by 25 percent. (Exhibit B3-14, pp. 6, 8)

PNG (N.E.)-TR

PNG takes the position that PNG (N.E.)-TR faces slightly higher risk than the Benchmark. PNG states that this division has a higher cost of delivery than FEI which is primarily a result of the very limited size of the TR utility and service area. In addition, all fixed costs that are associated with the safe, reliable and efficient delivery of gas are spread over a very small number of customers. The total delivered price of gas for the TR Division is slightly higher than that of the Benchmark ($9.51/GJ vs. $8.80/GJ). (Exhibit B3-14, pp. 6, 9)

PNG submits that the TR Division's slightly weaker competitive position relative to the Benchmark could deteriorate with any significant changes in CNRL volumes.

BCPSO Position

With reference to PNG-West's concern that a change in natural gas prices may nullify the price advantage over electricity, BCPSO submits that the likelihood of such a sizeable increase in the cost of gas in the next four years is low. Furthermore, BCPSO notes that the cost advantage has been increased for PNG-West when compared to FEI since 2009. (BCPSO Final Submission for PNG, p. 6) While BCPSO does make specific submissions with respect to FSJ/DC's competitive position, it states that PNG (N.E.) Divisions enjoy a similar cost advantage as PNG-West and that the relative competitive position for PNG compared to FEI is better today than it was in 2009. (BCPSO Final Submission, p. 6)

PNG Reply

PNG argues that PNG-West's competitive position has improved because of an increase in electricity prices and the operating cost advantage of PNG-West is significantly lower, more volatile and historically shorter than that of the Benchmark (PNG Reply, p. 5).

Commission Determination

The Commission Panel finds that all of the PNG utilities face some additional risk due to differentials in electricity rates when compared to the Benchmark. However, the Panel also finds there is insufficient evidence to support the view that electricity as compared to natural gas rates is more attractive.

The Commission Panel takes no issue with the assertion that the natural gas cost advantage relative to electricity is less for PNG than the Benchmark. The question is how much weight should be placed on these differences.

The Panel considers the primary competitor for PNG to be electricity. There appears to be no argument that both PNG utilities and the Benchmark are competitive with electricity prices. Therefore, any variance which exists between the prices charged by the PNG utilities and the Benchmark are less important since they are not competitors.

The Commission Panel acknowledges that the Benchmark's more favourable price differential between natural gas and electricity rates is an advantage in the event of rising natural gas prices. That being said, there is no evidence to suggest that this is likely to occur in the near future. **Therefore, while the Commission Panel finds that there is additional competitive risk relative to the Benchmark we place minimal weight on it.**

3.3.4 Regulatory Risk

PNG

All three divisions of PNG face similar regulatory risk and the following discussion combines all three PNG utilities.

PNG takes the position that it faces a higher level of risk relating to the regulatory framework than does the Benchmark. PNG has highlighted the following areas:

- Inconsistent treatment versus the Benchmark regarding pension assets.
- Inefficient treatment of the retirement compensation arrangement.
- Disallowance of some revenue requirement expenses.
- Regulatory burden regarding information requests for routine operating matters.

PNG claims that it faces higher regulatory risk than the Benchmark due to handling differences between the regulatory decisions for the FEI and PNG. PNG states that on multiple occasions, it received different treatment, which results in higher regulatory risk. In addition, PNG states that its "significantly different experience with respect to earning its allowed rate of return relative to that of the Benchmark is the prime evidence of this higher regulatory risk." (PNG Final Submission, pp. 12-14; Exhibit B3-14, p. 25)

<u>BCPSO Position</u>

BCPSO argues that the Commission has been extremely supportive of PNG especially during the difficult periods in which it lost major industrial customers and risked entering the death spiral. BCPSO made the following submissions:

- The Retirement Compensation Arrangement (RCA) that was put into place demonstrates one of the ways in which the Commission supported PNG during its difficult years.
- As set out in response to BCPSO IR 1.8.1, Figure 19, depicting PNG's actual against its allowed ROE, is based on PNG-West's actual equity, not deemed equity. This would depress the ROE when actual returns exceed the approved ROE.
- The 2011 actual ROE in Figure 19 was depressed due to the cost of the sale to AltaGas where the buyer agreed to a $54.2M premium (60% of the $94.9M NBV). This suggests that AltaGas, as an investor, viewed PNG's ROE as acceptable.
- The response to BCUC IR 1.9.1.1 suggests that FSJ/DC was close to the benchmark, but still under-earned the allowed ROE in 7 of the last 11 years. BCPSO notes that this does not alone indicate that the allowed ROE is too small. It could indicate that cost control has not been as robust as it could have been. BCPSO further submits that rates are set to allow a fair opportunity to earn the approved ROE.
- PNG's rates have been set by Negotiated Settlement Agreement since 2003 for all years but 2004, 2006, 2007, 2012 and 2013. BCPSO interprets this to mean that PNG agreed those rates were a reasonable balance which enabled the utilities to earn a fair return.

(BCPSO Final Submission for PNG utilities, pp. 6-8)

PNG Reply

PNG argues that it does not regard the RCA as supportive, but as disadvantageous and serves as an example of PNG facing different treatment than the Benchmark resulting in higher regulatory risk. PNG acknowledges that BCPSO is correct with respect to Figure 19 being based on actual and not deemed equity and, when actual equity exceeds deemed equity, it will have a depressing effect on ROE. PNG points out that BCPSO's submission ignores PNG's desire to maintain an investment grade rating equity ratio exceeding deemed levels (PNG Reply, p. 6).

Commission Determination

PNG has raised a number of concerns that it believes collectively justifies that it has higher regulatory risk than the Benchmark. To support this PNG has listed a number of decisions where it believes it received regulatory treatment that differed from FEI. Additionally, PNG believes there have been proceedings where the degree of scrutiny through information requests is unnecessary for what it considers to be routine operating matters. These have resulted in unnecessary cost burden and, in some instances, the Commission has disallowed some expenses that are typically allowed in other corporate organizations (Exhibit B3-14, pp. 24-25).

With regard to PNG's perceived treatment by the Commission respecting regulatory process, the Commission Panel reminds PNG that in ensuring a panel can consider all relevant evidence it is appropriate for IRs, including those prepared by Commission staff to test the evidence. Given that PNG agrees that being referred to as the riskiest utility in Canada remains an apt description, it is appropriate for the Commission to scrutinize PNG's applications and be thorough with its information gathering process.

The Commission Panel notes that there is no evidence to support PNG's assertion that it receives different treatment in its revenue requirements applications. It is not unusual for the Commission to disallow certain costs it deems unnecessary or require treatments which are unique to an individual utility.

The Commission Panel has considered BCPSO's statements with respect to PNG's ROE and earnings history and resultant ROE performance. The Panel notes that PNG's rates have been set by negotiated settlement in 2009, 2010, and 2011. We agree with BCPSO that it would be reasonable to conclude that PNG by its agreement considered rates to be "a reasonable balance which enabled the utilities to earn a fair return."

The Commission Panel has considered the DBRS Ratings Report for PNG of March 12, 2012, that has been filed in this proceeding. In the report, DBRS stated the following with respect to regulation: "Though DBRS continues to view the regulatory environment as supportive, the review could have an impact on PNG's future earnings and cash flow." The "review" referred to by DBRS is the Generic Cost of Capital proceeding. The Commission Panel also notes that the most recent DBRS Ratings Report of August 1, 2013, raised no concerns with respect to regulatory oversight. It therefore appears that DBRS does not view the regulatory environment as problematic. (Exhibit B3-7, p. 1 of 2, Tab 2; Exhibit B3-15, BCUC 1.23.1 Attachment)

Taking all of these factors into consideration the Commission Panel finds that there is no evidence to support PNG's assertion that it faces higher regulatory risk than the Benchmark. Accordingly, the Panel places no weight on this factor.

3.3.5 Aboriginal Rights

PNG-West, FSJ/DC and TR Divisions

The PNG-West system spans much of the province on an east to west basis and traverses many areas that are currently within existing Aboriginal territories or within disputed Aboriginal areas.

Furthermore, a large portion of PNG-West's assets are in the transmission business, which is significantly different than the primarily distribution function of the Benchmark (Exhibit B3-14, pp. 4-5).

PNG points to the 17 different First Nations with land claims in its region and the "non-treaty" status of many of those First Nations to conclude that it faces higher risk relative to the Benchmark (PNG Final Submission, pp. 16-17).

PNG believes that the FSJ/DC and TR Divisions face similar issues with respect to Aboriginal Rights and PNG (N.E.)'s risks related to Aboriginal Rights lie between those of the Benchmark and PNG-West. According to PNG, the risk stems from the fact that First Nations represent a larger percentage of communities and customers within the service area of PNG N.E. the Benchmark. This exposes the Utilities to greater relative uncertainty. (Exhibit B3-14, p. 5 of 41; PNG Final Submission, p. 24)

<u>BCPSO Position</u>

BCPSO notes that PNG has been fairly successful in maintaining good relations with First Nations in their territories, despite their smaller workforce when compared to FEI. As set out in BCUC IR 1.3.4, the Commission has never denied any costs related to First Nations issues. In this regard, BCPSO submits that PNG and FEI are not dissimilar. (BCPSO Final Submission for PNG utilities, p. 8)

Commission Determination

The Commission Panel finds there is no persuasive evidence that PNG is more at risk with respect to aboriginal rights than the Benchmark. The Panel acknowledges that PNG does face some level of risk with respect to aboriginal rights but is not persuaded it is materially different than FEI.

Specifically, PNG has provided no evidence to indicate any uncertainty in First Nations rights and titles have affected or are likely to affect PNG's ability to earn its return in the future as compared to the Benchmark.

3.3.6 Capital Structure and Equity Risk Premium Considerations

Credit Ratings

PNG-West, PNG (N.E.)-FSJ/DC, PNG (N.E.)-TR

PNG currently has a BBB(low) rating by DBRS on its existing third party debt which is considered investment grade. This rating is four notches below the Benchmark. In spite of this, PNG exhibits superior credit metrics and explains that the primary reason for this is that it has historically maintained a higher equity level in its capital structure than what has been approved. PNG has done this based on its assessment of the required level of equity to maintain the financial integrity of the utilities. In addition, PNG based this decision on what DBRS considers to be the minimum level of equity for maintenance of its BBB(low) credit rating.

PNG states that DBRS in its August 1, 2012 credit rating noted that to maintain investment grade ratings PNG must maintain a credit profile that is stronger than its peers and its debt-to-capital ratio is expected to remain at approximately 50 percent over the medium term. Based on its current rating, PNG states that it has a significantly higher debt cost than the Benchmark and much more limited access to capital. PNG also states that a downgrade by DBRS would have, among others, the following impacts on PNG and its customers:

- Significantly higher borrowing costs.
- Higher costs for existing debt facilities.
- Reduced access to markets.

- Stricter financial covenants.
- Higher counterparty requirements.

PNG submit that the negative impacts related to a downgrade are greater than the impact to customers of approving a higher level of common equity. Ms. McShane agrees stating that while the BBB rated companies face higher costs, reduced market access and more stringent covenants attached to debt issues relative to those in the A category, the implications of a non-investment grade category rating is significantly more serious. (Exhibit B3-14, pp. 33-34; Exhibit B3-14, Ms. McShane's Opinion, pp. 21-22)

PNG points out that "[t]he lack of a BB rated utility in Canada, or even additional BBB-rated utilities in Canada is instructive in and of itself." In addition, in the US, which has a larger universe of gas utilities than Canada, a BBB- or lower rating is the exception. In spite of this, PNG notes that historically, its level of common equity is significantly lower than those utilities rated much higher than PNG.

<u>BCPSO Position</u>

BCPSO submits "that DBRS view is that PNG is "stable" not "negative" is premised on the existing CERs and RoE." While undefined, the Panel takes CER to refer to equity thickness. (BCPSO Final Submission for PNG utilities, p. 9)

Commission Determination

The Commission Panel has considered the evidence submitted by the parties. The Panel in Sections 3.1.4 and 3.2.5 determined it appropriate that it continue to be guided by its Stage 1 finding as discussed in Section 1.3 of this Decision. The maintenance of current credit ratings is desirable but only to the extent that doing so does not go beyond what is required in the Fair Return Standard.

We have no reason to vary this. However, it is acknowledged that PNG does face a unique set of circumstances and a further credit rating downgrade will have impacts. The Commission Panel considers this in its overall cost of capital determination.

3.3.7 Commission Cost of Capital Determination

The Commission Panel has determined that the following common equity ratios and equity risk premiums are appropriate for the PNG utilities:

PNG West:	**Common equity ratio:**	**46.5 percent**
	Equity risk premium:	**75 bps**
PNG (N.E.)-FSJ/DC:	**Common equity ratio:**	**41 percent**
	Equity risk premium:	**50 bps**
PNG (N.E.)-TR:	**Common equity ratio:**	**46.5 percent**
	Equity risk premium:	**75 bps**

The Commission Panel has considered the business risks faced by the three PNG Utilities and in its judgement considers these common equity ratios and risk premiums to be appropriate for each utility. PNG-West has significant issues with customer growth, market demand and throughput and the Commission Panel has weighted these accordingly. In addition, the Panel has considered the operating risk and factors related to its relatively small size in reaching our determination.
PNG (N.E.)-TR has similar risks to those of PNG-West. However, the Panel has considered that factors related to size and difficulties with supply to be key determinants with less emphasis on customer growth, demand and throughput. PNG (N.E.)-FSJ/DC is less susceptible to some of the business risks and is closest to the Benchmark in terms of levels of business risk. All of the PNG utilities face some competitive risk relative to the Benchmark.

In reaching our common equity thickness determinations, the Commission Panel has considered the evidence related to credit ratings and has placed some weight on the desire to maintain a rating category higher than non-investment grade. This has been only to the extent that it does not go beyond what is required by the Fair Return Standard.

The Commission Panel has awarded an increase in equity premium over the Benchmark to all of the PNG utilities. PNG-West and PNG (N.E.)-TR have been awarded equity risk premiums of 75 bps, which are slightly higher than that of PNG (N.E.)-FSJ/DC at 50 bps. In the judgement of the Commission Panel, the variance among the PNG utilities reflects the difference in short term risk between the utilities as well as in comparison to the Benchmark. In addition, the Panel has considered the PNG utilities' debt ratings as affected by credit metrics and factors related to size and their impact on short term risk.

The Commission Panel acknowledges that the PNG utilities face a unique set of circumstances with respect to the level of business risk. The determinations that have been made in this proceeding are based on the Panel's assessment of the business risks which exist today and little weight has been placed on the potential for change to these risks in the near future. If, for example, the various LNG initiatives currently contemplated become a reality, the amount of business risk will shift accordingly. The same could be said about potential developments in the mining industry. In the view of the Panel, it is important to ensure that PNG's business risk assessment remains contemporary and its cost of capital aligned with it. **Accordingly, the Commission Panel directs the PNG utilities to include an updated business risk assessment in all future revenue requirements applications.**

3.4 TES Utilities

Introduction

In the Stage 1 Decision, the Commission acknowledged the FBCU submission that it may be efficient, given the small size of thermal energy systems, to have a simple process to address cost of capital issues for TES systems, irrespective of the provider (Stage 1 Decision, p. 94). Corix

Utilities Inc., Central Heat Distribution Limited and River District Energy Limited Partnership (the Companies) filed evidence jointly in Stage 2. FAES filed evidence for its TES projects: Delta School District, Tsawwassen Springs, PCI Marine Gateway, Telus Garden and Kelowna DES.

The TES Regulatory Framework Decision issued on December 31, 2013, and Order G-231-13A determined that District Energy System type projects, i.e., a system designed for intended future expansion to connect to future unknown customers and sites where the demand is uncertain and the capital costs to construct are in excess of $15 million are Stream B utilities. Stream B utilities must follow the regulatory requirements in the TES Regulatory Framework. Stream A TES utilities include on-site Discrete Energy Systems up to a capital cost of $15 million. The Commission no longer determines the deemed return on equity, capital structures and cost of debt for each Stream A utility from the outset once the exemption has been approved by the Lieutenant Governor in Council. (Exhibit B6-5, BCUC 31.1; Exhibit B2-18, BCUC 1.1)

FEI confirmed that the regulatory streams of FAES utilities are as follows:

- Delta School District – Exempt
- Tsawwassen Springs – Stream A
- PCI Marine Gateway – Stream A
- Kelowna DES – Stream B

(Exhibit B6-5, BCUC 2.40.1)[11]

On February 20, 2014, the Commission invited FAES to make submissions by February 27, 2014, with respect to the Commission Panel rendering a decision on the capital structure and equity risk premium only for Stream B utilities. FAES confirmed acceptance of this approach. (Exhibit B6-6)

[11] By letter dated February 27, 2014, in response to the Commission's invitation to make submissions whether there is a need for the Commission Panel to make determinations for FAES' Exempt and Stream A utilities, FAES updated its response to BCUC IR 2.40.1 regarding Delta School District, which will fall under Stream A.

In accordance to the TES Regulatory Framework, the Stream B utilities that require a deemed capital structure and a risk premium above the Benchmark ROE are:

- FAES Kelowna DES;
- Dockside Green Energy;
- Corix UniverCity;
- Central Heat;
- River District Energy.

The relevant conclusions from the Contextual Issues discussions are as follows:

- As a result of the TES Regulatory Framework, the determinations from this Stage 2 proceeding will only apply to the utilities identified above as Stream B utilities. (Section 2.3.2)
- With respect to regulating Stream B utilities, the Commission Panel will set a minimum default capital structure and equity risk premium minimum for Stream B TES projects (utilities, systems). (Section 2.4)
- As determined, no weight should be given to Ms. Ahern's framework for determining the cost of capital for small utilities. Regardless, the Panel will continue to consider the small size factor as one among a range of business and financial risks TES utilities are exposed to. (Section 2.5)
- For the purposes of this Decision the Panel will make determinations related to TES projects and will consider all risks faced by a TES project investor, which include the business development, construction and operation phases. (Section 2.6)
- A risk matrix is a useful tool for the purposes of identifying and describing risks or categories of risks. (Section 2.7)

Table 3.7 below summarizes the current and requested standard default capital structure and ERP.

Table 3.7

Summary of Capital Structure and Equity Risk Premiums (ERP)

	Current		**Requested by TES Utilities**		**Proposed by Intervener (BCPSO)**	
	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)	Equity Thickness (%)	ERP (bps)
FAES	n.a.	n.a.	**45**	**75**	n.a.	n.a.
Delta School District	40	50	FAES minimum default		FAES recommendation be given significantly more weight	75 bps as proposed by FAES be the maximum
Tsawwassen springs	40	50	FAES minimum default			
PCI Marine	40	0	FAES minimum default			
Telus Garden	40	0	FAES minimum default			
Kelowna DES	40	50	FAES minimum default			
The Companies	n.a.	n.a.	**60**	**250**		
Central Heat	36.31	50	The Companies minimum default			
Dockside Green	40	100	The Companies minimum default			
UniverCity	40	50	The Companies minimum default			
River District	40	50	The Companies minimum default			
Benchmark	38.5	0	n.a.	n.a.	n.a.	n.a.

3.4.1 Minimum Default Capital Structure and Equity Risk Premium

Summary of Submissions by Parties

The Companies request that the Commission take the following steps:

- Set the default debt/equity ratio at 40 percent debt/60 percent equity;
- Set the default equity risk premium relative to the Benchmark at a minimum of 250 bps;
- Set the default debt component of the capital structure to track a benchmark credit spread that reflects a BBB or BBB(low) rate debt relative to the 10 year Government of Canada bond yield;
- Any TES utility would be free to present a case for different financial parameters.

(the Companies Final Submission, pp. 1-2)

The Companies also stated that a utility could choose to accept a lower return as it saw fit to compete fairly in the TES market, so long as that conduct complies with the UCA. Further, the Companies submit the fact that FAES is willing to accept a lower equity ratio and lower ROE does not diminish the validity or value of the approach that their expert has proposed. (Exhibit B2-18, BCUC 1.4.8; the Companies Final Submission, p. 6)

FAES submits that, in light of the overriding similarities among TES utilities, the Commission should approve a default common equity ratio and equity risk premium of 45 percent and 75 bps respectively. Furthermore, FAES submits that a TES utility would retain the right to tender evidence in support of a higher equity risk premium than the default risk premium. (Exhibit B2-6, Appendix B, pp. 1-2, FAES Final Submission, p. 22)

BCPSO submits that small TES utilities should be allowed a slightly higher common equity ratio than the Benchmark. BCPSO also agrees with both FAES and the Companies that small TES utilities should be permitted a default risk premium relative to the Benchmark. (BCPSO Final Submission, pp. 5-6)

The Commission Panel Approach

As the Commission Panel already has reviewed the testimony put forward by the Companies' expert, Ms. Ahern, and found that no weight should be given to her framework, this section focuses on the principles outlined by Ms. McShane, the expert for FAES. Nevertheless, the risk descriptions below do not necessarily contradict the views put forward by the Companies. For ease of presentation, this section follows that adopted by Ms. McShane. Earlier in Section 2.2, the Panel reviewed Ms. McShane's quantification methodologies for establishing an optimal common equity ratio and ROE.

3.4.1.1 Business Risk of TES Projects

Ms. McShane states that although each TES project regulated by the Commission will have its own unique characteristics, TES projects share attributes which result in higher business risk for each project and for the BC thermal energy utility sector as a whole relative to the Benchmark. The higher business risk of TES projects relative to the Benchmark utility reflects the combination of:

1. Their greenfield characteristics, including the lack of an established customer base;
2. Reliance on non-traditional rate structures to make the projects competitive and provide an opportunity to recover the related investment;
3. Small size of individual TES projects, e.g., fewer customers to recover the costs of the assets constructed and operated to serve them;
4. Reliance on more complex systems to provide thermal energy service;
5. Competition to provide thermal energy services from conventional sources of energy;
6. Competition to provide thermal energy services from other TES providers;
7. The relatively high upfront capital costs that must be recovered only from thermal energy customers; and
8. Higher counterparty risk due to reliance on one or a limited number of counterparties for revenue.

Ms. McShane concludes that the higher business risk of TES projects relative to the Benchmark results in a higher cost of capital, which needs to be reflected in a higher overall allowed return. (Exhibit B6-2, Appendix B, p. 6)

3.4.1.2 Common Equity Ratios for TES Projects

Ms. McShane acknowledges that the determination of a reasonable equity ratio for TES projects, which appropriately reflects their higher business risk and smaller size, is largely a qualitative exercise and involves informed judgement. She also points out that because BC is the only province where TES projects are regulated, there are no directly comparable companies to serve as a benchmark, except for the recent BCUC decisions.

As a first step, Ms. McShane considers the fact that the small size of the TES projects, on a stand-alone basis, would preclude them from obtaining arms-length third party financing in similar proportions of debt and equity as the Benchmark. Consequently, she states that an equity ratio of 40 percent for projects of this type is too low to reasonably recognize the higher risks, small size and limited access to debt capital. She draws this conclusion despite the fact that over the last few years the Commission has adopted a 40 percent equity ratio for seven TES projects.

As the second step, Ms. McShane reviews the capital structures adopted for small electric and natural gas distribution utilities in Canada and provides the following Table 3.8.

Table 3.8

Capital Structures for Small Canadian Electric and Natural Gas Utilities

Utility	Regulator	Date of Decision	Allowed Common Equity Ratio	Equity Risk Premium Relative to Benchmark	Rate Base	Customers
					($M)	(000s)
AltaGas Utilities	AUC	Dec-11	43.0%	0%	$175	74
Enbridge Gas NB	NB EUB	Nov-10	45.0%	2.75%	$273	12
FEVI	BCUC	Dec-09	40.0%	0.50%	$779	101
FEW	BCUC	Dec-09	40.0%	0.50%	$42	3
FortisOntario	OEB	Dec-09	40.0%	0%	$200	64
Gazifère	Régie	Nov-10	40.0%	0.25%-0.50%	$78	39
Heritage Gas	NSUARB	Nov-11	45.0%	2.0% [1/]	$198	4
Maritime Electric	IRAC	Dec-12	43.5%	0.58%[2/]	$311	76
Natural Resource Gas	OEB	Jun-10	40.0%	0%	$13	7
Northland - (NWT)	NWTPUB	Nov-11	44.0%	0.30%[3/]	$15	3
Northland - (YK)	NWTPUB	Aug-11	43.5%	0.30%[3/]	$41	8
PNG (N.E.) - FSJ/DC	BCUC	May-10	40.0%	0.40%	$49	18
PNG (N.E.) -TR	BCUC	May-10	40.0%	0.65%	$2	1
PNG-West	BCUC	May-10	45.0%	0.65%	$128	20
Yukon Electrical	YUB	Feb-09	40.0%	0.46%	$34	17

Source: Exhibit B6-2, Appendix B, p. 8

After providing a number of caveats, Ms. McShane concludes that it is reasonable to rely on the upper end of the range for establishing the common equity ratio for each project: i.e., a common equity ratio of 45 percent. To support this, she specifically discusses the credit ratings for FEVI and PNG. Thus, her recommendation for "FAES as a whole, given the small size of the projects individually and in the aggregate, it is unlikely that either any individual TES project or FAES would be able to achieve a debt rating higher than BBB."

Ms. Ahern, expert for the Companies, states that it is her opinion as well as common sense that small companies, such as TES utilities, generally need to maintain a less financially leveraged capital structure than larger companies such as FEI. This is to provide a cushion against the effects of extraordinary events which will affect a smaller firm to a greater extent than a larger firm. (Exhibit B2-17-1, pp. 12-13)

3.4.1.3 Equity Risk Premium for TES Project

Ms. McShane highlights the difficulties inherent in setting equity risk premiums for TES projects. For instance, it is not possible to select samples of publicly-traded utilities that are of directly comparable risk to the regulated TES project. Moreover, there is no methodology available to quantify the impact of each difference in risk characteristics unique to a particular project. Accordingly, Ms. McShane recommends adoption of a single default equity risk premium as a reasonable and efficient approach to setting the premium. The default premium above the Benchmark ROE would apply unless the TES project proponent elects to submit evidence to support a higher equity premium.

To arrive at a reasonable recommendation, Ms. McShane considers different perspectives as follows:

- Equity risk premiums granted in the past by the BCUC (Dockside Green 100 bps, other TES projects 50 bps);
- Equity risk premium previously granted to PNG companies, FEVI and FEW (40 to 65 bps);
- Equity risk premiums adopted for smaller natural gas distribution utilities in other Canadian jurisdictions (Heritage Gas 200 bps, EGNB 275 bps).

Ms. McShane also provided some background on the relationship between size and return in conjunction with a linkage between the equity ratio and ROE. She first estimated a TES differential in the range of 150 to 300 bps. Based on this rationale, and assuming an equity ratio of 45 percent, she reduced the range by 80 bps, arriving at 70 bps at the lower end.

In conclusion, Ms. Shane submits that “taking the above considerations into account” it is her expert opinion that the default equity risk premium above the Benchmark of 75 bps would be applicable. (Exhibit B6-2, pp. 11-18)

Commission Determination

The Commission Panel first adopts the Guiding Principles for Setting Deemed Capital Structure and Deemed Debt as articulated in the GCOC Stage 1 Decision, Sections 7.3 to 7.5. **In reference to the Stage 1 Decision, the Panel confirms that the default debt component of the capital structure is set to track a benchmark credit spread that reflects BBB or BBB(low) rated debt relative to the 10 year Government of Canada bond yield.**

In the Stage 1 Decision, the Panel also posed the following questions for further consideration in the Stage 2 Proceeding:

- Can the combination of the deemed debt/equity ratio and the allowed ROE sufficiently compensate for the unique risks of a particular utility or project?
- How important is it to maintain consistency between the risk premium determination and assigning a deemed credit rating for a small utility without a third party debt? For instance, would it be reasonable to allow no risk premium over FEI for a TES project while setting the debt rate based on a BBB bond rating?

In an answer to these questions, the Panel finds that by setting the minimum default equity ratio above the 38.5 percent Benchmark and an equity risk premium over and above the allowed Benchmark ROE, the Panel is consistent with its deemed debt rate based on a BBB/BBB(low) bond rating. In general, the Panel agrees with the experts that a cushion is required for TES projects as a protection against the additional risk exposure. The Panel also accepts the validity of the eight TES specific risk factors put forward by Ms. McShane.

However, setting the actual amounts is ultimately a qualitative exercise, requiring informed judgement. The Panel notes again that British Columbia is the only Canadian jurisdiction that regulates TES projects. Therefore, it is obvious the most insight into those projects and their inherent risks exists within the Commission, which has been intimately exposed to these projects and their evolution over the last few years. Accordingly, this Panel will put more weight on the

TES decisions of the Commission than equity ratios set for small distribution utilities in other jurisdictions. **The Commission Panel finds that a minimum default capital structure consisting of 57.5 percent debt and 42.5 percent common equity represents a reasonable balance. This equity ratio is 4.0 percentage points higher than that awarded to the Benchmark.**

With regard to the default equity risk premium, the Panel again gives the largest weight to the findings of past TES project Panels. As noted earlier in this Decision, the Panel found there was insufficient data to support the conclusions made by Ms. McShane regarding her quantification methodology. **After considering the past TES project decisions and the evidence put forward by the experts, the Panel accepts the default equity risk premium of 75 basis points recommended by FAES and its expert, Ms. McShane.**

Finally, the Commission Panel finds that a TES project proponent, regardless of whether the project is old or new, retains the right to submit evidence in support of a higher equity risk premium than the default established above.

3.4.2 FAES Kelowna District Energy System

Most of the evidence provided by FAES in the Stage 2 proceeding addressed the current risk profile of FAES as a corporate entity as opposed to having the emphasis of individual TES projects. Similarly, the cost of capital evidence prepared by Ms. McShane addressed the TES projects in general. These submissions have already been summarized in previous sections and therefore there is no need for the Panel to reiterate the related findings here.

The only reference to the Kelowna District Energy System (KDES) is provided in the risk matrix that FAES filed based on a Commission request. Specifically, FAES points out that the KDES has no mandatory connection requirement and faces inherent uncertainty in load forecast. (Appendix B6-2, Appendix A, Table 4) The Panel acknowledges the concerns identified by FAES regarding the use of the risk matrix and refers to the discussion of Use of the Risk Matrix in Section 2.7.

Based on the risk profile of the KDES as compared to the Benchmark, the Commission Panel finds that no sufficient justification has been provided to deviate from the default standard. Accordingly, the common equity ratio for KDES shall be set at 42.5 percent and the equity risk premium at 75 bps.

3.4.3 The Companies Projects

The general submissions related to the risks of TES projects[12] and the requirement for a fair rate of return to compensate for these risks by the Companies have already been covered in previous sections. This section will briefly review the four existing projects: Dockside Green, UniverCity, Central Heat and River District Energy.

3.4.3.1 Dockside Green Energy Inc.

Dockside Green (DGE) provides hydronic energy for space heating and domestic hot water to the Dockside Green community in Victoria using a central plant. The plant consists of a biomass gasification system and a supplementary natural gas boiler. Corix has a 17 percent equity share and also operates the DGE system under an agreement.

[12] C-3-12-FortisBC Energy Inc.-Application for a Certificate of Public Convenience and Necessity for the Construction and Operation of Thermal Energy Service to Delta School District Number 37, March 16, 2012.

C-10-12-FortisBC Alternative Energy Services Inc. Application for a Certificate of Public Convenience and Necessity for the Approval for the PCI Marine Gateway Thermal Energy Project and Approval of Rates for Thermal Energy Service to PCI Developments Inc., September 27, 2012.

G-100-12-FortisBC Energy Inc. Application for Approval of a Capital Expenditure Schedule and Rate Design and Rates Established in an Operating and Maintenance Agreement between FortisBC Energy Inc. and the Strata Corporation of Tsawwassen Springs Development to Provide Thermal Energy Services, July 19, 2012.

C-1-13-FortisBC Alternative Energy Services Inc. Application for a Certificate of Public Convenience and Necessity for the TELUS Garden Thermal Energy System and for Approval of the Rate Design and Rates to Provide Thermal Energy Service to Customers at the TELUS Garden Development, February 4, 2013.

C-8-13-FortisBC Alternative Energy Services Inc. Application for a Certificate of Public Convenience and Necessity for the Kelowna District Energy System and the Approval of the Rate Design and Rates to Provide Thermal Energy Services to Customers in the Kelowna City Centre, July 26, 2013.

DGE currently has an allowed equity risk premium of 100 bps and a deemed equity ratio of 40 percent. Currently, it is significantly under-earning its allowed return on investment due to lack of build-out at its development and according to the Companies, if and when build-out occurs, the utility would expect to earn its allowed return (Exhibit B2-18, BCUC 1.4.5).

According to the Companies, their assessment of non-empirical risk factors for DGE is as follows:

- Competition risk – Low
  - Under the terms of the agreement with the developer, buildings within the DGE site are attached to the utility.
- Customer Load risk – High
  - Very small customer base, even at full build-out, variation of load between buildings difficult to predict.
- Development Cost risk – High
  - New technology with appreciably higher risks than Benchmark.
- Operating Cost risk – Medium
  - Relatively higher risk of operating small district energy system than Benchmark.
- Rate Design risk – Low
  - Similar to Benchmark.
- Regulatory risk – Medium
  - Evolving market.

(Exhibit B2-18, BCUC 8.1)

Commission Determination

The Commission Panel notes that the DGE project continues to face challenges and that its situation has not changed. Accordingly, the Panel is reluctant to reduce the 100 bps equity risk premium awarded by the Commission previously. **The Commission Panel determines that a reasonable equity ratio for Dockside Green shall be 42.5 percent and the equity risk premium 100 bps.**

3.4.3.2 UniverCity at Burnaby Mountain

UniverCity is developed as a district energy system in the UniverCity on Burnaby Mountain.[13] The initial system will provide service through a temporary natural gas boiler facility. A permanent central biomass energy plant will be constructed in later phases.

UniverCity currently has an allowed equity risk premium of 50 bps and a deemed equity thickness of 40 percent. The customer rates were set using a levelized approach, which helps to mitigate the impact on the initial customers of the large capital outlay required to develop district energy systems by deferring the utility's cost recovery until future years (Exhibit B2-22, BCPSO 1.2). The Companies believe that the Commission should let the terms of the contract determine the recourse either of the parties has in the event the Commission change the cost of capital (Exhibit B2-18, BCUC 4.5-4.6).

As part of Corix Utilities, a utility such as UniverCity is debt financed through Corix's consolidated credit facilities. Corix Utilities provides debt financing to its regulated utilities through intercompany loan agreements with a cost of debt that reflects the specific risk profile of that project. (Exhibit B2-17, p. 15)

According to the Companies, the non-empirical risk factors' assessment for UniverCity is as follows:

[13] C-7-11-Corix Multi-Utility Services Inc. Application for a Certificate of Public Convenience and Necessity to Construct and Operate a District Energy System for the UniverCity Neighbourhood Utility Service Project in Burnaby, BC and Approval of the proposed Revenue Requirements, Rate Design, Levelized rates and Service Agreement, March 6, 2012.

- Competition risk – Low
  - Under the terms of the agreement with the developer, buildings within the UniveCity site are attached to the utility.
- Customer Load risk – High
  - Very small customer base even at full build-out, variation of load between buildings difficult to predict.
- Development Cost risk – Medium
  - Development of small district energy system is relatively more risky than benchmark.
- Operating Cost risk – Medium
  - Relatively higher risk of operating small district energy system than Benchmark.
- Rate Design risk – Low
  - Similar to benchmark
- Regulatory risk – Medium
  - Evolving market.

(Exhibit B2-18, BCUC 8.1)

Commission Determination

The Commission Panel has considered the various risk elements vis-à-vis the Benchmark as well as in relation to the other existing district energy systems. **On balance, the Commission Panel finds that there is not sufficient evidence to deviate from the default standard. Accordingly, the common equity ratio for UniverCity shall be set at 42.5 percent and the equity risk premium at 75 bps.**

3.4.3.3 Central Heat Distribution Limited

Introduction

Central Heat is a provider of thermal energy in the form of steam to over 200 buildings in downtown Vancouver. It has operated as a regulated utility in BC since 1968 and has total assets of nearly $40 million. Central Heat is a mature utility that sets customer rates using a standard utility cost of service (Exhibit B2-22, BCPSO 1.2) and is financed, now on a stand-alone basis, through commercial credit arrangements with a bank, which also requires an equity component of approximately 50 percent. Its variable borrowing rate is prime plus 0.5 percent (Exhibit B2-17, p. 19).

In this Stage 2 proceeding, Central Heat has filed its evidence in conjunction with Corix and River District Energy. The Companies state they have significant differences in their operations but that they also share common perspectives and requested that the Commission establish a default standard, under which:

- The debt/equity ratio for small utilities be set at 40 percent/60 percent;
- The equity risk premium be set at a minimum of 250 basis points relative to the Benchmark utility; and
- The debt component of the capital structure to track a Benchmark credit spread that reflects a BBB or BBB (low) rated debt relative to the 10 year Government of Canada bond yield.

The Commission Panel has already addressed the default standard in earlier sections.

Central Heat describes the changing energy market as a reflection of the public and various levels of government taking more interest in different energy systems that have resulted in certain incentives, new policies, and increased competition from traditional utilities (Exhibit B2-17, p. 18).

Central Heat states that despite being a 45 year old utility, its credit facility requirement reflects materially more risk than the BCUC's Benchmark debt to equity ratio (38.5 equity thickness), and certainly more than the 100 bps equity allowed for Dockside Green. Central Heat also indicates that it had incurred losses during its first ten years of operations and did not achieve a rate of return comparable to the current benchmark (8.75 percent) until after twenty years. Its cost constraint was and continues to be a priority. Central Heat has operated without levelized costs and without deferral accounts in a competitive service area. (Exhibit B2-17, p. 21)

In the earlier parts of this Decision, the Panel has already made certain determinations on a number of contextual issues that should apply equally to Central Heat and will not be repeated here. In particular, this section should be read in conjunction with the Panel's determinations under Section 2.2 to 2.6 above, which also applies to Central Heat.

Risk Assessment

The Companies proposed that Central Heat should be given weighting of 25 percent and 15 percent respectively for utility size risk and financial risk, with the remaining 60 percent split between competition (25 percent), customer load (25 percent) and the remaining development cost, operating cost, rate design and regulatory (10 percent). Central Heat considered that it has low to medium business risk. (Exhibit B2-23, BCUC 1.8.1) Central Heat stated that if the requested risk premium and capital structure were approved, it would look to recover the change over at least two years. It estimated that the rate impact would be 12.7 percent to the utility margin and it would remain competitive with other energy options. (Exhibit B2-18, BCUC 4.4, BCUC 4.4.1)

In terms of the Commission's Risk Matrix, the Companies propose a simplified version of the Commission's risk matrix while providing their own assessment to the risk factors. The risk assessment related to Central Heat is included in pages 21-26 of the Company's evidence (Exhibit B2-17) but emphasizes that size is a major factor of risk because small utilities have fewer resources and are less able to mitigate adverse market effects and are less diverse.

Position of the Parties

The Companies believe that any discussion of the risk matrix must necessarily resolve how to relate the incidental risk factors to the fundamental risk factor of size (Exhibit B2-18, BCUC 4.12). No Intervener made submissions related to individual Group 3 utilities. However, FAES filed evidence with an accompanying proposal for a default capital structure of 45 percent equity ratio and 75 bps over Benchmark ROE.

Commission Determination

The Panel notes that under the Companies' proposed risk matrix, Central Heat and RDE are respectively assigned 25 percent weight in utility size risk whereas DGE and UniverCity are respectively assigned 50 percent. (Exhibit B-23, BCUC 1.9.1) Yet all these utilities have requested the default standard of 60 percent equity ratio and 250 bps size premium. This appears contradictory to the Companies' stated approach. The Panel further notes that a fairly low-risk Central Heat will be sharing the same parameters with RDE which by its own admission "its parent likely would not have undertaken to develop a TES project in the absence of considerations related to its desire to sell real estate." (Exhibit B2-18, BCUC 9.1)

The AES Inquiry Report identified Central Heat as being distinct from the TES projects. (AES Inquiry Report, p. 75) In the case of DGE, UniverCity and RDE, restrictions are in place so that residents are more obliged to use heat provided by the utility. In other words, in these developments customers are captive to the central heating system. Central Heat, on the other hand, operates its steam district energy system in the same geographic area in downtown Vancouver as BC Hydro (electricity) and FEI (natural gas). Building owners in downtown Vancouver are not obligated to obtain space heating from Central Heat, which must compete for the business. In this system there are limited barriers to entry or exit of customers as there are other heating options available. (AES Inquiry Report, p. 75) This comparison puts Central Heat in the higher risk category.

When viewed through a different lens, Central Heat is a mature, established utility which has functioned well in Vancouver as a hybrid, a "competitive natural monopoly," and found its niche next to the electric and natural gas utilities. Yet, the Panel notes that this mature utility continues to operate without any deferral accounts, unlike its other mature counterparts, and that its bank requires an equity component of approximately 50 percent to qualify for debt financing. Central Heat also acknowledged that hybrid energy systems have become both more popular and more practical to develop, and Central Heat itself has been involved in some conversions recently in a shift to using cleaner energy sources. Central Heat may very well find itself in transition and start on the path of conversion towards a low-carbon energy utility. Central Heat described how the public and various levels of government have become more interested in different energy systems recently. This in turn may result in government incentives, new policies, and increased competition from traditional utilities. (Exhibit B-17, pp. 18-19)

Based on the above discussion, which highlights reasons for Central Heat being either of lower or higher risk than the default standard, the Panel finds it cannot at this point in Central Heat's state of transition rationalize any other cost of capital than that resulting from the default standard. Once Central Heat has developed its business plan and timeline for the conversion, it is in a better position to adequately justify its cost of capital in terms of the risk profile on a go-forward basis. **Accordingly, for the time being, the common equity ratio shall be set at 42.5 percent and the equity risk premium at 75 bps as transitional amounts. The Commission Panel directs Central Heat to file within next 12 months either a 2016 or multi-year revenue requirement application with the Commission reflecting the new business plan with a comprehensive justification for the equity thickness and equity risk premium.**

3.4.3.4 River District Energy Limited Partnership

RDE is a district energy utility established to provide thermal energy for space heating and domestic hot water to the River District development in southeast Vancouver.[14] River District is under construction now and, at build-out in approximately 20 years, will contain 7.0 million square feet of residential and 0.5 million square feet of retail/commercial density. The development is to include approximately 60 separate legal parcels in the 130 acre site, each of which may include one or more air space parcels owned by separate stratas. To date, the RDE system consists of a temporary gas fired boiler, distribution piping system and one energy transfer station.

RDE is 100 percent funded by its parent Wesgroup Properties Limited Partnership. RDE will make application for financing in several years when it has positive cash flow to service the debt. (Exhibit B-17, p. 29) RDE currently has an allowed equity risk premium of 50 bps and a deemed equity thickness of 40 percent. Customer rates are set by benchmarking against other TES utilities in the region (Exhibit B2-17, p. 31).

The customer rates were set using a levelized approach which helps to mitigate the impact on the initial customers of the large capital outlay required to develop district energy systems by deferring the utility's cost recovery until future years (Exhibit B2-22 BCPSO 1.2). Based on the Companies' proposed cost of capital, the levelized rate would increase by approximately 5 percent at RDE. The Companies believe that the Commission should let the terms of existing's contract determine any recourse the parties have in the event the Commission changes the cost of capital. (Exhibit B2-18, BCUC 4.5-4.6)

[14] C-14-11-River District Energy Limited Partnership Application for a Certificate of Public Convenience and Necessity to Construct and Operate a District Energy System for the River District Energy System for the River District Development in Southeast Vancouver and Approval of the Proposed Revenue Requirement, Rate Design, Levelized Rates and Revenue Deficiency Deferral Account for the First Five Years of Operations, December 19, 2011.

According to the Companies, the non-empirical risk factors' assessment for RDE is as follows:

- Competition risk – Low
  - Zoning requires mandatory connection but does not preclude discrete building-specific alternatives.
- Customer Load risk – High
  - Customer Load risk is a function of the amount of energy used, which is influenced by occupant behaviour, construction practices and increasingly stringent energy use standards imposed by third parties; and timing which is determined by highly cyclical real estate market.
- Development Cost risk – High
  - Application of technology new to the region and few experienced contractors and suppliers, especially for alternative energy sources.
- Operating Cost risk – Medium
  - Appreciably less operating experience for TES generally than for Benchmark. Cost of fuel risk higher for alternative energy sources.
- Rate Design risk – Low
  - Similar to Benchmark
- Regulatory risk – Medium
  - Evolving market.

(Exhibit B2-18 BCUC 8.1)

Commission Determination

The Commission Panel has already determined the minimum default capital structure and default equity rate premium for KDES and UniverCity. **Similarly, and for consistency, the Commission Panel determines that the common equity ratio for RDE shall be set 42.5 percent and the equity risk premium at 75 bps.**

4.0 OTHER ISSUES

4.1 Stage 2 Cost of Capital Changes – Effective Period

On December 10, 2012, the Commission issued Order G-187-12 and directed the then current ROE and capital structure for FEI, the designated Benchmark as interim effective January 1, 2013. The same order also directed that the then current ROE and capital structure for all regulated entities, in BC that rely on the Benchmark to establish rates were to be made interim, also effective January 1, 2013. This did not apply to British Columbia Hydro and Power Authority.

The Stage 1 Decision and the accompanying Order G-75-13, issued on May 10, 2013, set the common equity component for FEI at 38.5 percent and the ROE at 8.75 percent. The Decision accompanying Order G-75-13 also states that the ROE will be effective until December 31, 2015, subject to variation commencing January 1, 2014, by the Automatic Adjustment Mechanism formula. As a result, the rates for FEI ceased to be interim and permanent rates were approved. Commission Letter L-1-14 issued on January 10, 2014, advises all parties that the Benchmark ROE for 2014 remains at 8.75 percent and that the appropriate ROE in 2014 for individual utilities will incorporate the risk premium for each utility relative to the Benchmark ROE.

Commission Letter L-31-13A issued on June 5, 2013, clarifies for all Parties that the rates for the other regulated utilities that depend on the Benchmark for rate setting will remain interim until a decision is rendered for GCOC Stage 2.

Commission Panel Determinations

In accordance with previous communications, the Commission Panel orders that interim rates be recalculated to include the effect of cost of capital determinations in the Stage 2 proceeding. New permanent rates are to be effective January 1, 2013.

FEVI, FEW and FBC and the PNG-West, PNG (N.E.)-FSJ/DC and PNG (N.E.)-TR are to each file within 40 days of this Decision and accompanying Order G-47-14: (a) a document setting out how and when it will implement the change to its capital structure; and (b) amended rate schedules in accordance to the cost of equity for each utility as determined in this Decision; and (c) a proposal on the treatment of the difference between the interim rates being charged to customers and the permanent rates established by this Order.

Central Heat is directed to inform all its customers that this Decision and accompanying Order G-47-14 approves new permanent rate increases effective January 1, 2013. Central Heat is to file within 40 days of this Decision and accompanying Order G-47-14: (a) a document setting out how and when it will implement the change to its capital structure; (b) a permanent Steam Tariff Schedule of Charges to reflect the changes as a result of this Decision and accompanying Order in a timely manner; and (c) a proposal on the treatment of the difference between the interim rates being charged to customers and the permanent rates established by this Order.

KDES, DGE, UniverCity, and RDE are directed to file with the Commission, within 40 days of this Decision and accompanying Order G-47-14, a document setting out: (a) if it would implement the minimum default capital structure and equity risk premium for rate setting, and if so, the time line; (b) whether it would let the existing contractual customer rates, if applicable, to take its course and if not, its proposed treatment of the difference between the current rates being charged to customers and the allowed rates as ordered in this Decision.

4.2 Impact of Amalgamation Reconsideration

FEVI and FEW, together with FortisBC Energy Inc. and FortisBC Energy Inc. Fort Nelson Service Area (collectively, the FortisBC Energy Utilities) and Terasen Gas Holdings Inc. made an application to the Commission on April 11, 2012, for their amalgamation into a single entity. After considering the matter, the Commission issued Order G-26-13 on February 15, 2013, in which it “declines to find that amalgamation of the FEU and Terasen Gas Holdings Inc. is beneficial in the public interest." In the accompanying Reasons for Decision, the Commission dismissed the amalgamation application. On April 26, 2013, FortisBC Energy Utilities made application to the Commission to reconsider the matter. By Order G-21-14 and accompanying Amalgamation Reconsideration Decision issued on February 26, 2014, the Commission determined that approval of amalgamation is warranted and approved the amalgamation of FEI,FEVI, FEW and Terasen Gas Holdings and the Fortis Energy Utilities proposal to adopt common rates on a three year phase-in basis for natural gas delivery in their service areas. The service area of Fort Nelson was excluded. This is to be effective upon confirmation that consent of the Lieutenant Governor in Council, by order, to the amalgamation has been received and the amalgamation has been effected.

In the view of the Commission Panel, the creation of a new entity does not necessarily mean that it would be a sum of the parts from the perspective of the cost of capital. For example, it is not unreasonable to assume that risk factors and the ability to raise capital might be affected and significantly alter cost of capital considerations. This point was raised by the Commission in the Amalgamation Reconsideration Decision. In considering the evidence in that hearing with respect to cost of capital in that proceeding, the Commission made the following recommendation:

> "**The Commission Panel finds that a final determination as to the appropriate ROE and capital structure for the amalgamated entity must be deferred to the Generic Cost of Capital Proceeding.**
>
> However, from the evidence and submissions filed in this Proceeding, the Commission Panel would recommend that the capital structure and ROE remain the same for the amalgamated entity as for FEI, as the low risk benchmark utility. In this Panel's view, the major benefit to the shareholder of the approval for the FEU to amalgamate and adopt postage stamp rates is a reduction in the risk faced by the two smaller utilities. The Panel does not see this risk as being transferred to the larger amalgamated entity. Rather, in this Panel's view, the risks attributable to the small size and small customer bases of FEW and FEVI combined with their higher rates, as highlighted in this Application, will be eliminated as these utilities are subsumed into a single, larger entity."

Commission Determination

The Commission Panel notes that evidence in this proceeding has treated FEI, FEVI and FEW as separate entities and does not contemplate the potential impact of an amalgamated entity. Therefore, there is no firm basis on which to make a determination with respect to the amalgamated entity once amalgamation has been effected. **In these circumstances, the Commission Panel determines that the most appropriate approach to the cost of capital is to apply the recommendation in the Amalgamation Reconsideration Decision for the same reasons found at page 30 of that Decision. Accordingly, once amalgamation has been effected and postage stamp rates implemented, the ROE and capital structure will be the same for the amalgamated entity as for FEI as the Benchmark utility. In the alternative, if FBCU considers the cost of capital for the amalgamated entity is not indicative of current circumstances, it may apply to the Commission on behalf of the amalgamated entity.**

4.3 Role of Commission Staff

In their Final Submissions, the Companies expressed concern with the nature and tone of Commission staff IRs with respect to its evidence. Their concern relates to the line of questioning and implied support for a particular position. The Companies state the following:

> "In this proceeding, it has been clear from the nature and tone of the information requests that the Commission Staff support a position that is distinct from any other registered participant. Since the Commission Staff have not filed evidence or argument to explain and support their position, it would be unfair for the Commission to give weight to that position. Otherwise, the Companies must attempt to respond to a position that is both influential and unknown.
>
> Any party that wishes to advocate a position should be obliged to explain and support it on the record so it can be tested and debated by others. This approach would meet the test of procedural fairness and would give the Commission a better record upon which to base its decision."
>
> (the Companies Final Submission, p. 7)

In making their assertions the Companies have not been specific with regards to those IRs that support this conclusion nor have they specified the position that they believe that Commission staff has taken. Lacking the specific examples to support the Companies' assertions, the Commission Panel is unable to respond directly to this matter. The Panel would like to point out that had these concerns been raised earlier in this proceeding, there would have been an opportunity to explore the Companies' allegations more completely.

It is a fundamental principle of natural justice that in administrative proceedings the parties are entitled to know the case they have to meet. The purpose of the IR process is to afford the opportunity for the case to be known and test the evidence. Without this valuable question and answer process a Commission Panel would be forced to make a decision on a less than fulsome evidentiary record. This would not serve the decision making process nor would it be in the public interest. The role of Commission staff is to utilize the IR process to test the evidence fully and provide the Commission Panel a fulsome record upon which to make its determinations and decisions.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of March 2014.

Original signed by:

____

D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

____

L.A. O'HARA
COMMISSIONER

Original signed by:

____

C. VAN WERMESKERKEN
COMMISSIONER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Generic Cost of Capital Proceeding
Stage 2

BEFORE: D.A. Cote, Commissioner/Panel Chair
L.A. O'Hara, Commissioner
C. van Wermeskerken, Commissioner

March 25, 2014

O R D E R

WHEREAS:

A. By Order G-20-12 dated February 28, 2012, the British Columbia Utilities Commission (Commission) established a Generic Cost of Capital (GCOC) proceeding to review: (a) the setting of the appropriate cost of capital for a benchmark low-risk utility; (b) the possible return to a Return on Equity Automatic Adjustment Mechanism (ROE AAM) for setting an ROE for the benchmark low-risk utility; and (c) the establishment of a deemed capital structure and deemed cost of capital methodology, particularly for those utilities without third-party debt. The Order also divided all participating public utilities regulated by the Commission into Affected Utilities and Other Utilities for the purpose of the GCOC proceeding;

B. By Order G-148-12 dated October 11, 2012, the Commission determined, among other matters, that: (a) the GCOC proceeding would proceed by way of an oral public hearing commencing December 12, 2012; (b) FortisBC Energy Inc. (FEI) in its pre-amalgamation state would serve as the benchmark utility; and (c) a Stage 2 would be added to the proceeding for the purpose of reviewing all other utilities against the benchmark;

C. A Procedural Conference for Stage 2 was held on April 25, 2013. The following utilities appeared and made submissions at the Procedural Conference: FortisBC Utilities (FBCU) comprising FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW), and FortisBC Inc. (FBC); Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively, PNG); FortisBC Alternative Energy Services Inc. (FAES); Corix Multi-Utility Services Inc. (Corix); River District Energy Limited Partnership (RDE); and Central Heat Distribution Limited (Central Heat);

D. The Industrial Customers Group of FBC (ICG) and the British Columbia Pensioners' and Seniors' Organization *et al*. (BCPSO) also appeared and made submissions at the Procedural Conference;

E. On May 10, 2013 the Commission issued Order G-75-13 and the accompanying Decision on Stage 1;

F. By Order G-77-13 dated May 13, 2013, the Commission determined that the Stage 2 review would take place by way of a written hearing for all applicant utilities, in accordance with the three Groupings of Utilities and the Regulatory Timetable that form Attachments 1 and 2 respectively to Appendix A of Order G-77-13. The Regulatory Timetable provided for the filing of evidence by the utilities, two rounds of Information Requests (IRs) on that evidence, the filing of Intervener evidence, and one round of Information Requests on that evidence. Order G-77-13 also deferred the decision on the review format for FBC until the Commission Panel had reviewed FBC's Stage 2 evidence;

G. The following utilities filed evidence: FEVI and FEW (jointly), Corix, RDE and Central Heat (jointly), FBC, PNG, and FAES. ICG filed Intervener Evidence;

H. By Order G-121-13 dated August 14, 2013, the Commission determined that the review of FBC would take place in a written hearing format in accordance with the Regulatory Timetable that forms Attachment 2 to Appendix A of Order G-77-13;

I. The following utilities filed Final Submissions: FEVI and FEW (jointly), Corix, RDE and Central Heat (jointly) FBC, PNG, and FAES ;

J. The following Interveners filed Final Submissions: ICG and BCPSO. BCPSO filed four separate Final Submissions: one for FortisBC; a second for FEVI and FEW; a third for PNG; and a fourth for the Group 3 Utilities;

K. FEVI and FEW (jointly), Corix, RDE and Central Heat (jointly) FBC, PNG, and FAES all filed Reply; and

L. The Commission has considered the evidence and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The common equity component of the capital structure and equity risk premium over the Benchmark for the following FBCU, effective January 1, 2013 are:

	Common Equity Component (%)	Equity Risk Premium (bps)
FEVI	41.5	50
FEW	41.5	75
FBC	40.0	40

2. The common equity component of the capital structure and equity risk premium over the Benchmark for the following PNG utilities, effective January 1, 2013 are:

	Common Equity Component (%)	Equity Risk Premium (bps)
PNG-West	46.5	75
PNG (N.E.) FSJ/DC	41.0	50
PNG (N.E.) TR	46.5	75

3. The common equity component for small TES utilities, effective January 1, 2013, is a minimum default capital structure consisting of 57.5 percent debt and 42.5 percent common equity. The minimum default risk premium over the Benchmark is 75 bps except for Dockside Green Energy Inc. where its existing 100 bps equity risk premium will not be reduced as a result of establishing the minimum default Equity Risk Premium. The minimum default capital structure and equity risk premium allowed for Central Heat is transitional until a decision on its next revenue requirement application.

	Common Equity Component (%)	Equity Risk Premium (bps)
Kelowna District Energy System	42.5	75
Dockside Green Energy Inc.	42.5	100
Univercity at Burnaby Mountain	42.5	75
Central Heat Distribution Limited	42.5	75
River District Energy Limited Partnership	42.5	75

4. FEVI, FEW, FBC and the PNG-West, PNG (N.E.)-FSJ/DC and PNG (N.E.)-TR are to each file, within 40 days of the date of this Order, a document setting out:

   a) How and when it will implement the change to its capital structure;

b) Amended rate schedules in accordance to the cost of equity for each utility as determined in the Decision issued concurrently with this Order; and

c) A proposal on the treatment of the difference between the interim rates being charged to customers and the permanent rates established by this Order.

5. Central Heat is directed to file, within 40 days of the date of this Order, a document setting out:

   a) How and when it will implement the change to its capital structure; and

   b) A permanent Steam Tariff Schedule of charges that reflects the changes to the cost of equity as determined in the Decision issued concurrently with this Order;

   c) A proposal on the treatment of the difference between the interim rates being charged to customers and the permanent rates established by this Order.

6. The Kelowna District Energy System, Dockside Green Energy Inc. UniverCity and River District Energy Limited Partnership are each to file, within 40 days of the date of this Order, a document setting out:

   a) Whether they would implement the minimum default capital structure and equity risk premium for rate setting, and if so, the time line; or

   b) Whether they would let the existing contractual customer rates, if applicable, take their course, and if not, their proposed treatment of the difference between the current rates being charged to the customers and the allowed rates as determined by this Order.

7. Each utility is to comply with all other applicable directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of March 2014.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

Attachment

Exhibit Number	Commission Order (Date)	Determinations
A-30 (Stage 1)	G-187-12 (December 10, 2012)	• Issued Interim Order establishing current ROE and capital structure for the benchmark utility and all regulated entities in B.C. that rely on the benchmark utility as interim, effective January 1, 2013
A-35	G-77-13 (May 13, 2013)	• Utilities divided into three Groups : Group 1-FortisBC Utilities; Group 2 - PNG Utilities; Group 3 – Small utilities engaged in thermal energy services • Issued Regulatory Timetable • Stage 1 record to form part of the Stage 2 record • Costs allocation principles for PACA
A-42	G-121-13 (August 14, 2013)	• Determined the review of FortisBC Inc. (FBC) to proceed by way of a written hearing in accordance with the Regulatory Timetable that is Attachment 2 to Appendix A of Order G-77-1

LIST OF ABBREVIATIONS AND ACRONYMS

Abbreviations and Acronyms	Descriptions
AAM	Automatic Adjustment Mechanism
Act, UCA	Utilities Commission Act
AES Report	Report on the Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives
BC Hydro	British Columbia Hydro and Power Authority
BCPSO	British Columbia Pensioners' and Seniors' Organization et al.
BCUC, the Commission	British Columbia Utilities Commission
bps	Basis Points
CAPM	Capital Asset Pricing Model
CCAA	Companies' Creditors Arrangement Act
Celgar	Zellstoff Celgar
Central Heat	Central Heating Distribution Limited
CNRL	Canadian National Resources Limited
Corix	Corix Utilities Inc.
CPCN	Certificate of Public Convenience and Necessity
D&P	Duff &Phelps
DBRS	Dominion Bond Rating Services
DC	Dawson Creek
DGELLP, DGE	Dockside Green Energy Inc.
ERP	Equity Risk Premium

FAES	FortisBC Alternative Energy Services Inc.
FBC	FortisBC Inc.
FBCU, FortisBC Utilities	Collective term for FEI, FEVI, FEW and FBC
FEI	FortisBC Energy Inc.
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FSJ	Fort Saint John
GCOC	Generic Cost of Capital
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GWh	Gigawatt hour
ICG	Industrial Customers Group of FortisBC Inc.
IRs	Information Requests
KDES	Kelowna District Energy System
LNG	Liquefied Natural Gas
Moody’s	Moody’s Investor Services
MW	Megawatt
OATT	Open Access Transmission Tariff
PBR	Performance Based Ratemaking
PCB	Polychlorinated biphenyls
PEC	Pacific Energy Corporation
PNG	Pacific Northern Gas
PNG (N.E.) FSJ, DC, TR	Pacific Northern Gas (North East) Fort St. John, Dawson Creek, Tumbler Ridge divisions

PPA	Power Purchase Agreement
RCA	Retirement Compensation Arrangement
RDE	River District Energy Limited Partnership
ROE	Return on Equity
RRA	Revenue Requirement Application
RSDA	Revenue Surplus Deferral Account
SBBI	MorningStar/Ibbotson Study on Stocks, Bonds, Bills and Inflation
TES	Thermal Energy Services
TGI	Terasen Gas Inc.
TGVI	Terasen Gas (Vancouver Island) Inc.
TGW	Terasen Gas (Whistler) Inc.
TJ	Terajoule
TR	Tumble Ridge
UniverCity	UniverCity at Burnaby Mountain
UPC	Use per Customer
VIGJV	Vancouver Island Gas Joint Venture
WAX	Waneta Expansion
WAX CAPA	WAX Capacity Exchange

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

British Columbia Utilities Commission
Generic Cost of Capital Proceeding (GCOC) Stage 2

EXHIBIT LIST

EXHIBIT NO.	DESCRIPTION
COMMISSION DOCUMENTS	
	STAGE 2
A-32	Letter dated March 22, 2013 – Stage 2 Procedural Conference
A-33	Letter dated April 3, 2013 – Procedural Conference List of Issues
A-34	Letter dated April 11, 2013 – Appointment of Panel Stage 2
A-35	Letter dated May 13, 2013 – Commission Order G-77-13 with Reasons for Decision, Grouping of Utilities, and Regulatory Timetable
A-36	Letter dated July 16, 2013 – Commissioner Mike Harle Withdrawal from Panel
A-37	Letter dated July 30, 2013 – Commission Staff Information Request No. 1 to FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.
A-38	Letter dated July 30, 2013 – Commission Staff Information Request No. 1 to FortisBC Inc.
A-39	Letter dated July 30, 2013 – Commission Staff Information request No. 1 to FortisBC Alternative Energy Services Inc.
A-40	Letter dated July 30, 2013 – Commission Staff Information Request No. 1 to the Companies
A-41	Letter dated August 6, 2013 – Commission Staff Information Request No. 1 to PNG

A-42	Letter dated August 14, 2013 – Commission Order G-121-13 with Reason for Decision
A-43	Letter dated August 19, 2013 – Request for comments – Information Request No. 2 to Group 3 Utilities
A-44	Letter dated August 27, 2013 – Commission Staff Information Request No. 2 to FortisBC Alternative Energy Services Inc.
A-45	Letter dated August 27, 2013 – Commission Staff Information Request No. 2 to FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.
A-46	Letter dated August 27, 2013 – Commission Staff Information Request No. 2 to FortisBC Inc.
A-47	Letter dated August 27, 2013 – Commission Staff Information Request No. 2 to the Companies
A-48	Letter dated September 3, 2013 – Commission Staff Information Request No. 2 to PNG
A-49	Letter dated October 22, 2013 – Commission Information Request No. 1 to ICG on the Intervener Evidence
A-50	Letter dated February 21, 2014 – Letter to FAES Request for Clarification

COMMISSION STAFF DOCUMENTS

A2-52	Letter dated July 30, 2013 - Commission Staff filing City of North Vancouver-Lonsdale-Energy – How LEC Rates are Calculated
A2-53	Letter dated July 30, 2013 - Commission Staff filing Statistics Canada-Study on Firm Dynamics
A2-54	Letter dated July 30, 2013 - Commission Staff filing BC Statistics Business Indicators – Manufacturing – June 26, 2013
A2-55	Letter dated July 30, 2013 - Commission Staff filing BC Statistics Industrial Employment – July 5, 2013

A2-56 Letter dated July 30, 2013 – Commission Staff filing Canadian Press Article – Interest Rates

A2-57 Letter dated July 30, 2013 – Commission Staff filing CKNW Article – Hydro rate increase coming within six months

A2-58 Letter dated August 27, 2013 – Commission Staff filing Sampson Research Inc.-2008 Residential End Use Study

A2-59 Letter dated August 27, 2013 – Commission Staff filing Moody's Regulated Utility Methodology

AFFECTED UTILITIES DOCUMENTS

B1-69 **BC UTILITIES OF FORTIS INC. COMPRISED OF FORTISBC ENERGY INC., FORTISBC ENERGY VANCOUVER ISLAND INC., FORTISBC ENERGY WHISTLER INC. AND FORTISBC INC. (FBCU)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B1-70 Letter dated April 24, 2013 – FBCU submission on Proposed Regulatory Timetable

B1-71 Letter dated July 9, 2013 –FEVI and FEW Submitting Evidence

B1-71-1 Letter dated August 15, 2013 – FEVI and FEW Submitting Revised Evidence

B1-72 Letter dated July 9, 2013 – FortisBC Inc. Submitting Evidence

B1-73 Letter dated August 13, 2013 – FortisBC Inc. Response to BCUC IR No. 1

B1-74 Letter dated August 13, 2013 – FortisBC Inc. Response to BCPSO IR No. 1

B1-75 Letter dated August 13, 2013 – FortisBC Inc. Response to ICG IR No. 1

B1-76 Letter dated August 13, 2013 – FEVI FEW Response to BCUC IR No. 1

B1-77 Letter dated August 13, 2013 – FEVI FEW Response to BCPSO IR No. 1

B1-78 Letter dated September 17, 2013 - FEVI-FEW Response to BCPSO IR No. 2

B1-79 Letter dated September 17, 2013 - FEVI-FEW Response to BCUC IR No. 2

B1-80 Letter dated September 17, 2013 - FortisBC Inc. Response to BCPSO IR No. 2

B1-81 Letter dated September 17, 2013 - FortisBC Inc. Response to BCUC IR No. 2

B1-81-1 **CONFIDENTIAL** Letter dated September 17, 2013 - FortisBC Inc. Confidential Response to BCUC IR No. 2.35.1

B1-82 Letter dated September 17, 2013 - FortisBC Inc. Response to ICG IR No. 2

B1-82-1 **CONFIDENTIAL** Letter dated September 17, 2013 - FortisBC Inc. Confidential Response to ICG IR No. 2

B1-82-2 **CONFIDENTIAL** Letter dated September 26, 2013 - FortisBC Inc. Confidential Response to ICG IR No. 2 Attachment 3(d) Additional Information

B1-83 Letter dated October 22, 2013 – FortisBC Inc. Information Request No. 1 to ICG on the Intervener Evidence

B1-84 Letter dated November 19, 2013 - FortisBC Inc. Rebuttal Evidence

B2-16 **CORIX MULTI-UTILITY SERVICES INC. (CORIX)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B2-17 Letter dated July 10, 2013 –Submission of Evidence On Behalf of Corix, Central Heat and River District Energy

B2-17-1 Letter dated July 10, 2013 –Submission of Additional Evidence On Behalf of Corix, Central Heat and River District Energy

B2-18 Letter dated August 13, 2013 – On Behalf of Corix, Central Heat and River District Energy Responses to BCUC IR No. 1

B2-19 Letter dated August 14, 2013 – On Behalf of Corix, Central Heat and River District Energy Responses to BCPSO IR No. 1

B2-20 Letter dated August 15, 2013 – On Behalf of Corix, Central Heat and River District Energy Responses additional filings related to evidence and IR No. 1 responses

B2-21 Letter dated August 20, 2013 – On Behalf of Corix, Central Heat and River District Energy Submitting Comment

B2-22 Letter dated September 17, 2013 – On Behalf of Corix, Central Heat and River District Energy Response to BCPSO IR No. 2

B2-23 Letter dated September 17, 2013 – On Behalf of Corix, Central Heat and River District Energy Response to BCUC IR No. 2

B3-13 **PACIFIC NORTHERN GAS LTD. AND PACIFIC NORTHERN GAS N.E. LTD. (PNG)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B3-14 Letter dated July 9, 2013 – PNG Submitting Evidence

B3-15 Letter dated August 20, 2013 – PNG Response to BCUC IR No. 1

B3-16 Letter dated August 20, 2013 – PNG Response to BCPSO IR No. 1

B3-16-1 Letter dated December 3, 2013 - PNG Revised Response to BCUC IR No. 1.10.2

B3-17 Letter dated September 24, 2013 – PNG Response to BCUC IR No. 2

B3-18 Letter dated September 24, 2013 – PNG Response to BCPSO IR No. 2

B4-9 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Letter dated April 9, 2013 – Registration for Stage 2 and comments regarding Procedural Conference attendance

B5-2 **RIVER DISTRICT ENERGY (RDE)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B6-1 **FORTISBC ALTERNATIVE ENERGY SERVICES INC. (FAES)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B6-2 Letter dated July 9, 2013 – FAES Submitting Evidence

B6-3 Letter dated August 13, 2013 – FAES Submitting notice of delay - responses to BCUC IR No. 1

B6-3-1 Letter dated August 14, 2013 – FAES Response to BCUC IR No. 1

B6-4 Letter dated August 20, 2013 – FAES Submitting Comments

B6-5 Letter dated September 17, 2013 - FAES Response to BCUC IR No. 2

B6-6 Letter dated February 27, 2014 – FAES Submissions response to Exhibit A-50

B7-1 **DOCKSIDE GREEN ENERGY (DGE)** Letter dated April 11, 2013 – Registration for Stage 2 and confirmation of intention to appear at Procedural Conference

B8-1 **CENTRAL HEAT DISTRIBUTION LTD. (CENTRAL HEAT)** Letter Dated April 5, 2013 – Registration for Stage 2 by John Barnes

INTERVENER DOCUMENTS

C4-18 **INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated April 11, 2013 – Registration for Stage 2

C4-19 Letter dated April 18, 2013 – ICG submitting Notice of Appearance

C4-20 Letter dated July 30, 2013 – ICG submitting Information Request to FBC

C4-21 Letter dated August 27, 2013 – ICG submitting Information Request No. 2 to FBC

C4-22 Letter dated October 1, 2013 – ICG submitting Evidence

C4-23 Letter dated November 5, 2013 - ICG submitting Response to BCUC IR No. 1

C4-24 Letter dated November 5, 2013 - ICG submitting Response to FBC IR No. 1

C5-16 **BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION (BCPSO ET AL)** Letter dated April 11, 2013 – Registration for Stage 2

C5-17 Letter dated April 16, 2013 – BCPSO submitting comments regarding registration

C5-18 Letter dated April 18, 2013 – BCPSO submitting Notice of Appearance

C5-19 Letter dated July 30, 2013 – BCPSO submitting IR No. 1 to FBC

C5-20 Letter dated July 30, 2013 – BCPSO submitting IR No. 1 to FEU

C5-21 Letter dated July 30, 2013 – BCPSO submitting IR No. 1 to Corix, Central Heat and RDE

C5-22 Letter dated August 6, 2013 – BCPSO Information Request No. 1 to PNG

C5-23 Letter dated August 20, 2013 – BCPSO Submitting Comments

C5-24 Letter dated August 27, 2013 – BCPSO Submitting Information Request No. 2 to FBC

C5-25 Letter dated August 27, 2013 – BCPSO Submitting Information Request No. 2 to Corix et al

C5-26 Letter dated August 27, 2013 – BCPSO Submitting Information Request No. 2 to FEW and FEVI

C5-27 Letter dated September 3, 2013 – BCPSO Information Request No. 2 to PNG

C8-1 **CENTRAL HEAT DISTRIBUTION LTD. (CENTRAL HEAT)** Letter Dated April 5, 2013 – Changed to Affected Utility B8.

Alberta

Alberta Utilities Commission 2013 Generic Cost of Capital Decision
March 23, 2015

Decision **2191-D01-2015**

Alberta Utilities Commission

100 YEARS of service to Alberta 1915 2015

2013 Generic Cost of Capital

March 23, 2015

Alberta Utilities Commission
Decision 2191-D01-2015
2013 Generic Cost of Capital
Proceeding 2191
Application 1608918-1

March 23, 2015

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Telephone: 403-592-8845
Fax: 403-592-4406

Website: www.auc.ab.ca

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Alberta Utilities Commission
Calgary, Alberta

Decision 2191-D01-2015
Proceeding 2191
2013 Generic Cost of Capital **Application 1608918-1**

1 Introduction

1. On October 18, 2012, the Commission initiated Proceeding 2191, the 2013 Generic Cost of Capital (GCOC) proceeding, by way of a letter requesting comments from interested parties on the scope of the GCOC proceeding. This decision sets out the approved return on equity (ROE) for all affected utilities for the years 2013, 2014, and 2015. This decision also sets out individual deemed equity ratios (also referred to as capital structure) for each affected utility.

2. The affected utilities are:

- AltaGas Utilities Inc. (natural gas distribution)
- AltaLink Management Ltd. (electricity transmission)
- ATCO Electric Ltd. (electricity distribution and transmission)
- ATCO Gas (natural gas distribution)
- ATCO Pipelines (natural gas transmission)
- ENMAX Power Corporation (electricity distribution and transmission)
- EPCOR Distribution & Transmission Inc. (electricity distribution and transmission)
- FortisAlberta Inc. (electricity distribution)
- TransAlta Corporation (transmission assets)

3. In addition to the utilities listed above, there are other utilities under the Commission's jurisdiction that could be affected by this decision, and which were provided an opportunity to participate in this proceeding. These utilities include:

- EPCOR Energy Alberta GP Inc. (regulated retail electricity operations)
- ENMAX Energy Corporation (regulated retail electricity operations)
- Direct Energy Regulated Services (regulated retail electricity and gas operations)
- City of Lethbridge (electricity distribution and transmission)
- City of Red Deer (electricity distribution and transmission)
- Various investor-owned water utilities regulated by the Commission

4. None of these other utilities actively participated in the proceeding. The ROE and debt to equity ratios prescribed in this decision do not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because they are regulated pursuant to the *Electric Utilities Act Regulated Rate Option Regulation*[1] and the *Gas Utilities Act Default Gas Supply Regulation*,[2] respectively. These statutory instruments prescribe methods for the determination of reasonable returns for regulated rate option (RRO) and default supply (DS)

[1] Alberta Regulation 262/2005.
[2] Alberta Regulation 184/2003.

providers, respectively, which address concerns relating to the development and maintenance of competitive retail energy markets in Alberta, and which flow from the implementation of terms and conditions of service applicable to those utilities.

5. The ROE established in this decision will apply to the City of Lethbridge Transmission, the City of Red Deer Transmission and to the revenue requirement established for certain TransAlta Corporation's transmission assets. The Commission has also established target debt to equity ratios for each of these utilities. Specific ROEs and capital structures for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding because, in the normal course, the Commission only considers these utilities' operations in response to a complaint. However, the determinations made in this proceeding may be considered in any cost of capital determinations applicable to these utilities, should issues respecting the matters of ROE and capital structure arise for these utilities.

6. AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Utilities, ENMAX Power Corporation, EPCOR Utilities Inc. and FortisAlberta Inc., (collectively the Alberta Utilities) after registering individually, filed joint submissions during the proceeding. The remaining parties that were active in the proceeding were the Office of the Utilities Consumer Advocate (UCA), The City of Calgary (Calgary), the Consumers' Coalition of Alberta (CCA), the Canadian Association of Petroleum Producers (CAPP) and TransAlta Corporation (TransAlta).

2 Procedural summary

7. On September 12, 2012, the Commission issued Decision 2012-237[3] which approved the performance-based regulation (PBR) plans for the electric and natural gas distribution utilities: AltaGas Utilities Inc. (AltaGas), ATCO Electric Ltd. (ATCO Electric), ATCO Gas, EPCOR Distribution & Transmission Inc. (EDTI) and FortisAlberta Inc. (FortisAlberta). Decision 2012-237 indicated that any change to the risk profile of affected companies resulting from the onset of PBR would be considered by the Commission in the 2013 GCOC proceeding.[4]

8. On October 17, 2012, a procedural schedule was established for the Commission's generic Utility Asset Disposition (UAD) proceeding (Proceeding 20). The intention was to conclude the UAD proceeding prior to the commencement of the 2013 GCOC proceeding.

9. On October 18, 2012, the Commission issued a letter requesting comments from interested parties on the scope of the matters that should be considered in the GCOC proceeding.

