



**YUKON
ENERGY**

YUKON ENERGY CORPORATION

FOLLOW-UP QUESTIONS ON YUKON ENERGY UNDERTAKINGS
2017 – 2018 GENERAL RATE APPLICATION

July 27, 2018

1 **REFERENCE: July 13, 2018 Undertaking 38, pdf page 51, footnote 1.**

2
3 **QUESTION:**

4
5 a) Please confirm that footnote 1 refers to BCUC Order G-110-12.

6
7 b) If confirmed, please place BCUC Decision G-110-12 on the record of this
8 proceeding. If not confirmed, please provide the decision referred to in footnote 1
9 on the record of this proceeding.

10
11 **ANSWER:**

12
13 **(a)**

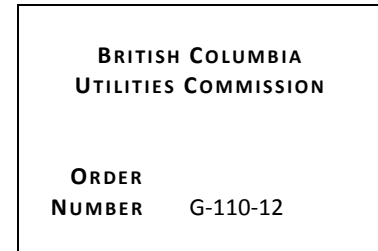
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15 Confirmed. This Order was referenced as per the footnote in BCUC Order G-47-14,
16 Section 3.2.6, page 97 of 168 (see YUB-YEC-1-52 Attachment 3 for a copy of BCUC Order
17 G-47-14).

18
19 **(b)**

20
21 Please see Attachment 1 to this response.



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

and

An Application by FortisBC Inc.
for Approval of 2012-2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: D.A. Cote, Commissioner
A.A. Rhodes, Commissioner August 15, 2012
N.E. MacMurchy, Commissioner

O R D E R

WHEREAS:

- A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 44.2, 56 and 59 to 61 of the *Utilities Commission Act* (the Act) for approval of its 2012-2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);
- B. The Application contains two parts:
 - 1) FortisBC's 2012-2013 Revenue Requirements (including the Company's 2012-2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the Act),
 - 2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the Act, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan;
- C. FortisBC sought, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also sought a permanent rate increase of 6.9 percent effective January 1, 2013;
- D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012-2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3)(a) and satisfies the requirements of section 45(6) of the Act;
- E. The Company also requested a Commission determination on whether the 2012 Integrated System Plan, which is comprised of three components (the 2012-2013 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand-Side Management Plan), is in the public interest pursuant to section 44.1 (6);
- F. A Workshop to review the Application was held in Kelowna on July 22, 2011;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

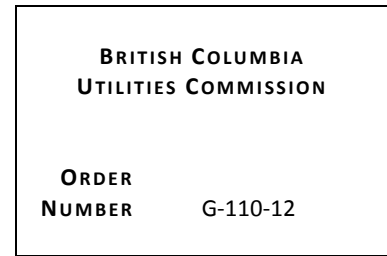
**ORDER
NUMBER G-110-12**

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- G. The Company filed an Evidentiary Update to the Application on November 4, 2011, which reduced the rate increase sought to 1.5 percent in 2012 and a 6.5 percent increase in 2013;
- H. The 2011 Annual Review was held in Kelowna on November 22, 2011, to review the Company's performance for the 2011 year, followed by a Procedural Conference to hear submissions on procedural matters regarding the current Application;
- I. By Order G-199-11, the Commission approved a 1.5 percent interim rate increase for FortisBC, effective January 1, 2012;
- J. Pursuant to Order G-214-11, the Oral Public Hearing to review the Application took place between March 5 and March 9, 2012 in Kelowna;
- K. Between April 5 and April 23, 2012, FortisBC and Interveners filed their Final Submissions. FortisBC filed its Reply Submission on May 3, 2012;
- L. The Commission has considered the Application, the evidence and all the submissions as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

- 1. Pursuant to sections 59 to 61 of the *Act*:
 - a. The requested permanent rate increase of 1.5 percent in 2012 and 6.5 percent in 2013 is not approved, as filed.
 - b. Cross charges between FortisBC and its affiliates regulated by the Commission are approved to be based on fully loaded costs, not including overhead.
 - c. The proposed Deferral Account for Power Purchase Expense variances from forecast is approved and is to be amortized into rates in 2014. The proposed Revenue Variance Deferral Account is also approved and is to be amortized into rates in 2014.
 - d. Determinations for the new proposed Deferral Accounts and treatment for existing Deferral Accounts are set out in Section 5.4.4 of the Decision.
 - e. Costs of Removal of \$4.7 million for 2011, \$5.4 million for 2012 and \$4.0 million for 2013 are approved to be included in Rate Base as set out in Section 5.4.2 of the Decision.
- 2. Pursuant to section 44.2(3) of the *Act*, FortisBC's 2012-2013 Capital Expenditure Plan is approved subject to the determinations and reductions set out in Section 5.4.3 of the Decision.
- 3. The Commission Panel accepts FortisBC's Long Term Capital Plan is in the public interest and the Long Term Resource Plan meets the requirements of the Act except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.



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4. FortisBC is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.
5. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. FortisBC is to provide all customers, by way of an information notice, of the change in rates.
6. If the 2012 permanent rates are less than the interim rates, FortisBC is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which FortisBC conducts its business. If the 2012 permanent rates exceed the interim rates, FortisBC is to reflect this difference in customer rates over the balance of 2012.
7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

BY ORDER

Original signed by:

D.A.Cote
Commissioner



IN THE MATTER OF

FORTISBC INC.

2012-2013 REVENUE REQUIREMENTS
AND
REVIEW OF 2012 INTEGRATED SYSTEM PLAN

DECISION

August 15, 2012

Before:

D.A. Cote, Commissioner/Panel Chair
A.A. Rhodes, Commissioner
N.E. MacMurchy, Commissioner

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COMMISSION ORDER G-110-12

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1.0 EXECUTIVE SUMMARY

On June 30, 2011, FortisBC Inc. filed its 2012-2013 Revenue Requirements (Application) and its 2012 Integrated System Plan for approval.

FortisBC sought across-the-board interim and permanent rate increases of 4.0 percent and 6.9 percent respectively for 2012 and 2013, pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (*Act, UCA*). This was revised with the filing of its Evidentiary Update on November 4, 2011, and FortisBC now seeks a rate increase of 1.5 percent for 2012 and 6.5 percent for 2013. Pursuant to subsection 44.2 (1) of the *Act*, the Company has also filed its 2012-2013 Capital Expenditure Plan with proposed gross expenditures over the test period of \$162.467 million as part of the Application.

A second part of the Application is the 2012 Integrated System Plan, which is made up of the 2012 Long Term Capital Plan, the 2012 Resource Plan and the 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that this is in the public interest pursuant to subsection 44.1(6) of the *Act*.

In reviewing this Application, the Commission Panel identified a number of overriding issues which have a direct impact on this proceeding and must be considered. These issues are as follows:

- The Magnitude of Rate Increase

The rate increases being sought in this Application and the expected future rate increases through 2016 indicate a trend that is well in excess of inflation. Given the economic challenges faced by all British Columbians including those within the FortisBC service area, the Commission Panel will review this Application with a view to minimizing current and potential future rate increases.

- Relevance of BC Hydro/FortisBC Inc. Rate Disparity

Considerable concern was raised in this proceeding with respect to the disparity in rates and practices of BC Hydro and FortisBC. The Commission Panel's notes that the two companies

operate with a different set of supply resources and a different customer base in terms of geography, population density and the residential/commercial/industrial mix. Therefore the Panel is of the view that there is no mandate nor would it be appropriate to expect FortisBC to have programs and rates that mirror those of BC Hydro.

- Importance of Productivity Improvements

The Commission Panel places considerable importance on the need for creating what it has described as a "productivity improvement culture" within utilities and, in the absence of evidence supporting its existence, to impose some form of productivity factor. The question facing the Panel is whether FortisBC has taken appropriate steps to demonstrate that it has processes in place to ensure productivity opportunities are explored.

These issues were not determinative in nature but did provide the Panel with a context to deal with specific issues as they arose within the proceeding.

Other key issue areas included:

- Power Purchase Management
- Departmental Operations and Maintenance (O&M) Expenses
- 2012-2013 Capital Expenditure Plan
- Deferral Accounts
- Demand-Side Management
- The Integrated System Plan

The Commission Panel has considered the views of all of the parties in making its determinations. We have not approved all of the FortisBC proposals nor have we agreed with all of the positions taken by the different Interveners. In the view of the Panel, the determinations made in this Decision are in the public interest and the resulting rates are just and reasonable as required under sections 59 and 60 of the Act.

A discussion of some of the highlights and key issues related to the Decision follows:

Power Purchase Management

A key function within FortisBC is the handling of power purchases through power purchase management. This Decision has examined a number of issues related to this function:

- A request for approval of increased power purchase expenses over the test period and a proposal to capture power purchase variances (both positive and negative) in a deferral account and flow them to customers in subsequent years.
- A proposal to increase power purchase management expenses (PPME) by 30 percent and include them as part of the estimate for power purchase expense.
- A proposal to implement a Planning Reserve Margin (PRM) late in the test period at an initial cost of \$310,000.

The Commission Panel made the following determinations:

- Approval of the deferral account to capture power purchase expense variances was granted, however, the Panel directed FortisBC to reduce its Power Purchase Expense Forecasts by \$1.5 million in consideration of previous forecast variances.
- PPME expenses were approved in a reduced amount and the proposal to move PPME from Operations and Maintenance and include it as part of power purchase expense was rejected.
- The proposal to implement a PRM and related expenses as part of the power purchase expense in this test period was rejected.

Departmental Operations and Maintenance Expenses

FortisBC has applied for O&M expenses of \$55.4 million in 2012 and \$56.8 million in 2013 (including PPME). A major consideration of the Commission Panel was whether FortisBC in this Application has demonstrated it has processes in place to ensure productivity opportunities are explored and implemented. The Commission Panel, while noting some concerns in specific departments, was not of

the view that imposing an overall productivity factor as proposed by some of the Interveners was appropriate given the size of proposed increases and the evidence on this matter.

The Commission Panel directs FortisBC to reduce O&M expenditures for labour by \$250,000 noting specific concerns in the Generation, Utility Operations and Community and Aboriginal Affairs departments. The Panel has made further determinations with respect to a reduction of proposed expenditures for the asset management program and non-labour related expenses in Customer Service and Community and Aboriginal Affairs.

2012-2013 Capital Expenditure Plan

FortisBC proposed capital expenditures totalling \$162,467 million. The Interveners that commented on the 2012-2013 Capital Expenditure Plan were unanimous in calling for a reduction in expenditures. BCPSO notes that there has been a significant build-out in recent years resulting in increased reliability, safety and quality of service to ratepayers. The Industrial Customers Group (ICG) argues that capital expenditures being made on the basis of reliability improvements should not form part of the Plan.

The Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time. The Panel has made specific determinations on projects which are inadequately supported or require additional work and has also made observations with regard to specific projects or project amounts we consider questionable given the evidence provided by the Company. The Commission Panel has rejected two projects totalling \$10.5 million. While the Panel has identified possible overall reductions of \$17.4 million, it has reduced that amount to \$ 10.5 million to allow FortisBC to achieve the level of service it requires and have sufficient flexibility to manage its projects and workforce. The Commission Panel has accepted capital expenditures of \$140,218 for the 2012-2013 test period.

Deferral Accounts

Important issues related to deferral account financing charges and the appropriate time period over which deferral accounts should be amortized have been examined. The Commission Panel has outlined the following guiding principles in making its determinations:

- A rate base rate of return applies only when a deferral balance has been transferred to become part of a capital project. Prior to this an interest rate of return based on the Weighted Average Cost of Debt (WACD) will apply.
- Deferred operating costs/current expenses are to attract an interest rate of return which varies based on the length of time they are deferred and the size of the amounts deferred.
- The length of amortization periods depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

These have been applied to the determinations on new and existing deferral accounts.

Demand-Side Management

FortisBC seeks approval of its 2012 Integrated System Plan which includes its 2012 Long-Term Demand-Side Management (DSM) Plan. In addition the Company has sought approval of DSM program expenditures of \$7.73 million in 2012 and \$7.88 million in 2013.

The Commission Panel has found that the 2012 Long-Term DSM Plan is adequate and cost effective. Citing the evidence of BCSEA's expert witness, Mr. Plunkett, that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, the Commission Panel approves the Company's DSM expenditures as requested.

Integrated System Plan

In addition to the 2012 DSM Plan the 2012 ISP includes the 2012 Long Term Capital Plan (LTCP) and the 2012 Long Term Resource Plan (LTRP). Both of these plans address the medium and the long term and cover requirements through 2031 in the case of the 2012 LTCP and 2040 in the 2012 LTRP. Based on our review of the evidence, the Commission Panel finds that the 2012 LTCP to be in the public interest and the 2012 LTRP as meeting the requirements of the *Act with the* exception of the Planning Reserve Margin which was rejected. FortisBC has been directed to file its next Long Term Resource Plan no later than June 30, 2016.

2.0 INTRODUCTION

2.1 The Application and Approvals Sought

FortisBC Inc. is a vertically integrated electric utility operating in British Columbia and is regulated by the British Columbia Utilities Commission (Commission).

This is an application by FortisBC Inc. (FortisBC or the Company) for approval of its Revenue Requirements of \$287.4 million for 2012 and \$310.4 million for 2013 which, if approved, will result in general rate increases for its approximately 161,000 direct and indirect customers of 1.5 percent effective January 1, 2012 and 6.5 percent effective January 1, 2013. (Exhibit B-12, Table 1.0) This approval is sought pursuant to sections 59 to 61 of the *Utilities Commission Act* (the *Act*) RSBC 1996 c. 473.

FortisBC also applies for Commission acceptance of proposed capital expenditures in the gross amounts of \$105.86 million for 2012 and \$129.08 million in 2013 as being in the public interest under subsection 44.2(3) of the *Act*. These amounts include previously-approved capital expenditures of \$7.92 million for 2012. They also include planned expenditures in the amounts of \$10.52 million and \$42.13 million for 2012 and 2013, respectively, for which the Company expects to file separate detailed applications for Certificates of Public Convenience and Necessity (CPCNs). (Exhibit B-1, Tab 6, p. 6, Table 1.1)

FortisBC has also filed its 2012 Integrated System Plan (ISP) which provides the long-term context for its 2012-2013 Revenue Requirements Application and 2012-2013 Capital Expenditure Plan. The Integrated System Plan outlines the long-term strategic direction of the Company in terms of capital, resource and energy conservation. The Integrated System Plan is made up of FortisBC's 2012 Long Term Capital Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan. FortisBC is seeking Commission acceptance that the Integrated System Plan is in the public interest pursuant to subsection 44.1(6) of the *Act*. (Exhibit B-1-1, Volume 1, pp. 1-2)

2.2 Legislative Framework

FortisBC is seeking approval of its proposed rate increases pursuant to sections 59 to 61 of the *Act*. Those sections basically require the Commission to have due regard to setting a rate that is not unjust or unreasonable in respect of the service provided by the utility. Subsection 59(5) provides that a rate is “unjust” or “unreasonable” if it is:

- “(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
- (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
- (c) unjust and unreasonable for any other reason”.

The utility is required to file rate schedules with the Commission setting out its approved rates.

Sections 59 to 61 are set out in their entirety in Appendix A.

As noted above, the Company is seeking Commission acceptance of proposed capital expenditures for the 2012-2013 test period pursuant to subsection 44.2(3) of the *Act*. Section 44.2 deals with expenditure schedules and is set out in its entirety in Appendix B.

Subsection 44.2(1) provides that:

“A public utility may file with the commission an expenditure schedule containing one or more of the following:

- (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
- (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
- (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

Subsection 44.2(3), pursuant to which approval of the proposed capital expenditures for 2012-2013 is sought, states:

”After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must

- (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
- (b) reject the schedule”.

By subsection 44.2(4), the Commission may also accept or reject a part of a schedule.

Subsection 44.2(5) provides the factors which the Commission is required to consider in its review of an expenditure schedule filed by a public utility (other than the British Columbia Hydro and Power Authority) stating:

(5) “In considering whether to accept an expenditure schedule...the commission must consider

- (a) the applicable of British Columbia’s energy objectives,
- (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- (c) the extent to which the [expenditure] schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

[only section 6 of the *Clean Energy Act* is relevant to subsection 44.2(5)(c) and requires the public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* [which deals with long-term resource plans] to consider British Columbia’s energy objective to achieve electricity self-sufficiency in planning for the construction or extension of generation facilities and energy purchases, (by subsection 6(4))].

- (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any,

[Demand-Side Measures Regulation BC Reg 326/2008 as amended by BC Reg. 228/2011 is applicable]

and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility”.

Subsection 44.2(5.1) is not relevant to the Commission’s review of the proposed capital expenditures in this case as that subsection applies only to British Columbia Hydro and Power Authority (BC Hydro).

Subsection 44.2(6) provides that:

“[i]f the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1(6),

(a) subsection 5 [which sets out the considerations for the commission’s acceptance of an expenditure schedule as set out above] does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule”.

British Columbia’s energy objectives, the applicable of which the Commission is required to consider in its review of an expenditure schedule, exceed fifteen in number and are listed in section 2 of the *Clean Energy Act (CEA)*. They relate in large measure to the use of clean or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions. Section 2 of the *CEA* is set out in Appendix C.

Also as noted above, FortisBC is seeking approval of its Integrated System Plan under section 44.1 of the *Act*, which relates to long-term resource and conservation planning.

Subsection 44.1(2) requires public utilities to file a long-term resource plan with the commission (in the form and at the times required by the commission) including all of:

(a) an estimate of the demand for energy the utility would expect to serve absent new demand-side measures taken during the period addressed by the long-term resource plan;

- (b) a plan of how to reduce that demand through cost-effective demand-side measures;
- (c) the resulting net demand, after cost-effective demand-side measures are taken;
- (d) a description of the facilities needed to be constructed or extended to serve the resulting net demand;
- (e) information on energy purchases necessary to serve the resulting net demand;
- (f) an explanation of why the resulting net demand which is to be served by the new facilities and energy purchases is not planned to be replaced by demand-side measures; and
- (g) any other information that the commission requires.

By subsection 44.1(6), once the Commission has reviewed the long-term resource plan, it must either accept it, if it determines that carrying out the plan would be in the public interest, or reject it. The commission may also accept or reject part of a long-term resource plan pursuant to subsection 44.1(7).

Subsection 44.1(8) sets out the factors which the Commission is required to consider in determining whether to accept or reject a public utility's long-term resource plan. These factors are consistent with those the commission is required to consider when considering a public utility's expenditure schedule and comprise:

- (a) the applicable of British Columbia's energy objectives;
- (b) the extent to which the [long-term resource] plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;

[Again, only subsection 6(4) of the *Clean Energy Act* is relevant. As noted earlier, this subsection requires the public utility, in planning for the construction or extension of generation facilities and energy purchases in accordance with its long-term resource planning under section 44.1 of the *Act*, to consider British Columbia's energy objective to achieve electricity self-sufficiency.]
- (c) whether the [long-term resource] plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and
- (d) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Demand-Side Measures Regulation

As noted above, BC Reg. 228/2011 amended the Demand-Side Measures Regulation, BC Reg. 326/2008.

The Demand-Side Measures Regulation applies to demand-side measures proposed in long-term resource plans filed under section 44.1 of the *Act* as well as those proposed in expenditure schedules filed under section 44.2 of the *Act*.

Among other things, the Demand-Side Measures Regulation defines the class composed of all demand-side measures proposed by a public utility in a long-term resource plan submitted under section 44.1 of the *Act* as a “plan portfolio”. It defines the class composed of all demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the *Act* as an “expenditure portfolio”.

Section 3 of the Demand-Side Measures Regulation sets out the criteria, all of which must be met (as long as the plan portfolio is submitted after June 1, 2009), for a utility’s plan portfolio to be “adequate” for the purposes of subsection 44.1(8) (c) of the *Act*. To be adequate, the plan portfolio must include:

- (a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
- (b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
- (c) an education program for students enrolled in schools within the public utility’s service area;
- (d) an education program for students enrolled in post-secondary institutions in the public utility’s service area.

Section 4 of the Demand-Side Measures Regulation provides for the calculation of the cost effectiveness of demand-side measures. It also prescribes how the “cost-effectiveness” of a demand-side measure is to be determined for a demand-side measure proposed in an expenditure portfolio.

The calculation prescribed by the Regulation has been called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost test (TRC).

In essence, for any demand-side measure proposed in an expenditure portfolio (i.e. filed pursuant to section 44.2 of the *Act*) which is not directed at residents of low income households, and for which the benefit amount to be used in the TRC test has not already been increased in accordance with the utility's request, the Commission is required to increase the benefit of the demand-side measure by an amount that:

- increases the benefits of the entire expenditure portfolio of which the demand-side measure is a part by 15 percent, and
- is equal to the increase made for all other demand-side measures making up the expenditure portfolio.

Thus, each individual demand-side measure in an expenditure portfolio is subject to a minimum increase of 15 percent.

However, other than for "specified demand-side measures" (which are defined) and "public awareness programs" (which are also defined) there is basically a 10 percent cap on demand-side measures which need the 15 percent adder to be cost-effective, in the case of electric utilities. (Demand-Side Measures Regulation, subsection 4(1.5))

The Commission also has the ability, in certain circumstances, to include other demand-side measures not included in the expenditure portfolio when determining cost-effectiveness and may, again in certain circumstances, and for certain demand-side measures, apply the utility cost test, as opposed to the modified Total Resource Cost test discussed above. (Demand-Side Measures Regulation, subsections 4(1.7), 4(1.8))

Demand-side measures which are required for a plan portfolio to be adequate, as set out above, are also subject to the Total Resource Cost test, but receive a 30 percent adder. (Demand-Side Measures Regulation, subsection 4(2))

2.3 Regulatory Process

FortisBC filed its Application on June 30, 2011. By Order G-111-11 of the same date, the Commission, among other things, established an Initial Regulatory Timetable and determined that the Company's Load Forecast would be reviewed by a Load Forecast Technical Committee, outside the Information Request (IR) process.

Ten Parties registered as Interveners, although not all participated in the regulatory hearing process. The Registered Interveners were:

- The British Columbia Municipal Electrical Utilities (BCMEU)
- British Columbia Hydro and Power Authority
- Mr. Alan Wait
- Mr. Norman Gabana
- British Columbia Pensioners' and Seniors' Organization *et al.* (BCPSO)
(The British Columbia Old Age Pensioners' Organization *et al.* filed a Notice of Name Change on July 23, 2012.)
- The BC Sustainable Energy Association and the Sierra Club of British Columbia (BCSEA)
- The Regional District of Okanagan Similkameen
- Ms. Buryl Slack
- The Industrial Customers' Group (comprising: Zellstoff Celgar Limited Partnership, ATCO Wood Products Ltd. International Forest Products Limited, Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, Springer Creek Forest Products)
- The Irrigation Ratepayers Group.

Five other parties registered as "Interested Parties".

The review of the Application included two rounds of Information Requests.

On September 16, 2011, FortisBC provided a summary of required changes to its Application including, among other things, an expected reduction to its Power Purchase Expense resulting from the Provincial Government's review of BC Hydro's proposed rate increases and BC Hydro's announced intention to amend its Revenue Requirements Application to seek lower rate increases. The Company proposed to recalculate its Revenue Requirements and resulting rate impacts following the report of the Load Forecast Technical Committee which was at that time expected on October 28, 2011. (Exhibit B-6)

On September 28, 2011 FortisBC submitted responses to Information Requests from the Commission and from the BCPSO on system losses. (Exhibit B-7)

On October 4, 2011 the Commission issued Order G-167-11 which, among other things, established a Revised Preliminary Regulatory Timetable and set the date of November 22, 2011 for a Procedural Conference. (Exhibit A-7)

BCSEA filed Intervener evidence on October 31, 2011 on the issue of demand-side management. One round of Information Requests was held on that evidence.

On November 4, 2011, FortisBC filed an Evidentiary Update to its Application. The Evidentiary Update amended the Application to, among other things, incorporate actual results to September 30, 2011, expected reductions to BC Hydro's F2012-2014 rates and updated forecast market rates for electricity, as well as to make certain corrections. The net impact of the changes set out in the Evidentiary Update was to reduce the Revenue Requirements in each year of the test period, resulting in a revised rate increase request for 2012 from 4.0 percent to 1.5 percent and a revised rate increase request for 2013 from 6.9 percent to 6.5 percent. (Exhibit B-12)

A Procedural Conference was held in Kelowna, British Columbia on November 22, 2011.

On November 25, 2011, FortisBC filed its Load Forecast Technical Committee Report.

On November 30, 2011, by Order G-199-11, the Commission Panel determined that FortisBC's Revenue Requirements Application would be reviewed through an Oral Public Hearing process to be held in Kelowna, British Columbia, commencing on January 24, 2012. The Commission Panel also ordered that FortisBC's interim rates for 2011 were to be made permanent, and a deferral account to capture any difference as between the impact of BC Hydro's interim and final rates was approved. The Commission Panel also approved an increase to FortisBC's interim rates, effective January 1, 2012, in the amount of 1.5 percent. (Exhibit A-13)

On December 7, 2011, FortisBC requested an amendment to the Regulatory Timetable to reschedule the Oral Public Hearing from January 24, 2012 to March 5, 2012, or later, in part because key FortisBC personnel were unable to devote the time required to prepare for a hearing commencing in January.

On December 15, 2011, the Commission issued Order G-214-11 amending the Regulatory Timetable and establishing the date of March 5, 2012 for the commencement of the Oral Public Hearing.

The Oral Public Hearing proceeded for five days commencing on March 5, 2012. FortisBC filed its Final Submissions on April 5, 2012. Final Submissions were received from participating Interveners by April 23, 2012. FortisBC filed its Reply on May 3, 2012.

2.4 Approach to this Application

The Commission Panel is of the view that there are a number of broader issues raised in this Application, which are important. These include: the magnitude of rate increases for the current test period and beyond, the relevance of the rate disparity between BC Hydro and FortisBC, and the importance of establishing a productivity improvement culture. These issues are introduced in Section 3 and, while not determinative, provide the Commission Panel with context to deal with specific issues as they arise. This will be followed in Section 4 with a discussion of a number of specific issues of importance, some of which require Commission Panel determinations. Section 5 is a review

of the 2012-2013 Application, its related issues and concerns and includes a discussion of operating and maintenance costs and various rate base issues in addition to the 2012-2013 capital plan.

Following this is a review of Demand-Side Management in Section 6 and the Integrated System Plan in Section 7.

3.0 OVERRIDING ISSUES

3.1 Magnitude of Rate Increase

Prior to the Evidentiary Update filed on November 4, 2011, FortisBC was seeking rate increases of 4.0 percent and 6.9 percent for 2012 and 2013, respectively. As noted previously, the net impact of the changes set out in the Evidentiary Update resulted in a reduction in the requested rate increase to 1.5 percent in 2012 and 6.5 percent in 2013.

FortisBC attributes the need for rate increases primarily to:

- (a) a growing rate base;
- (b) an increase in the cost of financing the rate base;
- (c) increased power purchase costs; and
- (d) taxes.

(Exhibit B-1, Tab 1, p. 6)

A number of Interveners took issue with the proposed rate increases.

The ICG asserts that FortisBC “needs to make immediate changes to reduce costs” and that that will not happen “as long as the Commission continues to approve rate increases...” (ICG Final Submission, p. 47)

The BCPSO argues that “[t]he present economic climate requires the Commission to carefully examine any cost increases that exceed inflation and are not essential to providing service as significant increases will only exacerbate the problems of struggling families during difficult economic times.” It submits that FortisBC’s capital build-out has been aggressive and agrees that this has resulted in increased reliability, safety and quality of service but argues that “a balance needs to be struck between appropriate levels of safety, reliability, quality of service and reasonable customer rates.” (BCPSO Final Submission, p. 3)

Similarly, the BCMEU, which represents the interests of FortisBC's five wholesale electricity customers which are municipal electrical utilities, encourages the Commission "to direct FortisBC to do better in terms of minimizing rate impacts on customers in this test period and beyond." The BCMEU adopts the position taken by the City of Penticton in its letter of comment (Exhibit D-4):

"The last three years have been very tough at the City of Penticton. The City has had to take drastic steps. The road was not easy. The City faced organizational restructuring, staff layoffs and terminations, elimination of bonuses and no or very low salary increases. In addition, efficiencies were also found. In short, the City of Penticton has worked very hard to reign in expenses so that costs for our customers do not have to increase. In fact, for 2011 the Penticton residential tax rate was reduced by 0.5%.

...

In closing I would ask that BCUC challenge FortisBC to also look internally to see what steps they can take to streamline their organization, increase efficiency and reduce costs in order that the proposed 2012 and 2013 rate increase can be reduced or eliminated."

(BCMEU Final Submission, pp. 2-3)

Mr. Norman Gabana also references the letter of comment from the City of Penticton as "what is happening in the real world" and asks the Commission to require FortisBC to produce operations plans that require no rate increases for 2012 and 2013. (Gabana Final Submission, pp. 1-2 referencing in part T2:84)

The Commission Panel acknowledges the position taken by the Interveners and agrees that the size of the proposed rate increases is significant, particularly in relation to inflation generally, and is therefore a very significant issue in these proceedings. The Commission Panel also views the main driver of this proposed increase as flowing from the increase in the size of rate base, as the other factors noted by FortisBC seem to be at or near historic lows. The Commission Panel also notes that rates are forecast to increase by a further 5.4 percent, 10.6 percent and 4.3 percent in 2014, 2015 and 2016, respectively. In the Commission Panel's view, these increases are also significant and likely to exceed inflationary increases for those years. (Exhibit B-12, Tab 7, p. 1) The Commission Panel acknowledges that

electricity is a necessity and, while customers are encouraged to reduce their consumption somewhat, it will take time for Energy Efficiency and Conservation (EEC) measures to take hold and consumption is unlikely to be significantly reduced during the test period, or in the near future. The Commission Panel, bearing in mind the requirements of subsection 59(5) of the *Act*, is sensitive to the comments of Interveners and will therefore make its determinations in this proceeding with a view to minimizing the proposed current and potential future rate increases, where possible.

3.2 Relevance of BC Hydro/FortisBC Inc. Rate Disparity

A number of interveners expressed concern about the disparity between FortisBC rates and BC Hydro rates. FortisBC acknowledges the disparity and the resulting customer concern. The “Fortis Group of Companies of BC Communications & Public Affairs Plan 2010/2011” states: “FortisBC rates are currently considerably higher than BC Hydro’s (approximately 20 percent). Although the spread is anticipated to diminish within the next five years, having higher rates remains a concern as they impact customer satisfaction and the company’s competitive position.” (Exhibit C1-7, p. 26)

As was demonstrated in evidence, FortisBC has gone through a period of significant capital expenditures over the last number of years in order to upgrade its generation and transmission infrastructure to provide greater safety and reliability. The bulk of this investment has now been made. In BC Hydro’s case, FortisBC testified that significant costs will be incurred by BC Hydro in the areas of new generation and refurbishment of existing plants that, when reflected in rates, will lower the disparity between FortisBC and BC Hydro rates. (Exhibit B-1, p. 6-7; T2:116, 221)

FortisBC operates with a different set of supply resources and with a different customer base in terms of geography, population density and the residential/commercial/industrial mix it faces. The Commission Panel has no mandate, nor does it find it appropriate, to require FortisBC to manage its utility business to produce rates or programs identical to those of BC Hydro. The Commission Panel believes that FortisBC’s responsibility is to provide safe and reliable service in a cost-effective manner consistent with British Columbia’s energy objectives. To do so, FortisBC must design and manage its system based on the resources available to it and the needs of its customers. This, at times, may result

in rates that are greater than those of BC Hydro and potentially times when they are less.

3.3 Importance of Productivity Improvements

A considerable number of submissions were made with respect to the need for productivity improvements and the need to impose a productivity factor. The Commission Panel believes there is value in addressing this at the outset by stating our position with respect to productivity improvements and outlining our expectations as to how a utility should address this issue within its day-to-day operations. In doing so, we would hope to provide greater clarity and insight into relevant parts of the Decision which follow.

The Commission Panel is of the view that there is an ongoing need for utilities to manage their business in a manner that actively seeks out and creates efficiencies resulting in what might be described as a “productivity improvement culture”. We believe this is in the interests of both the ratepayer and the shareholder. Put most simply, a productivity improvement culture is one where there is a demonstrated capability of a company to regularly undertake a review of the organization from both a macro and a micro point of view to examine what is being done, how it is being done and, where warranted, to make decisions to do things differently, or in some cases, not at all. When the Panel refers to the need for productivity measures we are not speaking of “cost cutting” but rather, “cost management”. It is not a difficult task to cut costs in order to achieve a desired result over a short term period. It is however, a difficult task to manage costs downward on a sustained basis with greater or no loss of efficiency over the longer term. It is this latter result that the Commission Panel believes needs to be addressed more comprehensively within utilities and best describes what can be achieved in a productivity improvement culture.

FortisBC notes that in the recent FortisBC Energy Utilities 2012 Revenue Requirements and Rates Decision which was issued on April 12, 2012, the Commission made a cut to FEU’s O&M budget and submits that such a reduction would not be appropriate in the context of the current proceeding. FortisBC states that imposing a percentage reduction as advocated by the BCMEU and BCPSO in this proceeding would not further the objective of subsection 60(1)(b)(iii) of the *Act* (which requires the

Commission to have due regard to setting a rate that encourages public utilities to increase efficiency, reduce costs and enhance performance) as the revenues as applied for by the utility accurately reflect the cost of service. The Company states that imposing a reduction would:

- Harm performance in the short term by denying access to necessary revenues it has forecast.
- Create an incentive for utilities to inflate revenues in a cost of service application in anticipation of such cuts; and
- Create regulatory inefficiency by undermining the process of review of the O&M part of a cost of service application.

(FortisBC Reply, pp. 24-25)

The Commission Panel agrees that imposing some form of productivity factor is not a decision to be taken lightly. However, there may be cases where a utility has been unable to satisfy the Commission that it has taken the necessary steps to ensure productivity and efficiency levels within the organization have been optimized. In these instances, some form of productivity adjustment to the O&M budgets of a utility are warranted. One purpose of examining productivity in greater detail in recent proceedings has been to encourage utilities to formalize processes to help create a productivity improvement culture and, where appropriate, to make the sometimes difficult decision to bring about change. These are difficult times for many ratepayers and the Commission Panel believes this is the least they can expect.

4.0 ISSUES OF IMPORTANCE

4.1 Load and Customer Forecast

FortisBC prepared a load forecast which was reviewed in detail by the Load Forecast Technical Committee (the Committee). This group was established by Order G-111-11. Members include representatives of FortisBC, BCUC staff, BCMEU, BC Hydro, and BCPSO and Ms. Beryl Slack Goodman.

The Committee met on various occasions and reviewed the load forecast, including the methodologies behind the forecast, for the 2012 and 2013 Revenue Requirements and for the Integrated System Plan. The review excluded assessment of the forecast of Demand-Side Management (DSM) savings, savings from rate structures or estimated system losses.

Committee members have accepted the load forecast and methodologies as put forward by FortisBC. Details of the forecast and the methodologies behind the forecast were filed by FortisBC on November 25, 2011. (Exhibit B-16)

The 2012 and 2013 Load Forecasts are summarized below:

Table 1

	2012 (GWh)	2013 (Gwh)
Residential	1,264	1,276
Commercial	696	709
Wholesale	926	935
Industrial	250	255
Lighting	14	14
Irrigation	44	43
Net	3,193	3,233
Loss	309	310
Gross	3,502	3,543
Winter Peak (MW)	721	731
Summer Peak (MW)	567	575

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 5.

The customer count summary for 2012 and 2013 is summarized below:

Table 2

	2012		2013	
	Number	% Change	Number	% Change
Residential	101,320	1.9%	103,279	1.9%
General Service	11,837	2.3%	12,130	2.5%
Wholesale	7	0.0%	7	0.0%
Industrial	36	0.0%	36	0.0%
Lighting	1,830	0.0%	1,830	0.0%
Irrigation	1,075	0.0%	1,075	0.0%
Total Direct	116,105	1.9%	118,357	1.9%

Source: Exhibit B-16, Appendix A, Attachment 1, Slide 30.

One issue that was raised by interveners with respect to the forecasting process was the use of a 1 in 20 peak forecast. Under this methodology, seasonal peaks are recorded from actual demand in the previous twenty years. Net energy growth is calculated from actual sales over the same time period. The maximum peaks of the past twenty years are then projected forward using the historical net energy growth calculation. (Exhibit B-16, Appendix A, Attachment 1, Slide 28) For the current 1 in 20 year forecast, the base year winter peak was 1990 and the base year summer peak was 1998. (Exhibit B-10, BCUC 2.3.1 (Losses))

BCMEU is concerned with this methodology and submits that the more commonly used 1 in 10 peak forecast would be more appropriate. (Exhibit B-10, BCUC 2 3.3; BCMEU Final Submission, p. 9)

FortisBC responded to these concerns by pointing out that the 1 in 20 forecast is not used for the purpose of determining the need for power purchases or directly for capital planning. It is used for benchmarking against the existing distribution planning forecast to confirm that it can accommodate load increases that result from extreme weather variations. (Exhibit B-10, BCUC 2.3.1 (losses), p. 9) FortisBC states that all capital projects were driven by the distribution planning forecast and that no

changes were made in terms of projects or timing as a result of the 1 in 20 forecast. (Exhibit B-10, BCUC 2.3.3)

Commission Panel Determination

The Commission Panel notes that in spite of the concerns raised by BCMEU concerning the use of a 1 in 20 peak forecast, all of the Committee members have accepted the Load Forecast. **The Panel further notes there was no evidence to suggest there were difficulties with the forecast or methodologies and therefore accepts the Load Forecast for the current test period.**

With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.

