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VIA EMAIL

March 25, 2014

To: All Registered Parties

Re: British Columbia Utilities Commission
Project No. 3698713/Order G-77-13
Generic Cost of Capital Proceeding-Stage 2

Enclosed please find the Commission's Decision on the Stage 2 of the Generic Cost of Capital proceeding.

Yours truly,

Erica Hamilton

EC/dg
Enclosure

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:

<u>Basis for Comparing Against the Benchmark Utility</u>

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.

<u>Need for a Minimum Default Capital Structure and Risk Premium</u>

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.

<u>Small Firm Effect- Applicability of Ms. Ahern’s Evidence</u>

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.

<u>TES Projects –What is Being Regulated</u>

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.

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[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

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[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)

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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 Company-Specific Interpolated Premium	D&P 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.)

BCPSO Position

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)

FEVI Reply

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.

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[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)

ICG Position

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.

FBC Reply

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)

<u>BCPSO Position</u>

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)

<u>ICG Position</u>

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).

<u>FBC Position</u>

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).

<u>BCPSO Position</u>

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)

<u>PNG Reply</u>

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)

BCPSO Position

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)

BCPSO Position

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.

BCPSO Position

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)

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[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)

<table>
<tr><th rowspan="2"></th><th colspan="2">Current</th><th colspan="2">Requested by TES Utilities</th><th colspan="2">Proposed by Intervener (BCPSO)</th></tr>
<tr><th>Equity Thickness (%)</th><th>ERP (bps)</th><th>Equity Thickness (%)</th><th>ERP (bps)</th><th>Equity Thickness (%)</th><th>ERP (bps)</th></tr>
<tr><td>FAES</td><td>n.a.</td><td>n.a.</td><td>45</td><td>75</td><td>n.a.</td><td>n.a.</td></tr>
<tr><td>Delta School District</td><td>40</td><td>50</td><td colspan="2">FAES minimum default</td><td rowspan="11">FAES recommendation be given significantly more weight</td><td rowspan="11">75 bps as proposed by FAES be the maximum</td></tr>
<tr><td>Tsawwassen springs</td><td>40</td><td>50</td><td colspan="2">FAES minimum default</td></tr>
<tr><td>PCI Marine</td><td>40</td><td>0</td><td colspan="2">FAES minimum default</td></tr>
<tr><td>Telus Garden</td><td>40</td><td>0</td><td colspan="2">FAES minimum default</td></tr>
<tr><td>Kelowna DES</td><td>40</td><td>50</td><td colspan="2">FAES minimum default</td></tr>
<tr><td>The Companies</td><td>n.a.</td><td>n.a.</td><td>60</td><td>250</td></tr>
<tr><td>Central Heat</td><td>36.31</td><td>50</td><td colspan="2">The Companies minimum default</td></tr>
<tr><td>Dockside Green</td><td>40</td><td>100</td><td colspan="2">The Companies minimum default</td></tr>
<tr><td>UniverCity</td><td>40</td><td>50</td><td colspan="2">The Companies minimum default</td></tr>
<tr><td>River District</td><td>40</td><td>50</td><td colspan="2">The Companies minimum default</td></tr>
<tr><td>Benchmark</td><td>38.5</td><td>0</td><td>n.a.</td><td>n.a.</td><td>n.a.</td><td>n.a.</td></tr>
</table>

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:

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[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.

<u>Position of the Parties</u>

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.

<u>Commission Panel Determinations</u>

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.

D.A. COTE
PANEL CHAIR/COMMISSIONER

L.A. O'HARA
COMMISSIONER

C. VAN WERMESKERKEN
COMMISSIONER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-47-14

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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;

…/4

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

D.A. Cote
Commissioner/Panel Chair

Attachment

LIST OF PROCEDURAL ORDERS

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

EXHIBIT NO.	DESCRIPTION
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

EXHIBIT NO.	DESCRIPTION
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

EXHIBIT NO.	DESCRIPTION
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

EXHIBIT NO.	DESCRIPTION
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

EXHIBIT NO.	**DESCRIPTION**
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

EXHIBIT NO.	DESCRIPTION
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.