10. On October 26, 2012, the Alberta Utilities submitted to the Commission that their GCOC evidence could not be prepared until final decisions were issued in the PBR Compliance Filings proceeding (Proceeding 2130), the 2013 Capital Tracker Applications proceeding (Proceeding 2131) and the UAD proceeding (Proceeding 20). The UCA supported the Alberta Utilities' submission in this regard. The Commission suspended the GCOC proceeding on November 9, 2012.

[3] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

[4] Decision 2012-237, paragraph 710.

11. On April 4, 2013, the Commission directed that the UAD proceeding would be suspended following submission of reply argument from the parties to that proceeding, which was due on June 3, 2013. In this letter, the Commission also resumed the GCOC proceeding, recognizing that the PBR compliance decision had been issued, the capital tracker proceeding was well underway, and because a limited GCOC-related proceeding had been contemplated to consider any UAD impacts that may result from determinations within the subsequently released UAD decision, if required.

12. In response to a submission from the Alberta Utilities filed on April 17, 2013, the Commission determined, by way of a letter dated April 23, 2013, that the decision in the UAD proceeding would be issued after the receipt of reply argument from parties to that proceeding, and without the need for additional GCOC process to finalize the ROE and capital structure. The Commission also confirmed that the established GCOC process schedule would allow three weeks from the release of the later of the Capital Tracker and UAD decisions for utilities to file their evidence in this proceeding.

13. On May 22, 2013, ENMAX Power Corporation and EDTI were granted two-week extensions for filing of their AUC Rule 005[5] filings. This resulted in a corresponding two-week extension of the GCOC process schedule.

14. By way of a letter dated July 15, 2013, the Commission issued the final issues list for the GCOC proceeding following its review and consideration of comments received from parties on June 14, 2013.

15. The UAD decision, Decision 2013-417,[6] and the 2013 Capital Tracker Applications decision, Decision 2013-435,[7] were issued on November 26, 2013 and December 6, 2013, respectively. In response to extension requests for submission of GCOC evidence from Calgary, the UCA and the Alberta Utilities, the Commission revised the GCOC process schedule on December 18, 2013 to provide for the filing of argument and reply argument on July 11, 2014 and August 1, 2014 respectively.

16. On December 19, 2013, the Commission issued Decision 2013-459[8] to establish an interim generic ROE of 8.75 per cent for 2014 and for each subsequent year thereafter until otherwise directed.

17. The GCOC proceeding oral hearing was conducted from May 26, 2014 to June 3, 2014 at the AUC's hearing room in Edmonton, Alberta. The Commission panel for this proceeding was Vice-Chair Mark Kolesar, Commission Member Bill Lyttle and Commission Member Tudor Beattie, QC.

18. During the course of the GCOC hearing, several parties made reference to what they perceived to be the potential significance of the Commission's upcoming decision in Proceeding 2682 on ATCO Electric's 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances application. These parties proposed that the Commission's decision in

5 Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
6 Decision 2013-417: Utility Asset Disposition, Proceeding, Application 1566373-1, November 26, 2013.
7 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.
8 Decision 2013-459: 2013 Generic Cost of Capital 2014 Interim Return on Equity, Proceeding 2191, Application 1608918-1, December 19, 2013.

Proceeding 2682 would inform its subsequent assessment of regulatory risk issues germane to the GCOC inquiry.

19. On June 20, 2014, the Commission issued a letter to participants in the GCOC proceeding that included an argument outline. The provided outline referenced the anticipated decision in Proceeding 2682.

20. On June 27, 2014, the Commission issued a letter to interested parties which directed parties to file their respective GCOC arguments and reply arguments by the previously established deadlines of July 11, 2014 and August 1, 2014 respectively, but to omit argument relating to the Commission's pending decision in Proceeding 2682. This correspondence confirmed that instructions would be communicated to the parties to the GCOC proceeding regarding the process for supplemental argument and reply argument, following the issuance of the decision in Proceeding 2682.

21. On October 29, 2014, the Commission issued Decision 2014-297,[9] which concluded Proceeding 2682. Accordingly, on October 30, 2014, the Commission established a supplemental process for submission of argument and reply argument related to Decision 2014-297 to facilitate the close of record for the GCOC proceeding. Supplemental argument and reply argument was subsequently received from parties in accordance with that process.

22. On January 25, 2015, the Commission issued Decision 3100-D01-2015,[10] which concluded proceedings 3100 and 3216, dealing with EDTI's 2013 Capital Tracker True-up Application and 2014-2015 Capital Tracker Forecast Application, respectively. Accordingly, on February 10, 2015, the Commission established a supplemental process for submission of argument and reply argument related to Decision 3100-D01-2015 to facilitate the close of record for the GCOC proceeding. Supplemental argument and reply argument was subsequently received from parties in accordance with that process.

23. Expert evidence was sponsored by a number of parties. The Alberta Utilities sponsored:

- Ms. Kathleen McShane, president and senior consultant with Foster Associates Inc. of Bethesda, Maryland
- Steven M. Fetter, president of Regulation UnFettered, Port Townsend, Washington
- Michael Sloan, principal and senior economist in ICF's Fuels and Technology Group

24. The UCA sponsored:

- Dr. Sean Cleary, Ph. D., Queen's University
- Mr. Russ Bell
- Mr. Mark P. Stauft

9 Decision 2014-297: ATCO Electric Ltd., 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 2682, Application 1609719-1, October 29, 2014.

10 Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565-1 and 1610362-1, January 25, 2015.

25. CAPP and Calgary individually sponsored:

- Dr. Laurence Booth, D.B.A., University of Toronto

26. Calgary also sponsored:

- Mr. Hugh W. Johnson

27. The Commission considers that the close of record for this proceeding was February 25, 2015, which is the date on which second supplemental reply argument was filed.

28. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

3 Overview of the Commission's approach to setting an allowed ROE and capital structure

29. In satisfying the fair return standard, the Commission is required to determine a fair ROE for the utilities under its jurisdiction. In previous GCOC decisions, including the 2011 GCOC Decision 2011-474,[11] the Commission established a generic ROE that uniformly applied to all of the affected utilities. In previous GCOC decisions, the Commission has historically accounted for the existence of particular business risks faced by utilities by making any adjustments to their respective capital structures on either a global, or individual, basis.[12] Such global and individual adjustments to capital structure have also been made concurrently. For example, in its 2009 GCOC decision, the Commission implemented a global two percentage point increase in the equity ratios of the affected utilities in order to account for generally elevated levels of risk and challenging credit market conditions arising from the 2008-2009 financial crisis, and other factors.[13]

30. Similarly, in this decision, the Commission approached setting an allowed ROE and equity structure with a view to providing recognition of changes in the overall levels of risk to which utilities have been exposed since the determination of the 2011 GCOC proceeding, including a consideration of impacts of any additional regulatory risk arising from its implementation of PBR for distribution utilities, its application of principles identified in the UAD decision, or both. The Commission also considers other potential risk factors identified by the Alberta Utilities for electric transmission utilities.

31. In determining a fair ROE for the utilities, the Commission begins, in Section 4, with an evaluation of changes in the global and Canadian financial environment since the conclusion of the 2011 GCOC proceeding. This review of the global and Canadian financial environment is a

[11] Decision 2011-474: 2011 Generic Cost of Capital, Proceeding 833, Application 1606549-1, December 8, 2011.
[12] See Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571-1, November 12, 2009 at paragraphs 77 and 78 and Decision 2011-474 at paragraph 2.
[13] Decision 2009-216, paragraph 411.

factor informing the Commission's subsequent determinations of a fair ROE and appropriate capital structures, as discussed in the relevant sections of this decision.

32. Consistent with the approach taken in previous GCOC decisions, the Commission establishes, in Section 5 of this decision, a generic ROE (or generic benchmark ROE), based on its consideration of conventional financial models such as the capital asset pricing model (CAPM), discounted cash flow (DCF) model, and others. The resultant generic benchmark ROE provides a starting point for the subsequent determination of a fair ROE for all affected utilities.

33. Having established the generic benchmark ROE, the Commission considers, in Section 6, the impact of any regulatory risk arising from the UAD decision. and the impact of any regulatory risk arising from the implementation of PBR for the affected distribution utilities. In the same section, the Commission also considers other potential risk factors identified by the Alberta Utilities for electric transmission utilities. Any requirement for adjustments to the generic benchmark ROE, capital structure, or both, are considered in that section.

34. Section 7 of the decision describes the Commission's assessment of the usefulness of an ROE automatic adjustment mechanism. In that section, the Commission also comments on the process to set an allowed ROE after 2015.

35. Capital structure matters are discussed in Section 8 of the decision. The Commission has determined deemed capital structures for each subject utility, which accounts for differences in risk among the individual companies. Approved capital structures of utilities may also be adjusted to account for any regulatory risk arising from the onset of PBR for distribution utilities, the Commission's application of UAD principles, changes in the overall levels of risk to which utilities have been exposed since the determination of the 2011 GCOC proceeding or a combination of these.

36. In this proceeding, the Commission sought parties' views on what ROE should apply on a final basis for 2013, 2014, and 2015, or whether a placeholder for 2015 should be established.[14] As discussed in Section 5.6, all parties in this proceeding put forward their recommendations on the final ROE value for 2015. The Commission is mindful that this decision is being issued in March 2015. Therefore, the Commission has determined that it will establish an ROE and capital structure on a final basis for 2013, 2014 and 2015 in this decision.

4 Relevant changes in global economic and Canadian capital market conditions since Decision 2011-474

37. All parties agreed that current global economic and Canadian capital market conditions have improved since the time of the 2011 GCOC proceeding resulting in Decision 2011-474. The parties, however, disagreed on the amount of risk remaining in capital markets.

38. The Alberta Utilities argued that despite declines since mid-2011, "systemic risks" remained higher than before the 2008-2009 financial crisis, whereas the other parties generally

[14] Exhibit 33.01, the Commission's letter with final issues list dated July 15, 2013.

contended that capital market conditions have stabilized, and that the financial pressures resulting from the 2008-2009 financial crisis have abated.[15]

39. Relying on Ms. McShane's evidence, the Alberta Utilities noted that long Canada bond yields are abnormally low, and submitted that this is not indicative of normal market conditions. They also highlighted the fact that high grade Canadian corporate bond spreads remain similar to those observed in mid-2011, which, in their view, indicates that credit risk has not been perceived to have declined. They further argued that, based on forward earnings/price ratios, the equity market risk premium does not appear to have changed materially since mid-2011.[16]

40. In her evidence, Ms. McShane cited reports by the Bank of Canada and the International Monetary Fund (IMF) to support her position that the risk of market disruptions remains elevated. The Bank of Canada's December 2013 Financial System Review identified a number of "significant vulnerabilities," which included risks stemming from the fragility of the euro-area financial system, Canada's high level of household debt, imbalances in some segments of the Canadian housing market, persistent low interest rates, and other risks from emerging markets.[17] The IMF report expressed similar concerns.[18]

41. Responding to the intervener experts' conclusions regarding the current perception of economic and financial stability, Ms. McShane cautioned that few experts actually predicted the sub-prime mortgage crisis in mid-2007 due to a perception of economic and financial stability that existed at that time.[19]

42. Based on the evidence of Dr. Cleary, the UCA submitted that growth in the Canadian gross domestic product (GDP) following the 2011 GCOC proceeding was lower than forecast because some of the potential risks identified in that proceeding had actually materialized, with the result that long Canada bond yields declined. The UCA also submitted, however, that A-rated utility yield spreads had remained stable since the 2011 GCOC proceeding, which, in conjunction with low long Canada bond yields, allowed A-rated utilities to borrow at declining costs. Despite acknowledging that this had been a challenging period, the UCA argued that the global economy was expected to grow in 2013 and improve significantly in 2014 as a result of recovery in the U.S. economy and modest growth in the Euro zone.[20] The UCA concluded that capital market conditions have stabilized, and the extreme financial pressures resulting from the 2008-2009 financial crisis have long since abated.

43. The UCA acknowledged that the Bank of Canada, in its December 2013 Financial System Review, had identified several key risks including high levels of consumer debt and inflated prices in the consumer housing market, continued uncertainty in the Euro zone, and stagnating export levels. The UCA argued that these risks, however, are not a "huge concern,"[21] nor "extremely elevated,"[22] and "do not appear to have been materially priced into the market."[23]

15 Exhibit 42.02, McShane evidence for Alberta Utilities, page 16.
16 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 16-28.
17 Exhibit 42.02, McShane evidence for Alberta Utilities, page 21, lines 546-567.
18 Exhibit 148.01, Alberta Utilities argument, pages 3-8.
19 Exhibit 148.01, Alberta Utilities argument, paragraph 6.
20 Exhibit 45.03, Cleary evidence for the UCA, pages 10-11.
21 Transcript, Volume 6, page 785, line 25 (Dr. Cleary).
22 Transcript, Volume 6, page 786, line 23 to page 787, line 1 (Dr. Cleary).
23 Exhibit 150.02, UCA argument, pages 1-6.

44. Dr. Booth was retained by both Calgary and CAPP to provide expert evidence regarding capital market conditions. Dr. Booth's evidence[24] [25] provided data concerning market and global conditions which, he argued, were consistent with traditional business cycles (e.g., the inflation rate had been lower than the T-bill rate during the first nine months of 2013). Dr. Booth also submitted that, although the yield spreads between both A and BBB-rated utility bonds and the government bond yield had widened since the previous generic cost of capital proceeding, this was the result of unusually low government bond yields and not attributable to utility bond yields being unusually high. Dr. Booth argued that current capital market conditions do not represent a "new normal," but rather, are indicative of a return to typical and expected economic conditions and business cycles, during a time period in which the U.S. Federal Reserve has eased back on monetary stimulus measures, and the U.S. economy continues to grow. Dr. Booth added that no Alberta utility has had problems raising capital. More specifically, in his assessment, Alberta utilities have been able to raise debt at very low rates for very long terms. As such, Dr. Booth argued there is no reason for the Commission to accept the Alberta Utilities' position that systemic risk is rising.[26]

45. In addressing the Bank of Canada report cited by Ms. McShane, CAPP argued that although the report determined that the overall risk of Canada's financial system remained "elevated," this is the second lowest of the four risk levels identified in the report. CAPP further added that the report indicated that this risk is decreasing.[27]

46. For its part, Calgary added that, despite the Alberta Utilities' argument that "unconventional monetary policy itself" is evidence of the persistence of abnormal economic conditions, no evidence has been provided by the Alberta Utilities that would suggest, for example, the Federal Reserve policy of quantitative easing was still directed at the financial crisis effects, as opposed to addressing normal cyclical economic conditions. Calgary argued that the Alberta Utilities are misattributing actions undertaken in prevailing economic conditions to events that occurred over five years ago. Calgary reiterated that, in its view, the central question is whether the Alberta Utilities have ready access to capital at reasonable rates. Based on its assessment of recent debt issuances undertaken by CU Inc., the parent of the ATCO utilities which issues debt on behalf of those utilities, Calgary argued that the Alberta Utilities are, in fact, currently able to raise debt for unprecedented terms at very low rates.

47. The CCA argued that there has been a significant improvement in global economic and capital market conditions since Decision 2011-474.[28] In response to the Alberta Utilities' observation that no one predicted the last crisis, the CCA replied that "whether anyone predicted the last crisis is largely irrelevant for several reasons. First, as Mr. Fetter pointed out, such one-time events are discounted by the rating agencies and, the CCA would argue, investors. Second, accepting for the moment that it was unpredicted, there is no basis to assume it will re-occur. Third, there is an assumption that if some event happens in the future it will be negative. However, booms typically follow busts as occurred in 2008 so if there is a bias to unpredictable

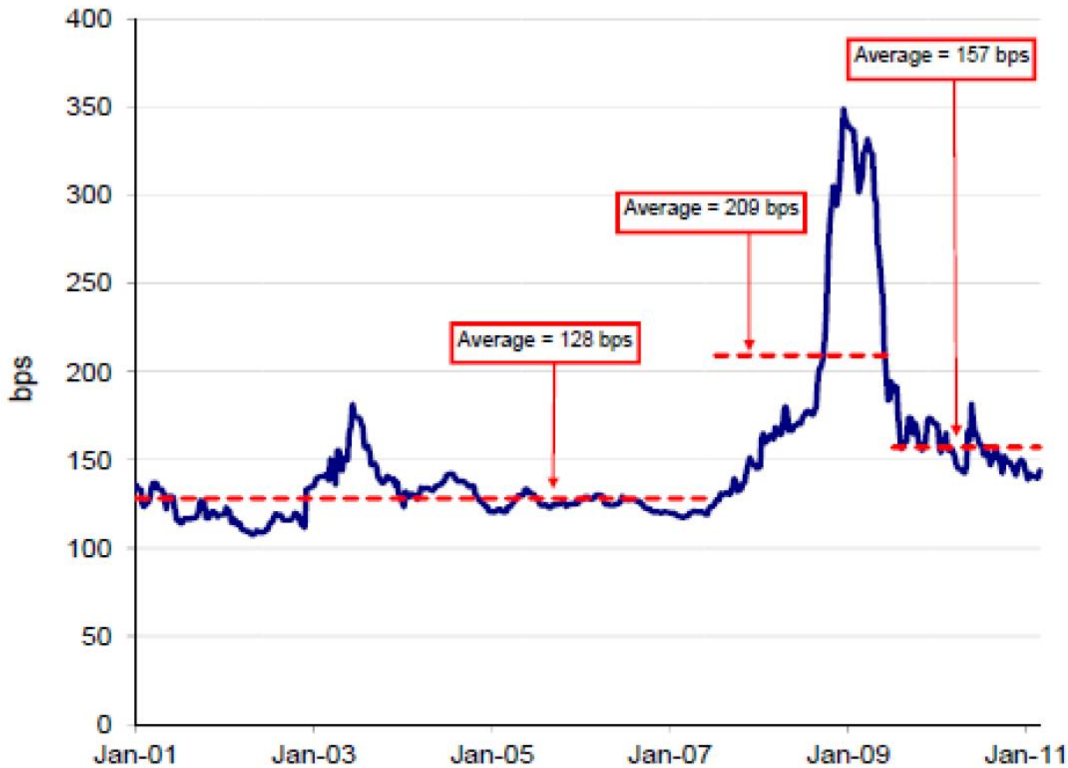
24 Exhibit 40.02, Booth evidence for Calgary, pages 13-14.
25 Exhibit 44.02, Booth evidence for CAPP, pages 10-33.
26 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 4, line 15 to page 5, line2.
27 Exhibit 151.01, CAPP argument, pages 3-7.
28 Exhibit 149.01, CCA argument, page 5.

outcomes one would expect a positive, rather than negative outcome. Therefore, this assertion should be ignored as reason to maintain or even increase equity thickness or return on equity."[29]

Commission findings

48. In Decision 2009-216, the Commission found that the "considerable amount of uncertainty in the financial markets" resulting from the credit crisis warranted regulatory support.[30] In Decision 2011-474, the Commission found that "by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels."[31] The Commission has reproduced a chart from Decision 2011-474 to illustrate the circumstances facing the industry during and leading up to the 2009 and 2011 GCOC decisions.

Figure 1 30-year bond spread for Canadian relatively pure-play regulated utilities[32]

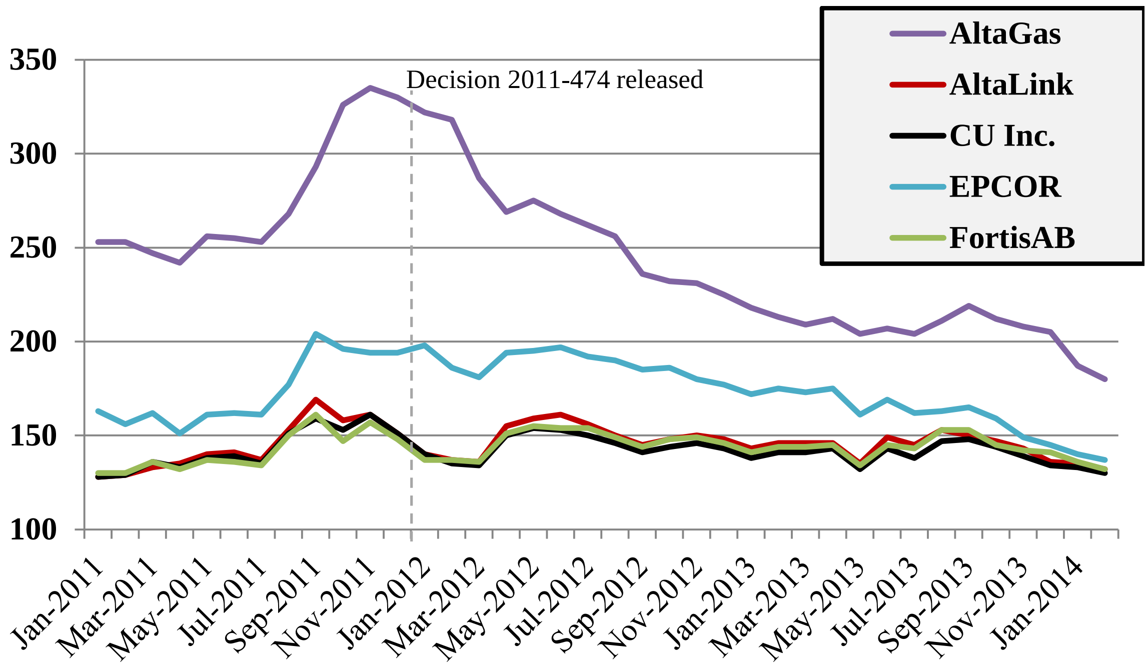


49. Having considered the evidence on the record of this proceeding, the Commission finds that global economic and Canadian capital market conditions have improved since the issuance of Decision 2011-474 and that the risks in capital markets are no longer significantly elevated, relative to market conditions prior to the 2008-2009 financial crisis. The Commission agrees with Dr. Booth that current capital market conditions are indicative of a return to typical and expected economic conditions.

29 Exhibit 152.01, CCA reply argument, page 7.
30 Decision 2009-216, pages 88 and 106.
31 Decision 2011-474, page 7.
32 Decision 2011-474, page 6.

50. Any global economic and capital market risks, such as those considered in the Bank of Canada 2013 Financial Review, have had no perceptible impact on the ability of Alberta utilities to raise capital at reasonable rates to fund growth and operations. As pointed out by Dr. Booth, Alberta utilities have recently been able to raise debt at very low rates for very long terms (e.g., on September 18, 2013, CU Inc. issued 50-year debt at a rate of 4.855 per cent).[33] Further, indicative 30 year credit spreads have remained relatively flat, or have settled lower, since Decision 2011-474 was released, as indicated in Figure 2 below.

Figure 2 Indicative 30-year credit spreads (basis points)[34]



51. In consideration of the foregoing, the Commission finds that the risks in the financial markets observed since Decision 2011-474 have moderated. At the same time, as discussed in Section 5 of this decision, in the current environment when sovereign and commercial borrowers are able to borrow at historically low rates, market conditions may not be reflective of a typical risk-return relationship on which risk-premium models are based.

5 Return on equity

52. In this section, the Commission will establish the generic benchmark ROE, based on conventional methods grounded in financial theory. This generic benchmark ROE will be the starting point for determining an allowed ROE for all of the affected utilities for 2013, 2014 and 2015.

53. The Commission was presented with a significant body of evidence on the tests to be considered when determining a fair generic benchmark ROE and a number of opinions on the proper methodology to be employed in the application of many of these tests. Consequently, the

33 Exhibit 66.01, AUC-Utilities-20, page 4 of 18.
34 Adapted from Exhibit 66.01, AUC-Utilities-20(c).

Commission was also provided with a wide range of proposed ROEs. The record of the proceeding included evidence to support various generic benchmark ROE estimates based on:

- changes in the global and Canadian financial environment since the conclusion of the 2011 GCOC proceeding
- applicability of CAPM methodologies
- applicability of the DCF model, as applied to proxy utilities as well as to the overall equity market
- return expectations of finance professionals such as investment managers, pension fund managers and economists
- market price-to-book values
- DCF-based equity risk premium tests
- historic utility equity risk premium tests
- bond yield risk premium estimates

54. In establishing the generic benchmark ROE, the Commission will consider the evidence in this proceeding on all of these analyses. However, as set out in Section 5.6, the Commission will not give equal weight to the results of every analysis on the record of the proceeding.

55. The Commission's review of the changes in the global and Canadian economic and capital market conditions since the conclusion of the 2011 GCOC proceeding is set out in Section 4 of this decision. The remainder of this decision is organized as follows. Sections 5.1 to 5.5 address each of the remaining factors that the Commission considers to be relevant to the establishment of an appropriate generic benchmark ROE. More specifically, sections 5.1 and 5.2 address the application of CAPM and DCF methods, respectively. Section 5.3 deals with equity price-to-book ratio considerations. Section 5.4 examines return expectations of finance professionals and Section 5.5 addresses other methods of estimating a fair ROE that were employed by various experts who participated in this proceeding. Finally, Section 5.6 summarises the Commission's findings on the generic benchmark ROE for 2013, 2014 and 2015.

5.1 Capital asset pricing model

5.1.1 CAPM methodology and predictive value

56. The CAPM approach is broadly based on the principle that investors' compensation for the use of their capital must recognise two factors: their foregone time value of money and any risk attendant in the investment. The time value of money is represented in CAPM by a component of the required rate of return that corresponds to a risk-free rate, which is intended to represent the return an investor would expect to receive for investing their capital in a risk-free security over a comparable time period. The second part of CAPM incorporates an adjustment to the risk-free rate intended to reflect a premium required to address the risk that an expected return will not be achieved (the market equity risk premium or MERP), and the β, or beta, which is a measure of how sensitive the subject security's required return is to the MERP. Beta is usually derived from an examination of the past statistical relationship between historical returns for a given security and the returns of the overall capital market during the same time period. In this way, CAPM calculates the expected return for a security as the rate of return on a risk-free security plus a risk premium.

57. In general terms, CAPM can be represented by the following formula:

$$Re = Rf + \beta[E(Rm)-Rf],$$

where:

Re is the required return on common equity
Rf is the risk-free rate
β, or **beta**, measures the sensitivity of a required return of an individual security to changes in the market return
E(Rm)-Rf is the market equity risk premium (MERP); i.e., the expected market return E(Rm) minus the risk free rate, Rf

58. Expert evidence supporting various proposed ROEs based on an application of CAPM, or variations thereof, was provided by Ms. McShane for the Alberta Utilities, Dr. Booth for CAPP, and Dr. Cleary for the UCA.

59. In his evidence, Dr. Booth repeated his view on why the CAPM is widely used, also referenced in previous GCOC decisions:

> The CAPM is widely used because it is intuitively correct. It captures two of the major "laws' of finance: the ***time value*** of money and the ***risk value*** of money… [T]he time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM normally gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory. It also reflects the fact that modern capital markets are dominated by large institutions that hold diversified portfolios.[35]

60. Dr. Booth further indicated that, currently, "the CAPM is overwhelmingly the most important model used by a company in estimating their cost of equity capital."[36] In supporting his position in this regard, he referred to a survey of 392 chief financial officers (CFOs) in the U.S., which indicated that 70 per cent of those surveyed use the CAPM methodology and that a further 30 per cent use a multi-beta variation of the CAPM.[37] Dr. Booth also referred to academic papers that provide empirical support for the CAPM, and pointed to the fact that this model has been accepted by Canadian regulators, including the AUC.[38]

61. Dr. Cleary also provided testimony related to surveys and academic studies showing that CAPM is used by over 68 per cent of financial analysts; over 70 per cent of the U.S. CFOs; and close to 40 per cent of Canadian CFOs. According to Dr. Cleary, "CFOs are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital

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35 Exhibit 44.02, Booth evidence for CAPP, paragraph 79.
36 Exhibit 44.02, Booth evidence for CAPP, paragraph 80.
37 Exhibit 44.02, Booth evidence for CAPP, paragraph 81.
38 Exhibit 44.02, Booth evidence for CAPP, paragraphs 81-84.

considerations." Dr. Cleary also commented that CAPM has been "heavily relied upon" by regulators.[39]

62. In contrast, Ms. McShane found Dr. Booth's and Dr. Cleary's focus on CAPM problematic and expressed her preference for other methods to estimate a fair ROE. In support of her view, Ms. McShane stated:

> … One of the three legs of the fair return standard is the comparable investment requirement, i.e., the return available from the application of the invested capital to other enterprises of like risk. The CAPM provides an estimate of what return the investor should require under the restrictive assumptions of the model. It does not tell us what investors do require or expect for comparable risk investments nor does it tell us what returns investors actually are able to achieve in comparable risk investments.[40]

63. Ms. McShane further indicated that "while a high proportion of companies use CAPM to estimate their cost of equity, the hurdle rates companies use for capital budgeting tend to exceed by a large margin what should be their corporate weighted average costs of capital [WACC] if they were using a simple or 'classic' CAPM to estimate their cost of equity." Ms. McShane referenced a survey which found that the actual hurdle rates used by corporations were close to twice the authors' CAPM-based WACC estimates.[41]

64. Therefore, Ms. McShane contended, while a form of CAPM may be widely used, its implementation may be quite different with material adjustments being made to the ROE estimates produced by the simple "classic" three input (risk-free rate, beta and MERP) CAPM. Ms. McShane pointed out that both Dr. Cleary and Dr. Booth made adjustments to their CAPM ROE estimates.

65. Ms. McShane indicated that she did not prefer to use a "classic" CAPM, but rather a "sort of a variant of the CAPM,"[42] which she referred to as a "risk-adjusted equity market risk premium test." In applying her variant CAPM analysis, Ms. McShane also provided two additional estimates of the equity risk premium, which were developed based on a discounted cash flow (DCF) based method and on historically achieved utility equity risk premiums. These two tests are addressed in Section 5.5 of this decision.

66. On the strength of Ms. McShane's evidence, the Alberta Utilities argued that any weighting accorded the CAPM by the Commission in the present proceeding relative to other tests (for example, the DCF analysis) must be significantly reduced. According to the Alberta Utilities, the "unsuitability of the CAPM, in current market conditions, as an indicator of the returns equity investors expect for comparable risk adjustments is widely recognized by witnesses and regulators alike."[43] The Alberta Utilities also echoed Ms. McShane's view that because practitioners and regulators must make material adjustments to the "classic" three input CAPM "expressly to avoid the results it would otherwise produce that would be patently unreasonable," the general validity of this model is questionable.[44]

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[39] Exhibit 45.03, Cleary evidence for UCA, page 27.
[40] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 31.
[41] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 32-33.
[42] Transcript, Volume 3, page 427, lines 15-16 (Ms. McShane).
[43] Exhibit 148.01, Alberta Utilities argument, paragraph 24.
[44] Exhibit 148.01, Alberta Utilities argument, paragraph 25.

67. In argument, CAPP supported the view of its expert, Dr. Booth, stating that the "CAPM, while not perfect, is conceptually valid and allows for far less error than other methods such as DCF that have bigger problems and can lead to much bigger errors."[45] The UCA[46] and Calgary[47] supported CAPP's view in this regard.

Commission findings

68. The Commission recognizes that, like any theoretical model, the applicability of CAPM has limitations. For example, as Ms. McShane pointed out, the "CAPM provides an estimate of what return the investor should require under the restrictive assumptions of the model."[48] As further discussed in Section 5.1.4 of this decision, one such restriction is the assumption that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments.

69. As previously discussed, Ms. McShane referenced a study showing that, while a high proportion of companies use CAPM to estimate their cost of equity, the hurdle rates these companies use for capital budgeting tend to exceed "by a large margin" the cost of capital estimate obtained from a "classic" three-part CAPM.[49] As such, it appears that the results of a classic CAPM often incorporate material adjustments, when used in practice. However, as discussed during the hearing, caution needs to be exercised when comparing hurdle rates to the CAPM cost of equity estimates, since hurdle rates are often project-specific, whereas the CAPM is intended to estimate the cost of capital for the company as a whole.[50] Ms. McShane acknowledged this issue in her rebuttal evidence:

> One reasonable interpretation of the observed difference between the hurdle rates that corporations use in their capital budgeting versus what they estimate as their CAPM cost of equity is that corporations are not investing in a portfolio of securities, they are investing in irreversible projects that comprise long-term assets.[23]
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> ---
>
> [23] The authors posit that the difference in the hurdle rates and the WACC reflects the availability of valuable alternative investment opportunities, i.e., the hurdle premium reflects the option to wait for better investment opportunities.[51]

70. Nevertheless, as noted in previous GCOC decisions, CAPM is a generally-accepted and theoretically well-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return.[52] In this proceeding, Dr. Booth indicated that currently, "the CAPM is overwhelmingly the most important model used by a company in estimating their cost of equity capital."[53] Dr. Cleary also indicated that the CAPM is widely used by CFOs, financial analysts and regulators.[54] All the experts who offered ROE evidence in this proceeding relied on some form of the CAPM in developing their ROE recommendation.

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45 Exhibit 151.01, CAPP argument, paragraph 14.
46 Exhibit 156.02, UCA reply argument, page 12.
47 Exhibit 157.02, Calgary reply argument, paragraph 29.
48 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 31.
49 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 32.
50 Transcript, Volume 4, page 477, lines 7-12.
51 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 33.
52 Decision 2011-474, paragraph 29; Decision 2009-216, paragraph 223.
53 Exhibit 44.02, Booth evidence for CAPP, paragraph 80.
54 Exhibit 45.03, Cleary evidence for UCA, page 27.

71. In previous GCOC decisions the Commission has found that the CAPM warranted a notable weighting among the alternative models in estimating the allowed ROE. As in Decision 2011-474, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

72. In considering the evidence on CAPM, the Commission reviewed the proposals on the individual components of CAPM, as well as each party's overall ROE estimate based on the CAPM approach. Each CAPM component, and the overall resulting CAPM estimates of ROE, are addressed in sections 5.1.2 to 5.1.6 that follow.

5.1.2 Risk-free rate

73. The CAPM analysis requires an estimate of the risk-free rate. For practical purposes, a yield on long-term government bonds is most widely used as a proxy for the risk-free rate, although it should be recognized that long-term government bond yields are not entirely risk-free. They are considered to be free of default risk, but are subject to interest rate risk.[55]

74. Ms. McShane, on behalf of the Alberta Utilities, maintained that when one is attempting to estimate the risk-free rate under current market conditions, it is necessary to recognize that "the current level and near-term forecasts of the long-term (30-year) Government of Canada bond yield are at abnormally low levels, but that they are expected to gradually return to more normal levels."[56] Accordingly, in her calculations, Ms. McShane used a risk-free rate estimate of 4.0 per cent, which was the forecast 2014-2016 long-term government of Canada bond yield, based on the October 2013 data from *Consensus Forecasts* by Consensus Economics.

75. Because *Consensus Forecasts* do not provide any projections for the long-term government of Canada bond yields, Ms. McShane estimated the long-term yields by taking the *Consensus Forecasts* for the 10-year government of Canada bond yields and adding a spread of 45 basis points between the long-term and 10-year government of Canada bond yields. Accordingly, Ms. McShane obtained her risk-free estimate of 4.0 per cent as follows:

> Based on the October 2013 Consensus Economics, Consensus Forecasts, the forecast 2014 30-year Canada bond yield is 3.45%, equal to the average of the three-month (2.7%) and 12-month (3.1%) forward consensus forecasts of 10-year Government of Canada bond yields (2.9%) plus the October 2013 actual spread between 30-year and 10-year Government of Canada bond yields (0.55%). The forecasts for 2015 and 2016 are, respectively, 4.1% and 4.6%. They reflect the October 2013 Consensus Forecasts' anticipated 10-year Canada bond yields of 3.6% and 4.1% for 2015 and 2016 plus a spread between the 30-year and 10-year Canada bond yields of 45 basis points. The 45 basis point spread, in turn, represents the average of the recent (December 2013) spread (55 basis points) and the historic average spread (35 basis points).[57]

76. CAPP's expert, Dr. Booth, forecast long-term Canada bond yields for 2014 "to be about 3.60% … as the [U.S. Federal Reserve System's] bond buying program is still depressing interest rates."[58] This forecast was based on the Royal Bank of Canada's interest rate forecast

55 Exhibit 42.02, McShane evidence for Alberta Utilities, page 83.
56 Exhibit 42.02, McShane evidence for Alberta Utilities, page 83.
57 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 94 on pages 83-84.
58 Exhibit 44.02, Booth evidence for CAPP, page 3.

dated January 10, 2014.[59] However, Dr. Booth also expressed his view that it is necessary to adjust this estimate to account for the fact that Canadian bond yields have been depressed by the "quantitative easing" actions of the U.S. Federal Reserve System (the Federal Reserve), including the "Operation Twist" program, in accordance with which, the Federal Reserve buys U.S. government bonds to drive interest rates down. Therefore, according to Dr. Booth, U.S. and Canadian long-term bond yields are not reflective of the opportunity cost for equity investors at this time. Based on his analysis of the preferred share yield spread over long-term government of Canada bond yields, Dr. Booth estimated the impact of the "Operation Twist" on the Canadian bond market to be an overall reduction in observed yields of approximately 0.40 per cent.

77. Dr. Booth's deliberations on the risk-free rate estimate can be summarized as follows:

> In my judgment risk premium estimates should be based on interest rates that reflect the actions of ordinary investors trading off risk and return, rather than the actions of the global policy maker. By examining preferred share yields, that are not affected to the same degree by the actions of the monetary authorities, I judge a reasonable lower bound estimate of the long Canada yield for 2014 to be 4.00% and use this in my risk premium estimates. The difference between my interest rate forecast and this 4.0% I refer to as my "Operation Twist" adjustment, as the objective of the Fed's bond buying program is to "twist" the shape of the yield curve.[60] [footnote omitted]

78. To estimate the risk-free rate for 2013, Dr. Cleary, on behalf of the UCA, observed with "the benefit of perfect hindsight" that long-term government bond yields averaged 2.8 per cent in that year. Dr. Cleary used this risk-free rate value in his CAPM ROE estimates for 2013.[61]

79. Dr. Cleary stated that, based on his outlook for capital market and economic conditions, his belief is that "it is reasonable to assume that bond yields will increase, albeit slowly, in the coming months. This seems to be the view of most economists in the fall of 2013…"[62] Using the December 2013 Consensus forecasts data, Dr. Cleary estimated an average 10-year government of Canada bond yield to be three per cent for 2014, and 3.2 per cent at the start of 2015. Assuming a 50 basis point spread of long-term bond yields over 10-year yields persists throughout 2014 and 2015, this implies long-term rates be 3.5 per cent and 3.7 per cent for 2014 and 2015, respectively. Overall, Dr. Cleary considered risk-free rates in the range of 2.4 to 3.2 per cent for 2013, 3.1 to 3.9 per cent for 2014 and 3.3 to 4.1 per cent for 2015.[63]

80. The CCA, in its argument, claimed that based on a five-year history, the accuracy of the *Consensus Forecasts* is poor. In comparing forecasted interest rates to actuals at twenty-four points during the five-year time period, the CCA observed only one instance in which a forecast value was lower than an actual interest rate. Consequently, it recommended a downward revision to the *Consensus Forecasts*, "given the recent very poor track record of the Consensus Economic forecasts and the very distinct possibility of continued government intervention to keep interests low."[64] Despite these concerns, the CCA supported Dr. Booth's and Ms. McShane's risk-free forecast of approximately 4.0 per cent.

59 Exhibit 44.02, Booth evidence for CAPP, pages 25-26.
60 Exhibit 44.02, Booth evidence for CAPP, page 3.
61 Exhibit 45.03, Cleary evidence for UCA, page 27.
62 Exhibit 45.03, Cleary evidence for UCA, page 22.
63 Exhibit 45.03, Cleary evidence for UCA, pages 22 and 27.
64 Exhibit 149.01, CCA argument, paragraph 9.

81. In her rebuttal evidence, Ms. McShane took issue with Dr. Cleary's use of the actual long-term government of Canada bond yield of 2.8 per cent for 2013 in his application of the CAPM. Ms. McShane held the view that long-term government of Canada bond yields "have been kept abnormally low due in large part to ongoing unconventional monetary policy."[65]

82. The Alberta Utilities submitted that Dr. Cleary had, in his analysis, failed to "recognize that the abnormally low recent and current levels of long-term Canada bond yields do not reflect the ordinary investor trade off of risk and return."[66] The Alberta Utilities also pointed out that two Canadian regulators have accepted "normalized" risk-free rate forecasts, recognizing the abnormal risk-return relationship for long-term government of Canada bond yields.[67]

83. During the hearing, Dr. Cleary addressed this point as follows:

> … I do acknowledge that monetary policy has played a role in this, particularly in the US. But again, I think coming from the point of investor, and if you look at the models and you look at the DCF models or the bond yield plus risk premium, or you don't even look at the models, and you think of how an investor thinks, they think about what I can earn on a bond today. The fact that it should be 4 percent isn't -- it's nice to know but it is 3 percent.[68]

84. Further, according to Dr. Cleary, there is no disconnect between the equity markets and the debt markets. In Dr. Cleary's view, "the equity markets pay very close attention to what's available on the bond markets and *vice versa*."[69] Based on this evidence, the UCA submitted that Dr. Cleary's recommended risk-free rates "accurately reflect the current and forecast state of the market which align with the purpose and rationale underlying the CAPM approach."[70]

85. Finally, both the UCA[71] and CAPP[72] pointed to the fact that Ms. McShane has adjusted, or "normalized" her risk-free rate estimate to account for abnormally low interest rates, while simultaneously adjusting the MERP to account for lower government of Canada bond yields. In the views of both the UCA and CAPP, in adjusting *both* the risk-free rate and MERP aspects of the CAPM, Ms. McShane has, in fact, accounted for any impact of the low interest rate environment twice.

Commission findings

86. In past GCOC decisions, the Commission considered it reasonable to rely on the Consensus Economics *Consensus Forecasts* of long-term government of Canada bond yields to estimate the risk-free rate. However, the Commission is mindful that, as the CCA pointed out, caution needs to be exercised when using the *Consensus Forecasts* outlook, because this forecast appears to have mostly overestimated the yields on long-term government bonds in the 2010 to 2014 period.[73] For example, as observed in response to Commission's IRs, the *Consensus Forecast*-based risk-free rate estimates of 3.8 per cent to 4.3 per cent accepted in the

65 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
66 Exhibit 148.01, Alberta Utilities argument, paragraph 41.
67 Exhibit 148.01, Alberta Utilities argument, paragraphs 42-43.
68 Transcript, Volume 5, page 739, lines 5-13 (Dr. Cleary).
69 Transcript, Volume 5, page 739, lines 17-21 (Dr. Cleary).
70 Exhibit 150.02, UCA argument, page 9.
71 Exhibit 150.02, UCA argument, page 12.
72 Exhibit 151.01, CAPP argument, paragraph 30.
73 Exhibit 149.01, CCA argument, paragraphs 2-3.

2011 GCOC proceeding proved to be much higher than actual rates experienced during that time period.[74] The Commission also observes that, in the time period preceding the close of the evidentiary record for this proceeding on August 1, 2014, long-term government of Canada benchmark bond yields have continued to decline.[75]

87. Ms. McShane's evidence indicated that, based on the October 2013 *Consensus Forecasts*, the 10-year government of Canada bond yield was estimated to be 2.9 per cent in 2014 and 3.6 per cent in 2015.[76] However, the more recent April 2014 *Consensus Forecasts* estimated the 2014 rate to be 2.7 per cent, and the 2015 rate to be 3.2 per cent.[77] Adding the historical spread of approximately 50 basis points between the 10-year and the long-term bond yields results in a long-term risk-free forecast of 3.2 per cent for 2014 and 3.7 per cent for 2015.

88. Both Ms. McShane[78] and Dr. Booth[79] adjusted their risk-free estimates upwards to account for the fact that current interest rates are abnormally depressed due to the effects monetary policy which, in effect, create a situation where government long-term bond yields do not accurately reflect the expectations of equity investors with respect to risk and return trade-offs. However, in an exchange with the Commission during the hearing, Ms. McShane acknowledged that developed countries, even those with elevated sovereign debt risks such as Italy and Spain, are currently borrowing at 10-year rates below three per cent:

> Q. But then -- so I look at it and I see the 4 percent and I think okay, it's out of sync with what's going on. So I looked up my little Wall Street Journal page of 10-year bond rates and I go, Okay, US 10 years, 2.44; German 10 year, 1.35; Italy a bastion of fiscal discipline, 2.94; Japan 0.57. These are all ten-year rates. Spain 2.84 -- I think they almost went bankrupt; the UK 2.55; and Canada as of yesterday in the ten year, although we have evidence for 2.3 -- it seems to be still railing -- at 2.22. So, suddenly, it's not the Canadian rates. You're talking the risk-free rate of 4 percent. We're talking a global doubling of interest rates, not just a Canadian doubling of interest rates in the long run. You're talking a global doubling of interest rates before the reality of that 4 percent number is even near.
>
> A. MS. MCSHANE: So you're right, the low government bond rate is not just a Canadian phenomenon. It is a worldwide phenomenon that is reflective of attempts by central banks to keep rates low. And, again, I mean, the bond issuers have benefited from that behaviour.[80]

89. Ms. McShane also confirmed that Alberta utilities are borrowing at low rates and "the utilities have been -- and other debt issuers -- have been the beneficiaries of the low long-term government bond yields."[81]

90. The Commission agrees with Dr. Cleary's view that "the equity markets pay very close attention to what's available on the bond markets and *vice versa*."[82] In circumstances where

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74 See, for example, preamble to Exhibit 68.02, AUC-UCA-2.
75 http://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/
76 Exhibit 42.02, McShane evidence for Alberta Utilities, Table 4 on page 22.
77 Exhibit 114.01, undertaking by Ms. McShane to Mr. Finn.
78 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
79 Exhibit 44.02, Booth evidence for CAPP, page 3.
80 Transcript, Volume 4, page 539, lines 2-21 (Ms. McShane).
81 Transcript, Volume 4, page 538, lines 18-20 (Ms. McShane).
82 Transcript, Volume 5, page 739, lines 17-21 (Dr. Cleary).

sovereign and commercial borrowers are able to borrow at historically low rates, the Commission does not accept that a CAPM analysis should be based on a "normalized" risk-free rate of 4.0 per cent, which represents what *should* have been in place to reflect investor risk-return expectations. As Dr. Cleary pointed out, "you think of how an investor thinks, they think about what I can earn on a bond today. The fact that it should be 4 percent isn't – it's nice to know but it is 3 percent."[83]

91. The Commission also agrees with the submissions of the UCA[84] and CAPP[85] that Ms. McShane's adjustment to both her risk-free rate estimate and MERP components of the CAPM to account for the abnormally low interest rates has the potential to result in over-compensation for the current low interest rate environment.

92. The Commission considers that it is preferable to base the risk-free estimate on the observed and expected long-term government bond rates, and account for any residual credit spread concerns by way of an adjustment to the MERP estimate, rather than adopt a normalized risk-free rate that is not adequately reflective of the actual interest rate environment. In adopting this approach, the Commission notes that all three experts agreed that adjusting the MERP is another way of dealing with an abnormal risk-return relationship triggered by ultra-low long-term bond yields.[86]

93. Based on the foregoing, the Commission considers the actual long-term rate of 2.8 per cent[87] in 2013 to be a reasonable lower bound estimate for the risk-free rate in its current analysis. Likewise, the latest *Consensus Forecasts* of 3.7 per cent for 2015 (as of April 2014) represents a reasonable upper bound of the risk-free rate. The Commission further notes that, in all likelihood, the adopted upper bound estimate may be optimistic, given that, based on recent history, the return to the long-term interest rate levels may not occur as quickly as the *Consensus Forecasts* predicted in April 2014.

5.1.3 Market equity risk premium

94. The next element of the CAPM analysis is the market equity risk premium, or MERP. The MERP value is not directly observable but can be estimated as the difference between estimates of the expected market return and the risk-free rate. The interveners' and the Alberta Utilities' experts in this proceeding differed in their estimates of the MERP.

95. Ms. McShane's MERP estimate was formulated on the basis of historic return and risk premium data drawn from both Canadian and U.S. capital markets. As Ms. McShane explained, this approach is premised on the notion that investors' return expectations and requirements are linked to their past experience. Analyzing the total equity return less bond income returns for the two long-term historic periods from 1924 to 2012 and 1947 to 2012, Ms. McShane arrived at an average achieved risk premium of approximately 5.0 per cent to 5.5 per cent for Canada and 6.5 per cent to 6.75 per cent for the U.S.[88]

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[83] Transcript, Volume 5, page 739, lines 11-13 (Dr. Cleary).
[84] Exhibit 150.02, UCA argument, page 12.
[85] Exhibit 151.01, CAPP argument, paragraph 30.
[86] Transcript, Volume 3, page 430, line 3 to page 431, line 19 (Ms. McShane); Exhibit 68.02, AUC-UCA-4; Exhibit 63.02, AUC-CAPP-4.
[87] Exhibit 45.03, Cleary evidence for UCA, page 27.
[88] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 87-88.

96. Ms. McShane observed that the MERP is not a fixed quantity; it changes with investor experience and expectations. Based on her analysis of historical bond income returns, Ms. McShane concluded that, on a cumulative average basis, lower bond income returns have been associated with higher achieved risk premiums: "In other words, the historical data are consistent with the conclusion that the market equity risk premium is higher at lower levels of bond yields and vice versa."[89]

97. Ms. McShane also analyzed the historical relationship between inflation and real equity returns, as well as other return considerations related to the MERP. Overall, Ms. McShane concluded from her analysis:

> Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, the higher achieved risk premiums at lower levels of government bond yields and the observed generally negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the equity market risk premium is a range of 7.0% to 7.5% (mid-point of 7.25%) at the forecast 4.0% 30-year Government of Canada bond yield. The indicated risk premium based on an analysis of the U.S. data supports an equity risk premium of approximately 7.0% to 8.5%. With preponderant weight given to the Canadian data, the indicated equity market risk premium at the forecast 4.0% Government of Canada bond yield is a range of 7.0% to 7.5% (mid-point of 7.25%). The corresponding indicated equity market return is 11.25%.[90]

98. Dr. Booth, on behalf of CAPP, estimated that long-term historic data suggests an experienced MERP in Canada of 5.0 per cent, and indicated that a range of 5.0 to 6.0 per cent was reasonable.[91] In developing this estimate, Dr. Booth gave weight to the U.S. evidence, since, with the removal of most restrictions on capital flows in Canada, the risk premium in Canada has moved closer to that in the U.S. In arriving at this conclusion, Dr. Booth also considered the results of an academic survey of professors of finance, financial analysts and companies.[92]

99. Dr. Booth also added 26 basis points to his risk premium estimates to account for elevated credit spreads. In response to a Commission IR concerning whether this adjustment can be reasonably incorporated in the MERP component, Dr. Booth stated:

> If the AUC accepts Dr. Booth's recommendation he would be happy to collapse the credit spread adjustment into the overall market risk premium as the AUC did in paragraph 128 of Decision 2011-474. However, conceptually Dr. Booth would not agree with this. The idea of the credit spread is that the overall market risk premium is relatively stable, but through the business cycle there are periods of pessimism and optimism that affect the fair rate of return and this is what is captured in the credit spread adjustment. It essentially makes the risk premium a conditional risk premium estimate and Dr. Booth would prefer it to be separate for consistency with his ROE adjustment methodology recommendations.[93]

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89 Exhibit 42.02, McShane evidence for Alberta Utilities, page 90.
90 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 96-97.
91 Exhibit 44.02, Booth evidence for CAPP, paragraph 90.
92 P. Fernandez et al, Market Risk Premium and Risk Free Rate used for 51 Countries in 2013: A Survey with 6,237 Answers. June 26, 2013.
93 Exhibit 63.02, AUC-CAPP-4(a).

100. Dr. Cleary indicated that the MERP, over the 1900 to 2010 period, averaged 5.3 per cent in Canada and 6.4 per cent in the U.S., as measured by the market return less the long-term government bond total yield. Based on this information, as well as the referenced survey by Professor Fernandez (also referred to by Dr. Booth), Dr. Cleary made the following recommendation for the MERP value to be used in the CAPM ROE estimate:

> Based on the previous discussion of capital markets, which seem to be in a reasonably stable state today; it is reasonable to assume that market participants would be satisfied with a figure slightly above the long-term average of 5.3% MRP. Therefore, I will use 5.5% as my best estimate for 2014 and 2015, and consider a range of 5 to 6%. At the start of 2013, more uncertainties existed, so I will use 6% - at the upper bound of the commonly used range, and historical figures. These estimates lie within the 4 to 6 percent range that is normally used, and is consistent with long-term averages. This seems appropriate in today's environment, where economic and market conditions are fairly stable; albeit not overwhelmingly positive. One would normally use 6 percent when market uncertainty is high, and lean toward values in the 4 to 5 percent range during periods of extreme market and economic optimism.[94]

101. Dr. Cleary also included a 0.2 per cent "yield spread" adjustment to his CAPM estimates to account for the variation in the risk premium over time.[95] In response to a Commission IR, the UCA indicated that using "an above average MERP has the same effect as making the adjustment that he [Dr. Cleary] recommended, and is also an appropriate way to deal with abnormally high yield spreads."[96]

102. The main point of disagreement among the experts in this proceeding regarding the MERP was the issue of whether the MERP should be estimated as the total equity return less bond *income* returns, (as advocated by Ms. McShane), or the total equity return less bond *total* returns (as advocated by Drs. Cleary and Booth).[97] Since bond income returns were smaller than bond total returns over the studied period, Ms. McShane's MERP estimates using bond income returns were higher than Dr. Booth's and Dr. Cleary's estimates. In support of their positions, the experts referenced several academic publications supporting their respective views on this matter.[98]

103. Addressing a related issue, Dr. Cleary pointed out that Ms. McShane used arithmetic averages in her MERP estimates, rather than geometric averages, despite acknowledging that "there are analysts who use geometric averages or some combination of geometric and arithmetic averages to estimate the market risk premium and cost of equity from historic data."[99] Dr. Cleary showed that, while using bond total returns would lower Ms. McShane's MERP estimate from

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94 Exhibit 45.03, Cleary evidence for UCA, page 29.
95 Exhibit 45.03, Cleary evidence for UCA, page 31.
96 Exhibit 68.02, AUC-UCA-4(a).
97 As Ms. McShane explained in her evidence, Exhibit 42.02, page 87, the "bond total return includes annual capital gains or losses and reinvestment of the bond coupons, i.e., it incorporates the interest rate risk that is inherent in a government bond. The bond income return reflects only the coupon payment portion of the total bond return." Dr. Booth preferred to refer to bond income returns as 'bond yields.'" (Transcript, Volume 7, page 1077, lines 18-19).
98 Exhibit 66.01, AUC-Utilities-8(b); Exhibit 68.02, AUC-UCA-7(b); Exhibit 63.02, AUC-CAPP-6(b).
99 Exhibit 73.01, UCA-Utilities-29(a) and (b).

5.4 per cent to 4.8 per cent, using geometric averages in place of arithmetic averages would further reduce Ms. McShane's historical MERP estimate to 3.8 per cent.[100]

104. Dr. Booth also expressed a concern with Ms. McShane's use of the current yield on long-term government bonds and the current rate of inflation in her MERP estimates:

> In answer to [Exhibit No. 70.01] CAPP-Utilities McShane 11(b) and (e), Ms. McShane provided the underlying data behind this analysis. What is clear is that what she has estimated is the *contemporaneous* relationship between the one-year actual equity return and the long Canada bond yield at that time. That is, her analysis does not show a relationship between the expected market risk premium for a future time period and the current level of the long Canada bond yield. To show this relationship, that is what is the expected market risk premium at the current low long Canada bond yields, we need the level of the long Canada bond yield at time t and the realised market risk premium over a subsequent, say ten year, period. If this were done the last observation would be for the bond yield in 2002 and the earned market risk premium for the period 2003-2012, rather than 2012 for 2012. I would regard the data in Tables 14 and 15 as being inappropriate with no implications for the current market risk premium.[101]

Commission findings

105. With respect to the issue of whether the bond total return or bond income return should be used in the MERP estimates, the Commission stated in Decision 2011-474 that it was not "convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, which is the traditional approach."[102] However, experts in this proceeding referenced several academic publications ostensibly supporting their contrary views on whether bond total returns or bond income returns should be used for estimating the MERP.[103] The academic debate on this issue appears to be unsettled. Therefore, for purposes of this proceeding, the Commission accepts that both methods may inform its judgment on the range of MERP values.

106. There is also ongoing disagreement among the expert witnesses regarding employing geometric or arithmetic averages in generating MERP estimates,[104] whether contemporaneous or forward-looking risk premiums should be used,[105] and the probative value of historical data suggesting that investors' return expectations and requirements are linked to their past experience.[106]

107. Although Ms. McShane recommended MERP values that were different from those recommended by Drs. Booth and Cleary, and employed different estimation techniques, the Commission recognizes that all three experts have largely relied on comparable long-term data, and produced similar historical estimates, before applying their expert judgment. Specifically, the long-term U.S. and Canadian capital markets data (with preponderant weight given to Canadian data) used by Ms. McShane,[107] Dr. Booth[108] and Dr. Cleary,[109] implies an average long-

[100] Exhibit 82.02, Cleary rebuttal evidence for UCA, page 6.
[101] Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 18.
[102] Decision 2011-474, paragraph 51.
[103] Exhibit 66.01, AUC-Utilities-8(b); Exhibit No. 68.02, AUC-UCA-7(b); Exhibit No. 63.02, AUC-CAPP-6(b).
[104] Exhibit 82.02, Cleary rebuttal evidence for UCA, page 6.
[105] Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 18.
[106] Exhibit 42.02, McShane evidence for Alberta Utilities, page 86.
[107] Exhibit 42.02, McShane evidence for Alberta Utilities, page 88.

run MERP in the range of approximately 5.0 to 6.0 per cent. Therefore, the Commission finds that a long-run historical MERP of 5.0 per cent continues to be a reasonable lower bound for the MERP to be used in the CAPM analysis.

108. In Decision 2011-474, the Commission observed that "it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates."[110] In the same decision, the Commission determined that "the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates."[111]

109. In this proceeding, Ms. McShane concluded that "the historical data are consistent with the conclusion that the market equity risk premium is higher at lower levels of bond yields and vice versa."[112] Dr. Cleary[113] and Dr. Booth[114] have also generally accepted this proposition, although they cautioned that the relationship between MERP and the interest rate level is not a mechanical cause and effect relationship. Further, there may be other factors that lead to the MERP fluctuating over time, and only some of those factors may be reflected in the level of interest rates.

110. As discussed in Section 5.1.2, at an average of 2.8 per cent, the government of Canada long-term bond yield remained near historic lows in 2013, and is forecast to move up to 3.2 per cent and 3.7 per cent in 2014 and 2015, respectively. In these circumstances, the Commission finds it is reasonable to assume that the currently expected MERP may be higher than its long-term average value of 5.0 to 6.0 per cent.

111. Drs. Cleary and Booth recommended using a MERP in the range of approximately 5.0 to 6.0 per cent, based on the observed long-run values. Both of these experts also included some additional adjustments to their CAPM results. Dr. Cleary included a 0.2 per cent "yield spread" adjustment to his CAPM estimates for 2013 to account for the variability of risk premiums over time,[115] and Dr. Booth added 26 basis points to his risk premium estimates to account for elevated credit spreads. As well, as discussed in Section 5.1.2, Dr. Booth added a 40 basis point "Operation Twist" adjustment to his risk-free rate estimate. In total, Dr. Booth recommended adding 66 basis points to his "simple" CAPM estimates.[116]

112. In Decision 2011-474, the Commission stated the following with respect to adjusting the CAPM results to account for bond spreads:

> 128. … the Commission considers that spreads have decreased from the 2009 levels but have not returned to their historic levels. The Commission also notes that it has set the top end of its CAPM market equity risk premium, assuming, on the basis of Ms.

108 Exhibit 44.02, Booth evidence for CAPP, paragraph 90.
109 Exhibit 45.03, Cleary evidence for UCA, page 29.
110 Decision 2011-474, paragraph 56.
111 Decision 2011-474, paragraph 58.
112 Exhibit 42.02, McShane evidence for Alberta Utilities, page 90.
113 Exhibit 68.02, AUC-UCA-3(a) and (b).
114 Exhibit 63.02, AUC-CAPP-3(a).
115 Exhibit 45.03, Cleary evidence for UCA, page 31.
116 Exhibit 44.02, Booth evidence for CAPP, paragraph 143.

> McShane's evidence, that the market equity risk premium may be higher than its historic average at this time of historically low interest rates. For these reasons, the Commission is not convinced that any addition to CAPM results is needed to account for the reduction in corporate bond spreads at this time.[117]

113. Consistent with its above-referenced findings in Decision 2011-474, and as set out in Section 5.1.2 of this decision, the Commission prefers to account for residual credit spread concerns by way of adjusting the MERP estimate, rather than adjusting the risk-free rate, or adding a separate component to CAPM. Given the beta range of 0.50 to 0.65 that the Commission finds to be reasonable in Section 5.1.4 of this decision, the adjustments proposed by Dr. Cleary and Dr. Booth imply that their MERP estimates should be increased by some 40 to 100 basis points.[118] In the Commission's assessment, this results in MERP estimate of 5.4 per cent to 7.0 per cent.

114. Ms. McShane estimated that the MERP, based on her forecast 4.0 per cent long term Canada bond yield, was 7.0 per cent to 7.5 per cent or, using the mid-point, approximately 7.25 per cent.[119] The Commission notes that this was the same value that Ms. McShane recommended in the 2011 GCOC proceeding, and which the Commission accepted as the higher end of its MERP estimate in Decision 2011-474.[120] However, as set out in Section 4, the Commission considers that market conditions have moderated since the time of the 2011 GCOC decision. Therefore, the Commission also considers the higher end of the MERP estimate should be somewhat lower than the 7.25 per cent that the Commission accepted in 2011.

115. For all of these reasons, the Commission finds that the current MERP may reasonably be as assumed to be higher than its historic average of 5.0 to 6.0 per cent, due to low interest rates. The Commission also accepts that current MERP expectations may reasonably be as high as 7.0 per cent, based on the lower range of Ms. McShane's estimate, and taking into account the adjustments to CAPM put forward by Drs. Cleary and Booth. Considering all of the above, the Commission finds that a reasonable range for the MERP is 5.0 per cent to 7.0 per cent.

5.1.4 Beta

116. Another element of the CAPM analysis is the beta value. In the CAPM, beta is a statistical measure describing the relationship of a given security's return with that of the equity market as a whole. In essence, beta measures the market risk of a security.[121] Past data (with or without adjustment) is normally used to estimate the reasonably expected beta going forward. In the Commission view, an appropriate beta to use is one which reasonably represents the relative risk of stand-alone Canadian utilities.[122]

117. Dr. Cleary observed that, based on previous decisions of Canadian regulators and expert testimony in other proceedings, as well as his own research, long-term betas for the subject utilities appear to approximate 0.5. Dr. Cleary calculated average betas using monthly total return data for the TSX Utilities Index over the 1988 to 2012 period. In doing so, he arrived at a

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117 Decision 2011-474, paragraph 128.
118 As explained Exhibit 63.02, AUC-CAPP-4(b), this range was obtained by dividing the proposed credit spread adjustments (in basis points) by the Commission-approved beta values: 20/0.5=40 and 66/0.65=102.
119 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 96-97.
120 Decision 2011-474, paragraph 58.
121 Exhibit 45.03, Cleary evidence for UCA, page 27.
122 Decision 2011-474, paragraph 60.

beta estimate of 0.29 using data for the entire 25-year period. With respect to the last two periods in his sample (2003 to 2007 and 2007 to 2012), he indicated that "the recent utility index beta has been about 0.4, below the long-term average of 0.5, and at the lower end of the typical range used for utilities."[123] Dr. Cleary also calculated beta estimates for several Canadian utilities as of December 20, 2013, based on 60 months of returns and arrived at an average beta of 0.25.

118. Dr. Cleary concluded that "it seems clear that a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. I will use the mid-point figure of this range of 0.45 as my best point estimate, which is slightly below the long-term average of around 0.50."[124]

119. On behalf of CAPP, Dr. Booth stated that he would not use recent beta estimates in his analysis, which in his judgment continue to reflect the aftermath of the financial crisis. Dr. Booth continued to support the adoption of a range 0.45 to 0.55 for betas of Canadian stand-alone utilities. His position in this regard was based on long-run beta estimates, and was the same range as he recommended in the 2009 and 2011 GCOC proceedings.[125] Dr. Booth supported his position through an examination of: the relative risk of utility holding companies (which are near the 0.30 level and still below the 0.50 level that utility stocks had 10-15 years ago); the TSX utility sub-index (which he found to be just above 0.40); the stock market performance of Canadian utilities as a group (and specific Canadian utilities as safe havens) during the financial crisis; and the low risk U.S. utilities referenced in the Alberta Utilities' expert evidence. As a further check, he also compared Canadian utility companies to the U.S. S&P 500 index.[126]

120. In its argument, Calgary supported Dr. Booth's beta recommendations based on long-run values as being "a conservative estimate for use in the CAPM calculation."[127] The UCA, in its argument, supported the beta estimates advanced by both Dr. Cleary and Dr. Booth.[128]

121. Ms. McShane noted that according to the theory behind the CAPM, equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments and that in the simple, single risk variable CAPM, the non-diversifiable risk relative to the market as a whole is measured by beta. Ms. McShane offered several criticisms of the theory behind the CAPM model in this regard. For example, Ms. McShane expressed her view that total risk, and not just diversifiable risk, should be considered for an undiversified investment, such as a utility investing capital in long-term assets. Ms. McShane also contended that the observed historical betas are not good predictors of required, or expected, returns. Therefore, instead of estimating a "single risk variable beta," Ms. McShane focused on what she termed a "relative risk adjustment," which took into account her CAPM criticisms.[129]

122. First, Ms. McShane estimated the relative total market risk of utilities by looking at the ratio of the standard deviation of the S&P/TSX Utilities Index to the mean and median standard

[123] Exhibit 45.03, Cleary evidence for UCA, page 30.
[124] Exhibit 45.03, Cleary evidence for UCA, page 31.
[125] Exhibit 44.02, Booth evidence for CAPP, paragraph 116.
[126] Exhibit 44.02, Booth evidence for CAPP, pages 41-46.
[127] Exhibit 146.02, Calgary argument, paragraph 15.
[128] Exhibit 150.02, UCA argument, page 13.
[129] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 97-98.

deviations of indexes for the 10 major sectors.[130] Application of this method suggested a risk adjustment to the market risk premium of 0.65 to 0.70.[131] Second, Ms. McShane undertook a regression analysis to determine the extent to which the calculated utility betas historically understated experienced returns. In isolation, that analysis demonstrated that a relative risk adjustment for a utility of approximately 0.75 is warranted.[132] Third, Ms. McShane used the adjusted betas published by two investment research firms, Bloomberg and Value Line (which give approximately two-thirds weight to the calculated "raw" beta and one-third weight to the equity market beta of 1.0), in lieu of "raw" (i.e., calculated historical) betas. These adjusted betas were in the range of 0.65 to 0.70.[133] Overall, based on these inputs, Ms. McShane supported a relative risk adjustment in the approximate range of 0.65-0.70.

123. With respect to Dr. Cleary's beta estimate of 0.45 (range of 0.30 to 0.60) and Dr. Booth's beta estimate of 0.50 (range of 0.45 to 0.55), Ms. McShane stated that:

> These relative risk adjustments bear no relationship to investor experience. My relative risk adjustment of 0.65-0.70 for a benchmark utility, in contrast, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 50% of the risk premiums achieved on the equity market portfolio.[134]

124. Dr. Cleary, in turn, took issue with Ms. McShane's calculation of the relative total market risk of utilities using the ratio of S&P/TSX Utilities Index standard deviations to those of 10 major sectors. In Dr. Cleary's view, such an approach is inconsistent with the central premise of the CAPM:

> This is an inappropriate risk factor to be used in the CAPM. First of all, the main premise underlying the CAPM is that systematic risk (as measured by beta), and not total risk, is the relevant risk for a well-diversified investor, since unsystematic risk can be eliminated by diversification. Total risk appears nowhere in the model.
>
> Secondly, for most, if not all, individual stocks, the standard deviation will be much higher than that of the market, since each stock possesses a high level of unique (or unsystematic) risk. Thus, these ratios would almost all be greater than one, with an average that would be much higher than one. Yet the average beta across all individual stocks is one, by definition. …[135]

125. Dr. Cleary and Dr. Booth disagreed with Ms. McShane's use of adjusted betas. They both pointed out that in the 2009 GCOC decision, the Commission rejected the use of adjusted betas.[136] Dr. Cleary noted that "there is no reason to believe that utility betas, which have averaged 0.4 to 0.6 over the long run, will drift toward 1."[137] Dr. Booth stated "looking at a chart

130 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 10. The 10 sectors are: consumer discretionary, consumer staples, energy, financials, health care, industrials, information technology, materials, telecommunication services and utilities.
131 Exhibit 42.02, McShane evidence for Alberta Utilities, page 99.
132 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 100-106.
133 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 106-107.
134 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
135 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 9.
136 Decision 2009-216, paragraph 251.
137 Exhibit No. 82.02, Cleary rebuttal evidence for UCA, page 9.

of utility betas over long periods of time … there is no indication of them trending toward 1.0. As far as I am aware no Canadian regulator has accepted the idea that utility betas regress toward 1.0."[138]

Commission findings

126. The Commission considers that Ms. McShane's approach of focussing on a "relative risk adjustment," rather than a traditional beta parameter calculated from past data, arises, at least in part, from her general criticisms of CAPM. As discussed in Section 5.1.1 of this decision, the Commission recognizes that CAPM, like any theoretical model, has its limitations. However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

127. In this regard, Dr. Cleary stated that, in his view, Ms. McShane's total market risk estimates violate "the main premise underlying the CAPM is that systematic risk (as measured by beta), and not total risk, is the relevant risk for a well-diversified investor, since unsystematic risk can be eliminated by diversification."[139] For its part, the Commission agrees with Dr. Cleary's criticism in this regard and, consequently, assigns no weight to Ms. McShane's total market risk analysis.

128. Dr. Booth[140] and Dr. Cleary[141] indicated that the long-run utility beta is approximately 0.5. In her regression analysis, Ms. McShane obtained long-run beta estimates of 0.40 to 0.465, even though the explanatory power of the regression models was rather low, as demonstrated by low coefficients of determination.[142] Given the identified shortcomings in the predictive value of the approach advocated by Ms. McShane, the Commission accepts the 0.5 long-run beta estimate as the lower range of its reasonable beta estimate.

129. However, in arriving at this assessment of the evidence, the Commission is, nonetheless, mindful of Ms. McShane's conclusion that betas calculated using historical data may be poor predictors of an investor's required or expected return.[143] The Commission also understands that, as one possible solution to this problem, equity market practitioners may use adjusted betas, which, according to some academic research, are better predictors of returns than "raw" betas (i.e., betas calculated using historical data).[144]

130. Therefore, even though the Commission did not accept the use of adjusted betas in Decision 2009-216,[145] and Dr. Booth was not aware of any Canadian regulator that "has accepted the idea that utility betas regress toward 1.0,"[146] the Commission acknowledges the fact that the adjusted betas "are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch."[147] However, the question still remains whether an adjustment is warranted for betas of regulated utilities.

138 Exhibit 44.02, Booth evidence for CAPP, paragraph 112.
139 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 9.
140 Exhibit 44.02, Booth evidence for CAPP, paragraph 116.
141 Exhibit 45.03, Cleary evidence for UCA, page 31.
142 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 102-103.
143 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 100-106.
144 Exhibit 42.02, McShane evidence for Alberta Utilities, page 106.
145 Decision 2009-216, paragraph 251.
146 Exhibit 44.02, Booth evidence for CAPP, paragraph 112.
147 Exhibit 42.02, McShane evidence for Alberta Utilities, page 106.

131. In light of the above considerations, the Commission accepts Ms. McShane's lower bound of beta estimate of 0.65, as representing the upper range of a reasonable beta estimate. Consequently, the Commission finds that a reasonable range for a beta estimate is 0.50 per cent to 0.65 per cent.

5.1.5 Flotation allowance

132. ROE estimates obtained through a CAPM or a DCF analysis are often adjusted upwards by a "flotation allowance." The Commission noted in previous GCOC decisions that a flotation allowance is normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[148] Historically, the Commission and its predecessors have allowed 0.50 per cent (50 basis points) additional return on equity to account for the costs of flotation, and to better ensure that investors can reasonably expect to receive at least the required return.

133. In this proceeding, the interveners' experts generally agreed with the stated purpose of the flotation allowance, as set out in the Commission's 2009 and 2011 GCOC decisions.[149] Both Dr. Cleary[150] and Dr. Booth[151] added a 50 basis points flotation allowance to their respective CAPM estimates, consistent with the Commission's determinations in previous decisions. Dr. Cleary stated that this number is consistent with long-term estimates.[152]

134. In its argument, Calgary supported the inclusion of a 50 basis point allowance for flotation costs, consistent with the Commission's, and its predecessors', historical approach. Calgary also noted that this number has been used by other regulators as well, for example, by the British Columbia Utilities Commission in its 2013 GCOC decision.[153]

135. For her part, Ms. McShane recommended a higher allowance of 100 basis points to permit financing flexibility and as an adjustment for financial risk. According to Ms. McShane, the financing flexibility allowance is intended to cover three distinct aspects: "(1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the 'fairness' principle."[154]

136. Ms. McShane stated that the financing flexibility allowance should be 50 basis points, which "is adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times."[155] However, Ms. McShane also indicated that a higher adjustment of 140 basis points may be warranted to account for financial risk:

> The cost of capital, as determined in the capital markets, is derived from market value data, and reflects a level of financial risk represented by market value capital structures. The cost of equity for the benchmark utility has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital

148 Decision 2011-474, paragraph 68; Decision 2009-216, paragraph 255.
149 Exhibit 68.02, AUC-UCA-5; Exhibit 63.02, AUC-CAPP-5.
150 Exhibit 45.03, Cleary evidence for UCA, page 32.
151 Exhibit 44.02, Booth evidence for CAPP, page 3.
152 Exhibit 45.03, Cleary evidence for UCA, page 32.
153 Exhibit 146.02, Calgary argument, paragraph 16.
154 Exhibit 42.02, McShane evidence for Alberta Utilities, page 128.
155 Exhibit 42.02, McShane evidence for Alberta Utilities, page 128.

> structures, than the financial risk inherent in the book value capital structures of the utilities to which the cost of equity is to be applied. Regulatory convention applies the allowed ROE to a book value capital structure. The application of the market-derived cost of equity to the book value of equity without taking account of the higher level of financial risk than the level inherent in the proxy utilities' cost of equity will underestimate the cost of equity and the fair return.[156]

137. During the hearing, Ms. McShane further explained the reasoning behind the 140 basis point adjustment for financial risk as follows:

> The upper end of the range that I have suggested is in the nature of what I call a financial risk adjustment, which is intended to recognize that the cost of capital is determined in the capital markets based on capital market data, including market value capital structures, but that overall cost of capital and the equity component thereof is applied to a book value common equity ratio, which is in today's markets lower than the market value common equity ratio, thereby indicating that there is more financial risk in the book value common equity ratio than in the market value common equity ratio.[157]

138. Ms. McShane therefore recommended a flotation allowance of 100 basis points, which, in her assessment, gives weight to both the minimum 50 basis points required for financing flexibility and the suggested 140 basis points adjustment for financial risk. Ms. McShane indicated that this approach "is similar to that taken by the National Energy Board in setting the allowed ROE for TransCanada Pipelines in *Decision RH-003-2011* …."[158]

139. Dr. Cleary did not agree with Ms. McShane's proposal to increase the flotation allowance to 100 basis points. He observed that since "Canadian utilities currently trade at M/B [market to book] ratios averaging 2.4, this indicates that these firms have earned and are expected to earn ROEs above the return required by investors."[159] The UCA, in its argument, submitted that "Ms. McShane offers no compelling evidence to support a deviation from the "usual regulatory convention of awarding a flotation allowance of 0.50 per cent … and the UCA recommends no such deviation is warranted."[160]

140. Dr. Booth stated that "Ms. McShane's use of 1.0% is outside anything I would regard as reasonable or found to be acceptable in Canadian regulatory decisions."[161] In this regard, Dr. Booth pointed out that some regulators actually estimate all the costs involved in issuing equity and their tax treatment. For example, the Régie de L'énergie du Québec has, in the past, assessed flotation or issuance costs at 0.30 to 0.40 per cent. However, he also pointed out that it is "a lengthy and expensive exercise to go back and track the costs attached to the shareholder's equity included in rate base."[162] As such, Dr. Booth was prepared to use a 0.50 per cent financial flexibility/issue cost allowance as a compromise, even though actual flotation costs could be lower. According to Dr. Booth, this compromise avoids significant testimony on a relatively minor issue.

156 Exhibit 42.02, McShane evidence for Alberta Utilities, page 129.
157 Transcript, Volume 4, page 489, lines 14-24 (Ms. McShane).
158 Exhibit 42.02, McShane evidence for Alberta Utilities, page 130.
159 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 14.
160 Exhibit 150.02, UCA argument, page 15, footnote omitted.
161 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 21.
162 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 20.