4.2 Capital Structure and ROE

In the Procedural Conference held in Kelowna on November 22, 2011, ICG questioned whether there was sufficient evidence for the Commission Panel to make a determination on FortisBC's capital structure and rate of return. ICG argued that the allowed capital structure of 60 percent debt and 40 percent equity and a risk premium of 40 basis points above the "benchmark" rate of return as approved by Order G-58-06 (Decision on an Application by FortisBC Inc. for Approval of its F2006 Revenue Requirement Application and Establishment of a Multi-Year Performance Based Regulation Mechanism (FBC 2006 RRA Decision)) could not be applied in this proceeding. In particular, ICG disputed the application of the benchmark rate of 9.5 percent as approved by Order G-158-09 (Decision on the Application by Terasen Gas Utilities for Return on Equity and Capital Structure (2009 ROE Decision)) considering its relationship to the automatic adjustment mechanism (AAM) which was eliminated by the same Order. (T1:27-38)

In the Reasons for Decision accompanying Order G-199-11 dated November 30, 2011, the Commission Panel addressed, among other things, the ICG's position on ROE and capital structure. The Panel noted that subsequent to the Procedural Conference on November 28, 2011, the Commission had issued a letter expressing its intent to conduct a Generic Cost of Capital (GCOC) Hearing designed to deal with capital structure and ROE with application to all utilities. In view of this, the Commission Panel concluded that there was little to be gained in terms of value or efficiency by considering the issue of capital structure and return on equity as part of this proceeding. The Panel's determination was as follows:

“Accordingly, the Commission Panel has determined there is no need to expand this hearing to include a comprehensive review of FortisBC's capital structure and ROE. Therefore, the Commission Panel has determined that given the Commission announcement regarding a generic hearing process, it would be appropriate to maintain the current ROE and capital structure pending determinations made in the Generic Cost of Capital Hearing.”

In its Final Submission, ICG argues that the cost of capital is “a significant component of a regulated utility's revenue requirements, and there should be no doubt that before rates are set the Commission Panel must determine the cost of capital for each year of the test period by applying the fair return standard”. (ICG Final Submission, p. 45)

ICG refers to its submissions at the November 22, 2011 Procedural Conference where it argued that the Commission has never accepted any evidence other than expert evidence regarding the cost of capital and in the absence of such evidence, the Commission should not approve the rates applied for. (ICG Final Submission, pp. 45-46)

ICG submits that Recital D of Order G-20-12 in the GCOC proceeding, which includes a statement that there have been changes in the financial markets since the 2009 ROE Decision, prevents the Commission from relying upon the cost of capital as determined by the 2009 ROE Decision to determine fair and reasonable rates. (ICG Final Submission, p. 46)

ICG also submits that the elimination of the ROE AAM upon which the Commission had been able to rely to ensure the fair return standard is met, now means the Commission Panel must determine the fair return standard before it approves rates for the first year of a test period. (ICG Final Submission, p. 46)

ICG continues by noting that, for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission relied upon negotiated settlements to ensure the fair return standard was met. ICG submits that, given Order G-47-12 dated April 18, 2012 in the GCOC proceeding, which states that the determination of the equity ratio and specific risk premiums for utilities will be no earlier than January 1, 2013, the Commission Panel has no other proceeding to rely on to ensure the fair return standard has been met for year one of the test period in this proceeding. (ICG Final Submission, p. 46)

ICG argues that subsection 58(1) of the *Act* requires a hearing before rates are set. It further submits that the onus is on the utility to justify all elements of its revenue requirement before the Commission sets rates. It submits there was no onus on the Interveners in this proceeding to file expert evidence on the cost of capital for the test period and, without expert evidence from the Company, the Application is deficient and cannot be approved. (ICG Final Submission, pp. 46-47)

ICG further submits that considerations of fairness require that there be an opportunity for the parties to challenge in a hearing, assertions of fact or opinion in dispute in order for a decision having an effect on rates to be made. Given Orders G-199-11 and G-47-12, it submits there will be no adjudicative process to determine FortisBC's cost of capital for the first year of the test period in this Application. ICG submits that this is a requirement before the Panel "can increase rates based on a return on equity of 9.9% and an equity ratio of 40%." (ICG Final Submission, p. 47)

The only other Interveners who comment on capital structure and ROE in their final submissions are the BCMEU and BCPSO. The BCMEU accepts that this issue will be addressed in the GCOC proceeding and, in particular, looks forward to the impact of the Commission's review on the Company's risk premium. BCMEU questions whether the existing risk premium is appropriate given FortisBC's

proposal to further mitigate risks through the use of deferral accounts. (BCMEU Final Submission, p. 10)

BCPSO submits that it “will be seeking through the GCOC [proceeding], to reduce the Company’s approved ROE to reflect current economic conditions.” (BCPSO Final Submission, p. 4)

FortisBC notes that the ICG arguments to make a return on equity an issue in this proceeding have been made several times and are contrary to the determinations of the Commission in the November 30, 2011 Reasons for Decision for Order G-199-11 in this proceeding and the Commission’s Reasons for Decision dated April 18, 2012 in the GCOC proceeding. Specifically, the Company notes that in the April 18, 2012 Reasons for Decision, the Commission reaffirmed that the current capital structure and ROE will be maintained pending GCOC proceeding determinations with specific determinations related to FortisBC to be made at a future proceeding following the generic hearing. (FortisBC Reply, p. 10)

Commission Panel Determination

The Commission Panel has reviewed the arguments of the parties and remains of the view that an examination of the ROE and capital structure for FortisBC is not a requirement in this proceeding and finds that the revenue requirements of FortisBC and resultant rate impacts can be adjudicated. Our reasons for this conclusion are as follows:

- FortisBC is not seeking a change to its capital structure or to its ROE in this proceeding. ICG submits that the onus was on FortisBC to file expert evidence on cost of capital in any event. FortisBC provided evidence that there had been no material change in its 40 point risk premium since the 2006 RRA Decision. In response to BCUC IR 2.31.1, FortisBC provides evidence with respect to maintaining the current ROE with a risk premium of 40 points over the benchmark in light of the Company’s improved credit metrics. In its response, FortisBC states that it bases its business risk profile on the long-term perspective and continues to support a risk premium over the benchmark. The Company refers to the Moody’s September 6, 2011 credit opinion which, among other things, states:

“financial metrics remain weak compared to Baa-rate peers” and

FortisBC submits that any reduction in ROE would challenge the Company's credit metrics as well as available liquidity which could potentially result in a credit downgrade and cost of debt increase. In addition, FortisBC refers to the October 6, 2011 DBRS credit opinion which commented upon challenges related to relatively large anticipated capital expenditures and their contribution to large free cash flow deficits as well as challenges related to the execution of the capital expenditure program. In response to BCUC IR 1.31.1, the Company noted that a credit rating upgrade is not the sole determinant of a business risk premium and listed a significant number of other risk factors that it faced. Included among these were the relative size of the utility, major businesses served by FortisBC, population and economic growth, competition and technological changes which the Company asserts has influence on an entity's long-term risk profile and collectively do not support a reduction to the Company's risk premium. The Commission Panel agrees as the FortisBC evidence supports the view that there has not been a substantive change in risk. As noted below, none of the parties challenged this evidence. (Exhibit B-8, BCUC 2.31.1; Exhibit B-8, Appendix 31.2)

- While paragraph 9 of Order G-158-09 issued concurrently with the 2009 ROE Decision eliminates the AAM, paragraph 8 of that Order approves the continued use by FortisBC of the benchmark return on equity of 9.5 percent which was determined as appropriate for Terasen Gas Inc. for rate setting purposes. Paragraph 8 of that Order provides that: "The TGI ROE approved in paragraph 3 of this order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates." In the view of the Commission Panel, this paragraph clearly establishes the Benchmark ROE for FortisBC for the purposes of this proceeding. In the Panel's further view, this approach is not substantially different in effect from what has been done in the recent past. In other words, in recent years, expert testimony on the cost of capital in a revenue requirements hearing has in fact been the exception, rather than the rule.
- The position of ICG is that for the period between the 2009 ROE Decision and the test period for this proceeding, the Commission could rely upon negotiated settlements to ensure the fair return standard was met. The last FortisBC RRA was completed on December 9, 2010 utilizing a negotiated settlement process (NSP) and resulted in a Commission approved Negotiated Settlement Agreement (NSA). The Commission Panel notes that the NSA which forms Appendix A to Order G-184-10 includes a list of issues and resolutions from the NSP. Neither ROE nor capital structure are referred to in the list of issues. Contrary to ICG's submission, the Panel's examination of the evidentiary record for that proceeding discloses that no expert evidence on capital structure or return on equity was filed by FortisBC or another party. Further, none of the parties raised this issue during the Information Request process. In their letters of support for the proposed NSA, none of the parties expressed any concern with the Commission approving the proposed NSA in the absence of expert evidence on capital structure or return on equity. While ICG was not a party to the NSA, Zellstoff-Celgar (a principal member of ICG) was a party, as were a number of the Interveners in this proceeding.

- The Revised Regulatory Timetable attached to Order G-167-11 provided for the filing of Intervener Evidence by October 31, 2011, after two completed rounds of information requests. Neither ICG nor any other Intervener filed evidence which challenged the FortisBC evidence that there had been no material change by that date or prior to the November 22, 2011 Procedural Conference. Consistent with the Commission Panel’s determination in the Reasons for Decision accompanying Order G-199-11, no party sought to file such evidence after November 30, 2011.
- The ICG argues that the Commission must apply the “fair return standard” before it approves rates for the first year of the test period and that it is not able to do so in the absence of expert evidence, given the automatic adjustment mechanism was eliminated by Order G-158-09.

The Commission Panel disagrees.

The Utilities Commission Act governs the rate-setting jurisdiction of the Commission. By subsection 59(1), a utility is prohibited from making, demanding or receiving a rate that is “unjust, unreasonable, unduly discriminatory or unduly preferential” or a rate that otherwise contravenes the Utilities Commission Act, its regulations, Commission orders or any other law.

By subsection 59(5), a rate is “unjust” or “unreasonable” if it is:

- (a) more than a fair or reasonable charge for service of the nature and quality provided by the utility, or
- (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
- (c) unjust or unreasonable for any other reason.”

The fair return standard has been articulated in various regulatory decisions across North America including the Commission’s August 26, 1999, Decision entitled “In the Matter of Return on Equity for a Benchmark Utility”. The standard provides the regulated utility the opportunity to:

- Earn a return on investment which is commensurate with that of comparable risk enterprises.
- Maintain its financial integrity; and
- Attract capital on reasonable terms.

In the Commission Panel’s view, the “fair return standard” is therefore intended to protect the utility. This is also apparent from the wording of subsection 59 (5)(b) that a rate is “unjust” or “unreasonable” if it is *insufficient* to yield a fair and reasonable compensation for the service provided by the utility or a fair and reasonable return on the appraised value of its property.

In the Panel's view, the rate for the first year of the test period is not insufficient to yield a fair and reasonable compensation to the utility for its service. This conclusion flows from the following:

- FortisBC has not sought to challenge the existing capital structure or ROE as yielding an insufficient return,
- The NSA for the previous test period arrived at rates which were approved by the Commission as not being "unjust" or "unreasonable". The rates for the first year of this test period are basically the same, when inflation is considered, and there has been no degradation in the nature and quality of the service provided as is indicated by the SAIDI and SAIFI statistics.
- The GCOC proceeding has been initiated to deal with the issues of ROE and capital structure for all utilities at the same time. This will ensure all of the utilities taking part in the GCOC proceeding are treated in a consistent manner. The Commission Panel considers this to be just and reasonable for both the utilities and the ratepayers.
- Reviewing cost of capital in a single process is an efficient and cost effective approach. The Commission Panel is of the view that holding a separate hearing process to examine cost of capital issues for FortisBC alone, for only one year in the test period, would result in significant additional costs which would be borne by FortisBC's ratepayers.

For these reasons **the Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.**

5.0 2012-2013 REVENUE REQUIREMENTS APPLICATION

5.1 Power Purchase Management

A key function within FortisBC is power purchase management. FortisBC has proposed a number of significant changes with respect to power purchase expense and the overall management of this important function. Additionally, the Company has proposed that the concept of a PRM be explored and put in place during the latter stages of this test period. In this section, the proposals put forth by FortisBC will be reviewed beginning with the handling of the Power Purchase Management group and related expenses, followed by a review of power purchase expense requirements and proposed changes in how these are handled and end with consideration of the PRM proposal.

5.1.1 Power Purchase Expense

FortisBC submits that the purpose of its resource acquisition policy is to allow customer load requirements to be met at the lowest reasonable cost with a minimum of environmental impacts. The Company can supply over 98 percent of its annual energy requirements from long-term, firm resources. In meeting its energy requirements, FortisBC uses a combination of Company-owned generation entitlements and firm supply which has been contracted, augmented by spot market purchases to deal with any capacity or energy deficits. FortisBC-owned generation entitlements include the Canal Plant Agreement (CPA) entitlements while examples of contracted firm supply include the Brilliant Power Purchase Agreement (BPPA) and the BC Hydro Rate Schedule (RS) 3808 Power Purchase Agreement (PPA). Other purchases include Independent Power Producers and market purchases made in advance, as well as those on the spot market. (Exhibit B-1, Tab 4, pp. 3-10)

FortisBC seeks approval for a power purchase expense forecast of \$89.0 million in 2012 and \$94.6 million in 2013 (Exhibit B-12).

As outlined in Table 3, FortisBC has consistently reported a power purchase expense under-expenditure variance. Over the period from 2007 through 2011 (actuals through 2010) the under-expenditure is expected to total in excess of \$26 million:

Table 3

	2007	2008	2009	2010	2011A	Total
	Over / (Under) Approved					
Sales Load Variance (Gwh)	13	0	50	(153)	25*	
Power Purchase Expense Variance (\$000s)	(5,631)	(2,528)	(168)	(8,444)	(9,693)	(26,464)

* 2011 is forecast

(Calculated from Exhibit B-1, Table 4.1.5-1 and Transcript 5, p. 849)

The Company explains that these power expense variances could result from a number of factors, including:

- Load variances related to variances in customer growth, usage or weather;
- Unit price variances from forecast (an example being BC Hydro rates which were not known at the time of application and were not finalized at the close of the evidentiary record);
- FortisBC’s ability to displace contracted purchase with lower-cost market purchases;
- True-up of BPPA costs; and
- CPA operational factors affecting the Company’s usage or timing of entitlements.

(Exhibit B-1, Tab 4, p. 23)

A Performance Based Regulation (PBR) Plan was in place over this period which allowed these variances to be shared equally between customers and shareholders through the ROE sharing mechanism.

In this Application, FortisBC has proposed a deferral account to capture variances in forecast and actual Power Purchase Expense. This is in part in response to a request from stakeholders in the 2011 Negotiated Settlement Agreement. FortisBC has requested that firm rates be set for the 2012-2013 test period and any accumulated variances be applied to rates in 2014. Thereafter, the Company proposes to flow through any variance in the Power Purchase Expense Variance Deferral Account to customers in the subsequent year. (Exhibit B-1, Tab 4, pp. 23-24)

None of the Interveners made specific submissions with respect to the proposed Power Purchase Expense Variance Deferral Account although it can be assumed that they support it given their request at the last NSP.

Commission Panel Determination

The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The Panel understands the complexity of managing the number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods.

Of concern to the Commission Panel however, is the level of accuracy of FortisBC's forecasts for power purchases over the past five years. As noted previously, the under-expenditure to forecast over this period has totalled more than \$26 million or more than \$5 million per year. Moreover, in only one of those five years has the under-expenditure been less than \$2.5 million. This matter was pursued by Commission Counsel at the oral hearing phase of the proceeding. FortisBC, using 2010 as an example, pointed out that much of the under-expenditure was driven by a load variance. (T5:831-832) The Commission Panel accepts this reasoning for 2010 but notes that, based on the information presented in the above table, the favourable sales load variances in 2007 and 2009 also resulted in significant over-forecasting of the power purchase expense in those years.

The Commission Panel finds that based on the past five years, FortisBC has been overly conservative with its power purchase expense forecasts. As discussed in Section 3.1, there have been significant concerns raised with respect to the continued increase in rates given the economic challenges faced by all customer groups. The Commission Panel is of the view that reducing the power purchase forecast is both justified and will provide some relief to customer groups. The Panel understands that much of the customer risk associated with an under-expenditure has been eliminated by the approval of the Power Purchase Expense Variance Deferral Account but is of the view that this does not justify setting rates on the basis of overly conservative forecasts. **The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by \$1.5 million in 2012 and 2013.** The Commission Panel notes that FortisBC forecasts its rate increases on the assumption that BC Hydro's rate increase, effective April 1, 2012, is 3.9 percent with a further 3.9 percent effective April 1, 2013. The Commission Panel notes that BC Hydro has recently adjusted its permanent rates for April 1, 2013 to 1.44 percent plus a 5 percent Deferral Account Rate Rider. **FortisBC is directed to adjust its power purchase expense forecast to reflect this change.**

5.1.2 Power Purchase Management Expense

FortisBC proposes a budget of \$1.2 million in 2012 and \$1.3 million in 2013 for PPME to be included in its Power Purchase Expense forecast. This represents an increase of \$284,000 or 30 percent over the 2011 Forecast for this function which is primarily responsible for planning and securing power from a variety of sources (company-owned generating units, power supply contracts and market transactions) on a short, medium and long-term basis. The Company submits that its Power Supply group is facing a need to secure an increasing future load while dealing with a regional environment which is becoming more constrained and more tightly regulated. FortisBC further submits that the Application includes funding for incremental staff and funding for power supply which it believes to be necessary to manage the growing complexity of efficiently meeting an increasing load. The incremental costs for 2012 over the previous test period are made up of the following:

- \$0.022 million for labour cost escalation.
- \$0.143 million for the addition of one Full Time Equivalent (FTE) employee.

- \$0.068 million for additional consulting resources.
- \$0.050 million for inter company transfers from FortisBC Energy Inc. for services provided.

Costs in 2013 are planned to increase by \$0.055 million reflecting inflationary changes affecting labour and some non-labour costs. Some examples of additional work requirements driving the increased costs over the test period include:

- The need for more in-depth analysis of power supply options
- The need to participate in outside organizations to cooperatively deal with common problems.
- Additional resource requirements with business continuity skills at the System Control Centre
- Requirement for more active management with dispatchers monitoring real-time resource load.

(Exhibit B-1, Tab 4, pp. 13-15; Exhibit B-8, BCUC 2.8.2)

A significant change that FortisBC has proposed for this test period is that the PPME be included in the estimate of Power Purchase Expense rather than maintaining it within the O&M budget as in the past. FortisBC submits that linking PPME directly to the Power Purchase Expense will help to ensure that there are sufficient resources to plan, implement and mitigate Power Purchase Expense. (Exhibit B-1, Tab 4, p. 13)

BCMEU is not supportive of increased staffing in order to purchase power supply. BCMEU expresses concern with the increase in PPME, given the longer term agreements being executed which it submits should provide stability in power purchase management. Additionally, BCMEU expresses concern that there is the potential for further efficiencies to be gained through the management of power purchase matters on a shared basis (i.e., with FortisBC Energy Inc.), which is not being pursued. BCMEU make no submission with regards to moving the PPME out of O&M. (BCMEU Final Submission, p. 17)

BCPSO expresses concerns similar to the BCMEU and points to the company's success in reducing power purchase costs over the PBR period. BCPSO suggests the Commission may wish to consider whether the additional power purchase costs are necessary and whether the benefits justify the additional cost. Like BCMEU, BCPSO makes no submission regarding the movement of the PPME out of O&M. (BCPSO Final Submission, p. 9)

FortisBC acknowledges the concerns of BCMEU and BCPSO and agrees that the current lower price environment has allowed it to realize power purchase cost savings against forecast through displacement of purchases under the BC Hydro RS 3808 PPA. However, FortisBC further notes that market conditions continue to change and submit that the Company must be proactive and responsive to these changes in order to maximize savings. FortisBC underlines this point with respect to the BCMEU comments regarding the apparent stability offered by long-term agreements. FortisBC notes that savings would be lost if it relied on existing agreements and did not take full advantage of opportunities to displace those purchases. In addition, FortisBC argues that the nature of long-term agreements continues to change and the yet-to-be negotiated BC Hydro RS 3808 PPA and the addition of Waneta Expansion capacity will not result in reduced workload. (FortisBC Reply, pp. 43-44)

Commission Panel Determination

The Commission Panel is in agreement with BCMEU and BCPSO with respect to the additional expenditures being proposed by FortisBC for PPME and is concerned as to whether there is a need for an increase of 30 percent of existing resources.

FortisBC has acknowledged that it has integrated its gas and power supply teams and has requested additional PPME funding for the services provided by the gas supply side as a means of creating greater efficiencies and leveraging off the experience of the two groups. (FortisBC Final Submission, p. 17) While the Commission Panel is disappointed that this integration has not led to some immediate savings, we do accept that there is potential benefit to utilizing some of the gas resources to maximize the productivity of existing PPME resources. However, we are not convinced that there has been a sufficient case made to justify the further FTE position that is proposed by FortisBC. As noted by

BCMEU in reference to the sizable under-forecast in power supply expense, favourable market transactions should continue to be achievable with existing staffing levels. (BCMEU Final Submission, p. 17) **The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of \$142,000 in each of 2012 and 2013.**

The Commission Panel has an additional concern with the proposal to move PPME from O&M to become part of the estimate of Power Purchase expense. We are somewhat confused by how this movement will help ensure there are sufficient resources for planning, implementation and mitigation of power purchases as submitted by FortisBC. (FortisBC Final Submission, p. 77) The proposed move will result in no cost savings, nor will it have any impact on rates so it is difficult to determine where the benefits attached to this move actually lie. While there is a potential for less scrutiny of the activities, this will only serve to reduce transparency rather than increase efficiency and will only muddy the waters with respect to direct annual comparisons of metrics based on O&M expenditures. **Accordingly, the Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.**

5.1.3 Planning Reserve Margin

Following the Western Electricity Coordinating Council (WECC) recommendations, FortisBC is proposing to implement a PRM within the test period. FortisBC has included \$310,000 in its Power Purchase Expense which is the forecast cost of holding an additional resource for the fourth quarter of 2013. FortisBC asserts that it is common practice to consider the level of capacity reserves required to handle long-term requirements and most neighbouring utilities carry PRM as a means to meet uncertain load requirements, provide operating flexibility and manage uncertainty in resource delivery. FortisBC states that while it is not mandatory, it believes it is prudent to carry an appropriate level of PRM. (T5:747, 748,763; T4:765; Exhibit B-8, BCUC 2.7.2)

FortisBC states there are three circumstances which have the potential to drive the need for PRM:

- Unavailability of supply due to unplanned generating unit or transmission outage,
- Unexpectedly high loads, typically due to extreme weather events, and
- A period of accelerated growth that outpaces the installation of new power supply resources. (Exhibit B-1-2, pp. 53-54)

FortisBC asserts that looking forward, a failure to carry a PRM will force the Company to rely on market purchases in order to meet future capacity shortfalls which, depending on the market, could become increasingly risky. Risk factors identified by FortisBC's consultant, Midgard Consulting, include increasing installed intermittent generation, decreasing regional capacity margins and the re-introduction of industrial load following an economic recovery, among others. (Exhibit B-1-2, Appendix D) FortisBC concludes that, given these risk factors, a failure to include PRM as part of its resource adequacy requirements exposes ratepayers to an unacceptable level of risk. (Exhibit B-8, BCUC 2.7.2)

With respect to quantification of the PRM requirement, FortisBC indicated that it has been doing further assessment. In testimony during the oral phase of the proceeding, Ms. Des Brisay, FortisBC Vice President of Energy Supply and Resource Development, stated that the formula-driven approach to determining PRM proposed in the Application may overstate PRM requirements. Ms. Des Brisay further stated that a detailed assessment is being undertaken and the Company is now taking a probabilistic approach to PRM and hopes to have an analysis completed by the end of the third quarter of the current year. (T5:766) Earlier, Ms. Des Brisay commented on that analysis by stating that "what is very clear is that it's not clear." In her testimony she continued by stating that there is a bit of art and science in determining an appropriate PRM and that it is very utility-specific. (T4:741)

ICG notes FortisBC's acknowledgement that its initial approach to PRM was not supported by evidence. ICG submits that the new approach to Planning Reserve Margin is not acceptable because it has not been sufficiently developed to where it can be relied upon by the Commission to determine fair and reasonable rates. ICG also points out that one of the underlying concerns leading to a need for PRM is risk associated with capacity shortfalls. ICG questions the submissions of FortisBC with regard to capacity constraints and submits that before the Commission Panel can approve PRM for ratemaking

purposes, it needs to agree that this region has become tight from a capacity perspective. In addition, ICG points out that FortisBC's RS 3808 PPA contract negotiations with BC Hydro have not been completed and FortisBC does not know whether it will include excess capacity provisions to allow the forecast load requirement to be met without a PRM. Accordingly, ICG concludes that a PRM should not be approved at this time as the RS 3808 PPA contract negotiations with BC Hydro have yet to be concluded and further development of the methodology to identify the appropriate PRM is required. (ICG Final Submission, pp. 29-34)

BCPSO submits that a key factor in FortisBC's need for PRM is capacity constraints. BCPSO agrees with ICG that FortisBC may not be facing the capacity constraints which it has predicted. BCPSO concludes that the Commission should be satisfied that capacity constraints actually exist before allowing PRM requirements into rates. (BCPSO Final Submission, p. 16)

FortisBC notes that the Midgard Planning Reserve Margin Report identifies six factors which are aligned with a potential increase in capacity resource market costs within the WECC-Canada and WECC –Northwest Regions. Each of these is described by the Midgard Report as a risk factor and none is a justification in itself. FortisBC points out that the Midgard Report lists three potential circumstances which drive the need for PRM (listed above in this Section). FortisBC argues that there is, therefore, no basis for the ICG assertion that the Commission needs to agree that the region is becoming increasingly tight for capacity before approving rates based on PRM requirements.

FortisBC acknowledges that it is adopting a different approach to assessing PRM than was originally proposed but argues that consideration of PRM in assessing the adequacy of its resource portfolio is prudent and should be accepted by the Commission. The Company proposes to complete its PRM study and recommendations by the end of the third quarter of 2012 and file these with the Commission at that time for review and approval of related power purchase costs required to meet the appropriate resource adequacy standard. (FortisBC Reply, pp. 64-68)

Commission Panel Determination

It is clear from the evidence that there is a significant amount of work to be completed with respect to development of a methodology to determine an appropriate PRM, a point with which neither the Applicant nor the Interveners seem to disagree. **The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional \$310,000 in planned Power Purchase Expense for 2013.**

The Commission Panel agrees with FortisBC's suggestion to complete its PRM methodology study and file it with the Commission along with its proposed recommendations later in 2012. Hopefully, by that time, the Company will have completed its BC Hydro RS 3808 PPA negotiations and any implications of the new agreement can be taken into consideration when reviewing the new proposal. The approval of the Power Purchase Expense Variance Deferral Account (PPEVDA) will allow any approved expenses incurred during the test period to be deferred to 2014.

5.1.4 Water Fees

FortisBC's power supply costs include not only power purchases but also water fees. (Exhibit B-1, Tab 1, p. 7) Water fees are assessed by the Province based on FortisBC's generation in the previous year and the rate is indexed to the BC Consumer Price Index (CPI). (Exhibit B-1, Tab 4, p. 28) Variance in water fees could be a result of either volume variances in FortisBC's generation in the prior year or from rate variances due to differences in water rental rates.

Water fees were \$9.3 million in 2010 and \$9.0 million forecast in 2011. FortisBC forecasts water fees to increase to \$9.7 million in 2012 and to \$9.8 million in 2013 due to increased plant entitlement use in 2011 and 2012, respectively, as well as the increase in water fee rates from 2011 levels based on the Company's forecast of BC CPI. (Exhibit B-1, Tab 4, p. 28; Exhibit B-12)

Although FortisBC has not proposed to include variances in water fees in the PPEVDA (Exhibit B-8, BCUC 1.22.1), during the oral hearing phase of the proceeding, Ms. Des Brisay stated that doing so would be consistent with the intent of the deferral account. (T5: 850)

Commission Panel Determination

The Panel agrees that water fees are solely related to the cost of generation. Given the intent of the Power Purchase Expense Variance Deferral Account, **the Panel directs FortisBC to include any variances related to water fees in that deferral account.**

5.2 Operations and Maintenance Expenses

5.2.1 Overriding Issues

The overriding issues pertaining to FortisBC's O&M budget are discussed in the following sections.

5.2.1.1 Demographic Challenges

FortisBC faces the challenge of having approximately half of its workforce eligible to retire in the next few years. Of these, 28 percent are eligible to retire with an unreduced pension. The Company states that it is difficult to predetermine the number of eligible employees that will retire but indicates that over a five year period beginning in 2006, 24 percent of those eligible to retire with an unreduced pension actually did so. Based on this past experience, this would indicate that roughly a quarter of those eligible to retire with unreduced benefits are likely to do so. FortisBC states that the biggest challenge departmentally is with Transmission and Distribution (T&D) with 33 of 72 employees eligible to retire in 2011 with an unreduced pension. Positions requiring focus are Power Line Technicians (PLTs) where there is a market shortage, Meter Technicians, Communication, Protection and Control Technicians and Power System Dispatchers. In addition, FortisBC notes that 30 percent of the management group in T&D are eligible to retire with unreduced pensions. (Exhibit B-1, pp. 35-39)

In addition to the retirement challenge is the risk of employee turnover. FortisBC states that voluntary turnover (not including retirements) was approximately 4.5 percent from 2008 through 2010. When viewed in relation to other companies, this turnover seems to compare favourably within the Transportation and Utilities sector and is well below the average of other comparable sectors. FortisBC has reported that 181 new employees were recruited from 2008 to 2010. It seems that many of these were not actually new employees but FortisBC employees moving to new positions within the organization. Such backfills often result in a cascading effect when filled with internal candidates. (Exhibit B-1, pp. 39-40)

Within the Application, FortisBC outlined a number of initiatives it has been undertaking as part of its workforce strategy to offset the combined effects of retirements and other turnover. Included among these are the following:

- A PLT apprentice program
- Sponsorship of the “Bright Futures” program to create interest in the industry within schools.
- Development and Execution of succession and workforce plans.
- Investment in Education.
- Offering Scholarships and participating in Co-op programs in conjunction with schools.
- Development of a Supervisory Skills program.

(Exhibit B-1, pp. 40-41)

Commission Panel Determination

The Commission Panel acknowledges the challenges faced by FortisBC with respect to planning for and dealing with the potential retirement of a significant number of employees in the near future. The Panel also acknowledges the work the Company has put into developing initiatives to mitigate or at least soften the impact of a large number of retirements if they were to occur. However, of concern to the Panel is the lack of clarity with respect to this problem beyond the current test period. During the

oral phase of the proceeding, Ms. Drope, FortisBC's Chief Human Resources Officer, was asked to comment upon whether FortisBC, looking beyond the current test period, had forecasted the size of the problem, the costs, and when an end can be expected to the "bubble" of retirements moving through the system. Ms. Drope replied that an analysis had not been completed because of the number of variables at play but estimated that 10 years is a likely time horizon. Further, when asked whether a detailed plan or cost estimates for that 10 year period had been developed, Ms. Drope failed to confirm that a plan had been completed and was unable to respond to the cost implications "off the top of [her] head." (T3:581-582)

The Commission Panel is of the view that this issue is sufficiently important to warrant further analysis, including a comprehensive plan outlining the implications, activities and costs of dealing with this workforce challenge. **Therefore, FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.**

5.2.1.2 Productivity Factor

As noted previously in Section 3.3, there were a number of submissions regarding the need for productivity improvement. The BCMEU in its submissions expressed concern that FortisBC had not included a productivity factor in the preparation of the O&M budgets and urged the Commission to impose a productivity target of 1.5 percent for both 2012 and 2013. BCPSO agreed with BCMEU with both the concept of a productivity factor and the amount. For purposes of clarification, the Commission Panel interprets these submissions to mean that both parties are in agreement that an overall reduction of 1.5 percent of O&M budgets should be imposed by the Commission as a means of driving productivity improvement.

FortisBC advanced the position that productivity improvement factors are not appropriate if applied outside of PBR. The Commission Panel has addressed the need for productivity improvement factors in Section 3.3 of this Decision. The Panel will now address the issue of productivity improvement from the following perspectives:

- whether FortisBC has demonstrated that it has adequately addressed productivity improvement in this proceeding.
- whether there is evidence to justify imposing a productivity factor as suggested by BCMEU and BCPSO.

FortisBC states that it has achieved O&M efficiencies of 10.4 percent as a result of the negotiated productivity improvement factors during the PBR period. The Company acknowledges that there have been increases in O&M expenditures forecast for both 2012 and 2013 but submits that an increase in O&M expenditures is not inconsistent with performance during the PBR period. FortisBC further submits that there are factors other than a lack of productivity which could result in an increase in O&M costs regardless of how efficient the Company has been. These include items such as inflation, but also could involve the need to undertake new expenditures in certain areas or the need to reclassify an expense from capital to operating. In support of its management of O&M costs and resultant productivity, FortisBC states that “[a]fter factoring out the \$3.78 million that was transferred from capital to O&M expense in 2011 as directed by Order G-195-10, concerning the Company’s 2011 Capital Expenditure Plan, and those items referred to under the PBR mechanism as extraordinary O&M expense, the O&M expense per customer, on a real basis, has declined over the period 2007 to 2010”. (FortisBC Reply, pp. 26-27)

Commission Panel Determination

The Commission Panel acknowledges that growth in O&M or O&M per customer are factors in determining whether an organization can be described as being efficient and productive. In the Panel’s view the forecasted growth of O&M for the test period is not unreasonable (2.8 percent in 2012 and 2.6 percent in 2013), as it is generally in line with inflation. (Exhibit B-1, Tab 4, p. 31; Exhibit B-12, Tab 7, p. 1) We also accept that there are factors beyond the control of the Company which can affect growth of O&M and related measures. However, while O&M metrics must be considered, they do not directly address the question of whether FortisBC has demonstrated that it has addressed the issue of productivity improvement within this proceeding.

In his testimony, Mr. Walker, FortisBC's President and CEO, spoke to the issue of productivity and stated that he believed that a continuous focus of the Company was on productivity and how to be more efficient and that this commitment to finding efficiencies was well demonstrated within the Application. (T2:118-119) Moreover, throughout the O&M departmental review (Exhibit B-1, Tab 4), the Company outlined steps which had been recently undertaken or were planned to be undertaken in each of the departmental workgroups in a subsection entitled "Management of Cost Efficiency." Many of the initiatives undertaken were in recognition of the need to do things differently as a means of controlling costs and creating efficiencies and, in the view of the Commission Panel, provide an excellent example of the types of practices required to keep rates from rising unnecessarily. Further evidence of the Company's commitment to improving productivity is illustrated in answer to BCUC IR 1.28.2 which summarizes productivity improvement measures taken over the PBR period. The Panel notes that these examples would be more instructive if they were measured and quantified in dollar savings.

Given the evidence and the fact that the increases in O&M expenditures are within a reasonable range, the Commission Panel is not in agreement with BCMEU and BCPSO with regard to imposing a productivity improvement factor. However, this should not be interpreted to mean that the Commission Panel is satisfied with the need for all of the expenditures within the O&M area. O&M expenditures will be addressed in greater detail in Section 5.2.2.

5.2.1.3 Integration of FortisBC and FortisBC Energy Utilities

The level and speed of integration of common functions among the FortisBC group of companies was very much at issue in this proceeding. FortisBC states that the process is at an early stage as a number of key foundational elements (among these is the proposed amalgamation of the gas utilities) must be put in place. To date, the senior management teams of both organizations have been combined with the result that total executive costs in 2013 are projected to be only \$13,000 higher than in 2007. Additionally, a Board of Directors has been shared by both organizations since in 2010, resulting in significant savings. FortisBC indicates that it is now about to start the process of looking for efficiencies

through alignment of operational elements of the business. As noted by Mr. Walker under cross examination, the Company expects to see additional benefits by the latter part of 2013 and expects there to be filings to deal with integrated activities in 2014 and 2015. Further, Mr. Swanson, FortisBC's Director of Regulatory Affairs, noted that the process is just starting and there will be a period of time required for investigation and trying to determine whether there are potential savings. (Exhibit B-1, pp. 95, 100; FortisBC Final Submission, pp.16-17; T2:135, 267)

While acknowledging that some progress has been made, BCMEU expresses scepticism with the level of effort that FortisBC has applied in pursuing opportunities for integration to the benefit of ratepayers. BCMEU believes that additional savings can be attained (presumably in the short term) and states that it is frustrated that opportunities may not be identified earlier. (BCMEU Final Submission, p. 7)

FortisBC states that it is unrealistic to expect benefits beyond those embedded in the Application to be achieved before the end of the test period and argues that it would not be reasonable to reduce FortisBC's revenue requirements. FortisBC points out that while savings may be achieved at the higher level within the companies, this does not necessarily apply to lower levels of the two organizations. The reasons for this relate to the differences in commodities sold, different customers (in most cases) and embedded systems that work well for each organization. FortisBC concludes by stating that further synergies may be achieved following the Company's filing of a shared services model, which is unlikely to occur before the 2014 RRA application. (FortisBC Reply, pp. 16-18)

Commission Panel Determination

The Commission Panel, like BCMEU, would like to see the process of integration of common functions move forward more quickly. However, we accept that proceeding in this direction may not be a simple matter and must be done only after careful consideration. **Because of this, the Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.**

5.2.1.4 Cost Allocations

FortisBC has stated that costs related to the Board of Directors' compensation and other expenses are shared amongst FortisBC and FEI utilizing a Massachusetts Formula which is applied to revenue, payroll and net tangible assets with a forecast allocation of 23.35 percent to FortisBC. The method for allocating the expenses of senior management between FortisBC and FEU differs significantly from this. In the case of senior management, FortisBC is charging FEI for those FortisBC executives who have responsibilities in FEI and is receiving charges for those FEI executives who have responsibilities at FortisBC based on estimated time spent.