Commission findings

141. The Commission has two primary concerns regarding Ms. McShane's proposal to increase this adjustment to 100 basis points to account for the fact that there is "more financial risk in the utilities' book value capital structures (to which the allowed return is applied) than in the market value capital structures which underpin the market cost of equity."[163] Firstly, as the Commission noted in Decision 2011-474, "[a]rguments that a market return should be applied to a market value based rate base, rather than a book value rate base, are circular since the market value is clearly dependent on the awarded return."[164] During the hearing, Ms. McShane acknowledged that "there is a relationship between return and market value. There's no getting around that."[165]

142. Secondly, the Commission is not persuaded that a valid purpose of the flotation allowance is to take account of the "higher cost of equity due to the higher financial risk inherent in the book value capital structures of the Alberta Utilities to which the return is applied compared to the market value capital structures of the proxy firms used to estimate the cost of equity," as was suggested by Ms. McShane.[166] As noted earlier in this section, in previous GCOC decisions the Commission included a flotation allowance in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[167] The Commission has not, in its review of the evidence and argument submitted in this proceeding, found any compelling reason to re-visit its previously stated position on this issue.

143. In this proceeding, Dr. Booth indicated that flotation or issue costs "are the discount to the market price at the time of issue, the costs of registering securities and compliance etc."[168] Dr. Cleary expressed his understanding that "this allowance … provides coverage of security issuance costs, as well as providing an additional margin of safety for firms in terms of raising financing."[169] All of Dr. Booth, Dr. Cleary and Ms. McShane,[170] agreed that a 50 basis point flotation allowance is sufficient to achieve these purposes (i.e., to cover security issuance costs, to avoid dilution of shareholders equity and to provide an additional margin of safety for firms when raising financing).

144. For the foregoing reasons, the Commission is unable to accept Ms. McShane's proposal to apply a flotation allowance of 100 basis points and finds that a flotation allowance of 50 basis points continues to be reasonable in the circumstances.

5.1.6 The resulting CAPM estimate

145. The following table sets out the recommended individual CAPM components and resulting ROE values for each of the experts that presented evidence on CAPM, or variations thereof.

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[163] Exhibit 155.01, Alberta Utilities reply argument, paragraph 65.
[164] Decision 2011-474, paragraph 75.
[165] Transcript, Volume 4, page 495, lines 8-9 (Ms. McShane).
[166] Exhibit 66.01, AUC-Utilities-5(a).
[167] Decision 2011-474, paragraph 68; Decision 2009-216, paragraph 255.
[168] Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 20.
[169] Exhibit 68.02, AUC-UCA-5(a).
[170] Exhibit 42.02, McShane evidence for Alberta Utilities, page 128, line 3297 to page 129, line 3303.

Table 1. CAPM recommendations

Expert witness	Risk-free rate (%)	MERP (%)	Market return (%)	Beta	Adder (%)	Flotation allowance (%)	ROE (%)
Dr. Booth[171] 2013-2015	4.0 (Note 1)	5.0 – 6.0	9.0 – 10.0	0.45 – 0.55	0.26	0.50	7.50 (7.01 – 8.06)
Dr. Cleary[172] 2013 2014 2015	 2.8 3.5 3.7	 6.0 5.5 5.5	 8.8 9.0 9.2	 0.45 0.45 0.45	 0.2 0.1 0.0	 0.50 0.50 0.50	 6.2 6.58 6.68
Ms. McShane[173] 2013-2015	4.00	7.25	11.25	0.65 – 0.70 (Note 2)	-	1.00	9.9 (9.7 – 10.1) (Note 3)

Note 1: Inclusive of 40 basis points “Operation Twist” adjustment.
Note 2: Ms. McShane estimated a “relative risk adjustment,” rather than a “single risk variable, beta.”
Note 3: Commission staff calculations. Ms. McShane presented her risk premium test results net of flotation allowance.

Commission findings

146. Applying its findings on the individual components of CAPM, as set out in sections 5.1.2 to 5.1.5, the Commission calculates a range of CAPM cost of equity estimates for investors in stand-alone Canadian utilities of 5.80 per cent to 8.75 per cent.

Table 2. Commission’s CAPM findings

Commission’s CAPM findings	Risk-free rate (%)	MERP (%)	Market return (%)	Beta	Flotation allowance (%)	CAPM ROE (%)
2013-2015	2.80 – 3.70	5.0 – 7.0	7.80 – 10.70	0.50 – 0.65	0.50	5.80 – 8.75

5.2 Discounted cash flow model

5.2.1 DCF methodology and predictive value

147. The discounted cash flow (DCF) model is used to estimate the cost of a company’s common equity based on the current dividend yield of the company’s shares plus the expected future dividend growth rate. The DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price.

148. There are several variations of the DCF model, including the single-stage constant growth model, the multi-stage growth model, and the “H-model.” A single-stage constant growth model assumes that growth in dividends and earnings is expected to occur, indefinitely, at the same annual rate. When future growth is expected to vary at different stages (e.g. in respect of a company that may experience a high growth rate in early stages of its development, transition to a slower growth rate as it matures, and finally, settle on a stable long-term growth rate), a multi-stage growth model is employed. The H-model is a variant of the two-stage model, which

[171] Exhibit 44.02, Booth evidence for CAPP, page 3.
[172] Exhibit 45.03, Cleary evidence for UCA, page 32.
[173] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108 and 131.

assumes that growth linearly declines from a current short-term growth rate towards a future stable long-term growth rate over a specified period of time (denoted as 2H).[174]

149. Using a single-stage constant growth model framework, the estimated cost of equity can be expressed as follows:

$$R_e = \frac{D_1}{P_o} + g,$$

where:

> $\boldsymbol{R_e}$ is the required return on common equity
> $\boldsymbol{D_1}$ is the next expected dividend[175]
> $\boldsymbol{P_0}$ represents the current common share market price
> $\boldsymbol{g}$ represents the expected long-term average growth rate in dividends and earnings

150. As can be seen from the equation above, the estimated ROE under a single-stage DCF model flows from a consideration of two components: the dividend yield, (D_1/P_0), and an expected growth in dividends and earnings, g. The application of multi-stage DCF models to calculating an implied ROE is somewhat more complex.[176]

151. All three experts in this proceeding used DCF models to some extent in developing their ROE recommendations. Both Ms. McShane and Dr. Cleary pointed out that the DCF model is commonly used in North America to estimate the cost of equity.[177] However, they did not agree completely with respect to the extent to which the DCF model can be relied on for this purpose.

152. Ms. McShane acknowledged that, in developing her ROE estimate, she placed greater weight on her DCF estimates than on her CAPM results.[178] In her evidence, Ms. McShane explained that the DCF test allows one to "directly estimate the utility cost of equity, in contrast to the [CAPM], which estimates the cost of equity indirectly."[179] Ms. McShane further elaborated on this point in response to UCA-Utilities-48:

> The CAPM model relies on three variables, only one of which is directly related to utility-specific market data, i.e., the relative risk adjustment. The other two variables are a broad market risk premium and a risk-free rate, neither of which represent comparable investments. The inputs to the DCF model (dividend yield and forecast growth) are both utility-specific, and thus relate specifically to comparable investments.[180]

153. The Alberta Utilities also submitted, in argument, that "the DCF test measures the return utility investors do expect, whereas the CAPM estimates the return investors should require under the specific restrictive assumptions of the model." As such, the Alberta Utilities argued

174 Exhibit 42.03, McShane evidence for Alberta Utilities, Appendix C; Exhibit 45.03, Cleary evidence for UCA, pages 34-35.
175 As Ms. McShane explained in Exhibit 42.03, Appendix C, D_1 can be alternatively expressed as $D_0(1+g)$, where D_0 is the most recently paid dividend.
176 See Exhibit 45.03, Cleary evidence for UCA, page 35 for the required return calculation under the H-model.
177 Exhibit 42.02, McShane evidence for Alberta Utilities, page 123; Exhibit 45.03, Cleary evidence for UCA, page 52.
178 Transcript, Volume 1, page 122, line 20 to page 123, line 10 (Ms. McShane).
179 Exhibit 42.02, McShane evidence for Alberta Utilities, page 123.
180 Exhibit 73.01, UCA-Utilities-48(a).

that given "these advantages of the DCF test, combined with the clear systemic problems of the CAPM, the DCF test should be given greater weight by the Commission than in the past."[181]

154. For his part, Dr. Cleary indicated that he would normally choose to rely more heavily on CAPM results over DCF results in determining the ROE estimate. He explained that this is because "CAPM is much more heavily relied upon in practice due to its conceptual advantages" and maintained that the CAPM model is "more intuitive from the point of view of a utility hearing."[182] In support of this position, Dr. Cleary referenced studies showing that only 12 per cent of Canadian CFOs and 15 per cent of U.S. CFOs utilize the DCF model, in contrast to the 40 per cent of Canadian CFOs and over 70 per cent of U.S. CFOs who utilize the CAPM.[183] However, Dr. Cleary also stated that, in this proceeding, he chose to give an equal weighting to the three models that he relied on because CAPM estimates are currently lower than might otherwise be expected due to low risk-free rates.[184]

155. The UCA argued that Ms. McShane "places undue weight on her benchmark utility DCF estimate in determining a proposed ROE for the Alberta Utilities, despite the obvious limitations inherent in such a model."[185] In support of its view in this regard, the UCA referenced the results of studies in Dr. Cleary's evidence demonstrating that CAPM is more widely used by Canadian and U.S. CFOs.

156. Dr. Booth indicated that, conceptually, the results of the DCF and CAPM tests should be consistent. In Dr. Booth's view, to the extent that CAPM and DCF estimates differ significantly, "it is mainly due to the difficulty in estimating the growth rate in the DCF model and the market risk premium [in the CAPM model]."[186] Dr. Booth further noted that he has traditionally viewed his DCF estimates as checks on his CAPM estimates, based on his view that CAPM estimates "are usually in the right 'ball-park.'"[187] However, because of depressed long-term interest rates, Dr. Booth indicated he had "spent more time analyzing [DCF] estimates of the fair rate of return."[188]

157. In argument, CAPP observed that the growth rate is a critical component of DCF, and also the most controversial one. CAPP submitted that "Dr. Booth provides detailed analysis to show that the growth rates used in Ms. McShane's evidence are unreasonably high."[189] Based on the evidence of Dr. Booth, CAPP reached an overall conclusion that "Ms. McShane's growth estimates are unreliable and excessive with the result that her DCF estimates are unreliable and excessive."[190]

158. In its argument, Calgary noted that "Dr. Booth did not do a DCF estimate for any specific company, as he pointed out the problems with this method when applied to specific companies"[191] and submitted that "the Commission should not rely upon a DCF approach to

181 Exhibit 148.01, Alberta Utilities argument, paragraph 71.
182 Exhibit 45.03, Cleary evidence for UCA, page 52.
183 Exhibit 45.03, Cleary evidence for UCA, page 52.
184 Exhibit 45.03, Cleary evidence for UCA, page 53.
185 Exhibit 150.02, UCA argument, page 24.
186 Exhibit 44.02, Booth evidence for CAPP, page 63.
187 Exhibit 44.02, Booth evidence for CAPP, page 63.
188 Exhibit 44.02, Booth evidence for CAPP, page 4.
189 Exhibit 151.01, CAPP argument, paragraph 56.
190 Exhibit 151.01, CAPP argument, paragraph 61.
191 Exhibit 146.02, Calgary argument, paragraph 18.

determine the fair return for the utilities under its jurisdiction."[192] In its reply argument, Calgary further submitted that it "agrees with and supports the CAPP submissions" with respect to the DCF estimates.[193]

Commission findings

159. As is the case with any theoretical model, the DCF method has advantages and drawbacks. For example, Ms. McShane indicated that one of the advantages of the DCF model is that it "directly measures expected utility returns by using utility-specific data only: prices, dividends and estimates of expected growth in the cash flows to investors."[194] However, she also conceded that the DCF model "is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth."[195] Similarly, Dr. Booth surmised that the main difference between the CAPM and DCF estimates is "due to the difficulty in estimating the growth rate in the DCF model and the market risk premium [in the CAPM]."[196]

160. As noted previously, the DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price. The Commission continues to hold the view that the DCF model is a relevant, and theoretically well-grounded economic method for estimating ROE. The Commission further notes that, according to the studies referenced by Dr. Cleary, although the DCF model is less widely used than the CAPM, it is nonetheless still employed by 12 per cent of Canadian CFOs and 15 per cent of U.S. CFOs.[197]

5.2.2 DCF estimates

161. To estimate the cost of equity, Ms. McShane used both a single-stage (constant growth) and a three-stage (variable growth) DCF model, applied to a sample of U.S. and Canadian utilities, which were selected to serve as proxies for the estimation of the benchmark utility cost of equity.

162. For the sample of U.S. utilities, Ms. McShane relied on two estimates of growth rates. The first estimate was based on the average of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg L.P., Thomson Reuters, Value Line Inc., and Zacks Investment Research. The second was an estimate of sustainable growth, calculated as an expected ROE multiplied by an earnings retention rate (a portion of the net income reinvested in a company) and then added to incremental earnings growth achievable as a result of external equity financing.[198]

163. For the Canadian sample, Ms. McShane developed her DCF results using only analysts' growth estimates provided by Reuters. Ms. McShane indicated that there are "no widely

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192 Exhibit 146.02, Calgary argument, paragraph 19.
193 Exhibit 157.02, Calgary reply argument, paragraph 39.
194 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 74-75.
195 Exhibit 42.02, McShane evidence for Alberta Utilities, page 75.
196 Exhibit 44.02, Booth evidence for CAPP, paragraph 160.
197 Exhibit 45.03, Cleary evidence for UCA, page 52.
198 Exhibit 42.02, McShane evidence for Alberta Utilities, page 125.

available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth."[199]

164. The results of Ms. McShane's DCF estimates are presented in the table below. Ms. McShane focused on sample median results in order to offset the effect of outlier forecasts that tended to skew the average.[200]

Table 3. Ms. McShane's DCF estimates (median values)

Sample/model	Dividend yield	Stage 1 growth rate	Stage 2 growth rate	Final growth rate	Investor required ROE
	(%)				
U.S. utilities sample, average analyst constant growth forecasts[201]	4.2	--	--	4.8	9.0
U.S. utilities sample, calculated sustainable growth[202]	4.2	--	--	4.2	8.5
U.S. utilities sample, average three stage growth estimates (GDP growth for final stage)[203]	3.99 (Note 1)	4.8	4.8	4.7	8.8
Canadian utilities sample, average analyst constant growth forecasts[204]	4.2	--	--	7.2	10.8
Canadian utilities sample, average three stage growth estimates (GDP growth for final stage)[205]	3.83 (Note 1)	7.2	5.8	4.3	9.8

Note 1: Median lagged dividend yield, D_0/P_0 (Commission staff calculations).

165. According to Ms. McShane's estimates, both the constant growth and three-stage DCF models indicate a utility cost of equity of approximately 8.75 per cent when applied to the U.S. sample. For the Canadian utilities sample, Ms. McShane calculated the cost of equity to be approximately 10.2 per cent, based on the mid-point of the range between the constant growth and three-stage models. Ms. McShane therefore concluded that the application of both constant growth and three-stage models to the two samples is supportive of a benchmark utility DCF cost of equity in the range of approximately 8.75 per cent to 10.2 per cent, and a mid-point of approximately 9.5 per cent, before the application of a flotation allowance.[206]

166. Dr. Booth performed a DCF analysis at both the market level, and for a sample of six U.S. utilities. In performing his analysis on the market as a whole, Dr. Booth obtained a DCF-based ROE estimate of 9.3 per cent using a high growth estimate and 7.85 per cent using a low growth estimate. According to Dr. Booth, the DCF-obtained estimate range of 7.85 per cent to 9.30 per cent "probably marginally understates the expected equity market return, since we should still expect some short term pick-up in growth in 2014."[207] This is because, at the current point in time, the Canadian economy has largely recovered from recession and is still in a growth phase of the business cycle.

199 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 152 on page 126.
200 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 154 on page 126.
201 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 18.
202 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 19.
203 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 20.
204 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 21.
205 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 22.
206 Exhibit 42.02, McShane evidence for Alberta Utilities, page 127.
207 Exhibit 44.02, Booth evidence for CAPP, paragraph 154.

167. Dr. Booth also used a two-stage growth DCF model in order to provide for a possibility of higher growth in the near term. Using a dividend yield of 3.01 per cent, a long run growth rate at 6.1 percent, and a short-run growth of 9.1 per cent for the next three years, Dr. Booth obtained a DCF-based ROE estimate for the Canadian market of 9.56 per cent. In Dr. Booth's view, this number represents the upper bound of the "overall ROE for a low risk utility" or in other words, "the fair ROE for a utility has to be less than the estimated return for the market as whole of 9.56%."[208]

168. Dr. Booth also performed a DCF analysis for individual firms. However, he voiced a concern that DCF estimates for individual companies have "significant measurement error and of little value added over risk premium estimates."[209] Using data for six U.S. utilities, Dr. Booth estimated an expected ROE averaging 8.23 per cent, based on an average analysts' forecast growth rate of 4.02 per cent. However, Dr. Booth admitted that this estimate "suffers some problems", including that "analysts are optimistic and forecasts start out very optimistic and gradually hone in on the real number as the company releases guidance."[210]

169. In attempting to address these problems, Dr. Booth calculated DCF estimates using the sustainable growth rate formula rather than analysts' forecasts. When using sustainable growth rates, Dr. Booth obtained a DCF ROE estimate averaging 6.08 per cent. In his view, "the use of analyst forecast growth rates provides an upper bound for the fair rate of return estimates for these US utilities and probably the estimates using the sustainable growth rates are marginally low. …"[211] Dr. Booth did not employ a multi-stage DCF model for individual utilities.

170. In a manner similar to Dr. Booth, Dr. Cleary applied a DCF model to the market as a whole, and at the industry level, "using numbers that are 'representative' of a typical publicly-traded utility company in Canada."[212] For the market-level estimates, Dr. Cleary used a long-run nominal GDP growth rate of 5.4 per cent over the 1962 to 2012 period, and a dividend yield of 3.16 per cent, to arrive at an ROE estimate of 8.56 per cent. Using a lower nominal GDP growth rate of 4.65 per cent over the 1992 to 2012 period, Dr. Cleary obtained a DCF ROE estimate of 7.79 per cent.[213]

171. Dr. Cleary also employed an H-model version of the DCF analysis to account for the fact that the expected GDP growth rate for 2013-2015 is currently below the forecast 5.4 per cent long-term level, but is expected to gradually return to that level. Using estimated short-term growth rates of 2.77 per cent and 3.84 per cent, and convergence periods of four and two years, he obtained DCF estimates of between 8.40 per cent and 8.52 per cent. Overall, Dr. Cleary obtained 2013-2015 DCF ROE estimates for the market in the range of 7.8 per cent to 8.6 per cent, and settled on best estimate averages from single-stage and multi-stage DCF models of 8.31 per cent for 2013 and 8.34 per cent for 2014 and 2015. Based on his view that "the implied rate of return for the overall market … should be significantly higher than that for the average utility company which is much less risky than the 'average' company in the market,"

208 Exhibit 44.02, Booth evidence for CAPP, paragraph 157.
209 Exhibit 44.02, Booth evidence for CAPP, paragraph 173.
210 Exhibit 44.02, Booth evidence for CAPP, paragraphs 181-182.
211 Exhibit 44.02, Booth evidence for CAPP, paragraph 184.
212 Exhibit 45.03, Cleary evidence for UCA, page 33.
213 Exhibit 45.03, Cleary evidence for UCA, pages 34-35.

Dr. Cleary concluded that "[a]t minimum, we could say that market DCF estimates above suggest that utility returns should be lower than 8.3%."[214]

172. Dr. Cleary went on to apply the single-stage and H-model DCF analyses to his sample of nine Canadian utilities and obtained single-stage DCF results in the range of approximately 4.9 to 8.2 per cent by adding sustainable growth rates calculated using ROE and retention rate averages to the average dividend yield. Applying the H-model, he obtained results in the range of approximately 6.1 to 8.1 per cent. Overall, Dr. Cleary calculated DCF ROE estimates for his Canadian utility sample of 7.32 per cent for 2013, and 7.67 per cent for 2014 and 2015 before addition of a flotation allowance.[215] Dr. Cleary did not perform a DCF analysis for the U.S. utilities, stating that they are not the best comparison for Alberta utilities. Notwithstanding, Dr. Cleary did observe that the Canadian numbers from this sample were "within range of typical U.S. figures."[216]

173. Ms. McShane, Dr. Booth and Dr. Cleary, all exchanged critiques regarding the specific DCF models employed in their respective analyses, and the results they obtained. For instance, Ms. McShane[217] and Dr. Cleary[218] questioned whether each other's choices of comparator utilities were valid with respect to Alberta utilities.

174. One of Ms. McShane's primary concerns with DCF results obtained by Drs. Booth and Cleary was that their estimates of expected growth rates were based on historical earnings and retention rates, not forecasts. She stated:

> The growth embedded in current prices (and thus the dividend yield component) reflects what investors expect going forward, which may be materially different than past growth rates. Equating expected growth to historic returns and payout ratios is particularly problematic when the companies are in the midst of major growth initiatives, either through capital expenditures or acquisitions as is the case with Canadian Utilities, Emera, Enbridge, Fortis and TransCanada.[219]

175. According to Ms. McShane, because Dr. Booth and Dr. Cleary calculated sustainable growth rates, rather than relying on analysts' earnings growth forecasts, their respective DCF models underestimate the real cost of equity. For example, in her view, if Dr. Booth had used analysts' earnings growth forecasts for his sample of utilities, the resulting DCF cost of equity estimate would be approximately 9.0 per cent, a value that would be comparable to her DCF results.[220]

176. The intervener experts, in turn, expressed concerns with Ms. McShane's reliance on analyst growth estimates, which have been criticized by Canadian regulators, including the AUC, for being overly optimistic. For example, Dr. Cleary stated that even Ms. McShane's median growth estimate of 7.2 per cent "remains an extremely high long-term growth estimate, well above the long-term growth estimate for the economy, which itself seems an ambitious target for

214 Exhibit 45.03, Cleary evidence for UCA, page 36.
215 Exhibit 45.03, Cleary evidence for UCA, page 44.
216 Exhibit 45.03, Cleary evidence for UCA, page 38.
217 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 40.
218 Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 10-11.
219 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 40-41.
220 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 43.

low-risk mature utilities."[221] Similarly, Dr. Booth observed that Ms. McShane's constant growth DCF estimates for the Canadian sample "have long run growth rates that exceed the forecast GDP growth rate which are not only logically impossible but … have already been previously rejected by the AUC."[222]

177. Ms. McShane also expressed concerns with Dr. Booth's and Dr. Cleary's DCF estimates for the market as a whole. She took the position that a constant growth DCF model should not be applied to the market as a whole, because, in her view, the basic underlying assumption that companies' dividends and earnings are expected to grow at a constant rate in perpetuity does not apply to most companies comprising the S&P/TSX Composite Index.[223] With respect to the multi-stage DCF model employed by Dr. Cleary (the H-model), Ms. McShane argued that his assumption that the short-term expected growth rate is lower than the long-term growth rate of the economy "is at odds with the earnings forecasts made by analysts for the specific companies that make up the [S&P/TSX Composite Index]."[224] Regarding the multi-stage DCF model employed by Dr. Booth, Ms. McShane similarly stated that the addition of a dividend yield applicable to the S&P/TSX Composite Index to a sustainable growth rate based on all of "Corporate Canada" is not appropriate, as the S&P/TSX Composite Index is not equivalent to "Corporate Canada."[225]

178. For their part, both Dr. Cleary[226] and Dr. Booth[227] observed that Ms. McShane's three-stage DCF model assumes five years of high growth at the outset (based on analysts' estimates), then declines to a point mid-way between this initial estimate and the long-term expected growth rate for the years six to 10, followed by a long-run terminal growth rate beginning at year 10. Consequently, the analysts' estimated initial growth rate affects subsequent growth estimates for the first 10 years. According to Dr. Cleary, it is "unclear why one would expect 'above' average growth would persist for 10 years in a mature industry, so this also represents an aggressive assumption."[228]

Commission findings

179. There was substantial disagreement between the Alberta Utilities' expert, Ms. McShane, and the interveners' experts, Dr. Booth and Dr. Cleary, regarding many aspects of the DCF model. One of the main points of disagreement between the experts was whether to use analysts' forecasts of growth rates or to calculate sustainable growth rates based on historical data.

180. In the Commission's view, each method described by the various experts presents with its own mixture of strengths and weaknesses. For example, analysts' forecasts of growth rates are forward-looking and aim to expressly account for events expected in the future. However, these same forecasts tend to incorporate a high degree of subjectivity and may be overly optimistic.[229] On the other hand, sustainable growth rate estimates are calculated objectively using historical data, but they do not allow for the possibility that the rate of growth going forward may be

221 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.
222 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 5.
223 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
224 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
225 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 40.
226 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 13.
227 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 7.
228 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 13.
229 Exhibit 44.02, Booth evidence for CAPP, paragraphs 181-182.

different from past growth rates.[230] Given these trade-offs, and considering that both methods are currently used to estimate the dividends and earnings growth component of the DCF model (as evidenced by the ongoing academic debate in the literature concerning the desirability of their use[231]), the Commission does not consider it necessary to accept one method to the exclusion of the other, but rather accepts the basic validity of both of these methods for purposes of this decision.

181. Consistent with its determinations in Section 5.4 of this decision, the Commission agrees with Dr. Cleary's and Dr. Booth's view that DCF model-generated ROE estimates for the equity market as a whole is a valid input in determining a fair cost of equity for the utilities industry. Ms. McShane contended that a constant growth DCF model should not be applied to the market as a whole because the underlying assumption that the companies' dividends and earnings are expected to grow at a constant rate in perpetuity does not apply to most of the 249 companies comprising the S&P/TSX Composite Index; the index upon which Dr. Booth and Dr. Cleary based their equity market DCF estimates.[232] However, in the Commission's view, the use of the long-term averages across many companies would tend to mute the individual characteristics of the companies comprising the index, and will, therefore, provide a reasonable approximation of both the long-term dividend yield and growth rate for the equity market as a whole.

182. The Commission observes that Dr. Cleary's and Dr. Booth's DCF ROE estimates for the market as a whole are generally consistent. In their respective analyses, both these experts estimated a dividend yield in the 3.01 to 3.16 per cent range. Dr. Cleary estimated a long-run nominal GDP growth rate of 5.4 per cent, resulting in a DCF estimate of 8.56 per cent,[233] while Dr. Booth estimated the growth rate to be in the range of 4.7 per cent to 6.1 per cent, resulting in a single-stage DCF estimate of 7.85 per cent to 9.30 per cent.[234]

183. However, the results of the multi-stage DCF models applied to the market as whole were not as consistent. Based on his H-model DCF analysis, Dr. Cleary estimated the ROE to be approximately 8.3 per cent; he was the only expert in this proceeding to assume that the short-term growth rate will be lower than the long-term nominal GDP growth. Using a two-stage DCF model, Dr. Booth obtained a DCF ROE estimate for the Canadian market of 9.56 per cent. However, this estimate assumes a short-term growth of 9.0 per cent for the first three years.[235] Due to this apparent divergence of opinion regarding appropriate short-term growth rate inputs, the Commission did not include the results of the multi-stage DCF models applied to the market as whole in its consideration of the ROE value.

184. Based on a single-stage DCF analysis applied to the market as a whole, as performed by Dr. Cleary and Dr. Booth using long-term averages, the Commission finds a DCF-based average ROE estimate for the equity market in the range of 8.0 to 9.0 per cent to be reasonable. The Commission agrees with these experts that ROE estimates for the market as a whole may be viewed as the upper bound of the fair ROE for regulated utilities, given that the average utility

[230] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 40-41.
[231] See for example, references to academic studies in Exhibit 42.03. Appendices to Ms. McShane evidence for Alberta Utilities, Appendix C, page C-6; Exhibit 44.02, Booth evidence for CAPP, footnote 46 on page 71.
[232] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
[233] Exhibit 45.03, Cleary evidence for UCA, page 35.
[234] Exhibit 44.02, Booth evidence for CAPP, paragraphs 153-154.
[235] Exhibit 44.02, Booth evidence for CAPP, paragraph 156.

company is typically less risky than the average company in the market.[236] Therefore, the Commission also considers that the higher-end estimate of 9.0 per cent may be considered an upper limit of a fair cost of equity for regulated utilities.

185. Ms. McShane, Dr. Cleary and Dr. Booth all applied single-stage DCF analyses to different samples of utilities to arrive at their respective ROE estimates. However, these three experts could not agree on the representativeness of each other's utility samples. In previous GCOC decisions, the Commission also expressed concern about using proxy companies in a DCF analysis that are utility holding companies engaged in significant unregulated activities.[237]

186. The Commission also notes that the individual experts' growth estimates varied greatly. For this reason, and in a manner consistent with its determinations in prior GCOC decisions,[238] the Commission will not accept the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate in a single-stage DCF model. This is because, as Dr. Booth explained, the terminal growth rate in the single-stage DCF model "cannot exceed the growth rate in the economy. Otherwise, sooner or later the firm is bigger than the entire economy."[239] The Commission does, nonetheless, accept that the use of higher growth rates in initial stages of multi-stage DCF models may well be justified in some circumstances as a means of addressing a time period that precedes the establishment of a stable, terminal growth rate.

187. In response to AUC-Utilities-4(a), Ms. McShane indicated that any issues arising from forecast earnings growth rates that exceed GDP growth rates relate primarily to her sample of Canadian regulated companies. She also explained that in the case of her U.S. utility sample, the growth rate is very close to the forecast GDP growth rate.[240]

188. In attempting to discern the impact of using forecast earnings growth rates that exceed GDP on the predictive value of Ms. McShane's DCF models, the Commission observes that, if a long-run nominal GDP growth rate range of 4.3 per cent[241] to 5.4 per cent[242] is used rather than Ms. McShane's median estimate of 7.2 per cent, the resulting single-stage DCF ROE estimate for her Canadian sample (using the median dividend yield of 4.2 per cent) ranges from 8.5 per cent to 9.6 per cent.[243] The Commission further notes that Ms. McShane's three-stage DCF model for her Canadian sample, which relied on a 7.2 per cent short-term growth estimate, produced a median ROE estimate of 9.8 per cent.[244]

189. Dr. Booth obtained DCF ROE estimates for his U.S. utilities sample ranging from 6.08 per cent to 8.23 per cent using sustainable growth calculations and analysts' growth forecasts, respectively.[245] Dr. Cleary's best estimate of a single-stage DCF ROE for his Canadian utilities sample was 6.77 per cent for 2013, and 6.94 per cent for both 2014 and 2015, before

236 Exhibit 45.03, Cleary evidence for UCA, page 36; Exhibit 44.02, Booth evidence for CAPP, paragraph 157.
237 Decision 2011-474, paragraph 87; Decision 2009-216, paragraph 269.
238 Decision 2011-474, paragraph 85; Decision 2009-216, paragraph 270.
239 Exhibit 44.02, Booth evidence for CAPP, page 59, paragraph 148.
240 Exhibit 66.01, AUC-Utilities-4(a).
241 Forecast nominal rate of GDP growth from Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 22.
242 Estimated long-run nominal GDP growth rate from Exhibit 45.03, Cleary evidence for UCA, page 35.
243 Exhibit 42.04, Ms. McShane evidence for Alberta Utilities, Schedule 21.
244 Exhibit 42.04, Ms. McShane evidence for Alberta Utilities, Schedule 22.
245 Exhibit 44.02, Booth evidence for CAPP, paragraph 184.

addition of a flotation allowance.[246] The Commission notes that both Drs. Booth and Cleary relied on sustainable growth estimates in the approximately two to three per cent range in developing their estimates.[247] The Commission further notes that the short-term and long-term growth estimates used by Dr. Cleary in his H-model DCF calculation fell within a similar range.[248]

190. Dr. Booth acknowledged that the 6.08 to 6.44 per cent ROE estimates generated using sustainable growth rates were "marginally low."[249] The Commission agrees, and further observes that if a long-run nominal GDP growth rate of between 4.3 and 5.4 per cent is used as a sustainable growth rate, the single-stage DCF models of both Dr. Cleary and Dr. Booth generate cost of equity estimates in the range of approximately 8.2 to 9.4 per cent (based on an approximate dividend yield of 4.0 per cent). However, the Commission is also mindful that, as both experts acknowledged, the GDP growth rate may be an ambitious target for long-run earnings growth in respect of low-risk, mature, utilities.[250]

191. After considering the characteristics of the various DCF-based ROE estimation models employed by the participating expert witnesses, the Commission finds that reasonable DCF estimates for the Alberta Utilities are in the range of 7.0 per cent to 9.0 per cent and that this range is consistent with an expected average equity market return of between 8.0 per cent and 9.0 per cent. In arriving at this conclusion, the Commission notes that Ms. McShane's DCF results for her U.S. utility sample, for which the growth rates were very close to the forecast GDP growth rate,[251] were in the range of 8.5 per cent to 9.0 per cent.[252] However, the Commission considers growth rates that are close to the forecast GDP growth rate to be overly optimistic for regulated utilities.

192. Consistent with its treatment of estimates obtained from the submitted CAPM analyses, the Commission has included a 50 basis points flotation allowance adjustment in its DCF analysis. Although these DCF results appear to suggest that investors expect a return of between 7.5 per cent to 9.5 per cent on utility investments, inclusive of a flotation allowance, the Commission is mindful that these estimates assume that the utilities' dividends and earnings will grow at the long-run GDP growth rate, which may be an optimistic target for relatively low risk mature regulated utilities.[253]

193. Finally, the Commission observes that in this proceeding, as in previous GCOC proceedings, there was a continuing debate regarding the representativeness of the various utility samples used to generate the many DCF estimates that were submitted for the Commission's consideration. Additionally, the participating expert witnesses employed widely divergent growth estimates. As a result, the Commission found itself unable to determine whether the DCF evidence of any particular expert was clearly superior to that of another in terms of either

246 Exhibit 45.03, Cleary evidence for UCA, Table 14, page 44.
247 Exhibit 44.02, Booth evidence for CAPP, page 71; Exhibit 45.03, Cleary evidence for UCA, Table 11, page 39; Exhibit 45.03, Cleary evidence for UCA, Table 12, page 41.
248 Exhibit 45.03, Cleary evidence for UCA, Table 13, page 42.
249 Exhibit 44.02, Booth evidence for CAPP, paragraph 184.
250 Exhibit 44.02, Booth evidence for CAPP, paragraph 185; Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.
251 Exhibit 66.01, AUC-Utilities-4(a).
252 Exhibit 42.02, McShane evidence for Alberta Utilities, page 127.
253 Exhibit 44.02, Booth evidence for CAPP, paragraph 185; Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.

methodology or data. Consequently, the Commission drew on various aspects of evidence provided by all witnesses and then used its own judgment and expertise in arriving at the determination that DCF estimates in the identified range are reasonable in all the circumstances.

5.3 Price-to-book ratios

194. As the Commission explained in previous GCOC decisions, an equity price-to-book (P/B) ratio, also known as a market-to-book ratio, is calculated by dividing the current market share price of a company's stock by its current per share book value. It is often used to compare the capital market's perception of a company's value, as reflected by the price investors are willing to pay for its stock, to the company's book value.

195. For example, an equity P/B value significantly above 1.0 indicates that a company's market value of equity is significantly higher than the book value at which the owner's equity in assets is carried on the company's balance sheet. The converse is also true. A P/B value below 1.0 indicates that the company's book value of its equity exceeds the market's valuation at a particular point in time.

196. There are many reasons why a company's observed P/B ratio may deviate from a value of 1.0. For example, as Dr. Cleary explained, an equity P/B value may be significantly above 1.0 when a company's ROE is exceeds the return required by equity investors whereas a ratio close to 1.0 indicates that the company's ROE equals the return required by equity investors.[254] In practice, a P/B ratio slightly above 1.0 is preferred, as it prevents equity ownership dilution when new shares are issued. This appreciation of P/B ratios was endorsed by the Commission in Decision 2009-216, where it expressed its view that "a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair."[255]

197. In Decision 2011-474, the Commission considered the issue of whether the utilities' P/B ratios have any significance to the establishment of a fair ROE. The Commission concluded:

> 121. In the Commission's view, it would not be rational for investors to purchase a utility at a premium, unless it was of the view that it could earn at least a market rate of return on the investment despite paying the premium. The payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational. A possible conclusion is that such purchases, at substantial premiums, would indicate that the awarded returns were more than sufficiently attractive.
>
> 122. Again, the Commission finds, as it did in Decision 2009-216, that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies. With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood. In these circumstances, it is difficult for the Commission to draw any conclusions about the significance of this transaction to the establishment of a fair return on equity. Nonetheless, the Commission agrees with the observation that a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true

[254] Exhibit 45.03, Cleary evidence for UCA, page 51.
[255] Decision 2009-216, paragraph 295.

> cost of capital. Estimates of the price to book ratio for the 2011 AltaLink transaction generally exceed 1.0 by a significant margin. This appears to be evidence that the allowed ROE at the time of the purchase was at least adequate.[256]

198. On May 1, 2014, Berkshire Hathaway Energy Co. (BHE) announced it "has reached a definitive acquisition agreement whereby Berkshire Hathaway Energy will acquire AltaLink, an indirect, wholly owned subsidiary of SNC-Lavalin Group Inc. (TSX:SNC). Under the terms of the agreement, Berkshire Hathaway Energy will purchase 100 percent of AltaLink for an estimated C$3.2 billion (approximately US$2.9 billion) in cash."[257] The Commission viewed this announcement as being potentially relevant to the determinations that it would be required to make in this proceeding. Consequently, it issued a supplemental IR to AltaLink[258] and provided for the filing of supplemental evidence by all parties on how, if at all, this transaction relates to matters that are being considered in the current GCOC proceeding.

199. In supplemental evidence filed by the UCA, Dr. Cleary estimated the P/B ratio associated with the BHE's proposed acquisition of AltaLink to be in the range of 1.53 to 1.68.[259] The Commission considers, however, that strictly speaking, this calculation does not represent an equity P/B ratio, since it includes debt and goodwill, and not just the common equity, on the entity's balance sheet. During the hearing, Dr. Cleary acknowledged that he had not made adjustments in his calculations to account for goodwill and the assumed debt associated with the transaction, which, if taken into account, would have raised the P/B ratio into the range of 1.5 to 2.3.[260]

200. According to Dr. Cleary, the fact that the calculated P/B ratios are greater than 1.0 "suggests the allowed and/or expected ROEs are well above the required rate of return by equity investors."[261] Overall, while Dr. Cleary did not assign any specific weight to these estimates for purposes of determining the required ROE, he concluded that "the bottom line of this discussion is that the P/B ratio paid for AltaLink supports my estimates for Ke [required ROE], and also clearly indicates that Alberta utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time."[262]

201. Ms. McShane did not agree that the P/B ratio resulting from the proposed acquisition of AltaLink by BHE had any probative value with respect to making ROE determinations for the Alberta utilities. During the hearing, Ms. McShane expressed her two concerns with relying on any P/B ratios for AltaLink:

> One is that the acquisition is not at the AltaLink LP level. It's a couple of levels up. And the second thing is that the purchase is not expected to be complete until the end of the year, so the common equity that's sitting here on the AltaLink LP balance sheet would be less than what would be expected to be in place at the time.[263]

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256 Decision 2011-474, paragraphs 121-122.
257 http://www.berkshirehathawayenergyco.com/news/berkshire-hathaway-energy-announces-acquisition-of-altalink-l-p-and-joint-transmission-development-agreement-with-snc-lavalin
258 Exhibit 86.01, AUC-Utilities-AML-21.
259 Exhibit 101.02, Cleary supplemental evidence for UCA, page 2.
260 Transcript, Volume 6, page 863, line 1 to page 864, line 20 (Dr. Cleary).
261 Exhibit 101.02, Cleary supplemental evidence for UCA, page 2.
262 Exhibit 101.02, Cleary supplemental evidence for UCA, page 3.
263 Transcript, Volume 4, page 528, lines 19-24 (Ms. McShane).

202. Both Ms. McShane[264] and Mr. Fetter[265] indicated that a multitude of reasons inform the price an investor is willing to pay in utility acquisitions, including geographic diversification ("establishing … a beach head in Alberta which allows for the potential entry into unregulated or competitive markets"[266]), synergies and "efficient structuring for tax purposes."[267] Overall, Ms. McShane concluded that "given the myriad of factors that determine what price someone is willing to pay for a company like AltaLink, that you can tell whether or not they would view – that the buyer would view 8.75, for example, as a fair return."[268]

203. Based on the views of their experts, Ms. McShane and Mr. Fetter, the Alberta Utilities argued that "Dr. Cleary's speculation and observations respecting the P/B ratio associated with the contemplated BHE transaction should be given no weight in the Commission's determination of the fair return for the Alberta Utilities in this proceeding."[269]

204. Dr. Booth and Mr. Johnson, who provided expert testimony for Calgary, also took note of the BHE proposed acquisition of AltaLink. They did not attempt to calculate a P/B ratio based on the particulars of the transaction, but instead, commented generally that based on the proposed purchase price and AltaLink's equity numbers from its Rule 005 financial statements, there appeared to be "a healthy premium over the book value of the equity (market to book ratio) …[which] indicates no shareholder concerns about either the allowed ROE or common equity for a major Alberta regulated utility."[270]

205. For his part, Dr. Booth also echoed some of Ms. McShane's concerns regarding the probative value of P/B ratios, and indicated that because regulators are usually looking at P/B ratios at the holding company level, rather than a pure-play utility level (giving rise to the "dirty window" problem[271]), it is "extremely difficult to look at market-to-book ratios to get anything other than a sense of do the shareholders seem to be satisfied with the rate of return."[272] Dr. Booth also stated that to properly calculate the P/B ratio associated with the proposed purchase of AltaLink, one needs to "extract goodwill, forecast the rate base and the extra injections of equity that SNC-Lavalin is going to be putting in, and then make an estimate of the market-to-book ratio and the price-to-book ratio should the transaction go through in December 2014."[273]

206. Without performing a detailed calculation, Dr. Booth surmised that the P/B ratio associated with the AltaLink purchase by BHE "is clearly going to be well above 1.15."[274] Dr. Booth concluded:

> I would say here, at the very minimum the Commission can say what it said in previous cases, which you looked at the market-to-book ratios and can take comfort in the fact that the financial metrics currently allowed are certainly not aggressive, because otherwise

264 Transcript, Volume 4, page 529, line 14 to page 530, line 11 (Ms. McShane).
265 Transcript, Volume 4, page 530, line 23 to page 531, line 3 (Mr. Fetter).
266 Transcript, Volume 4, page 529, lines 22-25 (Ms. McShane).
267 Transcript, Volume 4, page 530, line 3 (Ms. McShane).
268 Transcript, Volume 4, page 536, lines 17-21 (Ms. McShane).
269 Exhibit 148.01, Alberta Utilities argument, paragraph 111.
270 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 8.
271 Transcript, Volume 7, page 959, line 6 to page 960, line 7 (Dr. Booth).
272 Transcript, Volume 7, page 959, lines 22-25 (Dr. Booth).
273 Transcript, Volume 7, page 1119, line 23 to page 1120, line 2 (Dr. Booth).
274 Transcript, Volume 7, page 1120, lines 3-4 (Dr. Booth).

> you wouldn't be seeing goodwill layered on top of goodwill and such a premium paid for regulated assets.
> So I wouldn't go as far as professor Cleary at this stage in calculating in part a rate of return. You can do that using the DCF model. I would just say the Commission can take comfort that it's not being particularly tough on the utilities.

207. Based on the evidence of Dr. Booth, CAPP submitted the following in its argument:

> The continued attractiveness of utilities as acquisition targets both in Canada and in the U.S. at significant premiums to book-equity supports the conclusion that allowed returns are not too low and are consistent with Dr. Booth's view that there is room to lower ROEs. Regulators are cautious when dropping allowed returns apparently for fear it may affect capital attraction. Yet regulatory lag likely explains the reason why market-to-book values for utilities remain very high in a low interest rate environment. The use of formulas has shown that ROEs can be lowered year after year when it is done in a transparent, predictable way and still maintain capital attraction and financial integrity (despite utilities endless cries of 'no fair').[275]

208. In argument, the CCA, based on the evidence of Drs. Cleary and Booth, submitted that "it is a further fair inference the allowed rate of return for Alberta utilities was sufficient to attract a significant amount of capital from an investor. The CCA submits this speaks to the current level of return being satisfactory as significant capital attraction has occurred."[276] The CCA also stated:

> It is a fair further inference [that] the due diligence of a 3.2 billion dollar investor would include some assessment of the matters currently and expected to be at risk for the owner acquiring the assets and this, we submit, includes recent, ongoing and expected regulatory events which impact the operation of the assets, their financial performance and the return to the shareholder. …[277]

209. In the CCA's view, the above observations "are indicative of the significance of the proposed acquisition and this can provide comfort to the AUC that under the status quo in [light] of what may be expected the entities regulated by the AUC do attract capital."[278]

Commission findings

210. There was considerable debate in this proceeding as to the relevance, if any, of price-to-book ratios. Ms. McShane pointed to the following three issues as supportive of her view that examining the P/B ratio resulting from the proposed acquisition of AltaLink by BHE is of little or no probative value relative to the ROE determinations for the Alberta utilities:[279]

- The acquisition is not at the AltaLink LP (the regulated utility) level. It is "a couple of levels up,"[280] with BHE proposing to acquire the equity in (i) AltaLink Holdings, L.P. and (ii) SNC-Lavalin Energy Alberta Ltd. and by doing so will acquire interest in the subsidiary entities.[281]

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275 Exhibit 151.01, CAPP argument, paragraph 89.
276 Exhibit 149.01, CCA argument, paragraph 15.
277 Exhibit 149.01, CCA argument, paragraph 16.
278 Exhibit 149.01, CCA argument, paragraph 17.
279 Transcript, Volume 4, page 528, line 19 to page 530, line 11 (Ms. McShane).
280 Transcript, Volume 4, page 528, lines 19-20 (Ms. McShane).
281 Exhibit 86.01, AUC-Utilities-AML-21(b).

- The purchase is not expected to be completed until the end of 2014, so any calculation of the P/B ratio would require a forecast of common equity on the AltaLink L.P. balance sheet at the time of the transaction.
- There are multiple reasons that inform the price an investor is willing to pay in utility acquisitions, including geographic diversification, synergies and re-structuring for tax purposes.

211. Dr. Booth referred to the first issue as a “dirty window” problem.[282] This problem describes the difficulty attendant in interpreting market-to-book value ratios of corporate shares where the subject company has significant unregulated activities in addition to regulated operations. Dr. Booth pointed out that to properly calculate the P/B ratio at the regulated company level, it is necessary to adjust the observed P/B ratio by taking into account any goodwill, debt and equity at the holding company level (for which the P/B ratio is observed), at the time of the transaction.[283] Dr. Cleary generally agreed with this type of adjustment.[284]

212. In Decision 2011-474, the Commission indicated it was “unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies.”[285] The Commissions previous conclusion in this regard flows from the general “dirty window” concern identified by Dr. Booth. In this case, however, the Commission considers that any “dirty window” problem associated with the proposed purchase of AltaLink by BHE does not vitiate the probative value of the observed P/B ratio in making an ROE determination. This is because although the transaction in question involves the indirect acquisition of a regulated utility through the purchase of a holding entity, the holding entity has no operations, tangible assets, or earnings arising from sources apart from the utility. In this sense, the transaction may be appreciated as being the functional equivalent of an acquisition of a “pure-play” utility.

213. The organizational chart of the AltaLink companies provided in a DBRS rating report dated September 25, 2013, shows that the capital structure of the companies “a couple of levels up” from the regulated utility, AltaLink Holdings, L.P. and AltaLink Investments, L.P., include $640 million in senior unsecured debt non-consolidated in those entities, in addition to debt at the regulated utility level, AltaLink L.P.[286] In response to AUC-Utilities-AML-21, AltaLink confirmed that, as part of the transaction, “BHE will acquire 100% of the equity interests of the AltaLink entities including the assumption of debt existing at each entity at the date of the closing.”[287] Financial statements provided in response to that IR show that the balance sheet for AltaLink L.P. as of March 31, 2014, reflects goodwill in the amount of $202 million.[288]

214. As Drs. Booth[289] and Cleary[290] indicated, the P/B ratio in respect of the AltaLink transaction may need to be adjusted to account for additional layers of debt at the holding company level in order to mitigate any “dirty window” concern and adequately address valuation

282 Transcript, Volume 7, page 959, line 6 to page 960, line 7 (Dr. Booth).
283 Transcript, Volume 7, page 1119, line 23 to page 1120, line 2 (Dr. Booth).
284 Transcript, Volume 6, page 858; Transcript, Volume 6, pages 863-864 (Dr. Cleary).
285 Decision 2011-474, paragraph 122.
286 Exhibit 66.01, AUC-Utilities-20(d) Attachment, DBRS Rating Report on AltaLink Investments, L.P. dated September 25, 2013, PDF page 644.
287 Exhibit 86.01, AUC-Utilities-AML-21(c).
288 Exhibit 86.01, AUC-Utilities-AML-21(c)-(ii)-B, PDF page 44.
289 Transcript, Volume 7, page 1119, lines 7-22 (Dr. Booth).
290 Transcript, Volume 6, page 858, line 10 to page 859, line 2 and page 863, lines 8-20 (Dr. Cleary).

concerns relating to goodwill reflected on AltaLink L.P.'s balance sheets. Without evaluating the specific need for any such adjustments, the Commission observes that in this case, any such adjustments would directionally increase the implied equity P/B ratio for the tangible equity at the regulated utility level. The Commission also observes that AltaLink L.P. earns a regulated return on the equity invested in approved rate base (which is roughly equal to tangible book value) and that no additional return is awarded in respect of equity invested in goodwill, which is an intangible asset.

215. In relation to the second area of concern identified by Ms. McShane, the Commission considers that the magnitude of the potential adjustments discussed above is likely to exceed any effects on P/B ratio of equity injections to AltaLink L.P from March 31, 2014 (the date of the financial statements) to the end of 2014 (the date when the purchase is expected to be completed). In this regard, the Commission agrees with Dr. Booth's observation that it "would have to have huge capital injections by SNC-Lavalin to cause problems."[291]

216. Based on the above, the Commission considers that Dr. Cleary's estimate of the P/B ratio associated with the proposed purchase of AltaLink by BHE in the range of 1.5 to 2.3, after accounting for goodwill and the assumed debt associated with the transaction, is reasonable.[292] In arriving at this conclusion, the Commission notes that Dr. Booth also surmised that the P/B ratio associated with the AltaLink purchase by BHE "is clearly going to be well above 1.15."[293]

217. Ms. McShane's last identified area of concern related to reliance on P/B ratios was based on her observation that there are multiple reasons that inform the price an investor may be willing to pay in utility acquisitions, including geographic diversification, synergies and benefits associated with re-structuring for tax purposes. The Commission agrees that these are relevant considerations when assessing the significance of a P/B ratio associated with a given transaction.

218. In Decision 2011-474, the Commission stated: "With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood."[294] Furthermore, in its report on this particular acquisition, S&P indicated that "AILP [AltaLink Investments L.P.] will be of more strategic importance to BHE than its nonstrategic status to SNC-Lavalin and that this could affect the ratings after the close."[295]

219. However, even when these considerations are taken into account, the Commission accepts the general proposition of Drs. Cleary[296] and Booth that there is "a healthy premium over the book value of the equity"[297] associated with BHE's proposed purchase of AltaLink. The Commission further considers that this apparent "healthy premium" is sufficiently large to support a reasonable conclusion that it accommodates the influence of any strategic motives on behalf of BHE (diversification, synergies and re-structuring for tax purposes), as well as a

291 Transcript, Volume 7, page 1120, lines 4-5 (Dr. Booth).
292 Transcript, Volume 6, page 863, line 1 to page 864, line 20 (Dr. Cleary).
293 Transcript, Volume 7, page 1120, lines 3-4 (Dr. Booth).
294 Decision 2011-474, paragraph 122.
295 Exhibit 86.01, AUC-Utilities-AML-21(a), Standard & Poor's Ratings Services, Research Update: AltaLink Investments L.P. Outlook Revised To Positive On Announced Sale To Berkshire Hathaway Energy Co. Issued May 5, 2014, page 2.
296 Transcript, Volume 6, page 864, lines 17-20 (Dr. Cleary).
297 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 8.

conclusion that the utilities' previously awarded or expected ROE was sufficiently attractive for BHE to support its decision to invest in the utility at the proposed price.

220. Further in this regard, the Commission notes the CCA's argument that BHE's decision to purchase AltaLink's transmission business considered the impact of the regulatory framework, including the most recent Commission award of 8.75 per cent ROE in the 2011 GCOC decision:

> It is a fair further inference [that] the due diligence of a 3.2 billion dollar investor would include some assessment of the matters currently and expected to be at risk for the owner acquiring the assets and this, we submit, includes recent, ongoing and expected regulatory events which impact the operation of the assets, their financial performance and the return to the shareholder. …[298]

221. Overall, the Commission confirms its findings in Decision 2011-474[299] that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity.

222. The implied P/B ratio associated with the proposed purchase of AltaLink by BHE gives the Commission comfort that its previous ROE awards have not been too low. As stated in previous GCOC decisions, and most recently in Decision 2011-474, the "payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational."[300]

223. Directionally, the Commission concludes that the implied P/B ratio associated with the proposed purchase of AltaLink by BHE is relevant and supports continuation of an ROE no higher than the Commission's allowed ROE of 8.75 percent awarded in Decision 2011-474, all other things being equal.

5.4 Pension, investment manager and economist return expectations

224. In his evidence, Dr. Cleary considered return expectations of finance professionals such as financial planners, actuaries, investment managers and pension fund managers as a means of confirming his ROE estimates. Dr. Cleary observed:

> … Indeed, aggregate stock market return expectations of 8-9% has become the "norm" in terms of planning among today's investment professionals including actuaries, pension plans, financial advisors, and most professional and retail investors. Hence, it seems that in this environment, it is reasonable to expect that the required return on regulated utility companies should be lower than the average expected market returns, given their below average risk profiles.[301]

298 Exhibit 149.01, CCA argument, paragraph 16.
299 Decision 2011-474, paragraph 122.
300 Decision 2011-474, paragraph 121.
301 Exhibit 45.03, Cleary evidence for UCA, page 2.

225. In response to AUC-UCA-6, Dr. Cleary provided support for the referenced 8.0 per cent to 9.0 per cent aggregate stock market return expectations.[302]

226. Dr. Booth referenced the TD Economics projections "of the long-run returns of the type needed in defined benefit pension plans."[303] The TD Economics projected geometric long-run return for equities was seven per cent, which equals an approximately nine per cent arithmetic average annual rate of return, as calculated by Dr. Booth.[304] Dr. Booth also referenced the RBC long-run forecast of U.S. equity market return of 4.9 per cent, however, he regarded this forecast as "unduly pessimistic." Based on these market return projections, Dr. Booth concluded that his forecast for the overall equity market return of 9.56 per cent is not low.[305]

227. In response to UCA-Utilities-33(b), Ms. McShane referenced the 2013 Towers Watson Wyatt survey of economists and portfolio managers. According to this survey, the median forecast return for the S&P/TSX composite for the long-term was seven per cent,[306] which equals a 9.75 per cent arithmetic average rate of return, as calculated by Ms. McShane.[307]

228. Ms. McShane questioned the relevance of the return expectations of finance professionals to a determination of an appropriate ROE. In her view, this value "represents the return that investors might expect from a diversified equity stock portfolio, but does not represent the returns that investors expect or require from investments in companies of comparable risk. In other words, it does not address the comparable investment requirement of the fair return standard."[308] However, during the hearing, Ms. McShane also acknowledged that returns from low risk utility investments are likely to be lower than the overall equity stock portfolio return:

> Q. But just so I'm clear, utility -- investments in utilities, lower risk, lower return than generally you'd expect in an overall portfolio that a pension fund manager invests in. Is that a fair statement?
> A. MS. MCSHANE: I would say it's a fair statement that you would expect a lower return from a utility than an average risk stock.[309]

229. Ms. McShane also pointed out that finance professionals "have every incentive to be quite conservative."[310] With reference to Ms. McShane's evidence in this regard, the Alberta Utilities submitted that the Commission should decline to give weight to return expectations by finance professionals in establishing a fair ROE.[311]

230. In Calgary's view, the use of return forecasts by finance professionals should not be relied upon by the Commission without analyzing and making adjustments to the values being considered. Calgary submitted that "the Commission has the responsibility to determine a fair

302 Exhibit 68.02, AUC-UCA-6(a).
303 Exhibit 44.02, Booth evidence for CAPP, paragraph 169.
304 Exhibit 44.02, Booth evidence for CAPP, paragraph 170.
305 Exhibit 44.02, Booth evidence for CAPP, paragraph 198.
306 Exhibit 73.01. UCA-Utilities-33(b).
307 Transcript, Volume 4, page 480, lines 22-25 (Ms. McShane).
308 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 38.
309 Transcript, Volume 1, page 127, lines 16-22 (Ms. McShane).
310 Transcript, Volume 4, page 484, lines 3-10 (Ms. McShane).
311 Exhibit 148.01, Alberta Utilities argument, paragraph 92.

return, and it should not abdicate that responsibility to another party for which it has no detailed information as to how or on what basis the party made a forecast."[312]

231. In argument, the UCA observed that in Decision 2004-052,[313] the Commission's predecessor, the Alberta Energy and Utilities Board (the board), recognized the potential for forecast pension return estimates to be conservative, but nonetheless concluded "the Board would expect the required return for utilities to be below the required overall equity market return."[314] The UCA also noted that, in its 2011 GCOC decision, the Commission weighed the market return expectations of pension funds, investment managers and economists in reaching a conclusion as to the appropriate allowed ROE.

232. Therefore, in the UCA's view, return expectations by finance professionals continue to be illustrative in the current proceeding. In the UCA's submission, the expectations of investment professionals as to market returns remain relevant to, and create a benchmark and upper bound for, estimates of an appropriate allowed ROE.[315]

Commission findings

233. As pointed out by the UCA, previous GCOC decisions of the Commission and its predecessor, the board, took the return expectations by finance market professionals such as investment managers, pensions fund managers and economists into consideration in arriving at an allowed ROE value. The Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.

234. In Decision 2004-052, the board determined that "forecast pension returns on equity investment are a valid indicator, albeit potentially conservative, of the forecaster's current market equity return expectation."[316] The Commission agrees with its predecessor's assessment in this regard, and further notes that, in this proceeding, both Ms. McShane[317] and Dr. Booth[318] also observed that return estimates by pension fund managers tend to be rather conservative.

235. The Commission also agrees with the board's conclusion in Decision 2004-052 that it is reasonable to "expect the required return for utilities to be below the required overall equity market return,"[319] given that, on average, investments in utility stocks are typically less risky than investments in the average company stock in the market.

236. The Commission notes that while Ms. McShane expressed the view that return expectations of finance market professionals represent "the return that investors might expect from a diversified equity stock portfolio, but does not represent the returns that investors expect

312 Exhibit 146.02, Calgary argument, paragraph 21.
313 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., Application 1271597-1, July 4, 2004.
314 Decision 2004-052, page 29.
315 Exhibit 150.02, UCA argument, page 27.
316 Decision 2004-052, page 29.
317 Transcript, Volume 4, page 484, lines 3-10 (Ms. McShane).
318 Transcript, Volume 7, page 1087, lines 13-16 (Dr. Booth).
319 Decision 2004-052, page 29.

or require from investments in companies of comparable risk,"[320] she also acknowledged that one "would expect a lower return from a utility than an average risk stock."[321] In the Commission's view, the allowed ROE should reflect the return on a utility stock required by investors who hold the stock in a diversified portfolio. This assumption is consistent with the theoretical underpinnings of the CAPM.

237. In Decision 2004-052, the board observed 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."[322] In this proceeding, both Ms. McShane and Dr. Booth calculated arithmetic average rate of return numbers to correct for this understatement.

238. In her evidence, Ms. McShane referenced the 2013 Towers Watson Wyatt survey of economists and portfolio managers, which indicated that the median forecast return for the S&P/TSX composite for the long-term was seven per cent, which equals a 9.75 per cent arithmetic average rate of return.[323] Dr. Booth's evidence referenced a TD Economics projected geometric long-run return for equities of seven per cent, which equals approximately a nine per cent arithmetic average annual rate of return.[324] Dr. Cleary referenced aggregate stock market return expectations of eight to nine per cent.[325]

239. Based on its assessment of these estimates, the Commission finds that arithmetic return expectations of finance market professionals for the overall equity market can reasonably be estimated to be in the nine per cent range. The Commission further notes that this value is consistent with the results of the DCF analysis applied to the market as a whole, using long-term averages, as set out in Section 5.2. The Commission considers that, directionally, the required return for regulated utilities would be below the required overall market return.

5.5 Other methods for estimating cost of equity

240. In preceding sections of this decision, the Commission has considered the CAPM and DCF methods for estimating the cost of equity. As well, the Commission has considered the relevance of price-to-book ratios for ROE determinations, and examined return expectations of professional capital market participants such as managers of pension funds, investment managers and economists.

241. Experts who participated in this proceeding also employed a number of other methods for estimating a fair ROE. For example, Ms. McShane's ROE recommendations were influenced by the DCF-based equity risk premium test and historic utility risk premium test. Dr. Cleary used a bond yield plus risk premium estimate, in addition to his CAPM and DCF-based approaches.

5.5.1 DCF-based equity risk premium test

242. Ms. McShane explained that the DCF-based equity risk premium test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds. Another variant of this test estimates the risk premium as the difference

[320] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 38.
[321] Transcript, Volume 1, page 127, lines 16-22 (Ms. McShane).
[322] Decision 2004-052, page 29.
[323] Transcript, Volume 4, page 480, lines 22-25 (Ms. McShane).
[324] Exhibit 44.02, Booth evidence for CAPP, paragraph 170.
[325] Exhibit 45.03, Cleary evidence for UCA, page 2.

between the DCF cost of equity and yields on long-term A-rated utility bonds.[326] According to Ms. McShane, the DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by explicitly analyzing the company equity return data, as opposed to CAPM models, which estimate the required utility equity risk premium indirectly by focusing on the risk-free rate and returns at the overall market level.[327]

243. Dr. Booth expressed the view that “Ms. McShane’s DCF based risk premium analysis is also suspect.” In doing so, he pointed out that the “BCUC [British Columbia Utilities Commission], when confronted with this evidence, indicated serious concerns about the *ad hoc* nature of the models used by Ms. McShane” and placed no weight on the results of this analysis.[328]

244. In its reply argument, the UCA questioned the theoretical basis for a DCF-based equity risk premium test, on the grounds that the DCF model does not include a risk parameter. Further, the UCA submitted, “Ms. McShane’s DCF based equity risk premium tests suffers from the same flaws as are inherent in her overall DCF analyses – including heavy reliance on analyst’s forecasts for growth and income yield and a consideration of total income returns, as opposed to total bond returns, to measure returns over the RF [risk-free] rate.” On these bases, the UCA submitted “such a test suffers from serious theoretical and methodological defects, and ought not be adopted by the Commission.”[329]

Commission findings

245. The Commission agrees that, as was observed by both Dr. Booth[330] and the UCA, Ms. McShane’s DCF-based equity risk premium test combines elements of both the DCF and CAPM models to estimate the utility equity risk premium. The Commission also agrees with the submission of the UCA that, as a result, this approach suffers from drawbacks inherent in *both* the DCF and CAPM models, while its theoretical and methodological benefits are difficult to determine with certainty.[331]

246. In light of these identified concerns, and given that there is ample evidence on both DCF-based and CAPM-based estimates on the record of this proceeding, the Commission did not elect to include Ms. McShane’s DCF-based equity risk premium test in its overall considerations in determining a fair ROE for the affected utilities.

5.5.2 Historic utility equity risk premium test

247. In her ROE analysis, Ms. McShane considered the historic market returns for utilities, which, in her view, provided an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. In her view, the historical utility equity risk premium test provides estimates of market returns that have actually been available to investors and is based on the assumption that these same returns are likely to be available to investors from

326 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108 and 112.
327 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108-109.
328 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 13.
329 Exhibit 156.02, UCA reply argument, page 28.
330 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 14.
331 Exhibit 156.02, UCA reply argument, page 28.

comparable investments.[332] According to Ms. McShane, this test and the underlying data provide a direct measure of comparable investment returns.

248. In his rebuttal evidence, Dr. Booth pointed out that, in Decision 2011-474, the Commission stated:

> 99. The Commission agrees with the UCA that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. The Commission finds that the evidence on historic returns is inconclusive with respect to the return investors expect on comparable investments.[333]

249. Dr. Booth stated “Nothing has changed in this regard and … other regulators have also disregarded historic returns.” He confirmed his continued support of the conclusion drawn in Decision 2011-474, and recommended that the Commission continue to place no weight on Ms. McShane’s historic utility estimate.[334]

250. During the hearing, Ms. McShane indicated that she had prepared her evidence having regard to the Commission’s findings in Decision 2011-474, and focused on “the relative size historically of utilities versus the market as a whole”, which ultimately led her to the conclusion that “the returns on a size-adjusted basis are quite consistent with the relative risk.”[335]

251. The UCA, addressing Ms. McShane’s use of historic utility return estimates in its argument, submitted that “despite these apparent adjustments, Ms. McShane’s consideration of historic utility data, and her estimates arising from the same, are practically identical to those she put forth in the 2011 GCOC Decision.” The UCA ultimately recommended that the Commission give no weight to this evidence in considering a fair ROE, as it did in Decision 2011-474.[336]

Commission findings

252. Despite the fact that Ms. McShane adjusted her historical utility equity risk premium test to focus on the size of the utilities relative to the market as a whole, the Commission considers that this test still relies on the actual returns achieved by the utilities and these actual returns serve as a baseline against which the historical utility equity risk premium is measured.

253. As previously noted, in Decision 2011-474, the Commission held that actual achieved utility ROEs are not necessarily reflective of the return that investors expected, and required, for investments of comparable risk.[337] In Decision 2009-216, the Commission expressed a similar view (albeit with reference to the comparable earnings test).[338] The Commission considers that it has not, in this proceeding, been persuaded on the basis of new evidence or argument that it should alter its previous assessment of the predictive value of this method. Therefore, the Commission will not consider the historical utility equity risk premium test put forward by Ms. McShane in its determination of a fair ROE.

332 Exhibit 81.02, Ms. McShane rebuttal evidence for Alberta Utilities, page 31.
333 Decision 2011-474, paragraph 99.
334 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 4.
335 Transcript, Volume 4, pages 486-487 (Ms. McShane).
336 Exhibit 150.02, UCA argument, page 31.
337 Decision 2011-474, paragraph 99.
338 Decision 2009-216, paragraph 280.

254. The Commission finds support for its determination in this regard in its consideration of a table produced by Dr. Cleary, in this proceeding, which compared allowed ROEs with actual earned ROEs for eleven Alberta utilities for the period of 2009-2012. In discussing this data, Dr. Cleary observed that "overall, we can say that these utilities generate ROEs that are generally slightly above the allowed rates."[339] This being the case, the Commission concludes that one of the reasons that "utilities have earned almost as much as the average Canadian company"[340] may be that actual achieved ROEs have consistently exceeded allowed ROEs.

5.5.3 Bond yield plus risk premium estimates

255. In arriving at his recommended ROE estimate, Dr. Cleary relied on a "bond yield plus risk premium" approach, to which he attributed a one-third weight in his overall conclusions on the fair ROE. Dr. Cleary explained that the intent of this approach is to add a risk premium to the yield on a firm's outstanding publicly-traded long-term bonds.

256. Dr. Cleary noted that the usual range of risk premium utilized in this analysis is two to five per cent with 3.5 per cent being commonly utilized to reflect average risk companies; with lower values being used for less risky companies. Given the low-risk nature of Canadian regulated utilities, Dr. Cleary opined that an appropriate risk premium for these companies would be in the two to three per cent range, with a best estimate of 2.5 per cent.

257. While Dr. Cleary acknowledged that this approach appears to be somewhat *ad hoc* in nature, he maintained that it does provide a useful "reasonableness check" on CAPM and other estimates, and is intuitively attractive. The intuitive value underlying the approach is that it uses typical relationships between bond and stock markets, along with information that can be readily obtained from observable market-determined bond yields, to estimate a required rate of return on a firm's stock.[341]

258. Ms. McShane expressed concerns with the bond yield plus risk premium approach, noting that she has never seen this test used in a cost of capital proceeding in either Canada or the United States. Ms. McShane also asserted that there is no empirical support for the two to five per cent risk premium range that Dr. Cleary identified.[342]

259. In addition, Ms. McShane contended that the relative risk of regulated utilities has already been taken into account in the lower cost of debt to which the risk premium is applied. In light of this fact, she maintained that adding a lower than average risk premium to the utility cost of debt has the effect of accounting for the utilities' lower than average risk twice. Moreover, "the addition of a risk premium at the lower end of the range when the utility bond yields themselves are at the low end of historical levels fails to take account of the inverse relationship between interest rates and risk premiums. The result will thus understate the cost of equity."[343]

Commission findings

260. Dr. Cleary showed that the bond yield plus risk premium approach is commonly used by Canadian finance professionals. He conceded that "this approach appears to be somewhat

[339] Exhibit 45.03, Cleary evidence for UCA, page 48.
[340] Exhibit 45.03, Cleary evidence for UCA, page 49.
[341] Exhibit 45.03, Cleary evidence for UCA, pages 44-47.
[342] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 43.
[343] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 44.

'ad hoc' in nature," but that, nevertheless, it "does provide a useful reasonableness check on CAPM and other estimates, and employs solid intuition."[344]

261. The Commission agrees with Dr. Cleary's view that the bond yield plus risk premium approach does hold a certain appeal for finance professionals because it is simple to use and is based on the same premise as the CAPM; namely, that investors require a higher return for assets with greater risk.[345] However, the Commission is also mindful that this simplicity may not always be advantageous, particularly in the current environment of historically low interest rates. Indeed, as pointed out by Ms. McShane, "the addition of a risk premium at the lower end of the range when the utility bond yields themselves are at the low end of historical levels fails to take account of the inverse relationship between interest rates and risk premiums."[346] The Commission notes by way of comparison that CAPM estimates explicitly take this inverse relationship into account, as set out in Section 5.1.3.

262. Considering that, according to Dr. Cleary, the bond yield plus risk premium test has somewhat of an *ad hoc* nature and provides a "reasonableness check on CAPM"[347] and given the ample evidence on CAPM-based ROE estimates in this proceeding, the Commission will not place significant weight on this test in determining a fair ROE for the utilities.

5.6 The Commission's awarded ROE for 2013, 2014 and 2015

263. The Alberta Utilities requested a generic benchmark ROE of 10.5 per cent for 2013 and 2014, based on the expert evidence of Ms. McShane. Regarding the 2015 ROE, Ms. McShane indicated that because her analysis is based on a normalized long-term government of Canada yield of four per cent, she would recommend the same 10.5 per cent generic benchmark ROE for 2015 as she recommended for 2013 and 2014. The Alberta Utilities endorsed Ms. McShane's approach for 2015.[348] However, the Alberta Utilities submitted that if the Commission were to base the allowed ROE on different long-term Canada bond yields for each year, the 2015 ROE should be higher than the recommended 2014 value.[349]

264. The Alberta Utilities also submitted that "it is critical that the Commission base its generic ROE decision on the results of multiple tests" and urged the Commission "to not rely on the Capital Asset Pricing Model as the 'centerpiece' of its generic ROE decision as it has in previous GCOC decisions."[350] As Ms. McShane testified:

> Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return. Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions. These considerations emphasize the importance of reliance on multiple tests.[351] [footnotes omitted]

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[344] Exhibit 45.03, Cleary evidence for UCA, page 45.
[345] Exhibit 45.03, Cleary evidence for UCA, page 45.
[346] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 44.
[347] Exhibit 45.03, Cleary evidence for UCA, page 45.
[348] Exhibit 148.01, Alberta Utilities argument, paragraph 138.
[349] Transcript, Volume 3, page 426, line 13 to page 427, line 2 (Ms. McShane).
[350] Exhibit 148.01, Alberta Utilities argument, paragraphs 22-23.
[351] Exhibit 42.02, McShane evidence for Alberta Utilities, page 74.

265. CAPP, in its argument, submitted that Dr. Booth's evidence in this proceeding "shows that no increase in allowed ROE is warranted and if anything the ROE should be reduced."[352] Dr. Booth recommended an ROE of 7.50 per cent for 2013 and 2014.[353] For 2015, Dr. Booth indicated he would be "be quite happy with a fixed rate of return for all three years, exactly the same."[354]

266. Dr. Cleary, for the UCA, calculated a best estimate of a generic benchmark ROE of 6.78 per cent for 2013, 7.27 per cent for 2014 and 7.42 per cent for 2015.[355] The UCA, in its argument, recognized that the recommended ROEs put forth by Dr. Cleary are lower than those awarded in previous decisions. However, it nonetheless submitted that:

> … these estimates are supported by sound business and finance principles through a reasonable application of the models identified above, and are very consistent with the observed low costs of issuing market debt faced by utilities – for example, numerous examples have been entered into evidence of A-rated utilities issuing 30 and even 50-year debt with yields in the 4.0-4.5% range. These numbers are also very consistent with current long-term expectations for the overall stock market – falling in the range of 6-8.5% according to evidence reported by Dr. Cleary, as well as by Ms. McShane. The fact of the matter is that interest rates have fallen at the government level, and will remain at low levels by historical standards for the foreseeable future in our present low inflation rate environment – therefore the days of "double digit" expected returns on the overall stock market are behind us, and hence the required return by investors on low-risk utilities have also fallen below long-term averages.[356]

267. Table 4 below summarizes the recommended ROEs for 2013, 2014 and 2015.

Table 4. Summary of ROE recommendations

	Recommended by the Alberta Utilities[357] (Ms. McShane)	Recommended by the UCA[358] (Dr. Cleary)	Recommended by CAPP[359] (Dr. Booth)
		(%)	
2013	10.50	6.78	7.50
2014	10.50	7.27	7.50
2015	10.50	7.42	7.50

268. The CCA accepted the ROE recommendation of Dr. Booth for CAPP of 7.50 per cent for 2013 and 2014. It also considered that it would be appropriate to establish the 2014 ROE as a placeholder for 2015.[360]

352 Exhibit 151.01, CAPP argument, paragraph 93.
353 Exhibit 44.02, Booth evidence for CAPP, page 3.
354 Transcript, Volume 7, page 1160, line 18 to page 1162, line 8 (Dr. Booth).
355 Exhibit 45.03, Cleary evidence for UCA, page 53.
356 Exhibit 150.02, UCA argument, page 39.
357 Exhibit 148.01, Alberta Utilities argument, paragraphs 135-138.
358 Exhibit 150.02, UCA argument, page 40.
359 Exhibit 151.01, CAPP argument, paragraphs 93 and 97.
360 Exhibit 149.01, CCA argument, paragraphs 18-20.

269. Calgary adopted Dr. Booth's 2013-2015 ROE recommendations for application to ATCO Gas.[361]

Commission findings

270. In this decision, the Commission has set out to establish a fair rate of return on equity for 2013, 2014 and 2015 for the utility companies it regulates. As explained in previous GCOC decisions, most recently in Decision 2011-474, the awarded ROE must be based on an estimate of the risk-adjusted opportunity cost of equity capital. The Commission must estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than in other investments of similar risk that are available in the market. The difficulty that the Commission faces is that the ROEs that are available to be earned on investments of similar risk are not directly observable.[362] In keeping with the determinations in previous GCOC decisions, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities.

271. The Commission agrees with the view of Ms. McShane and the Alberta Utilities[363] that the benchmark generic ROE should be established on the results of multiple tests, as "each of the tests has its own strengths and weaknesses" and "no single test can pinpoint the fair return."[364] Indeed, as set out in preceding sections of this decision, the Commission has largely relied on the CAPM and DCF methods (including an analysis of the expected overall Canadian stock market returns) to estimate the cost of equity. As well, the Commission has considered the relevance of price-to-book ratios to ROE determinations, and examined return expectations by professional capital market participants such as managers of pension funds, investment managers and economists. While other methods were put forward in this proceeding (including Ms. McShane's DCF-based equity risk premium and historic utility risk premium tests and Dr. Cleary's bond yield plus risk premium test), the Commission assigned a lesser or nil weighting to them for the reasons discussed in Section 5.5.

272. As set out in Section 5.1, the Commission finds that a reasonable CAPM estimate is in the range of 5.80 per cent to 8.75 per cent based on its analysis of the relevant risk-free rate, MERP, beta and including the flotation allowance. This CAPM estimate is lower than the 2011 CAPM estimate of 6.4 to 9.0 per cent in Decision 2011-474,[365] because of the dramatic decrease in risk-free rates and a slight decrease in the MERP estimate, in circumstances where both beta and the floatation allowance remained unchanged.

273. In Section 5.2 of this decision, the Commission found that DCF-model results appear to suggest that investors expect a return of between 7.5 to 9.5 per cent on regulated utility investments. However, the Commission considers that these estimates assume that utilities' dividends and earnings will grow at the long-run GDP growth rate, which may be an optimistic target for low-risk mature regulated utilities.

274. In Section 5.3, the Commission considered the relevance of P/B ratios to ROE determinations with specific reference to the implied P/B ratio associated with the proposed purchase of AltaLink by BHE. In doing so, the Commission concluded that the implied P/B ratio

361 Exhibit 146.02, Calgary argument, paragraphs 26.
362 Decision 2011-474, paragraph 143.
363 Exhibit 148.01, Alberta Utilities argument, paragraph 22.
364 Exhibit 42.02, McShane evidence for Alberta Utilities, page 74.
365 Decision 2011-474, paragraph 77.

associated with the proposed purchase of AltaLink by BHE is relevant and supports continuation of an ROE no higher than the Commission's allowed ROE of 8.75 percent awarded in Decision 2011-474, all other things being equal.

275. Finally, in Section 5.4, the Commission determined that evidence provided by interveners suggests that pension fund managers', investment managers' and economists' return expectations for the market are in the nine per cent range. In the Commission's assessment, it is reasonable to expect the required return for regulated utilities to be below the required overall equity market return of approximately 9.0 per cent, given their low-risk nature.

276. Having considered and weighed all of the evidence and assessed it in the context of a further improvement in the global financial market and economic conditions since the 2011 GCOC proceeding, and considering the current environment of historically low interest rates, the Commission finds that some reduction in the ROE awarded in Decision 2011-474 is warranted. In this respect, the Commission generally agrees with the UCA's conclusion that the current environment of low interest rates may result in the creation of circumstances where, at least in the near term, "the days of 'double digit' expected returns on the overall stock market are behind us, and hence the required return by investors on low-risk utilities have also fallen below long-term averages."[366]

277. In light of the above considerations, the Commission finds that a generic ROE of 8.3 per cent is reasonable for each of 2013, 2014 and 2015.

6 Potential impact of regulatory risk requiring an ROE adjustment or capital structure adjustment, or both

278. The following sections summarize and discuss the views of the parties on the potential impacts on regulatory risk resulting from the UAD decision; the PBR framework for distribution utilities; as well as other potential risks perceived by the utilities.

6.1 Impact of Utility Asset Disposition decision

279. On November 26, 2013, the Commission issued the UAD Decision 2013-417. The Commission included on the issues list for this proceeding a consideration of what impact, if any, the issuance of the UAD decision had on the nature or amount of regulatory risk faced by the Alberta Utilities.

280. Expert evidence addressing the impacts of the UAD decision on risk was provided by Ms. McShane and Mr. Fetter for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary.

281. Ms. McShane asserted that:

> … the UAD Decision has introduced a level of uncertainty for which equity investors will require additional compensation. The increased uncertainty should be compensated for in the allowed ROE, which can be expressed as a premium to the benchmark utility

366 Exhibit 150.02, UCA argument, page 39.

> ROE. I have estimated the premium to compensate for the increased uncertainty alone created by the UAD Decision at approximately 1.25% to 1.5%.[367]

282. Ms. McShane explained that the:

> … AUC then broadly asserted that extraordinary retirements could include, according to the [UAD] decision, obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes and surplus land (para. 303) and property that should be removed from rate base because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or unexpected and permanent shutdown of an entire operating assembly or plant (para. 327).[368]

283. Ms. McShane also commented that the:

> … AUC's finding in the *UAD Decision* that extraordinary retirements are to the account of the shareholder, potentially disallowing the recovery of prudently incurred costs, is at odds with that premise and at odds with mainstream regulatory practice throughout North America, including past practice in Alberta.[369]

284. Mr. Fetter, on behalf of the Alberta Utilities, concurred, stating:

> Now, with the recent issuance of its Utility Asset Disposition ("UAD") Decision, the AUC has created the risk that shareholders will bear stranded asset losses, notwithstanding the absence of any imprudent behavior on the part of utility management. Such a policy would appear to stand alone among North American utility regulatory policies, and the manner in which it is implemented could have a major effect on the way investors and the rating agencies view the regulatory climate in Alberta.[370]

285. In Mr. Fetter's view, increased regulatory risk created by the issuance of the UAD decision could impact the ability of utilities to raise debt capital. He explained that credit ratings are important to regulated utilities with regard to raising capital on reasonable terms[371] and that how a utility is regulated is highly important to its credit rating.[372]

286. Mr. Fetter stated that:

> … positive views of Alberta regulation may be affected by the AUC's issuance of its UAD decision in which it has placed shareholders at risk that they will bear stranded asset losses, notwithstanding the absence of imprudent behavior on the part of utility managements. As a former utility regulator and utility bond rater, I believe it is important to emphasize that such potential denial of recovery of prudently incurred stranded costs or assets would, to my knowledge, represent the first breaking of faith with past regulatory determinations …[373]

367 Exhibit 42.02, McShane evidence for Alberta Utilities, page 6, lines 154-159.
368 Exhibit 42.02, McShane evidence for Alberta Utilities, page 33, lines 831-837.
369 Exhibit 42.02, McShane evidence for Alberta Utilities, page 34, lines 843-848.
370 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 5, lines 14-20.
371 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 7, lines 7-8.
372 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 10, lines 15-23.
373 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 16, lines 4-11.

287. On behalf of the UCA, Messrs. Bell and Stauft submitted that their "position is that the UAD Decision should have no impact on the Commission's determinations in this case."[374]

288. Messrs. Bell and Stauft explained that the:

> … difficulty that arises in connection with retirements of depreciable utility assets is that the Commission's long-standing and entirely conventional policies in relation to the fixing of depreciation rates for utility assets have the practical effect of allocating recovery risk for stranded asset and post-retirement costs largely to customers rather than utility shareholders. The Commission's approved depreciation mechanisms operate on a "mass account" basis, with depreciation reserve accounts that over time ensure that in aggregate the utilities recover in rates exactly their initial investments in depreciable assets, as well as any negative salvage and post-retirement costs associated with those assets.[375]

They discussed that unlike "the situation with land assets, the 'value' of depreciable assets when they are removed from utility service and from rate base is typically zero or, more likely, negative owing to negative salvage and post-retirement costs."[376]

289. Messrs. Bell and Stauft commented that there:

> … may be some suggestion in Decision 2013-417 that the Commission intends to examine more closely whether individual retirements of depreciable property are properly characterized as 'ordinary'", but there is no suggestion of any new and more rigorous test and no indication that the Commission will apply whatever test exists now in a way that would systematically disadvantage the Utilities.[377]

290. In response to an information request on whether the UAD decision had increased ATCO Pipelines' relative risk, Dr. Booth, on behalf of CAPP, stated that he:

> … does not believe that ATCO Gas [or ATCO Pipelines] will find any assets that are not "used and useful" in rate base since otherwise it implies that the rate base has been padded and management has not depreciated the assets correctly. If ATCO Gas [or ATCO Pipelines] does find that there are material assets likely to shortly meet this definition, Dr. Booth would expect them to file a new depreciation study so that they can be retired in normal course.[378]

291. Ms. McShane disputed Dr. Booth's assertion that ATCO Gas or ATCO Pipelines are not likely to identify assets which are not used and useful because it would mean that management has been depreciating these assets incorrectly. She argued that the Commission was responsible for approving depreciation rates, not the management. Changes to depreciation rates can be unforeseeable and depreciation rates are only as accurate as the information available when they are set. If an event qualified as an extraordinary retirement, then subsequent events would allow for recapture of the disallowed cost, and depreciation rates approved by the Commission may

374 Exhibit 45.02, Bell and Stauft evidence for UCA, page 3, lines 22-23.
375 Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 8-15.
376 Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 18-21.
377 Exhibit 45.02, Bell and Stauft evidence for UCA, page 20, lines 22-26.
378 Exhibit 72.02, UTILITIES-CALG-6(d); Exhibit 64.01, UTILITIES-CAPP-19(F).

reflect specific objectives such as public policy goals (e.g. transmission rate mitigation impacts).[379]

292. Ms. McShane indicated that she was not aware of any circumstances prior to the UAD decision where the post-retirement risk from extraordinary retirements was allocated to shareholders.[380] In an IR to the UCA, Messrs. Bell and Stauft could not identify any such cases.[381]

293. In rebuttal evidence, Messrs. Bell and Stauft submitted that the "Commission's conclusion was that *under the existing rules* 'stranded assets' are normally for the account of customers, although in cases of extraordinary retirements they will be for the account of shareholders."[382] [emphasis in original] They further argued that the "other fundamental principle the Commission relied on in the UAD Decision is that when assets are removed from rate base it is the utility that bears the risk associated with the residual value of those assets … the risks and rewards of asset ownership remain with utility shareholders once assets are no longer devoted to utility service."[383]

294. In their view, the "fact that with ordinary retirements of depreciable property any residual over-recover or under-recover risk is borne by customers is in some sense an exception to that general rule, although it is an exception that the Commission found to be consistent with the overall statutory scheme."[384]

295. Messrs. Bell and Stauft further submitted that:

> … it has been the utilities' position for many years that depreciable and non-depreciable assets that become stranded because they no longer have a utility purpose, like the Stores Block property and the Carbon and Salt Caverns storage facilities, must be removed from rate base, and the utility shareholders are at risk for the value of those assets once they leave utility service. The suggestion that it is a new or surprising concept that the Utilities might bear some "stranded asset risk" is inconsistent with the entire history of the UAD Decision …"[385]

and that "The claim that the UAD decision created new "stranded asset risk" for the Utilities is incorrect. Whatever risk the Utilities have in relation to stranded assets and extraordinary retirements has always been there, as the Commission explained in the UAD Decision."[386]

296. In their rebuttal evidence, Messrs. Bell and Stauft also disputed Ms. McShane's assertion that the UAD decision imposed new stranded asset risk on utilities, and submitted that if any stranded asset risk might be borne by the utilities it would not be significant enough to be meaningful to the market or relevant to the cost of capital.[387] They submitted that "[c]redit rating

379 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 3, lines 86-99.
380 Exhibit 42.02, McShane evidence for Alberta Utilities, page 5, lines 151-152.
381 Exhibit 65.02, UTILITIES-UCA-16(a).
382 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 27, lines 23-25.
383 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 5-10.
384 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 12-15.
385 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 16-22.
386 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 2-4.
387 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 27, lines 1-5.

reports that post-date the UAD Decision often fail to mention the Decision at all, and do not suggest any likely or potential ratings action."[388]

297. Further, and finally, they commented that the:

> … entire discussion of stranded asset risk in the evidence of Ms. McShane and Mr. Fetter is conceptual. Neither of them presented any evidence about any specific stranded or potentially stranded assets the Utilities are concerned about. The UCA asked the Utilities for information concerning historical and expected stranded assets and extraordinary retirements, and got no response.[389]

298. Dr. Booth, on behalf of Calgary, submitted that "many risks that people see for utilities and which they assume are borne by the shareholders end up being reallocated to ratepayers once they materialise,"[390] and further commented that "I would judge there to be minimal 'stranded asset risk' for ATCO Gas. I would judge that if it ever does become material, the regulatory dynamic will ensure that rates remain fair and reasonable and every effort taken to try and provide the shareholders with an opportunity to earn a fair ROE."[391]

299. In rebuttal evidence, Ms. McShane disagreed with Dr. Booth's position presented on behalf of Calgary that stranded asset risk is minimal. In her view, the UAD decision created uncertainty because it listed a wide variety of circumstances which could result in stranded asset cost disallowances. She argued that the recovery of prudent costs is uncertain based on considerations such as those under consideration in Proceeding 2682 regarding the costs related to distribution facilities destroyed in the 2011 Slave Lake fire.[392]

300. In rebuttal evidence, on behalf of CAPP, Dr. Booth submitted "there is no indication at this point from analyst reports or those of the rating agencies that there are any concerns regarding material 'stranded assets' in ATCO Gas' or ATCO Pipe's rate base."[393]

301. With regard to depreciation rates, Dr. Booth stated "it is the responsibility of the utility to determine whether the assets are used and useful and to depreciate them over the economically useful life. If there are substantial amounts of "stranded" assets in the rate base, it indicates that the rate base has been padded or the depreciation rate unduly low. Consistent with the Averch Johnson effect this could be because the allowed ROE is set too high and the utility has an incentive to keep the assets in the rate base, even when no longer used and useful."[394]

302. In rebuttal evidence on behalf of CAPP, Dr. Booth submitted that the very low debt cost of CU Inc. (50 years at 4.855 per cent) does not indicate any stress whatsoever, notwithstanding the fact that spreads are still higher than historical.[395] Dr. Booth commented that:

> … if utility witnesses push for US comparisons on the ROE why isn't it also appropriate to have comparisons with US utility bond ratings? My judgement is that CU Inc. is a Canadian utility that finances within Canada and is not cross listed in the US, so what is

[388] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 24-25.
[389] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 12-16.
[390] Exhibit 40.02, Booth evidence for Calgary, page 21, lines 9-10.
[391] Exhibit 40.02, Booth evidence for Calgary, page 21, lines 20-24.
[392] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 2-3, lines 34-66.
[393] Exhibit 80.01, Booth rebuttal evidence for CAPP, page 13, paragraph 25.
[394] Exhibit 80.01, Booth rebuttal evidence for CAPP, page 14, paragraph 26.
[395] Exhibit 80.01, Booth rebuttal evidence for CAPP, pages 14-15, paragraphs 28-30.

> important is its DBRS rating. Here there are no indications of any problems whatsoever.[396]

303. On October 29, 2014, the Commission issued Decision 2014-297, which determined Proceeding 2682 for ATCO Electric Ltd.'s 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances application (the Slave Lake fire decision). The Slave Lake fire decision constituted the Commission's first practical application of the principles elucidated in the UAD decision. Consequently, the Commission established a supplemental process for submission of argument and reply argument related to the Slave Lake fire decision to provide the opportunity for parties to provide their views on what, if any, impact its issuance had on the amount of regulatory risk faced by Alberta utilities.

304. The Alberta Utilities asserted that:

> With the finding of an extraordinary retirement and denial of recovery of prudently incurred costs in the Slave Lake Decision, there can be no doubt that the UAD Decision has resulted in significantly increased risk and uncertainty to the Utilities. It is therefore recommended that the pending GCOC decision adopt the upper end of the range of Ms. McShane's UAD Decision Uncertainty premium of 1.50%.[397]

305. The Alberta Utilities submitted the:

> … UAD Decision set out a long, non-exhaustive list of events: matters which include obsolete property, property that has been subjected to unusual casualties (fire, storm, flood, etc.), or that have undergone sudden and complete obsolescence, or seen an unexpected and permanent shutdown of an entire operating assembly or plant. The Slave Lake Decision has now addressed one, and only one of those circumstances, and has done so in the particular circumstances of the history of ATCO Electric's reserve for injuries and damages (RID) Account and the facts of the Slave Lake fire. …[398]

306. The Alberta Utilities also commented that they "are left without guidance as to how the myriad of uncertainties inherent in all the other matters raised by the long though only exemplary list in the UAD decision may bear on them."[399]

307. The UCA argued that the risks and costs discussed in the Slave Lake fire decision were not material for cost of capital determinations and were minor relative to the size of ATCO Electric's rate base and expected shareholder returns.[400]

308. The UCA argued that:

> … [the Slave Lake fire decision] reflects a straightforward application of accepted principles to a specific fact situation. It breaks no new policy ground in the analysis of asset retirements, and makes no change to the overall risk allocation scheme that has existed for many years and that was confirmed by the Commission in the UAD Decision.

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396 Exhibit 80.01, Booth rebuttal evidence for CAPP, page 17, paragraph 32.
397 Exhibit 161.01, Alberta Utilities supplemental argument, page 5, paragraph 15.
398 Exhibit 161.01, Alberta Utilities supplemental argument, page 4, paragraphs 10-11.
399 Exhibit 161.01, Alberta Utilities supplemental argument, page 4, paragraph 12.
400 Exhibit 160.02, UCA supplemental argument, page 4, paragraphs 11-12.

> Decision 2014-297 has no impact on, nor is it relevant to, the matters at issue in this proceeding.[401]

309. In supplemental argument, Calgary submitted that no UAD risk premium should be added to the benchmark ROE.[402] They asserted that "the relatively minor amount of the loss incurred by the ATCO Electric shareholders in the Slave Lake Decision supports the findings of Dr. Booth."[403] Dr. Booth had concluded that utilities could manage stranded asset risk by keeping their depreciation current and maintaining appropriate insurance.

310. Calgary submitted that the Slave Lake fire decision demonstrated that each case will be fact specific "as to whether any particular utility's shareholders will in fact suffer a loss (extraordinary retirement) for a particular event which destroys some of its assets."[404]

311. Calgary stated:

> … that each outcome/loss treatment will be different for each utility, depending upon the facts of the case, and particularly how the utility treats depreciation for the mass account in which the destroyed assets were placed. As such, to apply a pervasive and perpetual UAD premium for a risk that may not apply in each case of asset destruction is unreasonable and unwarranted.[405]

312. The CCA submitted that "no additional risk premium needs to be added with respect to the AUC's findings in Decision 2014-297."[406] "The CCA does not view the AUC's reliance on the Stores Block decision[[407]] and applying its reasoning to other circumstances in the area of utility dispositions and retirements as a 'forced extension'"[408] as argued by the Alberta Utilities.

313. In supplementary reply argument, the Alberta Utilities challenged Calgary's characterization of the cost recovery risk as trivial because "if the new Slave Lake assets were to succumb to the effects of another devastating fire, and if the Commission were to determine that the effects of that fire met their criteria for an extraordinary retirement, the loss that ATCO Electric would be required to absorb could well be in excess of 20 million dollars."[409]

314. The UCA concluded, in its supplemental reply argument, that:

> … there is simply no evidence, and no reasoned analysis, suggesting that Stores Block and the cases that derive from it, including the UAD and Slave Lake Decisions, have any measurable net or aggregate effect on the cost of capital, much less that they support an increase of 1.5% on ROE, or $100 million per year for the Alberta Utilities as a group.[410]

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401 Exhibit 160.02, UCA supplemental argument, page 5, paragraph 16.
402 Exhibit 163.01, Calgary supplemental argument, page 12, paragraph 38.
403 Exhibit 163.01, Calgary supplemental argument, page 9, paragraph 24.
404 Exhibit 163.01, Calgary supplemental argument, page 11, paragraph 33.
405 Exhibit 163.01, Calgary supplemental argument, page 11, paragraph 37.
406 Exhibit 159.01, CCA supplemental argument, page 6, paragraph 12.
407 *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (*Stores Block)*.
408 Exhibit 167.01, CCA supplemental reply argument, page 5, paragraphs 13-14.
409 Exhibit 165.01, Alberta Utilities supplemental reply argument, page 6, paragraph 17.
410 Exhibit 164.02, UCA supplemental reply argument, page 4, paragraph 12.

315. Calgary observed, in its supplemental reply argument, that although ATCO Electric shareholders did have to absorb a loss of $400,000, the Slave Lake fire decision provided the opportunity to earn a return on the replacement plant.[411]

316. On January 25, 2015, the Commission issued Decision 3100-D01-2015 dealing with EDTI's 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast applications. Among other issues, that decision set out the Commission's determinations on the application of principles contained in the UAD decision to EDTI's Advanced Metering Infrastructure (AMI) project. Therefore, in the context of the current GCOC proceeding, the Commission will refer to Decision 3100-D01-2015 as "the EDTI AMI decision." The Commission established a process for submission of second supplemental argument and reply related to the EDTI AMI decision in order to provide an opportunity for parties to provide their views on what, if any, impact its issuance had on the amount of regulatory risk faced by utilities.

317. The Alberta Utilities noted that the EDTI AMI decision represents the second time that the Commission's application of UAD principles has resulted in a finding that an extraordinary retirement has occurred, and argued that the outcome would have been different if the proceeding had been determined before the issuance of the UAD decision.[412] As a result, the Alberta Utilities argued that "there can be no doubt that the UAD Decision has resulted in significantly increased uncertainty, and thereby risk, to the Utilities" and that, consequently, the application of a UAD decision uncertainty premium in the range of 1.5 per cent was warranted.[413]

318. The UCA submitted that the Commission's ruling in Decision 3100-D01-2015 was "a straightforward application of the principles espoused in Stores Block and examined in the UAD Decision"[414] which did not create any new or additional risk.

319. The UCA argued that "both Decision 2014-297 and Decision 3100-D01-2015 represent factual determinations as to when a particular event will be determined by the Commission to give rise to an extraordinary retirement."[415] In the UCA's view, the result of these decisions was to minimize uncertainty for the classification of retirements for the Alberta Utilities.

320. In supplemental reply argument, the Alberta Utilities rejected the UCA's position that the Slave Lake fire and EDTI AMI decisions minimized uncertainty resulting from the issuance of the UAD decision. They stated that:

> … prior to the release of the Slave Lake and EDTI Tracker Decisions, *Stores Block* had never been applied as it has been in these Decisions. As a result of these Decisions, those who provide debt and equity capital to the Alberta Utilities, and those who own and operate the Alberta Utilities, are left to speculate as to what facts will be sufficient for the Commission to reach the conclusion that an event listed in paragraph 327 of the UAD Decision is an extraordinary retirement or not, and has or has not been accounted for in a prior depreciation study.[416]

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411 Exhibit 168.01, Calgary supplemental reply argument, page 6, paragraph 25.
412 Exhibit X0008, Alberta Utilities second supplemental argument, page 1, paragraph 3.
413 Exhibit X0008, Alberta Utilities second supplemental argument, pages 3-4, paragraphs 8-10.
414 Exhibit X0005, UCA second supplemental argument, page 5, paragraph 20.
415 Exhibit X0005, UCA second supplemental argument, page 4, paragraph 13.
416 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 5, paragraph 14.

321. Calgary submitted that the Slave Lake fire and EDTI AMI decisions were fact specific, and that they were not "… indicative of any underlying systemic basis for increased risk to utility shareholders." Accordingly, Calgary argued that "to apply a pervasive and perpetual UAD premium for a risk that may not apply in each case of asset removal is unreasonable and unwarranted."[417]

322. In its supplemental reply argument, the UCA submitted that the number of times the utility asset ownership principles have been applied is irrelevant because "the risk of shareholders being required to absorb the costs associated with extraordinary retirements has always existed." And that the UCA "echoes the submissions of Calgary that these decisions are fact specific and are not indicative of any increased systemic risk to utility shareholders."[418]

323. Calgary submitted that "the risk for shareholders which is associated with the undepreciated meters (including the net book value of the assets at any point in time) is, in large measure, predicated upon and a function of utility management's decisions."[419] Calgary argued that "customers should not bear the adverse consequences of decisions of utility management, when those decisions are open to reasonable question on prudence and in any event, were management's to make."[420]

324. In response to Calgary's position that EDTI should have taken steps to manage the AMI project risks resulting from *Stores Block*, which included drastically reducing the service life for the AMI assets, the Alberta Utilities commented in its supplemental reply argument that this suggestion did not address the identified concern as it presumed no difficulty in reducing the applicable depreciation service life.[421]

325. The CCA commented that the EDTI AMI decision did not alter the risk profile for Alberta utilities[422] and that EDTI had, in Proceeding 3100, implicitly indicated "that it both understands and is able to manage the consequences of the costs associated with its decision on continued use of the assets [or retirements] in accordance with the UAD decision."[423]

326. In response to CCA's assertion that EDTI had indicated it could manage the consequences of the costs from the application of the UAD decision, the Alberta Utilities responded in its supplemental reply argument that:

> … there is no basis for asserting that EDTI is somehow able to 'manage the consequences of the costs' of the Commission's application of the UAD Decision, and there is also no basis for claiming that the uncertainty and risk facing the Alberta Utilities as a result of the UAD Decision is somehow reduced.[424]

417 Exhibit X0007, Calgary second supplemental argument, page 5, paragraphs 16-17.
418 Exhibit X0011, UCA second supplemental reply argument, page 3, paragraph 8.
419 Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 10.
420 Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 11.
421 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 3, paragraph 7.
422 Exhibit X0003, CCA second supplemental argument, page 1,paragraph 4.
423 Exhibit X0003, CCA second supplemental argument, page 2,paragraph 5.
424 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 1, paragraph 3.

327. The UCA concluded, in its supplemental reply argument, that:

> … there is insufficient evidence on the record of this Proceeding to assess and/or quantify any alleged increased risk resulting from the UAD Decision. The UCA agrees generally with the submissions of Calgary in its Supplemental Reply Argument that if the Commission does determine it is necessary to award additional compensation as a result of the UAD Decision, the Commission should convene a further process to consider the issues noted by Calgary, including the probability and quantum of potential losses and the implications of the conceptual framework of Stores Block which emphasizes the symmetry associated with the utility asset ownership by shareholders.[425]

Commission findings

328. In 2006, the Supreme Court of Canada's decision in the *Stores Block* case settled the law applicable to dispositions of utility-owned assets in Alberta. In Decision 2013-417, the Commission summarized the issues considered in *Stores Block* as follows:

> 329. Prior to the Supreme Court of Canada of Canada's [*sic*] 2006 decision in *Stores Block*, the Public Utilities Board had adopted the principle that all gains and losses on the disposition of utility assets were for the account of utility customers. This principle applied whether the assets were disposed of inside or outside of the ordinary course of business or whether or not those assets were depreciable property. In response to *TransAlta*, the Alberta regulator modified its approach by determining that gains from the disposition of utility assets outside of the ordinary course of business would be shared between the utility company and its customers while losses would continue to be for the account of the customers. The Supreme Court of Canada's 2006 decision in *Stores Block* found that all proceeds, including any gains or realized losses, on the disposition of gas utility assets outside of the ordinary course of business were for the account of utility shareholders.[426]

329. Since that time, all Alberta utilities have conducted their respective operations with the benefit of the guidance provided by the court on the law applicable to dispositions of utility-owned assets. In the time since the *Stores Block* decision was rendered, the Alberta Court of Appeal has also provided further clarity with respect to the applicable law.

330. The Commission's first practical application of the *Stores Block* principles occurred in the 2011 GCOC Decision 2011-474, where the Commission determined, in the context of Rider I issues for transmission companies, that any stranded assets, regardless of the reason for them being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service. Specifically, Decision 2011-474 included the following findings:

> 542 … the Commission agrees with the AESO [Alberta Electric System Operator] that the likelihood of a customer becoming insolvent at the same time as the backer of it financial security becomes insolvent is extremely small. However, the Commission finds when a utility asset is stranded and is no longer required to be used for utility service, any outstanding costs related to that asset cannot be recovered from other customers. The Commission relies on the Decision of the Supreme Court of Canada in Stores Block for this conclusion. In that decision, the Court states that any assets that are no longer

[425] Exhibit 2191-X0011, UCA second supplemental reply argument, page 3, paragraph 11.
[426] Decision 2013-417, page 83, paragraph 329.

> required to be used in utility service are to be removed from rate base. [footnotes removed]
>
> …
>
> 545 … the Commission considers that any stranded assets, regardless of the reason for being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service.

331. In late 2013, the Commission issued Decision 2013-417 (the UAD decision), which set out its understanding of the *Stores Block* principles, as guided by the Alberta Court of Appeal's prior treatment of the issues. At paragraph 327 of the UAD decision, the Commission made the following statement regarding situations where a utility's shareholder would be responsible for undepreciated rate base associated with retired assets:

> 327. In order to give effect to the court's guidance that the "rate-regulation process allows and compels the Commission to decide what is in the rate base, i.e. what assets (still) are relevant utility investment on which the rates should give the company a return," the Commission directs each of the utilities to review its rate base and confirm in its next revenue requirement filing that all assets in rate base continue to be used or required to be used (presently used, reasonably used or likely to be used in the future) to provide utility services. Accordingly, the utilities are required to confirm that there is no surplus land in rate base and that there are no depreciable assets in rate base which should be treated as extraordinary retirements and removed because they are obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes, property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or un-expected and permanent shutdown of an entire operating assembly or plant. As stated above, these types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions. Each utility will also describe those assets that have been removed from rate base as a result of this exercise. At this time, the Commission will not require the utilities to make additional filings to verify the continued operational purpose of utility assets.[427] [footnotes removed]

332. Subsequent to the issuance of that decision, the Commission applied its findings in the UAD decision in the Slave Lake fire and the EDTI AMI decisions.

333. Since the *Stores Block* decision, any losses and any gains arising from the disposition of utility assets are for the account of the owners of those assets; the shareholders; not customers. The Commission upheld this principle in the 2011 GCOC decision and the UAD decision. As the Commission explained at paragraph 59 of Decision 2014-297:

> 59. … Since *Stores Block*, it can no longer simply be assumed that the costs of assets, once found by the regulator to be prudently acquired, will be recoverable under all circumstances (unless the actions of the utility justified different treatment). The owners of the property bear the benefits of gains on the assets and the risk of losses when those assets are no longer required for utility service.

[427] Decision 2013-417, pages 82-83, paragraph 327.

334. Given this, the Commission accepts that, in theory, utility shareholders in the period since the *Stores Block* decision may be subject to a greater degree of risk, than they were prior to the issuance of the that decision. The question before the Commission in this proceeding is whether any variability of returns that may be occasioned by the *Stores Block* decision, subsequent Alberta Court of Appeal decisions, and related Commission decisions, warrants an adjustment to the allowed ROE or capital structure, or both, for the Alberta Utilities.

335. Since 2006, the *Stores Block* decision and subsequent Alberta Court of Appeal decisions, as well as the above-noted decisions of the Commission applying the findings of the Supreme Court and the Alberta Court of Appeal, signalled to credit rating agencies and capital markets in general, information regarding changes to the regulatory landscape in Alberta. The Commission considers that credit rating agencies and capital markets have had an opportunity to consider and reflect upon, the regulatory impacts resulting from the Supreme Court of Canada's 2006 *Stores Block* decision and the subsequent line of related decisions for some time now.

336. The Commission considers that if these signals had been perceived as significantly increasing the overall riskiness of investments in Alberta utilities, any such perception could reasonably have been expected to be reflected in objective market measures. In the case of debt issues, any perceived increase in risk would have been reflected in utility credit spreads since 2006. As shown in figures 1 and 2 in Section 4 of this decision, as of the close of record of this proceeding, credit spreads for the Alberta Utilities are currently similar to those in 2006.

337. The Commission also considers that any regulatory risk specifically attributable to its own treatment of stranded assets, in light of the *Stores Block* decision, has been appreciated by capital market participants since at least the end of 2011, when Decision 2011-474 was issued. Similarly, the determinations in the UAD decision have been known to the investing public since the end of 2013. The Commission notes, however, there was no perceptible increase in credit spreads for the Alberta Utilities in either 2011 or 2013, when these decisions were issued.

338. The Commission finds no supporting evidence that the greater degree of risk postulated by the Alberta Utilities has had any impact on their ability to raise debt capital at reasonable rates, as demonstrated by the history of credit spreads for these utilities. In addition, credit rating reports available since at least 2011 do not indicate any changes to ratings for the utilities, arising from the asserted increase in risk. In this regard, the Commission agrees with Dr. Booth that the credit rating agencies have not reacted to the perception of risk that the utilities have put forward.[428]

339. In the UAD decision, the Commission indicated that a relevant consideration in determining whether a retirement is for the account of the utility shareholder is whether it is deemed extraordinary. In Decision 2014-297, the Commission applied the corporate and property law principles that were set out in the *Stores Block* line of decisions, applied in a manner consistent with the findings in the UAD decision, to the facts of that case. At paragraph 66 of Decision 2014-297, the Commission stated:

> 66. The UAD decision recognized the concepts underlying the currently-used depreciation methods as being consistent with the *Stores Block* principles because they are intended to recover the costs of assets used in utility service over their service lives in ordinary circumstances, recognizing that retirements outside of the relevant scope of

[428] Exhibit 80.01, Booth rebuttal evidence for CAPP, page 13, paragraph 25.

> considered retirement events, regardless of the effect on depreciation parameters, would be classified as extraordinary retirements and, in accordance with the *Stores Block* principles, would be for the shareholder's account. In the Commission's view it is the characteristics of the event that are relevant to the determination of whether the event had been contemplated or anticipated by a prior depreciation study …

340. In the Commission's view, the determination in the UAD decision that only "extraordinary retirements" are for the account of the utility shareholder, mitigates the risk associated with stranded assets, to which the Alberta Utilities are exposed.

341. Additionally, as Messrs. Bell and Stauft on behalf of the UCA explained:

> The Commission's approved depreciation mechanisms operate on a "mass account" basis, with depreciation reserve accounts that over time ensure that in aggregate the utilities recover in rates exactly their initial investments in depreciable assets, as well as any negative salvage and post-retirement costs associated with those assets."[429]

342. These witnesses also held the opinion that unlike "the situation with land assets, the 'value' of depreciable assets when they are removed from utility service and from rate base is typically zero or, more likely, negative owing to negative salvage and post-retirement costs."[430] The Commission agrees and considers that the use of mass property accounts for regulatory purposes further mitigates the risk associated with stranded assets.

343. In her evidence, Ms. McShane states that:

> In exposing the Alberta Utilities to stranded asset risk, the AUC increased the asymmetry in the risk to which Alberta utility shareholders are exposed. In principle, a utility's ability to earn a fair return should be symmetric, i.e., there should be an approximately equal probability that it will earn above or below its opportunity cost of capital. Under rate base/rate of return regulation, rates are generally set to ensure that utilities neither materially over-earn (i.e., the upside opportunities are limited) nor under-earn (downside risk is limited) their allowed returns. With the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded.[431]

344. The Commission is not persuaded that application of the fair return standard necessitates the creation of circumstances in which there is an "equal probability that [a utility] will earn above or below its opportunity cost of capital." In Decision 2009-216,[432] the Commission cited the following excerpt from *Northwestern Utilities Ltd. v. Edmonton (City)*[433] with approval, indicating that it was the "most authoritative source of guidance on the meaning of the term 'fair return:'"

> 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

[429] Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 8-15.
[430] Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 18-21.
[431] Exhibit 42.02, McShane evidence for Alberta Utilities, page 133, lines 3413-3421.
[432] Decision 2009-216, paragraph 88.
[433] *Northwestern Utilities Ltd. v. Edmonton (City)* [1929] S.C.R. 186.

> investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[434]

345. On a plain reading of the above-referenced excerpt from the Northwestern Utilities case, the Commission notes that the idea of fair return, as conceptualised by the Supreme Court of Canada, does not incorporate a suggestion (let alone a requirement) that the standard is to be met by attempting to place affected companies in circumstances where they are exposed to equal probabilities of earning returns that exceed, or alternatively, fall short of, a company's cost of capital.

346. Consequently, the Commission finds that, insofar as its issuance of the *Stores Block* and related line of decisions may have impacted the risk profile of Alberta utilities, the fact that these may have resulted in the probabilities of over- or under-earning relative to their allowed returns being other than equal is not sufficient to require the allowance of a premium on ROE in order to satisfy the fair return standard.

347. Ms. McShane offered an example of a "significant asymmetric risk" resulting from the UAD decision. In her example, Ms. McShane assumed that there is a 15 per cent probability that the utility will not recover 10 per cent of its equity investment in rate base.[435] With regard to this example, the Commission notes Dr. Cleary's position that:

> Ms. McShane acknowledges in her responses to UCA-AU-61 (a) & (b) that no debt ratings downgrades have occurred as a result of this [UAD] Decision, nor could she estimate the probability of any such downgrades. In addition, her analysis also ignores the fact that windfall gains would accrue to utility owners, which further calls into question the reasonableness of the assumption of 10% losses.[436]

348. The Commission agrees with Dr. Cleary and notes that, in accordance with the principles set out in the *Stores Block* line of cases, shareholders may realise either gains or losses associated with dispositions of utility property. Consequently, while the Commission found that the Slave Lake fire and EDTI AMI extraordinary dispositions were ultimately for the account of shareholders, there is no basis upon which to conclude that all dispositions given regulatory consideration will result in losses for utility shareholders.

349. Ms. McShane argued that the Slave Lake fire and EDTI AMI cases resulted in increased uncertainty and risk for Alberta utilities, which support the granting of a risk premium. However, a broader assessment of the regulatory treatment of utility asset dispositions in the post *Stores Block* period illustrates that any increased uncertainty regarding the possibility of companies realising earnings below their allowed return may reasonably be expected to be offset at least to some extent by the potential for the utilities to retain profits flowing from eligible dispositions.

350. Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores*

[434] *Northwestern Utilities Ltd. v. Edmonton (City)* [1929] S.C.R. 186 at paragraph 192.
[435] Exhibit 42.02, McShane evidence for Alberta Utilities, page 133, lines 3423-3433.
[436] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 16, lines 1-6.

Block decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.

351. In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.

352. TransAlta requested that the "Commission confirm that retirements arising from ongoing system developments such as those embodied in Approval U2013-460[[437]] will be recognized and treated as ordinary retirements."[438] The Commission considers that no advance ruling is possible or reasonable on treatment of assets related to the events identified in the UAD decision in a given set of circumstances because each situation is fact specific. The Commission will consider the treatment of TransAlta's assets with regard to the UAD decision, when the application is made.

6.2 Performance-based regulation implementation for distribution utilities

353. On September 12, 2012, the Commission issued Decision 2012-237 which included the following paragraph:

> 710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.[439]

354. The Commission included this topic on the issues list for the current proceeding to garner input from parties and to consider this matter. Expert evidence addressing the impacts of PBR on risk was provided by Ms. McShane for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary.

355. Based on Ms. McShane's evidence, the Alberta Utilities submitted that a 0.75 per cent premium should be added to any approved ROE to compensate electric and gas distribution companies for the additional risk related to PBR.[440] To estimate the incremental risk premium, Ms. McShane compared the common equity ratios proposed by the Alberta Utilities for taxable Alberta distribution utilities to an American benchmark utility sample to derive a difference in common equity ratios of 7 per cent which was then adjusted to an after tax basis, to arrive at the referenced 0.75 per cent ROE premium.

356. Ms. McShane stated that the main change in business risk for Alberta electric and gas distribution utilities since the 2011 GCOC was the implementation of PBR[441] and that under PBR, "earnings volatility will likely be higher than under cost of service regulation …"[442]

[437] Needs Identification Document, Approval No. U2013-460, Appendix 2 to Decision 2013-369, Alberta Electric System Operator, Amendment to Southern Alberta Transmission Reinforcement, Proceeding 2001, Application 1608846-1, October 28, 2013.
[438] Exhibit 41.01, TransAlta evidence, page 4, lines 34-36.
[439] Decision 2012-237, page 153, paragraph 710.
[440] Exhibit 148.01, Alberta Utilities argument, page 1, paragraph 1.
[441] Exhibit 42.02, McShane evidence for Alberta Utilities, page 38, lines 979-980.

357. Ms. McShane also testified that:

> Under the price/revenue cap plan adopted for the Alberta utilities, prices are to a large extent decoupled from the utility's own costs, which raises the uncertainty of cost recovery relative to a cost of service environment. The ability to flow through certain recurring costs (Y factors) or seek approval for recovery of exogenous event related costs (Z factors) mitigates the risk, but does not reduce it to the cost of service model level.[443]

358. The Alberta Utilities asserted that "[i]ndividually, the[se] events [Y or Z factors] may not meet the threshold, and thus not be eligible for Y or Z factor treatment, but together, the effect could be significant."[444]

359. As noted by Ms. McShane, the PBR framework instituted by the Commission is based on a five year term as compared to cost of service regulation, which typically employs two year test periods. Furthermore, the rate of inflation that is prescribed for purposes of the I-X price mechanism may deviate materially from the actual rate of increase in costs experienced by the utility over the term of the PBR.[445] Ms. McShane further observed that the "Alberta PBR plan does not permit a flow through of changes in cost of capital, either cost of debt or allowed return on equity, as the Commission concluded that changes in the cost of capital are captured in the I factor."[446] In addition, Ms. McShane stated that the absence of a final resolution to the capital tracker proposals of utilities which account for the preponderance of the electric and gas distribution assets in Alberta adds a further element of uncertainty to PBR regulation in the province.[447]

360. The Alberta Utilities submitted that "there have been several studies that have concluded that the cost of capital is higher under performance-based regulation than under cost of service regulation"[448] and "DBRS rated the Alberta PBR framework as 'Very Good', two steps down from the 'Outstanding' rating that it afforded cost of service regulation."[449]

361. Dr. Cleary challenged Ms. McShane's recommendation of adding 0.75 per cent to the allowed ROE to account for the additional risks imposed by PBR noting that in an information response, Ms. McShane stated she was unaware of any precedents for such an adjustment by Canadian utility regulators.[450] In Dr. Cleary's view, Ms. McShane's assessment of the additional risk imposed by PBR was also based on very dated evidence pertaining to risks faced by utilities operating under price cap regulation, which did not include the various Y, Z and K factor mechanisms implemented by the Commission in its approved PBR framework.[451] Dr. Cleary further submitted that "Ms. McShane's analysis also ignores the fact that PBR provides opportunities for utility firms to earn additional returns."[452]

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[442] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, line 183.
[443] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1046-1051.
[444] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1056-1058.
[445] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1060-1062.
[446] Exhibit 42.02, McShane evidence for Alberta Utilities, page 42, lines 1081-1083.
[447] Exhibit 42.02, McShane evidence for Alberta Utilities, page 43, lines 1125-1128.
[448] Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1156-1158.
[449] Exhibit 42.02, McShane evidence for Alberta Utilities, page 44, lines 1137-1138.
[450] Exhibit 73.01, UCA-UTILITIES-63(c).
[451] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 16-18.
[452] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 18, lines 11-12.

362. Dr. Booth, on behalf of Calgary, commented that "…the experience in Canada has been that PBR has benefitted the shareholder and resulted in significant over-earning of allowed ROEs."[453] Dr. Booth ultimately concluded that:

> … looking at the experience of the four major comparators for ATCO Gas [being FortisBC Energy, Gaz Metro, Union, and EBDI], all of which have been on PBR or under settlement for extended periods of time, … none of them have suffered any increase in risk whatsoever. In fact, their ability to over-earn has increased quite significantly.[454]

363. Mr. Johnson, on behalf of Calgary, disputed Ms. McShane's opinion that PBR increases the business risk or regulatory risk of ATCO Gas on the following three bases:[455]

(i) "… ATCO Gas has gone a period of time in the past without a test year. In those circumstances there was no 'i-x' or the benefits of a 'k', 'y' or 'z factor.'"

(ii) "… in implementing PBR the Commission has had the benefit of the PBR regimes in other jurisdictions."

(iii) "… often ATCO gas has earned more than its allowed return under a cost of service regime. Further, as Dr. Booth noted, companies under PBR have generally earned at least their allowed return on equity."

364. Calgary submitted that:

> … the Commission's confirmation [in the EDTI AMI decision][456] that the AMI project could qualify for Y, Z or K factor treatment, depending upon the application, also reduces the risk to EDTI, and indicates that the PBR regime does not increase the risk of the distribution utilities and does not require an increase in either the ROE or the equity ratio.[457]

365. In supplementary reply argument, the Alberta Utilities disputed Calgary's position that "…. the potential ability to apply for the AMI project under a Y, Z, K factor demonstrates that the PBR regime does not increase the risk of the distribution utilities."[458] The Alberta Utilities commented that for the project to qualify several significant criteria must first be met.

366. Mr. Bell and Mr. Stauft's position, submitted on behalf of the UCA, is that "the implementation of PBR will not increase risk for the PBR Utilities in any way that would justify higher equity returns or adjustments to the PBR Utilities' capital structures."[459] Messrs. Bell and Stauft were of the further opinion that even if PBR had a minor negative effect that increased earnings volatility and risk, this additional risk would be offset by the expectation that PBR utilities will earn returns higher than those embedded in going-in rates.[460] In their view:

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453 Exhibit 40.02, Booth evidence for Calgary, page 16, lines 13-15.
454 Exhibit 40.02, Booth evidence for Calgary, page 20, lines 4-7.
455 Exhibit 40.03, Johnson evidence for Calgary, page 4, lines 16-28.
456 EDTI Capital Tracker decision, page 708.
457 Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 12.
458 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 2, paragraph 5.
459 Exhibit 45.02, Bell and Stauft evidence for UCA, page 4, lines 1-2.
460 Exhibit 45.02, Bell and Stauft evidence for UCA, page 27, lines 10-13.

> If the Commission has no genuine expectation that the PBR Utilities will actually earn higher returns by making efficiency improvements during the PBR term, it cannot have a genuine expectation that PBR will benefit customers in the long run. Since the Commission clearly does have that expectation, it is clear that the expectation of higher returns is an integral part of the PBR model.[461]

367. Evidence provided by Messrs. Bell and Stauft also stated that "the Commission's PBR program appears to have been carefully designed to allocate to PBR Utility shareholders only a narrowly defined set of commercial risks that are closely connected with the efficiency objectives of PBR, with all other risks effectively allocated to customers."[462] In their view:

> ... many features of the PBR mechanism have the effect of shifting risk to customers, and in almost all cases those risks are explicitly shifted to customers *because* the risks are not reasonably within the control of the utility. Where the Commission has allocated risk to the PBR Utilities, that is generally *because* the risks are either reasonably within the control of the utility or already accounted for in either 'I' or 'X.'[463] [emphasis in original]

368. Messrs. Bell and Stauft also argued that "[i]n the design of the overall [PBR] mechanism the Commission identified a risk for gas utilities that average use per customer will decline, and prescribed a revenue per customer cap for gas utilities in order ensure that use-per-customer risk is borne by customers."[464] They also noted that in the 2013 PBR Capital Tracker Decision 2013-435, "the Commission addressed that issue by approving a 'K Factor' methodology that will have the effect of ensuring that the PBR Utilities are afforded an opportunity to recover in PBR rates identifiable capital-related costs in excess of what is funded or compensated for by the I-X escalation factor."[465]

369. In rebuttal, Ms. McShane communicated her complete disagreement with the stated position of the expert witness of the UCA and Calgary that PBR does not increase risk because earnings volatility will likely be higher than under cost of service regulation, and earnings volatility is one facet of business risk.[466] She argued that companies with more stable earnings were less risky than those with more volatile earnings and further that the Commission did not implement earnings sharing in Decision 2012-237 because "the Companies' reported earnings will 'generally vary, sometimes significantly, from year to year during the PBR term.'"[467]

370. Ms. McShane also challenged the assertion of Messrs. Bell and Stauft that any negative effect on PBR utilities risk profile would at least be offset by these utilities earning returns which are higher than the returns embedded in the going-in rates. In doing so, she maintained that the return included in going-in rates should be equal to the PBR utilities' cost of capital which reflects their level of risk. In Ms. McShane's view, " the utilities [under PBR] should be **incented** to earn returns above their cost of capital; they should not be **required** to earn returns above their allowed return in order to earn their cost of capital."[468] (emphasis in original)

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461 Exhibit 45.02, Bell and Stauft evidence for UCA, page 28, lines 23-27.
462 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 7-10.
463 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 20-24.
464 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 25-27.
465 Exhibit 45.02, Bell and Stauft evidence for UCA, page 25, lines 19-23.
466 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6-7, line 183-196.
467 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, lines 185-187.
468 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 8, lines 241-243.

371. In their rebuttal evidence, Messrs. Bell and Stauft claimed that Ms. McShane had not provided any evidence showing that providing utilities subject to PBR mechanisms with higher allowed equity returns is an accepted practice in Canada, or elsewhere. In fact, they argued that the universal Canadian practise has been to not award higher equity ratios or ROE to utilities subject to PBR.[469]

372. With respect to the suggestion that the onset of PBR for Alberta distribution utilities has increased their perceived regulatory risk, the UCA maintained that:

> The only concern expressed by the rating agencies in relation to PBR was the adequacy of the Commission's capital tracker provisions, which at that time had not been decided on. The Commission fully addressed those issues and concerns in the Capital Tracker Decision by approving the capital tracker proposals of AltaGas and EPCOR essentially as-applied for. It is true that the other distributors must still conform their capital tracker mechanisms to the AltaGas/EPCOR model, but there is no reason to expect that process to result in capital trackers for those PBR Utilities that are less supportive than the AltaGas and EPCOR examples …[470]

Commission findings

373. Ms. McShane, on behalf of the Alberta Utilities, stated that implementation of PBR may result in a higher volatility of earnings, as compared to the cost of service regime, for the affected utilities, thereby resulting in higher risk.[471] In support of her view, Ms. McShane referenced Decision 2012-237 at paragraphs 820-821, where the Commission stated that "the companies' reported earnings will generally vary, sometimes significantly, from year to year during the PBR term."[472]

374. As well, Ms. McShane referenced two academic articles supporting the conclusion that the cost of capital is higher under PBR (price cap) than under cost of service regulation.[473] In response to a Commission information request, Dr. Cleary cited two newer studies which suggest the cost of capital is not higher under PBR.[474]

375. With regards to these academic publications, the Commission observes that Ms. McShane included a quote in her evidence highlighting the fact that "a regulated firm's cost of capital under PC [price cap] regulation depends on the level of the price cap, and a tightening of the regulatory contract increases this cost."[475] In a similar vein, when commenting on the articles referenced by Dr. Cleary, Ms. McShane underscored the argument that "how the method of regulation is actually imposed may offset the theoretical impact."[476] Ms. McShane continued:

> It is also possible that the results are affected by how the different methods of regulation were characterized for purposes of the study. For example, the author considered a rate freeze for a utility otherwise subject to cost of service regulation to be a "high power" form of regulation, i.e., the same as price cap regulation, whereas a rate moratorium was

469 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 33, lines 10-13.
470 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 32, lines 19-24.
471 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, line 183.
472 Decision 2012-237, paragraph 820.
473 Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1156-1181.
474 Exhibit 68.02, AUC-UCA-9(b).
475 Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1162-1164.
476 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 9, lines 276-277.

> considered a "medium power" form of regulation, although the terms rate freeze and rate moratorium are typically used interchangeably. In other words, the lack of relationship between systematic risk (beta) and the regulatory regime in the author's study may be due in part to the misspecification of the regulatory model faced by firms.[477]

376. The Commission agrees with Ms. McShane's view that the result of any study that compares PBR and cost of service regimes is likely to be very sensitive to the level and type of the PBR plan in effect. Drawing from Ms. McShane's example, if utilities under rate freeze are included in the PBR sample, the conclusion that the cost of capital is higher for such companies would not be surprising, given the inherent risks associated with rate freezes.

377. In this regard, Ms. McShane acknowledged that the "PBR plan adopted by the Commission for the Alberta distribution utilities is not a pure price or revenue cap model, given the adoption of Y and Z factors and some level of incremental capital funding."[478] The Commission agrees and notes that during the PBR term the Alberta distribution utilities have the opportunity to apply for Y, Z, and K factor adjustments based on a specified criteria. Therefore, the Commission is not persuaded that a conclusion that the cost of capital is higher under PBR than under cost of service regulation is valid for the Alberta utilities under PBR.

378. Furthermore, the available actual experiences since PBR implementation for 2013 in Rule 005 reports show the majority of Alberta distribution utility ROEs exceeded their interim approved ROEs of 8.75 per cent. Specifically, the Commission notes that all but one of the ROEs earned in 2013 for the Alberta distribution utilities based on their Rule 005 submissions are higher than the 2013 interim ROE level and the approved level embedded in the 2012 going in rates. These returns may have resulted from the efficiency incentives that PBR offers, but the risks as asserted by the Alberta Utilities have not manifested themselves through credit rating downgrades. For these reasons, the Commission finds that there is no evidence on the record of this proceeding which supports the contention that there is appreciably more risk under a PBR regime that would warrant an ROE premium, as proposed by the Alberta Utilities.

379. Finally, the Commission notes that the uncertainty asserted by the Alberta Utilities related to the capital tracker proposals for distribution utility assets and the adequacy of the capital tracker provisions has been addressed in Decision 2013-435, dealing with the first round of capital tracker applications.

380. For the above reasons, the Commission is not persuaded that the transition to PBR for electric and gas distribution utilities has resulted in a change in risk profile that warrants any adjustments to the approved ROE, capital structure, or both. Accordingly, the requested premium of 0.75 per cent by the Alberta Utilities is denied.

6.3 Other risks perceived by the utilities

381. Ms. McShane submitted, on behalf of the Alberta Utilities, that the "[r]isks to which the Transmission Facility Operators (TFOs) are subject are higher, resulting largely from political and regulatory developments that point to a less supportive regulatory environment."[479]

[477] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 9, line 277 to page 10, lines 284.
[478] Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1176-1178.
[479] Exhibit 42.02, McShane evidence for Alberta Utilities, page 3, lines 78-80.

382. Ms. McShane identified the following areas of change which have increased risks for TFOs:

(i) amendment of the *Transmission Regulation* to remove the legislated presumption of prudence for project costs incurred by TFOs;

(ii) potential for the Cost Oversight Manager office to second guess or direct how a TFO manages the execution of capital projects;

(iii) no resolution regarding the level of CIAC-financed assets being constructed, managed and operated by the TFOs;

(iv) the introduction of competitive transmission in Alberta intended to promote the operation of competitive market forces in an area historically governed by cost of service regulation;

(v) potential deferred cost recovery mechanisms for Alberta TFOs resulting from the Transmission Cost Recovery Subcommittee Report; and

(vi) though utilities are expected to recover carrying costs incurred, the Minister of Energy sought to have rates frozen without citing statutory authority to do so, for an indeterminate period.[480]

383. The Alberta Utilities submitted that:

> Although no unique (or specific) increase in equity ratios for TFOs was recommended by Ms. McShane as a result of the increased risks identified above, since those risks are indicative of a general deterioration in regulatory support and an increase in government intervention, they support Ms. McShane's recommended across-the-board increase in the deemed common equity ratios of no less than two percentage points not just for TFOs, but for all of the Alberta Utilities.[481]

384. The UCA argued that Ms. McShane's claims were neither meaningful or relevant and therefore the utilities should not be entitled to additional compensation for risk with regard to these matters.

385. With regard to Ms. McShane's position that "amendment of s.46(1) of the Transmission Regulation to remove the legislated presumption of prudence for project costs"[482] increased risk for TFOs, the UCA submitted that this "legislative development may impose an administrative burden; however, it does not change the requirement that investments must be prudent."[483]

386. The UCA submitted that the Transmission Cost Management (TCM) policy referred to by Ms. McShane was only being discussed at the present time but that the "UCA's understanding is that the TCM Policy would be intended to reduce risk for the utilities once finalized 'by

480 Exhibit 148.01, Alberta Utilities argument, pages 71-79, paragraphs 189-214.
481 Exhibit 148.01, Alberta Utilities argument, page 79, paragraph 214.
482 Exhibit 156.02, UCA reply argument, page 51.
483 Exhibit 156.02, UCA reply argument, page 51.

ensuring that prudence issues for transmission projects are addressed early in the process, rather than only after new facilities have been constructed and put into service.'"[484]

387. Regarding Ms. McShane's assertion that there was no resolution regarding the level of CIAC-financed assets for TFOs, the UCA argued that the "current CIAC levels have no cost of capital implications."[485]

388. By way of response to an issue raised by the Commission Panel during the hearing regarding whether competitive bidding processes for construction of new electric transmission facilities represented an undermining of the regulatory compact, the UCA responded that, in its opinion, there was no intention on the part of the government or the AUC to expose operating transmission utilities to competition in the market. The UCA's understanding was that the intention of the competitive bidding process was to facilitate the construction of necessary transmission facilities on the most economical terms. In its view:

> … the transmission network would continue to be operated as it currently is, with TFOs exposed to essentially no competitive, market, or revenue risk. There is no reason for customers to compensate TFOs for the inconvenience and competitive risk associated with participating in a voluntary competitive procurement process. If TFOs are concerned as to potential increases in risk, they are not obligated to participate in the competitive procurement process.[486]

389. In response to Ms. McShane's assertion of "potential rate levelization approaches as contributing to the 'material increase in uncertainty,'"[487] the UCA responded that these approaches were only being discussed and had not been implemented or clearly defined.

390. Further, the UCA submitted that Ms. McShane's description of the 2012 rate freeze as arbitrary interference by government authorities was not an "attempt to interfere with the Commission's rate-making jurisdiction in relation to the Alberta Utilities. Rather, it was an ancillary part of the government's response to issues that arose in connection with the design of default energy supply services."[488] In addition, the UCA argued that the "rate freeze had no negative impact on the Alberta Utilities, as it was in place for less than a year (March 13, 2012 to January 29, 2013) and, upon its termination, each utility was able to apply for any carrying costs as required."[489]

Commission findings

391. As a preliminary observation, the Commission notes that the majority of the changes identified by Ms. McShane as contributing to the creation of a "less supportive regulatory environment" are related, in various ways, to the recent large-scale growth in Alberta's electricity transmission system.

392. The necessity of prudent procurement and operating practises in utility project execution has always been, and continues to be, an important feature of the Alberta regulatory

[484] Exhibit 156.02, UCA reply argument, page 51.
[485] Exhibit 156.02, UCA reply argument, page 51.
[486] Exhibit 150.02, UCA argument, pages 58.
[487] Exhibit 156.02, UCA reply argument, page 51.
[488] Exhibit 150.02, UCA argument, pages 57-58.
[489] Exhibit 156.02, UCA reply argument, page 50.

environment. In the Commission's view, recent amendments to the *Transmission Regulation*,[490] should not result in changes to transmission utilities' capital construction or operating practises, which should, in any event, be in accordance with prudent business conduct.

393. The Commission notes that the purpose of the cost oversight manager function, as identified by Ms. McShane, is to provide third-party expert review and comment on transmission project costs at specific stages of a transmission project from planning through construction completion. A pilot project is currently under way and, as identified by the UCA, the intention is to reduce risk by addressing cost related issues before new facilities are constructed and placed into service. In the Commission's view, the institution of the office of the cost oversight manager does not result in the imposition of additional risk on transmission utilities. In arriving at this conclusion, the Commission considers, to the contrary, that the creation of this oversight mechanism is intended to provide utilities, the AESO, and other stakeholders with additional certainty regarding cost consequences of direct assign project execution by TFOs.

394. The Commission is, likewise, not persuaded that Ms. McShane's concern respecting the level of TFO involvement in the construction of CIAC-financed assets has resulted in the creation of additional risk for those utilities beyond a *de minimus* level. In making this finding, the Commission notes that the AESO held a stakeholder consultation on July 22, 2014 to discuss any issues and concerns of stakeholders with the AESO's Rider I proposal, that would address the level of CIAC-financed assets, and the required next steps. In light of this fact, the Commission considers that any additional uncertainty perceived by capital market participants in relation to this aspect of TFO operations would be significantly ameliorated by the existence of active remedial steps taken by the AESO.

395. Competitive construction for transmission is under implementation and has been introduced for one project. An expanded competitive process for other major projects has been deferred pending the results of the first project. The Commission is not persuaded that the implementation of the market participant choice process for the competitive sourcing of system projects has resulted in additional volatility for transmission utilities.

396. Alternative approaches to transmission cost recovery are currently under consideration by the Commission. While the outcomes of this review are not yet determined, the Commission considers that this should not be presumed to create a material risk that would warrant an increased equity thickness or higher ROEs.

397. With respect to the Alberta Utilities' assertion that the 2012 temporary rate freeze has increased risk as perceived by credit rating agencies, the Commission does not agree that this is the case. In coming to this conclusion, the Commission notes that the 2012 rate freeze was in effect for a relatively short duration, and affected utilities were afforded an opportunity to recover carrying costs incurred as a result of the rate freeze. Further, and in any event, the Commission considers that the societal importance of utility operations means that, where and whenever they are carried out, they may be subject to conditions of the kind that resulted in the imposition of the 2012 rate freeze. This being the case, the Commission does not consider that this isolated occurrence can be appreciated to have contributed to a regulatory environment in Alberta that is "unsupportive" when compared to other Canadian jurisdictions.

[490] *Electric Utilities Act Transmission Regulation*, AR 086/2007.

398. On balance, the Commission is not persuaded that the above-referenced factors identified by the Alberta Utilities have contributed to the creation of a regulatory environment that is substantially less supportive than it was at the time of the previous GCOC proceeding. Consequently, the Commission finds that no adjustment to the utilities' respective deemed equity ratios is required to account for these factors over the test period.

7 Automatic adjustment mechanism for establishing ROE

399. In Decision 2011-474, the Commission indicated it would revisit the matter of a return to an automatic adjustment mechanism (AAM) for setting the allowed ROE on a go forward basis.[491] This mechanism is also referred to as an "ROE formula."

400. In this proceeding, expert evidence on the matter of a return to an ROE AAM was provided by Ms. McShane for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary. In their evidence, Messrs. Bell and Stauft for the UCA, commented on the use of an ROE formula.[492] However, in response to an Alberta Utilities' information request, Messrs. Bell and Stauft indicated that they took no position on whether an ROE AAM should be implemented.[493]

401. Ms. McShane indicated that:

> … in light of the persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields, it is, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.[494]

402. If the Commission determined that an ROE AAM is required for 2015 and beyond, Ms. McShane recommended the adoption of the following formula:[495]

ROE_{new} = Initial ROE + 50% X (Change in Forecast 30 Year GOC Bond Yield)
+ 50% X (Change in Utility Bond Yield Spread)

403. However, Ms. McShane cautioned that this ROE formula not begin to operate until the actual yield on the long-term Canada bond equals or exceeds four per cent. Ms. McShane advised that the initial spread from which subsequent years' changes would be calculated, must be compatible with the four per cent long-term Canada bond yield. Additionally, according to Ms. McShane, implementation of a 50 per cent elasticity factor on long-term Canada bond yields is only appropriate if the allowed ROE is initially set at a level that meets the fair return standard.

404. Dr. Booth supported the use of an ROE formula "but at the moment the advantages are quite slim and would only affect one year 2015."[496] In the event "the AUC wants a 'bullet proof'

491 Decision 2011-474, page 31, paragraph 168.
492 Exhibit 45.02, Bell and Stauft evidence for UCA, pages 37-39.
493 Exhibit 65.02, Utilities-UCA-23.
494 Exhibit 42.02, McShane evidence for Alberta Utilities, page 140, lines 3607-3612.
495 Exhibit 42.02, McShane evidence for Alberta Utilities, page 142, lines 3654-3656.
496 Exhibit 44.02, Booth evidence for CAPP, page 77, paragraph 199.

new ROE formula to account for events like the financial crisis," Dr. Booth recommended a two-part formula, of the type supported by Ms. McShane as referenced above. However, Dr. Booth's recommended ROE formula has a 75 per cent adjustment to changes in the forecast long Canada bond yield.[497]

405. Dr. Booth also advocated that an ROE formula does not start to operate until the yield on the long-term Canada bonds exceeds four per cent:

> I would not change the allowed ROE until the long Canada bond yield exceeds 4.0%. I expect this to happen for 2015, but the change is likely to be minor. Consequently adopting such an ROE formula is likely to result in the same ROE for 2013, 2014 and 2015. I would therefore recommend a fixed ROE for all three years and a very limited hearing in late 2015 confirming the appropriateness of any ROE formula for test year 2016.[498]

406. In his evidence, Dr. Cleary, on behalf of the UCA, presented his views on an ROE formula as follows:

> I would not advocate the use of an AAM for long periods of time, since it would be difficult to envision one that would adjust to changing capital market conditions over an extended period of time. In a 'perfect world' rates would be determined on an annual basis to reflect market and company situations – however this is obviously impractical in the real world. Hence the logistics dictate that regular hearings are a necessary burden. The trade-off is to determine intervals that consider the costs involved in such hearings versus not allowing too much time to elapse in between. Given the intervals will be every two to four years, it makes sense to implement an "interim" (but not long-term) AAM.[499]

407. During the hearing, Dr. Cleary, further commented on the implementation of an ROE formula at this time:

> So the way I would recommend it is if by 2016 there hasn't been another hearing to determine an allowable ROE, then having this in place -- and if things seem normal and it seemed fit to use the AAM -- may save the troubles of having -- you know, troubles and expense and everyone's time of having another hearing. Obviously if things are still conceived as so awry, then you can always another hearing, so.[500]

408. If the Commission determined that an ROE AAM was required, Dr. Cleary recommended the following formula be implemented to determine the 2016 ROE:[501]

> ROE (adj.) = ROE (base) + 0.75×[RF (now) – RF (base)] + 0.50×[Yield Spread (now) – Yield Spread (base)]

497 Exhibit 44.02, Booth evidence for CAPP, page 4.
498 Exhibit 44.02, Booth evidence for CAPP, page 4.
499 Exhibit 45.03, Cleary evidence for UCA, page 55, lines 3704-3720.
500 Transcript, Volume 6, page 837, lines 6-13.
501 Exhibit 45.03, Cleary evidence for UCA, pages 56-57.

409. However, unlike Ms. McShane and Dr. Booth, Dr. Cleary did not support using a minimum government bond yield value for the formula to be in effect. According to Dr. Cleary:

> Establishing a floor of 4% implies that the ROE would be adjusted upward for increases in government yields when they increase above 4%. This is consistent with adjusting for the associated increase in the financing costs with an increase in rates and/or yield spreads. However, establishing a minimum value on government yields implies that ROEs would not be adjusted downward if rates declined, even though this would result in lower financing costs, unless there was an associated increase in yield spreads.[502]

Commission findings

410. The Commission observes that all three expert witnesses recommended that, if an ROE formula was to be adopted, it should incorporate the two elements: changes in government bond yields, and changes in utility bond spreads. In Decision 2011-474, the Commission agreed that this type of a formula has advantages over the single-variable formula, as it is likely to better reflect any fluctuations in capital market conditions.[503]

411. Also in that decision, the Commission had considered evidence of continuing credit market volatility and determined that a return to the ROE AAM was not warranted at that time.[504] In Section 4 of this decision, the Commission observes that the risks in the financial markets have moderated since Decision 2011-474. However, it also considers that in the current environment of historically low interest rates, market conditions may not be reflective of a typical risk-return relationship for an investor. This is important in the current case because one of the components of the proposed two-part formula tracks changes in government long-term bond yields. Accordingly, the Commission finds that an abnormal risk-return relationship triggered by ultra-low interest rates would be a valid concern, if such a formula was to be implemented for this test period.

412. The Commission notes that submissions from all parties regarding the use of an ROE formula included suggestions for the incorporation of "safety valve" hearings, reviews, or other reopener mechanisms to ensure proper operation of any adopted formula, given the economic conditions prevailing at a particular time. The Commission agrees that the institution of such mechanisms as part of an AAM are reasonable and that, furthermore, the desirability of such controls provides additional support for the idea that correct operation of AAMs such as ROE formulae are dependent on prevailing market conditions falling within a range of normalcy.

413. The Commission notes that both Ms. McShane and Dr. Booth recommended against use of an ROE formula until the government of Canada long-term bond yield exceeds 4.0 per cent. The Commission notes that as of the close of record of this proceeding, the long-term Canada bond yield is well below 3.0 per cent.

414. For the above reasons, the Commission will not reintroduce the use of an ROE formula or other AAM at this time. The Commission is prepared to revisit the desirability of an ROE formula as part of future GCOC proceedings if its adoption would be warranted in light of the market conditions present at that time.

502 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 20, lines 10-15.
503 Decision 2011-474, paragraphs 164-165.
504 Decision 2011-474, paragraph 165.

415. For the purpose of regulatory efficiency, the ROE and equity ratios awarded in this decision will remain in place on an interim basis for 2016 and for subsequent years until changed by the Commission. The Commission considers that establishing an allowed ROE for 2015 and setting an interim ROE for 2016 and subsequent years will provide for a more supportive, and predictable regulatory environment.

8 Capital structure matters

8.1 Introduction

416. To satisfy the fair return standard, the Commission is required to determine a capital structure (also referred to as an equity ratio) for each of the affected utilities. In this decision, the Commission has established an allowed ROE of 8.30 per cent for all of the affected utilities. The Commission will account for the differences in risk among the individual utilities by adjusting their capital structures, if required, and recognizing changes in overall levels of risk to which utilities have been exposed, in a manner consistent with the approach in previous GCOC decisions.

417. This section of the decision determines the allowed percentage of rate base (net of no-cost capital) supported by common equity as opposed to debt. Where preferred share capital is present, it is considered, for the purposes of determining the common equity ratio, to be a substitute for a portion of the debt and does not affect the required common equity ratio. Whether or not a utility should use preferred shares in place of some of its debt is not considered in this proceeding.

418. As the Commission noted in previous GCOC decisions, in general, the return on investment-grade debt required by investors is lower than the return required on equity. This is because the return paid to investment-grade debt investors, barring extreme and unexpected circumstances, is set by the initial terms of the debt instrument and therefore, is not normally subject to uncertainty. Debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in capital structure increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk. This is because if debt levels are too high, debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and to provide them with their expected return.

419. The risk to debt investors is usually assessed, in part, by various interest coverage and debt ratio calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor's (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various credit metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations. Ultimately, it is debt investors that assess the risk of investing in various debt instruments. Investors rely greatly, but not exclusively, on credit ratings. The consensus judgment of debt investors is reflected in the credit spreads that can be observed in the primary and secondary debt markets for individual debt issues and issuers, including utilities.

420. The Commission's approach, consistent with past decisions, is to award common equity ratios that are intended to allow the affected utilities, on a stand-alone basis, to target credit ratings in the A-range.[505] As in past decisions, in setting the ROE, the Commission has considered that it will determine an equity ratio that, in its view, will allow the utilities (with the possible exception of the three smallest utilities) to target credit ratings in the A-range, when assessed on a stand-alone basis.

421. In determining capital structure, the Commission will analyze the equity ratios that are required for a typical pure-play regulated utility to attain the minimum credit metrics that were identified and used in both Decision 2009-216 and Decision 2011-474. This analysis has also been used to provide an indication of whether an overall uniform adjustment to existing equity ratios is required, in addition to any adjustments to account for differences in risk among individual utilities. The Commission will then turn to an assessment of the various types of utilities, and each individual utility, to determine whether their risk rankings have changed, and whether specific adjustments to each company's equity ratio are warranted.

8.2 Equity ratios requested by the Alberta Utilities

422. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2011-474 with the equity ratios recommended by the utilities and interveners in this proceeding.

Table 5. Recommended vs. last approved equity ratios

	Last approved[506]	Recommended by the Alberta Utilities[507]	Recommended by the UCA[508]	Recommended by the CCA[509]	Recommended by CAPP[510]	Recommended by Calgary[511]
	(%)					
Transmission						
ATCO Electric	37	39	33 – 35	35		
AltaLink	37	39	33 – 35	35		
ENMAX	37	39	35	35		
EPCOR	37	39	35	35		
ATCO Pipelines	38	44.5	33	35	35	
Distribution						
ATCO Electric	39	41	36	37		
ENMAX	41	43	38	39		
EPCOR	41	43	38	39		
ATCO Gas	39	41	36	35		35
FortisAlberta	41	43	38	39		
AltaGas	43	45	40	41		

505 Decision 2009-216, paragraphs 78, 273, 327, 334, 357 and 411.
506 Decision 2011-474, page 53, Table 10.
507 Exhibit 148.01, Alberta Utilities argument, page 2.
508 Exhibit 150.02, UCA argument, page 98-99.
509 Exhibit 149.01, CCA argument, paragraphs 134-146.
510 Exhibit 151.01, CAPP argument, page 32, paragraph 110.
511 Exhibit 146.02, Calgary argument, page 18, paragraph 61.

8.3 Credit ratings and credit metric analysis

8.3.1 Financial ratios, capital structure and actual credit ratings

423. Credit ratings measure the credit-worthiness of a firm as assessed by a credit rating agency. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments and to repay principal. This, in turn, allows the company to borrow at a lower interest rate. Canadian regulated utilities usually seek to maintain a credit rating in the A-range. In previous GCOC decisions, the Commission has recognized the importance of maintaining a credit rating in the A-range for the utilities under its jurisdiction, to facilitate their ability to obtain debt financing at optimal rates.

424. Credit metrics (financial ratios) are an important, although not the only, component that bond rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:[512]

- EBIT coverage (interest coverage ratio): which is the company's earnings measured before deducting interest and taxes divided by total interest costs.
- FFO/debt (funds from operations): which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt.
- FFO coverage: which is the company's funds from operations plus interest divided by total interest costs.

425. The Commission observed in Decision 2009-216 that a number of Alberta utility companies finance their debt requirements through direct participation in the debt market and independently of any affiliated companies, making it possible to directly observe equity ratios and credit metrics of stand-alone regulated utilities maintaining credit ratings in the A-range. Consequently, in that proceeding, the Commission examined the credit ratings and credit metrics of companies for which credit rating reports were available, in order to gain insight into the credit metrics required to achieve an investment-grade credit rating for a stand-alone utility.

426. In Decision 2009-216, the Commission observed the following minimum credit metrics to be associated with regulated utilities with an A-range credit rating:[513]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3 per cent

427. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

428. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the actual (as opposed to awarded) equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid-point of 38.5 per cent.[514] The sample

[512] Decision 2009-216, paragraph 345.
[513] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[514] Decision 2009-216, paragraph 359.

group of utilities that were examined in arriving at this observed range of actual equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

429. The minimum credit metrics and the actual equity ratios that were observed to be associated with A-range credit ratings were associated with all of the risks that the credit rating agencies perceived for the observed Alberta utilities at that time. These risks would implicitly have included all perceived financial and business risks, including regulatory risk, market risk, supply risk, and operating risk, including the impact of contributions in aid of construction (CIAC).

430. In Decision 2011-474, the Commission agreed with the parties to that proceeding that the minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, could be accepted as reasonable guidelines for the purposes of that proceeding.[515]

431. In this proceeding, Ms. McShane, who provided evidence on behalf of the Alberta Utilities, did not propose increases to the minimum credit metrics, but instead argued that the Commission should target metrics well above the minimums.[516] In argument, the Alberta Utilities stated that because the Commission has previously found the FFO/debt ratio to be the most critical credit metric, it should, at a minimum, target the high end of the range for this metric in its analysis.[517] The Alberta Utilities noted the evidence of Ms. McShane regarding current capital market conditions, increased regulatory risk, and the high levels of contributions in aid of construction being financed by the Alberta Utilities. They argued that this, along with the credit metric analysis, indicated that a two percentage point across-the-board increase in common equity is conservative.[518]

432. Messrs. Bell and Stauft, for the UCA, provided an analysis of the equity ratio that would be required to achieve the Commission's credit metric minimums or ranges, but did not propose an update to the observed target credit metrics. In argument, the UCA submitted that "based on the base case assumptions used by Messrs. Bell and Stauft, as shown in Table 1 at page 9 in their direct evidence, the minimum equity ratio that will meet all of the Commission's minimum standards is 34%, or 3% lower than the lowest equity ratio that was approved in Decision 2011-474."[519]

433. Mr. Fetter, on behalf of the Alberta Utilities, addressed the Commission's previous findings on credit metric ratios necessary to achieve A-range credit ratings. He generally agreed with the ranges used by the Commission but felt that the targets should be towards the top of the ranges as the top of the ranges provided greater ratings security.[520]

434. Dr. Booth, on behalf of CAPP, indicated that he did not agree with the Commission's practice of using credit metrics to target an equity ratio. In his view, targeting particular credit metrics ignores the fact that this is only part of what generates an actual bond rating. He

515 Decision 2011-474, paragraph 194.
516 Exhibit 42.02, McShane evidence for Alberta Utilities, line 1538.
517 Exhibit 148.01, Alberta Utilities argument, paragraphs 234-235.
518 Exhibit 148.01, Alberta Utilities argument, paragraph 229.
519 Exhibit 150.02, UCA argument, page 81.
520 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 23, line 12 to page 26, line 3.

submitted that "putting undue weight on financial metrics, such as the interest coverage ratio or the funds flow to debt ratio, misses the point, which is can the utility access credit on fair and reasonable terms?"[521]

435. In rebuttal, Ms. McShane submitted that Dr. Booth's approach of relying on the equity ratios awarded by other regulators was both circular and based on an assumption that those equity ratios were exactly correct.[522]

436. In rebuttal evidence submitted on behalf of Calgary, Dr. Booth and Mr. Johnson, stated that "we are not aware of any justification for allowing the equity holder a higher ROE, or larger common equity ratio, for bond market problems."[523]

Commission findings

437. Consistent with the approach in past GCOC decisions, the Commission awards, in this decision, common equity ratios that are intended to allow the affected utilities, on a stand-alone basis, to target credit ratings in the A-range.[524] The Commission observes that, except for the period around January 2009, interest paid on debt sourced by A-range utilities has typically averaged approximately 150 basis points above that payable on 30-year government of Canada bonds, as can be seen in figures 1 and 2 in Section 4. Recently, some utilities have been able to obtain 40-year and 50-year debt at spreads minimally above those for 30-year debt, highlighting the advantage of enabling utilities to achieve and maintain A-range credit ratings. In addition, this allows the utilities to more easily match the existing life expectations of the underlying assets to the maturity of their long-term debt.

438. In the Commission's view, increases in capital market risks, regulatory risks, and high levels of contributions in aid of construction for Alberta utilities should, if significant, lead to changes in the observed credit metrics that are associated with A-range credit ratings. In Decision 2009-216, the Commission referenced certain minimum credit metrics that were observed to be associated with regulated utilities with an A-range credit rating.[525] In this proceeding, none of the parties provided updated evidence on the actual credit metrics associated with A-range credit ratings, or proposed to change the ranges of the credit metrics referenced by the Commission in Decision 2009-216.