ICG disagrees with the method of cost allocation for executives. ICG submits that the costs of executive officers should also be allocated to FortisBC on the basis of the Massachusetts Formula. (ICG Final Submission, p. 17) ICG provided no reasons as to why this was appropriate.

BCMEU concurs with the position of ICG and submits that, relative to other members of the FortisBC group of companies, FortisBC is potentially being overcharged by not using the Massachusetts Formula. (BCMEU Final Submission, p. 15)

FortisBC submits that the allocation of executive costs based on executive estimates of where time is spent is appropriate and there is no cross-subsidization between gas and electric customers. FortisBC continues by stating that the use of the Massachusetts Formula to allocate costs is currently being considered and once it has completed an examination of optional methodologies, the Company expects to bring the results before the Commission for review and approval. (FortisBC Reply, pp. 40-41)

On a related matter, FortisBC seeks to streamline the cross charges for executives to and from FortisBC Energy Inc. and base it on a fully loaded wage (excluding the current overhead charge) thereby mirroring the process approved in the 2012-2013 FortisBC Energy Utilities Revenue Requirements Decision. (Exhibit B-1, Tab 4, p. 100)

Commission Panel Determination

The Commission Panel concurs with the position which has been taken by FortisBC. There is value in exploring a variety of options for cost allocation and considering the implications of each. In the meantime, the Panel is satisfied that the allocation based on time estimates is reasonable and does not result in a significant variance from an appropriate amount. **The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.**

5.2.2 Review of Operating and Maintenance Costs and Issues

5.2.2.1 Introduction

FortisBC's proposed O&M expenditures are approximately \$55.4 million in 2012 and \$56.8 million in 2013 which includes PPME as previously determined. This represents a 2.8 percent increase in 2012 and 2.6 percent increase in 2013. (Exhibit B-1, Tab 4, pp. 31-32; Exhibit B-12)

FortisBC submits that its 2012 and 2013 O&M Expense forecasts have been developed in support of the Company's business objectives, ensuring that O&M funding is appropriate and prioritized to meet the needs of customers. FortisBC states that its annual departmental O&M budgets are prepared by the department managers and incorporate both a trended and zero-based approach where appropriate. The budgets then go through a cycle of reviews and updates, and are eventually approved by the Company's Executive and Board of Directors. (Exhibit B-1, Tab 4, pp. 28-29)

FortisBC states that the costs for PPME have been excluded from these budgets but, if inclusion of the PPME costs in Power Purchase Expense is not approved by the Commission, the costs will be reclassified to O&M Expense. (Exhibit B-1, Tab 4, p. 29) A summary of the O&M expenses by department sought in this Application is provided in the table below:

Table 4

DEPARTMENTS	2012	2013
	Forecast	Forecast
	(\$000s)	
Generation	2,287	2,497
Utility Operations	18,503	18,964
Mandatory Reliability Standards	1,179	1,187
Cominco Facility Charge	46	46
Brilliant Terminal Station	3,160	3,192
Internal Audit	396	393
Legal & Regulatory	1,520	1,548
Customer Service	6,737	6,806
Community & Aboriginal Affairs	674	689
Communications	923	952
Human Resources	1,840	1,874
Information Technology	2,841	2,846
Health, Safety & Environment	925	953
Facilities Management	3,685	3,466
Finance & Accounting	3,275	3,360
Transportation Services	573	593
Supply Chain Management	498	505
Corporate & Executive Management	5,112	5,674
TOTAL O&M EXPENDITURE	54,174	55,544
Power Purchase Management Expense	1,211	1,266
TOTAL O&M EXPENDITURES incl. PPME	55,383	56,810

(adapted from Exhibit B-1, Table 4.3.1 and Exhibit B-12, Tab 7, p. 1)

The Commission Panel has reviewed the relevant material pertaining to O&M. In what follows, we will separate the O&M budgets into Labour related costs and Non-Labour related costs and address the issues related to each in turn. Following this, the Panel will address any remaining issues not specifically related to either of these categories.

5.2.2.2 Labour Related costs

Based on the information in Table 4.3.4 of the Application (Exhibit B-1-6, Tab 4, p. 45), the number of FTEs has remained relatively stable over time. This trend continues into the current test period with 3 additional FTEs planned for 2012 and an additional 1 FTE planned for 2013. Labour costs are projected to increase by 1.5 percent in 2012 and 2 percent in 2013 which is a positive outcome given the size of labour adjustments contemplated in Table 4.3.2.1 which is discussed below.

i. Labour Inflation

FortisBC identifies the Company’s three employee groups as unionized, exempt and executive employees. The Company states that its unionized employees are represented by either the Canadian Office and Professional Employees Union (COPE) or the International Brotherhood of Electrical Workers Union (IBEW).

FortisBC states that for each employee group, it targets a total compensation package which is at the median level of its peer group of companies and asserts that labour and benefits inflation are primarily non-discretionary cost increases. The Company affirms that given the demographic challenges, it must continually monitor and assess its total rewards framework and find a balance, allowing talented people to be attracted and retained. FortisBC states that the guiding principle is to have a total compensation program which is prudent, competitive, understandable and efficient to administer. Table 5 below outlines the labour adjustments which have been made from 2007 through to the present.

Table 5 – Labour Inflation (2007-2013)

	General Assumptions	2007A	2008A	2009A	2010A	2011F	2012F	2013F
2.0	Pay Increases							
2.1	COPE ⁽¹⁾	2.5%	2.5%	2.5%	3.5%	*	*	*
2.2	IBEW ⁽²⁾	1.5%	3.0%	3.0%	3.0%	4.0%	5.0%	*
2.3	Exempt	3.0%	4.0%	3.5%	4.0%	3.0%	3.0%	3.0%

(Exhibit B-1, Tab 4, p. 34)

FortisBC states that for the unionized staff and, consistent with past practice, length of service-related step increases have been included in labour inflation. Presumably, we can infer from this data that this is not the case for Exempt employees. Wage increases for IBEW total 4 percent and 5 percent for 2011 and 2012, respectively. Increases for COPE over this period remain subject to negotiations.

(Exhibit B-1, Tab 4, pp. 32-34)

FortisBC submits that a key consideration with respect to the IBEW contract is that it covers PLTs. The Company states that it has had difficulty in finding and retaining PLTs due to the high demand for this workforce. FortisBC further submits that over the last number of years, 15 percent of PLTs have left the organization (a slightly higher number than have retired) to seek employment elsewhere. (FortisBC Final Submission, p. 39; Exhibit B-1, Tab 4, p. 51; T6:1023-1028)

During the oral phase of the proceeding, Counsel for FortisBC had Ms. Drope provide information concerning collective bargaining agreements in re-examining certain evidence provided by Mr. Walker in his testimony. Ms. Drope's evidence included the following:

- Recent research published by the Canadian Electricity Association in 2011 states that 45,000 workers will need to be recruited by utilities by the end of 2016 and utilities have gone on record stating that they intend to poach employees for many critical positions.
- The base hourly rate for FortisBC PLTs is \$39.91.
- The Line Contractor Association base hourly rate is \$44.97.
- BC Hydro's comparative rate is \$37.96 for PLTs.
- The base rate for PLTs at Altalink in Alberta is \$45.12.
- BC Hydro's compensation package for PLTs includes specific provisions not offered by FortisBC that make the rates comparable. These include 17 additional days off.
- FortisBC was able to negotiate some productivity offsets as part of the package.

(T3: 286-292, 294-295)

ICG asserts that the IBEW contract illustrates the FortisBC approach to cost control and prudent management which sends a message "...that FortisBC does not yet appreciate the need for fiscal restraint." ICG states that this is in sharp contrast to the provincial government message of restraint regarding wage increases. ICG further states that if FortisBC had focused on reducing costs with respect to the IBEW contract, the Company would have followed the 2010 Zero mandate or the more recent 2012 Cooperative Gains mandate.

The position taken by ICG is that FortisBC negotiated a contract with the IBEW that included percentage increases which were well beyond the norm and were not reflective of the downward pressure on wages which existed in 2010 (when the contract was negotiated). ICG has relied on information from:

- the BC Bargaining database (Exhibit C 9-9) which reported BC Hydro signed an agreement with the International Brotherhood of Electrical Workers, Local 258 for 0 percent for the period April 1, 2010 to May 31, 2012;
- the 2012/13 to 2014/15 Budget and Fiscal Plan (Exhibit C-9-10), outlining the British Columbia Government's public sector compensation mandate; and
- a MMK Consulting Report (Exhibit B-4, BCUC 1.179.1), which provided statements in support of a downward trend in contract settlements since 2008 as putting pressure on 2010 negotiations to settle at lower rates.

ICG argues that Ms. Drope was unable to answer tough questions with respect to the IBEW contract especially in support of "her conclusion that there has not been a downward trend in contract negotiations since 2008." ICG states that, in response to queries looking for particulars, her evidence amounted to vague references to newspaper articles and a memorandum of understanding. Further, ICG asserts that the affirmative response of Ms. Drope to a question posed by the Panel Chair as to whether FortisBC has a turnover problem puts an end to suggestions that turnover is a justification for the increases within the IBEW contract. (ICG Final Submission, pp. 14-16)

BCMEU expresses concern that ratepayers are paying a significant rate increase to extract "productivity gains" over the test period which may reduce O&M to the benefit of shareholders. BCMEU submits

that the solution to ensure the ratepayer receives a share of the benefits for this investment is for the Commission to impose a productivity target. (BCMEU Final Submission, pp. 11-12)

BCPSO made no submissions with respect to this issue.

FortisBC argues that the position taken by ICG has no basis and is not supported by the evidence. The Company submits the following:

- with regard to ICG alleging that Ms. Drope was unable to comment on whether BC Hydro's PLTs would have settled for 0 percent over 2012 and 2013, FortisBC asserts that when the question was rephrased to ask whether BC Hydro PLTs settled for 0 percent over the two years, she answered "no."
- The part of the MMK Consulting Report focused on by ICG was construction labour which the Company argues is not at issue in this instance. Further, the report in question was prepared in May 2010 which was over a year past the conclusion of the IBEW negotiations.
- ICG's reliance on the statement that there was no turnover problem, while applicable to the company as a whole, did not apply to PLTs which were identified as a particular problem.
- Even if there was no percentage increase for BC Hydro PLTs over the test period, the differences in other aspects of the BC Hydro and FortisBC contracts result in greater absolute payments by BC Hydro.

FortisBC argues there is no basis to the BCMEU assertion that the contract may reduce O&M during the test period to the benefit of the shareholder only. The Company submits the contract negotiations were conducted several years ago and any implications of the contract can be readily forecast. (FortisBC Reply, pp. 31-34)

Commission Panel Determination

The Commission Panel agrees that on the surface the percentage increase offered to IBEW seems to be on the higher side of what might have been expected over the past few years. Moreover, the information provided through the BC Bargaining database suggests that in the time frame of the negotiations, other comparable negotiations in the Transportation, Communication and Other Utilities

areas resulted in settlements which were significantly lower on a percentage basis than that reached by FortisBC. (Exhibit C9-11) However, what is not known are the issues and circumstances that were at play in the comparable negotiations and whether they are actually comparable. Because of this, the Panel believes the information in Exhibit C9-11 should be given only limited weight.

What is known with respect to the FortisBC settlement is that a significant number of employees in the bargaining group, the PLTs, were and are in high demand and short supply. Moreover, the role played by PLTs is an important one and their contribution to the operations of the company cannot be ignored. Finally, in the view of the Commission Panel, FortisBC has made the case that the risk of retirement and turnover with regard to PLTs is significant.

Nonetheless, the question remains as to whether these circumstances justify the size of wage increase which was awarded in the recent IBEW contract. In the view of the Panel, the evidence provided by Ms. Drope with respect to comparative salaries was most informative. As described, the base rate for PLTs is slightly higher with FortisBC than it is with BC Hydro. However, when the additional benefits that BC Hydro PLT employees receive are considered, the total compensation between the two companies becomes more comparable. When a comparison is made with Altalink in Alberta the base rate very much favours employees of Altalink. While perhaps not directly comparable, the fact remains that both companies compete for people in the same market. **For these reasons, the Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.** In making this determination, the Commission Panel understands that there is a significant part of the IBEW bargaining unit that is not in a PLT position. However, there was little evidence to suggest that the wages negotiated for the other employees were unreasonable.

ii. Executive Compensation

FortisBC's executive compensation program involves four main elements – base pay, short term incentives, long-term incentives and benefits. Collectively, these comprise what the Company describes as the "Total Rewards" package which, FortisBC asserts, supports customer needs and contributes to the support of both long and short term corporate objectives. FortisBC states that the

compensation program is designed to provide competitive compensation and further its ability to attract and retain qualified and experienced executives. As a general policy, FortisBC has established its base program and related initiatives target for its executives to be compensated at the median level of a broad reference group of companies as established by Hay Management Consultants. This reference group is not weighted in favour of utilities. FortisBC submits that this is in keeping with its practice of hiring from a variety of other industries as well as energy and utilities. (Exhibit B-1, p. 44; Exhibit B-4, BCUC 1.34.4)

With respect to base salaries, FortisBC submits the normal range is between 80 and 110 percent, with the target amount being 100 percent. The Company further submits that an individual's placement within this range is determined after consideration of work experience and job performance. Short term incentives are related to the achievement of short term objectives and focus on key areas such as cost control, customer service, and safety and reliability and are tied to the achievement of specific targets. Long term incentives are intended to focus executives on sustained customer value creation through long-term strategies which provide a balance between long and short term company and customer interests. FortisBC has chosen to furnish its long-term incentives through participation in its stock option plan, the cost of which is funded by the shareholder. The Company submits that this would also be included in regulated expense but for Order G-52-05. To round out the executive compensation, the Company offers a Supplemental Employee Retirement Program (SERP) funded by the ratepayer which provides an accrual of 13 percent of all earnings in excess of the Canada Revenue Agency's RRSP limit. FortisBC states its consultant, Hay Management Consultants, advised that this is industry standard and the amount is reasonable and within the norm in Canada. (Exhibit B-8, BCUC 2.10.2; Exhibit B-4, BCUC 1.34.1, 1.34.5; T2:121; T3:439-440; FortisBC Final Submission, p. 48)

FortisBC argues the incentive portion of executive compensation is levered off of four broad categories, which make up the "scorecard", only one of which is earnings and directly benefits the shareholder. Additionally, the scorecard itself accounts for only 50 percent of the incentive pay with the remaining 50 percent being related to personal performance. FortisBC therefore concludes that Company earnings make up only a small component of the overall incentive plan. (FortisBC Final Submission, pp. 48-49)

BCMEU notes that over the test period, BC Hydro has a 0 percent increase in executive compensation. Further, BCMEU notes that in the oral phase of the hearing it was identified that FortisBC executive compensation was equal to or greater than that of the reference group. BCMEU submits that because the expansion of deferral accounts lowers the risk of operating a utility, it does not seem appropriate that FortisBC's executive compensation is so high and questions how this may affect the ability to negotiate settlements with the bargaining unit. Specifically, BCMEU also raises the following concerns:

- Executive base salaries are above the 100 percent target amount and the average compensation is above the average target median.
- Short term incentives are not sufficient to promote productivity improvements within the organization.
- The appearance is that FortisBC executives are getting the best of both worlds through base pay equal to or better than the reference group and further compensation through stock options.

BCMEU concludes by stating it would endorse an approach that would separate bonus elements of executive compensation from pensionable benefits. (BCMEU Final Submission, pp. 12-14)

BCPSO points out there is a need for benchmark information on FortisBC's executive long-term incentive plan (stock options) and submits the cost of these stock options should continue to be borne by the shareholder. (BCPSO Final Submission, pp. 6-7)

None of the other Interveners commented on this issue.

With respect to executive salaries, FortisBC states that prior to the job scope change in 2010, salaries were held flat and increases reflected the change in scope of executive positions and the roles executives play. Concerning a reduced level of risk for an executive operating a utility due to the expansion of deferral accounts, FortisBC responds that there is no basis to suggest reduced risk for the utility or the members of the executive and points out that Ms. Drope testified that if there was less risk, executive compensation would not necessarily be lower. Finally, with respect to concerns raised

with regard to the ability to negotiate a reasonable settlement with the bargaining unit, the Company points out that the scope changes with respect to executive roles are not occurring at the bargaining unit level.

FortisBC responds to the remaining BCMEU concerns as follows:

- On the matter of incentives to find productivity improvements, FortisBC submits that the evidence is that the Company has cost control incentives through its incentive program for non-union employees.
- Base salary and short term incentives do not exhaust the total compensation paid at other companies. FortisBC points to Ms. Drope's testimony that a stock option program is common and market competitive.
- Excluding executive bonuses from pension benefits would depart from how the pension contribution is arrived at. FortisBC points to Ms. Drope's testimony that the pension contribution is derived from both base and incentive pay which is consistent for both the gas and electric non-union groups.

(FortisBC Reply, pp. 34-36)

Commission Panel Determination

While having some concerns, which are commented on below, the Commission Panel is of the view there is no need to change the FortisBC Executive Management base pay or the incentive program at this time. The Panel considers that there is a need for both a competitive base pay and an incentive package to attract and retain quality executives. Relying upon statements attributed to Hay Management Consultants by FortisBC, the Panel is satisfied that the compensation program offered by the Company is in the range of those in the reference group of companies and therefore competitive. However, like the BCPSO, we are of the view that the entire compensation package must be reviewed to determine whether it is appropriate. **Therefore, the Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.** On a related matter, the Commission Panel would also like further information on the SERP program. Specifically, the Panel would like the benchmark study to address the following:

- whether the SERP is incentive-based or handled as a benefit; and
- how the 13 percent for SERP compares to amounts offered by comparable companies.

With respect to whether the incentive program should be included among pensionable benefits, the Commission Panel accepts that the incentive program is not levered solely off an earnings measure and therefore, there is some justification for the current practice of charging incentives in part to the ratepayer. What is less clear is the current practice in the labour marketplace with respect to allowing incentives to be included in pensionable benefits. We would like to see a more complete record on this matter in the future. **Accordingly, the Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.**

iii. Departmental Labour Expense Issues

In spite of the lack of significant growth in FTEs and overall labour costs, the Commission Panel has with specific areas of concern with a number of O&M departments.

a) Generation

Labour costs in the Generation department are forecast to increase from \$1.248 million in 2011 to \$1.374 million in 2012 and \$1.535 million in 2013 which represents an increase in excess of 10 percent in both years. FortisBC states that with the Upgrade and Life Extension program coming to a conclusion, the fluctuations in maintenance activities and costs of the past five years are expected to stabilize. The Company has explained that while it has managed to reduce planned routine repetitive maintenance costs, this has not fully offset the costs associated with the increase in working hours due to changes in legislation such as those relating to working alone and working in confined spaces. As a result, the Generation area is faced with an increase in planned maintenance costs of \$0.24 million (Exhibit B-4, BCUC 1.38.1; Exhibit B-1-6, p. 48)

FortisBC states that it will continue to refine its maintenance program in 2012 and 2013 through development of a more condition-based maintenance approach which, over time, will allow the Company to conduct equipment maintenance based on actual need as opposed to a time-based interval. FortisBC submits that the expected benefits of this approach are increased intervals between shutdowns for maintenance and an increased capability to perform operations and plant diagnostics remotely.

Presumably the benefits of moving to a more condition-based maintenance approach as described by FortisBC will also result in cost savings. Given the size of increase in maintenance costs over the test period the Commission Panel has concerns with the speed with which the Company is refining its maintenance program. Because of this and the fact that monitoring equipment has begun to be installed, the Commission Panel is of the view that an opportunity exists for some savings to be realized over the 2012-2013 time period. (Exhibit B-1, p. 50)

b) Utility Operations

Forecast labour costs in Utility Operations have increased from \$10.617 million in 2011 to \$11.587 million (an increase of 9.1 percent) in 2012 and \$11.974 M. (an increase of 3.3 percent) in 2013. This represents a corresponding increase of 11 FTEs in 2012 and a further 2 FTEs in 2013. FortisBC notes that it has had difficulty attracting and retaining skilled journeymen PLTs and system controllers because of the high demand for these positions. FortisBC reports there were 12 vacancies for PLT positions at the end of 2012. Given the demographic challenges outlined in Section 5.2.1.1 of this Decision, FortisBC states it will continue to actively recruit these positions and operational budgets will increase marginally over time.

FortisBC states that in response to the Commission's decision on the 2011 Capital Expenditure Plan, (Order G-195-10) capital expenditures for right-of-way reclamation, pine tree beetle hazard tree removal and hot tap connector replacements totalling \$3.78 million were reclassified as operating expenditures. The Company advises that these have been included in the 2012-2013 budgets for this department.

FortisBC states that infrastructure expansion occurs at an average growth rate of 1.1 percent per year and submits that budget forecasts for 2012-2013 reflect this increase in line kilometres. FortisBC also states that right-of-way maintenance costs will also increase in 2011. Additionally, maintenance expenditures for substations are forecast to increase based on historical load and a task driven budget through the Computerized Maintenance Management System. (Exhibit B-1, pp. 52-54)

When questioned as to the size of increase from 2011 to 2012 for the whole department at the oral phase of the hearing, Mr. Sam, FortisBC's Vice President of Engineering and Generation, responded that the \$1.1 million increase was made up of the following components:

- \$500,000 for salary increases.
- \$255,000 in incremental substation work.
- \$230,000 for four additional PLT apprentices. Two of the existing apprentices will "top out" this year.
- The remaining \$100,000 for various costs including the additional day in February and some additional training requirements.

(T6:1027-1029)

Of concern to the Commission Panel is whether there is sufficient justification for all of the additional expenses which have been forecast for 2012 and 2013. The Commission Panel accepts that the Company has faced challenges with respect to recruiting and retaining PLTs and acknowledges that steps have been taken to respond to this by establishing an apprentice program where there are currently four employees. The Company seeks to double the size of the program by hiring an additional four FTEs to this program during the current test period at an incremental cost of \$230,000. While the Panel remains supportive of the efforts to develop future PLT resources in-house, we are not persuaded that there is a need to double the size of the program at this time. Increasing the program to 5 or 6 FTEs from the current 4 employees, in the view of the Commission Panel, would still allow the Company to continue to grow the program as it assesses the performance impact of those employees that have "topped out" or completed the program.

c) Community and Aboriginal Affairs

Overall labour costs for Community and Aboriginal Affairs have risen dramatically since 2010. FortisBC attributes the growth in budgeted costs to the increased complexity of relationships with local governments and consultation requirements for First Nations. Staffing levels were increased from 1 FTE to 3 FTEs in 2011. In addition to these labour costs, the Company has included a provision for external contractors at a cost of \$36,000 for both 2012 and 2013.

FortisBC states it has worked to establish open and consultative relationships with First Nations and their communities which are important to enable decision making that incorporates the interests of the Company and its customers as well as those of First Nations. The Company submits that the development and maintenance of First Nation relationships is directly related to its ability to move initiatives forward in a timely fashion. FortisBC advises that increases in the departmental budget in recent years are a reflection of the increased cost of meeting First Nation consultation requirements due to the increasing complexity of these relationships. (Exhibit B-1, Tab 4, pp. 65-66; Exhibit B-9, Celgar 2.16.3.5)

FortisBC also argues that “under present case law FortisBC regards the Commission as having a duty to assess consultation...[so it has]... been doing its own consultation and summarizing that consultation to facilitate the Commission’s ...[assessment]”. (FortisBC Final Submission, pp. 51-52)

ICG maintains that while the complexity of First Nation relationships may have changed over the past 20 years, there has been no change with regard to there being a need to notify and consult with Aboriginal communities regarding facilities. The ICG notes that FortisBC has always had facilities located on First Nation lands, as it does today. Further, ICG argues the growth of costs in the past few years does not equate to the change in complexity of such relationships. (ICG Final Submission, p. 44-45)

The Commission Panel acknowledges the importance of the work that has been done with respect to building relationships with First Nations and Aboriginal communities. However, the point raised by ICG merits consideration. While building relationships and consulting with all stakeholders is undoubtedly a necessary part of doing business, and always has been, the formal “duty to consult” discussed in recent case law relates to a formal duty imposed upon the government and its agents and is grounded in the “honour of the Crown”. The formal duty to consult is not a duty imposed by law upon FortisBC.

The Commission Panel notes that FortisBC is nearing the end of an aggressive capital build out and is moving toward greater emphasis on sustaining capital. (FortisBC Final Submission, p. 100) The Panel is of the view that while there will still be a need for consultation, it will be less intensive as the Facilities already exist. Therefore, we question whether there is a need for the proposed level of labour resources.

Given this and the fact that costs have risen dramatically and further increases continue to be forecast in the current test period, the Commission Panel is of the view there is an opportunity for cost reductions within the Community and Aboriginal Affairs area.

Commission Panel Determination

Taking these departmental labour expense concerns into consideration and, in addition the concerns raised as to whether there will be a need for all of the forecast requirements for Mandatory Reliability Standards discussed later in Section 5.2.2.4, the Commission Panel is of the view that a reduction in O&M expenditures for labour is warranted. **As a result, the Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by \$250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.**

5.2.2.3 Non-Labour Costs

The following non-labour expenses in FortisBC's proposed O&M budgets are of concern to the Commission Panel and are individually addressed in the following sections. **Items not specifically addressed are approved by the Commission Panel.**

a) Asset Management Program

FortisBC proposes a staged approach to the development of an Asset Management strategy which it submits will require total expenditures of \$0.8 million in 2012 and 2013. These expenditures are to accommodate the development of a project team made up of internal and external resources to examine current processes and map out an implementation plan for submission in a future capital expenditures plan application. (Exhibit B-1, Tab 5, p. 34; FortisBC Final Submission, p. 110) The project team will examine FortisBC's existing asset management process, review approved asset management models and strategies used by other utilities, investigate and evaluate available software, and provide a comprehensive report and project cost estimates with recommendations for changes.

FortisBC submits that this development work is incremental to the Company's existing workload. Without this project, FortisBC argues that it will continue to do a form of asset management, relying on professional judgment, which is consistent with other utilities. (T6:994-995)

The costs for the initial development phase of asset management are proposed to be captured in a rate base deferral account and to be dealt with in a future application. FortisBC submits that the asset management strategy would result in the development of processes and implementation of software that would provide benefits in subsequent years and, therefore, the project should be capitalized. (FortisBC Final Submission, pp. 111-112)

BCMEU argues that the expenditure on such a program may not be prudent if preliminary investigations have not been completed. (BCMEU Final Submission, p. 5) BCMEU sees no justification for the proposal and further urges the Commission to direct FortisBC to find more cost effective ways to come up with asset management processes. (BCMEU Final Submission, p. 19)

The Commission Panel notes that in 2010, FortisBC undertook a maintenance rationalization project in the Generation department which resulted in reducing routine maintenance by 10 percent and savings in labour costs of \$110,000 per year. (Exhibit B-1, Tab 4, p. 50; Exhibit B-4, BCUC 1.39.4) The Panel expects these efforts and benefits from that project to continue into the test period. The Panel also notes that in 2011, additional monitoring equipment was installed at South Slocan which will assist in data collection and monitoring of equipment installed during the Upgrade and Life Extension (ULE) program. Over time, FortisBC claims that this monitoring will permit the company to further rationalize its maintenance activities by allowing maintenance on equipment to be conducted based on actual need rather than on a time based interval. The Panel notes that FortisBC's expected benefits of this approach are increased intervals between maintenance shutdowns and increased capability to perform remote operations and diagnosis of issues in the plants. (Exhibit B-1, Tab 4, p. 50) In light of the above, the Commission Panel acknowledges that FortisBC has made strides in improving asset maintenance activities and has realized benefits from these efforts.

The Commission Panel also notes the various systems that FortisBC currently has to review asset health and schedule maintenance such as GenJO, CMMS, Cascade, ArcFM and questions whether the full benefits of these existing systems have been exhausted. (Exhibit B-8, BCUC 2.15.1, 2.30.3)

Commission Panel Determination

The Panel understands that an asset management plan could provide system streamlining but the cost and benefits of such an undertaking have not been clearly presented in this proceeding. The Panel notes that there have been various asset management pursuits in the past so it is unknown whether this new proposal will create further additional cost savings or efficiencies to justify the incremental development costs. In addition, the Panel finds that, given the Company's adequate reliability performance, one of the goals of an asset management plan should be to identify and reduce non-essential maintenance to help control costs.

For these reasons, **the Panel denies the \$0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.** The Panel believes that improving efficiencies and finding strategic solutions are a responsibility of corporate management and therefore should not be allowed as a deferred capital expense. **The Panel approves funds in the amount of \$150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.**

b) Community Investment (Corporate Sponsorships and Donations)

FortisBC states that expenses for Community Investment relate to the actual costs of donations and sponsorships the Company has undertaken to connect with customers and contribute to the communities that FortisBC serves. (Exhibit B-4, BCUC 1.52.3, 1.52.4) FortisBC indicates that some of these donations were made to political parties as well. (T3:315-316)

The amount of the non-labour expenses budgeted for event sponsorship and charitable donations for 2012 is \$270,000 and for 2013 is \$282,000. (T3:313-314)

FortisBC states that much of its work activities, including the siting of infrastructure, has an impact on communities and maintains that it is critical that the Company has a good relationship with the communities in which it operates. It argues that sponsorships and donations provided through the community investment program build such relationships and can reduce the expenses of these work activities. The Company argues that community investment is a requirement for successfully operating the utility for the benefit of ratepayers and should continue to be borne by ratepayers. (FortisBC Final Submission, pp. 52-53)

In taking the position that the cost of sponsorship and donations should be fully recovered from the ratepayer, FortisBC argues that the trend in British Columbia has been in the direction of allowing full recovery of donations made in rates if sufficient justification of customer benefit is provided. The Company further notes that this is a move away from an earlier pattern of sharing costs evenly between the ratepayer and the shareholder. The Company cites examples from recent decisions

where the Commission allowed the utility to recover 100 percent of community expenditures in rates. In these cases, the Commission, in approving the expenditures, laid out expectations for further justification in future proceedings if the utility expected to continue with this practice. FortisBC argues that it has provided the justification required to support full recovery. (FortisBC Final Submission, pp. 54-56)

The Commission Panel notes the different treatment of these expenses in other jurisdictions in Canada, namely Alberta and Ontario, where donations and sponsorship costs are completely disallowed in revenue requirement applications. As noted previously, the treatment of donations and sponsorship costs in the recent past has been a 100 percent ratepayer expense until the 2012 FortisBC Energy Utilities RRA Decision (2012 FEU RRA Decision) in which community involvement spending was directed to be shared equally between the ratepayer and the shareholder. (Exhibits A2-7, A2-8, A2-9, A2-10, A2-11, A2-14; FEU 2012-2013 RRA Decision, p. 73)

ICG takes the position that all corporate sponsorships and donations should be borne 100 percent by the shareholder and not the ratepayer. ICG notes the testimony of Mr. Walker where he acknowledges that FortisBC determines the recipients of its corporate largesse and that its customers, whom FortisBC believes should continue to be responsible to pay 100 percent of these costs, may not share FortisBC's opinion as to the appropriate beneficiaries. (T2:181-182)

ICG argues that the line of reasoning set out in the March 17, 2006 decision of the Alberta Energy and Utilities Board (AEUB) in ATCO Electric Ltd.'s 2005-2006 General Tariff Application (ATCO Electric) on the issue of corporate donations, sponsorships and community relations expenses should be considered and followed. (ICG Final Submission, p. 43, citing excerpt from Decision-Exhibit A2-9) The ICG cites a quote from Decision 2004-067 of the Alberta Board which was noted and followed in the ATCO Electric:

...the Board considers that ***neither sponsorships nor donations*** (charitable or political) **should be included in a utility's revenue requirement.** The Board recognizes that ratepayers may not desire to support the same organizations that utility management or shareholders would support. **Therefore, the Board considers**

it inappropriate for ratepayers to bear such costs and *considers that all donations or sponsorships should remain as a shareholder expense.* (Emphasis in original)

In ATCO Electric, the AEUB went on to determine that donations and sponsorships should not be included in ATCO's revenue requirement. The Board noted that "[c]ustomers have the right to support whichever charitable organizations or functions they choose through their own donation dollars and should not be expected to provide the funds to support the causes chosen by [ATCO] and for which [ATCO] receives the acknowledgement." (Exhibit A2-9, ATCO Decision, p. 68)

Furthermore, the Commission Panel notes that the Ontario Energy Board's current filing requirements clearly state that "[t]he recovery of charitable donations will not be allowed for the purpose of setting rates except for contributions to programs that provide assistance to the distributor's customers in paying their electricity bills and assistance to low income consumers" because "these expenses are not related to the provision of electricity distribution services and therefore do not appropriately form part of the revenue requirement." (Exhibits A2-10, A2-11)

BCMEU supports the sharing of expenditures on community and Aboriginal affairs on a 50/50 basis between the ratepayer and the shareholder, as being consistent with prior Commission decisions including the 2012 FEU RRA Decision. (BCMEU Final Submission, p. 14)

BCPSO submits that, at a minimum, the shareholder should pay 50 percent of the cost of sponsorships and donations, but urges the Commission to order the shareholder to pay 100 percent of such costs. BCPSO submits that the shareholder realizes significant benefits from these expenditures. (BCPSO Final Submission, p. 7)

In reply, FortisBC reiterates its interpretation of the 2012 FEU RRA Decision in that it did not exclude the possibility that ratepayers pay for donations and sponsorships in full in the appropriate circumstances. (FortisBC Reply, p. 38)

Commission Panel Determination

The Commission Panel is of the view that there are significant benefits that accrue to the shareholder from the Company's community sponsorship and donations spending. These include recognition of FortisBC as a good corporate citizen supporting the brand and improving goodwill. The Commission is also concerned that when all of the costs of Community Investment spending are borne by the ratepayer, the incentive for the Company to clearly focus on those activities that will help achieve its objectives is diminished. The Commission Panel agrees that customers may not wish to support the same causes as the Company and is also of the view that greater discipline will occur if the shareholder bears some of the community investment costs. **The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.**

c) Customer Service

FortisBC is forecasting customer growth of 1.8 percent and 1.9 percent in 2012 and 2013, respectively. However, there does not appear to be any evidence of the linkage between customer growth and the need for increased customer service. The Commission Panel is not persuaded that an incremental customer addition would necessarily result in a need for increased incremental customer service expenses.

FortisBC indicates that customer growth has created the need for customer service to find more efficient ways to handle current business while creating room to take on more customers. (Exhibit B-4, BCUC 1.29.3) When describing some of the efficiencies the Company has embarked on during the PBR period, FortisBC identifies numerous activities where Customer Service has mitigated potential cost increases through improving efficiencies. FortisBC provided a list of specific actions which have created efficiencies and states that "[t]hese efficiencies have created more time for existing staff to absorb the continual customer growth." (Exhibit B-1, Tab 4, p. 63; Exhibit B-4, BCUC 1.28.2)

The Panel commends FortisBC for its efficiencies gained in this area and expects these efficiencies to continue into the test period. Given that FortisBC indicates that there are “no significant changes in cost drivers” (Exhibit B-1, Tab 4, p. 63) the Panel is not persuaded that the non-labour costs increases of 9 percent in 2011 and an additional 8 percent increase in 2012 are needed. **As such, the Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by \$113,000 in 2012 and \$100,000 in 2013.**

5.2.2.4 Summary of Operating and Maintenance Cost Changes

In light of the above discussions, the Commission Panel summarizes the following reductions to O&M:

Table 6 – Adjustments to Operation and Maintenance Budgets

	Commission Panel Determinations:
Asset Management Program	\$785,000 proposed in a rate base deferral account is denied. \$150,000 for external consultant is allowed in O&M for the test period.
Community Investment (Event / Community Sponsorships and Donations)	Expenses shared 50/50 between ratepayer and shareholder: 2012 reduce by \$135,000 2013 reduce by \$141,000 Political contributions are 100% disallowed
Customer Service	2012 reduce by \$113,000 2013 reduce by \$100,000
Labour Related Expense Adjustment	2012 reduce by \$250,000 2013 reduce by \$250,000

5.2.2.5 Other Revenue Requirement Issues

i. Capitalized Overhead

FortisBC states that in its 2006 Revenue Requirements Application, it introduced a new mechanism for allocating overhead costs to capital expenditures which suggested that 25.2 percent of Gross O&M Expense should be allocated to capitalized overhead. As part of the 2006 NSA, the parties agreed that a capitalized overhead of 20 percent would be set for the term of the PBR. The Company states that this methodology was further updated based on 2010 actual results and suggests that a 23.9 percent capitalized overhead would be appropriate. In this Application, FortisBC submits that the 20 percent rate currently in place should be maintained for 2012 and 2013, noting that this will serve to mitigate variances to Net O&M Expense and related fluctuations in revenue requirements. (Exhibit B-1, Tab 4, pp. 101-103)

BCMEU submits that there is insufficient evidence on the record to support a change from that which has been proposed by FortisBC. BCMEU submits that FortisBC should be ordered to update its overhead capitalization survey in recognition of the Company's move away from capital intensive activity. (BCMEU Final Submission, pp. 18-19)

BCPSO takes no position on the capitalization rate but does suggest there is a need to distinguish between the capitalization rate of 20 percent and direct loading which is meant to capture T&D supervisory and administrative costs. (BCPSO Final Submission, pp. 12-13)

FortisBC submits that it has included an updated capitalization study in this Application and Ms. Leeners, FortisBC's Vice President of Finance and CFO, testified that this was a detailed analysis and she was not sure what more work could be done in addition to that provided. (FortisBC Reply, pp. 48-49)

Commission Panel Determination

The methodology employed by FortisBC to determine capitalized overhead is consistent with what has been used in recent revenue requirements and the 20 percent rate is also consistent with past NSAs. Further, as noted by BCMEU, there is no evidence on the record in this proceeding that would suggest a better methodology or capitalized overhead rate. While the Commission Panel does not fully agree with BCMEU, as stated below, we are of the view that further work is required in the future.

Therefore, the Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time. The Panel also acknowledges the concerns raised by BCPSO with respect to the need to differentiate between capitalized and direct loadings which will be addressed in the next section.

ii. Department and Corporate Overhead Loadings

A number of issues related to departmental and corporate overhead loadings were raised by the participants in this proceeding. Some of these issues were examined in detail and were the subject of IRs and questions during the oral phase of the proceeding. In some cases these questions resulted in FortisBC Undertakings which were completed following or during the oral hearing. The issues raised involve departmental and corporate overhead directly related to the following:

- the significant increase in overhead loading rates from 2008 to 2012; and
- whether direct overhead loading, as currently applied, is appropriate.

The Commission Panel will now address these issues separately.

- Increase in Overhead Loading Rates

FortisBC states that for several operating business units, where an activity supports multiple projects, costs are estimated during the budgeting process and a direct overhead loading rate is used to distribute those costs among the projects. These are in addition to the capitalized overhead costs discussed above and both are applied to capital projects. (Exhibit B-1, Tab 4, p. 102)

A concern of the Commission Panel is the significant growth in the percentage of both capitalized and direct overhead loading being applied to the various projects. Table 7 below summarizes the growth of overhead as a percentage of capital expenditures for 2008, 2010 and the forecast for 2012 for T&D projects. The Okanagan Transmission Reinforcement Project (OTR) (CPCN Application for the Okanagan Transmission Reinforcement Project) has been excluded from the calculations as it was subject to a separate loading rate pursuant to the Reasons for Decision for the OTR project. As outlined in response to Undertaking #20, the total overhead percentage applied to T&D projects is only slightly more than that applied to Generation projects. Although the gross dollars for direct overhead have remained relatively stable during the period of 2008 to 2012, the total overhead loadings for T&D have increased from 16 percent to 26 percent, as shown in the table below.

Table 7 - Capital and Direct Loading Summaries

		2008 Actual	2010 Actual	2012 Forecast
Unloaded Capital Expenditure Excluding OTR	A	93,883	77,339	74,369
Capitalized OH Excluding OTR	B	8,691	5,604	11,512
Capitalized OH (Excluding OTR) Percentage	C=B/A	9%	7%	15%
Unloaded T&D Capital Expenditure Excluding OTR	D	67,268	47,004	46,695
Direct OH	E	4,720	5,157	5,000
Direct OH (Excluding OTR) Percentage	F=E/D	7%	11%	11%
Total Loadings Applicable to T&D Sustaining Projects	G=C+F	16%	18%	26%

(Source: Exhibit B-8, BCUC 2.51.2)

FortisBC states that loading percentages are a function of four parameters which include, in addition to overheads, other adjustments and the Company’s unloaded capital expenditure plan. By way of explanation, the Company advises that the loading rate is a calculation of the overhead amounts to be recovered, divided by the total unloaded capital expenditures. In this case, the numerator (or overhead to be capitalized) has continued to increase over the four year period while the capital expenditures have decreased. As a result, the overhead rate for both direct and capitalized overhead as a percentage of capital expenditures has increased. (Exhibit B-8, BCUC 2.51.2)

Of concern to the Commission Panel is that where capital expenditures may be reduced in any test period, the amounts being charged to capital through the capitalized overhead allocation continue to rise in both dollars and as a percentage. This appears to be counter-intuitive and indicates there may be a need to more closely align the capitalized overhead rate to the changing capital expenditures rather than to simply rely upon a percentage of operating costs as is currently the case.

An additional concern of the Commission Panel is the 2012 Forecast as outlined in FortisBC’s response to BCUC IR 2.51.2. While we have been able to reconcile the figures shown in the above IR response for 2008 and 2010 to comparative figures shown in FortisBC’s financial schedules and to its annual reports, the figures shown for forecast 2012 appear irreconcilable. The capitalized overhead figure of \$10.834 million in Table 8 below, (which is 20 percent of gross O&M), is inconsistent with the figure of \$11.512 million in the preceding table (an amount which excludes approximately \$155 thousand for overhead attached to the OTR project). We can find no explanation for this discrepancy.

Table 8 – E-Operating and Maintenance Expense

	Actual 2010	Forecast 2011	Forecast 2012	Forecast 2013
	(\$000s)			
Total Operating and Maintenance Expense	46,148	53,885	54,172	55,794
Capitalized Overhead	(9,529)	(10,777)	(10,834)	(11,159)
Net Operating and Maintenance Expense	36,619	43,108	43,338	44,635

(Source: Exhibit B-1, Tab 7)

Commission Panel Determination

One of the concerns with using a point-in-time study to determine a capitalized overhead rate is that the amount of capital expenditures varies from year-to-year. Therefore, what may be appropriate at one point-in-time, may be above or below what should be considered appropriate in any given year. Therefore, the failure to consider the amount of capital being expended over a given period of time leads to the potential for inaccurate capitalized overhead estimates where a capitalized overhead study has not been prepared for that period. Because of this, the Commission Panel is of the view that some consideration as to the amount of forecast or actual capital expenditure is an important variable in determining an appropriate level of capitalized overhead. This may well become increasingly important as FortisBC enters a period which BCMEU describes as a move away from “the capital intense activity of Fortis in recent years to a sustaining capital approach.” (BCMEU Final Submission, p. 19) **Accordingly, the Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.** This will reduce the need to complete a comprehensive capitalized overhead study for each revenue requirement and allow capitalized overhead rates to vary annually in accordance with capital expenditure requirements.

The Commission Panel is also concerned with regard to the differing amounts of capitalized overhead reflected in Tables 7 and 8 above. **FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.**

- Application of Direct Overhead

A second concern of the Commission Panel is whether FortisBC’s current practice of charging a direct overhead loading to capital projects is appropriate. FortisBC distinguishes this from the 20 percent

capitalized overhead rate applicable as well as from those cases where a person is working directly on a specific project and the time is charged directly to that project. According to FortisBC, direct overhead refers to the recovery of Transmission and Distribution supervisory and administrative costs that are not directly charged to specific projects. As noted in Table 7, the Direct Overhead is \$5 million which, when added to the capitalized overhead of \$10.834 million, totals \$15.834 million or 29 percent of total forecast operations and maintenance costs. (Exhibit B-8, BCUC 2.25.4) This does not appear to include the Absorption Overhead applied to Generation projects, as shown in the table below, an Undertaking provided by FortisBC.

Table 9 - Overhead Loading By Category of Asset

Category of Assets		Approximate Overhead Load % by Asset Category							
		Absorption Overhead ⁽¹⁾		Capitalized Overhead ⁽²⁾		Direct Overhead		AFUDC ⁽³⁾ (if applicable)	
		2012	2013	2012	2013	2012	2013	2012	2013
1	Generation	9%	9%	16%	15%	Not applicable		7%	7%
2	Transmission	Not applicable		16%	15%	11%	11%	7%	7%
3	Distribution			16%	15%	11%	11%	7%	7%
4	General Plant			16%	15%	Not applicable		7%	7%

Note-1: Absorption Overhead for Generation is the equivalent of Direct Overhead for Transmission and Distribution

Note-2: Capitalized Overhead % also includes the ISP amortization of \$677,000 per year.

Note-3: AFUDC is only applicable to specific projects that meet the AFUDC applicable criteria of >\$100k and over 3 months in duration.

(Source: Exhibit B-25, Undertaking #20)

Commission Panel Determination

The concerns of the Commission Panel are related to the lack of clarity as to how the amounts charged to direct overhead are calculated and whether there are some cases where costs which already form part of capitalized overhead are also charged as direct overhead, leading to duplication.

The Panel questions whether managerial and supervisory costs which are part of overall O&M expenses should be charged to capital projects. The Panel also notes that, in response to Undertaking 19, FortisBC has provided a list of departments that charge time to direct overhead loading. Among these are three Departments (Health and Safety, Finance and Procurement & Material) which are also included among those departments charged out through the capitalized overhead allocation. As noted above, our concern is that there is potential duplication in that the costs allocated through capitalized overhead are also being charged through direct overhead loading.

Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification. In preparing the material, the Company is encouraged to study the allocation methods of other comparable utilities and report on those findings.

iii. Mandatory Reliability Standards

On June 4, 2009, the Commission issued Order G-67-09 adopting certain Mandatory Reliability Standards (MRS). These standards are very similar to those developed by the North America Electric Reliability Corporation and the Western Electricity Coordinating Council and require affected BC entities to bring themselves into compliance with those standards that are applicable to them. Accordingly, FortisBC is responsible to ensure the Company is and remains compliant with all applicable standards. FortisBC states that it has reviewed the standards, filed mitigation plans to become compliant and submits that continued effort will be required to maintain compliance with all relevant standards and deal with changes to existing and new standards.

FortisBC has requested approval of O&M funds totalling \$1.179 million in 2012 and \$1.187 million in 2013 for Mandatory Reliability Standards in this Application. In addition, the Company seeks to amortize accumulated costs estimated at \$0.7 million for this program over five years starting in 2012. The Company states that effort and costs going forward will focus on transitioning from capital expenditures to operating costs to maintain compliance. FortisBC states it has moved from 100 percent of the effort being directed to capital in 2010 to 100 percent of the effort being directed to operating in 2012 and 2013. This has resulted in an increase of \$0.224 million in budget for 2012, with little additional requirements for 2013. (Exhibit B-1, Tab 4, pp. 54-55)

BCMEU has expressed concern with the program noting that the expenditures when compared to BC Hydro seem to be high.

FortisBC in response noted that in the oral phase of the proceeding, Mr. Chernikhowsky, FortisBC's Director of Engineering Services, testified that because BC Hydro has traditionally done business with the United States it has already implemented a number of the systems that support MRS. These standards had not been previously applicable to FortisBC because it was not trading across the border, nor did it have interconnections with other utilities. Given this context, FortisBC notes that its costs would understandably be proportionately higher than those of BC Hydro. (FortisBC Reply, p. 40)

Commission Panel Determination

The Commission Panel notes that the Company has built its forecast budget to cover the possibility that there will be changes to existing and the addition of new standards and there is no evidence to suggest that this is likely to occur in the future. However, the Panel acknowledges that the Mandatory Reliability Standards Program is an important program required by legislation. In addition, the Mandatory Reliability Standards program is still in the early stages of implementation and it is difficult to determine the exact costs which will be required to maintain compliance with all applicable standards. **Because of this, the Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.**

5.3 Financing Costs

FortisBC's financing costs are made up the cost of debt and the cost of equity. The Company's financing costs for cost of debt and cost of equity for the purposes of the Application are based on a deemed capital structure of 60 percent debt and 40 percent equity. The cost of debt is determined by the percentage of debt assumed to be included in the capital structure and the interest rate on that debt. The total percentage of debt discussed in the capital structure is determined by the Commission and the interest rate on the debt, by the banks, capital markets and the Company's credit ratings. The cost of equity is a function of the investment in rate base, the equity component in the capital structure and the rate of return on equity (ROE). (FortisBC Final Submission, p. 95)

Regarding the short-term and long-term interest rates, FortisBC submitted different forecasts at different points in time during the Proceeding. Tables 10 and 11 below summarize the Company's forecasts for short-term and long-term interest rates for the two-year test period. The first series of forecasts were used at the time of the Application, on June 30, 2011; the second, for the Evidentiary Update in early November 2011 and the third was presented during the oral phase of the proceeding, in March 2012.

Table 10 - Short-Term Interest Rate Forecasts for 2012 and 2013

		2012F ¹	2012F ²	2012F ³	2013F ¹	2013F ²	2013F ³	
	A	Average Forecast Rate for Bankers' Acceptance Rates (3-month T-bill)	2.33%	1.13%		3.80%	1.95%	1.90%
+	B	Spread	0.30%	0.30%		0.10%	0.30%	0.30%
=	C	Sub Total Before Stamping Fee ⁴	2.63%	1.43%		3.90%	2.25%	2.20%
	D	Rounded Up to Nearest 0.10% ⁵	2.70%	1.50%		3.90%	2.30%	2.20%
+	E	Acceptance Fee Rate	1.25%	1.25%		1.25%	1.25%	1.25%
=	F	Bankers' Acceptance Rate ⁶	3.95%	2.75%	2.85%	5.15%	3.55%	3.45%

¹ Exhibit B-4, Table BCUC 1.85.2a; Exhibit B-1, Table 4.7.1.2-1 p. 124

² Exhibit B-8, Table BCUC 2.35.2a; Exhibit B-8, Table BCUC 2.35.1

³ T4:536

⁴ Line C = Line A + Spread Line B

⁵ Line D is Line C rounded up to the nearest 0.10 percent

⁶ Bankers' Acceptance Rate (Line F) = Line D + Line E

Table 11 - Long-Term Interest Rate Forecast for 2013 Debt Issuance

	2013F ¹	2013F ²	2013F ³
Date of issuance	2013	2013	2013
Term (Years)	30	30	30
Average Forecast Rate for 30-year Government of Canada Bond	4.45%	3.55%	3.20%
Long-Term Debt Rate Spread	1.45%	1.70%	1.55%
All-in Borrowing Rate	5.90%	5.25%	4.75%

¹ Exhibit B-1, p. 122

² Exhibit B-8, BCUC 2.33.1.1

³ T4:535

During the oral phase of the proceeding, FortisBC confirmed the Company's intention to use the interest rate forecasts presented in the Evidentiary Update, dated November 4, 2011. (T4:529-530) With respect to short-term debt, FortisBC argues that, because the Bankers' Acceptance Rate went up by 10 basis points in 2012 while it went down by 10 basis points in 2013, there is an offset that reduces the issue to a fairly immaterial impact on the revenue requirement model. (T4:536-537) With respect to long-term debt, FortisBC submits the impact of the change to the all-in borrowing rate from 5.25 percent to 4.75 percent on the revenue requirement model would be \$100,000, in part because it is budgeted for the last part of 2013.

However, the BCMEU and BCPSO both support using the most current forecasts. The BCMEU submits that FortisBC has slightly overstated its financing costs and there should be an adjustment to recognize the lower interest rate environment that the entity is operating in. While the impacts are small and deferral accounts have been proposed, the BCMEU submits that the most current forecast should be used for financing costs in setting rates for the test period. (BCMEU Final Submission, p. 18) BCPSO also notes that the variances are small, but states that the use of more recent forecasts more accurately reflects current financial conditions. (BCPSO Final Submission, p. 11) Other Interveners did not take issue with the interest rate forecasts proposed by the Company.

In its Reply, FortisBC acknowledges the BCMEU and BCPSO's positions but emphasizes the need for a temporal cut-off point in establishing information for the test period. FortisBC also stresses that the difference is not material and the magnitude of the impact is not sufficient to depart from the need to have a temporal cut-off in preparing a revenue requirement application for a test period. In any case, the Company argues that any variances will go through a variance account for financing costs so that customers would only pay the actual costs. (FortisBC Reply, pp. 47-48)

Commission Panel Determination

The Panel agrees with the BCMEU and BCPSO that the use of more recent forecasts more accurately reflects current financial conditions. It also concurs with the BCMEU that FortisBC has slightly overstated its financing costs. For instance, the 2012 short-term principal that is financed at the

Banker's Acceptance rate is, on average, \$44.702 million whereas the 2013 short-term principal that is financed at that rate is, on average, \$69.442 million. (Exhibit B-8, Table, BCUC 2.35.1.1a) Therefore, when the Banker's Acceptance rate goes up by 10 basis points in 2012 (from 2.75 percent to 2.85 percent), the forecast interest expense should go up by \$45,000. However, when the Banker's Acceptance rate goes down by 10 basis points in 2013 (from 3.55 percent to 3.45 percent), the forecast interest expense should go down by \$69,000, which more than offsets the increase in interest expense the previous year. Even if the numbers are small, ratepayers benefit from using the most recent forecasts.

Regarding the 2013 long-term debt, the revised forecast saw a decrease in the all-in borrowing rate from 5.25 percent to 4.75 percent. The Panel notes that FortisBC has acknowledged this means a decrease in the revenue requirement for 2013 of about \$100,000. Even if this variance is small, ratepayers again benefit from using the most recent forecasts. In addition, FortisBC indicated during the oral phase of the proceeding: "... we do agree at this point in time, based on future forecasts on 30-year underlying long Canada's that the rate likely will go down, based on today's information, in 2013." (T4:530) In light of this evidence, the Panel believes it is even more important to use the most up-to-date forecast long-term interest rates. This is particularly important given our determination not to approve FortisBC's proposed deferral account for financing costs, which is addressed in Section 5.4.3.

Therefore, the Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.

5.4 Rate Base

Rate Base is generally described as a utility's net investment in the assets it needs to provide service to its customers. The primary components of FortisBC's rate base are:

- Plant in Service
- Construction Work in Progress not subject to Allowance for Funds Used During Construction (AFUDC)
- Plant Acquisition Adjustment
- Deferred and Preliminary Charges
- Accumulated Depreciation and Amortization
- Contributions in Aid of Construction
- Allowance for Working Capital
- Adjustment for Capital Additions

(Exhibit B-1, Tab 5, p. 1)

FortisBC’s mid-year Rate Base for 2010 to 2013 is set out below (in thousands of dollars):

Table 12

2010 (actual)	2011 (forecast)	2012 (forecast)	2013 (forecast)
\$945,637	\$1,070,756	\$1,145,910	\$1,215,357

(Exhibit B-12, Schedule 1)

As outlined in Table 12, Rate Base is forecast to increase 13 percent between 2010 and 2011, 7 percent between 2011 and 2012, and 6 percent between 2012 and 2013, representing an average increase of approximately 9 percent over the three year period.

As noted earlier in Section 3.1 of this Decision, the main driver of FortisBC’ requested rate increases is the growth of its rate base. (Exhibit B-1, Tab 1, p. 6)

ICG argues that FortisBC’s rate base has increased 142 percent since 2004 and that “this dramatic increase in rate base provides a very large benefit to shareholders.” (ICG Final Submission, p. 4)

ICG further notes that FortisBC's sales in 2004 were 2,874 GWh with an associated revenue requirement in the neighbourhood of \$170 million (or a revenue requirement of approximately \$60,000 per GWh) as compared to forecast sales of 3,233 GWh for 2013 (an increase of approximately 13 percent) with an associated revenue requirement of \$310 million, or \$96,000 per GWh, an increase in the order of 60 percent, (37 percent on an inflation-adjusted basis). (ICG Final Submission, p. 10)

ICG further argues that the "distortion in rate base relative to sale [sic] growth needs to be addressed by the Commission Panel in this proceeding". (ICG Final Submission, p. 12)

The Commission Panel is of the view that the increase in the size of FortisBC's rate base is an issue given that it is the main driver of rate increases which have been and are predicted to be well in excess of inflation. However, as noted by FortisBC, many of its capital expenditures and rate base additions are the result of past approvals by the Commission. (FortisBC Reply, p. 2) As noted earlier, however, the Commission Panel is concerned with the magnitude of rate increases, which are forecast to continue beyond the test period, and is of the view that capital expenditures must be scrutinized carefully.

5.4.1 Plant In Service

Plant In Service makes up by far the largest component of rate base. It is made up of Property, Plant and Equipment used in the generation, transmission and distribution of electricity. Capital additions increase Property, Plant and Equipment while Retirements reduce the account. Rate Base is reduced by accumulated depreciation and amortization of capital expenditures.

5.4.2 Accumulated Depreciation and Cost of Removal

For 2010 to 2011, FortisBC was using a composite depreciation rate of 3.2 percent. FortisBC filed an updated depreciation study prepared by the depreciation consultancy firm Gannett Fleming (2011 Depreciation Study) as part of the Application. (Exhibit B-1, Appendix J as corrected in Exhibit B-12, Appendix J) FortisBC is requesting Commission approval to apply new depreciation rates flowing from the updated study, commencing in 2012. The combined updated depreciation schedules result in a

virtually equivalent overall composite depreciation rate of approximately 3.2 percent. (Exhibit B-1, Tab 4, pp. 128, 131)

FortisBC is also seeking Commission approval to add \$4.7 million into rate base for the net cost of asset removal for 2011, and \$5.4 million and \$4.0 million for removal costs for 2012 and 2013, respectively. (Exhibit B-1, Tab 5, p. 9)

In addition, FortisBC has requested Commission approval to continue its current accounting treatment of asset removal costs, which it charges against accumulated depreciation as they are incurred, as opposed to what has been referred to as the “traditional method” of pre-collecting estimated net negative salvage during the asset’s estimated useful life.

Mr. Kennedy of the firm Gannett Fleming testified that both treatments of asset retirement costs are acceptable and “widely used.” (T3:499-500) Ms. Leeners testified that adoption of the traditional method of collecting net negative salvage in advance would result in a rate increase of five percent. (T3:499)

In its Reply, FortisBC notes that should the Company adopt the traditional method of collecting net negative salvage in advance, “current and future customers will be paying for both the historical actual costs of removal already incurred, as well as the future costs of removal for existing assets.” FortisBC suggests that if it were to adopt the traditional method for collection of net negative salvage, a transition period might be appropriate, given the otherwise immediate impact on customer rates. (FortisBC Reply, p. 43)

Commission Panel Determination

The Commission Panel notes the comments of Mr. Alan Wait concerning the erratic depreciation rates for certain particular classes of assets. However, as noted by the BCPSO, the overall effect on the composite depreciation rate for all classes is “relatively minor.” The Commission Panel appreciates that establishing ongoing depreciation rates for various asset classes is not an exact science. The

Commission Panel finds that the variances in the depreciation rates were adequately explained during the oral phase of the proceeding and therefore approves the depreciation rates from the updated Depreciation Study and the corrected information provided in the Evidentiary Update of November 4, 2011.

The Panel also approves the inclusion of asset removal costs for 2011, 2012 and 2013 in rate base as requested in the Application. The Panel notes, however, that the inclusion of asset removal costs in rate base does increase the value of plant in service rate base by an amount that is actually being removed from plant in service. This concept may need to be reviewed in the future.

In any event, the Commission Panel approves FortisBC’s continued use of recognizing actual asset removal costs as incurred, as requested. The Commission Panel acknowledges the view of the ICG that FortisBC “should not be permitted to delay the need to reduce costs by managing rates through accounting practices that do not follow the recommendations of the depreciation consultant”, and we agree with the general premise. (ICG Final Submission, p. 43) However, the Panel finds that the evidence tendered at the oral phase of the proceeding, as noted above, supports FortisBC’s current practice as being “widely used” and “acceptable.” The Panel further notes the significant rate increase which would result from a change from the current method of accounting for asset removal costs to the traditional method of recognizing negative salvage value at the asset acquisition stage and is not prepared to direct a change in this accounting method at this time.

5.4.3 2012/2013 Capital Expenditure Plan

FortisBC seeks Commission acceptance under subsection 44.2(3) of the *Act* that the 2012-2013 Capital Expenditure Plan (2012-13 CEP) is in the public interest. FortisBC also requests the Commission to find that the 2012-13 CEP satisfies subsection 45(6) of the *Act* which requires a public utility to file with the Commission, at least once each year, a statement of the extensions to its facilities that it plans to construct. In considering whether to accept an expenditure schedule, the Commission Panel is required to consider subsection 44.2(5) of the *Act*. Section 44.2 is set out in its entirety in Appendix B of this Decision.

Table 13

Table 5.3.3.1 - Proposed 2012-13 Capital Expenditure Plan										
		2012	2013	Total	2012	2013	2012	2013	2012	2013
		Requested			Previously Approved		CPCN Application		Total	
		(\$000s)								
1	Generation	4,496	2,939	7,435	5,636	8	0	0	10,132	2,947
2	Transmission and Stations	33,028	29,036	62,064	2,219	0	0	3,720	35,247	32,756
3	Distribution	29,249	25,888	55,137	0	0	0	0	29,249	25,888
4	Telecom SCADA Protection and Control	2,329	3,682	6,011	0	0	0	0	2,329	3,682
5	General Plant	12,503	19,317	31,820	69	75	10,521	38,408	23,093	57,800
6	Total Plant and Equipment	81,605	80,862	162,467	7,924	83	10,521	42,128	100,050	123,073

(Exhibit B-1, Tab 6, p. 2, Table 1.1; Exhibit B-1-6, Errata 2, updated page 60, Table 3.3.2)

The amounts requested in this Application total \$162.467 million in the current test period. In addition, FortisBC intends to submit applications for CPCNs in 2012 and 2013 for the following projects (Exhibit B-1, Tab 6, p. 6):

- Kelowna Bulk Transformer Capacity Addition project estimated at \$25.6 million (exceeds the cost threshold);
- Advanced Metering Infrastructure (AMI) project estimated at \$47.18 million (exceeds the cost threshold); and
- Kootenay Long Term Facilities Strategy estimated at \$16.5 million (the project planning process falls between capital expenditure plan applications).

(Exhibit B-1, Tab 6, p. 6)

FortisBC has identified a number of key considerations that underpin the 2012-13 CEP, several of which are as follows:

- It has invested approximately \$700 million in new or upgraded generation, transmission/distribution and general plant infrastructure since 2005 and is starting to move more into sustaining capital programs,
- It aims to level its annual capital spending where possible,
- It is not delaying expenditures for certain condition-based projects,

- The Company is making efforts to improve forecasting by narrowing the variance between approved and actual capital expenditures while increasing the accuracy of estimates by striving for, where possible, a Class 3 (Definition Phase) level of accuracy, and
- While committed to safety and reliability, FortisBC does not have the objective of attaining a gold “standard”.

(FortisBC Final Submission, pp. 100-106)

FortisBC states that for certain portions of the 2012-13 CEP where there is minimal forward looking information (such as unforeseen projects or new connects), the estimates tend to be based on historical information because the recent trend is the best information that FortisBC has available. However, the Company acknowledges that improvements could possibly be made and suggests asset management as a potential candidate. (FortisBC Final Submission, pp. 112-115)

BCPSO observes that FortisBC's capital program build-out since 2005 has been aggressive, and has resulted in increased reliability, safety and quality of service to ratepayers. It submits a balance needs to be struck between appropriate levels of safety, reliability, quality of service and customer rates. BCPSO further observes that while the costs of proposed transmission-related capital projects are declining, the costs for generation projects are not, which is a concern because of the rate impact to residential customers. In addition, it notes the Commission comments from the 2011 Capital Expenditure Plan Decision to the effect that estimates based primarily on historical average spending may not accurately address what is actually required in a given time period. BCPSO concludes by stating that in spite of having concerns with respect to specific capital projects, it requests the Commission Panel direct FortisBC to reduce the 2012-13 CEP by 15 percent, and leave FortisBC to determine which projects to cancel or postpone during the test period. (BCPSO Final Submission, pp. 3, 12-14)

BCMEU expresses concern as to whether FortisBC is implementing capital plans in the most prudent and cost effective manner and points to the Kettle Valley Project's cost overruns as an example. BCMEU also expresses concern with the use of historical rolling averages for budgeting purposes and encourages a more active use of zero based budgeting for capital as an alternative. With respect to specific capital projects, BCMEU states it has ongoing concerns that the investments in fibre optic

communications to service customers are above and beyond the necessary communication requirements for the area. Further, while not taking exception to any individual capital project, BCMEU recommends that a 10 percent reduction in capital expenditures is appropriate to implement discipline in the test period. (BCMEU Final Submission, pp. 9, 19-22)

ICG states that FortisBC has acknowledged that it is “approaching diminishing returns” from capital expenditures and submits that no capital expenditures which have been justified on the basis of reliability improvements should form part of the 2012-13 CEP. Furthermore, ICG recommends that until FortisBC develops alternate scenarios based on delaying capital expenditures as directed in the 2005 RRA Decision, only capital expenditures with ratings of 275 or higher (as shown on the project ranking scale submitted in Exhibit B-27, Undertaking 40), should be accepted. ICG has identified a few exceptions to this 275 threshold which include: Transmission Line Condition Assessment, Transmission Line Urgent Repairs, Transmission Line Right-of-Way Easements, Station Urgent Repairs, and Transmission Line Rehabilitation expenditures which it argues can be based on the average of the past five years of actual expenditures. (ICG Final Submission, pp. 40-42)

Mr. Gabana, in addition to comments concerning specific capital expenditures, recommends that the Commission Panel reject the Grand Forks Transformer Addition Project and that FortisBC confirm the estimates for all capital projects are accurate to within 3 percent. (Gabana Final Submission)

BCSEA and Mr. Wait had no comments with respect to the expenditures detailed in the 2012-13 CEP.

In reply, FortisBC states that any reduction to the capital expenditures would be arbitrary in light of the evidence it presented. FortisBC observes that in comparison to BCMEU and BCPSO’s proposed capital expenditure reductions of 10 percent and 15 percent respectively, the reductions ordered by the Commission in the 2011 Capital Expenditure Plan Decision amounted to 5.4 percent of the proposed expenditures in 2011 and 2012.

In response to ICG’s assertion that the Company should approve capital expenditures with a rating of 275 or greater, FortisBC argues that setting an arbitrary cut-off based on project rating, as suggested

by ICG, would mean that capital investment would be reduced to a level where projects which are necessary are not undertaken. In the view of FortisBC, the ICG proposal seeks to reduce expenditures to unsustainable levels. FortisBC argues the proposed reduction is not supported by evidence.

FortisBC states it has also addressed the concerns raised by the Commission in the 2011 Capital Expenditure Plan Decision regarding the use of historical average expenditures for budgeting purposes by canvassing other utilities and finding similar examples of rolling averages being used for those purposes. In support of continuing to use this approach, FortisBC notes that, despite the concerns regarding the use of historical average expenditures for budgeting purposes, no party has suggested “a specific, reliable alternate solution.” (FortisBC Reply, pp. 49-52)

Commission Panel Discussion

The Commission Panel notes that among the Interveners that commented on the 2012-13 CEP, the recommendations were unanimous for a reduction in expenditures. BCMEU and BCPSO call for general reductions of 10 percent and 15 percent respectively, while ICG is far more aggressive, calling for, by the Commission Panel’s estimate, a reduction of approximately 55 percent spread across generation, transmission, stations, distribution and telecommunications, Supervisory Control and Data Acquisition (SCADA) and protection and control related expenditures.

In response to whether a slow-down in the capital building program should be anticipated as FortisBC shifts toward a sustaining program, Mr. Walker stated that this has been reflected in the capital plan. (T2:221) The Commission Panel observes the slow-down is not apparent when comparing the proposed 2012 /2013 capital expenditures with the 2011 Capital Expenditure Plan. Specifically, the approved 2011 Capital Expenditure Plan was for an expenditure of \$103.3 million. (Decision accompanying Order G-195-10, p. 1) The current Application proposes additional expenditures (which include previously approved expenditures and expected CPCN applications) which bring the total capital expenditures to \$100.0 million in 2012 and \$129.1 million in 2013. (Exhibit B-1-6, Errata 2, Table 3.3.2)

A consideration in reviewing the 2012-13 CEP, is the level of reliability, safety and quality of service to ratepayers which is related to the recent capital expenditure program. The Commission Panel agrees with the comments of the BCPSO that it is important to strike a balance between safety, reliability, quality of service and achieving reasonable customer rates. The Commission Panel notes that System Average Interruption Frequency (SAIFI) and System Average Interruption Duration (SAIDI) are similar to or below Canadian Electricity Association average performance indexes. (Exhibit B-1-1, pp. 83-85) Within the oral hearing the issue was raised with Mr. Sam, the Vice President of Engineering and Generation, who was asked whether there was a need for further improvement in the SAIFI and SAIDI numbers with emphasis on the word “need”. Mr. Sam replied that the Company did not see that there was a need to improve these numbers on average and agreed that the desire was to maintain them. (T6:1200) Taking this into consideration, the Commission Panel is of the view that safety, reliability and quality of service to ratepayers are at an acceptable level and a focus on identified problem areas is considered most appropriate at this time.

As noted above, subsection 44.2 (5) of the *Act* requires the Commission to consider certain matters in considering whether to accept an expenditure schedule.

Subsection 44.2(5) (a) of the *Act* requires the Commission to consider the applicable of British Columbia’s energy objectives. With reference to this requirement, the Commission Panel is of the view that the following are the most relevant to this Application:

- (a) To achieve electricity self sufficiency;
- (b) To take demand-side measures and to conserve energy including the objective for the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent;
- (c) To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;... and
- (d) To encourage communities to reduce greenhouse gas emissions and use energy efficiently.

The Commission Panel finds that the 2012-13 CEP is generally consistent with these objectives as the proposed expenditures will assist the province to achieve energy self sufficiency by prolonging the life of hydro-electric generation and transmission assets.

Subsections 44.2 (5)(b) and (d) also require the Commission Panel to consider the most recent long term resource plan filed by the utility under section 44.1 and the cost effectiveness of any demand-side measures included in the expenditure schedule within the meaning prescribed by the Demand-Side Measures Regulation. Both of these have been filed with this Application. Demand-Side Measures are examined in Section 6 and the Long-Term Resource Plan is examined in Section 7 of this Decision.

Section 44.2 (5)(c) of the *Act* requires the Commission to consider the extent to which an expenditure is consistent with the applicable requirements under sections 6 and 19 of the *CEA*. Sections 6 and 19 of the *CEA* are primarily related to BC Hydro although section 6 does require a utility planning in accordance with section 44.1 of the *Act* to consider British Columbia's energy objective to achieve electricity self-sufficiency. Neither section applies to an expenditure schedule filed under section 44.2 of the *Act*.

The Commission Panel is also required under subsection 44.2 (5)(e) of the *Act* to consider the interests of persons in British Columbia who receive or may receive service from FortisBC. The Commission Panel finds that, except where an expenditure is reduced or rejected, the 2012-13 CEP is consistent with the interests of FortisBC's existing and potential customers.

The Commission Panel has reviewed the individual projects in the 2012-13 CEP in detail and in what follows will make specific determinations with respect to some projects which we have determined are inadequately supported or require additional work. In addition, the Commission Panel will make observations with regard to specific projects we consider to be questionable or program amounts which we consider to be unjustifiably high given the evidence provided by the Company. With this latter group of projects, the Commission Panel will not make specific determinations on individual programs, but will provide a determination directing FortisBC to reduce its overall expenditures by an amount we consider to be appropriate. The Panel will leave the final allocation of the approved capital expenditures for FortisBC to determine based on its objectives of providing reliable service and ensuring public and employee safety.

Generation

In the generation group of projects, the Commission Panel makes the following observations:

- Of the \$1.2 million in expenditures in 2012 and 2013 for the “All Plants Concrete and Structural Rehabilitation” project, only \$671,000 is related to public and worker safety which FortisBC has stated is a priority. (Exhibit B-4, BCUC 1.114.2)
- FortisBC has not sufficiently explained why all the windows in the Upper Bonnington, South Slocan and Corra Linn Powerhouses need to be opened on a daily or seasonal basis, especially with no noted ventilation deficiencies and the recent and proposed facility lighting upgrades. (Exhibit B-4, BCUC 1.115.3) The “Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows” project estimate is \$430,000. (Exhibit B-1, Tab 6, pp.12-13)
- With regard to the Corra Linn Unit 3 Completion project, FortisBC proposed expenditures related to the transformer and the acquisition of spare generator stator coils. However, FortisBC considers the risk of a transformer failure to be low and stated that individual stator winding coil failures could be bypassed to allow continued operation of the generation unit. This suggests that the need for both expenditures, estimated at \$460,000 from a project total of \$722,000, may be overstated. (Exhibit B-4, BCUC 1.116.2, 1.117.5)
- In the 2011 Capital Expenditure Plan Application, FortisBC stated that the “potential for refurbishment of the remaining four old units at Upper Bonnington is under review and will be addressed at a later date.” (2011 Capital Expenditure Plan Application, Exhibit B-1, p. 13) The Panel finds that the proposed expenditures of \$1.31 million (Exhibit B-1, Tab 6, Section 2.2.5, pp. 14-16) for the “Upper Bonnington Old Plant Various Unit Upgrades” project demonstrate a piecemeal approach to the disposition of the Upper Bonnington Old Plant units. The Panel considers that these may be better addressed as either maintenance expenditures or as part of a comprehensive project to address either overall rehabilitation or retirement.
- The incremental personnel safety that FortisBC claims as the driver for the \$509,000 “Fire Panels at Lower Bonnington, Upper Bonnington and Corra Linn” project may be better addressed by improving personnel egress. (Exhibit B-1, Tab 6, pp. 16-17)
- Many of the projects in the category of “Generation All Plants Minor Sustainment Capital Projects” appear to be discretionary in nature, with no reliability or safety impacts associated with deferral of the proposed expenditures. For instance, the “All Plants Air System Upgrade” (Exhibit B-1, Tab 6, pp. 19-20) and the “All Plants Upgrade Telephone Communications” projects (Exhibit B-4, BCUC 1.122.1) are intended to upgrade systems that, although not modern, have not been shown to be under-performing or failing. Similarly, the need for upgrading the spillway gate hoists and controls and removing old wiring at Lower Bonnington, Upper Bonnington and Corra Linn is not supported by either

recent control system failures, electrical code requirements or reliability indicators. (Exhibit B-4, BCUC 1.123.1 to 1.123.6, inclusive) In total, these projects account for \$1.034 million in the test period.