439. Based on its review of the evidence and argument in this proceeding, and in a manner consistent with its approach to determining capital structure in previous GCOC proceedings, the Commission finds it is helpful to continue the use of the target credit metrics referenced in Decision 2009-216, and subsequently applied in Decision 2011-474. The use of these target credit metrics will aid the Commission in determining the equity ratios that would be expected to be supportive of A-range credit ratings for Alberta utilities, on a stand-alone basis.

440. Dr. Booth did not agree with the Commission's practice of using credit metrics to target an equity ratio. The Commission does not share Dr. Booth's view. Since the issuance of Decision 2009-216, interest rates have declined significantly as capital markets reflect the continuing economic recovery. The Commission continues to consider that its credit metric ratio analysis

[521] Exhibit 44.02, Booth evidence for CAPP, page 16, lines 6-8.
[522] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, lines 665-673.
[523] Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 3, lines 1-2.
[524] Decision 2009-216, paragraphs 78, 273, 327, 334, 357 and 411.
[525] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.

contributes to a better understanding of the impact of issues currently facing utilities, while being cognizant of how these ratios must be interpreted within the context of an evolving market, and taking into account the differing growth rates and financing requirements faced by the Alberta Utilities. In the Commission's view, this approach provides an objective analysis to determine the equity ratios that would be expected to be supportive of A-range credit ratings for Alberta utilities, on a stand-alone basis.

441. As well, the Commission disagrees with Dr. Booth's and Mr. Johnson's recommendation, made on behalf of Calgary, against using a higher equity ratio, which they assert benefits the equity holder, to account for perceived problems in the bond market. In the Commission's view, the primary driver of minimum equity ratios is the need to provide an acceptable level of risk for bond investors. This in turn ultimately minimizes debt costs which are eventually borne by ratepayers. The primary vehicle of lowering risk for debt investors exposed to a given level of business risk is to allow increased equity. If earnings are ultimately less than forecast, bond interest must still be paid. A higher forecast level of equity earnings, associated with a higher equity ratio, provides a larger margin of safety for debt investors. When the Commission increases its awarded equity ratios, it does so to maintain a reasonable level of risk for debt investors by targeting an A-range credit rating that contemporaneously minimizes associated debt costs for ratepayers. Once incurred, these debt costs, borne by ratepayers, may last for 30 to 50 years and marginal increases can impose a costly burden in the long term.

8.3.2 Equity ratios associated with minimum credit metrics

442. In Decision 2011-474, at Table 9, the Commission provided a sensitivity analysis illustrating the impact of a range of equity ratios on the levels of the three principal credit metrics. The analysis was based on certain input parameters associated with the various applicant utilities. The analysis indicated that the following minimum equity ratios were required to achieve the observed minimum credit metrics:[526] The awarded equity ratios that were subsequently approved in that decision ranged from 37 to 43 per cent.

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 37 per cent.
- Minimum equity ratios in the range of 30 to 38 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 35 per cent was required to achieve an FFO coverage ratio of at least 3.0.

443. In this proceeding, the parties suggested revised and updated input parameter values to be used in calculating the resulting credit metric values at various equity ratios. The proposed revised parameter values are summarized in the following table, along with the values the Commission elected to use in its updated analysis. The Commission's reasons for selecting the identified updated parameter values follow.

[526] Decision 2011-474, paragraph 222.

Table 6. Parameters for calculating credit metrics

Parameter	Parameter values applied in Decision 2011-474	Proposed by the Alberta Utilities	Proposed by the UCA	Parameter values applied in this decision
	(%)			
Embedded average debt cost	6.4	5.7	5.1	5.1
ROE	8.75	8.75	8.0	8.3
Income tax rate	25.0	25.0	25.0	25.0
Depreciation	6.0	5.0	6.0	5.0
Construction work in progress (CWIP)	5.0	8.0	5.0	5.0

444. In arriving at the updated parameters, the Commission has considered the recommendations of parties and has reviewed the actual parameters from the 2013 Rule 005 filings.

445. The ROE input parameter is common to all utilities, as is the income tax rate input parameter (non-taxable utilities are considered in a later section). The Commission has summarized the other parameter values for each utility based on their respective 2013 Rule 005 filings, as shown below:

Table 7. Parameters by utility (excludes the smallest utilities)

Utility	Invested capital ($000)	Debt cost per cent	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
ATCO distribution	1,696,400	5.40	5.14	8.22
Fortis	2,285,200	5.34	6.75	2.92
ENMAX distribution	900,568	4.45	5.35	7.98
EPCOR distribution	674,431	5.70	4.46	1.40
AltaLink	3,592,600	3.90	3.82	36.73
ATCO transmission	3,640,600	5.02	2.90	34.00
ENMAX transmission	251,667	4.45	3.73	18.62
EPCOR transmission	471,067	4.78	3.59	15.53
AltaGas	195,732	5.08	5.25	1.05
ATCO Gas	1,860,195	5.90	6.51	2.45
ATCO Pipelines	868,417	5.64	5.42	7.28
Average		**5.06**	**4.81**	**12.38**

Commission findings

446. As set out in Section 8.3.1, the Commission's credit metric ratio analysis contributes to a better understanding of the impact of issues currently facing utilities, while recognizing that these ratios must be interpreted and appreciated within the context of an evolving market, and taking into account the differing growth rates and financing requirements faced by the Alberta Utilities. As shown in Table 7 above, the mid-year CWIP as a percentage of invested capital ranges from 1.05 per cent to 36.73 per cent. Given the range of this metric, the Commission considers that it cannot slavishly follow a numeric credit metric ratio analysis without understanding the reasons underlying the ratios.

447. In its credit metric analysis, the Commission employed the following five parameters: average embedded debt interest cost, ROE value, income tax rate, depreciation as a percentage of invested capital and CWIP as a percentage of invested capital.

448. In her credit metric analysis, Ms. McShane proposed that the average embedded debt interest cost be updated to 5.7 per cent.[527] The UCA proposed that the average embedded debt interest cost be updated to 5.1 per cent.[528] The Commission is cognizant that ENMAX has a debt cost that is lower than the typical utility due to its access to the Alberta Capital Financing Authority. The transmission utilities that have recently experienced rapid growth, will have lower than average debt costs reflecting a higher proportion of more recent debt issues. The Commission is also aware that the average embedded debt costs will likely continue to decline as older, higher-cost debt is retired, and assuming current debt issue costs will remain lower than the average historical embedded cost of debt. Therefore, the Commission finds the UCA's proposal to use an average embedded debt interest cost of 5.1 per cent in the Commission's credit metric analysis, to be reasonable.

449. Consistent with the Commissions' findings in Section 5.6, the Commission has applied an ROE value of 8.3 per cent in its credit metric analysis.

450. There was no controversy among the parties regarding the continued use of an income tax rate assumption of 25 per cent for a typical Alberta utility, prior to any utility-specific adjustments.

451. In addressing depreciation as a percentage of invested capital, Ms. McShane recommended, on behalf of the Alberta Utilities, that the value be decreased from 6.0 per cent to 5.0 per cent.[529] The UCA acknowledged that the depreciation rate as a percentage of invested capital was less than 6 per cent, but nonetheless suggested the use of 6.0 per cent as a rounded figure.[530] Based on the data in Table 7 above, the Commission finds the Alberta Utilities' recommendation of 5.0 per cent for the depreciation parameter to be reasonable.

452. Regarding CWIP as a percentage of invested capital, Ms. McShane and the Alberta Utilities recommended that the assumed value be increased to 8.0 per cent,[531] whereas the UCA recommended the continued use of 5.0 per cent.[532] The Commission notes that CWIP as a percentage of invested capital varies widely. The Commission is also cognizant that the utilities with the highest level of CWIP have previously been granted relief through the inclusion of CWIP in rate base. As a result, these utilities now have minimal CWIP as a percentage of their total capital, if CWIP in rate base is excluded from the calculation.

453. Given anomalies, such as low CWIP percentages for companies with CWIP in rate base, on one extreme, and companies with a CWIP percentage in the 30 per cent range, on the other extreme, the Commission finds that it is inadvisable to assign significant weight to such outlier values in its credit metric analysis. The purpose of the credit metric analysis is to estimate equity ratios for a typical Alberta utility. It therefore considers it reasonable to maintain the 5.0 per cent

[527] Exhibit 42.02, McShane evidence for Alberta Utilities, line 1594.
[528] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A4.
[529] Exhibit 42.02, McShane evidence for Alberta Utilities, line 1602.
[530] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A9.
[531] Exhibit 42.02, McShane evidence for Alberta Utilities, line 1605.
[532] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A6.

CWIP assumption that it used in the previous decision. Utilities that believe that they are experiencing difficulties associated with materially higher levels of CWIP can apply to the Commission for approval to include CWIP in rate base as a means of addressing such difficulties, if such action proves necessary.

454. Ms. McShane and the Alberta Utilities also proposed that the credit metric analysis reflect the impact of operating leases, debt/equity hybrids, pension liabilities and asset retirement obligations. The proposal was to increase the reported debt levels by 10 per cent to reflect the analytical adjustments that the S&P credit rating agency makes to reflect these items.[533] In its rebuttal evidence, the UCA indicated that any upward adjustments required to account for these variables were not warranted and that, in any event, any adjustment for preferred shares would require the amount of debt to be reduced rather than increased.[534]

455. The Commission is not convinced that typical Alberta distribution or transmission utilities are materially affected by operating leases, unfunded pension liabilities or asset retirement obligations. With respect to any potential impact of debt/equity hybrids such as preferred shares, the Commission notes that its method of setting common equity ratios already effectively categorizes preferred shares as a component of debt, as opposed to common equity. Based on the foregoing, the Commission finds that no adjustments to its credit metric analysis are required to account for these factors.

456. Based on the foregoing, the Commission's updated credit metric analysis is provided in the following table:

[533] Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1569-1583 and 1608-1609.
[534] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A17.

Table 8. Credit metrics compared to equity ratios – Commission analysis

	EBIT coverage		FFO / debt %		FFO coverage	
Equity Ratio	Decision 2011-474 Table 9	Updated	Decision 2011-474 Table 9	Updated	Decision 2011-474 Table 9	Updated
30%	1.7	1.8	11.73	10.19	2.79	2.95
31%	1.7	1.9	12.03	10.45	2.83	3.00
32%	1.8	1.9	12.32	10.72	2.88	3.05
33%	1.8	**2.0**	12.63	11.00	2.93	**3.11**
34%	1.8	2.0	12.95	**11.29**	2.98	3.17
35%	1.9	2.1	13.28	11.58	3.03	3.22
36%	1.9	2.1	13.62	11.89	3.08	3.28
37%	2.0	2.2	13.96	12.20	3.13	3.34
38%	2.0	2.2	14.32	12.53	3.19	3.41
39%	2.1	2.3	14.70	12.86	3.25	3.47
40%	2.1	2.3	15.08	13.21	3.31	3.54
41%	2.2	2.4	15.48	13.56	3.37	3.61
42%	2.2	2.4	15.89	13.93	3.43	3.68
43%	2.3	2.5	16.31	**14.32**	3.5	3.76
44%	2.3	2.6	16.75	14.71	3.57	3.84
45%	2.4	2.6	17.21	15.13	3.64	3.92

457. The bolded figures correspond to the minimums for each credit metric. Based on this analysis, minimum equity ratios associated with the targeted credit metrics, are set out in the following table:

Table 9. Minimum equity ratios to achieve target credit metrics

Credit metric target	Decision 2011-474	Updated
	(%)	
2.0 EBIT coverage	37	33
3.0 FFO coverage	35	33
11.1 – 14.3 FFO to debt ratio	30 to 38	34 to 43

458. The above analysis indicates that the minimum equity ratio to achieve the targeted EBIT ratio of 2.0 has decreased by four percentage point and the minimum equity ratio to achieve the targeted FFO coverage ratio of 3.0 has decreased by two percentage points. In contrast, the minimum equity ratio to achieve the lower end of the range for the FFO to debt ratio has increased by four percentage points.

459. In Decision 2011-474, the Commission awarded an equity ratio of 39 per cent to distribution companies (prior to company-specific adjustments). In that decision, the Commission considered this value to be a representative equity ratio for an average risk utility. Table 8 demonstrates that, as a result of updating the parameters of the Commission's credit metric analysis in this proceeding, a decrease of the 39 per cent representative equity ratio is warranted. In addition, having considered the findings in Section 4 with respect to global and

Canadian capital market conditions, there is less reason at this time to award equity ratios significantly higher than the minimums indicated by the credit metric analysis.

460. In light of the above considerations, the Commission finds that a one percentage point reduction of the 39 per cent representative equity ratio approved in Decision 2011-474 is warranted. In the Commission's view, the resulting 38 per cent equity ratio is sufficient to attain the targeted A-range credit rating for an average risk utility.

461. In the sections that follow, the Commission considers whether any further utility-specific adjustments to the one percentage point overall reduction are required so that the awarded equity ratio for each utility reflects the business risk ranking of the various industry segments.

8.4 Ranking risk by regulated sector

462. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (earnings before interest and income taxes) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.

463. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electric distribution sector was slightly more risky than the electric transmission sector. The Commission also agreed, in that case, that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[535]

464. In Decision 2011-474, the Commission reaffirmed many of its previous findings with respect to the business risk attributable to the various utilities. In particular, the Commission found that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas. However, it also lowered the risk ranking of ATCO Pipelines in the company-specific considerations section of that decision to reflect the impact of its integration agreement with NOVA Gas Transmission Ltd. (NGTL).

8.5 Additional Adjustments

8.5.1 PBR and UAD impacts

465. As indicated in sections 6.1 and 6.2 of this decision, the Commission determined that no adjustments are required with respect to the transition to PBR regulation or the UAD decision.

8.5.2 Adjustment for non-taxable status

466. In Decision 2011-474, the Commission reaffirmed its previous findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases the interest coverage ratio, thereby adding to risk from the debt holder's perspective. Accordingly, in Decision 2011-474, the Commission continued its addition of a two percentage point increase to the equity ratios of income tax exempt utilities.

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535 Decision 2009-216, paragraphs 370-371.

467. In Decision 2011-474, the Commission found that treating FortisAlberta as a non-taxable entity for the purposes of that proceeding was warranted, since it had not paid any income taxes since 2006, and was not expected to do so until at least 2016. The Commission indicated that its treatment of FortisAlberta would change if the company became an income tax paying entity, or if, in the future, the Commission were to change from the flow-through method of accounting for income taxes for regulatory purposes, to normalized taxes or another similar method.

468. In this proceeding, both the Alberta Utilities and the UCA supported the retention of the two percentage point increase for income tax exempt utilities, as well as for FortisAlberta, which was not collecting income tax in its revenue requirement. For its part, Calgary noted Dr. Booth's position that lower income tax does not increase the risk to a utility, but he did not propose any change to the Commission's approach.

Commission findings

469. The Commission finds that its practice of adding two percentage points to the equity ratio of non-taxable utilities and to FortisAlberta continues to be warranted.

8.5.3 ATCO Pipelines

470. Ms. McShane for the Alberta Utilities submitted that ATCO Pipelines' (AP) business risks are higher than they were when assessed at the time of the 2011 GCOC proceeding. She stated that:

> This conclusion is valid, in my opinion, despite the fact that NGTL is responsible for paying ATCO Pipelines' approved revenue requirement under the Integration Agreement. The degree of certainty that the approved revenue requirement will be recovered due to the existing regulatory framework or contractual arrangements is not synonymous with uncertainty of future earnings.[536]

471. Ms. McShane also submitted that, in contrast to the NGTL Alberta System and ATCO Pipelines, the Alberta electric distributors continue to have a monopoly for delivery of power.[537]

472. In rebuttal evidence, Ms. McShane disagreed that the primary risk to ATCO Pipelines was the credit risk of not getting paid by NGTL. In her view, the primary risk to ATCO Pipelines is the risk that its costs will not be approved for recovery by the Commission. Dr. Booth did not address the utility's uncertainty with respect to its ability to expand its business or any risks arising from competition.[538]

473. Mr. Sloan for the Alberta Utilities submitted that:

> The changes in North American natural gas markets that have occurred since the execution of the System Integration Agreement, and since the most recent 2011 Generic Cost of Capital was concluded, have increased existing market risks and created new sources of risk for the Alberta System and for AP.
>
> …

536 Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1334-1347.
537 Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1827-1828.
538 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, lines 417-435.

> At the same time, the Alberta System Integration has reduced AP's ability to effectively respond to the increase in market risk.[539]

474. The Alberta Utilities' argument included the following:

- Post integration, while test period throughput risk no longer exists, ATCO Pipelines nevertheless remains at risk for recovery of its costs of providing transportation service as a result of the ongoing GRA process.[540]

- When valuing a stock, a prospective investor makes an initial assumption about growth in capital (what will the stock be worth at the time the investor expects to sell it?), and an initial assumption about dividends (what dividend will the stock pay and at what rate will the dividend grow?)[541]

- Investors make initial base growth assumptions that require recovery and growth of capital, and achievement and growth of future earnings to pay and grow dividends. Changes in business risks affect these assumptions because business risks affect future earnings and asset cost recovery.[542]

- Market risks are relevant, and the Commission should accept the conclusions of Mr. Sloan's expert evidence and Ms. McShane's assessment of his findings in determining ATCO Pipelines' business risk and capital structure.[543]

- The record clearly supports the conclusion that changes in market demand, competition and supply have made the business of transporting natural gas in Alberta far more uncertain, and that these changes have increased ATCO Pipelines business risks.[544]

475. The Alberta Utilities also quoted the Commission's finding from 2011-474 that: "Unlike the AESO, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks … which should be taken into account."[545]

476. In his evidence, submitted on behalf of CAPP, Dr. Booth stated:

> In terms of the capital structure of ATCO Pipe, I note that barring some minor asset swaps that still have to be settled, it is now completely integrated into the Alberta system. While ATCO Pipe's revenue requirement has to be approved by the AUC it is completely recovered as a prior charge in Nova Gas Transmission's (NGTL) revenue requirement. This is an irreversible change in ATCO Pipe's risk and essentially makes its risk similar to that of NGTL's junior subordinated debt. Further NGTL sits on top of enormous reserves in the Western Canadian Sedimentary Basin (WCSB), where its move to federal regulation allows it to be the major player in the shipment of reserves in North East BC. Here, the Montney formation is becoming one of the most prolific gas plays in North America.[546]

539 Exhibit 42.07, Sloan evidence for ATCO Pipelines, page 2.
540 Exhibit 148.01, Alberta Utilities argument, paragraph 296.
541 Exhibit 148.01, Alberta Utilities argument, paragraph 300.
542 Exhibit 148.01, Alberta Utilities argument, paragraph 305.
543 Exhibit 148.01, Alberta Utilities argument, paragraph 319.
544 Exhibit 148.01, Alberta Utilities argument, paragraph 323.
545 Exhibit 148.01, Alberta Utilities argument, paragraph 308.
546 Exhibit 44.02, Booth evidence for CAPP, page 4.

> …
> In my judgement there is minimal risk to the equity holders in ATCO Pipe and I continue to recommend a 35% common equity ratio. As in 2011, I would point out the double leverage involved in Altalink and its effective common equity ratio at about 27% where DBRS notes that AltaLink's 37% common equity is financed by its parent with 27% equity and 10% debt. So ATCO Pipe is eminently financeable on 35% common equity.[547]
>
> In particular the ATCO Pipe revenue requirement is now recovered as a monthly charge in NGTL's tolls and collected from customers of the Alberta System. In 2011 my judgment was that this was substantially the same as the way AltaLink and other transmission facilities owners (TFO's) recover their system costs from the distributors via the Alberta Electric Systems Operator (AESO).[548]
> …
> If there are any shocks to NGTL's revenue requirement these do not seem to affect ATCO Pipe's recovery of its revenue requirement. Instead, the cost is effectively borne first by NGTL's shippers in terms of a readjustment of tolls, and then by NGTL's shareholders.[549]
> …
> My understanding is that ATCO Pipe is not going to be placed on performance based regulation and the asset swap transactions with NGTL imply no significant stranded assets.[550]
> …
> There may be some very minimal long run risk due to competition and supply, but if they exist they are smaller than they were in 2011 and I regard them as de minimus. Further to emphasise, ATCO Pipe must by definition be lower risk than NGTL and I would continue to recommend a common equity ratio no higher than 35%.[551]

477. For its part, CAPP argued that the two per cent adder from 2009 is no longer needed due to improved financial market conditions.[552]

478. CAPP noted Dr. Booth's argument that ATCO Pipelines' risk is no higher than that of electric transmission companies due to the integration agreement.[553]

479. CAPP acknowledged that the Alliance pipeline is a competitor, but also stated that this is not a new development, and that, in any event, the risk is to the combined NGTL/ATCO Pipelines entity and not to ATCO Pipelines alone. CAPP submitted that ATCO Pipelines has a claim for recovery of its costs from NGTL "come what may," in perpetuity.[554]

480. CAPP submitted that arguments about increased regulatory risk meriting a higher return are "fatally flawed" because, as a matter of law, utilities are exposed to fundamental market risks and Dr. Booth was unaware of allowances being given for increased regulatory risks.[555]

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547 Exhibit 44.02, Booth evidence for CAPP, page 5.
548 Exhibit 44.02, Booth evidence for CAPP, paragraph 240.
549 Exhibit 44.02, Booth evidence for CAPP, paragraph 246.
550 Exhibit 44.02, Booth evidence for CAPP, paragraph 266.
551 Exhibit 44.02, Booth evidence for CAPP, paragraph 267.
552 Exhibit 151.01, CAPP argument, paragraph 102.
553 Exhibit 151.01, CAPP argument, paragraph 104.
554 Exhibit 151.01, CAPP argument, paragraphs 105 and 109.
555 Exhibit 151.01, CAPP argument, paragraph 13.

481. CAPP reiterated in reply that ATCO Pipelines will recover all its costs from NGTL, and that ATCO Pipelines has failed to show how any of the market risks spoken of by its witnesses translate into the inability to recover its cost of service.[556]

482. In rebuttal evidence, Messrs. Bell and Stauft submitted, on behalf of the UCA, that any risks to ATCO Pipelines are divorced from those attributable to NGTL. They argued that ATCO Pipelines' shareholders "will be paid the full revenue requirement associated with the ATCO Pipelines system, including return, taxes, and depreciation, out of the revenues generated by the NGTL system, before NGTL shareholders are paid a dime of equity return, income taxes, or depreciation in connection with the facilities that NGTL itself owns."[557]

Commission findings

483. In Decision 2011-474, the Commission reiterated its earlier finding from Decision 2010-228[558] that post-integration, ATCO Pipelines will collect its Commission-approved revenue requirement through a monthly charge to NGTL (the AP charge) and that NGTL's revenue requirement, including the AP charge, will be collected from customers using the combined ATCO Pipelines and NGTL regulated gas transmission systems (the Alberta System). Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.[559]

484. In Decision 2011-474, the Commission found that ATCO Pipelines' post-integration business risk is higher than the level of risk faced by the electric transmission sector, but is somewhat lower than the risk of electric and gas distribution sectors. The Commission's determination with respect to ATCO Pipelines' capital structure for 2011 and 2012 reflected these findings by setting the equity ratio at the average of those two sectors.[560]

485. In Decision 2011-474, the Commission did not consider that its determination in this regard would have a significant impact on ATCO Pipelines' credit metrics. In the Commission's view at that time, setting the equity ratio for ATCO Pipelines at the midpoint of equity ratios for the transmission and distribution utilities was sufficient to attain the minimum credit metrics associated with credit ratings in the A-range. In the Commission's view, this conclusion was reasonable because it had awarded equity ratios to those two sectors designed to achieve A-range ratings, and found that ATCO Pipelines' risk was midway between the risk of those two sectors. Furthermore, the Commission considered that if, after assessing the impacts of Decision 2011-474, ATCO Pipelines remained concerned about its credit metrics, the matter could be addressed at the time of the company's next general tariff application.[561]

486. The Commission is not convinced that the relative risk ranking of ATCO Pipelines has changed since it made its determinations in Decision 2011-474. The Commission acknowledges that ATCO Pipelines faces a risk that costs will not be approved by the Commission for recovery. However, that is true for all of the utilities and does not change the relative risk ranking of ATCO Pipelines. With respect to the market risks discussed by Mr. Sloan, the

556 Exhibit 151.01, CAPP argument, paragraph 14.
557 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A23.
558 Decision 2010-228: ATCO Pipelines, 2010-2012 Revenue Requirement Settlement and Alberta System Integration, Proceeding 223, Application 1605226-1, May 27, 2010.
559 Decision 2011-474, paragraph 264.
560 Decision 2011-474, paragraph 267.
561 Decision 2011-474, paragraph 268.

Commission again notes that ATCO Pipelines will collect its Commission-approved revenue requirement through a monthly charge to NGTL, which considerably lowers its exposure to market risk. The Commission continues to consider that ATCO Pipelines' risks are higher than those of an electric transmission company and lower than those of the distribution utilities.

487. Regarding the risk of lower growth for ATCO Pipelines, the Commission found in Decision 2011-474 that, in theory, investors should be indifferent to growth if growth is only expected to provide a risk-adjusted return readily available elsewhere in the market.[562] The Commission considers that the awarded ROE is attempting to provide a proxy for just such a return. Utilities are entitled to an opportunity to earn a fair return on prudent investments that they have actually made. They are not entitled to additional return related to the lack of an opportunity to make investments to fuel future growth.

488. For all of the above reasons, the Commission finds that ATCO Pipelines' equity ratio will continue to be set midway between those of the electric transmission and the electric distribution sectors before considering any company-specific adjustments in those sectors.

8.5.4 ATCO Electric and AltaLink TFOs

489. In Decision 2009-216, the Commission awarded a one percentage point equity increase in the capital structure of ATCO Electric TFO, AltaLink TFO and TransAlta related to credit metric relief associated with their large capital growth programs.[563] In Decision 2011-474, the Commission awarded an additional one percentage point of equity in the capital structure of ATCO Electric TFO and AltaLink TFO related to credit metric relief associated with their large capital growth programs.[564]

490. In argument, the UCA discussed the impact of the "big build" on these two utilities and discussed the impact of CWIP in rate base. The UCA ultimately recommended that all of the utilities should have their approved equity ratios reduced by two per cent, but did not recommend a sector-specific change for these two TFOs.[565]

Commission findings

491. The Commission will continue to award a two percentage point equity increase in the capital structure of ATCO Electric TFO and AltaLink TFO related to credit metric relief associated with their large capital growth programs, and for the reasons outlined in Decision 2009-216 and Decision 2011-474. In doing so, the Commission also notes that it anticipates that this additional two per cent may no longer be required after most of the recent large transmission projects are completed and brought into rate base.

8.5.5 TransAlta

492. TransAlta noted that in Decision 2011-474, it had been awarded an equity ratio of 36 per cent, while the other taxable electric transmission utilities had been awarded 37 per cent,[566] and that the Commission had also awarded an additional one per cent to AltaLink

[562] Decision 2011-474, paragraph 136.
[563] Decision 2009-216, paragraph 412.
[564] Decision 2011-474, paragraphs 291-292.
[565] Exhibit 150.02, UCA argument, pages 88-91.
[566] Exhibit 145.01, TransAlta argument, paragraph 13.

and ATCO Electric transmission to provide credit metric relief necessitated by their large capital growth programs.[567]

493. TransAlta submitted that it should be awarded the same equity ratio as the taxable electric transmission utilities for a number of reasons. It claimed that its small size, its significant growth for which it has not received credit relief in the form of CWIP in rate base or the collection of future income taxes, and the fact that it has adopted AltaLink's cost of debt, which it could not attain on a stand-alone basis, all militate in favour of the Commission approving a debt/equity ratio for it that is the same as what will be provided to other taxable transmission utilities.

Commission findings

494. The Commission finds that TransAlta should be awarded the same equity ratio as the taxable electric transmission utilities for the reasons proposed by TransAlta, including its small size, and its capital growth and the fact that it does not have CWIP in rate base.

8.6 Summary of equity ratio findings

495. Given all of the above findings, the equity ratios awarded to each of the affected utilities are summarized in the following table:

Table 10. Equity ratio findings

	Last approved	2013-2015 approved	Change in approved common equity ratio
		(%)	
Electric and gas transmission			
ATCO Electric (transmission)	37	36	-1
AltaLink	37	36	-1
ENMAX (transmission)	37	36	-1
EPCOR (transmission)	37	36	-1
Red Deer	37	36	-1
Lethbridge	37	36	-1
TransAlta	36	36	0
ATCO Pipelines	38	37	-1
Electric and gas distribution			
ATCO Electric (distribution)	39	38	-1
ENMAX (distribution)	41	40	-1
EPCOR (distribution)	41	40	-1
ATCO Gas	39	38	-1
FortisAlberta	41	40	-1
AltaGas	43	42	-1

496. As set out in Section 7, the ROE and equity ratios awarded in this decision will remain in place on an interim basis for 2016 and for subsequent years until changed by the Commission.

[567] Decision 2011-474, paragraphs 291-292.

9 Implementation of GCOC decision findings

497. In Section 5.6 of this decision, the Commission determined that a generic benchmark ROE of 8.3 per cent is reasonable for each of 2013, 2014 and 2015. In Section 8.6, the Commission set out the approved capital structures for the affected utilities for the 2013 to 2015 period. In Section 6, the Commission determined that no adjustments to the generic benchmark ROE or capital structures are warranted to account for the application of principles identified in the UAD decision or the implementation of a PBR framework for certain distribution utilities; as well as some other risks perceived by the Alberta Utilities.

498. Any affected utility that has a Commission-approved revenue requirement under cost of service regulation for 2013, 2014 and 2015 was required to use ROE and capital structure placeholders until values could be approved by the Commission on a final basis. The Commission directs these utilities to apply, by July 31, 2015, to adjust their respective revenue requirements for 2013, 2014 and 2015, to reflect the final approved ROE and capital structure determinations set out in this decision. These proceedings may take the form of separate rider applications or be a part of a larger (and possibly ongoing) application dealing with other rate matters (e.g., a general rate or tariff application).

499. 2013 was the last year of the formula-based ratemaking (FBR) plan approved for ENMAX's distribution and transmission utilities in Decision 2009-035. In that decision, the Commission determined that the ROE approved in the subsequent GCOC proceeding would not be used in resetting ENMAX's distribution or transmission rates under the FBR plan.[568] Accordingly, no changes to 2013 FBR rates for ENMAX distribution or transmission result from the findings in this decision. However, as set out in Decision 2009-035, the approved 2013 GCOC ROE will be used as a target ROE for ENMAX's earnings sharing mechanism calculation for its distribution and transmission utilities.[569] In addition, the 2013 approved ROE and capital structure may be used in calculation of certain of ENMAX's flow-through items, where required (e.g., certain deferral account calculations that include WACC).

500. In Decision 2014-347,[570] the Commission approved the revenue requirement for ENMAX's distribution utility for the 2014 test period and ENMAX's transmission utility for the 2014-2015 test period, under a cost of service framework. As noted in that decision, ENMAX does not intend to apply for another term of FBR for its transmission utility.[571] The Commission directs ENMAX to apply on behalf of its distribution utility to adjust its revenue requirement for the 2014 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission also directs ENMAX to apply on behalf of its transmission utility to adjust its revenue requirement for the 2014-2015 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission further directs that any such application or applications must be made by July 31, 2015. Any adjustment proceeding may take the form of a separate rider application or be a part of a larger application dealing with other rate matters.

568 Decision 2009-035, paragraph 417.
569 Decision 2009-035, paragraphs 418-419.
570 Decision 2014-347: ENMAX Power Corporation ,2014 Phase I Distribution Tariff Application, 2014-2015 Transmission General Tariff Application, Proceeding 2739, Application 1609784-1, December 16, 2014.
571 Decision 2014-347, paragraph 2.

501. ENMAX has indicated on several occasions that it intends to file an application for a PBR plan to set rates for its distribution utility commencing in 2015.[572] Any issues associated with reflecting the 2015 approved ROE and capital structure in ENMAX's 2015 rates will be considered in a future proceeding dealing with ENMAX's second generation PBR plan.

502. As noted in Section 2, the following electric and natural gas distribution utilities are regulated under the 2013-2017 PBR plans approved in Decision 2012-237: AltaGas, ATCO Electric, ATCO Gas, EDTI and FortisAlberta. In that decision, the Commission determined that no specific changes to customer rates should be made to take into account changes in either the approved ROE, or changes in the cost of debt during the PBR term.[573] However, as noted in that decision, the then current approved ROE will be used as the ROE input for calculation of the +/-300 or +/-500 basis point reopener thresholds in a given PBR year.[574]

503. With respect to the impact of changes in capital structure on PBR rates, the Commission stated at paragraph 710 of Decision 2012-237:

> 710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.[575]

504. In Section 6.2 of this decision, the Commission determined that there is no evidence within this proceeding which supports the Alberta Utilities' assertions of appreciably more risk resulting from implementation of the current PBR regime. Consequently, no adjustment to capital structure was directed by the Commission as a result of certain distribution utilities coming under a PBR regime. Therefore, in accordance with paragraph 710 of Decision 2012-237, the Commission finds that no adjustment to rates for the utilities under PBR for changes in capital structure is required during the PBR term.

505. Finally, the Commission confirms that the ROE and capital structures approved in this decision may be used in calculation of certain flow-through items, where required (e.g., in treatment of deferral accounts that use WACC for the calculation of carrying charges). The Commission also confirms that the 2013-2015 approved ROE and equity ratios will also be used in the calculation of K factor amounts under the capital tracker mechanism. As set out in Section 4.4 of Decision 2013-435, the accounting test incorporated in the K factor calculation (as it relates to revenue) is comprised of two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. The second component is the revenue requirement calculations based on forecast or actual capital additions for the identified project or program for the PBR year. In Decision 3434-D01-2015,[576] the Commission determined that revenue requirement calculations in the second

572 Decision 2014-347, paragraph 2.
573 Decision 2012-237, paragraph 706.
574 Decision 2012-237, paragraph 738.
575 Decision 2012-237, paragraph 710.
576 Decision 3434-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

component of the accounting test should be based on the approved ROE and capital structure for that year.[577]

10 Order

506. It is hereby ordered that:

(1) The final approved ROE for 2013, 2014, and 2015 is set at 8.3 per cent.

(2) The final approved deemed equity ratios for the Alberta Utilities for 2013, 2014 and 2015, are as set out in the table below.

(3) The ROE, and deemed equity ratios set out in the table below are approved on an interim basis for 2016, and for each subsequent year thereafter, unless otherwise directed by the Commission.

(4) The Alberta Utilities are to apply to adjust their rates to implement the findings of this decision, as directed in Section 9.

	Last approved	2013-2015 approved	Change in approved common equity ratio
	(%)		
Electric and gas transmission			
ATCO Electric (transmission)	37	36	-1
AltaLink	37	36	-1
ENMAX (transmission)	37	36	-1
EPCOR (transmission)	37	36	-1
Red Deer	37	36	-1
Lethbridge	37	36	-1
TransAlta	36	36	0
ATCO Pipelines	38	37	-1
Electric and gas distribution			
ATCO Electric (distribution)	39	38	-1
ENMAX (distribution)	41	40	-1
EPCOR (distribution)	41	40	-1
ATCO Gas	39	38	-1
FortisAlberta	41	40	-1
AltaGas	43	42	-1

577 Decision 3434-D01-2015, paragraph 70.

Dated on March 23, 2015.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Tudor Beattie, QC
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd.
AltaLink Management Ltd. Borden, Ladner Gervais LLP
ATCO Gas
ATCO Pipelines
AltaGas Utilities Inc.
The City of Calgary (Calgary) McLennan Ross
Canadian Association of Petroleum Producers (CAPP)
Consumers' Coalition of Alberta (CCA)
EPCOR Distribution & Transmission Inc.
Encana Corporation
ENMAX Power Corporation
FortisAlberta Inc.
Industrial Power Consumers Association of Alberta (IPCAA) Drazen Consulting Group Inc.
City of Lethbridge Chymko Consulting Ltd.
NOVA Gas Transmission Ltd.
The City of Red Deer Chymko Consulting Ltd.
TransAlta Corporation (TransAlta)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP

Alberta Utilities Commission

Commission Panel
M. Kolesar, Vice-Chair
B. Lyttle, Commission Member
T. Beattie, QC, Commission Member

Commission Staff
R. Finn (Commission counsel)
D. Cherniwchan
S. Allen
O. Vasetsky
C. Pham

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
Alberta Utilities L. Smith, QC C. Warkentin	Panel 1 K. McShane M. Sloan Panel 2 K. McShane S. Fetter
AltaLink Management Ltd. R. Block	
FortisAlberta Inc. T. Dalgleish, QC S. Nagina	
AltaGas Utilities Inc. N. McKenzie	
TransAlta Corporation (TransAlta) L.-M. Berg	C. Codd A. Bosu
EPCOR Distribution & Transmission Inc. C. Bystrom J. Liteplo	
ENMAX Power Corporation L. Cusano D. Wood	
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Office of the Utilities Consumer Advocate (UCA) R. McCreary B. Schwanak I. Hanson	S. Cleary M. Stauft R. Bell
Canadian Association of Petroleum Producers (CAPP) N. Schultz	L. Booth
The City of Calgary (Calgary) D. Evanchuk G. Henderson	L. Booth H. Johnson

Alberta Utilities Commission

Commission Panel
M. Kolesar, Vice-Chair
B. Lyttle, Commission Member
T. Beattie, QC, Commission Member

Commission Staff
R. Finn (Commission counsel)
D. Cherniwchan
S. Allen
O. Vasetsky
C. Pham

Appendix 3 – Summary of Commission 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. Any affected utility that has a Commission-approved revenue requirement under cost of service regulation for 2013, 2014 and 2015 was required to use ROE and capital structure placeholders until values could be approved by the Commission on a final basis. The Commission directs these utilities to apply, by July 31, 2015, to adjust their respective revenue requirements for 2013, 2014 and 2015, to reflect the final approved ROE and capital structure determinations set out in this decision. These proceedings may take the form of separate rider applications or be a part of a larger (and possibly ongoing) application dealing with other rate matters (e.g., a general rate or tariff application). .... Paragraph 498

2. In Decision 2014-347, the Commission approved the revenue requirement for ENMAX's distribution utility for the 2014 test period and ENMAX's transmission utility for the 2014 2015 test period, under a cost of service framework. As noted in that decision, ENMAX does not intend to apply for another term of FBR for its transmission utility. The Commission directs ENMAX to apply on behalf of its distribution utility to adjust its revenue requirement for the 2014 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission also directs ENMAX to apply on behalf of its transmission utility to adjust its revenue requirement for the 2014-2015 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission further directs that any such application or applications must be made by July 31, 2015. Any adjustment proceeding may take the form of a separate rider application or be a part of a larger application dealing with other rate matters. .... Paragraph 500

Ontario

Ontario Energy Board Cost of Capital Parameter Updates for 2015 Applications
November 20, 2014

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

BY E-MAIL AND WEB POSTING

November 20, 2014

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2015 Cost of Service and Custom Incentive Rate-setting Applications

Re: Cost of Capital Parameter Updates for 2015 Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2015 applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2015 Rates

For rates with effective dates in 2015, the Board has updated the Cost of Capital parameters based on: (i) the September 2014 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:- (A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2015 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2015 rate applications for rates effective in 2015 are:

Cost of Capital Parameter	**Value for 2015 Applications for rate changes in 2015**
ROE	9.30%
Deemed LT Debt rate	4.77%
Deemed ST Debt rate	2.16%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board now updates Cost of Capital parameters for setting rates only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service and custom IR applications (as applicable) with rates effective in the 2015 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in individual rate hearings in support of different Cost of Capital parameters due to the specific circumstances, but must provide strong rationale and supporting evidence for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Industry Relations hotline, at 416 440-7604 or industryrelations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2015)

Cost of Capital Parameter Calculations

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2014

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
	Day	10-yr	30-yr	30-yr		
1	1-Sep-14					
2	2-Sep-14	2.09	2.64	4.04	0.55	1.40
3	3-Sep-14	2.09	2.63	4.03	0.54	1.40
4	4-Sep-14	2.12	2.66	4.06	0.54	1.40
5	5-Sep-14	2.11	2.67	4.06	0.56	1.39
6	6-Sep-14					
7	7-Sep-14					
8	8-Sep-14	2.14	2.68	4.07	0.54	1.39
9	9-Sep-14	2.17	2.70	4.09	0.53	1.39
10	10-Sep-14	2.20	2.72	4.11	0.52	1.39
11	11-Sep-14	2.20	2.72	4.11	0.52	1.39
12	12-Sep-14	2.24	2.76	4.15	0.52	1.39
13	13-Sep-14					
14	14-Sep-14					
15	15-Sep-14	2.23	2.76	4.15	0.53	1.39
16	16-Sep-14	2.24	2.77	4.16	0.53	1.39
17	17-Sep-14	2.26	2.79	4.18	0.53	1.39
18	18-Sep-14	2.28	2.79	4.18	0.51	1.39
19	19-Sep-14	2.25	2.76	4.14	0.51	1.38
20	20-Sep-14					
21	21-Sep-14					
22	22-Sep-14	2.22	2.74	4.11	0.52	1.37
23	23-Sep-14	2.17	2.72	4.09	0.55	1.37
24	24-Sep-14	2.20	2.73	4.10	0.53	1.37
25	25-Sep-14	2.15	2.68	4.05	0.53	1.37
26	26-Sep-14	2.16	2.68	4.06	0.52	1.38
27	27-Sep-14					
28	28-Sep-14					
29	29-Sep-14	2.13	2.65	4.04	0.52	1.39
30	30-Sep-14	2.15	2.67	4.06	0.52	1.39
31						
		2.18	2.71	4.10	**0.530**	**1.386**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* — Publication Date: September-08-14

	3-month	12-month		Average	
September 2014	2.500	3.200	❸	**2.850**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.850	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.530	%
Long Canada Bond Forecast (LCBF)	❹	**3.380**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75	%
Change in Long Canada Bond Yield Forecast from September 2009					
LCBF (September 2014) (from Step 3	④	3.380	%		
Base LCBF		4.250	%		
Difference		-0.870	%		
0.5 X Difference				-0.435	%
Change in A-rated Utility Bond Yield Spread from September 2009					
A-rated Utility Bond Yield Spread (September 2014) (from Step 1)	②	1.386	%		
Base A-rated Utility Bond Yield Spread		1.415	%		
Difference		-0.029	%		
0.5 X Difference				-0.015	%
Return on Equity based on September 2014 data				**9.30**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2014 (from Step 3)	④	3.380	%
A-rated Utility Bond Yield Spread September 2014 (from Step 1)	②	1.386	%
Deemed Long-term Debt Rate based on September 2014 data		**4.77**	%

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For rate changes effective in 2015)

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in September, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance		Date of input
Bank 1	100.0	bps	Sept., 2014
Bank 2	100.0	bps	Sept., 2014
Bank 3	82.5	bps	Sept., 2014
Bank 4	80.0	bps	Sept., 2014
Bank 5	100.0	bps	Sept., 2014
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	100.0	bps
Low estimate	80.0	bps

C. Average annual Spread	94.167	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2014

Month: **September 2014**

	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-14	Bank holiday	%
2	2-Sep-14	1.21	%
3	3-Sep-14	1.21	%
4	4-Sep-14	1.21	%
5	5-Sep-14	1.21	%
6	6-Sep-14		
7	7-Sep-14		
8	8-Sep-14	1.21	%
9	9-Sep-14	1.21	%
10	10-Sep-14	1.22	%
11	11-Sep-14	1.22	%
12	12-Sep-14	1.22	%
13	13-Sep-14		
14	14-Sep-14		
15	15-Sep-14	1.22	%
16	16-Sep-14	1.22	%
17	17-Sep-14	1.22	%
18	18-Sep-14	1.22	%
19	19-Sep-14	1.21	%
20	20-Sep-14		
21	21-Sep-14		
22	22-Sep-14	1.21	%
23	23-Sep-14	1.21	%
24	24-Sep-14	1.21	%
25	25-Sep-14	1.21	%
26	26-Sep-14	1.21	%
27	27-Sep-14		
28	28-Sep-14		
29	29-Sep-14	1.22	%
30	30-Sep-14	1.22	%
31			
		1.214	% ❷

Source Bank of Canada / Statistics Canada
Series V39071

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.942	%	①
Average Bankers' Acceptance Rate	1.214	%	②
Deemed Short Term Debt Rate	**2.16**	%	

Reference on Calculation Method:
• Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

Quebec

Regie De L'Energie – Demande relative à la détermination du taux de rendement
5 mars 2013

Regie De L'Energie - Demande d'approbation du plan d'approvisionnement et de modification des Conditions de service et Tarif de Société en commandite Gaz Métro à compter du 1er octobre 2014
16 mai 2014

D É C I S I O N

QUÉBEC **RÉGIE DE L'ÉNERGIE**

D-2013-036	R-3809-2012 Phase 2	5 mars 2013

PRÉSENTS :

Marc Turgeon
Jean-François Viau
Françoise Gagnon
Régisseurs

Société en commandite Gaz Métro
Demanderesse

et

Intervenants dont les noms apparaissent ci-après

Décision – Demande relative à la détermination du taux de rendement

Demande d'approbation du plan d'approvisionnement et de modification des* Conditions de service et Tarif *de Société en commandite Gaz Métro à compter du 1er octobre 2012 – Phase 2

Intervenants :

- Association des consommateurs industriels de gaz (ACIG);
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI);
- Groupe de recherche appliquée en macroécologie (GRAME);
- Option consommateurs (OC);
- Regroupement des organismes environnementaux en énergie (ROEÉ);
- Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ);
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA);
- TransCanada Energy Ltd. (TCE);
- TransCanada Pipelines Limited (TCPL);
- Union des consommateurs (UC);
- Union des municipalités du Québec (UMQ).

1. INTRODUCTION

[1] Le 6 juillet 2012, Société en commandite Gaz Métro (Gaz Métro ou le distributeur) dépose à la Régie de l'énergie (la Régie) une demande d'approbation du plan d'approvisionnement et de modification des *Conditions de service et Tarif* à compter du 1er octobre 2012[1]. Elle propose de traiter ce dossier en deux phases.

[2] Le 19 juillet 2012, la Régie rend sa décision D-2012-084 accueillant la proposition de Gaz Métro de procéder à l'examen de la demande en deux phases.

[3] Les 23 novembre et 18 décembre 2012, la Régie rend ses décisions sur la phase 1 de la demande, à l'exception des sujets relatifs à l'indicateur de performance[2].

[4] Le 14 décembre 2012, le distributeur dépose à la Régie une « *2ème demande ré-amendée* »[3] présentant les différents sujets prévus dans le cadre de la phase 2 de la demande, soit :

- I. Développement des ventes;
- II. Gestion des actifs;
- III. Investissements;
- IV. Stratégie financière;
- V. Établissement du revenu requis incluant le coût de service en distribution;
- VI. Substitution et efficacité énergétique;
- VII. Allocation des coûts;
- VIII. Vision, stratégie et grilles tarifaires;
- IX. Modifications aux *Conditions de service et Tarif*;
- X. Texte des *Conditions de service et Tarif*.

[5] Les conclusions recherchées par le distributeur à l'égard du taux de rendement prévu à la section IV de la « *2ème demande ré-amendée* » portant sur la « *Stratégie financière* » sont les suivantes :

---

1 Demande effectuée selon les articles 31 (1), 32, 48, 49, 52, 72 et 74.
2 Décisions D-2012-158 et D-2012-175.
3 Pièce B-0123.

> « ***DÉCLARER** que le taux de rendement établi par l'application de la formule n'est pas raisonnable pour l'année 2013;*
>
> ***PERMETTRE** un rendement sur l'avoir ordinaire de Gaz Métro de 9,3 % pour les fins d'établissement des tarifs;* » [soulignés de Gaz Métro]

2. DÉCISIONS PROCÉDURALES

[6] Le 14 janvier 2013, la Régie rend sa décision procédurale D-2013-003 par laquelle elle fixe les calendriers de la phase 2, notamment celui portant sur la demande de détermination du taux de rendement du distributeur (la Demande).

[7] Dans le cadre de cette décision, la Régie soumet une approche spécifique à l'égard de la Demande. Il apparaît utile de reprendre les paragraphes pertinents :

> « *[20] À la suite d'un examen* prima facie *de la demande, la Régie se questionne à savoir si le contexte évoqué précédemment et les motifs invoqués par le distributeur justifient une nouvelle « étude en profondeur » de son taux de rendement.*
>
> *[21] Par ailleurs, dans sa décision D-2011-182, la Régie a conclu que le taux de rendement raisonnable à autoriser pour le distributeur se situe dans une fourchette allant de 7,71 % à 9,60 %. Elle constate que le taux de rendement de 7,92 % généré par la FAA se situe à l'intérieur de cette fourchette.*
>
> *[22] Toutefois, la Régie note qu'il y a effectivement un écart important entre le taux sans risque prévisionnel qu'elle avait retenu dans sa décision D-2011-182 pour déterminer le taux de rendement autorisé du distributeur et la moyenne des taux sans risques prévisionnels établis en août 2012 qui sont utilisés pour l'application de la FAA. La fourchette retenue l'an dernier allait de 3,91 % à 4,50 %, alors que la moyenne d'août 2012 est de 2,7 %.*
>
> *[23] Toujours préoccupée par les coûts réglementaires associés aux demandes à l'égard de la détermination du taux de rendement du distributeur et pour des raisons d'efficience et d'efficacité, la Régie considère qu'il y a lieu d'adopter une*

approche adaptée aux circonstances et qui respecte à la fois les intérêts de Gaz Métro et de sa clientèle.

[24] Dans ce sens, pour l'année 2013, la Régie estime qu'il pourrait être approprié de suspendre l'application de la FAA et de maintenir le taux de rendement sur l'avoir de l'actionnaire fixé en 2012, soit 8,90 %.

[25] La Régie désire entendre le distributeur et les intervenants sur cette proposition. »

[8] Dans cette même décision, la Régie convoque les participants à une audience sur cette proposition, audience qui se tient le 14 février 2013.

[9] Le 12 février 2013, la Régie rend sa décision procédurale D-2013-024, laquelle dispose de la demande de renseignements n° 2 d'OC au distributeur. Plus particulièrement à la demande d'interrogatoire et de contre-interrogatoire d'OC à l'égard des renseignements devant être produits par le distributeur, la Régie précise comme suit la procédure qui sera applicable lors de l'audience du 14 février 2013 :

« *[6] Le but de l'audience du 14 février 2013 est d'entendre la position des participants sur le traitement envisagé de la question du taux de rendement autorisé du distributeur qui a été formulé par la Régie dans sa décision procédurale D-2013-003. La Régie juge donc qu'il n'y a pas lieu d'entendre des témoins et de procéder à des contre-interrogatoires. Chaque participant pourra présenter toute l'information qu'il juge nécessaire par l'intermédiaire de son procureur.* »

3. CONTEXTE JURIDIQUE

[10] Comme mentionné précédemment, par sa décision procédurale D-2013-003, la Régie propose de suspendre la formule d'ajustement automatique (la FAA) établie dans sa décision D-2011-182 et de maintenir le taux de rendement sur l'avoir de l'actionnaire fixé en 2012, soit 8,90 % (la Proposition).

[11] Il apparaît opportun de faire un rappel des événements à l'origine de cette Proposition, ainsi que des compétences et pouvoirs qui sont accordés à la Régie aux termes de la *Loi sur la Régie de l'énergie*[4] (la Loi) et du *Règlement sur la procédure de la Régie de l'énergie*[5] (le Règlement).

[12] De 2007 à 2012, la Régie a été appelée, à cinq reprises, à se prononcer sur le taux de rendement du distributeur[6]. Aux termes de la dernière demande, la Régie a fixé le taux de rendement à 8,90 % et, considérant les demandes et les coûts réglementaires qui y étaient associés, elle a approuvé une FAA pour trois ans à compter de 2013. La Régie reconnaissait également la possibilité pour le distributeur de présenter une nouvelle demande « *si la situation le requiert* »[7] :

> « *[305] Sans vouloir empêcher Gaz Métro de présenter une demande en matière de taux de rendement <u>si la situation le requiert</u>, la Régie juge que l'<u>efficacité</u>, l'<u>efficience</u> et la <u>stabilité</u> du processus règlementaire militent en faveur d'une <u>période d'application d'une FAA suffisamment longue avant de réviser ses paramètres</u> ou encore, avant de revoir la méthode d'établissement du taux de rendement.* ***C'est pourquoi la Régie approuve l'application de la nouvelle FAA pour une période de trois ans à compter du dossier tarifaire 2013.*** » [nous soulignons]

[13] Or, dès la première année d'application de la FAA, sans toutefois remettre en question sa pertinence, le distributeur allègue que la situation requiert que la Régie se penche à nouveau sur son taux de rendement[8] :

> « *Gaz Métro demeure favorable envers le maintien de la formule d'ajustement automatique en place. Bien que l'existence de telles formules au cours des dernières années n'ait pas produit de résultats considérés par Gaz Métro comme étant raisonnables, celle-ci considère qu'il est dans l'intérêt de toutes les parties-prenantes de la maintenir dans le futur. En effet, Gaz Métro est d'avis que dans une situation de relative stabilité dans les marchés, la Formule fournit une information utile sur la teneur de l'ajustement à apporter au taux de rendement autorisé.* »

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4 L.R.Q., c. R-6.01.
5 (2006) 138 G.O. II, 2279.
6 Dossiers R-3630-2007 (D-2007-116), R-3662-2008 (D-2008-140), R-3690-2009 (D-2009-152), R-3752-2011 (D-2011-182) et R-3809-2012.
7 Dossier R-3752-2011, décision D-2011-182.
8 Pièce B-0156, page 5.

[14] Pour justifier une nouvelle étude, le distributeur mentionne que l'application de la FAA conduit à un taux de rendement de 7,92 % sur l'avoir ordinaire pour 2013. À son avis, ce taux ne peut être qualifié de raisonnable en fonction des trois critères reconnus par les tribunaux pour établir la norme du rendement raisonnable. Plus spécifiquement, Gaz Métro considère que le critère de l'investissement comparable n'est pas atteint, en raison de l'instabilité dans les marchés financiers, notamment la baisse des taux sans risque. Le distributeur demande alors à la Régie de fixer, pour l'année 2013, un taux de rendement de 9,3 %[9].

[15] La compétence de la Régie quant au taux de rendement du distributeur est prévue à l'article 32 de la Loi, rédigé comme suit :

> « ***32.*** *La Régie peut <u>de sa propre initiative</u> ou à la demande d'une personne intéressée:*
>
> *1° <u>déterminer le taux de rendement</u> du transporteur d'électricité, du distributeur d'électricité ou d'un distributeur de gaz naturel;*
>
> […]. » [nous soulignons]

[16] Suivant cette disposition, pour déterminer le taux de rendement du distributeur, la Régie peut agir « *de sa propre initiative ou à la demande d'une personne intéressée* ». Cette disposition n'étant pas mentionnée à l'article 25 de la Loi, la Régie n'est donc pas tenue de procéder par audience publique :

> « ***25.*** *La Régie doit tenir une audience publique:*
>
> *1° lorsqu'elle procède à l'étude d'une demande faite en vertu des articles 48, 65, 78 et 80;*
>
> *2° lorsqu'elle détermine les éléments compris dans les coûts d'exploitation et fixe un montant en application de l'article 59;*
>
> *2.1°* (paragraphe abrogé)*;*
>
> *3° lorsque le ministre le requiert sur toute question en matière énergétique.*
>
> *La Régie peut convoquer une audience publique sur toute question qui relève de sa compétence.* »

9 Pièce B-0156, pages 31-32.

[17] Afin d'éviter toute ambiguïté quant à la compétence de la Régie en matière de taux de rendement, il y a lieu de rappeler la distinction entre l'article 32 et le troisième alinéa de l'article 49 de la Loi. En effet, cette dernière disposition mentionne que la Régie doit, lorsqu'elle fixe un tarif en application de l'article 48 de la Loi, « *permettre un rendement raisonnable sur la base de tarification* ». L'article 48 de la Loi étant visé par l'article 25 de la Loi, la Régie doit alors « *tenir une audience publique* ».

[18] La compétence de la Régie en vertu de l'article 32 de la Loi et celle découlant des articles 48 et 49 de la Loi sont distinctes l'une de l'autre et reçoivent un traitement procédural différent. À cet égard, on peut référer à la décision D-2012-076[10] :

> « *[68] Lorsque, de temps à autre, elle procède à cet* exercice [de détermination du taux de rendement], *généralement en s'appuyant sur des preuves d'expert, la Régie détermine un taux de rendement dit « autorisé ». Par la suite, ce taux autorisé servira d'intrant dans l'exercice d'établissement de tarifs justes et raisonnables.* » [nous soulignons]

[19] Ainsi, dans un premier temps, la Régie détermine le taux de rendement d'un distributeur aux termes de l'article 32 de la Loi. Dans un deuxième temps, selon les articles 48 et 49 de la Loi, lorsque la Régie fixe un tarif, elle s'assure que ce tarif permet un rendement raisonnable sur la base de tarification.

[20] En l'espèce, la Régie est saisie d'une demande pour déterminer le taux de rendement du distributeur en application de l'article 32 de la Loi. La Régie n'exerce pas cette compétence, ni aucune autre compétence, dans l'abstrait ou de manière cloisonnée. De par sa mission, ses pouvoirs et sa connaissance d'office, la Régie possède une expertise et une compétence lui permettant de traiter un dossier en fonction d'un contexte donné et d'établir le mode procédural approprié. De plus, lorsqu'elle exerce l'une ou l'autre de ses compétences, la Régie doit assurer « *la conciliation entre l'intérêt public, la protection des consommateurs et un traitement équitable*[11] » du distributeur.

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[10] Dossier R-3693-2009.
[11] Article 5 de la Loi.

[21] Comme le mentionnent les auteurs Pierre Issalys et Denis Lemieux[12] :

> « *Du fait de leur mission de surveillance continue d'un secteur d'activité économique, les organismes de régulation disposent de pouvoirs beaucoup plus étendus que les tribunaux administratifs. Cette mission déborde largement le cadre de la fonction juridictionnelle. L'organisme de régulation ne se borne pas à statuer, comme le fait typiquement un tribunal administratif ou judiciaire, à la demande de l'une des parties à une contestation portant sur la manière d'appliquer une règle de droit à une situation relativement aisée à circonscrire. Il est appelé à décider de questions plus «ouvertes», en tenant compte d'un contexte factuel plus large, et plus mobile, et sur la base de règles qui ne sont pas toutes des normes juridiques et qui, même lorsqu'elles en sont, demeurent souvent très souples. L'encadrement des pouvoirs discrétionnaires de l'organisme est donc, dans bien des cas, assez faible.*
>
> […] *Quel que soit le type de décision à rendre, l'organisme de régulation disposera, en raison même du caractère multifonctionnel de sa mission, de ses propres sources d'informations. Ses services d'enquête, de documentation et d'analyse pourront apporter aux débats qui se déroulent devant lui une contribution relativement indépendante par rapport à celle des autres parties ou intervenants. À cet égard, l'organisme de régulation se trouve placé dans une situation bien différente de celle d'un tribunal judiciaire ou de la plupart des tribunaux administratifs. Il n'est pas exclusivement tributaire de la « preuve » faite devant lui par les administrés. Il peut compter non seulement sur les compétences spécialisées de ses membres, mais aussi sur les ressources humaines et matérielles souvent importantes qui lui sont confiées pour l'exécution de sa mission de régulation.* […], *tandis que les juges judiciaires ne tranchent que les affaires qu'ils ont entendues, sur la seule base de ce qu'ils ont entendu, les membres des organismes de régulation pratiquent une collégialité plus large, et sont assistés de collaborateurs permanents dont la tâche est de contribuer à leurs décisions par des études, des rapports et des avis.* […] » [nous soulignons]

[22] Dans le même sens, dans sa décision D-99-110, la Régie écrit[13] :

> « *Les organismes de régulation économique, comme la Régie, disposent en matière de preuve d'une discrétion que n'ont pas les cours de justice. Il est généralement reconnu qu'ils peuvent recourir plus librement à leur expertise et à la doctrine de la connaissance d'office.* […] *«* Son pouvoir d'agir proprio motu en

12 P. Issalys, D. Lemieux, *L'Action gouvernementale*, 3e édition, Éditions Yvon Blais Inc., 2009, pages 460-462.
13 Pièce C-UC-0003, pages 7-11.

> matière de tarification lui permet de se servir de sa propre expérience et des données qu'elle a en sa possession pour rendre une décision ». » [nous soulignons]

[23] C'est dans ce contexte que la Régie a, à la suite d'un examen *prima facie* de la Demande et tel qu'indiqué dans sa décision D-2013-003 :

- constaté que le taux de rendement de 7,92 % généré par la FAA pour l'année 2013 se situe à l'intérieur de la fourchette de 7,71 % à 9,60 % déterminée dans sa décision D-2011-182[14];

- noté un écart important entre le taux sans risque prévisionnel retenu dans cette décision pour déterminer le taux de rendement et la moyenne des taux sans risques prévisionnels établis en août 2012 qui sont utilisés pour l'application de la FAA; la fourchette retenue en 2011 allait de 3,91 % à 4,50 %[15], alors que la moyenne d'août 2012 est de 2,7 %[16];

- proposé le maintien du taux de rendement sur l'avoir de l'actionnaire fixé en 2012, soit 8,90 %.

[24] Quant au processus d'examen de la Demande, la Régie a déterminé, dans sa décision D-2013-003, un mode procédural distinct de celui prévu pour les autres sujets devant être étudiés dans le cadre de la phase 2 du présent dossier. En effet, il est utile de rappeler que, selon l'article 12 du Règlement, pour toute matière ne requérant pas une audience publique, comme c'est le cas en l'espèce, « *la Régie détermine le mode procédural approprié* ». De plus, les articles 13, 14, 24 et 49 du Règlement permettent notamment à la Régie de donner des instructions spécifiques à la tenue d'une audience et au mode procédural choisi :

> « ***13.*** *La Régie peut donner des instructions pour la tenue de l'audience et l'élaboration d'un calendrier et d'un horaire et fixer notamment le temps accordé à chaque participant pour la présentation de sa position.*

14 Décision D-2011-182, paragraphe 307.
15 Décision D-2011-182, paragraphe 211.
16 Pièce B-0156, page 30.

> ***14.*** *La Régie peut donner des instructions pour la tenue de séances de travail ou pour tout autre mode procédural choisi.*
>
> ***24.*** *À moins d'instructions contraires de la Régie, un participant à une audience orale peut appeler et interroger des témoins, interroger les témoins des autres participants et présenter sa position.* […].
>
> ***49.*** *La Régie prend toutes les mesures nécessaires pour assurer le déroulement équitable, rapide et simple de la procédure.* » [nous soulignons]

[25] En somme, la Proposition de la Régie et le processus utilisé pour son examen découlent des pouvoirs que lui accordent la Loi et le Règlement et s'inscrivent dans l'exercice de sa mission, notamment celle de concilier l'intérêt public, la protection du consommateur et un traitement équitable du distributeur.

4. POSITION DES PARTICIPANTS

4.1 POSITION DU DISTRIBUTEUR

[26] Aux fins de l'exercice de la compétence de la Régie en matière tarifaire, le distributeur rappelle des « *considérations et objectifs* », soit[17] :

> « *a) la conciliation entre l'intérêt public, la protection des consommateurs et un traitement équitable du distributeur au sens de l'article 5* [de la Loi]*;*
>
> *b) la poursuite d'objectifs d'efficacité, de simplicité et d'allègement de la procédure tarifaire;*
>
> *c) la recherche d'économies de ressources et la réduction des coûts réglementaires associés à une demande de détermination du taux de rendement;*
>
> *étant entendu que, si l'adoption d'une formule d'ajustement automatique favorise l'atteinte des objectifs visés aux sous-paragraphes 12.b) et c), son application doit, à terme, mener à l'établissement d'un taux de rendement raisonnable suivant la norme et les critères reconnus à cette fin par la Régie et d'autres régulateurs canadiens.* »

[17] Pièce B-0243, paragraphe 12.

[27] Eu égard aux exigences statutaires applicables à la Régie et en tenant compte de ces « *autres considérations et objectifs* », le distributeur conclut que l'approche de la Régie est adaptée aux circonstances, bien que le taux de rendement de 8,90 % soit, à son avis, un « *taux insuffisant pour satisfaire au critère de l'investissement comparable* »[18].

[28] Enfin, invoquant le niveau prévisible du taux sans risque pour l'application de la FAA, l'imminence du dépôt du dossier tarifaire pour l'année 2014 ainsi que les économies et les gains d'efficacité, le distributeur considère souhaitable que la suspension de la FAA soit applicable pour les années 2013 et 2014 et, qu'à terme, en 2015, la FAA sera réputée être dans sa troisième et dernière année d'application[19].

4.2 POSITION DE L'ACIG

[29] D'entrée de jeu, le procureur de l'ACIG mentionne que[20] :

> « […] *je serais malhonnête, intellectuellement, de vous dire que le résultat de sept virgule quatre-vingt-douze pour cent, qui serait produit par l'application de la formule d'ajustement automatique cette année, n'est pas historiquement bas; et je mesure mes mots.*
>
> *D'abord, il est incontestable qu'il y a eu une chute exceptionnelle des taux sans risque sur les marchés depuis la décision D-2011-182. On parlait, à l'époque, d'une fourchette de trois virgule quatre-vingt-onze à quatre virgule cinq et on aurait été, avec l'application littérale de la formule, sur la base des prévisions du mois d'août deux mille douze (2012), à deux virgule sept pour cent. Ce qui est une chute, c'est presque du jamais vu.* […] »

[30] Dans ces circonstances, l'ACIG considère que la proposition de la Régie représente un « *compromis juste et raisonnable* » pour l'année 2013 et, « *dans un souci d'allégement réglementaire et d'économie sur les frais de réglementation* », elle appuie la suggestion du distributeur de maintenir également le taux de rendement à 8,90 % pour l'année 2014[21].

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18 Pièce B-0243, paragraphe 18.
19 Pièce B-0243, paragraphe 19.
20 Pièce A-0095, page 48.
21 Pièce A-0095, pages 51-52.

4.3 POSITION DE LA FCEI

[31] Selon la FCEI, le processus utilisé par la Régie dans le présent dossier « *n'est pas inintéressant* ». Elle se dit « *intéressée à voir la Régie développer des moyens alternatifs réglementaires pour faire en sorte qu'il y ait fluidité dans les dossiers* […] »[22].

[32] Cependant, la FCEI est d'avis que le processus suivi ne respecte pas la procédure habituelle de la Régie, soit que les participants n'ont pas la possibilité d'évaluer la qualité de la preuve du distributeur vu l'absence de demandes de renseignements, d'expertise et d'audition sur le fond. Elle mentionne :

> « *Bon, on parle que* « la preuve de fait et d'expertise proposée par Gaz Métro qui analyse avec détail les plus récents développements économiques ». *On n'en disconvient pas qu'il y a peut-être et certainement des développements économiques, mais le faire sans débat minimal nous apparaît non seulement problématique mais contraire à l'esprit de la Loi et contraire à la Loi, et contraire au processus même que la Régie a lancé dans le cadre des audiences publiques.*
>
> *Pourquoi sur une question aussi fondamentale et importante les intervenants seraient privés de débattre de cette question-là, alors que sur le plan de l'approvisionnement, sur les incitatifs qu'on aura, il y aura un débat?* »

[33] La FCEI fait également référence à l'écart entre les sommes engagées à ce jour par le distributeur pour sa demande de modification du taux de rendement et les montants accordés aux participants par la décision D-2013-003[23].

[34] Enfin, la FCEI mentionne que la dérogation à la règle établie dans décision D-2011-182, soit la mise en place de la FAA, pourrait être contraire au principe de la cohérence décisionnelle[24] :

> « *Alors le principe de la cohérence décisionnelle invite le décideur à examiner chaque situation en se demandant dans quelle mesure les raisons qui ont antérieurement justifié un résultat donné - la formule il y a quinze (15) mois -*

22 Pièce A-0095, page 55.
23 Pièce A-0095, page 58.
24 Pièce A-0095, page 61.

> *dans une situation semblable, pourrait justifier le même résultat dans une nouvelle situation examinée - la situation d'aujourd'hui - de façon à ce que les justiciables ne reçoivent pas relativement à la même question des réponses diamétralement opposées...* »

[35] En somme, la FCEI voit une « *iniquité du processus* » utilisé par la Régie dans le présent dossier et est d'avis que la façon de procéder pour déterminer le taux de rendement « *pourrait s'apparenter à une fixation arbitraire* », ce qui « *constitue un précédent dangereux* »[25].

[36] De façon subsidiaire, la FCEI considère qu'un taux de 8,4% serait acceptable[26].

4.4 POSITION D'OC

[37] À l'instar de la FCEI, OC soulève la question de l'équité procédurale[27] :

> « *On se trouve devant vous, nous, sans arme : pas d'expertise, pas de preuve, j'ajouterais, pas de budget non plus nous permettant de faire des vérifications requises. Alors, c'est sûr que d'un point de vue procédural, je suis cent pour cent (100 %) d'accord avec la FCEI à l'effet qu'il ne faut pas que ça constitue un précédent, ce qu'on est en train de faire aujourd'hui, parce que ça pose des problèmes assez fondamentaux sur la règle de l'*audi alteram partem. »

[38] Ainsi, en l'absence d'une audition complète sur le taux de rendement, la position d'OC est de maintenir l'application de la FAA. OC ajoute que la FAA établie par la Régie « *implique nécessairement qu'on doit vivre avec les bonnes années et les mauvaises années* ». Elle ajoute[28] :

> « *Si la formule ferait en sorte, cette année, que Gaz Métro aurait un taux de rendement plus élevé qu'il devrait l'avoir, est-ce que Gaz Métro vous aurait saisi de la question pour demander une baisse du taux de rendement? Poser la question c'est répondre. On ne peut pas avoir une formule triennale puis dire,*

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25 Pièce A-0095, page 69.
26 Pièce A-0095, page 70.
27 Pièce A-0095, page 73.
28 Pièce A-0095, pages 75-76.

« Bien, nous, on aime la formule quand ça fait notre affaire mais on ne l'aime pas quand ça ne fait pas notre affaire ». »

[39] Quant aux coûts réglementaires associés au taux de rendement, OC plaide que le distributeur n'a rien à perdre lorsqu'il présente une demande d'une année à l'autre[29] :

« […] *Année après année ils tentent de faire augmenter le taux de rendement puis c'est un «* win-win *» : soit qu'ils gagnent leur cause si le taux de rendement augmente ou ils perdent leur cause mais, de toute façon, ça ne leur a rien coûté parce que la facture est refilée aux consommateurs. Pour les consommateurs, c'est un «* lose-lose *» : soit qu'ils prennent le risque que le taux de rendement soit augmenté, dans quel cas leur facture va augmenter; et même dans une victoire où le taux de rendement n'est pas augmenté, ils paient quand même la facture.* […] »

[40] Selon OC, les coûts réglementaires engagés à ce jour associés à ce sujet peuvent être qualifiés de « *déraisonnables* » et devraient être assumés par les actionnaires du distributeur et non par ses clients[30].

[41] Enfin, comme position subsidiaire, OC serait disposée à accepter, pour les années 2013 et 2014, un taux de rendement de 8,4 % pour une période de deux ans, lequel est à mi-chemin entre le taux applicable en fonction de la FAA, soit 7,9 % et celui proposé par la Régie, soit 8,90 %[31].

4.5 POSITION DE S.É./AQLPA

[42] S.É./AQLPA, se basant notamment sur l'évolution des coûts associés aux émissions des gaz à effet de serre, se dit favorable à la Proposition de la Régie, soit « *à ce qu'une exception soit faite aux mécanismes prévus pour établir le taux de rendement pour une période de deux ans* »[32].

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29 Pièce A-0095, page 77.
30 Pièce A-0095, page 80.
31 Pièce A-0095, pages 81-82.
32 Pièce A-0095, pages 84-86.

[43] Sur le plan procédural, S.É./AQLPA mentionne que la règle du précédent (*stare decisis*) n'est pas applicable à la Régie et précise comme suit sa compréhension de l'audience en cours[33] :

> « *Par ailleurs, ce que nous comprenons c'est que, dans l'audience d'aujourd'hui, la Régie n'est pas saisie de... n'a pas à décider, à la suite de l'audience d'aujourd'hui, de l'opportunité de la demande de Gaz Métro, de revoir, en deux mille douze (2012), deux mille treize (2013), le taux de rendement. Elle n'est pas saisie au mérite de cette demande. Ce que nous comprenons c'est que la Régie a fait une proposition, qu'on pourrait qualifier d'allégement réglementaire, afin de voir ce que les différents participants penseraient de la proposition mitoyenne qui a été formulée par la Régie.* »

4.6 POSITION DE L'UC

[44] L'UC réfère d'abord à sa lettre transmise le 7 février 2013 à la Régie, dans laquelle elle exprime sa position à l'égard de la Proposition[34] :

> « *UC tient à souligner que dans le contexte où, Gaz Métro acceptait et adoptait la proposition de la Régie, UC ne présentait aucune preuve au contraire et retirait sa demande initiale telle que formulée UC ne contesterait pas une telle demande par soucis d'efficacité du traitement règlementaire du dossier et afin d'en limiter les coûts. Toutefois dans le contexte ou GM maintient sa demande initiale, UC s'objectera à la suspension de la formule d'ajustement automatique telle que proposée par la Régie.* »

[45] Elle explique sa compréhension de la démarche de la Régie de la façon suivante[35] :

> « […] *je ne pense pas que la Régie ait dit que, dans sa décision, ou ait même sous-entendu que sept point quatre-vingt-onze (7,91) n'était pas raisonnable. Ce qu'elle dit c'est qu'il semble y avoir une preuve qui pourrait mener à un débat. Je cherche à éviter le débat, alors je ne vous offre pas un taux pris arbitrairement. Ce que vous dites c'est : je continue d'appliquer le taux de l'année dernière, c'est-à-dire qu'on n'applique pas la formule, on applique le taux de l'année dernière.* »

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33 Pièce A-0095, pages 89-91.
34 Pièce C-UC-0019.
35 Pièce A-0095, pages 98-99.

[46] L'UC soumet cependant une réserve. Si le taux de rendement applicable est celui de l'année 2012, les coûts réglementaires encourus par le distributeur à ce jour à l'égard de la modification de son taux de rendement, qu'elle qualifie de « *faramineux* »[36] ne doivent pas être inclus dans les coûts de service. Elle pose ainsi la question suivante[37] :

> « […] *est-ce que les rendements de nos voisins et compétiteurs ont été modifiés à la hausse depuis deux mille douze (2012)? Est-ce qu'il y a eu cette différence? Et est-ce qu'on a besoin d'un expert et de dépenser trois cent quelques mille dollars (300 000 $) avec un expert pour établir ça, pour faire la preuve préalable de la raisonnabilité?* »

4.7 CONCLUSION

[47] En somme, le distributeur, l'ACIG et S.É./AQLPA se disent en faveur de la Proposition, telle que formulée par la Régie. Le distributeur, appuyé par l'ACIG et S.É./AQLPA, suggère, sans en faire une condition à l'acceptation de la Proposition, qu'elle soit applicable pour une période de deux ans.

[48] L'UC est également favorable à la Proposition, dans la mesure où les coûts réglementaires engagés par le distributeur et reliés au taux de rendement pour l'année 2013 ne sont pas inclus dans les coûts de service.

[49] Quant à la FCEI et OC, elles considèrent que la Proposition et le processus suivi par la Régie ne respectent pas les règles d'équité procédurale. Pour la FCEI, le principe de la cohérence décisionnelle n'est également pas respecté. Enfin, la FCEI et OC proposent, subsidiairement, un taux de 8,4 %. OC le propose pour une période de deux ans.

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36 Pièce A-0095, page 104.
37 Pièce A-0095, page 97.

5. OPINION

[50] Pour les motifs exposés ci-après, la Régie est d'avis qu'il y a lieu de suspendre la FAA et de maintenir le taux de rendement du distributeur à 8,90 % pour l'année 2013 seulement.

[51] Les commentaires des participants peuvent être regroupés selon les trois thèmes suivants : d'une part, les questions d'équité procédurale et de cohérence décisionnelle et, d'autre part, la question de la détermination d'un taux de rendement à 8,4 % ou à 8,90 % pour une période de deux ans et, enfin, la question des frais.

5.1 L'ÉQUITÉ PROCÉDURALE ET LA COHÉRENCE DÉCISIONNELLE

[52] Selon la FCEI et OC, le processus proposé par la Régie pour la détermination du taux de rendement n'est pas conforme aux règles d'équité procédurale. La procédure habituelle établie par la Régie n'étant pas respectée (demandes de renseignements, interrogatoires et contre-interrogatoires, plaidoiries), elles ne sont pas en mesure d'évaluer les prétentions du distributeur à l'égard de la raisonnabilité ou non du taux de rendement découlant de la FAA établie par la Régie dans sa décision D-2011-182.