Overall, the Commission Panel observes the proposed spending in the 2011 Capital Expenditure Plan for generation projects was \$2.513 million (December 17, 2010 Decision, Order G-195-10, p. 5, Table 1.1) compared with the request for approval of new expenditures in 2012 and 2013 of \$4.495 million and \$2.939 million respectively. This does not demonstrate a shift from a capital-intensive growth and rehabilitation oriented program to a sustainment oriented program. **From the preceding analysis, the Commission Panel is of the view that reductions of approximately \$4 million in the proposed generation portfolio over the test period are possible.**

Transmission Growth

The Transmission Growth portfolio consists of four large projects that are individually discussed the section below.

- 1) The Okanagan Transmission Reinforcement Project, which was previously approved by Order C-5-08.
- 2) The Kelowna Bulk Transformer Capacity Addition Project, forecast at \$3.72 million in 2013, and driven by the requirement to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions, will be subject of a CPCN application in 2012. FortisBC states that this CPCN application will contain a detailed option analysis, information on the recommended solution and a revised project cost estimate and expenditure schedule. (Exhibit B-1, Tab 6, pp. 38-42)
- 3) Ellison to Sexsmith Transmission Tie project. FortisBC describes the Ellison to Sexsmith Transmission Tie project estimate as the equivalent of an “AAACE Class 4” estimate. (Exhibit B-4, BCUC 1.126.2) FortisBC has updated this estimate to a class 3 estimate and notes that the remaining forecast costs are reduced by \$0.283 million. (Exhibit B-28, Undertaking 51) The Commission Panel approves the project with the expectation that the capital request will be reduced by the amount stated.
- 4) The Grand Forks Transformer Addition project is forecasted to cost \$7.205 million in 2013. FortisBC states that this project addresses two deficiencies in that it is intended to address transmission system reliability issues for the Grand Forks area as well as the gap between the Okanagan and Kootenay communications systems. (FortisBC Final Submission, p. 132) The project

economics are aided by revenues with an NPV of approximately \$2.5 million from a fibre leasing agreement (Exhibit B-4, BCUC 1.127.10), a redacted copy of which was provided by FortisBC. (Exhibit B-5, BCMEU 1.19, Appendix Q19) The proposed project has the highest NPV cost of the three options FortisBC analyzed for the project, one of which was the continued use of the existing 9L and 10L transmission lines. (Exhibit B-4, BCUC 1.127.1)

The Commission Panel notes that FortisBC was specifically directed to apply for a separate CPCN if it intended to proceed with the fibre installation portion of this project. (2011 CEP Decision) The filing of a CPCN application would allow the concerns expressed by the BCMEU regarding investments in fibre optic communications to be fully vetted. The Commission Panel notes the redacted fibre lease agreement contains a clause that requires the parties to negotiate in good faith to extend the agreement if the fibre is not in place by September 15, 2014. The Panel believes this to be more than sufficient time to accommodate a CPCN application and review.

In response to Mr. Gabana's comments regarding this project, FortisBC confirms that the transformer addition is not driven by capacity requirements, but is to maintain supply reliability in the Grand Forks area. (FortisBC Reply, p. 58) The Commission Panel notes that the customers served by the existing Grand Forks Terminal T1 have experienced better than average reliability in recent years. (Exhibit B-8, BCUC 2.46.2) Furthermore, the options reviewed by FortisBC, which include the continued use of 9L and 10L between Rossland and Christina Lake, have a lower NPV cost than the proposed project. (Exhibit B-4, BCUC 1.127.1) The removal of both the 9L and 10L transmission lines between Rossland and Christina Lake does not appear to be warranted at this time. **While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of \$7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.**

Transmission Sustainment

Approximately half of the capital expenditures proposed for Transmission Sustainment projects are driven by historical averages, and the other half are driven by specific transmission line condition issues. Rather than continuing to rely on simple rolling averages of historical expenditures, FortisBC was previously directed in the 2011 FortisBC Capital Plan Decision to investigate alternative means of developing capital budgets. As referenced earlier, this was also an issue of concern for some Interveners. FortisBC acknowledged that it has addressed the matter but it continues to use this method when there is a lack of better information. (T6:1124) FortisBC is encouraged to continue to investigate alternative methods of developing budgets for those project categories that were previously based on rolling averages of historical expenditures, with the caveat that the evaluation strategies and procedures be supported by direct linkage to fundamental objectives of reliability and safety. Absent direct linkage to direct reliability and safety effects, the Commission Panel is concerned that the cost of projects driven by specific condition issues may be inflated because the condition threshold may be set too high.

Furthermore, the Commission Panel notes that the true increase in the expenditures that underpin those budgets that are based on historic spending is made more difficult to determine because of the additive effects of both capitalized overhead loading rates and departmental direct overhead loading rates, both of which vary with the amount of overall capital expenditures. This will be considered in the discussion that follows. For transmission sustainment projects, the Commission Panel makes the following observations:

- For the “Transmission Line Condition Assessment” budget, the average of the last five years’ expenditures is approximately \$403,000. (Exhibit B-1-1, p. 129) The test period expenditures are proposed to be \$522,000 and \$485,000 in 2012 and 2013 respectively. The Commission Panel notes that even with the increases of 6 percent in capitalized overhead and 4 percent in direct overhead in 2012 compared with 2008 (Exhibit B-8, BCUC 2.51.2), for a total 10 percent increase in overhead, and an additional 8 percent for inflation over the same period, the proposed average expenditures over the test period are more than 5 percent, or over \$50,000, greater than the historical average.

- FortisBC states that the “Transmission Line Rehabilitation” budget is based on previous years’ transmission line condition assessment and explains the budget is also partially based on historical cost per pole expenditures because there is a delay in incorporating the condition assessment data from a given year into the next year’s rehabilitation budget. (Exhibit B-1-1, p. 129; Exhibit B-1, Tab 6, p. 45) The Commission Panel notes that forecast amounts have increased substantially over the test period for the “Transmission Line Rehabilitation” budget. The average of the last five years’ expenditures is approximately \$1.466 million, while over the test period expenditures are proposed to be \$3.372 million and \$2.621 million in 2012 and 2013 respectively. (Exhibit B-1-1, p. 129) As above, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 70 percent, or over \$2.5 million greater than the historical average. FortisBC confirmed that the work required involved the rehabilitation of 2,191 poles in 2012 and 1,565 poles in 2013 which represents approximately 25 percent of the total number of transmission poles. (Exhibit B-4, BCUC 1.131.3) When asked about the causes for the large increase over the previous years during the oral hearing, Mr. Chernikhowsky indicated that there was some work that was rescheduled over the 2007 to 2011 period creating some backlog as well as work coming due on its cycle. (T6:1174-1175)

The need for increased sustaining capital expenditures based on the current condition assessment is not immediately apparent given the level of reliability as indicated by SAIFI and SAIDI performance results. The Commission Panel is not suggesting delaying expenditures until reliability is seen to suffer but notes that large increases in sustaining capital expenditures over historical averages when reliability has been continually improving suggests that FortisBC’s methodology of identifying condition based expenditures may be too over-reaching. Therefore, the Panel is not persuaded that the amounts forecasted are actually required.

- For the “Transmission Line Urgent Repairs” budget, the average of the last five years’ expenditures is approximately \$476,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be \$594,000 and \$620,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 8 percent, or about \$90,000, greater than the historical average.
- For the “Transmission Line Right of Way Easements” budget, the average of the last five years’ expenditures is approximately \$215,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be \$400,000 in both 2012 and 2013. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent, or almost \$300,000, greater than the historical average. The Commission Panel notes that FortisBC provided justification for the increase in the rolling average based on the combination of transmission and distribution easements rather than solely for transmission. (Exhibit B-4, BCUC 1.133.4) With this proposed shift of distribution easement costs into the transmission category, the corresponding reduction in the distribution sustaining capital budget is not

apparent.

A number of the remaining Transmission Line Sustainment projects are driven by the line condition assessments where the lines themselves have experienced relatively good reliability performance. The Commission Panel has previously commented on the relationship between increasing reliability and increasing sustaining capital expenditures, and questions whether the condition threshold has been set too high for the following projects:

- The “21-24 Line Rebuild” project with proposed expenditures of \$2.219 million in 2012 does not appear to be driven by rapidly deteriorating line condition. Emergency expenditures in 2010 were less than 1 percent of the proposed capital project (Exhibit B-8, BCUC 1.55.2) and there is significant redundancy in the lines whereby no generation is lost for any single contingency (Exhibit B-4, BCUC 1.136.7)
- The “20 line Rebuild” project with proposed expenditures of \$4.664 million in 2013 is required to maintain service reliability and alleviate safety concerns. (Exhibit B-1, Tab 6, Section 3.2.9, p. 53) These concerns are in two major areas, one being structural integrity of the poles and another being inadequate circuit-to-circuit spacing resulting in transmission to distribution contacts. (Exhibit B-4, BCUC 1.138.2) The Commission Panel notes that FortisBC stated that there were no transmission to distribution contacts on 27 line since 2007 (Exhibit B-8, BCUC 2.57.1) and although FortisBC does not provide the same information for 20 Line, the installation of station class arrestors is being considered to prevent overvoltage caused by transmission to distribution contacts from affecting customers. (Exhibit B-4, BCUC 1.138.3)

Overall, there appears to be some opportunity for reduction in the Transmission Line Sustainment capital budget. The review above suggests that a reduction of as much as \$9.5 million over the test period is possible. FortisBC acknowledges that if approval is not granted for the these projects, it would still endeavour to mitigate risks associated with line failures. (T6:1048)

Station Sustainment

FortisBC has several station sustainment projects which involve the rehabilitation and ongoing upgrades to substation system. The Panel makes the following observations:

- The PCB Mitigation project, with \$22.822 million in capital expenditures in the test period represent over three-quarters of the proposed capital expenditure of \$28.395 million for Station Sustainment projects. (Exhibit B-1, Tab 6, p. 54, Table 3.3) The Commission Panel is concerned that the project estimate is an “AAE Class 4” estimate (where typical end usage is for study or feasibility) despite FortisBC’s objective of submitting “AAE Class 3” estimates (where typical end usage is for budget authorization or control) for acceptance or approval. (Exhibit B-4, BCUC 1.140.1) Because of this, **the Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.**
- For the “Station Urgent Repairs” budget, the average of the last five years’ expenditures is approximately \$622,000. (Exhibit B-1-1, p. 130) The test period expenditures are proposed to be \$818,000 and \$907,000 in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 11 percent, or over \$150,000, greater than the historical average.
- Although FortisBC does not endorse the approach (FortisBC Final Submission, p. 153), the Commission Panel notes the “Addition of Arc Flash Detection To Legacy Metal-Clad Switchgear” project goes beyond typical current practice in other utilities where mitigating procedures are used in place of switchgear modification. (Exhibit B-4, BCUC 1.143.3) This project is budgeted at \$1.083 million in the test period.
- In the “Huth Low Voltage Breaker Replacement” project, scope creep is expanding the scope of the project beyond the strict current need. (Exhibit B-4, BCUC 1.144.3; Exhibit B-8, BCUC 2.60.1) In an environment where the capital program is moving away from growth and towards sustainment, discipline must be reinforced to avoid the temptation of adding scope simply because a project is being proposed at a certain time or location. This project is budgeted at \$0.07 million in the test period.

Overall, the Commission Panel estimates there are possible reductions of \$1.3 million in the Station Sustainment portfolio.

Distribution

The Commission Panel makes the following observations with respect to the Distribution Projects Portfolio:

- For those budgets that continue to be based on historic rolling averages (“New Connects System Wide”, “Distribution Unplanned Growth”, “Distribution Urgent Repairs”, and “Forced Upgrades and Line Moves”), (Exhibit B-4, BCUC 1.145.2; Exhibit B-4, BCUC 1.149.2) the aggregate of FortisBC’s proposed budgets are more than \$2 million less than the average of the last five years’ expenditures. Additionally, a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012 is applied to the five year historical average. (Exhibit B-1-1, p. 160; Exhibit B-1-1, p. 161; Exhibit B-1-1, pp. 171-172; Exhibit B-1-1, pp. 172-173) The Commission Panel notes spending in these categories is largely non-discretionary as it is driven by third parties, and if the proposed test period spending is under-forecast, the true size of the capital budget may be understated.
- For the “Distribution Line Condition Assessment” budget, which is based on a historical average of the cost per pole times the number of poles being assessed, the average of the last five years’ expenditures is approximately \$777,000. (Exhibit B-1-1, p. 170) The test period expenditures are proposed to be \$1.410 million and \$1.398 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are more than 50 percent or almost \$1 million greater than the historical average.
- For the “Distribution Line Rehabilitation” budget, FortisBC acknowledges that at the time of the filing of the 2012-13 CEP, pole test results and condition reports were not available. Therefore, the Company has based its forecast expenditures on actual costs of previous years combined with the knowledge of the areas being assessed and equipment condition expectations. The Commission Panel notes that the average of the last five years’ expenditures is approximately \$2.757 million. (Exhibit B-1-1, pp. 170-171) The test period expenditures are proposed to be \$5.298 million and \$3.517 million in 2012 and 2013 respectively. As before, considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are about 35 percent, or about \$2.3 million, greater than the historical average.
- For the “Distribution Line Rebuilds” budget, the average of the last five years’ expenditures is approximately \$1.504 million. (Exhibit B-1-1, p. 171) The test period expenditures are proposed to be \$1.679 million and \$1.660 million in 2012 and 2013 respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are less than the historical average by more than \$200,000.
- For the “Distribution Line Small Planned Capital” budget, the average of the last five years’ expenditures is approximately \$793,000. (Exhibit B-1-1, p. 173) The test period expenditures are proposed to be \$726,000 and \$826,000 in 2012 and 2013, respectively. Considering a total increase of 18 percent attributable to overheads and inflation between 2008 and 2012, the proposed average expenditures over the test period are over the test period are less than the historical average by more than \$300,000.

Given the review of the Distribution Projects portfolio, the Commission Panel is of the view that reductions of \$2.5 million of proposed capital expenditures are possible. This is an amount which is lower than the combined potential savings of \$3.3 million and is reflective of there being a number of projects where FortisBC has forecasted budgeted amounts to be lower than the five year average.

Telecommunications, SCADA Protection and Control

The “Kelowna 138 kV Loop Fibre Installation” project (\$3.761 million for both 2012 and 2013) accounts for more than half of the expenditures in the Telecommunications, SCADA, Protection and Control portfolio. The Commission Panel notes that FortisBC has filed this project for acceptance with a Class 4 estimate rather than the required Class 3 estimate. In addition, the Panel is not persuaded that there is sufficient justification to support moving forward with the most expensive Option F as proposed. Accordingly, **the Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.**

The balance of the proposed 2012 and 2013 expenditures in the Telecommunications, SCADA, Protection and Control portfolio (\$2.25 million) are for Communications Upgrades and SCADA Systems Sustainment, a portion of which address MRS issues. (Exhibit B-8, BCUC 2.64.1) Specifically, the Commission Panel questions the need for the “JungleMUX Laser Upgrade” expenditures (\$144,000). FortisBC stated the JungleMUX equipment has been extremely reliable and it maintains a stock of spare equipment in both Trail and Kelowna. (Exhibit B-4, BCUC 1.157.3) The Commission Panel also questions the assignment of \$163,000 of “MRS System Sustainment Internal Labour” cost as a capital expenditure and suggests such sustainment costs should be part of O&M expenditures. (Exhibit B-8, BCUC 2.64.1)

For the remaining projects, the Commission Panel estimates possible capital expenditure reductions of \$300,000 in the Telecommunications, SCADA, Protection and Control portfolio.

General Plant

In the category of General Plant capital expenditures, the Commission Panel notes that the CPCN application for the Kootenay Long Term Facilities Strategy (Exhibit B-1, Tab 6, pp. 98-99) will be filed later this year and the Advanced Metering Infrastructure CPCN has been submitted to the Commission on July 26, 2012. Pursuant to the 2011 Revenue Requirements NSA, AMI costs are being collected in a non-rate base deferral account attracting AFUDC. FortisBC requests that the investigative funds be moved to a Rate Base deferral account in 2012 and, subject to the approval of the CPCN application, subsequently transfer the funds into the AMI capital project in 2012. (Exhibit B-1, Tab 5, p. 14) A determination on this issue is provided in Section 5.4.4.3 of this Decision.

Commission Panel Determination

The Commission Panel has rejected two projects, the Grand Forks Transformer Addition/High Capacity Communications Project and the Kelowna 138kV Fibre Loop Installation Project which result in a total reduction of \$10.966 million in capital expenditures. These projects may be resubmitted over the current test period.

In addition, the Commission Panel has identified a number of areas where further reductions are possible. These total \$17.6 million distributed as follows:

• Generation	\$4 million
• Transmission Sustainment	\$9.5 million
• Station Sustainment	\$1.3 million
• Distribution Projects	\$2.5 million
• Telecom/SCADA	<u>\$0.3 million</u>
Total	\$17.6 million

As outlined earlier in this Section, it is not the intention of the Commission Panel to make specific determinations on individual projects but to make an overall reduction to the capital expenditures portfolio and allow FortisBC to allocate the cost reductions as it deems appropriate. **Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of \$17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the \$17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of \$17.6 million to \$10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by \$10.5 million in addition to the two projects which have been specifically rejected above.** Collectively, these reductions and projects rejected result in a total reduction of \$21.466 million from the \$162.467 in additional capital expenditures requested over this test period. In addition to this there is a further reduction of \$0.283 million as outlined in the undertaking on the Ellison to Sexsmith Transmission Tie Project. **Taking all of these reductions into account, the Commission Panel accepts additional capital expenditures totalling \$140.218 million for the 2012-2013 test period.**

The Commission Panel confirms that FortisBC's 2012-13 CEP satisfies section 45(6) of the Act, which requires the utility to file a statement of the extensions to its facilities it plans to construct at least once each year.

5.4.4 Deferral Accounts

FortisBC is seeking a number of approvals relating to its existing and proposed new deferral accounts. These are summarized in Exhibit B-1, Tab 5, pp. 10-37.

In the view of the Commission Panel there are two important issues which must be considered in reaching a determination on whether to approve the deferral accounts as proposed by FortisBC. They are as follows:

1. Deferral Account Financing Costs

This refers to the financing cost appropriate for various deferral accounts.

2. Determining an Appropriate Amortization Period

This refers to the most appropriate time period over which specific deferral account groups should be amortized.

The Commission Panel believes that establishing principles to deal with these issues will be instrumental in helping provide a context for the determinations which follow. Accordingly, the Panel will address these two issues before undertaking to examine the specific deferral account approvals which are sought by FortisBC.

I. Deferral Account Financing Costs

FortisBC takes the position that all deferred expenditures or credits, other than notional or non-cash assets or liabilities should be included in rate base, which is financed at the Weighted Average Cost of Capital (WACC). It further submits that if a deferred expenditure is not included in rate base, then it should attract AFUDC. (FortisBC Final Submission, p. 81) The Commission Panel notes that these two rates are similar if not virtually the same.

The ICG argues that FortisBC's deferral accounts should be financed in the same way as those of BC Hydro, which is at the weighted average cost of debt, as opposed to the weighted average cost of debt and equity, as proposed by FortisBC.

In the alternative, the ICG argues that should the Commission Panel determine that some deferral accounts should attract the weighted average cost of debt and equity, then those should be limited to accounts where the balance is to be made part of a capital expenditure. (ICG Final Submission, pp. 39-40)

FortisBC argues in reply that BC Hydro is a Crown corporation with different access to resources. It argues that FortisBC, as an investor-owned utility, should properly earn an equity return on its rate base deferral balance to allow the shareholder an opportunity to earn a fair return on its invested capital. It argues that FortisBC's rate base, including deferral accounts, is financed as part of the total financing of the Company, and represents the actual cost being incurred by the Company. (FortisBC Reply, p. 47)

Commission Panel Determination

The Commission Panel agrees with the ICG that deferred expenditures or credits ought not to be included in rate base or attract a rate base rate of return. The Panel notes that deferral accounts are regulatory assets, not true capital assets. Capital assets which are recognized as such under standard accounting rules such as US GAAP do not require deferral account treatment. It is only amounts which would otherwise be required to be expensed under standard accounting principles for which deferral account treatment is needed. However, in the Panel's view, amounts which represent operating costs or other costs which would commonly be expensed as current period charges but which are deferred for rate-smoothing purposes do not become capital investments, simply by the fact of the deferral. Normally, a utility, whether a Crown corporation or shareholder-owned, is not entitled to receive a return on operating costs or current period charges but simply recovery of those amounts from its ratepayers, assuming recovery is otherwise justified. Current period charges are not "investments" which attract a capital return, they are deferred operating costs/current period expenses which, as noted above, in the Panel's view, should not attract rate base rate of return. **The Panel finds that a more appropriate financing cost is an interest return.** For expenditures which are amortized beyond one year, the Panel finds that the appropriate return is FortisBC's WACD. The Panel further finds that for true-up deferral accounts which are, by their very nature, a short term deferral, the appropriate interest return is FortisBC's short term interest cost.

The Commission Panel is also concerned about the proposed proliferation of smaller deferral accounts, all of which, as noted above, are proposed to be placed into rate base. The Commission Panel notes that deferral of current period expenses reduce the level of O&M expense recorded in a given period

and, therefore, has the potential to distort true operating costs. We also note the dramatic forecast increase in rate base over the test period and are of the view that care must be taken to ensure that rate base items are properly so categorized.

II. Amortization Period

The Commission Panel also notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The Commission Panel further notes that deferral of expenses only serves to increase their ultimate cost by the amount of the financing charge and is of the view that amortization periods should be as short as possible, while continuing to serve the rate-smoothing function. The length of amortization periods for a specific account depends on a number of factors including the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on the ratepayer.

In the same vein, deferral accounts which continue for long periods without being amortized into rates also increase the eventual cost to the ratepayer. The Commission Panel is of the view that decisions as to whether to proceed with a particular project where there is an associated deferral account for preliminary and investigative charges ought generally to be made within three years. This time period should be more than sufficient to complete preparatory work for a project and placing a limit of three years ensures that preliminary and investigative charges are not deferred indefinitely. **The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.** The amortization period to be used will depend upon the balance in the account. The amounts in these accounts, unless otherwise ordered, are to attract a return at FortisBC's WACD until such time as they are properly added to an approved capital project. For greater clarity, costs incurred in relation to projects for which a CPCN is eventually sought, or an expenditure schedule filed, will become part of the capital project upon approval or acceptance as the case may be.

5.4.4.1 Existing Deferral Accounts

A. Preliminary and Investigative Charges – Pumped Storage Hydro

FortisBC accumulates costs to investigate potential capital projects in the “Preliminary and Investigative Charges” category of deferral account. The current treatment is that if a capital project in fact proceeds, the costs are transferred to the project. In the event a project does not proceed, costs are expensed at that time.

FortisBC has identified “pumped storage hydro” as a potential resource to meet its future capacity requirements. FortisBC advises that the lead times associated with development of facilities for this resource are lengthy. FortisBC’s preliminary investigations have identified two possible sites at a cost of \$0.227 million. FortisBC does not seek disposition of this account during the test period.

Commission Panel Determination

The pump storage account is an example of a deferral account for amounts which do not meet the capitalization criteria required by standard accounting principles and would be required to be expensed. In the Panel’s view, this account should attract an interest return at FortisBC’s WACD, and is not to be included in rate base. **FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.**

B. Deferred Regulatory Expenses

Expenses related to regulatory proceedings are deferred until approved by the Commission, at which time they are amortized into rates. Incentive amounts are also deferred and used to adjust rates in subsequent years. FortisBC has a number of this type of regulatory expense deferral account, some of which are being sought to be amortized into rates during the test period.

Commission Panel Determination

The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates:

- **Implementation of new rate structures**
- **Residential Inclining Block Rate and Industrial Stepped Rate Applications**
- **2011 Revenue Requirements Application**

However, the Commission Panel takes issue with the proposed disposition of other regulatory deferral accounts sought in the Application and makes the following determinations.

- Shaw Application for Transmission Facility Access

FortisBC is requesting approval to amortize costs relating to Shaw's application to the Commission to continue to have access to FortisBC's transmission infrastructure in the amount of \$0.2 million, (\$0.3 million before tax) into rates in 2012. These costs were deferred pursuant to Commission Order G-184-10. These costs include:

- the cost of FortisBC disputing the Commission's jurisdiction to hear Shaw's application, which was addressed in Order G-24-10,
- subsequently seeking a Reconsideration of that Order, which was addressed in Order G-63-10, both with Reasons, and
- unsuccessfully appealing the Commission's ruling on its jurisdiction to hear Shaw's application to the British Columbia Court of Appeal, which loss resulted in an award of costs against FortisBC (FortisBC Inc. v. Shaw Cablesystems Limited, 2010 BCCA 552).

Commission Panel Determination

The Commission Panel rejects FortisBC’s proposal to amortize this deferral account into rates. As noted by the Court of Appeal (at para. 60), “[a] plain reading of s. 70 reveals that the legislation enables the BCUC to make decisions regarding electricity transmission facilities. That power is not limited to particular uses. The BCUC properly took jurisdiction over the matter...”

In the Panel’s view, FortisBC’s continued pursuit of this issue, without success, was not reasonable. Shaw was at all times seeking to continue to use FortisBC’s transmission infrastructure for a fee, which was the result obtained at the end of the day. In the Panel’s view these costs were entirely avoidable and ought not to be borne by ratepayers.

FortisBC is seeking to amortize the following regulatory expense deferral account into rates in 2013:

- Irrigation Rate Payer Group Consultation and Load Research

FortisBC is seeking approval to fully amortize costs in the amount of \$0.07 million (\$0.1 million before tax) which relate to segmenting the irrigation class customers into sub-groups and installing interval metering for a sample of each sub-group in 2013.

Commission Panel Determination

The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested. However, any ongoing balances for 2012 are to attract a short term interest financing charge only and will be carried as a non-rate base deferral account.

FortisBC is seeking to amortize the following deferral accounts over a longer period.

- Renewal of BC Hydro Power Purchase Agreement

FortisBC advises that it has been in negotiations with BC Hydro over renewal of its Power Purchase Agreement which expires in 2013, since 2005. FortisBC seeks Commission approval to begin amortizing its expected costs of negotiations in the amount of \$0.2 million (\$0.3 million before tax) over five years, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the costs relating to FortisBC's negotiations with BC Hydro, ongoing for a number of years, are more properly considered operating costs. **The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.** This deferral account is to be removed from rate-base and is to attract a financing charge at FortisBC's WACD.

C. Other Deferred Charges and Credits

- Revenue Protection

FortisBC forecasts expenditures of \$0.17 million (\$0.23 million before tax) in 2011 on its revenue protection program, which it proposes to amortize into rates in 2012. Revenue protection includes conducting inspections to detect and remedy illegal power diversion activities and also involves rental of poles and possibly other electrical infrastructure to third parties. FortisBC will be including the costs of its revenue protection program in Operating and Maintenance Expenses-Customer Service department commencing in 2012.

Commission Panel Determination

The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012, as requested.

- Right-of-Way Encroachment Litigation

FortisBC expects to defer approximately \$0.09 million (\$0.12 million before tax) of legal costs incurred to the end of 2011 related to its ongoing litigation with a land developer who is encroaching on one of its Right-of-Ways in Kelowna. FortisBC advises that it will include any recovered costs following resolution of the dispute in the deferral account and amortize the balance in rates, in accordance with Commission Order G-193-08. This residual will not be available for amortization until 2014 as the dispute has not been settled.

Commission Panel Determination

The Commission Panel approves the continuation of the Right-of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC's WACD.

- US GAAP

FortisBC seeks approval to amortize its costs for conversion to US GAAP in the forecast amount of \$0.6 million (\$0.8 million before tax) over a two year period commencing in 2012. These costs relate to audit, legal, advisory, and actuarial fees.

Commission Panel Determination

The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period. Any future costs are to be carried as a non-rate base account attracting interest at FortisBC's WACD.

- Mandatory Reliability Standards Project

FortisBC has deferred set up costs estimated at \$0.7 million (\$1.0 million before tax) by the end of 2011 to become and remain compliant with the new Mandatory Reliability Standards. FortisBC seeks approval to amortize these costs over 5 years commencing in 2012.

Commission Panel Determination

The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD. However, in the Panel's view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.

5.4.4.2 Proposed Deferral Accounts

(i) Preliminary and Investigative Charges

The Commission Panel notes that "Preliminary and Investigative Charges" are not properly considered to be capital expenditures under US GAAP, which is why Commission approval is sought for deferral account treatment. The Commission Panel further notes that FortisBC charges operating costs associated with capital projects directly to those projects, in addition to charging a percentage of operating costs to capital projects as capitalized overhead. In the Panel's view, Preliminary and Investigative Charges can be separated into two groups:

- Those costs which at a future time may become capital projects.
- Those that contribute to the development of Plans which are a regulatory requirement but are not actual capital projects.

Those projects which may in the future become capital projects are more properly considered operating expenses as they are not yet part of an approved capital project. Therefore, **the Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.** As noted previously, the decision to proceed with a capital project should generally be made within three years.

For those costs which contribute to the development of a required regulatory plan, the Panel is of the view that they are most appropriately handled as regulatory expenses and amortized over the period of time the plan is intended to cover. As a regulatory expense any deferral amounts will attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan

FortisBC forecasts that it will have spent \$3.4 million on the development of its Integrated System Plan which was filed contemporaneously with its 2012-2013 Revenue Requirements Application. The Integrated System Plan includes the Long-Term Capital, Resource and DSM Plans. FortisBC proposes to transfer these costs to approved capital projects over the five year period from 2012 to 2016.

Commission Panel Determination

The Integrated System Plan was prepared for regulatory purposes to cover a five year period commencing in 2012. **The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC's WACD and be amortized into rates over a five year period.**

- Plants 1-4 Capital Sustainment

This account is for investigative spending for project planning and engineering and includes "development of more investigation and development of detailed project scopes and cost estimates." FortisBC expects to spend \$0.03 million in each of 2012 and 2013, which amounts it proposes will then

be transferred to the associated projects, once construction begins. (Exhibit B-1, Tab 5, p. 13)

FortisBC argues that amounts in this account are not annual recurring O&M charges because the work relates to determining what capital programs are required in future years and the specific projects are different. (Exhibit B-8, BCUC 2.26.1)

Commission Panel Determination

The Commission Panel is of the view that the amounts at issue in this deferral account are small, in the order of \$30,000 per year, and finds deferral to be unnecessary. The Commission Panel also finds that these costs are not sufficiently associated with a capital project to be considered capital in nature. Rather these costs are more properly considered current operating costs and should be expensed as incurred. **The Commission Panel therefore directs that these costs be expensed during the test period.**

- Kelowna Bulk Transformer Capacity Addition

FortisBC expects to spend \$0.3 million in 2011 and 2012 for preliminary engineering involved in the preparation of an application for a CPCN for the Kelowna Bulk Transformer Capacity Addition. FortisBC plans to obtain approval for this project in 2013 and will transfer costs to the capital project at that time.

Commission Panel Determination

As discussed above in Section 5.4.4.1, the Commission Panel directs that any amount in this deferral account should be treated as a non-rate base item and attract a financing charge at FortisBC's WACD until such time as they are transferred to the capital project. As discussed above, this amount should be expensed if the project does not proceed within a three year period.

- 2014-2015 Capital Expenditure Plan

FortisBC expects to spend \$0.8 million on preliminary investigation and engineering costs for its 2014-2015 Capital Plan. FortisBC proposes to include these costs in the capital projects for those years.

Commission Panel Determination

Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.

(ii) Non-Controllable Items Variances

FortisBC is proposing to create a number of variance deferral accounts for expenditures which it suggests are either beyond its control or it has limited ability to control and which it views as for the account of the customer. FortisBC advises that many of these items have been approved in the past as flow through or "Z-Factor" items eligible for deferral.

The forecast balances for 2012 and 2013 are nil.

Commission Panel Determination

The Commission Panel notes that these accounts for the most part represent variances in current period expenses which are proposed to be trued up in the short-term. In the Panel's view, the creation of these deferral accounts represents a reasonable attempt to manage the uncertainty and unpredictability associated with accounts which are largely uncontrollable in nature. **The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.**

- **Power Purchase Expense Variance Deferral Account**
 - **any variance in this account is to be amortized in 2014**
- **Revenue Variance Deferral Account**
 - **any variance in this account is to be amortized in 2014**
- **HST Removal or Reform Variance Deferral Account**
- **Property Tax Asset Variance Deferral Account**
- **Pension and Other Post-Employment Expense Variance**

The Commission Panel declines to approve the following proposed non-controllable expense variance deferral accounts:

- **Income Tax Variance Deferral Account**

FortisBC is proposing to add a deferral account to capture and accumulate variances from forecast taxes, including federal and provincial income tax, sales tax and any other taxes. FortisBC proposes that the amortization period for this deferral account can be reviewed as part of its 2014 RRA.

FortisBC argues that it can face uncontrollable changes in tax laws or accepted assessing practices “at any time.” FortisBC proposes to include as well any required compliance costs, including changes to information systems which are required in this account. FortisBC advises that income tax variances qualified as “Z factors” in the prior PBR period and so were treated in a similar manner for rate-setting purposes.

FortisBC considers this account to be “Primarily Non-controllable” as it may have some control over the costs to adapt information systems for new tax laws. (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that it is not necessary to create a deferral account for possible variances in income taxes payable from those forecast. Taxes are a reality faced by all businesses and

in the Panel's view are predictable with some certainty. Approval for this proposed deferral account is therefore denied. In the event that there is a significant change in the tax landscape it is always open to FortisBC to apply to the Commission for relief on an as-needed basis.

- Interest Expense Variance Deferral Account

FortisBC is proposing a new deferral account to capture any variances between actual and forecast interest expense – both long and short term, as well as financing fees. FortisBC proposes to address the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel agrees with FortisBC that interest expense is at least "somewhat controllable" and also finds it to be somewhat predictable, in that numerous agencies publish opinions on future interest rates on a regular basis. Approval for this deferral account is denied on the basis that FortisBC should make its best effort to forecast and manage this cost as part of its day to day business operations.

- Insurance Expense Variance Deferral Account

FortisBC also proposes to capture the difference between forecast and actual insurance expenses in a new deferral account. FortisBC argues that global events can influence insurance costs and that such impacts cannot reasonably be incorporated into forecast expenses. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

FortisBC considers this account to be "Somewhat Controllable." (Exhibit B-8, BCUC 2.28.1)

Commission Panel Determination

The Commission Panel is of the view that the need for the Insurance Expense Variance Deferral Account has not been established and denies it. The Commission Panel notes the evidence of FortisBC's Vice President of Finance and CFO, Ms. Leeners, that FortisBC has in fact been able to manage its insurance premiums to a large extent, in spite of extraordinary catastrophic events affecting the world such as Hurricane Katrina, and that FortisBC's geographical diversification, claims history and affiliation with a large company contribute to this ability. (T4:575-577)

- Extraordinary Costs (Z Factor) Variance Deferral Account

FortisBC proposes a further deferral account to capture variances from "steady state" operations due to unplanned events. FortisBC cites Commission directives and decisions, legislation, changes to GAAP and Force Majeure as examples of extraordinary events. FortisBC proposes to review the amortization period for this account as part of its 2014 RRA.

Commission Panel Determination

The Panel declines to approve this deferral account. As noted above, the Panel is concerned with the proliferation of proposed deferral accounts. The Panel agrees with the ICG that it is open to FortisBC to apply for a deferral account on a case by case basis for extraordinary events.

(iii) Deferred Regulatory Expenses

FortisBC is seeking deferral account treatment for certain regulatory expenses as set out below.

- 2014 Revenue Requirements Application

FortisBC is seeking approval to defer what it expects to be costs in the amount of \$0.08 million (\$0.1 million before tax) for its 2014 Revenue Requirements Application in 2013. FortisBC proposes to apply

for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and should be capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2014-2015 Capital Expenditure Plan Regulatory Costs

FortisBC is seeking approval to defer costs related to the regulatory review of a 2014-2015 Capital Expenditure Plan which it expects to file, in the estimated amount of \$0.08 million (\$0.1 million before tax) in 2013. FortisBC intends to apply for disposition of these costs in a future application.

Commission Panel Determination

The Commission Panel is of the view that these regulatory expenses are operating costs and are capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is also prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes. This deferral account is to attract a financing charge at FortisBC's WACD.

- 2012 Integrated System Plan and 2012-2013 Revenue Requirements Application

FortisBC is seeking approval to amortize the costs of the 2012 -2013 Revenue Requirements Application and Integrated System plan which it expects to be approximately \$2.4 million (\$3.3 million before tax) in 2011 over a five year period, commencing in 2012.