[53] Dans l'exercice de ses fonctions, la Régie doit appliquer les règles d'équité procédurale, dont le contenu varie selon les circonstances, le cadre juridique et la nature de la question à trancher[38] :

> « *La caractéristique principale de la règle audi alteram partem en common law est la souplesse; la Cour suprême l'énonce ainsi :* […] *Aussi bien les règles de justice naturelle que l'obligation d'agir équitablement sont des normes variables. Leur contenu dépend des circonstances de l'affaire, des dispositions législatives en cause et de la nature de la question à trancher.* » [nous soulignons]

[54] À l'égard de la Proposition, il ne fait aucun doute que la Régie s'est conformée en tout point aux règles d'équité procédurale. La Régie a fait connaître le processus dans sa décision procédurale D-2013-003 et les participants ont tous été entendus lors de l'audience du 14 février 2013.

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[38] P. Garant, *Droit administratif*, 6e édition, Éditions Yvon Blais, 2010, page 629.

[55] La FCEI et OC soulèvent un questionnement, à savoir si la Régie doit nécessairement procéder au fond sur la Demande ou si elle peut, comme c'est le cas en l'espèce, formuler une proposition et trancher après avoir entendu les participants sur cette proposition.

[56] Comme mentionné à la section 3 de la présente décision, la Demande découle de l'article 32 de la Loi. En tenant compte de ses compétences et pouvoirs, la Régie est dûment habilitée à formuler la Proposition. Par conséquent, la Régie est d'opinion que la Proposition et le processus suivi pour son examen respectent les règles d'équité procédurale.

[57] Quant à la question de la cohérence décisionnelle, les décisions auxquelles réfère la FCEI portent sur l'existence d'une jurisprudence contradictoire (conflit juridictionnel) en raison de décisions divergentes des décideurs au sein d'un même organisme[39]. Or, ce n'est manifestement pas le cas en l'espèce. Au surplus, la Régie note que dans l'une des décisions, la Cour suprême précise que l'autonomie décisionnelle des tribunaux administratifs a préséance sur l'objectif de cohérence décisionnelle[40].

5.2 UN TAUX DE RENDEMENT À 8,4 % OU À 8,90 % POUR UNE PÉRIODE DE DEUX ANS

[58] D'une part, le distributeur considère souhaitable, considérant le niveau prévisible du taux sans risque pour l'application de la FAA, l'imminence du dépôt du dossier tarifaire pour l'année 2014 ainsi que les économies et les gains d'efficacité, que la suspension de la FAA soit applicable pour les années 2013 et 2014. L'ACIG et S.É./AQLPA sont en faveur de cette demande formulée par le distributeur.

[59] D'autre part, bien que la FCEI et OC soient contre la proposition de la Régie, elles proposent, subsidiairement, l'établissement d'un taux de rendement à 8,4 %, soit à mi-chemin entre celui résultant de la FAA établie en 2012 et la proposition de la Régie.

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39 C-FCEI-0019 et C-FCEI-0020.

40 C-FCEI-0019, pages 795-801.

[60] Enfin, l'UC est disposée à accepter la proposition de la Régie dans la mesure où les coûts réglementaires reliés à l'étude du taux de rendement pour la présente année ne sont pas assumés par les clients du distributeur. La FCEI et OC ont également questionné l'ampleur des frais engagés à ce jour par le distributeur[41].

[61] L'application de la Proposition de la Régie sur une période de deux ans ou l'établissement d'un taux de rendement à 8,4 % sont des sujets qui dépassent le cadre de l'audience dans le présent dossier, lequel porte sur la Proposition, telle que présentée par la Régie dans ses décisions procédurales D-2013-003 et D-2013-0024.

[62] **Bien que la Proposition ne fasse pas l'unanimité, elle est accueillie favorablement par une partie des participants. La Régie considère donc que suffisamment d'éléments ont été présentés en audience, ce qui lui permet de conclure que la Proposition assure la conciliation entre l'intérêt public, la protection des consommateurs et un traitement équitable du distributeur.**

5.3 FRAIS ENGAGÉS PAR GAZ MÉTRO

[63] Quant à la question des frais engagés à ce jour par le distributeur pour la présentation de sa Demande, la Régie, tout comme certains participants, est préoccupée par leur ampleur.

[64] Par ailleurs, la Régie a cette préoccupation depuis 1999, année où elle a établi une FAA avec l'objectif de permettre un allègement significatif sur le plan réglementaire et une réduction du coût des audiences publiques[42].

[65] En 2011, par sa décision D-2011-182, la Régie a mis en place une FAA pour un terme de trois ans pour des raisons d'efficacité, d'efficience et de stabilité du processus réglementaire. La Régie reconnaissait également la possibilité pour le distributeur de présenter, avant ce terme, une nouvelle demande si la situation le requérait. La Régie considère qu'il aurait été préférable que le distributeur lui présente les changements de situation avant d'engager des frais.

41 Pièce B-0242.
42 Dossier R-3690-2009, décision D-2009-156, paragraphe 201.

[66] L'audience actuelle n'est toutefois pas le forum approprié pour reconnaître ou non de tels frais dans le coût de service du distributeur. Cette question fera l'objet d'une étude plus approfondie à l'étape de l'étude du coût de service.

[67] Toutefois, étant donné que la FAA s'appliquera en 2014, la Régie s'attend à ce que le distributeur, s'il croit que la situation requiert de prolonger la suspension de la FAA pour une année additionnelle, lui présente une demande portant sur les conditions d'ouverture préalables en temps opportun et avant d'engager des frais importants, notamment à l'égard des ressources externes (frais d'expert, frais juridiques, etc.).

[68] **Pour ces motifs**,

La Régie de l'énergie :

SUSPEND l'application de la formule d'ajustement automatique pour l'année 2013;

MAINTIENT le taux de rendement sur l'avoir de l'actionnaire fixé en 2012, soit 8,90 %.

Marc Turgeon
Régisseur

Jean-François Viau
Régisseur

Françoise Gagnon
Régisseur

Représentants :

- Association des consommateurs industriels de gaz (ACIG) représentée par M^{e} Guy Sarault;
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI) représentée par M^{e} André Turmel;
- Groupe de recherche appliquée en macroécologie (GRAME) représenté par M^{e} Geneviève Paquet;
- Option consommateurs (OC) représentée par M^{e} Éric David;
- Regroupement des organismes environnementaux en énergie (ROEÉ) représenté par M^{e} Franklin S. Gertler;
- Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ) représenté par M^{e} Annie Gariépy;
- Société en commandite Gaz Métro (Gaz Métro) représentée par M^{e} Vincent Regnault et M^{e} Hugo Sigouin-Plasse;
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA) représenté par M^{e} Dominique Neuman;
- TransCanada Energy Ltd. (TCE) représentée par M^{e} Pierre Grenier;
- TransCanada Pipelines Limited (TCPL) représentée par M^{e} Pierre Grenier;
- Union des consommateurs (UC) représentée par M^{e} Hélène Sicard;
- Union des municipalités du Québec (UMQ) représentée par M^{e} Steve Cadrin.

D É C I S I O N

QUÉBEC **RÉGIE DE L'ÉNERGIE**

D-2014-078	R-3879-2014	16 mai 2014

PRÉSENTS :

Gilles Boulianne
Louise Rozon
Pierre Méthé
Régisseurs

Société en commandite Gaz Métro
Demanderesse

et

Personnes intéressées dont les noms apparaissent ci-après

Décision interlocutoire

Demande d'approbation du plan d'approvisionnement et de modification des* Conditions de service et Tarif *de Société en commandite Gaz Métro à compter du 1er octobre 2014

Personnes intéressées :

Association des consommateurs industriels de gaz (ACIG);
Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI);
Groupe de recherche appliquée en macroécologie (GRAME);
Regroupement des organismes environnementaux en énergie (ROEÉ);
Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (SÉ/AQLPA);
TransCanada Energy Ltd. (TCE);
Union des consommateurs (UC);
Union des municipalités du Québec (UMQ).

1. DEMANDE

[1] Le 14 mars 2014, Société en commandite Gaz Métro (Gaz Métro ou le Distributeur) dépose à la Régie de l'énergie (la Régie) une demande d'approbation du plan d'approvisionnement et de modification du texte des *Conditions de service et Tarif* (les Conditions de service et Tarif) à compter du 1er octobre 2014. Cette demande est présentée en vertu des articles 31 (1), (2) et (2.1), 32, 34(2), 48, 49, 52, 72 et 74 de la *Loi sur la Régie de l'énergie*[1] (la Loi).

[2] Gaz Métro propose à la Régie de traiter sa demande en deux phases.

[3] Dans le cadre de la phase 1, Gaz Métro identifie les enjeux suivants :

- les stratégies d'intégration du Système de plafonnement et d'échange de droits d'émission de gaz à effet de serre (SPEDE);
- le prolongement de l'ordonnance de suspension de l'application de la formule d'ajustement automatique (FAA) jusqu'au 30 septembre 2015;
- le maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 %;
- un allègement réglementaire pour la fixation des dépenses d'exploitation 2015, 2016 et 2017;
- une révision du mode de partage des trop-perçus et des manques à gagner.

[4] Gaz Métro propose que la phase 2 porte sur l'approbation du plan d'approvisionnement et sur la fixation des Conditions de service et Tarifs applicables à l'ensemble de la clientèle à compter du 1er octobre 2014.

[5] Le 16 avril 2014, la Régie rend sa décision D-2014-061 par laquelle elle accueille la proposition de Gaz Métro de procéder à l'examen de la demande en deux phases et fixe un échéancier pour le dépôt des demandes d'intervention.

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[1] RLRQ, c. R-6.01.

[6] Dans cette même décision, la Régie demande aux personnes intéressées de commenter, lors du dépôt de leur demande d'intervention, les sujets suivants :

- la demande de Gaz Métro visant le prolongement de l'ordonnance de suspension de l'application de la FAA jusqu'au 30 septembre 2015 et le maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 %;
- la possibilité de fixer les tarifs pour l'année tarifaire 2014-2015 (l'année tarifaire 2015), de Gaz Métro en fonction de l'encadrement réglementaire qui prévaut actuellement et de l'inviter à déposer, en juin 2014, sa preuve relative aux modifications aux Conditions de service et Tarif.

[7] Huit personnes intéressées déposent une demande d'intervention ainsi que des commentaires sur ces sujets.

[8] Dans une lettre datée du 2 mai 2014, Gaz Métro commente les demandes d'interventions, les budgets de participation et réplique aux commentaires formulées par les personnes intéressées sur les sujets identifiés précédemment.

[9] Le 6 mai 2014, en suivi de la décision D-2013-179, Gaz Métro dépose une preuve sur la méthode de prévision de la journée de pointe et demande notamment le report des suivis relatifs à la nouvelle classe de service interruptible et l'accroissement de la vaporisation de l'usine LSR. Les 9 mai et 14 mai 2014, respectivement, la FCEI et l'ACIG répliquent à Gaz Métro. Le 15 mai 2014, Gaz Métro réplique aux commentaires de la FCEI.

[10] Le 9 mai 2014, le ROEÉ réplique aux commentaires de Gaz Métro sur son budget de participation.

[11] Dans la présente décision, la Régie se prononce sur la reconnaissance des intervenants, les enjeux proposés par Gaz Métro pour la phase 1, les demandes de prolongement de l'ordonnance de suspension de l'application de la FAA et le maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 % pour l'année tarifaire 2015, l'encadrement procédural de l'examen du plan d'approvisionnement 2015-2017 ainsi que sur la demande d'ordonnance de confidentialité de Gaz Métro à l'égard de certains documents.

[12] La Régie se prononcera ultérieurement sur les budgets de participation soumis pour le traitement de la phase 1.

2. RECONNAISSANCE DES INTERVENANTS

[13] La Régie a reçu les demandes d'intervention de l'ACIG, la FCEI, le GRAME, le ROEÉ, SÉ/AQLPA, TCE, l'UC et l'UMQ.

[14] La Régie examine les demandes d'intervention à la lumière de la Loi et du *Règlement sur la procédure de la Régie de l'énergie*[2] (le Règlement).

[15] Toutes les personnes intéressées désirent intervenir activement dans le cadre des deux phases du dossier.

[16] **La Régie juge que toutes les personnes intéressées ont démontré un intérêt suffisant et leur accorde, en conséquence, le statut d'intervenant.**

[17] Cependant, la Régie ne permet pas à l'UMQ d'intervenir sur le SPEDE, puisque cette dernière n'a pas précisé dans sa demande d'intervention les conclusions recherchées ni les recommandations sommaires proposées à ce sujet, tel qu'exigé au Règlement.

[18] À cet égard, l'article 6 du Règlement prévoit que :

> « *6. Une demande d'intervention doit être faite par écrit, signée par l'intéressé ou son représentant et transmise à la Régie et au demandeur dans le délai fixé par celle-ci. <u>L'intéressé indique</u> :*
>
> *1° son nom, son adresse, son numéro de téléphone et, le cas échéant, son adresse électronique et son numéro de télécopieur;*
>
> *2° la nature de son intérêt et, s'il y a lieu, sa représentativité;*

[2] (2006) 138 G.O. II, 2279.

3° les motifs à l'appui de son intervention ;

4° de façon sommaire, les conclusions qu'il recherche ou les recommandations qu'il propose ;

5° la manière dont il entend faire valoir sa position et notamment s'il désire faire entendre des témoins et présenter une preuve d'expert, de même que le temps d'audience estimé ;

6° ses suggestions pour faciliter le déroulement de l'étude de la demande ».
[nous soulignons]

[19] En vertu de cet article, il n'est pas suffisant, dans une demande d'intervention, d'énumérer les sujets sur lesquelles une personne intéressée désire intervenir. Il faut notamment préciser de façon sommaire les conclusions recherchées ou les recommandations proposées.

[20] La Régie informe toutefois l'UMQ, qu'elle pourra soumettre des observations au sujet du SPEDE dans le cadre de la phase 1.

[21] **La Régie définira le calendrier et les modalités de la phase 2 à la suite du dépôt de la preuve du Distributeur.**

3. ENJEUX DE LA PHASE 1

[22] Dans le cadre de la phase 1, Gaz Métro identifie les enjeux suivants :

- les stratégies d'intégration du SPEDE;
- le prolongement de l'ordonnance de suspension de l'application de la FAA jusqu'au 30 septembre 2015;
- le maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 %;
- un allègement réglementaire pour la fixation des dépenses d'exploitation 2015, 2016 et 2017;
- une révision du mode de partage des trop-perçus et des manques à gagner.

[23] Dans sa décision D-2014-061 la Régie demande :

« *[12] Par ailleurs, la Régie demande aux personnes intéressées de commenter, lors du dépôt de leur demande d'intervention, la demande de Gaz Métro visant le prolongement de l'ordonnance de suspension de l'application de la FAA jusqu'au 30 septembre 2015 et le maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 %. Le cas échéant, le traitement de cette demande pourrait suivre un processus allégé d'examen sur dossier.*

[13] Également, en ce qui a trait à l'allégement réglementaire proposé par Gaz Métro pour la fixation de ses dépenses d'exploitation 2015, 2016 et 2017, ainsi qu'à la révision du mode de partage des trop-perçus et des manques à gagner, la Régie est d'avis qu'une telle demande soulève des enjeux importants. Son examen pourrait ainsi nécessiter plusieurs semaines d'analyse et avoir pour conséquence de retarder l'examen de la phase 2 portant sur l'approbation du plan d'approvisionnement et sur les modifications des Conditions de service et Tarif pour l'année tarifaire 2015.

[14] De prime abord, la Régie croit qu'il serait plus efficace de fixer les tarifs 2014-2015 de Gaz Métro en fonction de l'encadrement réglementaire qui prévaut actuellement et de l'inviter à déposer, en juin 2014, sa preuve relative aux modifications aux Conditions de service et Tarif. La Régie demande aux personnes intéressées de soumettre leurs observations à ce sujet lors du dépôt de leur demande d'intervention ».

[24] Dans la présente section, la Régie se prononce sur les enjeux à traiter dans le cadre de la phase 1, en tenant compte des commentaires formulés par le Distributeur et les personnes intéressées.

3.1 SUSPENSION DE L'APPLICATION DE LA FAA ET TAUX DE RENDEMENT

[25] L'ACIG, la FCEI, le ROEÉ, SÉ/AQLPA, l'UC et l'UMQ déposent, dans leur demande d'intervention, des commentaires sur la suspension de l'application de la FAA et sur le taux de rendement.

[26] La Régie constate qu'aucune personne intéressée ne s'oppose aux demandes de prolongement de l'ordonnance de suspension de l'application de la FAA jusqu'au 30 septembre 2015 et de maintien du taux de rendement sur l'avoir de l'actionnaire à 8,90 %.

[27] Gaz Métro fait valoir que ce consensus pourrait permettre à la Régie de reconduire le taux de rendement sans autre formalité.

[28] **Tenant compte des commentaires des personnes intéressées et de Gaz Métro, la Régie considère qu'elle a suffisamment d'éléments de preuve pour se prononcer sur les demandes du Distributeur à cet égard dans la présente décision.**

3.2 PROPOSITION D'ALLÉGEMENT RÉGLEMENTAIRE

[29] L'ACIG, la FCEI, le GRAME, le ROEÉ, SÉ-AQLPA, l'UC et l'UMQ déposent des commentaires sur la proposition d'allègement réglementaire de Gaz Métro.

[30] En réponse à ces commentaires, Gaz Métro constate que sa proposition d'allègement réglementaire soulève plusieurs préoccupations légitimes chez les diverses personnes intéressées. Le Distributeur propose, à l'instar de la FCEI, que la Régie fixe un calendrier procédural qui lui permettrait de rendre une décision sur les sujets du SPEDE et de l'allègement réglementaire à la fin août ou au début septembre 2014.

[31] En ce qui a trait à la phase 2, Gaz Métro se voit dans l'obligation de réviser l'échéancier originalement prévu et de créer une phase 3. En effet, elle mentionne que la préparation d'un dossier tarifaire basé sur le coût de service global de l'entreprise, incluant une prévision détaillée des dépenses d'exploitation, est un exercice qui exige du temps. Elle soutient que cet exercice ne pourra être complété pour la fin juin 2014, tel que prévu initialement, d'autant plus que la décision de la phase 3 du dossier tarifaire 2014 n'est pas encore rendue et qu'elle pourrait fournir certains éléments pertinents à la préparation de la prévision des dépenses d'exploitation pour 2015.

[32] Par ailleurs, Gaz Métro mentionne que les divers suivis demandés à l'égard des exercices de fonctionnalisation (incluant des groupes de travail) et à l'égard du renouvellement des contrats d'entreposage avec le regard neuf d'un expert ne pourront être complétés avant septembre prochain. Or, tant que ces exercices ne seront pas complétés, la Régie n'aura pas entre les mains l'ensemble des informations pertinentes à l'égard de la proposition tarifaire de Gaz Métro pour le dossier tarifaire 2015.

[33] En conséquence, advenant le rejet de la proposition d'allègement réglementaire et de modification au mécanisme de partage des trop-perçus ou des manques à gagner, Gaz Métro informe la Régie que les pièces du dossier tarifaire 2015 relatives au coût de service et à la stratégie tarifaire, ainsi que les divers suivis ci-haut mentionnés pourront être déposés d'ici le 30 septembre 2014.

[34] Considérant les modifications à l'échéancier originalement prévu, Gaz Métro suggère à la Régie d'ordonner la tenue d'une rencontre préparatoire pour planifier le déroulement de l'audience du présent dossier, tel que l'autorise l'article 28, paragraphe 4^{o}, de la Loi.

[35] La Régie retient des commentaires des personnes intéressées à l'effet que l'examen de la proposition d'allègement réglementaire du Distributeur soulève des enjeux importants et complexes.

[36] La Régie se questionne sur la flexibilité de Gaz Métro à l'égard de sa proposition d'allègement réglementaire. Elle se questionne notamment sur l'ouverture du Distributeur à scinder l'examen de la formule paramétrique pour les dépenses d'exploitation de l'examen du mode de partage des trop-perçus et des manques à gagner.

[37] Par ailleurs, la Régie prend acte du fait que le revenu requis du dossier tarifaire 2015 sera déposé d'ici le 30 septembre 2014. Elle constate que ce dépôt tardif engendrera, pour une troisième année consécutive, un retard important dans le calendrier réglementaire.

[38] En vue de planifier le déroulement de l'audience dans le présent dossier, la Régie tiendra une rencontre préparatoire pour entendre les participants sur le traitement de la proposition d'allègement réglementaire du Distributeur et pour obtenir, plus spécifiquement, leurs commentaires à l'égard des deux points suivants :

- la possibilité d'examiner la proposition d'allègement réglementaire du Distributeur sans procéder à l'examen du mode de partage des trop-perçus et des manques à gagner;
- la possibilité d'examiner conjointement dans un même dossier le revenu requis des années tarifaires 2015 et 2016 et ainsi rattraper le retard réglementaire.

[39] La rencontre préparatoire aura lieu le **30 mai 2014** à compter de **9 h** aux bureaux de la Régie à Montréal.

3.3 SPEDE

[40] L'ACIG, la FCEI, le GRAME, le ROEÉ, SÉ-AQLPA, TCE, l'UC et l'UMQ désirent intervenir sur le SPEDE.

[41] Gaz Métro ne dépose aucun commentaire à cet égard.

[42] La Régie convient de traiter du SPEDE dans le cadre de la phase 1 et est d'avis que l'ensemble des intervenants, à l'exclusion de l'UMQ, ont justifié leur intérêt pour intervenir sur ce sujet.

[43] La Régie rappelle qu'il y a une réglementation qui encadre, notamment, les modalités d'application du SPEDE. Le présent dossier ne constitue pas l'occasion de remettre en question ce cadre réglementaire.

[44] La Régie fixe l'échéancier suivant pour le traitement de la demande de Gaz Métro portant sur le SPEDE :

Le 3 juin 2014 à 9 h	Séance de travail
Le 10 juin 2013 à 12 h	Date limite pour le dépôt des demandes de renseignements adressées au Distributeur
Le 23 juin 2014 à 12 h	Date limite pour les réponses du Distributeur aux demandes de renseignements
Le 7 juillet 2014 à 12 h	Date limite pour le dépôt de la preuve des intervenants ou pour mettre fin à leur intervention
Le 18 juillet 2014 à 12 h	Date limite pour les demandes de renseignements sur la preuve des intervenants
Le 14 août 2014 à 12 h	Date limite pour les réponses des intervenants aux demandes de renseignements
Le 21 et si nécessaire le 22 août 2014	Période réservée pour la tenue de l'audience

4. SUSPENSION DE L'APPLICATION DE LA FAA ET MAINTIEN DU TAUX DE RENDEMENT

4.1 DEMANDES

[45] Le Distributeur demande à la Régie de prolonger l'ordonnance de suspension de l'application de la FAA et de maintenir le taux de rendement sur l'avoir de l'actionnaire à 8,90 % pour l'année tarifaire 2015.

[46] Gaz Métro considère que l'application de la FAA, dans les circonstances actuelles, et en regard de l'évolution des conditions de marché depuis son adoption, produit un taux de rendement déraisonnable pour l'année tarifaire 2015.

[47] En effet, le taux de rendement sur l'avoir propre établi par l'application de la FAA est de 8,41 %, sur la base d'un taux sans risque de 3,44 % en date du 17 février 2014.

[48] Gaz Métro souligne que ce taux constituerait un rendement déraisonnable par rapport aux distributeurs comparables, lesquels supportent un risque inférieur à celui du Distributeur et évoluent dans des conditions économiques et financières similaires.

[49] Par ailleurs, Gaz Métro estime que les similitudes du contexte économique et financier entre les dossiers tarifaires 2013, 2014 et 2015 justifient le maintien de la suspension de la FAA. En effet, les taux d'intérêts demeurent anormalement bas, situation qu'a reconnue la Régie dans sa décision D-2014-034[3], ce qui rend la FAA inopérante. Sous ces mêmes conditions, la Régie a jugé qu'il n'était pas opportun de mettre en place une FAA pour Hydro-Québec. Par conséquent, étant assujettie aux mêmes conditions, Gaz Métro demande de prolonger l'ordonnance de suspension de l'application de la FAA.

[50] Sous ces conditions, Gaz Métro propose de revenir à la Régie dans le cadre du dossier tarifaire 2016 avec une étude détaillée et une proposition à l'égard du taux de rendement, permettant ainsi un allégement réglementaire et l'optimisation du déroulement du dossier tarifaire 2015.

4.2 POSITION DES PERSONNES INTÉRESSÉES

[51] Aucune personne intéressée ne s'oppose aux demandes de Gaz Métro.

[52] La FCEI prend note de l'intention de Gaz Métro de présenter une preuve complète sur le taux de rendement au dossier tarifaire 2016. Considérant la lourdeur et les coûts associés aux dossiers de taux de rendement, la FCEI estime que la Régie devrait exiger que la présentation d'un dossier sur le taux de rendement en 2016 comprenne une formule d'ajustement automatique.

[53] En conséquence, la FCEI demande à la Régie de l'énergie d'ordonner dès à présent à Gaz Métro de préparer le dépôt d'une nouvelle formule d'ajustement automatique pour adoption, afin que cette dernière entre en vigueur au 1er octobre 2015.

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[3] Dossier R-3842-2013.

[54] L'UMQ note qu'il s'agit d'une troisième demande de suspension pour une FAA qui ne s'est encore jamais appliquée concrètement, malgré l'intention affichée par la Régie au paragraphe 310 de sa décision D-2011-182. De l'avis de l'intervenante, cette situation, qui devrait être exceptionnelle, semble devenue un expédient normal pour le Distributeur.

[55] L'intervenante mentionne que si, dans le cadre du présent dossier tarifaire, la Régie devait consentir à nouveau aux arguments présentés par le Distributeur et traiter la question par un processus allégé d'examen sur dossier, cette décision devrait logiquement militer en faveur d'un réexamen ultérieur en profondeur du taux de rendement du Distributeur et de la formule d'ajustement.

4.3 OPINION DE LA RÉGIE

[56] La Régie constate que les conditions économiques et financières actuelles sont semblables à celles ayant mené, dans les décisions D-2013-036 et D-2013-085, à la suspension de l'application de la FAA et au maintien du taux de rendement à 8,90 %.

[57] **En conséquence, la Régie accepte de prolonger l'ordonnance de suspension de l'application de la FAA et de maintenir le taux de rendement sur l'avoir de l'actionnaire à 8,90 % pour l'année tarifaire 2015. Elle prend acte du fait que Gaz Métro déposera une preuve détaillée et complète pour le taux de rendement applicable pour l'année tarifaire 2016. La Régie demande au Distributeur de prévoir, dans le cadre de cette preuve, l'utilisation d'une FAA.**

5. PLAN D'APPROVISIONNEMENT 2015-2017

5.1 DEMANDE

[58] Dans sa décision D-2013-179, la Régie demandait notamment au Distributeur de déposer dans un délai de 6 mois les trois suivis suivants :

- modèle de prévision de la journée de pointe;
- nouvelle classe de service interruptible;
- accroissement de la capacité de vaporisation de l'usine LSR.

[59] Le 6 mai 2014, Gaz Métro dépose un nouveau modèle de prévision de la journée de pointe.

[60] Gaz Métro demande l'autorisation de déposer les deux autres suivis après le délai de 6 mois initialement imparti par la Régie. Elle précise que le dépôt de la preuve de la phase 2 relative au plan d'approvisionnement n'aura lieu qu'en juin prochain et que le report de ces suivis permettrait de regrouper la plupart des pièces relatives au plan d'approvisionnement dans un seul et même dépôt, sauf pour le suivi relatif à la méthode de prévision de la journée de pointe.

[61] Par ailleurs, dans sa lettre du 6 mai 2014, Gaz Métro indique également à la Régie qu'elle :

> « […] *souhaite contracter* […] *les capacités additionnelles requises qui découlent notamment de cette nouvelle méthode afin d'être en mesure de répondre à la demande projetée en 2014-2015. Ces capacités seront de courte durée et seront présentées dans le plan d'approvisionnement à être déposé en juin prochain. La Régie aura alors pleinement l'occasion de prendre connaissance des caractéristiques* <u>*des contrats conclus*</u> *et de les approuver tel que la Loi l'exige. Cette façon de faire nous apparaît conforme à la mission qui incombe à Gaz Métro aux termes de la Loi sur la Régie de l'énergie et en tant que service public, soit celui de desservir la clientèle qui le requiert notamment en garantissant la sécurité d'approvisionnement.* […]
>
> *Nous invitons la Régie à nous faire part d'ici au 16 mai prochain de tout commentaire à l'égard de ce qui précède* »[4].
>
> [nous soulignons]

[62] Enfin, Gaz Métro précise que la méthode de prévision de la journée de pointe qu'elle propose sera utilisée dans le plan d'approvisionnement du présent dossier tarifaire[5].

4 Pièce B-0015.
5 Pièce B-0017, p. 36.

5.2 POSITION DE LA FCEI ET DE L'ACIG

[63] La FCEI s'oppose au report du dépôt de la proposition de nouvelle classe de clients interruptibles. Elle rappelle que cette proposition vise à mitiger l'impact de la modification potentielle à la méthode de prévision de la journée de pointe et qu'elle a été formulée en réponse à celle-ci. Il paraît donc tout à fait nécessaire, selon elle, de traiter ce sujet parallèlement à la méthode de prévision de la journée de pointe afin de maximiser les chances que cette option tarifaire soit offerte au même moment qu'entrerait en vigueur cette nouvelle méthode de prévision, le cas échéant. Retarder le traitement de cet enjeu au mois de juin risquerait de compromettre cette possibilité, ce qui pourrait entraîner des coûts d'approvisionnement additionnels pour la clientèle.

[64] La FCEI indique également que s'il est techniquement possible qu'une hausse de la capacité de vaporisation à l'usine LSR soit réalisable pour l'hiver 2014-2015, ce suivi ne devrait pas non plus être retardé. Elle précise toutefois que, si cela n'est pas techniquement possible, elle ne s'oppose pas au report de ce suivi, dans la mesure où il permet d'accélérer le traitement de la modification à la méthode de prévision de la journée de pointe et la proposition de créer une nouvelle classe de service interruptible.

[65] En réplique à la FCEI, Gaz Métro souligne que, même si les deux suivis étaient déposés dans les prochains jours, la mise en œuvre des solutions évoquées ne pourrait pas se faire pour le prochain hiver. En conséquence, le Distributeur demande à la Régie de ne pas donner suite à la demande de la FCEI.

[66] L'ACIG exprime son plein appui à la démarche proposée par le Distributeur visant à contracter les capacités de transport additionnelles requises en vertu de la nouvelle méthode de prévision de la journée de pointe. L'intervenante est préoccupée par la gravité de la situation et des conséquences potentiellement néfastes sur la clientèle du Distributeur. Selon l'ACIG, cette démarche est prudente et responsable.

[67] Par ailleurs, l'ACIG ne s'oppose pas au report des suivis relatifs à la nouvelle classe de service interruptible et l'accroissement de la capacité de vaporisation de l'usine LSR. Elle s'en remet à la Régie à cet égard. Toutefois, l'ACIG souligne qu'il est plus efficace d'analyser une preuve dans son ensemble que de la traiter en différents segments.

5.3 OPINION DE LA RÉGIE

5.3.1 MODÈLE DE PRÉVISION DE LA JOURNÉE DE POINTE ET OUTILS ADDITIONNELS REQUIS

[68] Dans sa décision D-2013-179, la Régie mentionnait :

> « *[28] La Régie partage l'avis du Distributeur selon lequel une méthode de prévision de la journée de pointe doit être fiable et stable. Dans ce sens, elle considère <u>qu'un examen rigoureux de l'ensemble de la méthode doit être fait</u> plutôt que des modifications à la pièce, année après année, comme cela est le cas depuis 2007.*
>
> […]
>
> *[42] La Régie est d'avis que <u>la preuve actuellement au dossier ne lui permet pas de juger l'ampleur des besoins de la journée de pointe, tant que le Distributeur n'aura pas présenté une nouvelle étude.</u>*
>
> *[43] La Régie ne peut exclure cependant que des besoins de pointe supplémentaires pourraient s'avérer fondés.*
>
> *[44] Il ressort cependant de la preuve au dossier que ces besoins de pointe auraient une faible récurrence. En effet, l'estimation d'une occurrence par période de 10 ans n'a pas été contredite.*
>
> *[45] Le Distributeur affirme, en réplique, ne pas avoir eu le temps ou « le luxe » de discuter maintenant de solutions alternatives. Cependant, la Régie constate que le Distributeur n'a pas, depuis le 23 janvier 2013, examiné les solutions alternatives au transport ferme.*
>
> *[46] La Régie considère qu'il est important que le <u>Distributeur étudie en temps utile les solutions alternatives pour répondre à des besoins de faible récurrence</u> plutôt que de s'engager sans faire les analyses normalement requises pour une période de 15 ans.*

[47] L'audience a permis de faire ressortir trois solutions susceptibles de répondre à des besoins de pointe de faible récurrence, soit :

- *la modification des conditions de service pour que les clients en GAI s'interrompent afin d'assurer, au besoin, le service aux clients en service continu;*
- *la création d'une nouvelle classe de service interruptible pour des interruptions exceptionnelles;*
- *l'augmentation de la capacité de vaporisation à l'usine LSR.*

[48] La Régie est d'avis que ces solutions pourraient vraisemblablement coûter moins cher que la solution proposée et être implantées d'ici novembre 2016.

[…]

[50] La Régie ordonne également au Distributeur de développer et de lui soumettre, d'ici six mois, un projet de nouvelle classe de service interruptible lié à des événements exceptionnels visant les clients au tarif D_4. Le Distributeur doit envisager la mise en vigueur de cette nouvelle classe de service interruptible pour le 1er novembre 2014 ou le 1er novembre 2015 au plus tard. Les volumes annuels retenus par Gaz Métro seraient fonction des besoins du réseau.

[51] La Régie ordonne à Gaz Métro de déposer, d'ici six mois, une étude de faisabilité physique et économique pour un accroissement de la capacité de vaporisation à l'usine LSR pour le 1er novembre 2014 ou le 1er novembre 2015 au plus tard.

[52] La Régie ordonne à Gaz Métro de réduire ses besoins de pointe de 1 090 000 m3/jour pour l'année 2016 et, en conséquence, de réduire d'autant, toutes choses étant égales par ailleurs, la capacité de transport FTLH qu'elle détiendra au 1er novembre 2015 auprès de TCPL.

[53] En ce qui a trait au Plan pour l'année 2015, la Régie, à la lumière des études demandées dans la présente décision, statuera dans le prochain plan d'approvisionnement sur les solutions alternatives que Gaz Métro devra implanter et les mesures à prendre pour minimiser les coûts de transport.

> *[54] Quant au Plan pour l'année 2014, la Régie constate que le Distributeur a retenu une solution de transport pour répondre à une demande de base afin de satisfaire des besoins de pointe de faible occurrence, sans examiner de solution alternative au transport ferme. La Régie constate également qu'il est trop tard pour implanter une solution alternative* »[6].
>
> [nous soulignons]

[69] Il ressort de cette décision :

- que la Régie n'avait pas les outils nécessaires pour évaluer l'ampleur des besoins de pointe du Distributeur, tant qu'il n'y aurait pas de nouvelle étude;
- qu'elle considérait que si des besoins de pointe additionnels étaient identifiés, le Distributeur devait examiner la possibilité de répondre à ces besoins par des outils appropriés, plutôt que par des outils pour répondre à des besoins de base;
- qu'elle demandait au Distributeur de proposer un nouveau modèle de prévision de la journée de pointe et d'examiner différentes alternatives quant à d'éventuels outils pour répondre à ces besoins de pointe.

[70] La Régie considère qu'il est de la responsabilité du Distributeur de répondre, en temps opportun, aux préoccupations de la Régie qui ont été énoncées dans la décision D-2013-179. Or, elle constate qu'à la date ultime de l'échéance, Gaz Métro dépose un modèle de prévision de la journée de pointe, demande le report de deux suivis reliés aux outils alternatifs pour répondre à ces besoins et mentionne vouloir contracter du transport sur une courte période.

[71] La Régie est d'avis que le Distributeur était bien au fait de ses préoccupations et qu'il n'a pas pris les mesures nécessaires pour répondre à ces demandes en temps utile.

[72] La Régie partage également l'avis de la FCEI sur le fait que le retard dans l'examen des suivis associés à des outils alternatifs pour répondre à une demande de pointe additionnelle pourrait entraîner des coûts d'approvisionnement supplémentaires pour la clientèle.

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6 Dossier R-3837-2013 Phase 2.

[73] La Régie considère que le Distributeur ne lui laisse pas suffisamment de temps pour faire un examen rigoureux de la nouvelle méthode de prévision de la journée de pointe avant de conclure des contrats de court terme.

5.3.2 CONFORMITÉ DE LA DEMANDE DE GAZ MÉTRO

[74] La Régie a pris connaissance de la correspondance[7] du Distributeur dans laquelle ce dernier affirme vouloir contracter des capacités additionnelles requises découlant de la nouvelle méthode de prévision de la journée de pointe. À cet égard, Gaz Métro souligne que ces capacités seront de courte durée et seront présentées dans le plan d'approvisionnement à être déposé en juin 2014.

[75] Le Distributeur mentionne que :

> « *La Régie aura alors pleinement l'occasion de prendre connaissance des caractéristiques des contrats conclus et de les approuver tel que la Loi l'exige. <u>Cette façon de faire nous apparaît conforme à la mission qui incombe à Gaz Métro aux termes de la Loi sur la Régie de l'énergie et en tant que service public</u>, soit celui de desservir la clientèle qui le requiert notamment en garantissant la sécurité d'approvisionnement* ».
>
> [nous soulignons]

[76] La Régie rappelle à cet effet sa décision D-2014-064, rendue le 17 avril 2014 dans le dossier tarifaire 2013-2014 :

> « *[53] L'article 72 de la Loi mentionne que le Distributeur doit :*
>
> *« préparer et soumettre à l'approbation de la Régie, suivant la forme, la teneur et la périodicité fixées par règlement de celle-ci, un plan d'approvisionnement décrivant les caractéristiques des contrats qu'il entend conclure pour satisfaire les besoins des marchés québécois ».*
>
> […]

[7] Pièce B-0015.

[55] De l'avis de la Régie, une fois approuvé, un tel plan ne peut être modifié unilatéralement quant à ses éléments importants. Si c'était le cas, il y aurait lieu de se questionner sérieusement sur l'utilité de l'approbation accordée par la Régie aux termes de l'article 72 de la Loi et, incidemment, sur sa capacité de s'assurer de la suffisance des approvisionnements et du paiement d'un juste tarif par les consommateurs.

[…]

[57] La Régie considère qu'en présence d'une modification substantielle au plan d'approvisionnement du Distributeur, il est logique de soutenir qu'il doit s'adresser à la Régie afin d'obtenir une approbation. […]

[…]

[59] La Régie est d'avis que la modification à la méthode de prévision de la journée de pointe constitue une modification significative au plan d'approvisionnement, considérant son impact important sur l'approbation de tarifs justes et raisonnables. Ainsi, la Régie considère que le Distributeur aurait dû lui présenter une telle modification <u>avant</u> de contracter des capacités de transport ferme auprès de TCPL afin de remplir ses obligations en matière de plan d'approvisionnement »[8].

[nous soulignons]

[77] La Régie considère que la proposition de Gaz Métro relative à l'examen par la Régie dans le plan d'approvisionnement des caractéristiques des contrats déjà conclus à la suite de la modification du modèle de prévision de la journée de pointe, va à l'encontre de sa décision D-2014-064 et n'est donc pas conforme aux obligations qui incombent à Gaz Métro aux termes de la Loi.

5.3.3 CONCLUSIONS

[78] Tenant compte de l'ensemble de ces éléments, la Régie constate que le Distributeur ne pourra pas déposer au moment requis l'ensemble des suivis demandés.

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[8] Dossier R-3837-2013 Phase 2.

[79] La Régie précise qu'il est de la plus haute importance que le Distributeur dépose son plan d'approvisionnement 2015-2017 le plus rapidement possible, puisqu'une décision doit être impérativement rendue sur le plan de l'année tarifaire 2015 avant le 1er décembre 2014.

[80] Dans ce contexte, la Régie examinera la modification de la méthode de prévision de la journée de pointe, les outils alternatifs pour satisfaire des besoins de pointe additionnels et le plan d'approvisionnement 2015-2017 au moment du dépôt dudit plan.

[81] Par ailleurs, dans la mesure où Gaz Métro choisit de conclure des contrats, avant que les caractéristiques desdits contrats ne soient approuvées, la Régie précise que les sommes associées à ces contrats sont à risque et pourraient ne pas être reconnues dans son revenu requis. Le Distributeur aura donc le fardeau de preuve à cet égard, tenant compte du fait qu'il dispose, comme il en fait mention dans sa lettre[9], d'une capacité additionnelle de transport ferme de 1 090 10^3 m^3/jour jusqu'au 30 septembre 2015 contractée en raison des modifications refusées à la méthode de prévision de la journée de pointe.

[82] Enfin, la Régie note que la méthode de prévision de la journée de pointe proposée sera utilisée dans le plan d'approvisionnement du présent dossier tarifaire. **Elle demande cependant au Distributeur de présenter également un scénario d'approvisionnement utilisant le modèle actuel de prévision de la journée de pointe.**

6. DEMANDE D'ORDONNANCE DE CONFIDENTIALITÉ

[83] L'article 30 de la Loi prévoit ce qui suit :

> « *La Régie peut interdire ou restreindre la divulgation, la publication ou la diffusion de renseignements ou de documents qu'elle indique, si le respect de leur caractère confidentiel ou l'intérêt public le requiert* ».

[84] Le Distributeur transmet sous pli confidentiel la section 7 de la pièce B-0006. Il dépose à cet effet un affidavit de monsieur Vincent Pouliot, chef de service, Marché du carbone et efficacité énergétique chez Gaz Métro.

9 Pièce B-0015.

[85] L'article 30 de la Loi constitue une exception à la règle générale du caractère public des audiences. C'est à celui qui demande une ordonnance de confidentialité qu'incombe le fardeau de prouver que les renseignements visés par sa demande ont un caractère confidentiel qui doit être respecté.

[86] Aux fins du présent dossier, la Régie prend en considération la nature des informations visées par la demande et le préjudice commercial auquel Gaz Métro serait exposé, selon l'affirmation solennelle déposée au dossier.

[87] La Régie constate qu'aucune personne intéressée ne s'oppose à cette demande d'ordonnance de confidentialité et note que deux d'entre elles ont déjà souscrit un engagement de confidentialité et de non-divulgation[10].

[88] Après examen de cette affirmation solennelle, la Régie juge que les motifs invoqués justifient l'émission de l'ordonnance demandée à l'égard de la section 7 de la pièce B-0006. Elle est en effet d'avis que la divulgation des informations y contenues peut être préjudiciable aux intérêts commerciaux de Gaz Métro dans le cadre de négociations ou de ventes aux enchères, notamment en permettant à des acteurs susceptibles d'intervenir dans le cadre du SPEDE d'ajuster leur positionnement. La Régie note, de surplus, que le fait pour Gaz Métro de divulguer les informations contenues à la section 7 de la pièce B-0006, irait à l'encontre de l'article 51 du *Règlement concernant le système de plafonnement et d'échange de droits d'émission de gaz à effet de serre*[11] qui prévoit que :

> « *51. Un enchérisseur ne doit pas divulguer publiquement les informations de nature confidentielle relatives à sa participation à une vente aux enchères, notamment les suivantes:*
>
> *1° son identité;*
>
> *2° sa stratégie d'enchères;*
>
> *3° le montant de ses enchères et la quantité d'unités d'émission visée;*
>
> *4° l'information financière soumise au ministre.*

[10] Pièces B-0021 et B-0022.

[11] RLRQ, c. Q-2, r. 46.1.

De plus, un enchérisseur qui retient les services d'un conseiller pour développer sa stratégie d'enchères doit transmettre au ministre le nom et les coordonnées de ce conseiller, incluant l'adresse de son domicile. L'enchérisseur doit veiller à ce que ce conseiller ne divulgue aucune information visée au premier alinéa et qu'il ne coordonne pas de stratégies d'enchères entre les différents enchérisseurs ».

[89] La Régie accorde donc le traitement confidentiel de la section 7 de la pièce B-0006. Elle souligne toutefois que les intervenants pourront, moyennant la conclusion d'un engagement de confidentialité et de non-divulgation avec le Distributeur, consulter ladite pièce au greffe de la Régie.

[90] Le Distributeur dépose également, le 6 mai 2014[12], une correspondance accompagnant le dépôt de la pièce B-0015 dont certains passages sont caviardés et pour lesquels il demande le traitement confidentiel pour les motifs invoqués à l'affidavit de monsieur Frédéric Morel. Comme mentionné précédemment, elle souligne que les intervenants pourront, moyennant la conclusion d'un engagement de confidentialité et de non-divulgation avec le Distributeur, consulter ladite pièce au greffe de la Régie.

[91] La Régie, pour les motifs invoqués par le Distributeur, accueille la demande de traitement confidentiel des informations caviardées présentées à la pièce B-0015.

[92] **Pour ces motifs**,

La Régie de l'énergie :

ACCORDE le statut d'intervenant aux personnes intéressées suivantes : l'ACIG, la FCEI, le GRAME, le ROEÉ, SÉ/AQLPA, TCE, l'UC et l'UMQ;

SUSPEND l'application de la FAA jusqu'au 1er octobre 2015;

MAINTIENT le taux de rendement sur l'avoir de l'actionnaire fixé en 2012 et maintenu en 2013 et en 2014, soit 8,90 %;

---

[12] Pièce B-0013.

ACCUEILLE la demande de Gaz Métro de traiter de façon confidentielle :

- la section 7 de la pièce B-0006;
- les informations caviardées contenues à la pièce B-0015;

INTERDIT la divulgation, la publication et la diffusion des pièces mentionnées ci-dessus et des renseignements qu'elles contiennent;

CONVOQUE une rencontre préparatoire le **30 mai 2014** à compter de **9 h**;

FIXE l'échéancier pour le traitement du SPEDE dans le cadre de la phase 1, tel qu'établi à la section 3.3 de la présente décision;

DEMANDE à Gaz Métro de se conformer à l'ensemble des décisions de la présente décision.

Gilles Boulianne
Régisseur

Louise Rozon
Régisseur

Pierre Méthé
Régisseur

Représentants :

Association des consommateurs industriels de gaz (ACIG) représentée par Me Guy Sarault;

Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI) représentée par Me André Turmel;

Groupe de recherche appliquée en macroécologie (GRAME) représenté par Me Geneviève Paquet;

Regroupement des organismes environnementaux en énergie (ROEÉ) représenté par Me Pascale Boucher Meunier;

Société en commandite Gaz Métro représentée par Me Vincent Regnault;

Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (SÉ/AQLPA) représenté par Me Dominique Neuman;

TransCanada Energy Ltd. (TCE) représentée par Me Pierre D. Grenier;

Union des consommateurs (UC) représentée par Me Hélène Sicard;

Union des municipalités du Québec (UMQ) représentée par Me Marc-André LeChasseur.

Nova Scotia

Nova Scotia Utility and Review Board: Settlement Agreements approved with adjustments for pension costs and executive compensation. Three FAM related disallowances totaling $6,503,000. See Summary of Findings starting at paragraph 460.
December 21, 2012

DECISION **2012 NSUARB 227**
M04972

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for Approval of Certain Revisions to its Rates, Charges and Regulations, including the review of the Fuel Adjustment Mechanism Audit

BEFORE:
Peter W. Gurnham, Q.C., Chair
Roland A. Deveau, Q.C., Vice-Chair
Kulvinder S. Dhillon, P.Eng., Member

APPLICANT:
NOVA SCOTIA POWER INCORPORATED
Terry Dalgleish, Q.C.
John J. (Jack) Marshall, Q.C.
René Gallant, LL.B.
Nicole Godbout, LL.B.

INTERVENORS:

AFFORDABLE ENERGY COALITION
Claire McNeil, LL.B.

ALTON NATURAL GAS STORAGE LP
Alan V. Parish, Q.C.

AVON GROUP
Nancy G. Rubin, LL.B.
Maggie A. Stewart, LL.B.

CONSUMER ADVOCATE
John P. Merrick, Q.C.
William L. Mahody, LL.B.

SMALL BUSINESS ADVOCATE
E.A. Nelson Blackburn, Q.C.
Paul B. Miller, LL.B.

HALIFAX REGIONAL MUNICIPALITY
Martin C. Ward, Q.C.
Angus Doyle
Julian Boyle

LIBERAL CAUCUS OFFICE
Stephen McNeil, M.L.A.
Andrew Younger, M.L.A.
Shawn Lawlor

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
David MacDougall, LL.B.
Albert Dominie
Donald Regan

PROGRESSIVE CONSERVATIVE CAUCUS OFFICE
Jamie Baillie, M.L.A.
Chuck Porter, M.L.A.
Jennifer Edge

PROVINCE OF NOVA SCOTIA (Departments of Energy and Environment)
Stephen T. McGrath, LL.B.

BOARD COUNSEL: S. Bruce Outhouse, Q.C.
Richard J. Melanson, LL.B.

LIST OF PARTICIPANTS: Appendix “A”

HEARING DATE(S): September 13-14, 18-20, October 29-31 and November 1, 2 and 9, 2012

UNDERTAKINGS: November 19, 2012

FINAL SUBMISSIONS: November 30, 2012

DECISION DATE: **December 21, 2012**

DECISION: **Settlement Agreements approved with adjustments for pension costs and executive compensation. Three FAM related disallowances totaling $6,503,000. See Summary of Findings starting at paragraph 460.**

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1.0 INTRODUCTION

[1] This Decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the “Board”) on September 13-14, 18-20, October 29-31, and November 1, 2 and 9, 2012, in the matter of an application by Nova Scotia Power Incorporated (“NSPI”, the “Company”, the “Utility”), dated May 8, 2012, for approval of revisions to its Rates, Charges and Regulations (the “Application” or “GRA”).

[2] Consistent with the Plan of Administration (“POA”) for NSPI's fuel adjustment mechanism (“FAM”), Liberty Consulting Group (“Liberty”) was engaged to do a comprehensive audit with respect to the FAM for the period covering 2010 and 2011 (“FAM Audit”). The POA provides that an audit of the FAM will be done every second year. Liberty filed its FAM Audit with the Board on July 10, 2012. The Board directed that its consideration of the FAM Audit would be consolidated into the hearing of NSPI's general rate application. This Decision also includes the Board's findings relative to the FAM Audit.

[3] The NSPI Application seeks the Board's approval of a Rate Stabilization Plan (“RSP”). The proposed RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposes the remaining revenue requirement be deferred for future recovery commencing in 2015. The various elements of the proposed RSP are explained in further detail later in this Decision.

[4] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows:

> **Approval of schedule of rates and charges of utility**
> **64 (1)** No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.
>
> **(2)** The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act.
>
> **Notice of hearing of application for rate changes**
> **86** Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board.

[5] A total of 15 formal Intervenors responded to the application of NSPI. A number of these parties were represented at the hearing by counsel. The Small Business Advocate ("SBA"); the Consumer Advocate ("CA"); the Affordable Energy Coalition ("AEC"); Alton Natural Gas Storage LP ("Alton"); Avon Group ("Avon"), whose counsel represented 13 Intervenors; Halifax Regional Municipality ("HRM"); the Liberal Caucus Office; the Progressive Conservative Caucus Office; the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); and the Nova Scotia Departments of Energy and Environment (the "Province") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's Application.

2.0 WRITTEN AND ORAL SUBMISSION FROM THE PUBLIC

[6] In the advertised Notice of Public Hearing, the public was advised that they could file submissions with the Board outlining their views regarding NSPI's Application. In response to this notification, the Board received 64 written submissions from the public and 13 individuals made presentations at the evening session on September 18, 2012.

[7] Most of the written submissions noted impacts that another rate increase would have on customers, especially on low and fixed-income customers. Some of the concerns noted were: the number of recent rate increases; executive compensation levels; rate of return and company earnings; the need for renewable energy; and employee bonuses.

[8] During the evening session, some of the same concerns were raised. Presentations were made by 10 individuals and by a representative from the Canadian Federation of Independent Business ("CFIB"), by the M.L.A. for Pictou West, and the President of the Halifax-Dartmouth and District Labour Council.

[9] The Honourable Charlie Parker, M.L.A. for Pictou West and Minister of Energy, stated that his government has heard the concerns of Nova Scotians, caused by higher electricity rates, and planned to introduce legislative amendments in the fall of 2012 to deal with executive salaries and bonuses, reducing the number of rate hearings, and dealing with the performance of NSPI in general.

[10] Leanne Hachey, representing the CFIB and 5,200 small and medium size businesses in Nova Scotia, noted that her membership cannot absorb any further increases and also cannot pass these on to its customers. She stated NSPI should find

efficiencies within its organization to pay for increased operating costs. She requested that the demand meter threshold be raised to allow additional small businesses to migrate out of this rate class.

[11] Kyle Buott, representing the Halifax-Dartmouth and District Labour Council and 25,000 union workers, stated that within the last four months his delegates have voted twice, unanimously, against the rate increase. He made three points: objecting to the process followed in the rate hearing via settlement agreement; the rate hike proposed does not reflect the cost of electricity but profit for the company; and the Board should get more input from ratepayers who live outside the Halifax area.

[12] Archie Stewart collected an electronic petition which he filed with the Board before the evening session. He noted that he was speaking on behalf of 31,334 Nova Scotia families and the Board should deny the proposed rate increase, including the Settlement Agreement.

[13] Gene McManus stated that the NSPI pension plan is being run by its employees who are also the beneficiaries of the plan. He suggested that the NSPI pension plan should be run by an independent third party.

[14] The Board considered all the comments made in the written submissions and during the evening session in making its decision on the Application. The Board is mindful of its responsibility to protect the public interest and does give due weight to the comments received from the public. The Board has to balance this with the needs of the Utility to provide a safe and reliable service at a minimum cost. No one likes rate increases; however, the Utility’s costs are increasing, similar to other businesses, and rates need to be adjusted in order to recover these cost increases.

3.0 BACKGROUND

[15] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. The *Act* requires the Board to use a cost for service method for setting rates. The Board must allow NSPI to recover its prudent and proper costs of providing each type of service and a return on its rate base or capital assets.

[16] In legislation, the word "shall" is mandatory. Therefore, the Board is required to determine NSPI's costs and assets in providing each type of service. Section 42(1) provides:

> **42(1)** The Board <u>shall fix and determine a separate rate base</u> for each type or kind of service furnished, rendered or supplied to the public by a public utility. [Emphasis added]

[17] The Board must provide a rate of return to NSPI each year. Section 45(1) reads:

> **45(1)** <u>Every public utility shall be entitled to earn annually such return</u> as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly. [Emphasis added]

[18] This return must be in addition to NSPI's prudent and proper operating expenses of providing the services. Section 45(2) states:

> **45(2)** <u>Such return shall be in addition to such expenses</u> as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[19] NSPI, like all other business, experiences cost increases in virtually every expense it incurs to produce electricity for the people of Nova Scotia. The *Act* requires the Board to ensure these prudent and proper costs are recovered in NSPI's rates.

[20] A fair return on rate base is important for the sustainability of the service. A low return on rate base may cause people to not invest in the Utility. It may also lead to a poor bond rating, which may cause financial institutions to increase the rate of interest on monies NSPI needs to borrow to provide the service. This may result in NSPI's rates increasing solely to cover the additional costs of borrowing money, without even addressing the increases in the operating expenses.

[21] In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental ratemaking principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
>
> 2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

[Decision, March 31, 2005, p. 14]

[22] The Board continues to make its decisions in accordance with the *Act,* and the principles noted above.

[23] After seeking an adjournment at the commencement of the public hearing on September 13, 2012, NSPI notified the Board on September 14th that it had reached a Settlement Agreement (the “GRA Agreement”) on many of the outstanding issues in the NSPI Application. The GRA Agreement has the support of the CA, the SBA and Avon. The Board adjourned the hearing to provide an opportunity for all other parties to review the GRA Agreement. The hearing reconvened on September 18, 2012, at which point NSPI witnesses explained the terms of the GRA Agreement and testified with respect to the outstanding issues. However, the GRA Agreement was only executed as of October 15, 2012 and was not filed with the Board until November 2, 2012.

4.0 SETTLEMENT AGREEMENT

4.1 The Board's approach to settlement agreements

[24] In its previous Decisions, the Board has set out the principles it applies in its consideration of settlement agreements. Those principles bear repeating. In its Decision dated November 5, 2008, the Board outlined its general approach to settlement agreements submitted to it for approval:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.
>
> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.
>
> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [Decision, 2008 NSUARB 140]

4.2 The GRA Agreement in the present case

[25] The GRA Agreement addresses many outstanding issues between NSPI and most of its customers. However, several issues were not resolved, including the FAM audit, pension costs, LED street lighting and the underground storage of natural gas.

[26] Notably, the GRA Agreement adopts the two year RSP proposed by NSPI.

[27] The GRA Agreement reads as follows:

2013-2014 General Rate Application
Settlement Agreement
October 15, 2012

Whereas NS Power filed a General Rate Application for 2013 and 2014 on May 8, 2012;

And Whereas the Board Hearing Schedule provided for Information Requests to NS Power and Responses, Testimony from Board and Intervenor consultants with corresponding Information Requests and Responses, Reply Evidence from NS Power, and Opening Statements from parties and consultants;

And Whereas the Parties to this Settlement Agreement, which include NS Power, Avon Group, the Consumer Advocate and the Small Business Advocate, desire to resolve the General Rate Application by way of this Agreement;

The Parties agree:

1. The 2013-2014 Rate Stabilization Plan is accepted and adopted, as filed, subject to the changes contained in this document. This includes a three percent overall rate increase for each of 2013 and 2014, plus a deferral of forecasted revenue requirement that is not otherwise recovered by the two rate adjustments, using the August 31 update. The deferral recovery would begin in 2015 in an amount that is equivalent to the s.21 amount in rates.
2. NSPI will identify, at its own discretion, and manage the business in order to achieve a $27.5 million reduction in the deferral balance over the two year period. None of the reductions will be achieved through fuel forecast reductions. This will resolve all issues relating to revenue requirement, subject to items 3 and 6 (below).
3. ROE will be set at 9.0% for rate making purposes, with a 0.25 band. Therefore the ROE range will be from 8.75% to 9.25%.
4. The result of the changes in items 2 and 3 will be that the fixed cost deferral amount will not exceed $84.8 million, which includes the financial effect of the lower ROE and the resulting lower interest costs relating to financing a lower deferral amount. For the purpose of calculating interest, the deferral will be reduced by $13.75 million in each year of 2013 and 2014.
5. S.21 amounts will be accepted as filed. The S.21 AAA Mechanism will continue as part of the Rate Stabilization Plan, as proposed in the Application.
6. Fuel - Base Cost of Fuel will be set as per the August 31 update. Liberty's proposals regarding natural gas will be determined by the outcome of the FAM Audit process. If the UARB accepts Liberty's views in that process, the Base Cost of Fuel and therefore the revenue requirement (and deferral) will be reduced to the extent the audit outcome affects the fuel forecast for 2013 and 2014. Liberty's suggested

reductions relating to imports are not adopted but the suggestion will be referred to the Small Working Group for study and possible changes to the forecasting methodology for future implementation.

7. The FAM Audit issues will continue to be litigated in accordance with the Board schedule for the hearing that commences October 29. The financial result of the hearing, if any, will be implemented beginning January 1, 2013 separate and apart from the Rate Stabilization Plan.
8. NS Power's proposal to update OATT pricing, with the exception of its request for an ECRM (which has already been determined by the Board), will be accepted as filed. The matter of the MEUNSC responsibility for deferrals, in the event of departure from the system, may be determined in a future application before the UARB. Parties are free to take any position on OATT related matters in future proceedings.
9. The SBA request for an adjustment to the R/C ratios for small business classes and narrowing of the band (0.95 to 1.05) will be referred to the Cost of Service Study proceeding.
10. Adjustments will be made to the Large Industrial Interruptible class to ensure this class of customers receives the same 3% adjustments as experienced by other customer classes, similar to the approach taken in the 2009 GRA Settlement Agreement.
11. The Interruptible Rider to the Large Industrial Tariff will be revised as provided in the attached September 28, 2012 letter from NS Power to the UARB.
12. During the hearing parties to the agreement will refrain from seeking any changes to the agreement or additional reductions to revenue requirement. This settlement is without prejudice to any position that parties may take on these issues in future proceedings.

[Exhibit N-201]

[28] The GRA Agreement has an attachment related to the Interruptible Rider.

[29] In his Opening Statement at the hearing, Rob Bennett, NSPI's CEO, stated that the GRA Agreement, which incorporates the RSP, provides the Utility and its customers with the time to adjust to significant changes in NSPI's load and costs:

> The Rate Stabilization Plan provides the best approach to the complex challenges we face, together, with the Board and our customers. Input costs are rising, new renewable energy is being added to the system, and load is dropping – quickly and dramatically. Any of these challenges would create upward pressure on electricity rates; and we are experiencing them all at once.
>
> Mr. Chairman, we will continue to work on behalf of our customers to meet the challenges that will arise during this Rate Stabilization period. This agreement gives everyone time to adjust to the lost pulp and paper load, but does not solve that problem. In 2015 we will have to incorporate the lost load into general rates, including the final payment of the 2012 Fixed Cost Deferral, and any other changes in our cost structure that are forecast for that test year.

[NSPI Opening Statement, Exhibit N-123, p. 1]

[30] In NSPI's Closing Submission, counsel for the Company submitted:

> The Settlement Agreement reflects agreement by the parties to accept and adopt the Rate Stabilization Plan, as filed, subject to specific changes provided in the Settlement Agreement. That includes a net 3 percent overall increase in each of 2013 and 2014, with a deferral of forecast revenue requirement, based on the Company's August 31 Load and Fuel Update filing, not otherwise recovered by the 3 percent rate increases in each of the next two years. …
> Key to the settlement is the fact that it reflects a commitment by the Company to be responsible for $27.5 million of the original deferral of revenue requirement. The parties agreed that no deferral reductions will be made through fuel adjustments, but that the Company will identify at its own discretion, and manage the business in a manner that will achieve the $27.5 million deferral reduction. This commitment represents a significant challenge to the Company over the next two years, and will provide a substantial long term benefit to customers.
>
> [NSPI Closing Submission, November 23, 2012, p. 12]

[31] NSPI counsel also noted the benefits to customers of reducing the return on equity:

> …This includes the agreed reduction in NS Power's return on equity (ROE) for rate setting purposes from 9.2 percent to 9.0 percent along with a change to the earnings band to +/- 0.25 percent, making the earnings band 8.75 to 9.25 percent. This change also contributed to reductions to the Company's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the $27.5 million.
>
> [NSPI Closing Submission, November 23, 2012, p. 15]

[32] The CA supports the approval of the GRA Agreement. In his view, after analyzing all of the Pre-filed Evidence, the result was not likely to be better by pursuing a contested hearing:

> It is to be noted that the settlement agreement calls for a reduction in NSPI's requested revenue requirement. The Consumer Advocate and other signatories to the settlement agreement analyzed all of the pre-filed evidence and, with the benefit of assessments by expert consultants, concluded that rate increases proposed in the settlement agreement are reasonable and justified. Furthermore, it is the view of the Consumer Advocate and the settling intervenors that the agreed-upon reduction in revenue requirement was not likely to be improved through additional litigation. One important aspect of the proposed settlement agreement, as noted by Commissioner Dhillon in his questioning of the NSPI panel, is that the proposed increases are 3% class revenue increases. ...
>
> In addition to the rate increases in 2013 and 2014, the settlement agreement also provides for deferred collection of a significant portion of NSPI's revenue requirement. Although the Consumer Advocate continues to be leery of deferral mechanisms, there was an identified and important correlation between the deferral proposed in this settlement agreement and the extinguishment of the section 21 deferral which is presently in rates. The net effect is that the deferral contemplated in this settlement will

be collected once the section 21 deferral has been paid off and therefore represents an opportunity to smooth or even out rate increases experienced by customers.

[CA Closing Submissions, November 23, 2012, p. 4]

[33] The SBA also submitted that, after a review of the evidence, the GRA Agreement represented a reasonable resolution of most issues in the Application:

The Settlement Agreement signed by the Consumer Advocate, the Avon Group, Nova Scotia Power and the SBA, was the result of much consultation and discussion and was not taken lightly. Accordingly, after assessing the Application and merits of achieving greater results by litigating before the Board, and after reviewing the experts' reports, asking numerous questions, followed by numerous hours of negotiations, the SBA was satisfied the Settlement Agreement dated October 15, 2012, represents a reasonable resolve with respect to many items referred to in the General Rate Application when compared with the uncertainty of successful litigation.

[SBA Closing Argument, November 23, 2012, pp. 1-2]

[34] Counsel for Avon noted that the GRA Agreement represents a resolution of issues between all customer classes, excluding municipal customers:

In each case, Intervenors must carefully evaluate the evidence to judge the costs and risks of challenging the Utility’s application against the advantage of a negotiated settlement. With the exception of the Municipal customers, the Settlement Agreement has the support of representatives of all customer classes who participated in the process - the Avon Group (Large Industrial), the Consumer Advocate (Residential) and the Small Business Advocate (Small General, General, Small Industrial), as well as NSPI. It is a reflection of the good faith efforts of the participants that a settlement was achieved in a very compressed time frame. There were compromises among all signatories but only time will tell whether it is a “good” deal for all concerned.

[Avon Final Submissions, November 23, 2012, para. 5]

[35] Counsel for Avon also highlighted a number of the elements of the GRA Agreement which will benefit customers:

The Agreement results in an across-the-board 3% increase in each of 2013 and 2014 plus a deferral of forecasted revenue requirement not to exceed $84.8 million (clause 4). At the end of the two years, the deferral is planned to be recovered in an amount equal to the Section 21 payment that is already embedded in rates (clause 1). As part of the Settlement Agreement, NSPI has agreed to a $27.5 million reduction in the deferral balance spread equally over the two year period (clause 2). In addition, the ROE will be set at 9.0% plus or minus 25 basis points, i.e. 8.75% - 9.25% (clause 3). *The Settlement Agreement continues the previously agreed-upon cap on ROE through the s.21 AAA mechanism with any excess applied against the deferral (clause 5). This is an element of*

> *the negotiated Agreement that would not have been achieved through a contested proceeding*. [emphasis added]
>
> [Avon Final Submissions, November 23, 2012, para. 7]

[36] Moreover, Avon Counsel noted that the GRA Agreement contains two clauses which are particularly significant for large industrial interruptible customers, including a clause which provides that this class receives the same 3% increase in rates as other classes, together with revisions to the Interruptible Tariff Rider which balances the risk between NSPI and its interruptible customers respecting notices to reduce load.

[37] The Province does not oppose the settlement process and suggests that the proposed GRA Agreement is worthy of serious consideration by the Board:

> Although it is not a signatory to the Settlement Agreements filed in this case, the Department of Energy does not oppose the settlement process, as outlined and applied by the Board in its past decisions. In this case, the Settlement Agreement has been executed by representatives of almost all of NSPI's classes of customers and therefore we would respectfully suggest warrants serious consideration.
>
> [Province Closing Submissions, November 23, 2012, para. 12]

[38] The Province also noted that the GRA Agreement benefits customers. Counsel pointed out that the proposed $27.5 million non-fuel cost reduction in NSPI's deferral is not to be achieved through reductions in forecasted fuel costs. After noting the benefits of the RSP, as described immediately below in this Decision, counsel for the Province added:

> …At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan. These revenue requirement reductions include a lowering of NSPI's return on equity, which the Department of Energy applauds.
>
> [Province Closing Submissions, November 23, 2012, para. 13]

4.3 Rate Stabilization Plan

[39] A major component of the NSPI Application is the RSP. Subject to the changes noted in the GRA Agreement, the 2013-2014 RSP is adopted as part of the GRA Agreement.

[40] NSPI has forecast the revenue requirement for each of the next two years instead of the traditional single year approach. The elements of the RSP are set out in the NSPI Application:

> The Rate Stabilization Plan, which provides for recovery of the 2013 and 2014 revenue requirements is as follows:
>
> i. For each customer class, an average three percent increase on January 1, 2013 and an average three percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,
>
> ii. Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,
>
> iii. FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 Balance Adjustment, will be deferred, to be incorporated into customer rates in 2015, and the FAM incentive will remain suspended until the end of 2014.
>
> [NSPI Application, Exhibit N-3(i), pp. 2-3]

[41] The 2012 Fixed Cost Recovery Deferral, which accommodated uncertainty about the province's pulp and paper load, was approved by the Board as part of NSPI's 2012 general rate application. In that proceeding, the settlement agreement approved by the Board initiated the Fixed Cost Recovery Deferral. The 2012 Fixed Cost Recovery Deferral was accepted by the same parties to the present GRA Agreement.

[42] NSPI's Application provided that the RSP deferral would be $130.7 million [Undertaking U-6]. Under the proposed GRA Agreement, the deferral will not exceed

$47.1 million at December 31, 2013 and will not exceed $84.8 million at December 31, 2014.

[43] NSPI's Application states that the amount of the deferral will be calculated separately for each class of customer, such that the "across-the-board 3-percent increase" will result in deferrals that accurately reflect the specific cost of serving each class of customer.

[44] Under the proposed RSP, the annual three percent adjustment will incorporate forecast decreases connected to the phase-out of the 2010 FAM Deferral. Also, the FAM will continue to operate, but additional AA and BA changes in 2013 and 2014 fuel costs will be deferred within the FAM until the RSP ends.

[45] NSPI submits that recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which NSPI has been collecting from ratepayers over eight years ending in March 2015:

> In the current situation, NS Power believes a modest, short-term deferral of increased expenses is an appropriate way to stabilize rates for customers over the next two years. We propose to begin recovering the deferred costs in 2015, just as the Section 21 Tax Deferral expires. By timing the deferral this way, and if the deferred amount is less than $110 million, [NSPI] will be able to recover it in full over eight years, with no change in rates. In effect, as soon as [NSPI] finish[es] collecting the Section 21 Tax Deferral, [NSPI] will replace it with an eight-year recovery of the Fixed Cost Recovery deferral.
>
> [NSPI Application, Exhibit N-2, p. 28]

[46] Counsel for Avon also submits that the RSP benefits the members of the Avon Group by providing a "predictable measure of stability" over the next two years:

> From the perspective of the Avon Group, the Settlement Agreement results in a predictable measure of stability for the next two years and avoids the time, expense and uncertainty of a contested rate case. ... Members of the Avon Group shoulder their own regulatory costs, so the ability to predictably budget for energy costs over the next two years without the risks and costs of contested proceedings was attractive.
>
> [Avon Final Submissions, November 23, 2012, para. 6]

[47] Similar reasoning was expressed by the SBA:

> The SBA is further of the belief the two (2) year rate stabilization plan which calls for an overall average 3 percent rate increase for customer classes effective January 1, 2013, and further increase of 3 percent effective January 1, 2014, will help reduce litigation fatigue, and give stability for small business with respect to rate stabilizing increases for the next two (2) years. …
>
> [SBA Closing Argument, November 23, 2012, p. 2]

[48] Counsel for the Province refers to the RSP as a positive aspect of the GRA Agreement:

> From the Department of Energy's perspective, there are many positive aspects to the proposed Settlement Agreement. The acceptance and adoption of the 2013-2014 Rate Stabilization Plan, while not avoiding rate increases, will dampen the impact of those increases. At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan...
>
> [Province Closing Submissions, November 23, 2012, para. 13]

4.4 Findings

[49] The GRA Agreement represents a comprehensive resolution of many contested issues between NSPI and the Intervenors representing most of its customers. It addresses a number of significant components raised in the NSPI Application.

[50] The Board is mindful that the GRA Agreement represents a negotiated settlement by most represented customer classes, with the exception of the municipalities, whose involvement was directed to other issues in the GRA proceeding as described later in this Decision.

[51] In the Board's view, an important component which will benefit customers is the RSP, which limits across-the-board increases of 3% in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015 when the Section 21 Tax Deferral will be fully retired. The net effect of the RSP is that the

revenue requirement deferral will only be collected after the Section 21 Tax Deferral has been retired. The deferral will be collected over an 8 year period beginning in 2015.

[52] Without the RSP, customers would have faced much larger rate increases, particularly in 2013. As noted by the CA, this will "smooth or even out rate increases experienced by customers". Counsel for Avon agreed that this will provide ratepayers with a "predictable measure of stability" over the next two years.

[53] In its original Application, NSPI had proposed that the deferral would be about $124.4 million (Exhibit N-3(i), Appendix P, Attachment 2), later amended to $130.7 million in Undertaking U-6. The GRA Agreement provides for a $27.5 million non-fuel cost reduction in NSPl's deferral. Accordingly, the deferral will not exceed $84.8 million at December 31, 2014, which includes additional adjustments made by NSPI in the hearing.

[54] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a revised earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the $27.5 million non-fuel cost reduction.

[55] Finally, as noted by counsel for Avon, the GRA Agreement continues the previously agreed-upon cap on return on equity through the s.21 AAA mechanism, with any excess applied against the deferral. This would not have been achieved through a contested proceeding.

[56] Taking into account the evidence and the submissions, the Board is satisfied that the GRA Agreement is in the public interest and that it should be

approved. In the view of the Board, the GRA Agreement provides for rates that are just and reasonable.

[57] The Board approves the NSPI Application, except as amended by the terms of the GRA Agreement or as otherwise varied in this Decision. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014. The Board notes that it also approves the requested changes to Accounting Policy 5900 – Tax and the proposed updated OATT pricing.

[58] The Board directs NSPI to outline in 2013 and 2014 where it has applied the $27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

5.0 PENSION COSTS

5.1 Regular Pension Plans

[59] In its Decision of November 28, 2011 (2011 NSUARB 184), the Board indicated that it would investigate the issue of pension costs in this proceeding.

[60] Peter Hayes, of Eckler Ltd., was retained by Board Counsel to examine NSPI's pension costs.

[61] Mr. Hayes noted that Company contributions to the NSPI pension plan have grown to be several multiples of what employees contribute. He goes on to say:

> In managing its pension costs, I believe NSPI faces serious impediments. These impediments are largely self-imposed, and to an extent cultural, but until they are removed it will be difficult for NSPI to gain control of its pension costs. In the meantime, these costs will continue to grow at a high level.
>
> [Exhibit N-59, p. 2]

[62] Among the impediments Mr. Hayes noted were:

a) A management focus on the performance of plan assets at the exclusion of more holistic plan management;

b) A lack of willingness to engage unionized employees in meaningful discussion around the reform of the pension;

c) Certain concerns raised in confidence about the governance structure.

[63] It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs. The Company witnesses cited constraints of the collective agreement with NSPI's Union and the recent influence on pension expense of the financial market losses as reasons for not doing so earlier.

[64] Among other recommendations Mr. Hayes suggested the test year revenue requirement should be set at a level which reflects higher employee contribution rates.

[65] NSPI was, in fact, engaged in collective agreement negotiations during the course of the hearing.

[66] NSPI confirmed to the Board that it had reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012. In a letter dated November 16, 2012, NSPI outlined changes to the pension plan.

Employee contributions:

- Employee contributions to the DB Plan will change from the current level of 5.4% of pensionable earnings up to the Year's Maximum Pensionable Earnings ("YMPE") plus 7.0% of pensionable earnings in excess of the YMPE as follows:
  - Effective January 1, 2013, members will contribute 6.15% of pensionable earnings up to the YMPE and 8.00% of pensionable earnings in excess of the YMPE;
  - Effective January 1, 2014, members will contribute 6.90% of pensionable earnings up to the YMPE and 8.75% of pensionable earnings in excess of the YMPE; and

- o Effective January 1, 2015, members will contribute 7.40% of pensionable earnings up to the YMPE and 9.50% of pensionable earnings in excess of the YMPE.

Final Average Earnings definition:

- Effective January 1, 2013, the Final Average Earnings definition will change from the “best average four years” to the “best average five years”.

[67] The Board sees these changes as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[68] NSPI, in its Final Submission, submitted that the changes that had been recently negotiated to the pension plan should be considered as part and parcel of NSPI’s effort to reduce expenses by the $27.5 million agreed to in the GRA Agreement. Clearly contract negotiations were well advanced when NSPI agreed to the GRA Agreement and the Board accepts that there does not need to be a further adjustment to the revenue requirement to reflect these changes that were achieved through negotiation.

[69] In future years these costs savings will be embedded in the revenue requirement asked of customers.

[70] The Board, however, expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

5.2 Supplemental Executive Retirement Plan

[71] Two issues arose in the course of the hearing with respect to NSPI’s Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately $150,000 per year.

[72] Such plans are not unusual; indeed the Province of Nova Scotia provides a SERP plan for certain of its employees who earn above the pensionable payout limits permitted by the Canada Revenue Agency.

[73] The first issue is that NSPI secures this pension by purchasing a letter of credit. The letter of credit is, in part, to secure the pension plan in the event NSPI was to discontinue operations and therefore be unable to fund this obligation.

[74] The other issue is that the eligible employees of NSPI do not make any contribution towards these additional benefits. In other words, the Company, using funds paid by ratepayers, is funding 100% of this pension plan.

[75] Contrast that with the Province of Nova Scotia where employees eligible for the Province's SERP fund 50% of the contributions to the SERP with the employer paying the other 50%.

[76] With respect to the letter of credit, it appears to the Board that the letter of credit places the senior executives at NSPI in a more secure position than any other employee in the Company with respect to their pension entitlement. The NSPI employee pension plan is not secured by a letter of credit. NSPI is a regulated monopoly in the Province of Nova Scotia. The chance of NSPI going out of business is extremely remote.

[77] In the Board's view, payment for that portion of the letter of credit that secures the SERP is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[78] With respect to the SERP, the Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[79] NSPI is free to continue to provide that benefit. However, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. In the test years, the Board, based on projected benefit payments identified in Exhibit N-3(v), believes the amount to be disallowed is $2.05 million in 2013 and $2.2 million in 2014.

[80] NSPI can discuss with Board Counsel the most tax efficient way of implementing this direction from the Board.

[81] These deductions and the letter of credit deduction are in addition to the $27.5 million provided for in the GRA Agreement.

6.0 EXECUTIVE COMPENSATION

[82] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[83] By regulation, the remuneration amounts are governed by amounts contained in the Province of Nova Scotia's Senior Officials Pay Plan.

[84] The Board assumes that pension payments on behalf of executives would reflect only amounts of salary permitted by the *Act*.

[85] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation. This reduction is in addition to the $27.5 million agreed to as part of the GRA Agreement.

7.0 LED STREETLIGHTING

7.1 Evidence

[86] The *Energy-efficient Appliance Regulations* were amended by the Province on September 10, 2012, requiring all NSPI owned streetlights to be of the LED type after December 31, 2019. NSPI proposed to implement this change over a number of years as a part of its Annual Capital Expenditure plan. The cost of this changeover is the responsibility of the municipalities based on the number of streetlights in each jurisdiction. The Union of Nova Scotia Municipalities ("UNSM"), which represents all municipalities in the Province, is objecting to the cost which NSPI plans to pass on to the municipalities.

[87] NSPI proposes to defer a decision on the LED streetlight stranded cost to a later date, stating it plans to file a capital work order with the Board:

> …As explained in Appendix I of this Evidence, NS Power proposes to treat the non depreciated net book value of these streetlight fixtures as a stranded cost that constitutes a regulatory asset. We propose to defer the amortization of this asset until the Board approves the recovery of this cost through the implementation of appropriate LED streetlight conversion charges. This will happen in concert with the Capital Work Order Application for the LED streetlight conversion program. We propose to recover the capital carrying costs associated with this regulatory asset from the full service LED streetlight customers.
>
> [Exhibit N-2, p. 130]

[88] In Appendix I of its Application, NSPI provided a *Cost of Service and Pricing Study for Unmetered Services* which included streetlights and other services such as traffic lights, ornamental streetlights, crosswalk lights, etc. The report provided

details of NSPI's proposed rate making methodology and calculations of streetlight rates.

[89] The UNSM, in its Pre-filed Evidence, noted that municipalities are struggling to provide normal services and an additional $100 million for LED streetlights conversion is a significant burden. The UNSM has concerns with the cost of stranded assets and time allowed for conversion of these streetlights. The UNSM's understanding is that as a part of the 2012 GRA Settlement Agreement, the net book value of stranded streetlights is $12 million and is supposed to decline over time as only LED streetlights are installed/replaced after 2011. The UNSM also noted inconsistencies when NSPI deals with the municipalities in billing and stranded asset fees for streetlights.

[90] HRM, in its Pre-filed Evidence, noted its concerns with NSPI overcharging municipalities. HRM noted its concern with respect to the total charge for streetlights. It stated that NSPI's maintenance and capital charges do not align with the actual cost for these services. HRM also disagreed with NSPI that the energy component is being subsidized by the other components of the total streetlight charge.

[91] HRM further noted that NSPI's evidence over time has been inconsistent and difficult to follow:

> On the rate setting front, the LED street light conversion has exposed some of the long standing issues with respect to the lack of accounting detail in the unmetered Cost of Service. It appears NSPI has made it extremely complex to use cost of service accounting principles for a simple street light because it has not tracked the age or quantity of lights properly. The process has become very onerous, non-transparent and inefficient. Clearly NSPI has had significant challenges in determining unmetered rates over a protracted period.
>
> [Exhibit N-54, p. 7]

[92] HRM agreed with UNSM that the issues in dispute are the stranded cost and phase-in time for LED streetlights conversion. HRM noted that its understanding of the 2012 GRA settlement is different from NSPI's understanding.

[93] Albert Dominie, a consultant for HRM, noted problems with the current pool of assets in the streetlights category. This includes types, quantity and how the stranded costs are allocated between streetlights and other assets in the pool.

[94] Mr. Dominie questioned the use of the Bank of Canada Inflation Calculator to determine the net book value of retired streetlights. He recommended the use of the Handy-Whitman Index of Public Utility Construction Costs which is also used by the Federal Energy Regulatory Commission. He explained that the Bank of Canada Inflation Calculator provides a higher actual installed cost than the Handy-Whitman Index.

[95] Mr. Dominie does not agree with NSPI's method to calculate the stranded cost of current streetlights. He proposed a true up and reconciliation process during the LED streetlights conversion by carrying out a physical survey of each streetlight to determine actual life based on the date stamp.

[96] NSPI, in its Reply Evidence, noted that the net book value of streetlights has been approved by the Board in past applications, including the depreciation hearings and it is entitled to recover these costs from its customers. It disagrees with the use of the Handy-Whitman index method and field survey proposal by Mr. Dominie.

[97] NSPI outlined the process it has followed to calculate the stranded cost of streetlights:

> NS Power's approach with regards to calculating a stranded asset pool is simple and has not changed. That is, the net book value of the assets is the unrecovered investment. To determine per unit value, NS Power has proposed dividing the asset pool by the number

> of lights billed in the Customer Information System. NS Power has repeatedly stated through the 2013 & 2014 GRA application that the rates should be set with the capital work order process consistent with the 2012 Settlement Agreement. In an effort to be helpful, NS Power has provided information over the last couple of years. In fact, draft regulations were only issued April 25th, 2012.
>
> [NSPI Reply Evidence, Exhibit N-106, pp. 96-97]

[98] The Board and HRM during the hearing requested clarification on the type of streetlights being replaced after the 2012 GRA Settlement Agreement approved by the Board in the 2012 GRA. That Settlement Agreement required NSPI to install only LED streetlights when replacing the old streetlights. NSPI responded:

> …So we've been continuing on using materials that were already in inventory, not buying -- not in any way, shouldn't be characterized as spending more than we should have. We're just fixing the lights that people call in and say are broken.
>
> [Transcript, September 19, 2012, p. 547]

7.2 Findings

[99] The Board has considered the evidence filed and issues raised by the UNSM, HRM and NSPI. NSPI proposed that the matter of LED streetlights be deferred to a later date when it intends to file a capital work order with the Board. HRM does not have a problem with this approach except the amount of net book value of current streetlights which NSPI plans to use in its work order.

[100] NSPI proposed to use the current net book value of streetlights (estimated at $23 million) based on methods and records it has used in the past including depreciation hearings. However, HRM argued that the net book value NSPI proposes to use is not correct and should be $12 million as noted in the 2012 GRA Settlement Agreement. HRM further stated that this amount is to be confirmed by actual survey of all current streetlights, which will also determine the number and age of streetlights.

HRM also raised the issue of non-streetlight assets being in the streetlight class and whether some of the current net book value belongs to these other assets.

[101] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach, with the exception of the net book value question. The net book value of streetlights has been calculated under the current method for a long time and any change in the net book value now would be unfair to other ratepayers. The current method has been approved in prior depreciation Decisions of the Board. The net book value amount is the responsibility of the streetlight class and any reduction in this amount would shift the responsibility to other customer classes. The Board does not agree with HRM's proposal to change the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[102] The Board denies HRM's request to recalculate the net book value of streetlights.

[103] The second issue raised by HRM is the type of replacement streetlights used by NSPI since the Board's 2012 GRA Decision [2011 NSUARB 184]. It is the Board's understanding of the 2012 Settlement Agreement that NSPI was to use only LED streetlights when replacing the current streetlights. NSPI has stated that it has only used non-LED streetlights which were in its inventory.

[104] In the circumstances, if the non-LED streetlights were already in inventory, the Board finds this to be an acceptable approach. However, NSPI should have clarified the use of inventory with Intervenors during the 2012 GRA settlement discussions.

[105] The Board is not certain, based on the evidence, if NSPI has purchased new non-LED streetlights after the 2012 GRA Board Decision.

[106] The Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

8.0 LOW INCOME RESIDENTIAL CUSTOMERS

8.1 Submissions

[107] At the request of the CA item 15 was added to the Final Issues List, "Matters Related to Low Income Residential Ratepayers".

[108] The Affordable Energy Coalition, the CA and NSPI tabled a Settlement Agreement which the CA described as an agreement which addresses many long-standing issues faced by low income customers. Essentially the Agreement sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers". The text of the Agreement is as follows:

> The following provisions are requested to be included in final Order of the NSUARB in GRA 2013 NSUARB-NSPI-P-893 - Matter M-04972 with the consent of NSPI, the Consumer Advocate, and the Affordable Energy Coalition.
>
> Residential Low Income Issues
>
> 1. NSPI, the Affordable Energy Coalition and the Consumer Advocate, shall seek an adjournment of the hearing on the matters identified in paragraph 4 of this joint proposal in this proceeding, in order to engage in a consultative process with a view to resolving bill payment, credit and collections matters affecting low income residential consumers, and the parties reserve the right to contest any of the evidence filed with the NSUARB in this proceeding, as may be appropriate, at a future hearing.
>
> 2. The consultative process shall be non-binding and without prejudice to either side to request the matters be brought back before the NSUARB to resolve any issue in relation to Board regulations or other matters and the parties agree to the appointment of a facilitator by the NSUARB on an as-needed basis.
>
> 3. The consultative process may solicit input from other social service agencies, non-governmental organizations involved in low income energy issues, as well as other resources and supports, as agreed to by the parties.
>
> 4. The items to be discussed by the parties are:
>
> a. Development of a Low-income Customer Charter;
>
> b. Changes to NSPI policy regarding deposits and payment agreements;

c. Development of joint recommendations, where appropriate, with respect to regulatory reforms, including with regard to deposits, payment agreements, interest charges and other miscellaneous charges, disconnection procedures, and requirements for the residential budget plan as they affect low income residential consumers;

d. Any other matters as agreed to by the parties.

5. The parties shall meet on a regular basis, at a minimum once every two months. The parties shall agree on a timetable, which shall reflect the following:

a. The first meeting shall take place not later than November 1, 2012;

b. The parties shall report back regarding the status of the consultation, with any agreements reached by the parties, and to the extent that agreement is not reached, request a further appearance and hearing before the NSUARB not later than June 30, 2013, and the evidence filed on behalf of the AEC in this proceeding shall form part of the evidence at that hearing;

c. NSPI shall provide a proposal regarding items (b) and (c) to the Affordable Energy Coalition and the Consumer Advocate one week in advance of the first meeting;

d. NSPI shall provide the results of its research with respect to regulatory differences in other jurisdictions to the Affordable Energy Coalition and the Consumer Advocate not later than December 1, 2012.

[Exhibit N-116]

[109] The Board approves the Agreement which will be appended as a Schedule to the Compliance Order and acknowledges, with appreciation, the work of the Affordable Energy Coalition, NSPI and the CA in moving this initiative forward.

[110] The Board receives literally hundreds of letters and emails a year from consumers who are struggling to pay their power bills and at the same time manage the cost of home heating, medication, groceries, etc. There is only so much the regulatory system can do to respond to these concerns but this Settlement Agreement is a welcome development.

9.0 COST OF SERVICE – BIOMASS

[111] NSPI has recently constructed a 60 MW biomass plant at Point Tupper, Nova Scotia. For purposes of rate base NSPI has determined the biomass plant is being added for environmental purposes only and should be classified totally as energy.

With respect to OM&G costs, however, the classification is the same as for all other steam plants, a portion of which is classified to demand, and a portion that is classified as energy.

[112] Mel Whalen, a witness on behalf of Board Counsel, recommended that until a more complete assessment is done as part of the upcoming cost of service review, NSPI should classify the biomass plant on the basis of system load factor, the same as other thermal plants, for the following reasons:

> a) Biomass is a steam plant.
> b) Biomass makes a contribution to capacity.
> c) The biomass plant was justified in part on the grounds that it would provide firm, dispatchable power and alleviate some of the concerns with respect to adding only non-dispatchable renewable resources.
> d) Classifying the biomass as other steam plants are classified is consistent with NSPI's classification of the biomass OM&G as all other steam OM&G is classified.
>
> [Exhibit N-42, p. 10]

[113] NSPI, in its Reply Evidence, says that even though the biomass generation is firm and is dispatchable, it considers the capacity related aspects of this plant to be of secondary importance to that of RES compliance. NSPI says classifying the asset on the basis of system load factor would mean there would be no distinction between this project and ordinary fossil fuel baseload generation.

[114] The Board notes that recent *Regulations* passed by the Province of Nova Scotia require that this plant, as opposed to being dispatchable, is essentially must-run.

[115] The Board agrees with Mr. Whalen that the characteristics of this plant are similar to any other steam plant. It makes a contribution to capacity and provides firm power, meaning that it should be classified on the basis of system load factor and

directs NSPI to do so. This issue may be reviewed in the upcoming cost of service proceeding.

10.0 NATURAL GAS STORAGE

10.1 Evidence

[116] Alton, in its Pre-filed Evidence, stated that the New England and Maritime market currently does not have a natural gas storage facility which can provide security of supply and manage the price of natural gas used by NSPI. The natural gas prices in this region have been volatile and NSPI can benefit from the use of a storage facility given the amount of natural gas used, which Alton estimates to be $110 million annually.

[117] Alton retained Gregory W. Hopper of Black & Veatch who, in his Pre-filed Evidence, provided analysis of the Maritime and New England natural gas market and price behavior. He noted that the lack of a natural gas supply in the region could make natural gas prices rise even higher and also increase volatility.

[118] Alton also retained Jan van Egteren of Anthem Economic Consulting Inc. who, in his Pre-filed Evidence, outlined various hedges used by NSPI to reduce gas price volatility. The hedges currently used by NSPI are financial, physical and geographic hedges. He then calculated the savings NSPI could achieve by using the natural gas storage facility by buying when the prices are low and using when prices are high. He noted that there is a possibility of additional savings in case of a “basis blowout” similar to what happened in December 2010.

[119] Alton proposes to construct a natural gas storage facility off the Halifax lateral to supply gas to Tufts Cove generating station. The proposed storage facility is

being designed to store a minimum of 4 BCF of natural gas at a maximum pressure of 2,028 pounds per square inch gauge ("psig") and a minimum operating pressure of 418 psig. The storage facility can also be used in the integration of intermittent renewable energy generation such as wind energy.

[120] NSPI, in its Reply Evidence, argued that this proceeding is not the place to discuss this issue which, in future, could be the subject of negotiations between Alton and NSPI. NSPI questioned the commissioning of the storage facility, which has an expected in-service date of April 1, 2015.

[121] NSPI disagreed with the benefits noted by Alton because in its opinion Alton has not considered certain items in its calculations to determine the cost savings.

[122] In response to Alton counsel's question on the use of natural gas storage facility, NSPI explained:

> MR. SIDEBOTTOM: I think storage can play an important part in the portfolio. The question to be asked is when is it the right time to enter into an agreement to secure storage? To date, it hasn't been the right choice for us and our customers. There could be a point in the future when it is the right time to secure some storage. So it's very much dependent on what's going on at a point in time.
>
> If gas sources were not as reliable there is an advantage to natural gas storage. Whether it completely justifies itself today or from some future date really is dependent on what your market circumstances are.
>
> [Transcript, September 18, 2012, p. 164]

[123] NSPI further stated that:

> MR. SIDEBOTTOM: To be partners with a potential supplier of that and have them be intimately knowledgeable of the value proposition to customers puts me or us in a compromised position in negotiating effectively the best overall cost to customers.
>
> I believe we will be looking at natural gas storage and studying that in the coming year when we have more information on wind integration. But Nova Scotia Power is happy to do that at its own cost. And we would see that it is difficult to be in a co-authored study with a potential recipient of the contract at the end of the day.
>
> [Transcript, September 18, 2012, p. 183]
>
> …

> All we're trying to say here is that we think it's appropriate to study the viability of natural gas storage. We think it's appropriate for it to be done on an impartial basis, not including the people who potentially propose to provide the storage.
>
> [Transcript, September 18, 2012, p. 193]

[124] In its Closing Submission, NSPI objected to Alton's request to order that NSPI be part of the study because this issue is not on the Board's Final Issues List for this hearing. NSPI stated that, if approved, other parties doing business with NSPI may view the GRA as a forum to advance their interest.

10.2 Findings

[125] Alton requested the Board order NSPI to participate in a natural gas storage study being carried out by Alton and Heritage Gas. NSPI objected to this request as this item is not on the Board's Final Issues List and also may interfere in its ability to minimize fuel cost and achieve a cost effective alternative for fuel purchases.

[126] Alton argued that NSPI's fuel cost can be reduced by the use of a gas storage facility.

[127] The Board understands that the use of gas storage is a type of hedge against higher gas prices in the future. Similar to other hedges, for the gas storage to be cost effective, there are many factors and assumptions one has to make so that the cost of the hedge is beneficial to ratepayers. These include the amount of gas, price of other fuels, and the cost of storage, to note a few.

[128] NSPI purchases fuel in conformance with its Fuel Manual developed over time with input from its stakeholders. The purpose of the Fuel Manual is to reduce cost and to secure a reliable fuel supply. NSPI actions in the purchase and management of fuel are audited every two years for prudency. Directing NSPI to purchase a certain

type of fuel or follow certain procurement procedures in advance of the audit may compromise the Board's ability to make a fair judgment on the audit findings.

[129] During the hearing NSPI agreed that gas storage does have benefits, but disagreed with Alton that now is the time to enter into a long-term gas storage commitment. NSPI intends to do its own study later in 2013 after the IRP update planned for 2013. NSPI's customer load has changed substantially due to the reduction in electricity demand caused by reduction in two paper mills' production volumes in the Province. The matter is further complicated by the *Renewable Electricity Regulations* requirements. The proposed IRP update is expected to provide directions on the amount and type of generation required to keep customer cost to a minimum and also meet renewable energy targets.

[130] The Board's intention is not to micromanage NSPI. Its management needs flexibility in its operations if it is to be judged on the prudency of its actions.

[131] The Board denies Alton's request to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

11.0 FAM AUDIT

11.1 Introduction

[132] It should be noted that much of the evidence regarding the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Accordingly, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[133] The FAM has generally been described as a mechanism that allows periodic adjustments to customer rates, outside general rate proceedings, to reflect

increases and decreases in the Utility's cost of fuel, provided they are prudently incurred.

[134] In its Rate Decision dated February 5, 2007, the Board identified at least four prerequisites prior to the implementation of a FAM:

> [45] For the guidance of the parties, however, and without in any way prejudging the issue, in the Board's view there are several prerequisites that must be in place in order for the Board to consider the adoption of a FAM now or in the future:
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [46] This list is not meant to be exhaustive.
>
> [Decision, 2007 NSUARB 8, paras. 45-46]

[135] In its GRA Decision dated November 5, 2008 the Board approved the FAM to take effect on January 1, 2009, conditional on the final approval of the Tariff and POA. A revised Tariff and POA were received on November 26, 2008 and approved by the Board in a letter dated December 11, 2008.

[136] Section 5 of the POA addresses the audit requirements and excerpts are included below:

> **5.0 AUDIT AND OVERSIGHT**
>
> The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM proceeding to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NSPI or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if

appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit every second year. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NSPI's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1, 20XX to December 31, 20XX+1. The first audit period will be for the year 2009. Subsequent audits will cover two-year periods.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NSPI, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NSPI's procurement as described in the NSPI Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production …

…

Prior to setting the final audit scope, the auditor shall meet with NSPI and interested stakeholders.

Timing of the Audit

The first audit will commence on February 1, 2010, and subsequent audits are expected to commence in February of every second year. The final report for the first audit will be filed with the Board and Stakeholders by July 2, 2010. Final reports for subsequent audits will be filed by July 2 of every second year. The final report will evolve from a draft report which is provided to NSPI and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

[FAM POA, August 13, 2010, pp. 13-15]

[137] It should be noted that the original POA anticipated that the first audit would cover 2009 and 2010 and that the draft report would be provided to NSPI and the Board "forty-five days before the final report is filed". During 2010, following stakeholder engagement, NSPI requested Board approval of certain changes to section 5 of the

POA. Specifically, those changes included recognition that the first audit covered only 2009 and also a revision to the audit timing to state that the draft report will be provided to NSPI and the Board "within 30 days of the filing of the final report". Those changes were approved in the Board's letter dated October 12, 2010.

[138] As noted above, the first FAM Audit was conducted in 2010 and covered the 2009 calendar year. The Liberty Audit Report, which was filed with the Board on July 2, 2010, presented Liberty's findings, conclusions, and recommendations in eleven chapters, each of which comprised a principal area of examination and review. A total of thirty-one recommendations were included in Liberty's Audit Report.

[139] The 2010 Audit Report was included as an exhibit in the proceeding to set the Base Cost of Fuel ("BCF") for 2011. On page 12 of its evidence filing in the 2011 BCF proceeding, NSPI stated:

> The Company generally agrees with most of the recommendations of the Report. There are recommendations that require additional context or currently have alternative solutions that the Company has carried out or is in the process of implementing. NSPI suggests that the FAM can continue to provide an effective forum for dialogue about the conclusions and recommendations of the Audit Report.
>
> [Decision, 2010 NSUARB 219, p.12]

[140] NSPI's response to that Audit report was contained in Appendix C of its evidence Exhibit N-10 which outlined agreement and/or comments regarding each of the recommendations.

[141] As directed by the Board, NSPI filed its FAM Audit Recommendation Action Plan on December 9, 2010. Following subsequent discussions between NSPI and Liberty, a report dated June 9, 2011 was filed by Liberty which noted that NSPI had established acceptable action plans for 25 of the 31 recommendations. Some of the

outstanding issues were resolved, but others remained and were carried over to the 2012 FAM Audit.

[142] It bears repeating that in approving the FAM in 2007, the Board highlighted the importance of transparency and timely disclosure in its approval of the FAM:

> [59] NSPI now indicates it is committed to transparency and timely disclosure.
>
> [60] The Board wishes to make it clear to NSPI that if full and timely disclosure of complete and adequate information to assess its fuel procurement practices continues to be a problem, the implementation of a FAM will not occur...
>
> [Decision, 2007 NSUARB 174]

11.2 Prudency Test

[143] In 2005 NSUARB 27 (NSPI - P-881), the Board adopted the definition of prudence as set out in a decision of the Illinois Commerce Commission as a reasonable test to be applied in Nova Scotia.

[144] That test was set out at paragraph 84 of the Board's Decision:

> The standard for determining prudency of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, "prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made….Hindsight is not applied in assessing prudence….A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. … The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.
>
> [Decision, 2005 NSUARB 27, para. 84]

[145] The Board went on to say:

> [89] While the Board recognizes that the definition of imprudence varies somewhat among the jurisdictions cited, there are several fundamental principles which are common. These include:
>
> - Were the utility's decisions reasonable in the context of information which was known (or should have been known) at the time?
> - Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?

- The imprudency test should relate to the circumstances at the time in question and not to hindsight.

[Decision, 2005 NSUARB 27, para. 89]

[146] NSPI, in its Closing Submission in the present matter, confirmed that from its perspective this is the test the Board should apply.

11.3 Lingan Derates

11.3.1 Evidence

[147] Liberty recommended a disallowance with respect to derates which occurred at the Lingan generating plant in December 2010. Derates occur when an operator must reduce, for one or more of a variety of reasons, the anticipated level of plant output.

[148] In its FAM Reply Evidence, Liberty described the risks known to NSPI in July and August 2010, when it re-introduced the local Prince coal, after the Province relaxed the mercury limits:

> The specific quality aspects of concern for the reintroduced local supply were ash, sulphur, and Btu content. Resuming its use in the Lingan fuel blend caused July and August results that failed to meet NS Power's own recognized guideline for identifying opacity risks. The operative metric was maintaining or exceeding a 1,000 parts per million concentration of SO_2 in unit stacks. Following the reintroduction of local supply, those concentrations fell well below the minimum guideline, ...
>
> Moreover, variability in the quality of reintroduced local supply and problems in its conformity to contract specifications were known issues. The coal's Btu content fell below minimum specification in January, July, and August 2010. Ash content was at the upper limit of specification in January, was well above the limit in July, and remained at the upper limit in August. ... Experience in January 2010 (after which NS Power discontinued use), and July 2010 (when NS Power resumed use) demonstrated, particularly in light of concern about stack SO_2 levels, that what was impossible to predict was that the coal blend, including reintroduced local supply, would sustain the ability to meet opacity limits without curtailing generation...
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF pp. 110-111]

[149] In Liberty's opinion, NSPI was imprudent in that it did not appropriately address coal quality issues in July/August 2010 when there were signs that there were substantial risks of failure to meet opacity limits.

[150] While Liberty was mindful that NSPI was running the plant aggressively close to the limits, it stated that NSPI should have planned its coal burns to avoid the potential for problems, especially when Prince coal exhibited quality issues in July/August 2010.

[151] It bears repeating that some of the relevant evidence related to the Lingan derates in the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Therefore, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[152] Some background on the importance of coal blends will be helpful to the reader.

[153] The Lingan generating facility was designed to operate at optimum efficiency while burning coal having specific characteristics. The primary fuel that the plant was originally designed to use was high sulphur coal that was available from the local mines in Cape Breton. Over the years, availability of that coal decreased while, at the same time, federal and provincial environmental regulations mandated reduced emission levels from generating stations burning fossil fuels.

[154] NSPI has regularly blended high sulphur domestic coal with low sulphur imported coal in order to optimize compliance with overall utility sulphur emission restrictions. It has also used mid-sulphur imported coal in its blend.

[155] In order to satisfy opacity limits and reduce emission levels, electrostatic precipitators are used at Lingan along with varying combinations of coal blends. Coals with various levels of sulphur, ash, moisture, and Btu are included in the blends. Changing the type of coal being burned can also change the efficiency of the plant. For example, burning coal that has a higher Btu content essentially means that higher levels of energy output can be obtained, while burning less fuel and producing lower overall emissions. However, this must be balanced against the design parameters of the generating facility and the effects of other fuels and chemicals in the fuel mix.

[156] Typically, the higher quality coals, in terms of lower sulphur, ash, moisture and higher Btu, are more expensive. Thus, coal blends must be carefully planned in order to maximize output at the lowest possible cost, while not exceeding emission limits.

[157] Further, government regulations which mandated a reduction in the mercury levels being emitted from the stacks required additional equipment and operational changes. This included altering fuel blends to reduce the mercury content and installing mercury abatement equipment along with chemical additives, such as powder activated carbon, to capture the mercury in the stack emissions. This abatement equipment and the powder activated carbon were designed to perform well with lower sulphur levels, but its use with higher sulphur coal can result in reduced performance.

[158] As of July 2010, the Province relaxed the targeted levels for mercury emission. This change identified graduated levels of mercury reduction, which also extended the compliance timeframe for achieving the revised emission target. As a

result of this, NSPI was able to use larger quantities of high sulphur, high mercury, domestic coal from the local Prince mine. Prince coal was available at a lower cost than imported coal. One of the benefits of burning this higher sulphur coal is that it improved precipitator performance so that derates due to exceeding stack opacity limits were less likely to occur.

[159] Along with managing the levels of sulphur dioxide and mercury emissions, NSPI needs to manage nitrogen oxide emissions, greenhouse gas emissions, and to ensure that the opacity of the stack emissions does not exceed the acceptable level specified in the operating permit. Clearly, a process of balancing fuel blends and chemical additives is needed in order to satisfy emission restrictions, while still maintaining efficient plant operation, maximizing energy output levels, and minimizing costs.

[160] In its Audit Report regarding derates at Lingan, Liberty stated:

> NSPI experienced the derates because the station precipitators were operating at the margin of performance, and could not tolerate any changes in coal quality, coal flow rates, or additional moisture in the coal. When above normal amounts of rain were experienced in December 2010, the station had no choice but to derate in order to comply with stack opacity limits. If NSPI had taken action to make the appropriate alternative coals [i.e., blends], there would have been the necessary margin in stack performance to have continued operation at normal power levels without derating. …
>
> [Liberty FAM Audit Report, Exhibit N-171, p. IV-28]

[161] In response, NSPI stated that the derates were caused by an uncharacteristically high amount of rainfall in December 2010. In its view, the 1 in 30 year rainfall event increased the moisture level in the coal (which is typically stored outdoors), which, in turn, reduced the MW output of the plant because it reduced the mill grinding efficiency, reduced the mill temperatures and resulted in feeder pluggages.

[162] NSPI also noted that the quality of the local Prince coal deteriorated in the relevant time period, further exacerbating the situation. However, Liberty states this is the risk when using poorer quality coal in that it can be unpredictable.

[163] In its Reply Evidence, NSPI summarized its view of the causes of the derations:

> 1. Many factors - moisture, initial sizing, wear, inlet temperatures - affect the performance of coal mills. In December, 2010, the Lingan Generating Station experienced a 1-in-30 year rainfall event. When coal contains unusual moisture levels, it reduces the temperature inside the coal mill, so the coal does not dry properly. Grinding efficiency and combustion are compromised, lowering generation. Coal with increased moisture levels has a greater tendency to build up on surfaces until the coal feeders that regulate the amount of coal going into the mills begin to plug up. When a feeder plugs, the flow of fuel to the boiler slows and the units are derated.
>
> 2. In December, the ash, moisture, and sulphur content of Prince coal all increased. The increased moisture resulting from the rainfall event, together with the increased ash content, reduced the effectiveness of the precipitators and led to derations. NS Power could not reasonably be expected to mitigate the effects of a 1-in-30 year event, especially one that coincided with high ash content in the coal received from a low cost supplier. When the impact of the record rainfall event began to subside, the Lingan units returned to full load capability.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 27]

[164] While Liberty stated in the FAM Audit that its review of the documentation "disclosed no expression of concern about opacity issues at the Lingan station" leading to the December 2010 derates, NSPI replied that it had identified the moisture issue and the precipitator performance, and its action to address the issue, in its April 2011 presentation of November - December Plant Performance.

[165] NSPI engaged Dr. Stan Harding to assist in its response to Liberty's claim of imprudence respecting the Lingan derates. He is a consultant with experience in coal generation facilities.

[166] Dr. Harding's conclusions included:

...

- The unusually high precipitation in December 2010 combined with the high moisture levels in the coal, resulted in significant boiler derates and mill pluggages during this time period.

- The load reductions noted in December 2010/January 2011 were primarily due to coal quality and high moisture-related pulverizer pluggages rather than opacity.

- The high precipitation in December 2010 would have resulted in an increase in mill pluggages and boiler derates even if a design coal was being used. ...

[Harding Report, Exhibit N-77, p. 14]

[167] NSPI also called Emily Medine as a witness on this issue. She is a consultant who regularly assists NSPI in its solid fuel management issues. In her view, Liberty ignored the impact of a 1 in 30 year rainfall event in December 2010, which she stated was the primary reason for the derates. She added that Liberty ignored NSPI's strategies for addressing all potential derates due to provincial limits on SO_2 emissions. She also noted that NSPI immediately dealt with the derates after 2010.

11.3.2 Findings

[168] The Board considers NSPI's evidence on the Lingan derating issue to be tenuous and unreliable in several respects.

[169] First, the Board has several concerns about the evidence of Dr. Harding.

[170] In Information Requests IR-6(d) and 7, Dr. Harding was asked to provide a description of the design and operational features at Lingan, including the spare mill capacity on each unit, which was designed to avoid unit operational consequences due to mill plugs. He was also asked to provide the number of pulverizers assigned to each of the four Lingan units and to provide information about the derates specifically caused by pulverizer pluggages, including the generating unit involved. He responded by stating that he had not received this information from NSPI. He stated that the issue of

spare mill capacity was outside his scope of work, although he acknowledged it was relevant to the derate issue.

[171] Based on Liberty's investigation, it confirmed that "Lingan's use of four mills per unit allows for each unit to remain at full load with one of its mills down" [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 115].

[172] Surprisingly, in questioning by Board Counsel, NSPI Fuel Panel member John Hawkins acknowledged that Dr. Harding had asked him for information about spare mill capacity, but NSPI did not provide him with that information.

[173] As a result, on an issue as important to derates as spare mill capacity, which Dr. Harding conceded was a relevant consideration, he was not provided with the information, even when he inquired about it.

[174] Another aspect of Dr. Harding's testimony which concerns the Board is that he did not test the data for seasonality. In response to questions from the Board, he testified:

> MR. DHILLON: Now, did you consider expanding the database to consider the seasonality factor in the -- in your issues that maybe because a different season of the year might affect your results?
> MR. HARDING: That's a good question.
>
> No, I did not. The reasoning was the -- when I was contacted and asked to evaluate the data, the event was in December and so I had just asked for information a few months prior to that.
>
> And when I got the rainfall information, which is shown in my report also for November/December for the previous -- I think -- five years, I didn't -- I didn't go back any farther, for example, in 2009 or '08, anything like that, no.
>
> MR. DHILLON: So I guess did you go back five years in December each year?
>
> MR. HARDING: Just with -- just with -- no. Just with the rainfall data to show that it was indeed, a different -- something out of the ordinary occurred in December 2010 in terms of rainfall.
>
> …

> MR. DHILLON: But if you had considered wider data and there was derating beyond July to February the following year, would that have given any indication that there are reasons in the past this issue may have arisen and that there's reason to have some kind of a study done or something?
>
> MR. HARDING: Okay. That's a good point. I think had I noticed -- or had there been some information in this July-August-September time period that showed me that they were -- again, the -- we were focusing on de-rates due to opacity. So had there been some significant opacity de-rates -- de-rates due to opacity -- excuse me -- I would have asked for additional data.
>
> But since -- again, as I mentioned, perhaps not the greatest consultant, I should have asked for another study, but I didn't. Once I asked for the information I had, I -- it became quite obvious to me that there was an event, something happened in December of 2010 that was different than the previous five months that I had looked at. …
>
> [Transcript B, November 1, 2012, pp. 1304-1306]

[175] Further, despite Dr. Harding's theory that the derates were attributable to the December 2010 rainfall, the NSPI data requested by Liberty confirmed that the moisture level of the coal in July/August 2010, or after January 2011 (when the plant was not derating), was equal to or higher than moisture levels during the December 2010 deratings:

> ...The response to IR-8 shows moisture data from July 2010 through June 2011. The response to this IR-8 (see attachment II-2) shows several periods in July and August 2010 and in June 2011 with moisture levels at or exceeding the December 2010 [values](when a 30-year rain was experienced)...
>
> Thus, Lingan operated both: (a) in July and August 2010, without derating, despite equal or higher moisture levels than under the coal blend being used through the December deratings, and (b) after January 2011, without derating, despite equal or higher moisture levels than under the revised coal blend.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 113]

[176] Accordingly, in the Board's view, Dr. Harding's opinion that moisture and mill pluggages caused the derates is not supported by the evidence.

[177] In the end, Dr. Harding's engagement seemed to have been simply to correlate the rainfall to the derates. However, he did not conduct a root cause analysis; he did not fully investigate the pluggages (including spare mill capacity); he did not

consider seasonality; and did not evaluate ash. Despite his undoubted expertise in this field, NSPI did not provide him with the information or the necessary latitude in his scope of work to conduct an independent evaluation of the Lingan derates. As a result, the Board is not able to assign much weight to his evidence, if any.

[178] The Board also concludes that it cannot accept the evidence of Ms. Medine in this proceeding. Counsel for Avon described the concerns with Ms. Medine's testimony:

> 40. The Avon Group respectfully submits that the objectivity of Ms. Medine's opinion that NSPI's actions were prudent during this time period is undermined by the fact that she was actively advising NSPI on the very issues (coal procurement and the Lingan derates) that are central to the disallowance recommendation. ...Ms. Medine's lack of objectivity was further apparent when she consistently referred to the actions of NSPI using the pronoun "we". She is now showing a laudable degree of loyalty to the utility, consistent with her long-term engagement by NSPI, but it appears to have coloured her perspective, to the extent that she would not even acknowledge that she characterized NSPI's actions in the 2002 GRA as "imprudent" despite being presented with her sworn response to IR which described NSPI's "imprudent practices".
>
> [Avon Final Submissions, November 23, 2012, para. 40]

[179] The Board accepts Avon's submission on this point.

[180] The Board observed Ms. Medine to be combative and non-responsive in her testimony at the hearing, as demonstrated by her refusal to acknowledge her recommendation of imprudence in the 2002 GRA hearing (where she previously appeared as a witness for Avon before being engaged by NSPI).

[181] She acted at times as an advocate, rather than as an expert witness. While the Board has accepted Ms. Medine's evidence on numerous instances in past proceedings, it concludes that her relationship with NSPI in its solid fuel activities, including the events related to the derates at Lingan, coloured her objectivity in this proceeding. The Board assigns little weight to her evidence.

[182] At the hearing, NSPI urged the Board to consider the benefits to ratepayers of NSPI staff "pushing" the limits of its generation fleet. Mr. Bennett stated:

> MR. BENNETT: We're not asking for a free pass, we're just asking for a realization that this is not easy, it doesn't happen by itself, and when you're pushing the limits in order to keep costs low, an unpredictable event like extremely heavy rains causes you to have to be nimble. And we've been as nimble as you can reasonably be without pushing costs up.
>
> [Transcript, November 9, 2012, p. 1720]

[183] The Board is mindful that the task of "pushing" the Lingan units is a challenging one for NSPI's staff. The Utility and ratepayers benefit from the high output that can be achieved from the successful operation of these units.

[184] However, the Board also expects NSPI to act prudently in the operation of its generation fleet, including Lingan. It is not reasonable for the Utility to push its coal plants while disregarding the known risks of its choices of coal blends over a period of time.

[185] Mr. Spangenberg noted the importance of foresight and proper operational planning in striking the appropriate balance:

> MR. SPANGENBERG: …what we're saying is that in the middle of the year, when they started to get an indication that they were going to have some operational problems in terms of opacity, the bell should have gone off and they said, "Now, how -- what can we do at this Lingan station to make sure we don't have trouble when the real high load period comes in the winter, in December, January and February? Because if we can't run this unit, we're going to have to go out and buy very expensive power from some alternate source. And we don't know what that's going to be, but generally the power is either going to be another combustion turbine generating more expensive power or power that you buy."
>
> And so the issue to them should have been, "Let's balance the economics." You know, inventory that you're talking about is an issue. The existing blend of contracts coming in is an issue. Cost associated with derating the unit should be an issue and what alternate energy was going to cost you.
>
> And they have models to perform these calculations, and they should have been doing that. So that's -- that's really ---

> MR. MARSHALL: So are you saying the trigger for this look they should have taken that at this would have come in, what, July or so, in the summer? You say they were beginning to experience some ---
>
> MR. SPANGENBERG: Well, this particular coal was not a surprise coal. They had been burning this coal for 10 years.
> …
> MR. MARSHALL: Local domestic coal.
>
> MR. SPANGENBERG: And that's the one that should have caused them to perk up their ears and say, "Hey, we'd better worry about what's going to happen in December to make sure that we've got this economical Lingan unit available to run and that we don't have to derate it because of opacity violations."
>
> [Transcript, October 29, 2012, pp. 100-102]

[186] The Board accepts Mr. Spangenberg's description of the appropriate balance that should be reasonably expected of NSPI in the operation of this type of coal fired plant.

[187] Based on its review of the evidence, the Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI also acknowledged "pushing" the Lingan plant in order to achieve maximum output. Notwithstanding this factual background, NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[188] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Lingan facility.

[189] Accordingly, the Board orders a disallowance with respect to the derates.

[190] In the event of a finding of imprudence on the Lingan derate, Liberty and NSPI disagree on the calculation of the amount of the disallowance.

[191] The total $3.6 million amount of the disallowance proposed by Liberty is based on the sum of two $1.8 million amounts (the fact that the two amounts are identical is coincidental). The first $1.8 million relates to corrections made by Liberty to NSPI's assumptions in its calculation of replacement energy. The second $1.8 million disallowance was proposed by Liberty as a consequence of the fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[192] In determining the disallowance, Liberty calculated a cost associated with replacement energy resulting from the 21% derating at Lingan. In its Reply Evidence, Liberty stated:

> The Audit Report calculated the cost consequences of Lingan December 2010 deratings using data for the whole month. We recognized that hourly data would provide a more accurate basis for calculation, but did not have that data at the time we provided the draft report to NS Power for comment. NS Power did not comment or provide hourly data then, but did so [later] in support of its determination that the number was $750,000.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, pp. 20-21]

[193] In reviewing its calculation of the disallowance based on NSPI's methodology, Liberty made two adjustments. The first adjustment takes account of the reduced output from specific Lingan units in calculating the amount of replacement energy. Liberty modified this adjustment slightly to reflect that NSPI's model underestimated the amount of replacement energy resulting from reduced output at Lingan. The second adjustment made by Liberty to improve the accuracy of the calculation was related to the assignment and pricing of the replacement energy to the units that provided that power. NSPI had applied a figure which reflected an average for all units in the fleet. Liberty concluded that the "true cost of the Lingan derates should be calculated at the margin, not homogenized over the other units…". Accordingly, Liberty calculated the Lingan replacement costs "at the top of the dispatch

stack rather than the average" [Liberty FAM Audit Reply Evidence, Exhibit N-170, PDF pp. 108-109].

[194] The Board considers these two adjustments in the calculation to be reasonable.

[195] Liberty also stated:

> …Our basis for the proposed disallowance is NS Power's decision to undertake operating risks without evaluating those risks and taking mitigating measures as deemed appropriate. The optimum solution could have resulted in higher or lower fuel costs. Taking the coal blend eventually utilized by NS Power in early 2011, which did indeed solve the opacity issues, our calculations show that fuel costs would have actually declined, not increased. Consideration of changed fuel costs, which NS Power appears to consider the appropriate method, would have thus produced an additional $1.8 million of avoided costs. That approach would call for increasing the proposed disallowance by that amount.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 99]

[196] The $1.8 million disallowance calculated by Liberty as replacement energy cost did not take account of replacement fuel costs. As noted by counsel for Avon, it was NSPI which suggested that Liberty should have considered how fuel costs would have changed if a fuel solution had been introduced earlier. This methodology results in an additional $1.8 million disallowance attributed to fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[197] The Board finds that it is appropriate to calculate the disallowance by considering, as NSPI suggested, how fuel costs would have changed if a fuel solution had been introduced earlier.

[198] Accordingly, the Board disallows $3.6 million related to the Lingan derates.

11.4 Natural Gas Contracts

11.4.1 Evidence

[199] With NSPI's long term natural gas supply contract with Shell (the "Shell contract") coming to an end on October 31, 2010, NSPI issued a Request for Proposals ("RFP") in September 2008 and August 2009 to acquire replacement quantities of natural gas to supply its projected needs.

[200] Four counterparties submitted seven proposals in response to the September 2008 RFP. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption. That particular bid included primary injection into the Maritime and Northeast Canadian Pipeline ("M&NP-CA") at Goldboro but did not include primary delivery rights to the Tufts Cove plant. However, it did include firm secondary delivery rights to points along the M&NP-CA pipeline. Its duration was for eleven years, from November 1, 2010 to October 31, 2021.

[201] In the FAM Audit, Liberty addressed NSPI's natural gas purchases and highlighted issues regarding the two low contract bids which were not taken by NSPI. In recommending a disallowance of $5,969,252 for costs deemed to have been avoidable, Liberty identified five principal components associated with that cost determination. Those components included two base load contracts ($3,436,000), monthly purchases ($1,512,250), seasonal purchases ($276,800), and daily and intra-day purchases ($744,202).

[202] During the hearing John Adger, of the Liberty Group, was asked to explain how the $3.4 million proposed disallowance regarding the two base load contracts was

determined. His response was a simple calculation consisting of the daily contracted supply amounts in MMBtu between November 2010 and December 2011, multiplied by the price differential between the contracts taken and the lowest offers not taken.

[203] Also during the hearing Liberty was asked to provide their calculations of Bid B with transportation attached, which illustrated how long it would take for the commodity cost savings under that bid (with the transport cost included) to offset any transportation costs that would remain if NSPI was faced with an inability to continue using that transportation component at some future time. Liberty provided that information in their Undertaking U-15 which showed that the crossover point would have occurred about five years into the contract period.

[204] Regarding Bid A, Liberty acknowledged that there was not an accepted offer that was repudiated by Bidder A. Liberty's concerns were two-fold.

[205] Firstly, in early 2009, a subsidiary of Emera, Emera Energy Inc., entered into an agreement to market the Bid A gas. This was seen by Liberty as part of a pattern where the interests of Emera affiliates were favoured over NSPI.

[206] Secondly, Liberty felt NSPI should have been more aggressive with the offeror in attempting to obtain a suitable resolution to the issue.

[207] In his Pre-filed Evidence, dated September 17, 2012, NSPI's expert witness, Leonard Crook, stated that Liberty's characterization of Bid A is incorrect in just about all particulars. With respect to the other rejected offer, Bid B which included the transportation component, Mr. Crook stated that Liberty mischaracterized the offer to make it something that it never was.

[208] Mr. Crook recommended that the Board reject Liberty's proposed disallowance of $1,512,000 related to the first base load contract, as well as the proposed disallowance of $1,924,000 related to the second base load contract. He also recommended rejection of the proposed disallowance of $1,512,250 for excess monthly purchase costs and the proposed net disallowance of $1,021,002 associated with seasonal, daily, and intra-day purchases.

[209] In his Opening Statement at the hearing, Mr. Crook stated that:

> Liberty has an erroneous theory that all gas sold in Nova Scotia should be at a full Dracut netback price and NSPI overpaid whenever it bought gas at a price higher than that, although yesterday, Liberty does seem to have modified its position somewhat.
>
> ...
>
> Liberty's recommendations for disallowances follow this logic. As others have pointed out, this theory is incorrect and Liberty's recommendations based on it should be rejected.
>
> My testimony also challenges Liberty's allegations in the particulars of two specific decisions on bids to supply NSPI. Contrary to Liberty's assertions, the first offer, once it was clarified, not repudiated, was not at the price that we originally thought it was, but would have been at a price higher than the offer of the bidder whose NSPI -- whose gas NSPI ultimately selected. NSPI properly declined, after negotiation, to take this gas at the higher price, and the offer was withdrawn.
>
> …
>
> Contrary to Liberty's assertions, my recommendation to reject the second offer, which was an apparent full netback price, was based on sound judgment about the reliability of the supply and the risks associated with pipeline capacity.
>
> …
>
> Liberty maintains that secondary delivery rights under the M&NP Canadian tariff would have provided sufficient assurance of deliverability, but the Maritimes tariff is clear; secondary delivery rights are subordinate to primary firm delivery rights.
>
> The issue with the contract is fairly straightforward -- is a fairly straightforward matter. I considered it an unacceptable risk to take ownership of a long-term firm gas transportation contract for the purpose of delivering gas to a point not along the pathway of that contract, simply to access what might be a favourable supply contract that itself might not be reliable.
>
> [Transcript B, October 31, 2012, pp. 848-851]

[210] Regarding Bid A, Mr. Crook was asked about his understanding of the price stated by the offeror and about actions that should have been taken by NSPI when the offer was withdrawn. Mr. Crook confirmed that he and the NSPI team all understood the price to be the same as the price that was understood by Liberty. He also noted that this same understanding was presented to NSPI's Fuel Strategy Table where approval was granted to proceed with the contract. At that point NSPI emailed a term sheet to the offeror and understood that it had accepted the offer. It was not until about six days after the term sheet was emailed that NSPI was informed its price interpretation was incorrect.

[211] Board Counsel asked NSPI's fuel witnesses how NSPI dealt with the situation in order to ensure that its acceptance of the offer could be preserved. Ms. Trenholm stated NSPI did not want to damage the relationship with the counterparty. She confirmed that NSPI did contact Bidder A and expressed as strongly as they could their disappointment but did not feel they could negotiate a better price:

> … to express as strongly as we could our disappointment, at the same time acknowledging that this is a very illiquid market.
>
> This is actually a new counterparty for us…
>
> …
>
> …It wasn't to the point where it was enforceable, and that was our view, it is -- it's too bad, and it is really -- I think it as a lot of hopeful thinking, maybe, on our part that blinded us a little bit, that we didn't push on that more, to hope that we had actually got [redacted] pricing…
>
> [Transcript, November 9, 2012, pp. 2060 - 2061]

> MS. TRENHOLM: --- we had gotten an approval to transact with them… It was a simple misunderstanding, a confusion on their part.
>
> MR. OUTHOUSE: Did you attempt to negotiate a better price? Did you attempt to use that occasion to strike a better price than you had from [redacted]?

> MS. TRENHOLM: …They weren't willing to move off of that price; that was their final price.
>
> [Transcript, November 9, 2012, pp. 2065-2066]

[212] NSPI's primary concern with respect to Bid B, the rejected offer, was the risk of transportation interruption if the main line became full or congested.

[213] While the gas under that contract was favourably priced, indeed comparable to the price NSPI had enjoyed under the Shell contract, this contract had a transportation obligation attached to it with a secondary delivery point at Halifax. The primary delivery point was upstream of Halifax.

[214] NSPI pointed out that, to the best of its knowledge, no other market player in the Maritimes' market took an assignment of the Bid B contract.

[215] As noted, Liberty stated that, based on its analysis, the Bid B offer was sufficiently favourable in that after five years NSPI would have suffered no loss. In other words, there would have been a net benefit even if the balance of the transportation rights had become valueless at that time.

[216] This was explored with Liberty during the hearing:

> THE CHAIR: It's a contract with transportation attached. And I guess my question is, is it your opinion that that contract would, after approximately five years, have proved so valuable that even if Nova Scotia Power could not get the gas to Halifax after five years, customers would have been better off with the acceptance; is that what that line is telling me?
>
> MR. ANTONUK: That was actually the crossover point. Up to that -- if the crossover came roughly five years into the contract, on a strict economic basis, the offer that they rejected was better than the offer they accepted.
>
> THE CHAIR: So they only needed to get the gas to where they wanted it to go for five years?
>
> MR. ANTONUK: It was --- yes.
>
> THE CHAIR: In your opinion?

MR. ANTONUK: Yes.

[Transcript, October 29, 2012, pp. 332-333]

[217] During cross-examination of NSPI's expert witness, Mr. Crook, counsel for the Avon Group explored the issues regarding primary and secondary delivery rights on the M&NP:

MS. STEWART:

…

I just have a few questions about the gas contract that involved transportation rights. Would you agree that curtailment of secondary firm delivery on a pipeline would only occur when the pipeline capacity was fully contracted under primary firm contracts?

MR. CROOK: Depending on the locations of the -- of the pathways. My concern about that contract was that it was firm but outside the pathway that needed to have secure deliverability to the Halifax Lateral.

…

So you were right, it has to be -- all of the shippers have to be shipping at their maximum daily quantity or our – and that maximum daily quantity then precludes delivery of secondary -- of gas under secondary delivery rights.

MS. STEWART: And are you aware of whether or not there is today capacity on the M&NP Canada Pipeline?

MR. CROOK: The M&NP Canada Pipeline is not fully subscribed at this point.

MS. STEWART: Was it fully subscribed in 2008?

MR. CROOK: It was approximately, maybe 500, 520,000 out of the 600,000, I believe, was -- subject to check, of the maximum quantity of the pipeline. So you had some spare in there.

MS. STEWART: Has there, in your experience, been curtailment on the M&NP Canada Pipeline?

MR. CROOK: I'm not aware of any particular incident.

…

MS. STEWART: Sure, maybe I'll rephrase it. So there's been concern that there's risk associated with this contract, and the risk is that there -- because there's only secondary delivery rights, that in the event of curtailment the transportation that has been paid for would not be -- could not be used because it would only -- because there would be curtailment.

MR. CROOK: Correct.

…

MS. STEWART: Unless there is curtailment, secondary firm delivery is adequate to delivering gas?

MR. CROOK: I'm going to hedge the question -- hedge my answer a little bit on that. It should be adequate. I think, depending on the pathway, it may have some bearing on that.

…

So if you have a firm delivery pathway that goes from Goldboro all the way to Baileyville and there is some curtailment on the pipeline, then -- that is, that the pipeline is at maximum capacity, you would still be able to deliver gas to some secondary points along the way, provided there wasn't, you know, firm there already blocking you.

…

MS. STEWART: And I think your answer there, again, was with the hypothesis that there is curtailment, and I understand what you're explaining, but I'm not sure that it was responsive to the question.

So the question that I was saying was that, in the absence of curtailment, and the experience has been, and your evidence is that you are not aware of any curtailment on the M&NP CA, that without curtailment, secondary firm delivery is adequate and even possibly equal to primary firm delivery?

MR. CROOK: Yes.

[Transcript B, October 31, 2012, pp. 902-909]

[218] Following up on this questioning about transportation rights, counsel for the Province sought further clarification from Mr. Crook and asked if it was possible to have firm delivery rights on a lateral without having associated rights on the main pipeline. He replied that in order to get the natural gas to the specific lateral being discussed, transport along the mainline would be necessary. Firm delivery rights on the upstream lateral also include associated rights on the main pipeline in this instance. Mr. Crook also confirmed that payment for service anywhere on the M&NP, with a primary delivery point on the lateral, is covered by a single postage-stamp toll.

[219] Board Counsel also sought further clarification on this issue.

> MR. CROOK: Well, as I say, it's a common practice in the industry that you can -- that you can deliver to secondary delivery points along your pathway as long as that secondary delivery point is available. Outside your pathway you can't.
>
> MR. OUTHOUSE: And so when I read the tariff which says a particular customer who has a primary delivery point on the pipeline and -- primary delivery point, and then says that he can deliver anywhere else on the pipeline at a secondary delivery point that doesn't apply, that doesn't apply to this particular customer?
>
> MR. CROOK: It applies as long as there's capacity available on the Mainline, but it doesn't -- the problem would occur is if sometime between now and 2021 some congestion would occur onto the Mainline…
>
> [Transcript B, October 31, 2012, p. 919]

[220] Mr. Crook provided a response to Undertaking U-16 regarding available capacity on the Canadian portion of the M&NP. Mr. Crook advised that the physical capacity of the M&NP is 600,000 MMBtu per day. During 2008, the contracted capacity was 511,792 MMBtu which represents about 85% of the physical capacity. He also stated that the average daily flow throughout 2008 was 482,091 MMBtu or 80% of capacity. In addition, the average daily flow during March 2008, the peak month, was 527,383 MMBtu or 88% and on the peak day, also during March 2008, the maximum flow was 560,098 MMBtu or 93%. These figures clearly indicate that throughout 2008, capacity was available on the main pipeline to accommodate secondary delivery rights.

[221] Mr. Crook also noted that the pipeline capacity on the US side of the border was higher than the Canadian side in order to accommodate additional flows from the LNG facility at Canaport.

[222] Board Counsel sought further clarification of transportation rights:

> MR. OUTHOUSE: Mr. Crook you remember yesterday when we were discussing this we were looking at 6.1?
>
> MR. CROOK: Correct.
>
> MR. OUTHOUSE: And it says:
>
> "That the quantity is nominated for transportation by customers shall be scheduled by Pipeline for receipt and delivery in the following order." (As read)

And the first tier in that order, the first tier of customers:
"Firm service utilizing primary points of receipt and primary points of delivery." (As read)

Right?

MR. CROOK: Yes.

MR. OUTHOUSE: And the second (b) is:

"Firm service utilizing second points of receipt and/or second points of delivery provided, however, that if a pipeline is restricting service at a particular receipt or delivery point, then a customer utilizing that point as a primary point, regardless of the status at the corresponding delivery or receipt point, shall have priority over a customer using that restrained point as a secondary point or receipt of delivery." (As read)

In other words, and my understanding of that and you can correct me if I'm wrong obviously, is that if I have -- if both of us have primary receipt points at Goldboro and I have a primary delivery point at Halifax and you have a primary delivery point in Saint John and there's a constriction at Saint John, then you have priority over me at Saint John; is that correct? If I want to use my secondary rights to deliver to Saint John and it's a primary point of delivery for you, you have priority over me in scheduling.

MR. CROOK: You mean, if I -- mine was at Halifax?

MR. OUTHOUSE: If -- no.

MR. CROOK: I'm sorry, I ---

MR. OUTHOUSE: If your primary point of receipt -- of delivery is Saint John, my primary point is Halifax.

MR. CROOK: Yes.

MR. OUTHOUSE: And there's a constraint at Saint John, but I'm trying to get in there using my secondary delivery rights, you have priority over me because it's your primary point of delivery?

MR. CROOK: Yes.

MR. OUTHOUSE: Correct?

MR. CROOK: I believe so.

MR. OUTHOUSE: All right. But if neither of us have primary points of delivery at Saint John, but we both want to exercise secondary rights to deliver there, we're on an equal footing; are we not?

MR. CROOK: Yes.

MR. OUTHOUSE: Okay. And when you look at 6-3, and this is the part that wasn't in the tariff that's in your document. Six three (6-3) says that:

"In the event a tie for capacity exists among category A, B, C, or D customers, quantities within that category will be scheduled pro rata on the basis of the customer's MDTQs." (As read)

Correct?

MR. CROOK: Yes.

[Transcript A, November 1, 2012, pp. 937-941]

[223] In an effort to obtain a better understanding of the pipeline constraint issue, the Board requested further clarification from Mr. Crook:

> THE CHAIR: So I guess once it enters the Mainline, I'm having difficulty understanding what the constraints are, then getting it to the Halifax Lateral given that there's no gas entering the Maritimes & Northeast Pipeline between Goldboro and New Glasgow, where the Halifax Lateral comes off. Could you help me with that?
>
> MR. CROOK: My understanding is that there is a decline in pressure over the length of the line and that you can take quantities off a short distance down the line and not affect -- and by terms of the tariff then, you have secondary rights to any downstream takeoff points from your -- from the [redacted]. I'm not a pipeline engineer so I don't know exactly ---
>
> THE CHAIR: So are you saying that ---
>
> MR. CROOK: --- the dynamics of the flows.
>
> THE CHAIR: So if you put 600,000 MMBtu's in at Goldboro, you're saying you can't get that to, say, New Glasgow?
>
> MR. CROOK: Point taken. Yeah, I'm not sure then.
>
> THE CHAIR: And you'd agree with me that no gas enters that line, or frankly, is likely to enter that line between Goldboro and New Glasgow?
>
> MR. CROOK: That's correct.
>
> [Transcript A, November 1, 2012, pp. 995-996]

[224] Mr. Crook was asked if he did any economic analysis of the price of gas under Bid B, compared to the contract that eventually was entered into by NSPI, to determine what the economic benefit would have been versus the risk on the pipeline. His response was that he did not do the sort of analysis that Liberty had done with respect to the benefit of the contract. Likewise, John Reed, another one of NSPI's expert witnesses, did no such economic analysis.

[225] As NSPI's generation pattern moved toward greater reliance on gas-fired units, a requirement for additional supplies of natural gas was identified. In addressing that need, NSPI entered into a number of short-term agreements resulting from bilateral negotiations, rather than through an RFP process. These purchases consisted of various forms of seasonal, monthly, daily, and intra-day agreements and involved a range of transaction pricing. In the FAM Audit Report, Liberty identified excess costs of $276,800 for seasonal purchases, $1,512,250 for monthly purchases, $767,706 for daily purchases, and an intra-day saving of ($23,504). Liberty's calculations are based on the difference between the price paid by NSPI and the price that Liberty determined NSPI could have achieved with more informed and aggressive negotiations and with access to LNG from Canaport.

[226] NSPI responded to those conclusions regarding excessive costs for natural gas by dismissing Liberty's assertions that lower prices could have been achieved. NSPI stated that it is committed to champion customer interests in the pricing of natural gas supplies and it takes the position that Liberty is confused about the operation of the natural gas market in the Maritimes.

[227] In his Pre-filed Evidence, NSPI's expert witness, Mr. Crook, addressed the excessive procurement costs identified by Liberty regarding seasonal, monthly, daily and intra-day purchases. Mr. Crook noted that the characteristics of gas contracting include various obligations such as delivery, duration, and different supply tranches which will result in gas prices that are higher than those attributed to basic gas commodity trading. He also stated that:

> …My observation here is that in the daily and intraday market, where supply is short, one can expect to pay higher prices than when supply is at surplus or for previously contracted supply. The argument that these volumes also should have been priced at

> [redacted] misunderstands the operations of the gas market. Liberty's recommendations for eliminating these expenditures from the FAM should be rejected by the Board.
>
> [Exhibit N-129, p.10]

[228] Mr. Reed also disagrees with Liberty's recommended disallowances for NSPI's seasonal, monthly, daily and intra-day purchases. In his direct evidence, Mr. Reed stated:

> Liberty believes that higher natural gas prices in the Maritimes that have been experienced since the expiration of NSPI's Original Shell Contract are inconsistent with the NEB's prior findings regarding exports of natural gas from Canada. Liberty states that "NSPI's expectations of [redacted] did not appear to be consistent with either the general regulatory regime for gas exports from Canada or the specifics of the authorities granted to Repsol." (Liberty Audit, p. III-5).
>
> [Exhibit N-134, p. 25]

> …it is my opinion that the changes in wholesale gas pricing in the Maritimes reflect exactly the way a functioning market would work as it moves from having a supply surplus to a supply deficit. The increasing natural gas prices in the Maritimes are not due to market flaws, but rather a shortage of indigenous supply.
>
> [Exhibit N-134, p. 31]

[229] He went on to say that in determining these disallowances, Liberty based its finding on its interpretation of prior NEB decisions regarding natural gas exports from the Maritimes. Mr. Reed stated that he agrees:

> …the NEB's policies are that the natural gas needs of Canadians are to be met on terms that are similar to those charged to export customers. However, I strongly disagree with Liberty's interpretation of these NEB rulings and how Liberty has applied its conclusions to NSPI's circumstances in this proceeding.
>
> …
>
> Contrary to Liberty's interpretation, the NEB has not previously concluded that purchasers of natural gas in the Maritimes are entitled to a Dracut netback price. In fact, the NEB specifically recognized in MH-2-2002 that producers/marketers selling in the Maritimes natural gas market are entitled to seek reimbursement for transportation costs to which they have committed.
>
> [Exhibit N-134, pp. 32 - 34]

[230] In its Closing Submission, with respect to Bid A, NSPI stated that Bid A suffered from vagueness in its terms such that NSPI and the bidder had two

understandings of the offer. NSPI argued that Liberty's position with respect to Bid A was not as much about the ability of NSPI to obtain competitively priced gas but related to Liberty's concern about affiliate transactions.

[231] With respect to these affiliate concerns, NSPI noted the evidence of its expert, Mr. Reed, who found no evidence that the affiliate or NSPI violated the Affiliate Code of Conduct or conspired in any way in connection with Bid A.

[232] In the final analysis NSPI stated that:

> NS Power could not have forced [Bidder A] to honour a proposal that [Bidder A] believed it had not made.
>
> [NSPI Closing Submission, November 23, 2012, p.66]

[233] NSPI goes on to state:

> Liberty initially claimed NS Power to have been imprudent in respect of the [Bidder A] offer because NS Power did not obtain the benefit of the pricing structure as that structure had initially been understood by NS Power. In contradiction to Liberty's position, the discussion could simply not get to a consideration of whether it was within the band of reasonable choices to have rejected the [Bidder A] proposal because there was no legally enforceable proposal on the table – a fact acknowledged by Liberty during its testimony. [Bidder A] withdrew its proposal and accordingly that alternative choice was simply not available. It cannot be unreasonable or imprudent not to accept an offer that no longer existed.
>
> [NSPI Closing Submission, November 23, 2012, p. 66]

[234] With respect to Bid B, NSPI argued as follows:

> NS Power had sought gas for terms of 1-5 years and up to 20,000 MMBtu/day. The [Bid B] offer had several components – one was a 4,000 MMBtu/day supply to which NS Power already had access, while the second was for a gas supply contract of 7,000 MMBtu/day of additional gas supply (non-firm for as many years as SOEP supply would support). The third and final component was 11,000 MMBtu/day of must-take pipeline capacity through a Firm Service Agreement whose term extended until 2021 – well beyond the term of the associated gas supply.
>
> It was NS Power's and ICFI's considered view that the value of the 7,000 MMBtu/day did not outweigh the risk of committing to paying transmission costs to 2021 on a portion of pipeline that has no (firm) primary delivery rights to the Halifax lateral. In fact, NS Power's financial analysis indicated that the contract would cost customers almost $20 million due to the capacity costs outweighing the cost of gas. Given what we now know about [Bid B], it is understandable that [Bid B] would have wanted to find a way out of its costly transportation contract.

> NS Power tried, and failed, to get firm transportation to Halifax. It is also worthy to note that [Bid B's] offer to sell gas under its proposed conditions was not accepted by any other buyer.
>
> [NSPI Closing Submission, November 23, 2012, p. 60]

[235] In its Closing Submission, Avon noted that NSPI's involvement in the regional natural gas market had been an issue of concern raised by Liberty in the 2010 FAM Audit and again in the 2012 FAM Audit. Avon also stated:

> The evidence that has emerged through this process demonstrates that while NSPI has a strong understanding of the complexities of the natural gas market, it tends to take a conservative approach to its role within the market and, in some key instances, failed to undertake rigorous analysis of its natural gas contracting and hedging options. As a result, stakeholders are left to question whether NSPI has truly made every reasonable effort to ensure that it is obtaining the lowest possible natural gas prices.
>
> [Avon Closing Submission, November 23, 2012, p. 8]

[236] Regarding NSPI's activity with natural gas contracts, Avon noted that NSPI and its expert witnesses have repeatedly stated that natural gas prices, as low as those contained in the two lowest bids from the 2008 RFP, have not been seen for several years. Therefore, prior to rejecting the bids:

> One would expect that this decision would come after a serious analysis of the financial and operational risks associated with the bids. However, it appears that this is not entirely the case.
>
> [Avon Closing Submission, November 23, 2012, p. 9]

[237] Regarding the lowest bid which had been withdrawn (Bid A), Avon stated this situation appeared to be:

> …a significant miscommunication between NSPI and the counterparty, at best, or interference from an NSPI affiliate, at worst.
>
> …In the NSPI evaluation of the RFP outcomes, this bid was ranked number one. Based on the wording of the bid and ongoing negotiations, it was widely believed by NSPI and its consultant, Mr. Crook, that the counterparty was offering gas with a deduction for both Canada and US pipeline transportation charges.

> The bid was selected by staff and was presented for approval to the Fuel Strategy Table; upon approval, a term sheet was provided to the counterparty. Only then did the bidder indicate that it had only intended to deduct a portion of the transportation costs. This significantly changed the economics of the bid and, ultimately, the offer was determined to be unfavourable. It is surprising that there would be such a significant miscommunication between NSPI and a potential counterparty.
>
> [Avon Closing Submission, November 23, 2012, p. 12]

[238] Although NSPI testified that it had discussed this situation with the counterparty and voiced its dissatisfaction with what appeared to be a change in the bid, Avon noted that:

> NSPI's full reaction to the clarification with respect to the bid did not become apparent until Ms. Trenholm was under cross-examination during the audit hearing. Only then, did it come to light that NSPI voiced significant discontent with respect to the sudden change in the counterparty's bid. Ms. Trenholm stated that although NSPI was "indignant", the Utility ultimately preferred to preserve the relationship with the counterparty and so decided not to press the matter further. It is noted that both NSPI and Liberty agree that the bidding process, though advanced, had not, yet, resulted in an enforceable contract.
>
> [Avon Closing Submission, November 23, 2012, p. 13]

[239] Regarding the rejected bid with the transportation component (Bid B), Avon noted that there was no dispute that NSPI would have accepted the bid if it did not have the specific transportation component attached to the offer. In this instance, Avon submitted that NSPI should have considered the actual capacity and forecasted capacity of the M&NP-CA pipeline as of 2008, prior to rejecting that bid.

> The transportation contract had firm entry rights at Goldboro and so would be unaffected by increased use of the pipeline by Deep Panuke gas, insofar as entry rights are concerned. The issue, then, is whether potential increased gas supply to be shipped on the M&NP-CA would impact delivery, on a secondary basis, to Tufts Cove.
>
> …We understand that Mr. Crook was suggesting that secondary delivery along the pathway between the primary injection site and the primary delivery site would have priority over secondary delivery along another "pathway" on the pipeline. This position does not appear to be supported by the tariff provisions or the logic of a postage stamp pipeline system, such as the M&NP-CA Pipeline.
>
> Despite taking this position, Mr. Crook was not able to provide an example of priority being affected by pathways on a postage stamp pipeline in Canada…

…Little or no evidence was given with respect to sources of curtailment, either additional injections of gas between Goldboro and the Halifax Lateral or other major primary delivery rights' holders to the Halifax Lateral. Therefore, it seems that there was no particular risk of curtailment with respect to the intended secondary delivery point at Tufts Cove.

…

It is submitted that the risks associated with secondary delivery to Tufts Cove were not exceptional and that, in light of the preferential pricing of the natural gas that was being offered in the bid, one might expect that NSPI would undertake a rigorous financial analysis to determine whether the economic benefits outweigh the risks associated with the transportation portion of the contract. However, it does not appear that such an analysis was undertaken prior to rejecting the bid.

Although NSPI produced a table comparing the benefits (gas) and liabilities (transportation) associated with this bid, the Utility confirmed that this assessment was undertaken after-the-fact as part of NSPI's response to the 2012 Audit and that no economic analysis had been performed in 2008, because the "*exposure was easily understood at that time*."

Ms. Trenholm confirmed, on behalf of NSPI, that although Mr. Crook undertook an informal risk analysis of the contract, he did not produce an in depth economic analysis, either. Further, Mr. Reed gave evidence that he did not undertake any type of analysis in relation to preparing his evidence…

[Avon Closing Submission, November 23, 2012, pp. 10-11]

[240] Avon went on to point out that Liberty's analysis determined that the risks associated with the transportation component of Bid B would be outweighed by the benefits of the natural gas contract after about five years. Avon concluded that:

… the risks associated with the transportation contract were not properly analyzed, either by NSPI or its consultants, and a contract that could have provided gas at a price that NSPI acknowledges it has not been seen in many years was rejected without the type of rigorous analysis one might expect in this situation. In these circumstances, the Avon Group supports a finding of imprudence with respect to NSPI's rejection of this contract.

[Avon Closing Submission, November 23, 2012, p. 12]

[241] The Small Business Advocate, in its Reply Closing Argument, stated:

The FAM Audit Report provided recommended finding V-1, that added fuel costs were incurred due to NSPI's inaction addressing gas market conditions, which the Board's consultant recommends should be a disallowance of $6 million. The SBA supports this finding because NSPI has not provided sufficient evidence in this proceeding or in its closing submission that this incremental cost could not have been avoided had NSPI

> pursued earlier efforts to replace expiring contracts as well as more negotiated more aggressively for more favorable pricing terms in replacement contracts.
>
> [SBA Reply Closing Argument, November 30, 2012, p. 3]

11.4.2 Findings

a) Bid A

[242] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Initially NSPI, and their advisor Mr. Crook, thought NSPI had a very favourable offer and recommended it to NSPI's Fuel Strategy Table. They agreed to accept it. However, when the term sheet confirming acceptance was presented to Bidder A, it then became clear that there was not agreement on the proposal. Liberty acknowledged that there was not an enforceable contract.

[243] While it may be argued that NSPI should have more aggressively pursued Bidder A to obtain a favourable compromise price, the Board does not believe NSPI's failure to do so was sufficient to meet the test of imprudence. Concern about the future business relationship with Bidder A is a relevant concern for NSPI to have taken into account.

[244] Finally, while Liberty was right to be concerned that Bidder A entered into a subsequent contract for the same gas with Emera Energy Inc., there is no basis, in the Board's view, to find that activity frustrated the contract or that NSPI played any role in the contact between Emera Energy Inc. and Bidder A.

b) Bid B

[245] The Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[246] For ten years under the Shell contract, which expired in 2010, NSPI enjoyed a gas price that was favourable vis-à-vis the Dracut hub. The Bid B contract would have permitted that favourable pricing to continue, albeit for a much smaller volume of gas, possibly for an additional eleven years.

[247] NSPI stated that the gas supply contract was available "for as many years as SOEP supply would support". Mr. Crook noted that the gas supply contract had renewable provisions that made it potentially attractive.

[248] NSPI spent a great deal of time explaining during the hearing, principally based on the evidence of Mr. Reed and Mr. Henning, that the evolution of the gas market in the Maritimes had taken place in such a way that gas is now being less favourably priced in the Maritimes, vis-à-vis the Dracut hub, to the point where it is virtually impossible to obtain Dracut minus bids.

[249] Based on this evidence, by foregoing the Bid B contract, NSPI has passed up an opportunity that may never present itself again, at least in the foreseeable future.

[250] What appeared to concern NSPI was the associated transportation capacity. Halifax would have been a secondary delivery point on the M&NP pipeline.

[251] The evidence, however, is that virtually all of the gas being delivered to Tufts Cove is being delivered pursuant to transportation contracts where Halifax is a secondary delivery point. While a shipper with Halifax as a primary delivery point would have priority over other shippers with only secondary delivery rights to come to Halifax, there were no such shippers. If there were to be any constraints on the M&NP pipeline,

those with secondary delivery rights would share the capacity pro rata. However, in 2008 the M&NP pipeline was not being used to its full capacity. There was never a day, based on the evidence of Mr. Crook, where the pipeline capacity was met or exceeded.

[252] Mr. Crook's principal concern seemed to be that somehow the gas would not get to Halifax. That is not logical to the Board. The gas destined for the Bid B primary location must enter the M&NP mainline. It then proceeds along the M&NP pipeline until it reaches the upstream lateral leading to the primary delivery point. The Halifax lateral meets the M&NP pipeline near New Glasgow. There is no gas being injected into the M&NP pipeline between the take off point for the upstream lateral and the Halifax lateral. In the circumstances, therefore, it is not at all clear to the Board what the risk was that NSPI thought it was avoiding. Mr. Crook as much as conceded that under questioning from the Board.

[253] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[254] It is apparent to the Board that NSPI, at the time, did no such analysis.

[255] NSPI, in its Reply Brief, included a section which attempted to criticize and undercut Liberty's analysis. The Board is very concerned that this analysis was not made available in NSPI's principal argument and, by saving it for the Reply Brief, no party had a chance to respond or comment on it. In the circumstances, while the Board has reviewed this submission, the Board gives little weight to that analysis.

[256] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[257] In the circumstances the Board disallows $903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e., 426 days). The details of the calculation are based on confidential information. As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

c) Seasonal, Monthly and Daily Pricing

[258] Liberty's theory in recommending a disallowance with respect to monthly, seasonal and daily purchases has as its foundation its belief that inaction by NSPI contributed to the market conditions that existed.

[259] In terms of making its recommendation with respect to disallowance, it made certain assumptions as to how the market would have worked if buyers on the Canadian portion of the M&NP had access to LNG. On a seasonal basis Liberty felt there would be opportunities for NSPI to obtain favourably priced gas recognizing the volumes of LNG flowing into the U.S.

[260] All of this evidence was filed in confidence so it is difficult to be more precise about this calculation. Essentially what Liberty did was compare the market as it was compared to the market as it could have been.

[261] In respect to the Bid A and Bid B contracts, the circumstances are fairly clear and the Board is able to make a judgment as to whether or not NSPI acted prudently. With respect to seasonal, monthly and daily purchases the evidence is much

less clear. Based on the market conditions as the Board now understands them, and as more particularly described in the natural gas market section, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases. It is not at all clear to the Board that NSPI could have achieved what the FAM Audit suggests in terms of price in seasonal, monthly or daily contracts.

11.5 Natural Gas Markets

11.5.1 Evidence

[262] As noted elsewhere in this Decision, for ten years ending in late 2010, NSPI enjoyed the benefit of what is now considered to be a favourably priced natural gas contract with Shell Canada for Sable offshore gas.

[263] Indeed, during much of the life of that contract, NSPI was in a position of selling natural gas, not just purchasing it. The Shell contract provided much more gas than NSPI, in those years, could economically use to generate electricity. Among other things the Shell contract recognized, in terms of price, that Halifax was closer to the source of supply than the trading hub of Dracut, Massachusetts. By 2008, when NSPI started the process to find replacement gas, it appeared that market conditions had deteriorated with respect to the price for gas purchases in the Maritimes. It appeared that instead of paying a price that excluded transportation on the U.S. portion of the pipeline, NSPI would be faced with prices tending to a level reflecting increasing amounts of transportation from the Canadian border to Dracut because shippers had contracted for that capacity and, with dwindling gas supplies, needed to be reimbursed for that transportation commitment.