Commission Panel Determination

The Commission Panel is of the view that the amortization period requested for these regulatory expenses is too long and that FortisBC's ratepayers will suffer from the associated increased carrying charges. The Commission Panel approves a non-rate base deferral account attracting interest at FortisBC's WACD, to be amortized over a period of two, as opposed to five years.

(iv) Other Deferred Charges and Credits

- Prepaid Pension Costs

FortisBC has recorded the difference between the actuarial valuation of the pension net benefit cost and the forecast Company contributions on a net of tax basis in a "prepaid pension deferral account" for 2011. This treatment accords with pre-changeover Canadian GAAP (which no longer exists), was approved by Commission Order G-184-10 and is consistent with prior years' treatment in revenue requirement applications over the PBR term. This treatment is also similar to that allowed by US GAAP.

FortisBC has now been approved to use US GAAP, which, unlike current IFRS, permits deferral accounting. (Exhibit B-1, Tab 5, p. 23)

The 2012 and 2013 prepaid pension cost consists of the net benefit cost, relating to the following pensions:

- IBEW (defined benefit) Pension Plan
- COPE (defined benefit) Pension Plan
- FortisBC (defined benefit) Retirement Income Plan
- Supplemental pension arrangements for current and former executives.

FortisBC is requesting approval to recognize total Prepaid Pension Costs as a Rate Base deferral account, on a net of tax basis, for 2012 and 2013. FortisBC forecasts a \$0.7 million (\$1.0 million before tax) and a \$2.7 million (\$3.6 million before tax) increase in this deferral account in 2012 and 2013, respectively.

Commission Panel Determination

In keeping with its earlier determinations, the Commission Panel approves this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- US GAAP Pension Transitional Obligation Deferral Account

FortisBC also seeks approval to establish a "Pension Transitional Obligation Deferral Account" as a Rate Base deferral account, with an equal offset to the Prepaid Pension Costs Deferral Account, to separate these proposed rate base items. The Pension Transitional Obligation Deferral Account will recognize the difference between pension net benefit costs calculated under Canadian GAAP and US GAAP, as required by US GAAP. This amount is forecast to be \$2.2 million as of January 01, 2012. It consists of unamortized net transition obligations determined pursuant to Canadian GAAP, which are required to be fully amortized under US GAAP, and the net benefit cost for a three month period resulting from the change in measurement date from September 30th to December 31st, as required by US GAAP.

FortisBC proposes that the balance in the US GAAP Transitional Obligation Deferral Account be amortized over an approximate twelve year period, to accord with the expected average remaining service life of the Company's pension plans. FortisBC forecasts a further addition of \$1.6 million (\$2.2 million before tax) to this account for 2012.

Commission Panel Determination

The Commission Panel approves the creation of this deferral account as a non-rate base deferral account attracting interest at FortisBC's WACD.

- Accumulated Other Comprehensive Income

FortisBC is also requesting regulatory recognition and acknowledgment of a non-rate base deferral account to record amounts representing accumulated unrecognized losses/gains and unrecognized prior service costs/credits which would otherwise be required to be recognized as “Accumulated Other Comprehensive Income” and offset against prepaid pension costs for external financial reporting purposes. (Exhibit B-1, Tab 5, p. 26, Appendix E)

Commission Panel Determination

The Commission Panel approves the creation of this non-rate base deferral account, attracting interest at FortisBC’s WACD.

- Other Post-Employment Benefits Deferral Accounts

FortisBC also records the difference between the actuarially determined OPEB net benefit cost and actual payments to retirees in an OPEB Deferral Account on a net of tax basis. FortisBC forecasts a \$2.1 million (\$2.8 million before tax) addition to the OPEB Deferral Account for 2011. The 2011 accounting treatment is consistent with pre-changeover Canadian GAAP and was approved by Commission Order G-184-10. As of January 1, 2012, the Company has been relying on US GAAP.

FortisBC therefore now requests approval to recognize US GAAP OPEB Liability as a rate base deferral account, to which it expects to add \$5.7 million (\$7.7 million net of tax) in 2012 with a further \$1.7 million (\$2.2 million before tax) in 2013.

Commission Panel Determination

The Commission Panel approves the creation of a non rate-base deferral account attracting interest at FortisBC’s WACD for Other Post-Employment Benefits.

- US GAAP OPEB Transitional Obligation Deferral Account

FortisBC is also requesting a further US GAAP OPEB Transitional Obligation Rate Base Deferral Account to record differences resulting from the calculation methodology for Other Post-Employment Benefits required under Canadian as opposed to US GAAP. (US GAAP would require all remaining unamortized net transition obligations determined under Canadian GAAP to be fully amortized). The proposed US GAAP OPEB Transitional Obligation Deferral Account would also include the net benefit cost for three months resulting from the change in the measurement date from September 30th to December 31st, which is required by US GAAP. These amounts are forecast to be \$2.0 million, as of January 1, 2012. FortisBC proposes to recover this amount over 12 years.

FortisBC also proposes that a remaining transitional obligation in the amount of \$3.5 million which resulted from a change from cash to accrual accounting for OPEB under Canadian GAPP in 2005 be recognized in the US GAAP OPEB Transitional Obligation Rate Base Deferral Account. It has been tracked to this time in a Non-Rate Base deferral account.

An amount equal to the US GAAP OPEB Transitional Obligation Deferral Account is proposed to be offset against the US GAAP OPEB Liability Deferral Account. FortisBC forecasts a \$4.1 million (\$5.5 million before tax) increase to this account in 2012.

As requested for the pension accounting treatment, FortisBC is also requesting regulatory recognition and acknowledgement of a Non Rate Base Deferral Account to accumulate unamortized gains (losses) and unrecognized prior service costs (credits) rather than flowing such amounts through Accumulated Other Comprehensive Income and back into OPEB.

Commission Panel Determination

The Commission Panel approves the creation of a US GAAP OPEB Transitional Obligation Deferral Account as a Non Rate Base Deferral account, attracting interest at FortisBC's WACD. The Commission

Panel also approves the inclusion of the remaining transitional obligation in this Non-Rate Base Deferral Account.

The Commission Panel approves the offset account and agrees to the deferral of unamortized gains (losses) and unrecognized prior service costs, again in a Non-Rate Base Deferral Account attracting interest at FortisBC's WACD.

- Asset Management

This proposed Deferral Account is rejected, as discussed in subsection 5.2.2.3 (a).

- Joint Pole Use Audit 2013

FortisBC advises that its various joint pole use agreements require that an audit be performed on the joint use pole contacts every five years. The last audit was in 2008. FortisBC is seeking approval "to defer funds of \$0.2 million (\$0.3 million before tax) and to begin amortization in 2013 over a five year period."

Commission Panel Determination

The Commission Panel approves the deferral of costs of audits for joint pole use contacts in a Non-Rate Base Deferral account attracting interest at FortisBC's WACD. In the Panel's view, these expenses should be recovered over a shorter period than five years, to reduce carrying charges. The Commission Panel therefore directs that these costs be recovered over a two year period.

- Deferred Debt Issue Costs

FortisBC advises that it expects to issue \$120 million in unsecured debentures with a term of 30 years in 2013. FortisBC estimates that the total issue costs for the debt will be approximately \$1.6 million.

FortisBC seeks approval to defer the issuance costs and to amortize them over the term of the debt, subject to approval of the debt issuance itself, which will be sought in a separate application.

Commission Panel Determination

The Commission Panel approves deferral of the debt issuance costs as a Non-Rate Base Deferral account to be amortized over the term of the debt and attracting interest at the same rate as the debt issuance. In the event that the debt issuance does not proceed, and subject to further Commission order, the related costs are to be expensed at that time.

5.4.4.3 Existing Deferral Accounts with Proposed Change in Treatment

- Advanced Metering Infrastructure

FortisBC advises that the forecast amount of \$1.8 million is for the preparation of an application for a CPCN for advanced metering infrastructure which was to be filed in 2011. This amount is being held in a non-rate base deferral account, and includes AFUDC in the amount of \$0.121 million. FortisBC is seeking to transfer these funds to a rate base deferral account, pending transfer to the AMI capital project in 2012. FortisBC advises that, although AFUDC is not generally applied to balances in Preliminary Investigative Deferral Accounts, AFUDC was accrued pursuant to a specific agreement made in the 2011 RRA NSA, which was approved by Commission Order G-184-10 on a without prejudice basis. (Exhibit B-1, Tab 5, p. 14; Exhibit B-8, BCUC 2.27.1)

Commission Panel Determination

As noted in Section 5.4.4.1, the Commission Panel is of the view that the costs incurred in respect of a CPCN Application should not form part of rate base until such time as the capital project is approved. Accordingly, FortisBC' request to make this a rate base deferral account is denied. This account is to attract an interest financing charge at FortisBC's WACD going forward, until such time as a determination on the CPCN Application is made.

6.0 DEMAND-SIDE MANAGEMENT

FortisBC is seeking two approvals regarding its Demand-Side Management (DSM) programming. The first is approval under subsection 44.1(6) of the *Act* that its 2012 ISP is in the public interest. FortisBC’s ISP includes its 2012 Long-Term DSM Plan. The second approval sought is to spend \$7.73 million in 2012 and \$7.88 million in 2013 on demand-side measures, pursuant to section 44.2 of the *Act*. These two requests are addressed below.

6.1 Long-Term Demand-Side Management Plan

FortisBC’s Long-Term DSM Plan includes the years 2012-2030. The Plan sets out the expected DSM programming, energy savings and spending for 2012-2016 as an extension of the spending and savings levels from the 2011 DSM Plan previously approved by the Commission. For the years 2017-2030, FortisBC has included a constant proxy figure of 28 GWh/year in energy savings. Overall, the Plan was designed to achieve electricity savings to offset 50 percent of FortisBC’s load growth until 2030. (Exhibit B-1-2, Volume 2, p. 1)

The expected energy savings for the 2012 DSM Plan are shown in the table below.

Table 15 – Savings Targets

Year	Residential	Commercial	Industrial	Proxy '17-31
	GWh			
2011	16.4	13.5	1.1	-
2012	16.1	12.2	1.7	-
2013	16.9	12.3	1.8	-
2014	19.5	11.9	1.8	-
2015	21.1	11.9	1.8	-
2016	22.6	9.9	1.9	-
2017-30	-	-	-	28

(Exhibit B-1-2, Volume 2, p. 15)

FortisBC plans to update its DSM Plan and the contributing studies (end-use studies and a Conservation Potential study) that are used in the development of the DSM Plan, every 5 years. (Exhibit B-1-2, Volume 2, p. 17)

6.2 Monitoring and Evaluation Plan

Included in the 2012 DSM Plan is FortisBC's Monitoring and Evaluation Plan (M&E Plan) for 2012-2014. The M&E Plan sets out the principles FortisBC will follow in evaluating its DSM programs and a schedule of programs that will be evaluated in 2012-2014.

As background on DSM evaluation, there are four major types of evaluation studies of DSM programs:

i. **Process Studies**

These studies review how efficiently and effectively a program is run and are typically done 6-18 months after a program is launched;

ii. **Market Studies**

These studies review how effective a DSM program is at increasing the market share of energy efficient technologies and are typically done 24-36 months after program launch and then every 2-3 years afterwards;

iii. **Impact Studies**

These studies review and determine the energy savings that are directly attributable to a DSM program and are typically done 24-36 months after program launch and then, every 2-3 years afterwards;

iv. **Pilot Studies**

These studies typically involve using a process study with some measurement and verification of energy savings and are usually completed during or immediately following a pilot program.

(Exhibit B-1-2, Volume 2, Appendix D, pp. 4-5, 7)

The M&E Plan proposes that each year FortisBC will conduct a Process, Market and Impact Study (what FortisBC terms a "Comprehensive Review") on two of its DSM programs and a Process Study and some M&E activities (what FortisBC terms a "Mini Review") on three of its programs. The Plan establishes a threshold to trigger evaluation, that is, when a DSM program is estimated to have achieved 10 GWh in

energy savings, evaluation studies will be conducted. (Exhibit B-1-2, Volume 2, Appendix D, p. 11)

The proposed M&E plan would cost \$385,000/year to implement which is approximately 5 percent of FortisBC’s total requested annual DSM expenditure. (Exhibit B-1-2, Volume 2, Appendix D, p. 4)

6.2.1 The Commission’s Review of the Long-Term DSM Plan

As discussed in Section 2.2 of this Decision, subsection 44.1(8) of the *Act* applies to the Commission’s review of the ISP as a whole. The Long-Term DSM Plan, which is filed as part of the larger ISP, is appropriately assessed under subsection 44.1(8)(c) and (d) for adequacy, cost-effectiveness, and the public interest.

6.2.1.1 Adequacy and Cost Effectiveness

FortisBC currently runs and plans to continue running the four programs required for adequacy under the Demand-Side Measures Regulation which are:

Required DSM program for adequacy	Current or planned FortisBC program(s)
A program for low-income households	<ul style="list-style-type: none"> • Residential Energy Savings Kits • Residential Energy Conservation Assistance Program • First Nations Residential Households Program
A program for rental accommodation	<ul style="list-style-type: none"> • “Whole Home” financial incentives for landlords, property managers and rental agencies
An education program for students enrolled in schools in the utility’s service area	<ul style="list-style-type: none"> • Financial sponsorship of educational events and programs • Designed Grade 11 curriculum-based course on energy and conservation
An education program for students enrolled in post-secondary institutions in the utility’s service area	<ul style="list-style-type: none"> • Okanagan College “Home for Learning” energy efficiency training opportunities • Provide guest lecturers • Sponsorships and training for trades • Support energy management training workshops

(Exhibit B-1-2, Volume 2, pp. 24, 28-29)

FortisBC submits that the result of its mTRC test for its 2012-2013 DSM expenditure portfolio is 1.4 and that over the 2012 Long-Term DSM Plan the costs (avoided costs and measure costs) will change but that FortisBC will ensure the cost effectiveness of the portfolio will remain above one. (Exhibit B-27, Undertaking 31; Exhibit B-1-2, Volume 2, p. 14)

Commission Panel Determination

The Commission Panel finds that FortisBC's 2012 Long-Term DSM Plan is adequate and cost-effective as per subsection 44.1(8)(c) of the *Act*. No evidence was raised in the hearing to dispute FortisBC's position. The Commission Panel assesses the cost-effectiveness of FortisBC's DSM Plan on a portfolio basis and accepts FortisBC's calculation.

6.2.1.2 The Public Interest

Various issues were raised about FortisBC's Long-Term DSM Plan during the proceeding.

The first issue is whether the Plan is in fact a long-term plan or, more accurately, a five-year plan because a placeholder for energy savings has been used for 2017-2030. FortisBC's position is that detailed planning data is only valid for 5 years due to rapidly changing DSM technology and costs. (Exhibit B-8, BCUC 2.94.1.1)

The second issue is whether an increase in DSM spending is needed over the next five years, rather than FortisBC's Plan which proposes fairly flat DSM savings targets (and by extension, spending) for this period. FortisBC argues that it has increased DSM spending by almost 500 percent since 2000 and that further increased spending is not warranted at this time. (Exhibit B-8, BCUC 2.94.2)

The third issue is whether FortisBC's planning criteria of targeting 50 percent of load growth is appropriate. BCSEA argues that targeting DSM as a percentage of load growth does not aim to achieve all available energy savings and points out the following disadvantages of FortisBC's methodology: where there is no load growth, no DSM programs would be run; and when there is significant large

load growth, all available energy savings may not be achieved. (T4: 620) BCSEA advocates the approach of targeting energy savings as a percentage of energy sales which FortisBC acknowledges is used in other jurisdictions. (T4: 621) In part as a result of consultation with its customers, FortisBC chose a “medium” DSM plan portfolio over a more costly “high” plan portfolio. BCSEA submits that FortisBC’s choice of a “medium” DSM scenario over a “high” scenario was flawed because FortisBC exaggerated the risk of DSM relative to new supply, failed to apply the same ranking criteria to DSM as new supply, and inappropriately considered rate impacts in its decision not to pursue more DSM activities. (BCSEA Final Submission, p. 14)

The issue of the rate impact of DSM programs and whether the rate impact should be used as a Plan selection criterion was also well-canvassed during the proceeding. BCSEA submits that rate impacts must be assessed in conjunction with bill impacts and that even if a higher level of DSM spending causes a rate increase, “the increase in average rates must be compared against the decrease in average bills.” (emphasis in original) (Exhibit C6-5, pp. 32-33) In other words, because DSM activities can help customers use less energy, their energy bills will decrease even if FortisBC’s increased spending on DSM causes an overall rate increase.

FortisBC cross-examined BCSEA’s expert witness, Mr. Plunkett, on his focus on bill impact versus rate impact suggesting that if only 10 percent or less of FortisBC’s customers participate in DSM programs, only that 10 percent will see bill savings from DSM, while the remainder of FortisBC ratepayers will see a rate (and bill) increase from the Company’s DSM activities. (T5: 941-944)

Mr. Plunkett agreed that, in the short term, bill savings will only be seen by ratepayers participating in DSM programs but postulated that bill savings will be obtained by most ratepayers over time. Mr. Plunkett testified that is “exactly how it works” because over time the Company will be in a position to avoid high cost new energy which will lower the total cost of service for everyone. (T5: 944)

BCSEA requests the Commission find that FortisBC’s Long-Term DSM Plan is not in the public interest because it does not show the utility’s intent to pursue all cost-effective demand-side measures. (BCSEA Final Submission, p. 28) It cites the evidence of Mr. Plunkett who recommends the Commission

direct FortisBC to implement DSM programming by 2016 to target roughly 2 percent of annual sales, an increase from the current plan which targets approximately 0.85 percent of annual energy sales. BCSEA notes Mr. Plunkett's estimate that it would cost FortisBC approximately \$33 million/year to achieve energy savings of 2 percent of energy sales. This yearly spending translates to roughly 5.5 cents/kWh which is less than the 10 cents/kWh FortisBC uses to estimate its avoided supply cost in its Long-Term DSM Plan. (BCSEA Final Submission, pp. 6-7)

BCSEA further recommends the Commission direct FortisBC to, among other things,

- Apply the same ranking criteria to DSM alternatives as it applies to generation alternatives;
- Take into account the ability to shape efficiency acquisitions to match energy and capacity requirements, in comparing DSM to generation alternatives;
- Address the timing of an updated Conservation Potential Review in its 2014 DSM expenditure schedule; and
- Revise its Long-Term Resource Plan if natural gas fired generation is added.

(BCSEA Final Submission, pp. 28-29)

6.2.1.2.1 Monitoring and Evaluation Plan

During the proceeding, FortisBC was questioned on the adequacy of its M&E Plan, especially given that the current plan and its 10 GWh savings threshold results in some DSM programs never being evaluated and others being evaluated very infrequently. (Exhibit B-4, BCUC 1.298.2) As noted, the proposed M&E Plan would cost FortisBC \$385,000 per year to implement, which equates to 5 percent of its overall DSM budget. The 2004 California Evaluation Framework, a seminal document for DSM evaluation, references a spending range of 2-10 percent of overall DSM budget spending on DSM evaluation among utilities in North America, with the average spending being 4 percent. (Exhibit B-8, BCUC 2.98.7; Exhibit B-4, BCUC 1.297.1)

During the oral hearing, FortisBC referenced an evaluation study conducted by BC Hydro of the Energy Savings Kits program that FortisBC and BC Hydro both run. The study showed that of 700 kWh of

possible energy savings in the kits, only 203 kWh in savings were realized if the kits were self-installed by the customer, whereas 350 kWh of savings were realized if maintenance personnel installed the kits. (T4:707-8)

FortisBC also testified as to the importance of conducting monitoring and evaluation studies on a regular basis to confirm that expected savings from a program are actually realized in the field. (T4:721-2) FortisBC agreed that administrative cost savings may be found when process studies are conducted on DSM programs and also stated that it intended to use M&E data from other utilities to supplement FortisBC studies. (T5: 873; FortisBC Final Submission, p. 215)

FortisBC outlined a possible alternative evaluation plan where every program undergoes evaluation according to the typical timing for the various evaluations described in Section 6.1.2 above. FortisBC estimates the alternative M&E plan would cost an additional \$100,000 per year to implement. (Exhibit B-8, BCUC 2.98.7) This would represent just over 6 percent of the Company's total DSM budget.

FortisBC submits that its M&E plan, as proposed, is "robust." BCSEA submits it is generally satisfied with FortisBC's M&E plan for the 2012- 2014 period but notes that it is not best practice to never evaluate a program because "you'd eventually want to do some kind of evaluation of a program unless you had an awfully good reason not to." (T5: 884, 965; BCSEA Final Submission, p. 28)

Commission Panel Determination

The Commission Panel finds FortisBC's 2012 Long-Term DSM Plan to be in the interests of persons in British Columbia who receive or may receive service from FortisBC in accordance with subsection 44.1(8) (d) of the *Act*. Subject to the further findings relating to the M&E Plan and in accordance with subsection 44.1(7) of the *Act*, the Panel accepts the Plan under subsection 44.1(6) of the *Act*.

The Commission Panel recognizes that this acceptance means that FortisBC may simply maintain current levels of DSM spending over the next five years, subject to future DSM expenditure schedules filed for approval with the Commission. However, as discussed in relation to FortisBC's section 44.2 expenditure schedule request (below), FortisBC received approval to spend approximately twice the amount on DSM in 2011 over 2010 and was unable to spend to the higher approved level. As well, the Commission Panel acknowledges that the Company is implementing new programs that will take time to gain participants. The Panel is also persuaded that FortisBC can employ other best practises to achieve additional savings without adding to its budgeted spend.

The Commission Panel accepts FortisBC's proposal to submit a revised Plan and to update the contributing studies every 5 years.

The Commission Panel is also of the view that the rate impact from DSM spending is a relevant consideration for the public interest, at least in the short term, as increased participation in DSM programs may take some time.

With respect to BCSEA's proposals for the Company's next Long-Term DSM Plan, the Commission accepts that FortisBC may wish to apply the same ranking criteria to DSM as it applies to generation alternatives but does not accept that FortisBC should necessarily change its DSM target from one based on load growth to energy sales at this time. The Commission Panel is satisfied that FortisBC is taking a reasonable approach to setting targets for energy savings in the current environment.

Regarding FortisBC's proposed M&E Plan, the Commission Panel sees FortisBC's testimony concerning the Energy Savings Kits evaluation as highlighting the importance of the evaluation process. It would appear that if BC Hydro had not evaluated the kits, the utilities might assume savings of 700 kWh of energy savings per kit when in fact, the kits are producing savings of less than half of this amount. As stated by Mr. Warren, FortisBC's Director of Customer Service, M&E studies are done to ensure the savings claimed are actually occurring in the field. The Commission Panel expects that the energy savings estimates FortisBC puts before the Commission will actually occur because this represents the value of DSM to all ratepayers. An accurate account of energy savings cannot occur without M&E

studies conducted on programs. **The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.** Given that FortisBC's alternative M&E plan costs \$100,000 more per year and that amount remains within the California Evaluation Framework range of common budget allocations to M&E, the Commission Panel recommends that FortisBC resubmit an alternative M&E schedule, such as that submitted in response to BCUC IR 2.98.7, that does not apply a 10 Gwh threshold to trigger evaluation and that follows the typical sequence of evaluations as laid out in the M&E Plan for acceptance by the Commission. Any additional funds for this alternative schedule should come from the currently proposed expenditure schedule and no additional funds above the requested amounts are approved. The Commission Panel encourages FortisBC to supplement its own studies with data from other utilities wherever appropriate and to conduct shared evaluations on integrated programs.

6.3 FortisBC's Expenditure Request for 2012-2013

As part of this Revenue Requirement Application, under section 44.2 of the *Act*, FortisBC is requesting approval to spend \$7.73 m in 2012 and \$7.88 m in 2013. The 2012-2013 DSM expenditure schedule is an extension of its previously approved 2011 DSM plan.

As background, in 2011 FortisBC was approved to spend \$7.842m which is almost double the amount it was approved for in 2010. In 2011, FortisBC spent \$5.917 million of the total \$7.842 million approved. (Exhibit B-29, Undertaking 32)

The 2012-2013 proposed DSM expenditure schedule comprises DSM programs in the Residential, Commercial (or General Service) and Industrial sectors as well as funding for Supporting Initiatives and Planning and Evaluation.

Table 16

	<u>2011</u>		<u>2012</u>		<u>2013</u>		TRC incl MTRC B/C ratio
	Approved		Plan		Plan		
	<u>Savings</u>	<u>Cost</u>	<u>Savings</u>	<u>Cost</u>	<u>Savings</u>	<u>Cost</u>	
	<u>MWh</u>	<u>\$(000s)</u>	<u>MWh</u>	<u>\$(000s)</u>	<u>MWh</u>	<u>\$(000s)</u>	
Programs							
Residential	16,422	3,636	16,101	3,717	16,946	3,944	1.6
General Service	13,940	2,118	13,380	2,199	11,980	2,085	1.5
Industrial	9,360	613	2,480	350	2,580	364	3.3
Sub-total Programs:	39,722	6,367	31,961	6,266	31,506	6,393	1.6
Supporting Initiatives		725		725		\$ 725	
Planning & Evaluation		750		740		760	
Total (incl. Portfolio spend):		7,842		7,731		7,878	1.4
Income Tax Impact		<u>-2,078</u>		<u>-1,933</u>		<u>-1,969</u>	
Total deferred (net of tax)		5,764		5,798		5,908	

(Exhibit B-27, Undertaking 31)

As shown in Table 16 above, FortisBC calculates that its proposed DSM portfolio has an mTRC of 1.4 and is thus cost effective.

6.3.1 The Commission's Review of the DSM Expenditure Request

As noted in Section 2.2 of this Decision, in considering whether to approve an expenditure schedule, the Commission must consider the following under subsection 44.2(5) of the Act:

- (a) the applicable of British Columbia's energy objectives,
- (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- (c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
- (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and
- (e) the interests of persons in British Columbia who receive or may receive service from the public utility.

The Commission has considered the applicable of British Columbia's energy objectives in the context of FortisBC's proposed Capital Expenditure Plan. FortisBC's long-term resource plan is considered in Section 7 of this Decision. Sections 6 and 19 of the *CEA* are not applicable to DSM expenditures.

Regarding the cost effectiveness of the DSM programs, the Commission has previously assessed FortisBC's DSM programming at a portfolio level and will continue to do so in this case. The Commission Panel accepts the cost effectiveness calculations put forward by FortisBC and thus **finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).**

Given the assessment of the above items, the issue remaining for the Commission to consider is whether acceptance of the expenditure schedule is in the interests of persons in British Columbia who receive or may receive service from FortisBC. Of relevance to this issue is whether FortisBC's proposed spend is sufficient.

6.3.1.1 Sufficiency of DSM Spending Level

FortisBC is requesting approval to spend \$7.73 million in 2012 and \$7.88 million in 2013 on its DSM portfolio. As previously discussed in relation to FortisBC's Long-Term DSM Plan, BCSEA's position is that FortisBC is under spending on DSM and should ramp up spending to approximately \$33 million per year.

FortisBC disagrees with BCSEA's position and counters that in 2011 they were approved for double the spend over 2010, that they have not yet been able to implement the increase, and that spending \$33 million/year would result in a 6.4 percent rate increase between 2012 and 2016 which is significant. (T5: 869-70; Exhibit B-27, Undertaking 33, p. 26)

BCSEA's expert witness, Mr. Plunkett, provided testimony explaining his analysis of DSM programs in various jurisdictions across North America. Mr. Plunkett advised that he grouped the jurisdictions he reviewed into four tiers, based on energy sales avoided through DSM, with the first tier being the best. In Mr. Plunkett's analysis, only three jurisdictions were in Tier 1, California, Vermont and Connecticut. These jurisdictions were able to achieve one and one half per cent or more of energy sales being

avoided through DSM. Mr. Plunkett placed FortisBC squarely in Tier 2, along with nine other jurisdictions which succeeded in achieving approximately one percent of energy sales being avoided through DSM. (T5:926-929)

Commission Panel Determination

Many of the issues related to FortisBC's 2012 Long-Term DSM Plan are the same as the issues related to the section 44.2 expenditure schedule request including spending level, rate impact and value for money.

Based on the conclusions the Panel has reached in relation to these issues for the Long-Term DSM Plan, and considering the testimony of Mr. Plunkett that FortisBC has achieved a ranking placing it in his second tier of jurisdictions with successful DSM programs, **the Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of \$7.73 million in 2012 and \$7.88 million in 2013.** The recovery of these expenditures is to continue in the manner previously approved for FortisBC.

6.3.1.2 FortisBC Industrial Incentives

An issue raised primarily by the Industrial Consumers Group is the difference in DSM incentive levels offered by BC Hydro and FortisBC and whether FortisBC's industrial incentives are sufficient. ICG requests the Commission direct FortisBC to enhance its industrial DSM programs to match BC Hydro's incentives and to implement an energy manager program, similar to that offered by BC Hydro to its industrial customers. (ICG Final Submission, p. 38)

FortisBC indicates a concern as to the persistence of savings from funding an energy manager position. (Exhibit B-5, Celgar 1.10.4)

BC Hydro's industrial DSM program offers incentives of 30.9 cents/kWh with no payback period limit and with 100 percent of the project cost being eligible for rebate for projects costing up to \$1 million and 75 percent being eligible for projects costing more than \$1 million. (Exhibit B-9, Celgar 2.12.1, 2.12.3)

FortisBC offers 10 cents/kWh with a two year payback period limit on the incentive amount. FortisBC compared the incentive it would offer an industrial customer under its DSM program to that which would be available to a BC Hydro customer. In the comparison, FortisBC would pay the industrial customer \$1.5 million in incentives while BC Hydro would pay \$4.635 million in incentives for the same project. (T4:732; T5:795)

FortisBC recognizes that there is significant difference in incentives offered by FortisBC and BC Hydro but takes the position that it does not have to offer the same programs as BC Hydro, although FortisBC does try to match BC Hydro's residential DSM incentives. (Exhibit B-9, Celgar 2.5.5, 2.10.3, 2.11.1; T5:801)

FortisBC was questioned during the oral phase of the proceeding about the difference in incentive levels, to which its witness responded:

MR. WARREN: In this case I would have -- with a 1.0 benefit/cost ratio TRC, I would have -- I have some difficulty justifying paying the kind of numbers that B.C. Hydro pays, which is effectively 58 percent of the TRC value. For example, our air source heat pump customers, measured on the same benefit/cost ratio basis, have about a 1.0 TRC as well at \$85, and we pay about 12 percent of the total cost of those upgrades.

So it would be difficult to justify.

(T5: 795-6)

ICG's position is that there is "simply no explanation" for the differences in BC Hydro and FortisBC industrial DSM programs and that at FortisBC's incentive levels, it is no surprise that Celgar, one of FortisBC's industrial customers, did not proceed with a planned DSM project. (ICG Final Submission,

pp. 35-36)

BCSEA submits that the fact that FortisBC's commercial and industrial program incentives are capped at 10 percent of annual kWh savings with a two-year payback period limit discourages cost-effective energy savings. (BCSEA Final Submission, p. 12)

BCSEA advocates for consistent DSM programs across the province and requests the Commission to direct FortisBC to revise its DSM incentives to be better aligned with those offered by BC Hydro and to increase, wherever possible, standardization of common DSM program features across the Province, including marketing, financial incentives, and eligibility requirements. (BCSEA Final Submission, pp. 28-29)

FortisBC replies that increasing industrial incentives to match those of BC Hydro could result in millions of dollars in additional expenditures and argues that ICG did not file any evidence to explain why Celgar did not proceed with its planned DSM project. (FortisBC Reply, pp. 73-74) FortisBC also submits that the FortisBC and BC Hydro DSM programs which ICG references are comparable and that FortisBC takes a reasoned approach by preferring to have customer co-investment. (FortisBC Reply, pp. 75-77)

Commission Panel Determination

The Commission Panel does not accept ICG's request to direct FortisBC to match BC Hydro's industrial incentives or to implement an energy manager program. The Commission Panel acknowledges that BC Hydro does offer larger incentives to its industrial customers. However, we are not persuaded that BC Hydro's level of incentive is necessarily optimal and that FortisBC should move to that level.

As noted earlier, in the Panel's view, BC Hydro and FortisBC are different utilities, operating in different contexts. The Commission Panel is not prepared to direct FortisBC to implement the same DSM programs as BC Hydro, particularly in the industrial sector where the customer base is very different.

The Commission Panel also reiterates its view that FortisBC's DSM Program, as advanced, is reasonable.

6.3.1.3 Transfers of DSM Funding Among Programs

Currently FortisBC has no official policy in place for the transfer of funds between sectors such as residential and industrial but rather makes a judgment call to determine when transfers are appropriate. FortisBC agrees that customers might be concerned about a large transfer between sectors. FortisBC submits that it will seek concurrence of its DSM Advisory group in some cases prior to transferring funds. (Exhibit B-9, Celgar 2.2.2; T5:888-9)

FortisBC indicated in the oral phase of the Hearing that it was amenable to gaining Stakeholder Group approval and informing the Commission prior to making a transfer of funds between sectors where the proposed transfer would exceed a threshold of 30 percent of a sector's budget. (T5: 890-1)

Commission Panel Determination

The Commission Panel is of the view that a more formal policy regarding fund transfers among sectors/ program areas is appropriate at this time, given the substantial increase in the budget for DSM programs. The Commission Panel is also of the view that a threshold of 25 percent is most appropriate. **The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission.** In cases where a proposed transfer into or out of an approved Sector is greater than 25 percent of that sector, prior Commission approval is required. The Commission Panel recommends that funding transfers of 25 percent or more requiring prior Commission approval, should, where feasible, be presented to FortisBC's DSM Advisory Committee for feedback before the approval request is made to the Commission.

6.3.1.4 Integration of DSM Programs Among BC Utilities

In its Final Submission BCSEA also recommends the Commission direct FortisBC to “provide evidence of concrete progress in terms of coordinating, integrating and standardizing DSM program design and delivery among FortisBC, BC Hydro and the FEU in FortisBC’s next DSM expenditure schedule filing.” (BCSEA Final Submission, pp. 28-29)

BCMEU requests the Commission direct FortisBC to “work more closely with Fortis Gas as well as BC Hydro to find efficiencies for investment in DSM which provides opportunities to ratepayers while reducing costs to ratepayers.” (BCMEU Final Submission, p. 90)

FortisBC submits that it has always collaborated with other BC utilities on DSM and that a direction in this regard is not necessary. (FortisBC Final Submission, p. 208; FortisBC Reply, pp. 72-73)

Commission Panel Determination

The Commission Panel agrees that every effort should be taken to integrate and collaborate among BC utilities to maximize the effectiveness and efficiency of DSM programs and minimize cost to ratepayers. **The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.**

7.0 INTEGRATED SYSTEM PLAN

7.1 Long-Term Capital Plan

FortisBC's Long-Term Capital Plan is the component of its Integrated System Plan that lays out the long-term strategic direction the company intends to follow to meet its infrastructure and asset needs. The overall capital plan has three components – the short term (2012-2013), dealt elsewhere in this Decision, the medium term (2014-2016) and the long term (2017 onwards). The Long-Term Capital Plan sets out projects that are expected to be developed over the next 20 years and, in the case of bulk transmission assets, projects expected over the next 30 years are also included.

The Company is not seeking approvals for any specific projects in its 2012 Long-Term Capital Plan, but does request Commission acceptance of its ISP, of which the LTCP is a component, as being in the public interest. (Exhibit B-1-1, p. 1)

The planning process to prepare a long-term capital plan has a number of key inputs, including load forecasts, cost estimation and capital-related accounting practices. FortisBC filed a detailed description of the processes utilized in developing the 2012 Long-Term Capital Plan. The filing includes details by types of projects (e.g. transmission infrastructure, generation infrastructure) and by region. Estimates for the medium term (2014 to 2016) are provided on an annual basis. For the longer term (2017-31) a single estimate is provided for the entire period. (Exhibit B-1-1, pp. 9-209)

While there was considerable focus on the 2012 -2013 capital expenditures in both the filed evidence and in information requests and cross-examination, parties to the proceeding generally did not express concerns with respect to details of the capital plan outside of the 2012-2013 period. A general concern explored in this proceeding was that, having gone through a major period of infrastructure renewal, FortisBC should be in a sustainment mode where its focus should be on cost containment. (ICG Final Submission, p. 5; BCMEU Final Submission, p. 2; BCPSO Final Submission, p. 3)

Commission Panel Determination

While the focus in this proceeding was largely on cost containment in the short term, the Commission Panel believes that the economic pressures many of FortisBC's customers are now facing and are likely to face in the foreseeable future, make this a long-term issue as well. The Commission Panel encourages FortisBC to pursue vigorously means to minimize costs in the long run while maintaining safe, reliable service. **The Commission Panel accepts the Long-Term Capital Plan (2014-2031) as being in the public interest.** Given the lack of detail in the long-term part (2017-31) and the limited information in the medium term part (2014-16) of the capital plan, the Commission Panel wishes to make it clear that acceptance of the LTCP for 2014-2031 is on that basis. In other words, capital programs based on limited information that may appear acceptable at a high level a number of years out, may be found not to be acceptable following a detailed review at a future time, when there is more detailed information and costs are carefully scrutinized or the context has changed significantly.

7.2 Long-Term Resource Plan

The Commission's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives. The Commission's Resource Planning Guidelines set out a comprehensive process to assist utilities in the development of their resource plans and provide a basis upon which to assess the LTRP. The Commission requires that any plan submitted under subsection 44.1(2) of the *Act* be prepared in accordance with these guidelines.