[264] In the 2010 Audit, Liberty made a number of recommendations to NSPI, including:

1. Become more proactive in obtaining competitive market prices for NSPI gas supplies;

2. Maintain contacts with existing sources of gas supply components and work aggressively to develop new ones.

[265] In both this audit and the previous audit Liberty expressed concerns that NSPI was being too passive with respect to obtaining competitively priced gas supplies by failing to be more aggressive with gas suppliers; by failing to take sufficient steps to enforce regulatory protections to Canadians, including the National Energy Board's ("NEB") Market Based Procedure; and, in Liberty's view, deferring to Emera affiliates with respect to the operation of the gas market.

[266] Liberty described the NEB's Market Based Procedure:

> The Board adopted in 1987 a new "Market-Based Procedure" (MBP) for reviewing export applications. This decision observes that:
>
> > *The fundamental premise of the MBP is that the marketplace will generally operate in such a way that Canadian requirements for natural gas will be met at **fair market prices**. However, the MBP was designed to provide for intervention if there was evidence that the market was not working to **adequately and fairly serve** Canadian needs.*
>
> This language does not define any of the emphasized terms. It does, however, appear to add a test beyond pricing at market, observing that whatever prices the market produces must be adequate to serve and fair in treating Canadian buyers.
>
> This decision describes the Complaints procedure in connection with export licenses as follows:

> *Under the Complaints Procedure, Canadian natural gas buyers have an opportunity to intervene with respect to an application for a natural gas export license if they believe they have not been able to purchase natural gas on terms and conditions that were **similar** to those of the proposed export. [Emphasis in original]*

[Exhibit N-171, pp. III-5 to III-6]

[267] Liberty relied significantly on a 2002 decision of the NEB where the Province of New Brunswick initiated an application requesting the NEB establish rules to apply when considering applications for short term exports for incremental supplies of Nova Scotia offshore gas. Gas exported under short term exports is subject to less regulatory oversight than long term licenses. While the NEB did not intervene directly in the exports of gas, it did signal that it would take on a heightened monitoring role.

> In summary, the Board is of the view that the developing Maritimes gas market faces many challenges that are not faced by buyers in the mature export market.
>
> Given these market realities, the Board shares the concerns of New Brunswick and PEI about access to incremental gas supplies on fair market terms. Although the Board does not believe that the record in this hearing warrants direct regulatory intervention, it did raise sufficient concern that the Board believes it must enhance its monitoring efforts in Maritime Canada

[NEB Decision MH-2-2002, Exhibit N-191, p. 42]

[268] Liberty also noted the NEB's findings in the Brunswick Pipeline decision related to LNG delivered to Canaport:

> The NEB stated as follows:
>
> > *… the Board is of the view that one aspect for the justification of this Project is its ability to provide an opportunity for access to a new source of natural gas supply to the Maritimes. While some parties expressed concerns regarding the ability of Maritime Canada markets to access the incremental gas supply provided by the Project, the evidence before the Board indicates that Irving Oil is the largest user of natural gas in Maritime Canada. Therefore, Irving Oil's access to the gas supply supports the Board's finding that there will be Canadian access to the Project's gas supply. Furthermore, Maritime Canada could also access this new natural gas supply source, to fulfill current and anticipated future natural gas needs, through the use of backhauls, swaps and direct connection to the Brunswick Pipeline.*

[Exhibit N-171, p. III-13]

[269] Among Liberty's conclusions with respect to NSPI's conduct in the natural gas market are the following:

1. NSPI has demonstrated that customers cannot rely upon it to champion their interests with respect to prices for natural gas in the Maritimes market;

2. NSPI should have been contesting and should continue to contest gas market circumstances; however there is no basis for confidence that it can be relied upon to do so even if it did undertake the effort.

[270] Liberty's view is that NSPI should have more aggressively pursued discussions with the NEB, including a possible application to the NEB, and been more active with respect to negotiations in the gas market reminding suppliers, among other things, of the Market Based Procedure.

[271] In NSPI's view, Liberty had a flawed understanding of how the U.S. Northeast and Maritimes gas market operates. NSPI submitted:

> The overwhelming weight of evidence is that NS Power's gas acquisition prices were sound and the contracts it achieved during the audit period delivered excellent value to customers.
>
> [NSPI Closing Submission, November 23, 2012, p. 51]

[272] NSPI, in its Reply Evidence, stated:

> Over the past five years, the balance of supply and demand in the Maritimes has shifted. Local supplies have dwindled, and local demand has increased. … Since January 2010, the usage of natural gas on the M&NP system (both M&NP Canada and MN&P US) has ranged from approximately 200,000 MMBtu/day to 500,000 MMBtu/day. On the other hand, estimated production of natural gas in Atlantic Canada has ranged from approximately 280,000 MMBtu/day to 340,000 MMBtu/day (excluding supply disruptions).
>
> …
>
> The current supply/demand imbalance, and the cost of the next available supply source, has caused the spread NS Power pays for natural gas supply … The price for natural gas supply in the Maritimes market will remain higher than it had been previously … until such time that supply and demand return to a more balanced state.
>
> [Exhibit N-98, pp. 34 & 36]

[273] With respect to its activity in the gas market, vis-à-vis customers and the NEB, NSPI points to a very favourable contract it entered into with a supplier for offshore natural gas. Unfortunately, supply conditions have not enabled NSPI to take full advantage of that contract through no fault of NSPI.

[274] With respect to the interaction with the NEB, NSPI stated as follows:

> NS Power has not filed a complaint with the NEB over the gas supply/pricing structure. Nor has any other natural gas customer in this market. NS Power continues to believe there are no grounds for such a complaint. Apparently all market participants and stakeholders in the Maritimes market except Liberty agree. If circumstances change in the future such that filing a complaint with the NEB may have merit, NS Power will re-evaluate accordingly.
>
> [Exhibit N-98, p. 39]

[275] With respect to LNG gas, NSPI pointed out that it is not economic to purchase gas at international LNG prices and bring the gas to Nova Scotia.

[276] In the view of NSPI's expert witness, John Reed, the change in market pricing in the Maritimes is not due to market flaws as he says Liberty alleges, but reflect a change in the market circumstances because of the region's shortage of supply. With respect to market conditions in the Maritimes and the role of the NEB, Mr. Reed stated as follows:

> …it is telling that no other market participant in the Maritimes filed a complaint with the NEB to correct what Liberty concludes are market failures. In other words, of the many sophisticated market participants that were also affected by the market conditions for which Liberty has expressed concern in the audit, not one deemed that filing a complaint had merit. …
>
> Therefore, since NSPI's conduct in the market was consistent with all of the other sophisticated market participants that were also affected by changing market dynamics and prices, NSPI's conduct cannot be deemed to be outside the range of reasonable behavior during this same time period. …
>
> Furthermore, even if NSPI had asked the NEB to intervene in 2010 and the NEB had complied, it is not at all likely that the NEB's review would have led to lower gas prices for NSPI, and, presumably, if it did, that outcome would have been some years into the future, not for 2010/2011.
>
> [Exhibit N-85, p. 27]

[277] On November 9, 2012, the last day of hearing and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision.

[278] It turns out that NSPI had indeed consulted a leading Calgary law firm concerning a possible complaint to the NEB and received advice. In part, based on that advice, NSPI had engaged in much more aggressive behavior with possible gas suppliers concerning price leading, in its view, to favourable pricing. NSPI also explained its strategic view with respect to LNG supply and its importance for supplying additional gas to a gas constrained market and the favourable effect that may have on the Maritimes market.

[279] Liberty had been advised in March of 2012 that NSPI had contacted outside counsel in 2010 but no reference to the fact they had contacted counsel prior to negotiations with the gas supplier where the favourable price was obtained. When asked about counsel's advice Liberty was advised by NSPI it was privileged.

[280] The Board was concerned as to the extent of Liberty's knowledge of this information, which came out on the last day of the hearing and asked for an Undertaking from Liberty, who responded in part as follows:

> This undertaking addresses Liberty's knowledge of contacts that Mr. Janega testified he had with outside counsel and with [redacted] about NEB authority to address market concerns. To summarize, we were not aware until reading the transcript of Mr. Janega's reported contacts with outside counsel. We were aware that NS Power did communicate with [redacted] about supply, but not as Mr. Janega described those contacts.
>
> Regarding consultation with outside counsel, we have no recollection of Mr. Janega's having discussed with Liberty any consultations regarding authority of the NEB to address gas market issues of concern to NS Power. A search of our notes since 2008 for reference to any such discussion found none. The issue of response to market concerns has been of interest to us since late 2008, at least. See for example, the April 2009 ICF International, *Report on Planning for Future Natural Gas Supply: A Review of the Activities of Nova Scotia Power, Inc.*, submitted by NS Power to the UARB, and

> discussed during this proceeding. That report came at the UARB's request, following our expressions of concern in the 2009 NS Power GRA. Thus, it is extremely unlikely that statements by Mr. Janega or anyone of this nature would have escaped attention.
>
> We addressed market-facing actions with Mr. Sidebottom in a March 31, 2010 interview during the prior FAM audit. He cited no communications with attorneys. He did say that he viewed [redacted] favorably, and cited no problems or concerns. He stated that he and Mr. Janega sought a meeting with [redacted] following its failure to bid in the Fall 2009 gas supply solicitation.
>
> [Undertaking U-27, November 19, 2012, p.1]

11.5.2 Findings

[281] NSPI, in their Closing Submission, stated as follows:

> **After years of debate about the merits, or lack thereof, of filing a complaint with the NEB, it is now clear that NS Power has, in fact, done exactly what Liberty has wanted the company to do.** [Emphasis added]
>
> [NSPI Closing Submission, November 23, 2012, p. 59]

[282] The problem is that the extent and importance of this activity was not disclosed to Liberty, the Board, or the parties until the last afternoon of the hearing. NSPI says in its submission that this should have been clear from a reading of Responses to Information Requests during the 2010 FAM proceeding. The Board has re-read those responses and, while they do disclose details of contractual negotiations with the counterparty, they do not disclose in any way the evidence that was provided by Mr. Janega on the last afternoon of the hearing and its importance and effect. Even if the 2010 FAM Information Responses did disclose this information it seems odd NSPI would suggest the Board must plumb the depths of the evidence in a prior proceeding to find it.

[283] The Board's dismay and concern about this cannot be overstated.

[284] A fundamental underpinning of Liberty's criticism of NSPI over the years was NSPI's failure, in the view of Liberty, to pursue regulatory avenues open to it and,

as a companion to that, to more aggressively pursue marketers of gas, recognizing the existence of the Market Based Procedure.

[285] In 86 pages of FAM Audit Reply Evidence, the evidence provided by Mr. Janega was not disclosed. The Board can only assume that if NSPI had been forthcoming on the consultations with a leading Calgary law firm and conversations NSPI had with the counterparty following those consultations, in the thousands of pages of evidence and IRs and in the hearing, the nature of the Audit and most certainly the nature of the hearing, one of the most rancorous the Board has ever seen, would have been very different.

[286] NSPI's actions in withholding this information are both inexplicable and inexcusable.

[287] NSPI has criticized Liberty to the point of ridicule for this recommendation in the present Audit and, previously, that NSPI should more aggressively pursue discussions with the NEB and be more active with respect to negotiations with gas marketers given the existence of the Market Based Procedure.

[288] Remarkably, NSPI now says it was, in fact, following Liberty's advice which has been given over a period of four years. The Board cannot understand what NSPI thought it was doing by withholding that information and continuing to ridicule Liberty for making the recommendation.

[289] While it may have been slow to act, it now appears NSPI was acting appropriately with respect to their consultation with the Calgary lawyers and in certain of their recent dealings with suppliers, as a consequence. However, the failure to disclose that has added significant time, cost and rancor, unnecessarily, to this hearing.

[290] In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance as more particularly described in Section 11.10 of this Decision.

[291] In its Final Submission, Avon stated as follows:

> 158. It is understood that there is a long-standing disagreement between NSPI and Liberty with respect to the level of engagement or aggressiveness that NSPI ought to be demonstrating in respect of the development of the natural gas market in the Maritimes. The Avon Group agrees with Liberty that NSPI has demonstrated an unreasonably passive approach to the natural gas market and that it is likely that a more aggressive approach, one that is commensurate with NSPI's purchasing power in the market, may have produced more economically priced gas contracts for NSPI customers.
>
> 159. It would be acceptable if NSPI had tried and failed but it is problematic, from the perspective of the Avon Group, that NSPI continues to insist that the market is behaving well and that there are no problems that require the Utility's intervention. NSPI's approach to natural gas market, in the Avon Group's opinion, has had detrimental effects and leads us to question whether NSPI has made every reasonable effort to obtain economically priced natural gas.
>
> [Avon Final Submission, November 23, 2012, p. 29]

[292] That submission was made even with the knowledge provided by NSPI in the last day of the hearing.

[293] The Board accepts that the gas market in the Maritimes has in recent years posed significant challenges to NSPI and other gas users. Mr. Reed described those challenges in response to a question from Board Counsel:

> In fact, the prevailing market of course represents the confluence of all of those sources of supply and what you see in the Maritimes market is that the marginal source of supply sets the prevailing price and that marginal source of supply has shifted from being indigenous production to production that's outside the region. And in fact, as you start to bid gas away from either the Portland system or Dracut, you end up having to pay a higher price. In fact you -- again that marginal resource is setting the prevailing price in the region and that marginal resource is now coming from someplace else.

> I expect that actually long term certainly will be the case. We may have an interim period in which the new gas causes us to go back to a Dracut netback market for a period of time; that would be great if it did. But long term, most people expect that in fact, gas will flow from south to north, into the Maritimes and that will be a Dracut-plus pricing regime. Even though there may be production in the Maritimes, the marginal source of supply will be from elsewhere.
>
> [NSPI Closing Submission, November 23, 2012, p. 52]

[294] The Board accepts that the pricing dynamics of the Maritimes gas market have changed over the last few years as explained by Mr. Reed.

[295] Indeed, the evidence provided by Mr. Reed has given the Board an enhanced appreciation of how the gas market is unfolding in the Maritimes.

[296] Circumstances have given NSPI limited room to maneuver with respect to gas pricing given the shortage of supply.

[297] Finally, Liberty expressed its continued concern about affiliate relationships and, in particular, Emera's relationship as owner of the Brunswick Pipeline, with the principal shipper Repsol, a company who was also a dominant player in the Maritimes gas market. These concerns are reinforced by the fact that the Maritimes market is currently not transparent and is not liquid. The market has few buyers and sellers and a dwindling supply.

[298] While the Board is, and has been, concerned about affiliate relationships and as a consequence has imposed a rigorous code of conduct on NSPI, the Board does not see evidence in this proceeding which would, applying the test of a balance of probabilities, cause it to make any disallowance because of affiliate activity.

[299] In the circumstances, the Board makes no other disallowance with respect to NSPI's gas market activity. The Board, in future, expects NSPI to do "exactly what

Liberty has wanted the Company to do" with respect to aggressively pursuing any reasonable opportunities to purchase gas at as competitive as possible prices.

[300] Again, much of the evidence on this topic was filed in confidence and, accordingly, the Board is only in a position to give an overview of both the evidence and a summary of its findings.

11.6 Natural Gas Hedging

11.6.1 Evidence

[301] A common reference point for the pricing of natural gas in the Northeast is at Dracut, Massachusetts. The Henry Hub, a distribution hub at Erath, Louisiana, is used as the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The price difference between the Henry Hub and another trading hub, including Dracut, is called the "basis differential", or simply, the "basis".

[302] In the winter of 2010-11, there was a marked increase in the "basis differential" with Dracut as a result of a series of events (referred to as a "basis blowout"), causing NSPI's natural gas costs to rise.

[303] Liberty found NSPI's natural gas costs for November and December 2010, and at least January 2011, were unreasonably high due to the Company's failure to hedge Northeast Market "basis". As a result of this finding, Liberty recommended the Board defer NSPI's recovery of $12.8 million pending a study of what hedges would have resulted under a properly designed hedging program for the winter of 2010-2011 and determine based on that program whether there would have been a cost associated with what Liberty identified as imprudent.

[304] The Northeast Market "basis blowout" was described by NSPI as follows:

> A series of events starting in December 2010 caused the Dracut basis differential to rise throughout the winter of 2010-2011. First, the Henry Hub did not experience its usual winter price increase, so the baseline for the basis differential was lower than normal. Second, unusually cold weather in the northeast caused supplies in the area served by the Dracut hub to tighten. Third, severe weather prevented LNG tankers from docking at the Canaport terminal in Saint John, further exacerbating the supply shortage. Finally, in February, the Trans-Canada Pipeline ruptured and exploded at Beardmore, Ontario, 190 kilometres northeast of Thunder Bay, Ontario. This temporarily cut off supplies of Western Canadian gas to the Trans-Quebec and Maritimes pipeline and the Portland Natural Gas Transmission System, which serve the northeastern US. All these factors conspired to drive up the Dracut basis in an untypical and unforeseeable manner.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 54]

[305] Liberty indicates this $12.8 million is a place-holder based on results NSPI provided as the potential savings for the two months, November and December 2010, extrapolated over the five winter months. A study was undertaken by NSPI after the “basis blowout” event in December 2010, related to the need to hedge the “basis”. However, Liberty indicates this study did not provide the proper hedging program to accomplish the objective of reducing basis volatility at least cost, nor did it identify the appropriate financial instrument that would accomplish this.

[306] NSPI indicated they appropriately considered these risks and addressed the risks associated with the change from the long-term Shell contract that expired October 31, 2010, stating the only significant change in risk was moving from monthly to daily pricing and that there was no material impact to basis exposure.

[307] NSPI took the position that its hedging during this period aligned with the objectives and requirements of the Fuel Manual, and that the direction within the Fuel Manual does not allow them to hedge the “basis”. It claims an appropriate study was completed in anticipation of the changes related to the long-term Shell contract, indicating it retained Black & Veatch to undertake a comprehensive study of natural gas pricing risks. Black & Veatch did not identify any need to change NSPI’s approach to

basis risk or hedging. This report dated November 23, 2010 was entered into evidence during the hearing. The Board agrees the Utility's consultant on hedging objectives and risks did not identify the "basis" risks. However, the Board notes that the scope of the study does not expressly include the assessment or identification of basis risks and the study makes no mention of them.

[308] NSPI also indicated their assessment of the risks associated with the expiration of the long term contract resulted in the implementation of swing/swaps at Henry Hub.

[309] During the hearing NSPI testified that an appropriate hedging program was in front of the FAM Small Working Group and that no other party identified a need to review basis differential.

[310] NSPI has also indicated that regardless of whether their response was appropriate, the cost to hedge the basis would have cost customers more than they would have saved from putting the hedges in place. Mr. Crook stated in his Pre-filed Evidence that there are no exchange traded hedging products for Dracut. Alternatives are costly, with few market participants willing to do it for Dracut.

[311] The SBA concurred with the recommendation to conduct a study of NSPI's hedging program. However, he did not recommend setting aside the $12.8 million, stating this estimate is hypothetical. The SBA concluded though that, if it was found through the study that there is a cost associated with the imprudence, it should be disallowed.

[312] Other parties have supported Liberty's recommendations, including holding back $12.8 million until the recommended hedging policy is studied and the cost determined.

11.6.2 Findings

[313] In setting the context for its consideration of this issue, the Board is mindful of the discretionary nature of hedging practices. Hedging, by any party, has never been intended to safeguard a company or utility from all risks that might occur in the future.

[314] The Board understands that NSPI, like any other party involved in hedging practices, requires some latitude to exercise judgment in the development and implementation of a hedging strategy. In the hearing, hedging was described as an art, rather than an exact science.

[315] In fact, the decision to enter into any specific hedge or hedging strategy is akin to the purchase of insurance to protect against future losses. Like insurance, there is a wide range of hedging products that are available to parties to protect their positions. These products also come at a range of prices. In choosing any particular hedging product, it is appropriate for a party to consider the reasonable risks which might be encountered in the future.

[316] Further, the Board recognizes that it is not appropriate to rely solely on hindsight in an analysis about the reasonableness or prudence of a hedging strategy. No person can predict the future. Accordingly, if circumstances occur which result in losses as a result of a particular event or a series of events, it does not necessarily follow that the chosen hedging strategy was wrong or unreasonable. Conversely, windfalls which occur as a result of unexpected future events which were not hedged do

not make the hedging decision a brilliant one. Further, the size of any loss does not factor into the consideration of the appropriateness of a hedging strategy.

[317] The Board considers that the reasonableness of a hedging strategy must be analyzed in the context of the facts or circumstances known or reasonably expected by the person or utility at the time the hedging strategy was developed or applied.

[318] In this instance, NSPI was faced in 2010 with a long term natural gas supply contract with Shell, which was coming to an end on October 31, 2010. In replacing that contract, two significant elements of NSPI's circumstances changed. First, the price of the gas under the new contract would be based on daily prices, which are more volatile, rather than monthly prices that existed under the former contract. Second, because of the interplay between natural gas and coal prices, NSPI generally started using the natural gas in its generation fleet under the new contract, rather than selling the gas to third parties. The impact of this latter element caused NSPI to bear the increased costs itself, rather than being able to pass them to third parties purchasing the gas.

[319] The Board is satisfied that NSPI did consider the impact of the impending conclusion of the long term Shell contract. In order to protect from negative fluctuations of prices for its gas purchases, it entered into a hedging strategy which adopted swing/swaps. This would help reduce the risk of volatility in daily natural gas prices, effectively replacing the daily prices with average monthly prices which were more stable.

[320] While the swing/swaps did provide some protection to NSPI from the above noted monthly/daily price risk, swing/swaps did not, unfortunately, protect from a

significant change in the "basis differential". They are not intended to operate as a direct hedge of the "basis".

[321] However, the Board accepts the hedging evidence of NSPI that an assessment of NSPI's program in the fall of 2010 would not have reasonably uncovered the need to hedge the "basis". The Board finds that no one could have reasonably foreseen the combined series of events which led to the "basis blowout".

[322] The Board notes that NSPI had the benefit of expert advice from its consultants on the issue of hedging. As described in the hearing, both Black & Veatch and Leonard Crook have expertise in this area. Both consultants assisted NSPI with the development and implementation of its hedging practices. Black & Veatch was involved in a broad sense in its periodic review of hedging generally, while Mr. Crook was more actively involved in the decision-making process by advising NSPI in relation to gas purchases and hedging risk.

[323] The Board is satisfied that it was reasonable to retain and rely on the advice of Black & Veatch and Mr. Crook.

[324] Neither expert specifically identified a potential "basis differential" as a stand-alone risk to be hedged.

[325] The Board also notes that Liberty's position on the issue of hedging practices appeared to change from the FAM Audit report through to the hearing. Initially in its report, Liberty concluded that NSPI should have placed a hedge on the basis differential, but at the hearing their opinion seemed to change to the view that NSPI should have examined this type of hedge in anticipation of the Shell long term contract coming to an end. Given the apparent softening of Liberty's position on this issue, the

question becomes one of possible or potential imprudence, rather than actual imprudence. However, on the balance of probabilities, the Board concludes there is not sufficient evidence to warrant a finding of imprudence.

[326] After reviewing the evidence and the submissions, the Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the basis differential and result in the "basis blowout".

[327] Further, even if NSPI had applied a hedging strategy to deal with a potential blowout in the basis differential, the cost of purchasing such hedging products, to the extent they were available, may possibly have cost ratepayers more than the "basis blowout" itself, which NSPI addressed immediately, early in 2011.

[328] Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI as a result of the "basis blowout" in the winter of 2010-11. Consequently, no specific review is required to study what amount NSPI might have saved in the winter of 2010-11 if it had adopted a different hedging strategy.

[329] During the hearing, NSPI's hedging witness panel stated that a further examination of NSPI's hedging practices would appear appropriate on a prospective basis.

[330] On the question of a prospective study, the Board does not consider that a specific direction is necessary. The Board expects that NSPI should be continually undertaking any studies or analyses about any aspect of its fuel management practices, including hedging, if considered prudent or appropriate to lower or stabilize fuel costs.

[331] Notwithstanding the Board's findings above, it wishes to comment on one submission by NSPI on this hedging matter. In its FAM Audit Reply Evidence, NSPI suggested that "the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual" (p. 52).

[332] However, NSPI's own expert, Peter K. Nance, of Black & Veatch, stated that the Fuel Manual does not preclude NSPI from applying a new hedging strategy:

> MS. STEWART: You would agree that the fuel manual doesn't dictate a certain strategy?
>
> MR. NANCE: No, I don't think that it dictates one strategy. I think that it has guidelines, and fairly strong ones, for certain elements of the risk -- of the hedging strategy, and I tend to -- when I think about that, what I'm thinking about are the percentages of fixed price risk, as I refer to it, that is best to be -- suggested to be managed under the program. The less -- but in -- if -- but in terms of developing an overall response, my suggestion to you would be that, yes, I believe that NSPI has the authority and the ability to do that under the manual.
>
> MS. STEWART: And so there could be different types of hedges that are entered into and still meet the requirements for fixed price management risk management ---
>
> MR. NANCE: Yes.
>
> [Transcript, October 31, 2012, pp. 868-869]

[333] Thus, in the Board's view, NSPI should not rely blindly on the express terms of the Fuel Manual to prevent it from using a new or different hedging strategy that would otherwise be reasonable in the circumstances.

11.7 FAM Audit Process

11.7.1 Evidence

[334] In its Reply Evidence, NSPI asserted that Liberty's FAM Audit is "fundamentally flawed", to the extent that the Board should reject all of the FAM Audit's conclusions and recommendations (including those which were supportive of NSPI's activities related to fuel).

[335] Among other criticisms, NSPI asserted that Liberty "has not acted in accordance with professional auditing standards"; "bases its major conclusions on a misapprehension of known facts"; its "approach, conclusions, and recommendations demonstrate insufficient knowledge and expertise in the subject matter of the audit"; and that "Liberty combines a lack of industry knowledge with a misguided approach to prudence review and a pre-existing bias against utility-affiliate relationships in order to develop a conspiracy theory that unjustly maligns NS Power, Emera, and the employees and executives of both companies": see Exhibit N-135, pp. 4-5.

[336] NSPI asserted that:

> The faulty conclusions of the FAM Audit arose from methodologies that were procedurally unfair and as such, did not meet the minimum professional standards for such an audit. Other than providing NS Power an opportunity to correct factual errors in the draft report, Liberty did not put its most serious allegations to NS Power during the course of the audit. This deprived NS Power of the chance to respond to these specifics, many of which could have been shown to be false merely by pointing to data already supplied to Liberty. Liberty's investigative methodology was flawed. It took no steps to interview the Chief Executive Officers or the Chief Human Resources Officers of NS Power or Emera, each of whom are impugned by the Report.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 5]

[337] In addition to its request that the entire FAM Audit prepared by Liberty be rejected, NSPI suggests that Liberty should not conduct any future FAM Audit duties:

> Despite [Liberty's] extensive involvement with the creation, implementation, and operation of the FAM, Liberty Consulting Group has conducted the FAM Audits. We respectfully submit that Liberty's deep involvement in the design and operation of the FAM precludes it from meeting the POA's requirement that an "independent firm" conduct the audit.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 9]

[338] Moreover, NSPI also requests revisions to the FAM Plan of Administration:

> NS Power proposes that the FAM Plan of Administration be revised in order to bring greater discipline and clarity to the audit provisions. These changes are designed to

ensure that the Board and customers are able to obtain the benefit of a constructive and efficient review of NS Power's fuel procurement and FAM compliance, and that the Company and its employees will not experience the kind of disruption and distraction that has been experienced in this most recent audit process.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 82]

[339] NSPI submits that the following changes be made to the POA:

- Adopt the Institute of Internal Auditors (IIA) – International Standards as applicable to FAM Audits;
- Define auditor independence, objectivity, and competence;
- Require FAM Auditors to be selected by competitive solicitation (RFP) under the authority of the UARB, independently of NS Power or FAM participants;
- Require the audit scope to be established and finalized, and provided to NS Power and interested parties to the FAM, prior to commencement of the audit;
- Establish fixed parameters for the audit, in terms of the time to complete the audit, and for NS Power to correct errors in the draft audit;
- Require auditors to raise serious matters of concern, or significant negative recommendations, with management during the course of the audit so that management can respond and action can be taken to remedy matters as appropriate;
- Establish a standard for the anticipated cost of the audit, with an appropriate process for the UARB to approve additional costs when appropriate, and allow the utility to recover the costs of the audit and related processes, pursuant to the FAM;
- Prohibit hindsight forecasting by auditors;
- Require that any subsequent consulting work that arises from an audit recommendation must be undertaken by a consultant that is not the auditor.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 83]

[340] In support of its position on the auditing standards to be applied in a FAM Audit, NSPI retained Deloitte.

[341] Deloitte drafted an audit plan and testimony that outlined potential differences between their audit approach and that of Liberty, based on a review of the final report. They observed:

- For some conclusions (presented in the section below), the report does not clearly state the evidence based on which the conclusions were drawn. We did not see evidence in the Liberty Report the Auditor conducted detailed audit procedures consistent with known standards of auditing to provide assurance to the NSUARB of compliance and use of good practices by NSPI in all cases as it relates to the FAM Audit

- The report appears to present points/conclusions relating to areas that extend beyond the scope of the FAM audit outlined under Section 5 of the POA. Circumstances/ other audit evidences that led to such extended scope will need to examined or analyzed; and
- In specific cases (e.g., conclusions on hedging program), the conclusions appear to be based on a few selected months that might have had issues rather than the whole audit period or based on a randomly selected sample. It is important to examine if the same conclusions would be drawn on a random sample; Circumstances or selection criteria which led Liberty to form opinions based on specifically selected samples needs to be better understood to validate the conclusions.

[Exhibit N-131, p. 3]

[342] NSPI had Deloitte, Ms. Medine and Mr. Reed testify to auditing standards, with Deloitte recommending the Institute of Internal Auditors Standards and the US Government Accountability Office Auditing Standards, and others referring to the National Association of Regulatory Utility Commissions ("NARUC") standards. During its testimony, Deloitte agreed the NARUC standards would also be appropriate:

> MS. RUBIN: Would you concur that the NARUC guidelines would also offer suitable guidelines to the preparation of a FAM Audit?
>
> MR. LOBAREC: Yes, I think that's a reasonable question and I would agree, it could. It's more about whether or not we go from assertion to specific ordered steps and then provide evidence that's sufficient against those steps to reach a conclusion. Any of the ordered standards could lead you to that as long as those steps are followed in concert.

[Transcript, October 31, 2012, p. 820]

[343] NSPI experts also testified they had concerns related to Liberty's compliance with auditing standards, referring to concerns with Liberty's Audit Report with respect to the NARUC standards. Ms. Medine stated:

> The FAM Audit and the FAM Audit Report do not meet industry standards with respect to guidelines established by the National Association of Regulatory Utility Commissioners (NARUC), the U.S. General Accounting Office (GAO), and other entities in a number of material ways. The most significant issues are as follows:

- Material areas of the FAM Audit were not conducted by individuals that have sufficient expertise and relevant experience.
- Confidential information was disclosed during the course of the FAM Audit.
- The FAM Audit Report was not objective and did not have a balanced tone.

- Liberty failed to support all material findings with relevant evidence.

[Exhibit N-133, pp. 2-3]

[344] In its FAM Audit Reply Evidence, NSPI placed particular emphasis on the Deloitte opinion, stating:

> Deloitte's opinion is important for the Board to consider. Deloitte is a global auditing and consulting organization with the highest reputation for professionalism and integrity. The firm assigned accomplished international experts to the review of the FAM Audit. Deloitte identifies and applies established professional auditing standards. The Deloitte assessment identifies what NS Power respectfully suggests are serious gaps in the Liberty Report.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 81]

[345] The Board notes, as did Liberty in its Reply Evidence, that despite NSPI's characterization of Deloitte's evidence, nowhere did Deloitte describe any possible gaps in Liberty's audit as serious or significant in any way.

[346] Ms. Medine claimed other utilities have encountered similar problems with Liberty audits.

[347] However, Board Counsel witness Robert E. Curry, Jr., presented a different opinion. Mr. Curry is experienced in the field of utility regulation, including as a former Commissioner of the New York Public Service Commission. Based on responses from senior officials in 11 State regulatory entities, and based on his own personal experience with Liberty, he stated:

> All of the respondents spoke highly of: Liberty's professionalism; the value Liberty's reports added to the regulatory process for both the utility and the regulator; its attention to keeping Staff of the client informed of its progress; the general interaction with the utility being audited (in spite of differences in views of the subject matter of the review); and, its overall effectiveness. No respondent reported any instance of prejudice or bias either for or against the utility or its regulator. "Tough but fair" was a term used by several commentators. …
>
> [Exhibit N-168, p. 5]

[348] In Board Counsel's questioning of the NSPI witness panel, he referred the panel to the views of National Grid about Liberty. National Grid delivers electricity to approximately 3.3 million customers in the U.S. Northeast. In a news release about a five month independent review of its accounting systems and practices, National Grid stated:

> We engaged Liberty because of their reputation as being both thorough and independent. We wanted a report that would take a critical look at those areas where we need to improve, and this will help guide us going forward.
>
> …
>
> The company will share the report shortly with regulators in its various US operating areas. Liberty Consulting is a nationally recognized leader in providing independent reviews of regulated businesses. Its report is based on hundreds of data requests and employee interviews, site observations of systems operations, on-site document reviews, transaction testing and numerous working sessions
>
> [Exhibit N-207]

[349] The NSPI witness panel did not challenge National Grid's view of Liberty.

[350] The Province also suggested that some revisions may be appropriate for the documents relevant to the FAM Audit:

> The issues raised during the FAM audit suggest that it may be appropriate to consider a review of some of NSPl's guiding documents. It may be advisable for the FAM small working group to consider whether the hedging practices in NSPl's Fuel Manual should be assessed. It may also be appropriate to consider whether NSPl's Affiliate Code of Conduct should be reviewed to consider whether, and to what extent such a document can address NSPl's non-transactional relations with its affiliates (i.e., the extent to which NSPl's actions or inactions may or may not be influenced by the activities of its affiliates even when NSPI is not engaged in specific transactions with them).
>
> [Province Closing Submissions, November 23, 2012, para. 26]

[351] However, the Province was concerned with the tone of the debate respecting the audit, including NSPI's response:

> NSPl's FAM Plan of Administration ("POA") is also ripe for review. In many ways, the level of debate in this case over the FAM audit, a critical element of a successfully functioning NSPI FAM, was unfortunate. From NSDOE's perspective, the tone set by the FAM report audit could have been viewed negatively. Of course, tone can be difficult to

> infer from the printed word, and sometimes tone can be imputed when it is not intended. Particularly if one is not engaged in actual dialogue.
>
> Regardless of how it viewed the FAM Audit Report, NSDOE respectfully submits that NSPI's response did not help matters. NSPI apparently took the criticism as cause for war. Rather than responding quickly and confidently - it defensively called forth a battalion of high-priced experts to wage a war of words. And the FAM process has suffered collateral damage.
>
> [Province Closing Submissions, November 23, 2012, paras. 27-28]

[352] The CA retained David P. Vondle to make recommendations with respect to the FAM Audit process. He is a partner with SAGE Management Consultants LLC, with 25 years of management consulting experience that includes leading 31 management audits. Mr. Vondle observed the NSPI response to the Audit was unprecedented, stating:

- With few exceptions, NSPI attacks conclusions and recommendations rather than findings (facts).
- NSPI admits it did not make factual corrections when it had the chance prior to the publication of the report. Normally, utilities take this opportunity to try to influence the conclusions and recommendations as well.
- NSPI attacks the NSUARB for hiring Liberty to do the FAM audit after Liberty acted as an extension of the NSUARB in putting the FAM process in place.
- The NSPI complaint about not having the scope of the audit is NSPI's own fault. NSPI could have insisted on having the work scope, work plan and schedule before beginning its participation in the audit. Also, the Liberty FAM Audit Report for 2010-2011 had the same chapters as the 2009 Report, with the exception that Economic Dispatch and Power Purchases and Sales were divided into two separate chapters for 2010-2011. (Tables of Contents) The 2009 Report had multiple negative conclusions and one quantification of excess cost, $220 thousand, which could have been avoided by NSPI not granting a quantity flexibility option and more diligently enforcing the maximum volume limits of solid fuel contracts. (Page VI-21). The 2009 Report also recommended retroactive adjustments to the calculation of FAM carrying costs, but did not quantify the amount. (Page X-13) NSPI should not have been surprised by the scope of the 2010-2011 Audit.
- On the FERM staff turnover issue, the NSPI Reply Evidence confirms the Liberty finding that the entire FERM senior management team plus the next level-down Solid Fuels Scheduling and Logistics Coordinator turned over in the 2010-2011 period and that two of them left for affiliate positions. In the two-year period, FERM lost 10 of 18 employees and downsized to 16 positions – only eight employees were added. This is a lot of turnover in a small unit by any measure. At the end of the two year period, only eight of 18 original employees remained and none of the senior managers.
- The NSPI ad hominem attacks against Liberty are unprecedented in my experience.

- I am not familiar with Deloitte participating in the management audit or fuel audit business. I cannot recall them bidding or winning a Commission sponsored study. Perhaps they do in Canada or Europe. For example, the New Jersey Board just pre-qualified a set of seven management audit firms for the next round of management audits. Deloitte was not one of them. However, Liberty was one of the selectees.

[Exhibit N-169, pp. 8-10]

[353] Mr. Vondle does support potential changes to the Plan of Administration, however not as put forward by NSPI, indicating that some of NSPI's requests are "unusual" or "odd".

[354] The CA submitted in its Closing Submissions that it "has seen no evidence to support NSPI's attack on Liberty" (p. 8).

[355] The SBA submitted that there is no basis to reject the FAM Audit's findings or to dismiss Liberty as the auditor. He also noted NSPI's failure to respond to the FAM Audit as contemplated in the POA:

> SBA argues there has been no substantive evidence filed or testimony heard at this F AM Audit hearing which supports the removal of Liberty as a FAM Audit Consultant. The uncomplimentary and unprofessional exchange of communication between Liberty and NSPI and the consultants is unfortunate. However, the SBA argues this does not establish that Liberty did not prepare an Audit report in an expert and detailed manner and they did forward a copy of the draft Audit report to NSPI for their review and comments; however, the reply that was forthcoming was to the effect, it was not worth replying to and the matter will be responded to through litigation at the FAM Audit hearing. SBA argues the long standing position of the Board was for the Board Consultant to prepare a draft report to be sent to NSPI for review and comments before finalization. It is undisputed that Liberty did send a draft audit report to NSPI for comments.
>
> SBA argues there was ample opportunity before the time the report was filed, even up to the hearing, to attempt to negotiate areas of concern. Unfortunately, that did not occur.
>
> …

> Accordingly, SBA argues there was no substantive evidence filed by NSPI to have Liberty removed as auditor nor is there substantive evidence to request a new audit by a different auditor, and accordingly, this Board should reject NSPI's request in that regard and deal with the Audit Report on its merits.
>
> [SBA Closing Argument, November 23, 2012, pp. 7-8]

[356] Avon also expressed its approval of the Audit conducted by Liberty, and its confidence in Liberty:

> It appears to the Avon Group that upon finding that the Liberty Audit continued to press NSPI on certain issues, particularly related to the natural gas market and affiliate relationships, NSPI embarked on a strategy which focused on reputation management for NSPI through press conferences, media releases, direct contact with customers, expert evidence, overzealous confidentiality redactions and a concerted attack on the motives and credentials of the Liberty staff who performed the Audit, culminating in a recommendation that the entire Audit be rejected and Liberty prohibited from ever performing another audit of NSPI for the Board.
>
> At the end of the day, and after all the noise, perhaps what was most telling is that despite the massive pre-hearing efforts to undermine the expertise of the Liberty witnesses, when given the opportunity during the hearing, NSPI did not ask one question to challenge the expert qualifications of the Liberty witnesses. Not one.
>
> The Avon Group relies very much on the experience and expertise of Liberty and while there may be other auditors who could accomplish what is done by Liberty, there would be a steep learning curve which is neither efficient nor practical. It seems to the Avon Group that with Liberty's historical experience with NSPI comes greater knowledge regarding "problem areas" and the questions to ask. If Liberty ruffles feathers, so be it.
>
> As noted by the Board in its decision on confidentiality of the FAM Audit, the focus in regulating NSPI is to examine whether NSPI's costs are prudently incurred. That goes to the heart of the regulatory compact, and the FAM is an integral component of the costs which NSPI seeks to recover. A meaningful, transparent audit is an essential part of the FAM. The Avon Group has seen nothing in the Liberty Audit Report or its dealings with Liberty that suggest that the Audit Report is so fundamentally flawed that it should be rejected in its entirety or declared "invalid" as urged by NSPI.
>
> In the end, at best, NSPI's strategy in responding to the Audit was distracting; at worst, it served to frustrate the process. The Avon Group would strongly urge the Board in its decision to address not only the specific recommendations made in the Audit but also the Board's expectations regarding meaningful participation in the Audit process as a requirement for continued enjoyment of a FAM so as to ensure that these tactics do not interfere with the next audit process.
>
> [Avon Final Submissions, November 23, 2012, paras. 33-37]

[357] Further, two Intervenors specifically noted their disappointment with the fact that NSPI only provided their opinion on the remaining recommendations in the FAM Audit in Undertaking U-22 filed at the very end of the hearing.

[358] The Province stated:

> A response to the FAM Audit report, like the one seen in NSPI's response to Undertaking U-22 should have been a first response, and not dragged out during the last days of the hearing. …
>
> The FAM POA should be reviewed and revised to ensure that stakeholders receive appropriate responses to a FAM audit from NSPI, as soon as possible, and at a very early stage in the proceeding.
>
> [Province Closing Submissions, November 23, 2012, paras. 29-30]

[359] Avon also expressed its concern with the lateness of NSPI's position on the remaining recommendations in the Audit report:

> By failing to respond substantively to the draft Audit, and by taking the position that the entire Audit should be rejected by the Board, NSPI failed to provide key information to Liberty, the Board and stakeholders. Indeed, the Utility never indicated which of the 2012 Audit recommendations it accepted. This information was not provided until the last day of evidence in response to an undertaking given during the hearing.
>
> Of 42 recommendations, NSPI apparently agrees with 27. Some of the recommendations with which NSPI does not agree were raised in a substantive way through this hearing, but others have not been addressed at all. NSPI's failure to provide this basic information in a timely fashion has impeded the Board and Intervenors from properly examining NSPI's position with respect to the 2012 FAM Audit.
>
> [Avon Final Submissions, November 23, 2012, paras. 31-32]

11.7.2 Findings

a) Auditing Standards

[360] The Board will first address the issue of auditing standards. While NSPI cross-examined the Liberty witness panel at the hearing with respect to its evidence related to NSPI's fuel related activities (including the activities noted above which attracted disallowances), counsel for NSPI did not challenge or question any of Liberty's witnesses on their professional qualifications, nor did NSPI counsel cross-examine the Liberty witness panel on the auditing standards or methodology applied by Liberty in the FAM Audit.

[361] NSPI relied on Deloitte's evidence. However, the Board notes that while Deloitte is a reputable auditing and consulting firm, the scope of its engagement in this matter was limited.

[362] First, Deloitte was not engaged to express an opinion on the correctness of Liberty's FAM Audit opinions:

> MS. RUBIN: And you were engaged to identify deficiencies in the report rather than provide an opinion on the correctness of Liberty's opinions?
>
> MR. LOBAREC: We were engaged to identify potential differences, based on the way we would do our work and the way we're able to observe that it was done in the report we were provided from Liberty.
>
> [Transcript, October 31, 2012, p. 814]

[363] Second, even though Deloitte was engaged to identify "differences" in the Liberty FAM Audit Report, Mr. Lobarec, Deloitte's national leader for energy and resources across Canada, acknowledged in his testimony that they did not review any of Liberty's working papers, nor did Deloitte even interview anyone at Liberty:

> MS. RUBIN: …And is it fair to say that the -- even at the end of your work, you were only able to identify some potential differences in approach?
>
> MR. LOBAREC: That is correct. As we've said in our report, there may be factual evidence contained in work papers or other areas that we were not able to observe that would form a more reasonable basis for reaching some of those conclusions.
>
> MS. RUBIN: Right. And the reason for that, identifying potential differences, is because you only took a high-level review of the Liberty report; correct?
>
> MR. LOBAREC: It's probably more because we're engaged to develop an audit plan. So it's only based on the way that we would do the work and the factual basis or evidence that we would require against a report. So I hope that answers your question.
>
> MS. RUBIN: But what you did was a high-level review of the Liberty report?
>
> MR. LOBAREC: We were only able to read the report, that's correct.
>
> MS. RUBIN: Right. You didn't review any supporting work papers?
>
> MR. LOBAREC: No, we don't have access to that.
>
> MS. RUBIN: Okay. And did you interview anyone at Liberty?

MR. LOBAREC: No.

[Transcript, October 31, 2012, pp. 814 – 816]

[364] Notably, Mr. Lobarec of Deloitte also admitted that none of the individuals involved in the preparation of Deloitte's evidence had, in fact, ever carried out a fuel management audit on behalf of a regulator:

> MS. RUBIN: Were there -- how many people were involved in the preparation of the Deloitte evidence?
>
> …
>
> MR. LOBAREC: It is 10.
>
> MS. RUBIN: It's 10, okay. Now, of those 10, is it correct that none have performed fuel management audits on behalf of a regulator?
>
> MR. LOBAREC: In -- yes, that's correct.

[Transcript, October 31, 2012, pp. 816-817]

[365] Finally, Mr. Lobarec acknowledged that there is no single standard for an auditor conducting a fuel management audit:

> MS. RUBIN: …Now, would you agree that there's not one single correct approach to a fuel management audit?
>
> MR. LOBAREC: Yes, it is open to interpretation. The adoption of standards and the way it's done varies. I do agree with that.

[Transcript, October 31, 2012, p. 814]

[366] In light of the above, the Board assigns little weight to Deloitte's evidence with respect to the issues in this FAM Audit.

[367] Ms. Medine was very critical of Liberty's auditing methodology.

[368] As noted earlier in this Decision, the Board gives little weight to Ms. Medine's evidence.

[369] This is not Liberty's first FAM Audit of NSPI. The 2010 Audit conducted in relation to the 2009 fuel related activities was met with general agreement by NSPI. At that time, NSPI did not express any concerns with the auditing standards applied by Liberty.

[370] Further, NSPI's assertions that Liberty has an "insufficient knowledge and expertise in the subject matter of the audit" and that it has a "lack of industry knowledge" is not borne out by the evidence. In this respect, the Board accepts the evidence of Mr. Curry, whose evidence was not challenged by NSPI, that Liberty possesses an excellent reputation with at least 11 regulatory commissions in the U.S., both in terms of Liberty's professionalism and its effectiveness in the conduct of audits.

[371] It is also instructive that NSPI did not cross-examine any member of the Liberty witness panel about their professionalism, qualifications or expertise.

[372] The Board is aware of the NARUC guidelines. On the basis of the evidence before it, the Board is satisfied that Liberty's FAM Audit is consistent with the NARUC guidelines. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board.

[373] In addition, it is noted that NSPI's customers were satisfied with Liberty's work on this file. The Board places significant weight on the support given to Liberty by the Intervenors representing most customer classes. The CA, the SBA and Avon all support Liberty in its conduct of the present audit and in future audits. It is clear that the present audit was conducted in a manner which met the expectations of these customer classes.

[374] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards.

b) Future Audits

[375] The second issue considered by the Board relates to future audits. NSPI made a number of requests for changes to the POA and to restrict the engagement of Liberty on future FAM Audits.

[376] The Board notes that the issue of POA amendments or future audits was not on the Final Issues List approved by the Board for this proceeding.

[377] On this point, the Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion. The Board maintains its view on this issue.

[378] Accordingly, the Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits.

c) NSPI's Response to the Audit

[379] Another issue which arose out of the evidence and submissions respecting the audit process relates to NSPI's response to the draft Audit Report submitted to it by Liberty. The Board shares many of the Intervenors' concerns.

[380] NSPI asserts that the nature of the allegations in the Audit Report justified its decision not to comment to Liberty on the draft Report and, instead, to launch a strong reply to the Report as part of the GRA hearing, including the engagement of numerous expert consultants.

[381] On the other hand, the CA, SBA, Avon, and the Province, submit that NSPI, in failing to respond to the draft Audit Report, acted contrary to the FAM Audit process contemplated in the FAM POA. Moreover, they assert that NSPI's failure to disclose material information in the hearing process, including in its FAM Audit Reply Evidence, in its Responses to Information Requests from Intervenors, and even in its testimony under cross-examination by the Intervenors, frustrated the FAM Audit process.

[382] These Intervenors are represented by experienced counsel who, except for the SBA, have been involved in the proceedings leading to NSPI’s request for a FAM and the adoption of the FAM by the Board. NSPI’s strategy in responding to the FAM Audit fell far short of the expectations of these counsel.

[383] As noted earlier in this Decision, the POA provides that NSPI would be provided with a draft Audit.

[384] When provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the terms of the POA that the final FAM Audit report is to “evolve” from the draft Report. This clearly contemplates input from NSPI about the contents of the draft Report. The POA provides that NSPI has 30 days to comment. Liberty specifically requested NSPI’s comments. The prior 2010 FAM Audit had proceeded in this fashion.

[385] In its evidence, NSPI claimed that it did, indeed, respond to the draft Audit Report, referring to a reply email from its counsel Rene Gallant on June 24, 2012. However NSPI chooses to characterize Mr. Gallant's email, the Board finds that it

amounted, in effect, to a non-response on the substantive issues in the draft Report. Further, it was not the type of response contemplated under the POA.

[386] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances. Further, if NSPI had discussed its concerns with Liberty about the tone of the draft Report, or about some of the observations in it, the language of a final Audit Report might have been more restrained. No one will ever know because of NSPI's response.

[387] NSPI's tactical response to the draft Audit Report contributed to further difficulties in the audit process. In accordance with the POA, Liberty did provide NSPI with a draft Report of its findings. NSPI's initial non-response led Liberty to file the draft Audit Report with the Board, in effect, becoming Liberty's final FAM Audit Report.

[388] In fuel management or prudence audits, the Board expects the auditor to report disputed or unresolved issues to the Board. Faced with NSPI's non-response to the draft Audit report, it was entirely reasonable for Liberty to then file its findings with the Board.

[389] Based on its review, the Board finds that NSPI's decision to ignore the draft Audit Report did not comply with the terms of the POA and its related conduct was unreasonable. Moreover, the Board notes that all of the auditing standards or guidelines cited by Deloitte, Ms. Medine, or Mr. Vondle contemplate the audited party reviewing a draft audit report and responding to any deficiencies that should be addressed. In this case, NSPI decided, for whatever reason, to forego the opportunity to respond and to challenge all of Liberty's findings and recommendations in the hearing

(even those findings which it later acknowledged it agreed with in Undertaking U-22). In so doing, the Board concludes that NSPI's conduct was contrary to what would have been reasonably expected under the POA. It certainly was contrary to the reasonable expectations of the Board and the Intervenors. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[390] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[391] At this point, the Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

[392] Nevertheless, the tone used by Liberty in a few of its findings is no excuse for the nature of NSPI's comments respecting the FAM Audit Report. NSPI's comments and non-responsive strategy only served to escalate the rhetoric and to hinder the efficient review of the Audit Report by the Intervenors and the Board.

[393] In making these findings, it is not the Board's intention to suggest that NSPI should not challenge any finding or recommendation by a fuel management

auditor, in a hearing if necessary. However, before it embarks on such a challenge, it has a responsibility under the POA, and to its ratepayers, to provide its comments in a timely fashion on a draft Audit Report delivered to it by the auditor. Such a response would help to resolve or narrow the issues identified during the Audit and would have allowed the Intervenors and the Board to conduct an efficient review of the Audit Report.

[394] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the draft Audit Report.

d) Non-contested Recommendations in the Audit Report

[395] Finally, the Board is concerned with NSPI's failure to comment at an early stage with respect to the remaining recommendations in the FAM Audit. While it initially issued a blanket dismissal of the entire Audit Report (including the findings supportive of NSPI's fuel related activities), it ultimately agreed, at the end of the hearing, in an Undertaking requested by Avon, to identify which recommendations it agreed were reasonable. Initially, counsel for NSPI sought to limit the scope of the undertaking and questions about the other recommendations in the Audit Report. In Undertaking U-22, filed at the conclusion of the hearing, NSPI identified the recommendations it agreed with and which ones it did not. Interestingly, however, NSPI stated in its response to Undertaking U-22, "NS Power makes no comment on the conclusions in the Liberty report." Again, NSPI's approach unnecessarily lengthened the hearing and resulted in the inability of the Board and the Intervenors to delve into an efficient and meaningful assessment of the substantive issues identified in the FAM Audit.

[396] Despite its initial blanket rejection of all Liberty's FAM Audit recommendations, NSPI appeared to adopt a more conciliatory tone after the hearing was completed. In its Closing Submission, NSPI stated:

> … NS Power's response to Undertaking U-22 outlines NS Power's position on each of the recommendations contained in the Liberty audit report. Out of 42 recommendations, NS Power agrees with 27 recommendations. At least 15 of these 27 Liberty recommendations are items that had already been undertaken by NS Power...or that are existing practices or plans of the Company...
>
> [NSPI Closing Submission, November 23, 2012, p. 27]

[397] In its Reply to Closing Submission, NSPI asked the Board for the "rejection of the disputed conclusions and recommendations from the FAM Audit Report", offering no further comment on the remaining recommendations.

[398] Counsel for Avon noted that the late filing of such information deprived the Intervenors of the opportunity to conduct a meaningful assessment of the issues and, indeed, frustrated the conduct of the FAM Audit process itself. The Province, which typically takes no position in GRA proceedings, expressed similar concerns.

[399] In the future, the Board expects NSPI to outline, no later than in its Reply Evidence, which audit findings or recommendations it agrees with and which it does not.

11.8 FAM Small Working Group

[400] Another issue arose out of the FAM Audit hearing which the Board considers should be addressed. It is apparent that NSPI has a different view than the Board about the role of the various participants in the FAM Small Working Group ("SWG").

[401] In a few instances related to its gas hedging practices, NSPI indicated its reliance on the SWG for its decisions or course of action.

[402] For example, with respect to the losses incurred by NSPI as a result of the "basis blowout" commencing in December 2010, NSPI appeared to place some of the responsibility for its decisions on gas hedging strategies on Liberty and other members of the SWG:

> Liberty is also a participant in the FAM Small Working Group. Minutes of the FAM SWG for the six months leading up to the basis blowout period make no reference to any comment by Liberty, or by any other stakeholder, identifying the need for a study to examine the potential for reducing fuel cost volatility by hedging the basis differential.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 55]

[403] Similarly, in its Closing Submission, NSPI stated:

> As Mr. Bennett and Mr. Sidebottom explained, the Black & Veatch study was discussed with stakeholders during FAM Small Working Group (SWG) meetings, and the results of the study were provided to the FAM SWG. No concerns or objections were raised about the study or whether it was sufficiently comprehensive or focused. Liberty also reviewed the study and agreed with the study conclusions in a December 10, 2010 memo to NS Power. Despite Liberty providing its written comments just days before the December 2010 "basis blowout", Liberty provided no complaint or criticism that the basis differential risk had not been addressed nor that additional focused study work should be done on basis differential or any other component of risk. Clearly Liberty did not, at the time, see basis differential as a significant risk any more than NS Power did. …
>
> [NSPI Closing Submission, November 23, 2012, p. 45]

[404] NSPI also appeared to implicate Liberty and the SWG in the "development" of the Fuel Manual:

> The Fuel Manuel is a highly prescriptive document, developed in close consultation with stakeholders and Liberty, and approved by the Utility and Review Board. NS Power believes the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 52]

[405] The Board wishes to reiterate that the role of the SWG, or any of its individual participants, is not to manage NSPI's fuel related activities. The responsibility for such activities lies squarely on NSPI and not on any other SWG participant. Accordingly, NSPI should not seek to cast any responsibility on the participants for

particular actions taken by NSPI or to reproach the other participants for not suggesting an alternative course of action.

11.9 Remaining recommendations in FAM Audit

[406] As noted earlier in this Decision, NSPI did not initially indicate in its Reply Evidence which findings or recommendations of Liberty it agreed with. On the last day of the hearing, in an Undertaking requested by Avon, NSPI agreed to provide an Undertaking to the Board outlining which recommendations it rejects, which it accepts, and which it has implemented. In the latter case, NSPI was to outline its action plan.

[407] NSPI filed Undertaking U-22 on November 9, 2012. As noted by NSPI in its Closing Submission, it agrees with 27 of 42 recommendations. However, Avon states that NSPI's late filing of this information has impeded the Board and Intervenors from "properly examining NSPI's position with respect to the 2012 FAM Audit".

[408] The Board directs that NSPI proceed with the implementation of the recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[409] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[410] The Intervenors will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

11.10 Disallowed Costs related to the FAM Audit

11.10.1 Evidence

[411] Earlier in this Decision, the Board reviewed instances in which NSPI undertook a course of conduct which, the Board considers, was contrary to what would have been reasonably expected under the FAM POA.

[412] NSPI repeatedly refuted a recommendation by Liberty to pursue concerns with the NEB and potential sellers of natural gas about the state of the Maritimes natural gas market. Moreover, Liberty's recommendation was, in effect, summarily dismissed by NSPI, who even went as far as to assert that Liberty did not understand the regulatory regime in Canada and that this was a basis for concluding that Liberty was inept and unqualified to perform its FAM auditing duties.

[413] However, on the very last day of the hearing, the NSPI witness panel, primarily Mr. Janega, revealed that NSPI had indeed carried out a course of action over the past few years which had actually taken into account Liberty's concern on the state of the natural gas market in the Maritimes. Of particular concern to the Board, in terms of the FAM Audit generally (including the administration of the POA), is the fact that NSPI, notwithstanding its course of action to the contrary, denied that Liberty`s concern was in any way legitimate or worthy of any action.

[414] NSPI maintained its dismissal of Liberty`s concern during the period leading to the release of the FAM Audit, as well as in its FAM Audit Reply Evidence, in its Responses to Information Requests from the Intervenors, and in its sworn testimony in cross-examination by these same Intervenors. NSPI's revelation about its actual course of action only occurred on the very last day of the hearing during questioning by Board Counsel.

[415] NSPI's course of action distracted and misdirected all parties in this proceeding (and the public) from the real issue which should have been addressed at the hearing about the natural gas markets. Moreover, NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties, notably those of the Intervenors who participated in this proceeding, including experienced legal counsel and, likely in some cases, their expert consultants. This conduct resulted in increased costs for all Intervenors, including those representing most customer classes served by the Utility.

[416] The lack of disclosure by NSPI was not restricted to the matter involving the NEB.

[417] First, it was not until the hearing that NSPI disclosed the true extent of its response with the circumstances surrounding the withdrawal of Bid A by the counterparty, as described earlier in this Decision. It was not until her testimony that Ms. Trenholm, under cross-examination, revealed NSPI's actual reaction following those events. NSPI, in fact, voiced its strong displeasure with the counterparty, but decided that its interests would best be served in the long term by preserving the relationship. However, NSPI's actions and reasoning on this issue were not fully disclosed to Liberty or the Intervenors until the hearing.

[418] Another instance of inadequate disclosure arose in the context of the Lingan derate matter. Liberty had proceeded with its analysis of the issue using NSPI's schedule of different coal blends used at Lingan over the relevant period. However, during their cross-examination by NSPI, the Liberty witness panel was presented with a different schedule of coal blends used over the same time span. This required Liberty

to reconsider its analysis in an Undertaking. It is curious that, later in the hearing, when asked about the revised schedule by Board Counsel, Marie Thomas, of the NSPI Fuel Panel, was required to be briefly excused by the Board to confirm whether the revised schedule was, in fact, the correct schedule. Fortunately, her records matched the revised schedule, but what appeared to be confusion in communication among NSPI's different representatives was disconcerting to the Board.

[419] Yet another example of poor disclosure, for whatever reason, was in relation to the gas hedging issue and the Black & Veatch report. While it was clear from a plain reading of the Black & Veatch report that the issue of the "basis differential" could not reasonably be seen as a specific issue within the scope of the engagement, NSPI, in its testimony at the hearing, specifically its Fuel Panel, nonetheless characterized the Black & Veatch report as dealing directly with the issue. The Company had not previously disclosed its reliance on that report specifically for that purpose, even though it became a central theme of its testimony at the hearing on the hedging issue.

[420] The second issue which causes great concern to the Board is NSPI's failure to follow the process contemplated by the FAM POA for the development of the FAM Audit report itself.

[421] As noted earlier in this Decision, when provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the express terms of the POA that the final FAM Audit report is to "evolve" from the draft report. This clearly contemplates input from NSPI about the contents of the draft

Report. The prior 2009 FAM Audit had proceeded in this fashion. The POA provides that NSPI has 30 days to comment.

[422] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances.

[423] On a related point, NSPI initially dismissed all the other FAM Audit findings and recommendations which were supportive of the Utility's fuel related activities or those which NSPI later indicated, in Undertaking U-22, that the Utility agreed with.

[424] Again, the result of NSPI's conduct, in failing to comment on the draft Audit report, is that it unnecessarily lengthened the hearing and wasted the time, money and effort of the Intervenors in this proceeding, as well as Board Counsel.

[425] In its Closing Submissions, the CA specifically requested that the Board sanction NSPI as a result of its conduct in responding to the FAM Audit:

> In its pre-filed evidence and throughout much of its testimony before the Board, NSPI aggressively challenged Liberty's experience, qualifications, ethics, and independence.
>
> Put simply, the Consumer Advocate has seen no evidence to support NSPI's attack on Liberty. Furthermore, the Consumer Advocate sees NSPI's attack as offensive to the regulatory process itself. Clearly, a mature utility needs to understand the difference between disagreeing with an auditor's recommendations and a baseless assault on the auditor's reputation.
>
> In such circumstances, where a utility initiates and maintains baseless attacks on auditors appointed by the regulatory body, there ought to be a consequence for the utility.
>
> An obvious consequence would be to assess some portion of the costs of the hearing which have been generated as a result of NSPI's intransience and to have them borne by the company and its shareholders. The assessment could consist of either a reduction of the costs that NSPI could otherwise recover and/or an assessment of a portion of the costs incurred by the Board and intervenors against NSPI. The assessment could be by way of a lump sum set by the Board in consideration of all the particular circumstances.
>
> [CA Closing Submissions, November 23, 2012, p. 8]

11.10.2 Findings

[426] The Board is responsible for the general supervision of NSPI under the *Public Utilities Act*. Section 18 provides:

> **Supervision of utility by Board**
> **18** The Board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by the said public utilities with the provisions of law and shall have the right to obtain from any public utility all information necessary to enable the Board to fulfil its duties.

[427] While the CA requests that NSPI be sanctioned for its conduct generally, the Board considers that any such sanction should relate to specific instances where NSPI has showed imprudence or ignored direction from the Board.

[428] In this respect, the Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures such as the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and the aggressive pursuit of gas supplies, and its decision not to comment on the draft Audit Report, were both unreasonable and inappropriate. Further, as noted above, its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[429] In these circumstances, the Board finds that a sanction is warranted as against NSPI. In accordance with its jurisdiction under s. 18 of the *Public Utilities Act*, as well as its mandate under the *Act* generally, the Board concludes that a disallowance of $2 million is appropriate and it so orders.

[430] In determining the disallowance of $2 million, the Board has relied, in part, on its evaluation of unnecessary costs incurred by the CA, SBA and the Board as a

result of NSPI's response to this FAM Audit. Likewise, NSPI, itself, would also have incurred unnecessary costs.

11.11 Implementation of the FAM disallowances

[431] As a result of the Board's findings earlier in this Decision, disallowances have been made as against NSPI with respect to its imprudence and its conduct in relation to directives by the Board. These disallowances must now be implemented in this Decision.

[432] As noted earlier, the Board has approved the GRA Agreement. Further, in a separate proceeding, by Order issued December 10, 2012, the Board has approved the 2013 FAM Actual Adjustment (AA) and Balance Adjustment (BA) recovery values. Both of these approvals were made subject to any further adjustment arising from this Decision.

[433] There are several options to implement the disallowances.

[434] The SBA recommended as follows:

> SBA points out while the overall amount of imprudence disallowance amounts are small as a percent of revenues they still maintain an important monetary issue for small businesses of Nova Scotia. Small businesses have felt the hard impact of the current economic climate. Increases in electric rates associated with raising [sic] NSPI costs and the losses of large customer loads will present the SBA's constituents with yet [another] straw to add to a burdened back. SBA suggests that the manner to return the benefits of any disallowance is to first go to offset or wipeout the 2012 FAM AA adjustment. This would reduce the specter of looming future rate increases and the potential for the timing of recovery in 2015 to coincide with any other increases, including fuel prices. NSPI's business customers need stability as much as they would benefit from lower rates. SBA believes this is especially true of the small businesses where there is less medium and long term business and financial planning. This would allow the 3% already agreed upon to be implemented.
>
> If there are disallowances in excess of the 2012 FAM AA adjustment SBA urges the Board to consider providing the benefit of the returning funds for disallowances to customer classes as a single month rebate within two months of the Board issuing a decision. This would provide a more pronounced benefit to SBA's small business constituents, an economic stimulus of sorts.
>
> [SBA Closing Argument, November 23, 2012, p. 24]

[435] In its Closing Submissions, the Province "urged the Board to ensure that any savings that result from the FAM Audit be passed along to customers as soon as possible".

[436] The political parties who participated in this proceeding submitted that any disallowance should be returned to ratepayers immediately.

[437] With respect to the fuel-related disallowances totaling $4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment ("2013 BA").

[438] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenors for the non-fuel reductions they negotiated in the GRA Agreement.

[439] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[440] A different implementation procedure applies for the $2 million disallowance arising from NSPI's conduct contrary to the POA.

[441] While some Intervenors may have suggested different alternatives were available to the Board, it considers that this disallowance must be applied against NSPI's 2012 earnings.

[442] The Board has decided that the 2012 revenue requirement is to be adjusted for purposes of applying clause 26 of the 2012 Settlement Agreement. Clause 26 reads as follows:

> Subject to necessary adjustments to incorporate paragraph 7 above, the s.21 AAA Mechanism will continue to operate on a go forward basis until the s.21 amount is fully paid. Amounts in excess of both the range of return on equity and in excess of the room available in the s.21 AAA Mechanism will be returned to customers.
>
> [Decision, 2011 NSUARB 184, p. 13]

[443] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be $2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional $2 million will be applied to the deferrals for the benefit of ratepayers.

[444] The Board notes that while this $2 million disallowance does not provide a direct benefit to ratepayers going forward, it could, as explained above, benefit ratepayers if there is an impact on the treatment of the s. 21 amount under the 2012 Settlement Agreement.

[445] The Board directs the implementation of all the disallowances as described in this section.

11.12 Perspective

[446] NSPI's fuel budget over the two year period covered by the Audit is approximately $1 Billion or $500 Million per year. The Liberty Audit recommended a disallowance of approximately $10 million in fuel spending, approximately 1% of the budget. Liberty recommended further investigation of the hedging issue. While Liberty made other recommendations in the Audit, it did not question 99% of the fuel spending undertaken by NSPI and indeed, parts of the Audit were very complimentary to NSPI's fuel acquisition activities.

[447] From the outset NSPI chose to focus its own and the public's attention on this 1% - ignoring the balance of the Audit and indeed trashing the whole Audit.

[448] NSPI also chose to focus on reputation; its own reputation alleging defamation, which lead to a separate preliminary hearing in August, and attacking Liberty's reputation, alleging bias, incompetence, and irresponsibility, among other things.

[449] Power rates are, at the best of times, a top of mind issue with the public in Nova Scotia. The majority of the members of the public are NSPI's customers.

[450] NSPI is free, and must be free, to conduct any case before the Board in the manner that best suits it.

[451] However, having read the comments of the CA, SBA and Avon, who are all regular parties to these proceedings, and having reflected on the matter, the Board cannot help but observe that NSPI's relationship with the public and other parties to most of these proceedings has suffered damage.

[452] One of the conditions attached to the approval of the FAM was "a meaningful audit process under the administration of the Board". The Board and customers expect the Board's auditor to ask the tough questions and to identify areas where costs might have been avoided. Simply because the Audit recommends a disallowance, does not mean the Audit is flawed or biased. In making a disallowance the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional.

[453] Credit rating agencies and others who follow these proceedings should understand this perspective. The FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result,

accepted two recommendations for disallowance, amounting to much less than 1%. NSPI has a functioning FAM.

12.0 MISCELLANEOUS

12.1 Information Requests

[454] The Board observed a practice NSPI adopted in this hearing which had not been prevalent in the past by answering an IR as follows:

> NS Power will provide this information to the Board upon request.
>
> [Exhibit N-32, IR-33]

[455] Such an answer is not responsive or helpful to the questioner. An IR is either "in scope" and relevant and deserves an answer or is "out of scope" and irrelevant, in which case NSPI can refuse to answer it. NSPI should take a position in the original answer which, if the questioner disagrees, can be further reviewed by the Board at the request of the questioner. The response noted above simply delays proceedings which are often on a very tight time schedule. This is not acceptable.

13.0 COMPLIANCE FILING

[456] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively.

[457] NSPI is directed to file a Compliance Filing as soon as conveniently possible.

[458] The Formal Intervenors must provide comments, if any, no later than three full business days thereafter.

[459] Further, the Board directs NSPI to outline in 2013 and 2014 where it has applied the $27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

14.0 SUMMARY OF BOARD FINDINGS

Settlement Agreement

[460] This Decision deals with the Board's consideration of both NSPI's general rate application and of the FAM Audit Report.

[461] NSPI's Application requested the Board's approval of a Rate Stabilization Plan ("RSP"). The RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposed the remaining revenue requirement be deferred for future recovery commencing in 2015.

[462] NSPI reached a settlement agreement ("GRA Agreement") with most of its customer classes, including the CA, the SBA and Avon.

[463] The Board approves the GRA Agreement, which adopts the two year RSP proposed by NSPI and represents a comprehensive resolution of many contested issues between NSPI and the Intervenors, who indicated that, without the RSP, customers would have faced much larger rate increases, particularly in 2013. They stated that the RSP will "smooth out rate increases experienced by customers" and provide a "predictable measure of stability" over the next two years.

[464] The GRA Agreement provides for a $27.5 million non-fuel cost reduction in NSPI's deferral account balance. The deferral of forecasted revenue requirement will not exceed $47.1 million at December 31, 2013 and will not exceed $84.8 million at December 31, 2014.

[465] In the Board's view, an important component of the GRA Agreement which will benefit customers is the RSP, which limits across-the-board 3% increases in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015. The recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which has already been included in existing rates over eight years ending in March 2015. The deferral in the RSP will be collected over an 8 year period beginning in 2015.

[466] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a change to the earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014.

[467] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014.

Pension Costs

[468] In last year's general rate Decision, the Board indicated that it would investigate the issue of pension costs in this proceeding. It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs.

[469] NSPI confirmed to the Board that it reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012, including changes to the pension plan.

[470] The Board sees this change as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[471] In future years these costs savings will be embedded in the revenue requirement asked of customers. However, the Board expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

[472] Two issues also arose in the course of the hearing with respect to NSPI's Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately $150,000 per year. The Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[473] NSPI is free to continue to provide that benefit, however, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. The Board understands the amount to be disallowed is $2.05 million in 2013 and $2.2 million in 2014.

[474] Also, NSPI secures the SERP pension by purchasing a letter of credit, using funds paid entirely by ratepayers. In the Board's view, payment for that portion of the letter of credit that secures the pension is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[475] These deductions are in addition to the $27.5 million provided for in the GRA Agreement.

Executive Compensation

[476] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[477] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation, including pension payments on behalf of executives.

LED Streetlighting

[478] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach with the exception of the net book value question.

[479] The Board denies HRM's request to recalculate the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[480] In a second issue raised by HRM, the Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

Low Income Residential Customers

[481] The Board approves the Settlement Agreement filed by the Affordable Energy Coalition, NSPI and the CA, which sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers".

Cost of Service – Biomass

[482] The Board finds that NSPI's recently constructed 60 MW biomass plant at Point Tupper, Nova Scotia, has similar characteristics to any other steam plant. The Board directs that it should be classified on the basis of system load factor, because it makes a contribution to capacity and provides firm power.

Natural Gas Storage

[483] The Board denies the request of Alton Natural Gas Storage L.P. to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

FAM Audit

[484] The Liberty Consulting Group was engaged by the Board to conduct the FAM Audit for the period covering 2010 and 2011. The FAM Plan of Administration ("POA") provides that an audit of the FAM will be done every second year.

[485] The Board made a number of findings in relation to the FAM Audit Report. The Board noted the importance of transparency, as well as the full and timely disclosure of complete and adequate information, in its original approval of the FAM.

[486] Credit rating agencies and others who follow these proceedings, including the public, should understand that the FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result, accepted two recommendations for disallowance, amounting to much less than 1%. In making a few disallowances, the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional. NSPI has a functioning FAM.

Lingan Derates

[487] The Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[488] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Lingan facility.

[489] The Board orders a $3.6 million disallowance with respect to the Lingan derates.

Natural Gas Contracts

[490] With NSPI's long term natural gas supply contract with Shell coming to an end on October 31, 2010, NSPI issued a Request for Proposals to acquire replacement quantities of natural gas to supply its projected needs. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption.

[491] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Liberty acknowledged that there was not an enforceable contract.

[492] However, with respect to Bid B, the Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[493] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[494] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[495] The Board disallows $903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e.,

426 days). As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

[496] Finally, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases.

Natural Gas Markets

[497] On the last day of hearing, and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the natural gas market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision. This evidence was not previously disclosed to Liberty, the Intervenors or the Board.

[498] NSPI's actions in withholding this information are both inexplicable and inexcusable. In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance to NSPI, as described below.

[499] However, on the substantive issue related to natural gas markets, the Board makes no other disallowance with respect to NSPI's gas market activity.

Natural Gas Hedging

[500] The Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the "basis differential" and result in the "basis blowout". Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI with respect to this issue.

FAM Audit Process

[501] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board. In addition, the Board noted that Liberty's work on this file was supported by the Intervenors representing most customer classes.

[502] The Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits. The Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion.

[503] The Intervenors and the Board were disappointed with NSPI's response to the FAM Audit. In failing to respond to the draft Audit Report, NSPI acted contrary to the process contemplated in the FAM POA. Its conduct was also contrary to the reasonable expectations of the Board and the Intervenors. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[504] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[505] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the

draft Audit Report, along with an indication of which audit findings or recommendations it agrees with and which it does not.

[506] The Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

Remaining Recommendations in the FAM Audit

[507] The Board directs that NSPI proceed with the implementation of the remaining recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[508] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[509] The Intervenors will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

Disallowed Costs Related to FAM Audit

[510] The Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures like the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and its decision not to

comment on the draft Audit report were both unreasonable and inappropriate. Its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[511] In these circumstances, the Board finds that a sanction is warranted as against NSPI and concludes that a disallowance of $2 million is appropriate.

Implementation of the FAM Disallowance

[512] With respect to the fuel-related disallowances totaling $4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment ("2013 BA").

[513] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenors for the non-fuel reductions they negotiated in the GRA Agreement.

[514] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[515] A different implementation procedure applies for the $2 million disallowance arising from NSPI's conduct contrary to the POA. This disallowance must be applied against NSPI's 2012 earnings.

[516] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be $2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional $2 million will be applied to the deferrals for the benefit of ratepayers.

Other Revenue Requirement Reductions

[517] As noted earlier in this summary, the reductions in pension costs and executive salaries will lower the test year revenue requirements, in addition to the $27.5 million provided for in the GRA Agreement.

[518] An Order will issue following the Compliance Filing.

DATED at Halifax, Nova Scotia, this 21st day of December, 2012.

Peter W. Gurnham

Roland A. Deveau

Kulvinder S. Dhillon

APPENDIX A

NOVA SCOTIA POWER INC.
2013 RATE APPLICATION – INCLUDING THE FAM AUDIT P-893/M04972

LIST OF PARTICIPANTS

Affordable Energy Coalition

Alton Natural Gas Storage LP

Avon Group
(Avon Valley Greenhouses Ltd.)
(Canadian Salt Company Limited)
(CFK Inc.)
(Crown Fibre Tube Inc.)
(Halifax Grain Elevator Limited)
(Imperial Oil Limited)
(Lafarge Canada Inc.)
(Maritime Paper Products Ltd.)
(Michelin North America (Canada) Inc.)
(Minas Basin Pulp & Power Company Ltd.)
(Oxford Frozen Foods Limited)
(Sifto Canada Corp.)
(Nustar Terminals Canada Partnership)

Bowater Mersey Paper Company Limited

Cape Breton Explorations Ltd.

Consumer Advocate

Halifax Regional Municipality

Municipal Electric Utilities of Nova Scotia Co-operative

Municipality of the District of Yarmouth

Nova Scotia Department of Energy and Nova Scotia Environment

Nova Scotia Liberal Caucus

Nova Scotia Power Inc.

Progressive Conservative Caucus Office

Small Business Advocate

Strait Area Mayors & Wardens and Town of Port Hawkesbury

Union of Nova Scotia Municipalities