Under the guidelines, the utility is to prepare a range of gross (pre-DSM) demand forecasts structured in such a way that savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast. The plans should identify feasible supply and demand resources and measure each supply and demand resource against the objectives set out for the plan. The objectives include:

- provision of adequate and reliable service,

- economic efficiency,
- preservation of the financial integrity of the utility,
- equal consideration of DSM and supply resources,
- minimization of risks,
- compliance with government regulations and stated policies, and
- consideration of social and environmental impacts.

For each of the gross demand forecasts the utility should develop several plausible resource portfolios, each consisting of a combination of supply and demand resources needed to meet the gross demand forecasts. The process should lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts. Out of this process should come an action plan setting out the detailed acquisition steps which would need to be initiated over the next four years in order to meet the most likely gross demand forecast.

On June 30, 2011 FortisBC filed its 2012 Long Term Resource Plan (2012 LTRP) as Volume 2 of its 2012 ISP. FortisBC states that its plan is consistent with the requirements under section 44.1 of the *Act* and with the Commission's Resource Planning Guidelines. (Exhibit B-1-2, p. 1) The Company states that it has also prepared its 2012 LTRP to be consistent with the objectives set out in the *CEA* which are believed to be relevant to the FortisBC resource planning process. (Exhibit B-1-2, p. 2)

7.2.1 2012 Long-Term Resource Plan Summary

The FortisBC LTRP sets out FortisBC's demand forecasts and supply requirements for the period 2012 to 2040. It summarizes FortisBC's objectives as: (1) providing cost-effective reliable power over the forecast term; (2) assessing the uncertainty and risks in its market purchase strategy and, over time, achieving 100 percent self sufficiency; and (3) balancing the provision of cost effective power against the applicable of British Columbia's energy objectives. (Exhibit B-1-2, p. 1) There are 16 energy objectives set out in Part 1, section 2, of the *CEA*. The objectives which FortisBC argues are applicable to it and which are addressed in the LTRP are:

- To achieve electricity self sufficiency;
- To generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build infrastructure necessary to transmit that electricity;
- To ensure that BC Hydro's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract* continue to accrue to the authority's ratepayers;
- To reduce BC greenhouse gas emissions;
- To reduce waste by encouraging the use of waste heat, biogas and biomass;
- To maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia; and
- To take demand-side measures and to conserve energy.

(*Clean Energy Act*, Section 2; Exhibit B-1-2, p. 2)

The Company has prepared high, low and expected forecasts of demand before DSM through to the year 2040. The Company is targeting to meet 50 percent of its load growth through DSM and sets out an expected forecast on this basis. Due to the uncertainties inherent in DSM resources, FortisBC treats DSM as contributing to a range of outcomes, rather than as a single pre-determined percentage component meeting the gross demand needs. (Exhibit B-1-2, p. 3)

As discussed earlier, FortisBC owns four hydroelectric generating plants providing about 30 percent of its current capacity needs and 45 percent of its current energy requirements. It also has long-term power purchase agreements with BC Hydro and with the Brilliant Power Corporation, and a five year capacity agreement with Powerex. These resources provide a total winter peak capacity of about 710 MW and a summer peak capacity of 524 MW. (Exhibit B-1-2, pp. 2-3)

Subsequent to this Hearing, FortisBC received approval to purchase capacity from the Waneta Expansion Project. This capacity purchase agreement (WAX CAPA) is expected to come into effect in early 2015 and will both replace the Powerex capacity agreement and meet FortisBC's forecast capacity needs through the period of the 2012 LTRP. FortisBC is currently negotiating to extend its

RS 3808 PPA with BC Hydro. In the LTRP, it is assumed the RS 3808 PPA will be renewed in 2013 with the same right to the capacity and all associated energy that FortisBC currently has under the existing agreement. Although existing resource arrangements are expected to meet most of FortisBC's energy requirements, the Company expects that, in the near term, there will be some energy gaps during the winter period due to the shape of the load. (Exhibit B-1-2, p. 7)

To address capacity and energy requirements in the near and longer term FortisBC looked at resource options characterized as "New Resources" (Build strategy), "Wholesale Market" (Buy Strategy) and a "Combined Strategy" incorporating elements of build and buy. These potential resource solutions were looked at from a short term (2011-2015), medium term (2016-2020) and long term (2021-2040) perspective. Potential resources in the build category were evaluated based on their ability to meet capacity gaps, their environmental impact and their relative economics. Detailed evaluation of a number of resource options was provided by Midgard Consulting Inc. in its "FortisBC – 2010 Resource Options Report." (Exhibit B-1-2, Appendix C) For the buy strategy, FortisBC assessed future market risk (price and availability) based on a further study (2011 FortisBC Electricity Market Assessment) provided by Midgard Consulting Inc. (Exhibit B-1-2, Appendix B)

With respect to capacity requirements, FortisBC's proposed solution is to rely on wholesale market purchases in the short and medium term (2012 to 2020) with the possibility of accelerating construction of new resources in the medium term (2016-2020), if necessary. For the longer term (2021-2040), new capacity resources are anticipated to be built by the mid-to-late 2020s, with additional resources in the 2030s. To meet energy needs FortisBC intends to rely on wholesale market purchases in the short and medium term (2012-2020) while continuing to assess new clean energy resources. No energy gap is anticipated until 2018. By 2020, an energy gap of 13 GWh is predicted. In the long-term (2021-2040), this gap is expected to increase by about 14 GWh/year, reaching 287 GWh by 2040. (Exhibit B-1-2, pp. 64, 86)

No planned capital expenditures for capacity resources are included in the LTRP. To meet energy needs, new clean energy resources and the Similkameen Hydroelectric Project are expected in the 2021 – 2040 period, but further evaluation will be required before any specific projects are selected.

FortisBC states that it cannot prioritize the preferred resource options that have been identified at this time. (Exhibit B-5, BCSEA 1.15.1)

ICG takes the position that the Commission should reject the Integrated System Plan (containing FortisBC's LTRP) on the basis that the ISP does not meet the requirements of the Commission's Resource Planning Guidelines. Specifically, ICG is concerned that FortisBC failed to include a portfolio analysis of resource options as set out in Guidelines 5 and 6. ICG quoted from the Commission's Decision on the BC Hydro 2006 Integrated Electricity Plan (IEP): "[t]he Commission Panel also agrees with BC Hydro that a portfolio analysis is a best practice for IEP or IRP analysis" (2006 IEP and LTAP Decision dated May 11, 2007, pp. 89-90) FortisBC testified that because its forecast energy gaps are small and its capacity gaps are being met for some time into the future, it did not do a full portfolio analysis for its LTRP. The Company characterized its resource plan work as a supply/demand resource gap analysis. (T5: 789-791; ICG Final Submission, pp. 17-26)

Commission Panel Determination

The Commission Panel agrees that portfolio analysis is a "best practice" for resource plan analysis. However, the Resource Planning Guidelines do not state that portfolio analysis "must" be done, but that it "should" be done. **The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.**

7.2.2 Requirements under the Utilities Commission Act

As noted earlier, under section 44.1 of the *Act*, in determining whether to accept or reject a long-term resource plan (or a part thereof), the Commission must consider:

- The applicability of British Columbia's energy objectives;
- The extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*;
- Whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and
- The interests of persons in British Columbia who receive or may receive service from the public utility.

Section 7.2.1 of this Decision outlines those British Columbia energy objectives which FortisBC argue apply to its Long Term Resource Plan. Within the 2012 LTRP the Company has addressed these objectives and assert that these objectives have played an important role in shaping its analysis and decision-making. Specifically, FortisBC has identified resource options and related strategies to handle forecast capacity and energy deficits over the short, medium and longer term. The Commission Panel finds that the LTRP is generally consistent with the applicable British Columbia energy objectives as they are a key input in the evaluation of capacity and energy alternatives.

As noted in Section 5.4.3 of this Decision, sections 6 and 19 of the *CEA* are primarily related to BC Hydro. However, section 6 does have application when a public utility is planning in accordance with section 44.1 of the *Act*. The Commission Panel is of the view that the steps taken by FortisBC to identify and evaluate resource options and related strategies to handle forecast capacity and energy deficits as described in the 2012 LTRP, address the British Columbia energy objective to achieve self-sufficiency.

In Sections 6.2.1.1 and 6.2.1.2 of this Decision, the Commission Panel has found that the FortisBC 2012 Long Term DSM Plan is adequate and cost effective and in the public interest under subsection 44.1(8) of the *Act*.

The Commission Panel considers acceptance of the 2012 LTRP to be in the interests of British Columbians who receive or may receive service from FortisBC. In our view the 2012 LTRP has adequately met the provisions for considerations laid out in subsection 44.1 (8) of the *Act*.

Therefore, based on the Commission’s Panel’s review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the Act with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.

In reaching this conclusion, the Commission Panel notes that acceptance of the 2012 LTRP does not constitute approval of any of the potential initiatives addressed within this plan. The resource planning process by its nature is a high level exercise. Because of this, the Commission Panel would like to point out that in “accepting” the LTRP, the programs and initiatives outlined in the plan are not sufficiently “fleshed out” to finally determine whether they will pass careful scrutiny when a more detailed application is put forward.

7.2.3 Filing of the Next LTRP

FortisBC stated that its intention is to file its next long-term resource plan five years from the date the last plan was filed (June 30, 2011). The Company also stated that a revision to the current plan would be filed in the event of a material change such as the final RS 3808 PPA contract with BC Hydro having significantly different terms than those FortisBC is currently anticipating, a significant change in the marketplace (such as a marked increase in natural gas prices) or an unforeseen addition of major new loads onto the system. (T5:821-822)

The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.

8.0 SUMMARY OF DIRECTIVES

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

	Directive	Page
1.	With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relevant merits of each as a planning tool.	25
2.	The Commission Panel reaffirms its Decision of November 30, 2011, to maintain the current ROE and capital structure pending determinations made in the GCOC proceeding.	32
3.	The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC.	34
4.	The Commission Panel directs FortisBC to reduce its Power Purchase Expense forecasts by \$1.5 million in 2012 and 2013.	35
5.	FortisBC is directed to adjust its power purchase expense forecast to reflect this change.	35
6.	The Commission Panel agrees with BCMEU and because FortisBC has not sufficiently justified the need for an additional FTE, denies the additional FTE and related costs of \$142,000 in each of 2012 and 2013	38
7.	The Commission Panel directs FortisBC to continue to maintain PPME as part of O&M expenses.	38
8.	The Commission Panel also agrees with this assessment and therefore denies the proposal to implement a PRM at this time and the proposed additional \$310,000 in planned Power Purchase Expense for 2013	41
9.	The Panel directs FortisBC to include any variances related to water fees in that deferral account.	42
10.	FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.	44

11.	The Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.	47
12.	The Commission Panel accepts FortisBC's proposal to continue to allocate costs for executive time based on the executives' estimates until such time as alternatives have been reviewed and a new proposal is put forward by the Applicant. The Commission Panel also approves the proposed handling of cross charges for executives based on a fully loaded wage only.	49
13.	The Commission Panel has determined that acceptance of the IBEW contract as it applies to rates is reasonable.	55
14.	The Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.	58
15.	The Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.	59
16.	The Commission Panel directs FortisBC to reduce O&M expenditures for labour for each of 2012 and 2013 by \$250,000. The Panel believes this reduction should be applied to the specific areas where concerns have been raised but will leave the decision as to where these costs are applied to the discretion of FortisBC.	63
17.	The Panel denies the \$0.8 million deferral account treatment sought by FortisBC in pursuit of the Asset Management Program.	66
18.	The Panel approves funds in the amount of \$150,000 which may be required for external assistance over the test period. These funds may be included in the O&M budget.	66
19.	The Commission Panel finds that contributions to political parties should be solely for the account of the shareholder. Consistent with the 2012 FEU RRA Decision, the remaining budgeted amounts are to be shared equally between the shareholder and the ratepayer.	69
20.	The Commission Panel will only approve an increase equal to the forecast BC CPI of 2.2 percent in 2012 and another 1.9 percent in 2013. (Exhibit B-1, Tab 4, p. 43) FortisBC is directed to reduce its non-labour expense forecast for this department by \$113,000 in 2012 and \$100,000 in 2013.	70

21.	The Commission Panel approves the requested capitalized overhead rate of 20 percent for the test period. For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.	72
22.	The Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.	75
23.	FortisBC is directed to prepare and file a report with the Commission by September 30, 2012, explaining this apparent inconsistency. If an amount greater than the 20 percent approved for capitalized overhead has been used in the calculation of rates, FortisBC is directed to adjust the capitalized overhead rates downward to reflect the approved amount for capitalized overhead.	75
24.	Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification.	77
25.	The Commission Panel is reluctant to take issue with the forecasts that have been prepared by FortisBC and approves the forecast expenditures, as requested.	78
26.	The Panel directs FortisBC to use the most recent interest rate forecasts available at the time of the oral phase of the proceeding of 2.85 percent for short-term and 3.45 percent for long-term debt.	82
27.	The Commission Panel approves FortisBC's continued use of recognizing actual asset removal costs as incurred, as requested.	86

28.	While the Commission Panel endorses the relocation of a spare transformer to the Grand Forks Terminal to reduce the downtime associated with a failure of the current transformer, we reject the proposed expenditure of \$7.205 million for the Grand Forks Transformer Addition Project because the need for increased reliability is not apparent. In addition, the Panel notes that FortisBC was previously directed to apply for a CPCN for certain elements of the proposed project and failed to do so. If FortisBC intends to proceed with advancing either the fibre optic communications portion of the proposed project or the installation of the spare transformer at Grand Forks Terminal, it is directed to apply for a separate CPCN. In pursuing a CPCN for fibre optic communications, FortisBC is expected to diligently pursue the extension of the fibre leasing agreement to preserve the potential benefit to ratepayers.	95
29.	The Commission Panel is concerned about the estimate quality and control of actual costs associated with the PCB Mitigation project, and directs FortisBC to file a comprehensive scope and schedule for this project by October 1, 2012 and semi-annual progress reports thereafter.	99
30.	The Commission Panel rejects the expenditures for the Kelowna 138 kV Loop Fibre Installation project. FortisBC may provide Class 3 estimates for both Option E and Option F and additional justification for its recommendation in a future filing.	101
31.	Based on our review of the 2012-13 CEP the Commission Panel is of the view that an overall reduction to the CEP of \$17.6 million over the test period is possible. However, the Panel believes imposing all of the reductions related to the \$17.6 million may not provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion. By reducing the amount of \$17.6 million to \$10.5 million (which is approximately 60 percent), the Panel can be reasonably assured that FortisBC can achieve the level of service it requires and will still have sufficient flexibility to manage its projects and workforce. Accordingly, the Commission Panel directs FortisBC to reduce its capital expenditure budget by \$10.5 million in addition to the two projects which have been specifically rejected above.	103
32.	The Commission Panel therefore directs that such deferral accounts, with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates.	106
33.	FortisBC is directed to commence the amortization of this deferral account into rates in the next test period if the associated project has not commenced by that time.	107

34.	The Commission Panel approves the amortization in 2012, as requested, of the following regulatory expense deferral accounts into rates: <ul style="list-style-type: none"> • Implementation of new rate structures • Residential Inclining Block Rate and Industrial Stepped Rate Applications • 2011 Revenue Requirements Application 	108
35.	The Commission Panel rejects FortisBC’s proposal to amortize this deferral account into rates.	109
36.	The Commission Panel approves the full amortization of the research costs relating to Irrigation rate payers in 2013, as requested.	108
37.	The Commission Panel approves amortization of these amounts over a shorter, two year period to reduce carrying costs.	110
38.	The Commission Panel approves the amortization of 2011 Revenue Protection expenses into rates in 2012.	110
39.	The Commission Panel approves the continuation of the Right-of-Way litigation deferral account, with the inclusion of any recovered costs following resolution of the dispute, as a non-rate base deferral account, attracting an interest financing charge at FortisBC’s WACD.	111
40.	The Commission Panel approves the amortization of costs relating to conversion to US GAAP over the test period.	111
41.	The Commission Panel approves deferral of the set up costs relating to Mandatory Reliability Standards in a Non-Rate Base Deferral Account attracting interest at FortisBC’s WACD. However, in the Panel’s view, the amortization period requested is too long. Therefore, the Commission Panel directs that these costs be amortized into rates over a three year period, as opposed to the five year period sought, to reduce the associated carrying costs.	112
42.	The Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC’s WACD until such time as they become part of a specific capital project.	113
43.	The Commission Panel considers this item to be a regulatory expense not a capital expense related to any specific project and therefore, directs that this account attract an interest financing charge at FortisBC’s WACD and be amortized into rates over a five year period.	113

44.	The Commission Panel therefore directs that these costs be expensed during the test period.	114
45.	Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD.	115
46.	<p>The Commission Panel therefore approves the following variance deferral accounts as non rate base deferral accounts attracting a short term interest financing charge.</p> <ul style="list-style-type: none"> • Power Purchase Expense Variance Deferral Account <ul style="list-style-type: none"> ○ any variance in this account is to be amortized in 2014 • Revenue Variance Deferral Account <ul style="list-style-type: none"> ○ any variance in this account is to be amortized in 2014 • HST Removal or Reform Variance Deferral Account • Property Tax Asset Variance Deferral Account • Pension and Other Post-Employment Expense Variance 	115
47.	The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.	134
48.	The Commission Panel finds FortisBC's 2012-2013 DSM Expenditure Schedule to be cost effective in accordance with the Demand-Side Measures Regulation (Ministerial Order No. 271) and the Amendments to the Demand-Side Measures Regulation (Ministerial Order No. 335).	136
49.	The Commission Panel approves FortisBC's section 44.2 expenditure request for DSM in the amounts of \$7.73 million in 2012 and \$7.88 million in 2013.	137
50.	The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission.	140
51.	The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.	141

52.	The Panel accepts FortisBC’s argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard “FortisBC – 2010 Resource Options Report” is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP.	147
53.	Based on the Commission’s Panel’s review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the Act with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected.	149
54.	The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines.	149

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DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

Original signed by:

D.A. COTE
COMMISSIONER

Original signed by:

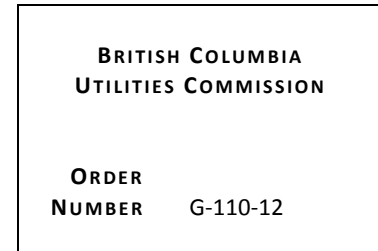
A.A. RHODES
COMMISSIONER

Original signed by:

N.E. MACMURCHY
COMMISSIONER



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

and

An Application by FortisBC Inc.
for Approval of 2012-2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: D.A. Cote, Commissioner
A.A. Rhodes, Commissioner August 15, 2012
N.E. MacMurchy, Commissioner

O R D E R

WHEREAS:

- A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 44.2, 56 and 59 to 61 of the *Utilities Commission Act* (the Act) for approval of its 2012-2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);
- B. The Application contains two parts:
 - 1) FortisBC's 2012-2013 Revenue Requirements (including the Company's 2012-2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the Act),
 - 2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the Act, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand-Side Management Plan;
- C. FortisBC sought, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also sought a permanent rate increase of 6.9 percent effective January 1, 2013;
- D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012-2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3)(a) and satisfies the requirements of section 45(6) of the Act;
- E. The Company also requested a Commission determination on whether the 2012 Integrated System Plan, which is comprised of three components (the 2012-2013 Resource Plan, 2012 Long Term Capital Plan, and the 2012 Long Term Demand-Side Management Plan), is in the public interest pursuant to section 44.1 (6);
- F. A Workshop to review the Application was held in Kelowna on July 22, 2011;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

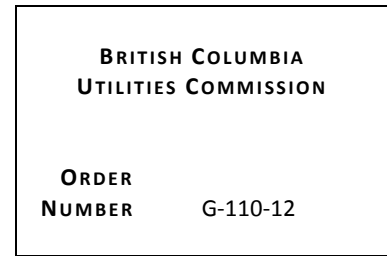
**ORDER
NUMBER G-110-12**

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- G. The Company filed an Evidentiary Update to the Application on November 4, 2011, which reduced the rate increase sought to 1.5 percent in 2012 and a 6.5 percent increase in 2013;
- H. The 2011 Annual Review was held in Kelowna on November 22, 2011, to review the Company's performance for the 2011 year, followed by a Procedural Conference to hear submissions on procedural matters regarding the current Application;
- I. By Order G-199-11, the Commission approved a 1.5 percent interim rate increase for FortisBC, effective January 1, 2012;
- J. Pursuant to Order G-214-11, the Oral Public Hearing to review the Application took place between March 5 and March 9, 2012 in Kelowna;
- K. Between April 5 and April 23, 2012, FortisBC and Interveners filed their Final Submissions. FortisBC filed its Reply Submission on May 3, 2012;
- L. The Commission has considered the Application, the evidence and all the submissions as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

- 1. Pursuant to sections 59 to 61 of the *Act*:
 - a. The requested permanent rate increase of 1.5 percent in 2012 and 6.5 percent in 2013 is not approved, as filed.
 - b. Cross charges between FortisBC and its affiliates regulated by the Commission are approved to be based on fully loaded costs, not including overhead.
 - c. The proposed Deferral Account for Power Purchase Expense variances from forecast is approved and is to be amortized into rates in 2014. The proposed Revenue Variance Deferral Account is also approved and is to be amortized into rates in 2014.
 - d. Determinations for the new proposed Deferral Accounts and treatment for existing Deferral Accounts are set out in Section 5.4.4 of the Decision.
 - e. Costs of Removal of \$4.7 million for 2011, \$5.4 million for 2012 and \$4.0 million for 2013 are approved to be included in Rate Base as set out in Section 5.4.2 of the Decision.
- 2. Pursuant to section 44.2(3) of the *Act*, FortisBC's 2012-2013 Capital Expenditure Plan is approved subject to the determinations and reductions set out in Section 5.4.3 of the Decision.
- 3. The Commission Panel accepts FortisBC's Long Term Capital Plan is in the public interest and the Long Term Resource Plan meets the requirements of the *Act* except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.



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4. FortisBC is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 30 days of this Order.
5. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision. FortisBC is to provide all customers, by way of an information notice, of the change in rates.
6. If the 2012 permanent rates are less than the interim rates, FortisBC is to refund to customers the difference in revenue with interest at the average prime rate of the principal bank with which FortisBC conducts its business. If the 2012 permanent rates exceed the interim rates, FortisBC is to reflect this difference in customer rates over the balance of 2012.
7. FortisBC is directed to comply with all other directives in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of August 2012.

BY ORDER

Original signed by:

D.A.Cote
Commissioner

Sections 59 through 61 *Utilities Commission Act*

Discrimination in rates

59 (1) A public utility must not make, demand or receive

- (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
- (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

- (a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or
- (b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

- (a) whether a rate is unjust or unreasonable,
- (b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or
- (c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

- (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
- (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
- (c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

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Rate schedules to be filed with commission

- 61** (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.
- (2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.
- (3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.
- (4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.
- (5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,
- (a) on complaint of a person whose interests are affected, or
 - (b) on its own motion,
- direct an inquiry into the new schedule of rates having regard to the setting of a rate that is not unjust or unreasonable.
- (6) After an inquiry under subsection (5), the commission may
- (a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or
 - (b) confirm the increase or part of it.

Section 44.2 Utilities Commission Act

Expenditure schedule

44.2 (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:

- (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
- (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
- (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.

(2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless

- (a) the expenditure is the subject of a schedule filed and accepted under this section, or
- (b) the amendment or rescission is for the purpose of setting an interim rate.

(3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6), must

- (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
- (b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider

- (a) the applicable of British Columbia's energy objectives,
- (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- (c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
- (d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

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(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider and be guided by

(a) British Columbia's energy objectives,

(b) an applicable integrated resource plan approved under section 4 of the *Clean Energy Act*,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

Clean Energy Act – Section 2

British Columbia's energy objectives

2 The following comprise British Columbia's energy objectives:

- (a) to achieve electricity self-sufficiency;
- (b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;
- (c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
- (e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;
- (f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;
- (g) to reduce BC greenhouse gas emissions
 - (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
 - (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
 - (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
 - (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
 - (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;
- (h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
- (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

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(j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

(k) to encourage economic development and the creation and retention of jobs;

(l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

(m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

(o) to achieve British Columbia's energy objectives without the use of nuclear power;

(p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

APPENDIX D
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APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
G.A. MACINTOSH L. HERBST	FortisBC Inc.
C. WEAVER	British Columbia Municipal Electrical Utilities
R. HOBBS	Zellstoff Celgar Limited Partnership, Atco Wood Products Ltd., Kalisnikoff Lumber Company Ltd., Porcupine Wood Products, Springer Creek Forest Products, and International Forest Products Limited
S. KHAN	British Columbia Old Age Pensioners' Organization <i>et al.</i>
W. J. ANDREWS	B.C. Sustainable Energy Association, Sierra Club of Canada, British Columbia Chapter
A. WAIT	Self
N. GABANA	Self

LIST OF ACRONYMS

2012 LTRP	2012 Long Term Resource Plan
2012-13 CEP	2012-2013 Capital Expenditure Plan
AAM	automatic adjustment mechanism
AEUB	Alberta Energy and Utilities Board
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
Atco Electric	ATCO Electric Ltd.
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	The British Columbia Municipal Electrical Utilities
BCPSO	The British Columbia Pensioners' Organization <i>et al.</i>
BCSEA	The BC Sustainable Energy Association and the Sierra Club of British Columbia
BPPA	Brilliant Power Purchase Agreement
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union
CPA	Canal Plant Agreement
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
DSM	Demand-Side Management
EEC	Energy Efficiency and Conservation
FEU	FortisBC Energy Utilities (FortisBC Energy Inc.; FortisBC Energy (Vancouver Island) Inc.; FortisBC Energy (Whistler) Inc.)
FortisBC or the Company	FortisBC Inc.
FTE	Full Time Equivalent

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GCOC	Generic Cost of Capital
IBEW	International Brotherhood of Electrical Workers Union
IEP	Integrated Electricity Plan
IFRS	International Financial Reporting Standards
IR	Information Request
ISP	Integrated System Plan
LTCP	Long Term Capital Plan
LTRP	Long Term Resource Plan
M&E Plan	Monitoring and Evaluation Plan
MRS	Mandatory Reliability Standards
mTRC	Modified total resource cost
NSA	Negotiated Settlement Agreement
NSP	negotiated settlement process
O&M	operations and management
OTR	Okanagan Transmission Reinforcement Project
PBR	Performance Based Regulation
PLTs	Power Line Technicians
PPA	Power Purchase Agreement
PPA	Power Purchase Agreement
PPEVDA	Power Purchase Expense Variance Deferral Account
PPME	Power Purchase Management Expense
PRM	Planning Reserve Margin
ROE	return on equity
RS 3808 PPA	Rate Schedule 3808 Power Purchase Agreement

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SAIDI	System Average Interruption Duration
SAIFI	System Average Interruption Frequency
SCADA	Supervisory Control and Data Acquisition
SERP	Supplemental Employee Retirement Program
T&D	Transmission and Distribution
the Act	<i>Utilities Commission Act</i>
the Committee	Load Forecast Technical Committee
TRC	total resource cost
ULE	Upgrade and Life Extension
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAX CAPA	Waneta Expansion Project capacity purchase agreement
WECC	Western Electricity Coordinating Council

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

and

FortisBC Inc.
2012 – 2013 Revenue Requirements and
Review of 2012 Integrated System Plan Application

EXHIBIT LIST

Exhibit No.	Description
<i>COMMISSION DOCUMENTS</i>	
A-1	Letter dated June 30, 2011 and Order G-111-11 – Establishing an Initial Regulatory Timetable and Procedural Conference
A-2	Letter dated July 19, 2011 – Commission Appointment of Panel
A-3	Letter dated August 10, 2011 – Commission Information Request No. 1
A-4	Letter dated August 24, 2011 – Letter L-65-11 issuing Revised Initial Regulatory Timetable
A-5	Letter dated September 30, 2011 – Commission Information Request No. 2
A-6	CONFIDENTIAL Letter dated September 30, 2011 – CONFIDENTIAL Commission Information Request No. 2
A-7	Letter dated October 4, 2011 – Order G-167-11 and Revised Preliminary Regulatory Timetable
A-8	Letter dated October 7, 2010 – Commission Information Request No. 1 on Exhibit B-7
A-9	Letter dated November 2, 2011 – Notice of 2011 Annual Review and Procedural Conference
A-10	Letter dated November 10, 2011 – Commission Information Request No. 1 to BCSEA et al on Intervener Evidence
A-11	Letter dated November 10, 2011 – Procedural Conference Agenda
A-12	Letter dated November 18, 2011 – Letter to Participants Zellstoff/Celgar

Exhibit No.	Description
A-13	Letter dated November 30, 2011 – Order G-199-11 issuing Amended Regulatory Timetable with Reasons
A-14	Letter dated December 15, 2011 – Order G-214-11 issuing Amended Regulatory Timetable
A-15	Letter dated February 10, 2012 - Panel Letter to FBC
A-16	Letter dated February 10, 2012 – Oral Public Hearing Information
A-17	Letter dated March 23, 2012 – Request for Comments on FortisBC’s Testimony Clarification
A-18	Letter dated April 19, 2012 – Response to FortisBC request for Filing Extension
A2-1	Submitted at Oral Hearing March 5, 2012 – Commission Staff Filing EXTRACT FROM "REPORT 8: OCTOBER 2011; BC HYDRO: THE EFFECTS OF RATE-REGULATED ACCOUNTING...OFFICE OF THE AUDITOR GENERAL OF BRITISH COLUMBIA"
A2-2	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXECUTIVE SUMMARY FROM 1994 BC GAS PHASE 1 REVENUE REQUIREMENT APPLICATION
A2-3	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM BC GAS UTILITY LIMITED 2003 REVENUE REQUIREMENTS APPLICATION DECISION DATED FEBRUARY 4, 2003
A2-4	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE BC GAS UTILITY LIMITED MULTI-YEAR PERFORMANCE-BASED RATE PLAN FOR 2004/2008 APPLICATION
A2-5	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE FORTISBC ENERGY UTILITIES 2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION, EXHIBIT B-1
A2-6	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing DOCUMENT ENTITLED "BCUC STAFF WITNESS AID - SERP..."
A2-7	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing ORDER G-64-07 AND AN EXTRACT FROM THE ACCOMPANYING DECISION

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Exhibit No.	Description
A2-8	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing COMMISSION DECISION DATED APRIL 3, 1992 ON A RATE APPLICATION OF PACIFIC NORTHERN GAS LIMITED
A2-9	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM THE DECISION OF THE ALBERTA ENERGY UTILITY BOARD IN THE MATTER OF ATCO ELECTRIC LIMITED 2005/2006 GENERAL TARIFF APPLICATION DATED MARCH 17, 2006
A2-10	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, CHAPTER 2 OF THE FILING REQUIREMENTS FOR TRANSMISSION AND DISTRIBUTION APPLICATIONS, JUNE 22, 2011
A2-11	Submitted at Oral Hearing March 6, 2012 – Commission Staff Filing EXTRACT FROM ONTARIO ENERGY BOARD, RP-2004-0188, 2006 ELECTRICITY DISTRIBUTION RATE HANDBOOK, REPORT OF THE BOARD, 2005 MAY 11
A2-12	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "BCUC STAFF WITNESS AID: FINANCING COSTS, FORTISBC 2012-2013 RRA & ISP"
A2-13	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing "WITNESS AID - DEFERRAL ACCOUNTS"
A2-14	Submitted at Oral Hearing March 7, 2012 – Commission Staff Filing EXTRACT FROM BCUC DECISION "BRITISH COLUMBIA HYDRO AND POWER AUTHORITY AND F2009 AND F2010 REVENUE REQUIREMENTS DECISION, MARCH 13, 2009"
A2-15	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing STAFF "WITNESS AID, FORTISBC, DSM PANEL"
A2-16	Submitted at Oral Hearing March 8, 2012 – Commission Staff Filing LETTER FROM FORTISBC DATED SEPTEMBER 29, 2011, WITH ATTACHED EXCERPT OF "FORTISBC INC., SEMIANNUAL DSM REPORT, SIX MONTHS ENDED JUNE 30, 2011
A2-17	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing FORTISBC F2012-2013 RRA & ISP WITNESS AID - CAPITAL EXPENDITURES PLAN
A2-18	Submitted at Oral Hearing March 9, 2012 – Commission Staff Filing EXCERPT FROM BCUC "FORTISBC INC. 2011 CAPITAL EXPENDITURE PLAN DECISION", DATED DECEMBER 17, 2010

Exhibit No.	Description
<i>APPLICANT DOCUMENTS FORTISBC INC</i>	
B-1	FORTISBC INC. (FBC) Letter dated June 30, 2011 – 2012/13 Revenue Requirements and Review of 2012 Integrated System Plan Application
B-1-1	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 1
B-1-2	Letter dated June 30, 2011 – FBC Submitting 2012 Integrated System Plan Volume 2
B-1-3	CONFIDENTIAL Letter dated June 30, 2011 – FBC Submitting Confidential Page 34 of Tab 4, Section 4.3.2.1 of the Application
B-1-4	Letter dated July 11, 2011 – FBC Submitting Addendum to Tab 7 (Financial Schedules) of the Application
B-1-5	Letter dated July 21, 2011 – FBC Submitting Errata 1 to the Application
B-1-6	Letter dated September 9, 2011 – FBC Errata 2 to Application
B-2	Letter dated July 22, 2011 – FBC Presentation submitted at July 22, 2011 Workshop
B-3	Letter dated July 25, 2011 – FBC Submitting Adoption of US Generally Accepted Accounting Principles and 2012/ 2012 Revenue Requirements Application Compliance Filing Order G-117-11
B-4	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from BCUC
B-5	Letter dated September 9, 2011 - FBC Responses to IR No. 1 from Interveners BCOAPO, BCSE, Celgar, and Alan Wait
B-6	Letter dated September 16, 2011 – FBC Submitting comments regarding Material Updates to the Application
B-7	Letter dated September 16, 2011 – FBC Submitting responses to BCUC and BCOAPO System Losses Information Requests
B-8	Letter dated October 21, 2011 - FBC Submitting Responses to BCUC IR2
B-8-1	CONFIDENTIAL Letter dated October 21, 2011 - FBC Submitting Responses to BCUC CONFIDENTIAL IR2
B-8-2	Letter dated March 2, 2012 - FBC Submitting Errata to its Responses to Information Request No. 2 - Replacement pages

Exhibit No.	Description
B-9	Letter dated October 21, 2011 - FBC Submitting Responses to Intervener IR2
B-10	Letter dated October 21, 2011 - FBC Submitting Responses to FortisBC Responses to BCUC IR2 (Losses)
B-11	Letter dated October 21, 2011 - FBC Submitting Errata 3 to Application and IR1 Responses
B-12	Letter dated November 4, 2011 - FBC Submitting Evidentiary Update
B-13	Letter dated November 10, 2011 - FBC Submitting IR No. 1 to BCSEA
B-14	Letter dated November 17, 2011 - FBC Submitting comments on Reconsider Application of Order E-29-10 Exhibit C9-4
B-15	Letter dated November 22, 2011 - FBC Submitting Presentations from 2011 Annual Review
B-16	Letter dated November 25, 2011 - FBC Submitting Load Forecast Technical Committee Report
B-17	Letter dated December 7, 2011 – FBC Submitting Request for Amendment to Timetable
B-18	Letter dated February 1, 2012 – FBC Submitting Witnesses Anticipated Testimony
B-19	Letter dated March 1, 2012 - FBC Submitting Opening Statement
B-20	Letter dated March 2, 2012 - FBC Submitting Witness Panel
B-21	Letter dated March 2, 2012 - FBC Submitting Opening Statement of John Walker
B-22	Submitted at Oral Hearing March 7, 2012 – FBC Submitting DOCUMENT HEADED "2005 REVENUE REQUIREMENTS - REGULATORY POLICY/PERFORMANCE STANDARDS - TAB 10"
B-23	Submitted at Oral Hearing March 7, 2012 – FBC Submitting "FORTISBC 2012-2013 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-24	Submitted at Oral Hearing March 8, 2012 – EXTRACT FROM "IMPLEMENTING ENERGY EFFICIENCY: PROGRAM DELIVERY COMPARISON STUDY", IEE WHITEPAPER, MARCH 2010

Exhibit No.	Description
B-25	Submitted at Oral Hearing March 8, 2012 – FORTISBC 2012-13 REVENUE REQUIREMENTS APPLICATION, ORAL HEARING UNDERTAKINGS FROM MARCH 6, 2012"
B-26	Letter dated March 16, 2012 - FBC Submitting Clarifications to testimony at the 2012-13 RRA and ISP Oral Hearing
B-27	Letter dated March 16, 2012 - FBC Submitting Oral Hearing Undertakings
B-28	Letter dated March 23, 2012 - FBC Submitting Oral Hearing Undertaking 51
B-29	Letter dated March 30, 2012 - FBC Submitting Oral Hearing Undertaking 32
B-30	Letter dated April 3, 2012 – FBC Submitting Undertaking 50
B-31	Letter dated April 19, 2012 – FBC Request for Filing Extension

INTERVENER DOCUMENTS

C1-1	BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU) Online Registration dated July 5, 2011 – Request for Intervener Status by Heather Grant
C1-2	Letter dated July 11, 2011 – Notice of Mr. C. Weafer, Owen Bird as counsel for BCMEU
C1-3	Letter dated August 10, 2011 – BCMEU Information Request No. 1
C1-4	Letter dated September 30, 2011 – BCMEU Information Request No. 2
C1-5	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing REVIEW OF BC HYDRO, JUNE 2011
C1-6	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing NEWS RELEASE FROM OFFICE OF THE PREMIER, MINISTRY OF ENERGY AND MINES, "CANADA STARTS HERE - THE BC JOBS PLAN", DATED FEBRUARY 3, 2012"
C1-7	Submitted at Oral Hearing March 5, 2012 – BCMEU Filing "FORTIS GROUP OF COMPANIES OF BC COMMUNICATIONS & PUBLIC AFFAIRS PLAN 2010/2011, 25 AUGUST 2010"
C1-8	Letter dated April 19, 2012 – BCMEU Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension

Exhibit No.	Description
C2-1	BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCHYDRO) Online Registration dated July 5, 2011 – Request for Intervener Status by Janet Fraser
C3-1	WAIT, ALAN (WA) – Online Registration dated July 6, 2011 – Request for Intervener Status
C3-2	Letter dated August 10, 2011 – WA Information Request No. 1
C4-1	GABANA, NORMAN (GN) – Email dated July 7, 2011 Request for Intervener Status
C4-2	Letter dated September 23, 2011 Via Email – GN Information Request No. 2
C4-3	Letter dated November 22, 2011 – GN comments regarding Order E-29-10 review
C5-1	BRITISH COLUMBIA OLD AGE PENSIONERS’ ORGANIZATION ET AL. (BCOAPO) – Letter dated July 8, 2011 requesting Intervener Status by Ros Salvador
C5-2	Letter dated August 10, 2011 – BCOAPO Information Request No. 1
C5-3	Letter dated September 30, 2011 – BCOAPO Information Request No. 2
C5-4	Letter dated November 10, 2011 – BCOAPO Information Request No. 1 to BCSEA et al on Intervener Evidence
C5-5	Letter dated November 18, 2011 – BCOAPO Submitting change of counsel request
C5-6	Letter dated November 21, 2011 – BCOAPO Submitting clarification on counsel details
C5-7	Letter dated April 19, 2012 – BCOAPO Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C6-1	BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB OF BRITISH COLUMBIA (BCSEA ET AL.) – Letter dated July 14, 2011 - Requesting Intervener Status by William J. Andrews
C6-2	Letter dated August 10, 2011 – BCSEA Information Request No. 1
C6-3	Letter dated September 30, 2011 – BCSEA Information Request No. 2
C6-4	Letter dated October 31, 2011 - BCSEA Submitting Evidence
C6-5	Letter dated November 24, 2011 - BCSEA Submitting Response to BCUC IR No. 1

Exhibit No.	Description
C6-5-1	Letter dated November 24, 2011 - BCSEA Submitting Errata
C6-6	Letter dated November 24, 2011 - BCSEA Submitting Response to FBC IR No. 1
C6-7	Letter dated November 24, 2011 - BCSEA Submitting Response to BCOAPO IR No. 1
C6-8	Letter dated February 20, 2012 – BCSEA Submitting Witness Panel Notification
C6-9	Submitted at Oral Hearing March 7, 2012 – BCSEA Submitting COPY OF UTILITIES COMMISSION ACT, DEMAND-SIDE MEASURES REGULATION
C6-10	Submitted at Oral Hearing March 8, 2012 – BCSEA Submitting "A STATISTICAL MODEL FOR PREDICTING FUTURE ELECTRIC ENERGY EFFICIENCY RESOURCES CLASSES (DRAFT)", MARCH 6, 2012
C6-11	Letter dated April 19, 2012 – BCSEA Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C7-1	REGIONAL DISTRICT OF OKANAGAN SIMILKAMEEN (RDOS) – Online Registration dated July 15, 2011 – Requesting Intervener Status by Doug French
C8-1	SLACK, BURL – Facsimile Registration dated July 15, 2011 – Requesting Intervener Status
C8-2	Letter dated November 10, 2011 by Fax – SB submitting comments
C9-1	ZELLSTOFF CELGAR, ATCO WOOD PRODUCTS LTD., INTERNATIONAL FOREST PRODUCTS LIMITED (INTERFOR), KALESNIKOFF LUMBER CO. LTD., PORCUPINE WOOD PRODUCTS, AND SPRINGER CREEK FOREST PRODUCTS COLLECTIVELY, THE INDUSTRIAL CUSTOMERS GROUP (ICG) – Letter dated July 20, 2011 requesting Intervener Status by Adrian Hay, Brian Merwin and Robert Hobbs
C9-2	Letter dated August 10, 2011 – Celgar Information Request No. 1
C9-3	Letter dated September 30, 2011 – Celgar Information Request No. 2
C9-4	Letter dated November 10, 2011 – Celgar Submitting comments regarding WAX CAPA
C9-5	Letter dated November 28, 2011 – Celgar Submitting additional Interveners Atco Wood Products Ltd., International Forest Products Limited (Interfor), Kalesnikoff Lumber Co. Ltd., Porcupine Wood Products, and Springer Creek Forest Products collectively, the Industrial Customers Group (ICG)

Exhibit No.	Description
C9-6	Letter dated November 25, 2011 – Celgar / ICG Submitting reply and comments
C9-7	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT "APPENDIX 1 TO ORDER NO. G-10-03, PAGE 7 OF 25"
C9-8	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM "FORTISALBERTA IN 2010/2011 TARIFF APPLICATION", PAGES 2-27 AND 2-28
C9-9	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 03, NO. 02-APRIL 2010, SETTLEMENT SUMMARIES (FEBRUARY 2010 TO APRIL 2010)"
C9-10	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing EXCERPT FROM DOCUMENT "BUDGET AND FISCAL PLAN, 2012/13 - 2014/15"
C9-11	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 02, NO. 10 - OCTOBER 2009, SETTLEMENT SUMMARIES (AUGUST TO OCTOBER 2009)"
C9-12	Submitted at Oral Hearing March 5, 2012 – Celgar / ICG Filing DOCUMENT HEADED "BC BARGAINING DATABASE, VOL. 01, NO. 3 - JULY 2008, SETTLEMENT SUMMARIES (APRIL 2008 TO JUNE 2008)"
C9-13	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "BC BARGAINING DATABASE, VOL. 05 NO. 01 - JANUARY 2012" QUARTERLY WAGE SETTLEMENTS IN BC (2005-2011)
C9-14	Submitted at Oral Hearing March 6, 2012 – Celgar / ICG Filing "F2012 TO F2014 REVENUE REQUIREMENTS APPLICATION, BC HYDRO, APPENSIC C-2, ORDER IN COUNCIL NO. 021, HERITAGE SPECIAL DIRECTION NO. HC2"
C9-15	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INITIATIVES FOR INDUSTRIAL CUSTOMERS - PROJECT INCENTIVES TRANSMISSION"
C9-16	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLAN - MEETING #2, JANUARY 27 & 28, 2011"
C9-17	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing EXCERPT FROM "NERC...2010 LONG-TERM RELIABILITY ASSESSMENT, OCTOBER 2010"
C9-18	Submitted at Oral Hearing March 7, 2012 – Celgar / ICG Filing "NERC...2011 LONG-TERM RELIABILITY ASSESSMENT, NOVEMBER 2011"

Exhibit No.	Description
C9-19	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing FERC "WINTER 2011-12 ENERGY MARKET ASSESSMENT...OCTOBER 20, 2011"
C9-20	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing DOCUMENT HEADED "PLANNING RESERVE MARGIN, PAGE 1 OF 1"
C9-21	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "2005 REVENUE REQUIREMENTS, FORECASTS - POWER PURCHASE & WHEELING - TAB 7...NOVEMBER 26, 2004", PAGES 19, 20 AND 21
C9-22	Submitted at Oral Hearing March 8, 2012 – Celgar / ICG Filing "INTEGRATED RESOURCE PLANT, MEETING #2, JANUARY 27 & 28, 2011, 2011 IRP TECHNICAL ADVISORY COMMITTEE SUMMARY BRIEF"
C9-23	Letter dated April 19, 2012 – Celgar / ICG Filing Submitting comments regarding Exhibit B-31 FBC Request for Filing Extension
C10-1	IRRIGATION RATEPAYERS GROUP (IRG) – Letter dated July 20, 2011 requesting Intervener Status by Fred Weisberg
C11-1	CITY OF TRAIL (CT) – Letter dated July 20, 2011 requesting Intervener Status by Carolyn MacEachern
C11-2	Letter dated November 4, 2011 withdrawing Intervention

INTERESTED PARTY DOCUMENTS

D-1	ACTIVE RENEWABLE (BC) – Online Registration dated July 17, 2011 – Request for Interested Party Status by Bill Daly
D-2	POWELL, JOHN O. – Email Registration dated July 14, 2011 – Request for Interested Party Status
D-3	KAROW, HANS (CORE) – Email Registration dated November 22, 2011 – Request for Interested Party Status
D-4	CITY OF PENTICTON (CP) Letter dated December 21, 2011 – Submitting Letter of Comment
D-5	FLYNN, JERRY Online Registration dated January 5, 2011 – Request for Interested Party Status by Jerry Flynn

APPENDIX F
Page 11 of 11

Exhibit No.	Description
D-5-1	January 25, 2010 - Registration of Interested Party Status withdrawn

LETTERS OF COMMENT

E-1	KRISTIAN, BEN – Letter of Comment dated July 20, 2011
-----	--

1 **REFERENCE:** July 13, 2018 Undertaking 38 pdf page 51-52, BCUC Decision G-
2 110-12 (page 23, pdf page 30)

3
4 **QUOTE:** PPEVDA: includes 100% deferral of power purchase expense
5 variances during the test years...

6
7 a. Load variances due to variances in customer growth, usage, or
8 weather; (Undertaking 38)

9
10 ...FBC revenue variances due to load are also flowed 100% through to
11 ratepayers... (BCUC Decision G-110-12)

12
13 **QUESTION:**

14
15 a) The YEC undertaking notes that FBC's PPEVDA covers load variances. Further
16 examination of BCUC G-110-12 shows that the load forecast process for FBC
17 differs from the load forecasting method of YEC in that forecast input is provided
18 by parties outside of FBC. Please confirm that the FBC load forecast is reviewed
19 by a technical committee, including FBC staff, BCUC staff, BC hydro staff and
20 interveners.

21
22 **ANSWER:**

23
24 **(a)**

25
26 As noted in page 23 of Order G-110-12, with regard to the 2012/13 Revenue Requirement
27 and the review of its 2012 Integrated System Plan, FortisBC prepared a load forecast
28 which was reviewed by the Load Forecast Technical Committee (the Committee).

29
30 The Committee was established at FortisBC's request by Order G-111-11 [this Order is
31 provided as Attachment 1 to this response]¹. Members of the Committee included
32 representatives of FortisBC, BCUC staff, BCMEU, BC Hydro, and BCPSO and Ms. Buryl
33 Slack Goodman.

¹ Order G-111-11 notes FortisBC proposed that its Load Forecast be reviewed by a Load Forecast Technical Committee to be made up of FortisBC, interested Interveners and Commission Staff, and that the Load Forecast be exempt from the Information Request process. Per the Order FortisBC would submit a report outlining the Load Forecast Technical Committee's review and recommendations in the proceeding.

- 1 • Per Order G-111-11, FortisBC proposed that its Load Forecast be reviewed by a
2 Load Forecast Technical Committee made up of FortisBC, interested Interveners
3 and Commission Staff, and that the Load Forecast be exempt from the Information
4 Request process.
5
6 • Per Order G-111-11, FortisBC was directed to submit a report outlining the Load
7 Forecast Technical Committee's review and recommendations as part of the
8 proceeding [this was provided as Exhibit 16 in the review process].
9

10 The scope of the Committee's review was to examine the Company's load forecast and
11 methodologies associated with the 2012 and 2013 Revenue Requirements and the 2012
12 Integrated System Plan. This review did not include the forecast of DSM savings or
13 savings from rate structures, or the estimate of System Losses.²
14

15 While it is clear that the load forecast submitted as part of FortisBC's 2012/13 Revenue
16 Requirement and 2012 Integrated System Plan review was reviewed by the Committee, it
17 is not clear that each FortisBC load forecast is reviewed by a technical committee.
18 Subsequent filings by FortisBC refer back to the 2011 review process and indicate the
19 methods are consistent with methods accepted by the Load Forecast Technical
20 Committee in 2011.³

² 2012 – 2013 Revenue Requirements and 2012 Integrated System Plan Load Forecast Technical Committee Report.

³ For example, BCUC Order G-139-14 (YUB-YEC-3-3 Attachment 1, page 180) notes that a report was filed by the LFTC which outlined the methodology to be undertaken by FBC in developing its 2014 Load Forecast. Also see Order G-38-18 regarding FortisBC's Annual Review for 2018 rates which notes, "FBC states that its load forecast methods are consistent with those used in prior years and accepted by the Load Forecast Technical Committee in 2011."



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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER G-111-11**

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

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

and

an Application by FortisBC Inc.
for Approval of 2012 – 2013 Revenue Requirements and
Review of 2012 Integrated System Plan

BEFORE: A.A. Rhodes, Commissioner

June 30, 2011

O R D E R

WHEREAS:

- A. On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed an application pursuant to sections 44.1, 56 and 59 to 61 of the *Utilities Commission Act* (the *Act*) for approval of its 2012 – 2013 Revenue Requirements and the review of its 2012 Integrated System Plan (collectively referred to as the Application);
- B. The Application contains 2 parts:
 - 1) FortisBC's 2012 – 2013 Revenue Requirements (including the Company's 2012 – 2013 Capital Expenditure Plan filed pursuant to section 44.2(1) of the *Act*),
 - 2) FortisBC's 2012 Integrated System Plan filed pursuant to section 44.1 of the *Act*, comprising its 2012 Long Term Capital Expenditure Plan, its 2012 Resource Plan, and its 2012 Long Term Demand Side Management Plan;
- C. FortisBC seeks, among other things, approval of interim and permanent rate increases of 4.0 percent effective January 1, 2012, with any difference between interim and permanent rates to be refunded to or collected from customers by way of a general rate adjustment between the effective date of the permanent rates and December 31, 2012. FortisBC also seeks a permanent rate increase of 6.9 percent effective January 1, 2013;
- D. The Company requests a determination from the British Columbia Utilities Commission (the Commission) on whether the 2012 – 2013 Capital Expenditure Plan is in the public interest pursuant to section 44.2 (3) (a) and satisfies the requirements of section 45(6) of the *Act*. A list of capital projects is contained in the Application in Tables 2.0, 3.0, 4.0, 5.0, 6.0 and 7.0 of the 2012 – 2013 Capital Plan;
- E. The Company also requests a Commission determination on whether the 2012 Integrated System Plan is in the public interest pursuant to section 44.1 (6);
- F. FortisBC proposes a Workshop to review the Application on Friday, July 22, 2011, commencing at 9:00 a.m., at the Holiday Inn Express, 2429 N. Highway 97, Kelowna, BC;

**BRITISH COLUMBIA
UTILITIES COMMISSION**

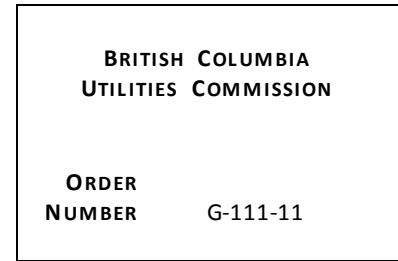
**ORDER
NUMBER G-111-11**

2

- G. FortisBC proposes that the Application proceed through a negotiated settlement process, or alternatively, by way of a written hearing process including two rounds of Commission and Intervener Information Requests to be followed by a Procedural Conference on Wednesday, October 26, 2011, commencing at 9:00 a.m., in Kelowna, BC, at a location to be determined;
- H. The Company proposes that its Load Forecast be reviewed by a Load Forecast Technical Committee to be made up of FortisBC, interested Interveners and Commission Staff, and that the Load Forecast be exempt from the Information Request process. FortisBC states that a report outlining the Technical Committee's review and recommendations will be submitted as evidence in the proceeding;
- I. According to the terms of the Company's Performance-Based Regulation Plan for 2011, an Annual Review is required to assess the Company's forecast 2011 financial results and non-financial performance. FortisBC proposes to hold the 2011 Annual Review in Kelowna on Tuesday, October 25, 2011;
- J. The Commission has reviewed FortisBC's proposed regulatory timetable and considers that an initial regulatory timetable should be established.

NOW THEREFORE the Commission orders as follows:

1. The Application will proceed according to the Initial Regulatory Timetable, attached as Appendix A to this Order.
2. FortisBC will hold a Workshop to review the Application on Friday, July 22, 2011, commencing at 9:00 a.m., at the Holiday Inn Express, 2429 N. Highway 97, Kelowna, BC.
3. The Company's Load Forecast will not be subject to the initial Information Requests process and will instead be reviewed by a Load Forecast Technical Committee to be established following the Workshop. FortisBC will submit a report outlining the Load Forecast Technical Committee's review and recommendations in this proceeding.
4. The Company's 2011 Annual Review will be held in Kelowna, at a date and location to be determined.
5. A Procedural Conference will be held on a date and at a location to be determined, in Kelowna, BC. The Procedural Conference will address matters such as:
 - a. Process options for review of the Application, including:
 - Negotiated settlement process
 - Written hearing
 - Oral public hearing
 - Or, as appropriate, some combination of processes;
 - b. Timetable (further information requests, intervener evidence, etc.);
 - c. Interim rates;
 - d. Location(s) of the proceedings;
 - e. Other matters that will assist in the efficient review of the Application.



3

6. FortisBC is to provide a copy of this Commission Order and the Initial Regulatory Timetable attached as Appendix A to this Order to all parties who registered and/or participated in the 2011 Revenue Requirements Application and the 2011 Capital Expenditure Plan proceedings.
7. FortisBC will publish the Notice of Application and Workshop, attached as Appendix B to this Order, in local news publications in the FortisBC service area, as soon as possible. Publication will be in display-ad format.
8. The Application, together with any supporting materials, will be made available for inspection at the following locations:

FortisBC Inc. Suite 100 - 1975 Springfield Road Kelowna, BC V1Y 7V7 Telephone: 1-866-436-7847	BC Utilities Commission Sixth Floor, 900 Howe Street Vancouver, BC V6Z 2N3 Telephone: 604-660-4700
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FortisBC will make available the Application available on its website at <http://www.fortisbc.com>.

9. Those who wish to participate in the FortisBC Application proceeding as Interveners or Interested Parties should register with the Commission, via written or electronic submission, by Wednesday, July 20, 2011. Interveners should provide the following information: the nature of their interest in the Application, the nature of the issues they intend to pursue during the proceeding, the nature and extent of their anticipated involvement in the review, including whether they expect to file written evidence as part of the hearing.
10. Interveners intending to apply for Participant Assistance/Cost Awards (PACA) must submit a budget estimate by Monday, August 22, 2011. These applications should be consistent with the Commission's PACA Guidelines outlined in Order G-72-07. Copies of the Guidelines are available upon request or can be downloaded from the Commission's web site at http://www.bcuc.com/Documents/Guidelines/2010/DOC_5014_G-72-07_PACA_2007_Guidelines.pdf.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of June 2011.

BY ORDER

Original signed by:

A. Rhodes
Commissioner

Attachments

An Application by FortisBC Inc.
 for Approval of 2012 – 2013 Revenue Requirements and
 Review of 2012 Integrated System Plan

INITIAL REGULATORY TIMETABLE

ACTION	DATE (2011)
Registration Deadline for Interveners and Interested Parties	Wednesday, July 20
Workshop	Friday, July 22
Commission and Intervener Information Requests (IR) No. 1 to FortisBC	Wednesday, August 10
Participant Assistance Budget Submission	Wednesday, August 31
FortisBC Response to Commission and Intervener IR No. 1	Friday, September 9
BCUC and Intervener IR No. 2 to FortisBC	Friday, September 30
FortisBC Response to Commission and Intervener IR No. 2	Friday, October 21
2011 Annual Review	To be Determined
Procedural Conference	To be Determined
Load Forecast Technical Committee Report filed	Friday, October 28
Procedural Order and Approval of Interim Rates Effective January 1, 2012	Tuesday, November 1



APPENDIX B
to Order G-111-11
Page 1 of 2

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An Application by FortisBC Inc.
for Approval of 2012 – 2013 Revenue Requirements and
Review of 2012 Integrated System Plan

NOTICE OF APPLICATION AND WORKSHOP

Date:	Friday, July 22, 2011
Time:	9:00 a.m.
Location:	Holiday Inn Express 2429 N. Highway 97 Kelowna, BC

THE APPLICATION

On June 30, 2011, FortisBC Inc. (FortisBC or the Company) filed its 2012 – 2013 Revenue Requirements, which includes the 2012 -2013 Capital Expenditure Plan, and its 2012 Integrated System Plan (collectively, the Application) with the British Columbia Utilities Commission (Commission).

The Company is seeking approval, among other things, of rate increases of 4.0 percent effective January 1, 2012, and 6.9 percent effective January 1, 2013. The Company states that the rate increases are required due to the need for ongoing investment in electrical infrastructure and increasing power purchases driven by customer growth. The Application outlines capital expenditures of \$106 million in 2012 and \$129 million in 2013.

The 2012 Integrated System Plan outlines FortisBC's medium term and long term strategies for meeting its customers' energy needs. The Integrated System Plan includes:

- 2012 Long Term Capital Expenditure Plan, outlining expected capital projects to sustain and upgrade the Company's generation, transmission, distribution, and other assets;
- 2012 Resource Plan, which examines FortisBC's electricity requirements and the potential generation resource options available to meet these forecast requirements;
- 2012 Long Term Demand Side Management Plan, which describes the Company's plans to offset future load growth through energy efficiency and conservation measures.

THE REGULATORY PROCESS

The Commission has issued an Initial Regulatory Timetable for a public review of the Application. A Workshop will be held at the Holiday Inn Express, in the City of Kelowna, in the morning of Friday, July 22, 2011 to review the Application.

PUBLIC INSPECTION OF THE APPLICATION

The Application is available for inspection at the following locations:

FortisBC Inc. Suite 100 - 1975 Springfield Road Kelowna, BC V1Y 7V7 Telephone: 1-866-436-7847	BC Utilities Commission Sixth Floor, 900 Howe Street Vancouver, BC V6Z 2N3 Telephone: 604-660-4700
---	--

The Application is also available for viewing on the following websites:

<http://www.fortisbc.com>

<http://www.bcuc.com>

REGISTERING TO PARTICIPATE

Persons who expect to actively participate in the review process or processes should register as Interveners with the Commission. Interveners will receive copies of the Application, all correspondence and filed documents. Those not expecting to actively participate should register with the Commission as Interested Parties and will receive a copy of the Application's summary and the Commission's Decision when issued.

Interveners and Interested Parties should inform the Commission Secretary, in writing, by Wednesday, July 20, 2011 of their intention to become Interveners or Interested Parties, and their intention to attend the Workshop.

All submissions and/or correspondence received from active participants or the public relating to the Application will be placed on the public record and posted to the Commission's website.

PARTICIPANT ASSISTANCE/COST AWARDS

Any party intending to apply for a Participant Assistance/Cost Award is advised to review the Commission's Guidelines with respect to the requirements for eligibility. The Participant Assistance/Cost Award Guidelines may be obtained by writing to the Commission Secretary, or online at http://www.bcuc.com/Documents/Guidelines/2010/DOC_5014_G-72-07_PACA_2007_Guidelines.pdf

FURTHER INFORMATION

For further information, please contact Ms. Alanna Gillis, Acting Commission Secretary as follows:

Telephone: (604) 660-4700 Facsimile: (604) 660-1102	Email: Commission.Secretary@bcuc.com BC Toll Free: 1-800-663-1385
--	--

1 **REFERENCE: Undertaking 38 pdf page 51**

2

3 **QUOTE:** PPEVDA: includes 100% deferral of power purchase expense
4 variances during the test years

5

6 **QUESTION:**

7

8 a) Does the deferral account operate in non-test years? If so, please provide the
9 source for your confirmation.

10

11 **ANSWER:**

12

13 **(a)**

14

15 The relevant flow through provisions of power purchase expense variances continue to
16 operate in non-test years.

17

18 Review of FortisBC's [FBC's] Application¹ and Order G-110-12² indicates that the intent
19 for the 2012/13 application was to defer amounts during the test period and apply deferred
20 amounts to rates in 2014. Thereafter each year's Power Purchase Deferral Account
21 balance would be flowed through into rates completely in the subsequent year.

22

23 Subsequent to the 2012/13 test period, FBC filed an application for rates pursuant to a
24 performance based regulation (PBR) plan. While FBC sought continuance of the

¹ The 2012/13 Revenue Requirements Application, Tab 4 Cost of Service notes at page 24:

As this Application requests firm rates to be set for 2012 and 2013, the Company proposes that the variance accumulated in the Power Purchase Expense deferral account be applied to rates in 2014. Thereafter it is expected that each year's Power Purchase Deferral Account balance would be flowed through completely in the subsequent year. This flow through mechanism would ensure that customers only pay for the actual amount of power purchased.

² Order G-110-12 (see YUB-YEC-3-1 Attachment 1, page 34 of BCUC Order) notes as follows regarding the establishment of the PPEVDA:

The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods.

1 PPEVDA, the BCUC ordered that the PPEVDA be discontinued. However, pursuant to
2 BCUC direction, variances in forecast cost items previously addressed by the PPEVDA
3 continue to be flowed through to ratepayers annually. Further detail is noted below.

4
5 The FortisBC Multi-Year Performance Based Ratemaking Plan for 2014 through
6 2018 filing proposed the continuation of the Power Purchase Expense Variance
7 deferral account and its Revenue Variance deferral account approved pursuant to Order
8 G-110-12.

- 9
10 • FBC noted that any variances between actual and forecast sales revenue would
11 accrue to the Revenue Variance deferral account with the majority of variances
12 attributable to weather related to load variances, customer usage rates and
13 customer count.
14
15 • Both the Power Purchase Expense Variance deferral account and the Revenue
16 Variance deferral account would have one-year amortization periods.

17
18 The BCUC in its Decision G-139-14 dated September 15, 2014 directed FBC to
19 discontinue the Power Purchase Expense deferral account and its related Revenue
20 Variance deferral account during the PBR term, noting that these expenses and revenues
21 would be flowed through to ratepayers each year through the annual flow-through
22 mechanism. Decision G-139-14 is provided as Attachment 1 to this response.

23
24 Decision G-139-14 [see Attachment 1 to this response] notes as follows:³

25
26 In keeping with the Panel's discussions and determinations for FBC's Flow-
27 Through Items (Section 2.2.5.1 of this Decision), the Panel is not persuaded that
28 continuation of the Power Purchase Expense Variance and Revenue Variance
29 deferral accounts are necessary in order to allow for the flow through of these
30 expenditures and revenues during the PBR. This is particularly relevant given the
31 fact that these deferral accounts only have one-year amortization periods and thus
32 are not being utilized for rate smoothing purposes. Accordingly, the Panel directs
33 FBC to discontinue the Power Purchase Expense deferral account and its related
34 Revenue Variance deferral account during the PBR term. These expenses and

³ Page 228 and 229.

1 revenues shall be flowed through to ratepayers each year through the annual flow-
2 through mechanism.

3

4 In its Compliance Filing, FBC is directed to provide its 2013 ending balances in
5 these deferral accounts and illustrate the rate impact of flowing through these
6 variances to 2014 rates. Variances between FBC's forecast and actual results in
7 2014 and beyond shall to be flowed through to ratepayers annually.

8

9 The following is noted in the FortisBC Inc. Annual Review for 2018 Rates [please see
10 YUB-YEC-3-3 Attachment 2]:⁴

11

12 FBC's forecast of power purchase expense is based on FBC's firm resources in
13 place at the time of filing and is consistent with the 2017/18 AECF. FBC will
14 continue to work toward optimizing its power purchase portfolio. Any variances in
15 the costs of power supply, including any power purchase expense decrease due
16 to further portfolio optimization, are recorded in the Flow-through deferral account
17 and returned to or recovered from customers in the subsequent year.

18

19 Therefore, FBC continues to be protected from this risk through this automatic adjustment.

⁴ http://www.bcuc.com/Documents/Proceedings/2017/DOC_49776_B-2_FBC_Annual_Review_2018_Rates_Application.pdf at page 41.

1 **REFERENCE: Undertaking 38 pdf page 52**

2

3 **PREAMBLE:** In summary, FBC's PPEVDA fully defers to customers all variances in
4 resource unit prices (similar to Rider F for YEC) as well as water
5 variability (similar to the DCF for YEC). The FBC PPEVDA also fully
6 defers to customers both the cost and revenue variance related to any
7 impact from changes to load or sales.

8

9 **QUESTION:**

10

11 a) Please provide a direct reference in the referenced BCUC decision or other BCUC
12 decision where the PPEVDA defers to customers all variances due to water
13 variability.

14

15 **ANSWER:**

16

17 **(a)**

18

19 In addressing "variances due to water variability" for FBC, it is necessary to understand
20 the context of this utility's hydro power supply arrangements with BC Hydro as well as the
21 mechanisms as approved by BCUC for cost flow through to customers of any FBC supply
22 cost variances, and the extent collectively to which these arrangements remove risk from
23 FBC related to water variability cost impacts. The two key factors in this regard are as
24 follows:¹

25

26 1. FBC arrangements with BC Hydro (Canal Plant Agreement) whereby all of the
27 local BC Hydro, FBC and other party hydro generation goes into a pool and FBC
28 receives an annual entitlement, i.e., BC Hydro bears all of the FBC hydro supply
29 risk for water level variances.

30

31 2. To the extent that FBC could still face some purchase power costs that are higher
32 or lower due in part to water level changes (at its facilities or in other places), as

¹ Beyond review of documents, this broad understanding was confirmed through personal communication with Joyce Martin of Fortis on July 25, 2018, who confirmed that FBC is not exposed to water variability risk.

1 well as risks related to water rental cost changes, any such residual risk flows
2 through to FBC customers annually through the mechanism as approved by BCUC
3 in FBC's current annual PBR filing (or in past filings as approved regarding the
4 PPEVDA).

5

6 Overall, the response to Undertaking #38 does not suggest that there is any BCUC
7 decision that specifically defers to customers all variances due to water variability. Nor is
8 the response intended to suggest that FBC has a specific deferral account "similar to the
9 DCF for YEC" – the "similarity" being referenced here goes to the ultimate outcome (i.e.,
10 the utility has no cost risk related to water variability) as opposed to the factors or
11 mechanism responsible for this outcome. In summary, FBC has no risk due to water
12 variability based on several linked factors as described above versus a specific BCUC
13 order that addresses water variability risk. The reference to FBC's PPEVDA points to the
14 existence of a specific approved deferral account that does address any residual variance
15 in power supply costs that may occur.

16

17 In short, the point made is that FBC bears no risk for such water-related power supply cost
18 variances – and that this results from the combined arrangements for FBC with BC Hydro
19 and with BCUC approved flow through of power supply and other cost variances.

20

21 Additional detail is provided below on FBC's power supply cost variance flow through
22 arrangements. See response to YUB-YEC-3-5 for additional information on FBC power
23 supply context and arrangements with BC Hydro.

24

25 **BCUC approved Power Supply Cost Variance Flow Through to FBC Customers**

26

27 Additional details on BCUC approval of flow through to FBC customers of FBC power
28 supply and other cost variances is provided below.

29

30 Order G-110-12 (see YUB-YEC-3-1 Attachment 1) notes as follows regarding Power
31 Purchase Expense and FBC's related power supply arrangements [at page 32]:

32

33 FortisBC submits that the purpose of its resource acquisition policy is to allow
34 customer load requirements to be met at the lowest reasonable cost with a
35 minimum of environmental impacts. The Company can supply over 98 percent of
36 its annual energy requirements from long-term, firm resources. In meeting its

1 energy requirements, FortisBC uses a combination of Company-owned generation
2 entitlements and firm supply which has been contracted, augmented by spot
3 market purchases to deal with any capacity or energy deficits. FortisBC-owned
4 generation entitlements include the Canal Plant Agreement (CPA) entitlements
5 while examples of contracted firm supply include the Brilliant Power Purchase
6 Agreement (BPPA) and the BC Hydro Rate Schedule (RS) 3808 Power Purchase
7 Agreement (PPA). Other purchases include Independent Power Producers
8 and market purchases made in advance, as well as those on the spot market.
9 (Exhibit B-1, Tab 4, pp. 3-10)

10
11 At page 33, Order G-110-12 notes as follows regarding potential FBC power expense
12 variances, and FBC's proposed deferral account to capture all such variances:

13
14 The Company explains that these power expense variances could result from a
15 number of factors, including:

- 16
17
- 18 • Load variances related to variances in customer growth, usage or weather;
 - 19 • Unit price variances from forecast (an example being BC Hydro rates which
20 were not known at the time of application and were not finalized at the close
21 of the evidentiary record);
 - 22 • FortisBC's ability to displace contracted purchase with lower-cost market
23 purchases;
 - 24 • True-up of BPPA costs; and
 - 25 • CPA operational factors affecting the Company's usage or timing of
26 entitlements. (Exhibit B-1, Tab 4, p. 23)

27

28
29 In this Application, FortisBC has proposed a deferral account to capture variances
30 in forecast and actual Power Purchase Expense. This is in part in response to a
31 request from stakeholders in the 2011 Negotiated Settlement Agreement. FortisBC
32 has requested that firm rates be set for the 2012-2013 test period and any
33 accumulated variances be applied to rates in 2014. Thereafter, the Company
34 proposes to flow through any variance in the Power Purchase Expense Variance
35 Deferral Account to customers in the subsequent year. (Exhibit B-1, Tab 4, pp. 23-
36 24).

1 At page 34 of Order G-110-12 the BCUC specifically approves the variance deferral
2 account as reviewed above, noting:

3
4 The Commission Panel finds that a deferral account to capture variances between
5 forecast and actual power purchase expense represents a reasonable attempt to
6 manage uncertainty and approves establishing the Power Purchase Expense
7 Variance Deferral Account as proposed by FortisBC. The Panel understands the
8 complexity of managing the number of variables affecting the power purchase
9 process and is in agreement that any positive or negative variances are most
10 appropriately borne by the customer. The establishment of a Power Purchase
11 Expense Variance Deferral Account is the most effective way to manage this
12 process with variances being handled in customer rates in subsequent periods.

13
14 At page 42 of Order G-110-12 the BCUC also approved including water fees in the
15 PPEVDA:²

16
17 The Panel agrees that water fees are solely related to the cost of generation. Given
18 the intent of the Power Purchase Expense Variance Deferral Account, the Panel
19 directs FortisBC to include any variances related to water fees in that deferral
20 account.

21
22 While the PPEVDA is no longer in place, all variances due to water variability continue to
23 be flowed through to customers through arrangements as approved by BCUC.
24 Specifically, FortisBC's annual review for 2018 rates [provided as YUB-YEC-3-3
25 Attachment 2] states that "Any variances in the costs of power supply, including any power
26 purchase expense decrease due to further portfolio optimization, are recorded in the Flow-
27 through deferral account and returned to or recovered from customers in the subsequent
28 year".³ This was approved by the flow through mechanism discussed in response to
29 Decision G-139-14 [provided as YUB-YEC-3-3 Attachment 1].

² The Board Order notes as follows: "FortisBC's power supply costs include not only power purchases but also water fees. (Exhibit B-1, Tab 1, p. 7) Water fees are assessed by the Province based on FortisBC's generation in the previous year and the rate is indexed to the BC Consumer Price Index (CPI). (Exhibit B-1, Tab 4, p. 28) Variance in water fees could be a result of either volume variances in FortisBC's generation in the prior year or from rate variances due to differences in water rental rates." And "Although FortisBC has not proposed to include variances in water fees in the PPEVDA (Exhibit B-8, BCUC 1.22.1), during the oral hearing phase of the proceeding, Ms. Des Brisay stated that doing so would be consistent with the intent of the deferral account. (T5: 850)"

³ Lines 13 through 16, page 41.

- 1 A list of items addressed in the existing flow through mechanism are set out in Table 12-
 2 4 of FortisBC's Annual review of 2018 rates [provided as YUB-YEC-3-3 Attachment 2]. An
 3 excerpt is provided below [from page 122 of the Annual review of 2018 rates]:

Table 12-4: Variances Captured in the Flow-through Deferral Account³⁷

	FEI	FBC
<u>Delivery Revenues (FEI):</u>		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
<u>Revenues and Power Supply (FBC):</u>		
Revenue variances	N/A	Flow-through deferral
Power purchase variances	N/A	Flow-through deferral
Water fees variances	N/A	Flow-through deferral
<u>Gross O&M:</u>		
Formula driven O&M variances	Earnings sharing	Earnings sharing
BCUC fees variances	BCUC Variances deferral	Flow-through deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances *	Flow-through deferral	Flow-through deferral
<u>Capitalized Overhead:</u>		
Capitalized overhead variances	N/A - no variance	N/A - no variance
<u>Property Tax:</u>		
Property tax variances	Flow-through deferral	Flow-through deferral
<u>Depreciation and Amortization:</u>		
Depreciation variances	Flow-through deferral	Flow-through deferral
Amortization of deferrals	N/A - no variance	N/A - no variance
<u>Other Revenues (FEI)/Other Income (FBC):</u>		
SCP Mitigation Revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
All other other revenue/income variances	Flow-through deferral	Flow-through deferral
<u>Wheeling (FBC)/Transportation costs (FEI):</u>		
Transportation and wheeling variances	Flow-through deferral	Flow-through deferral
<u>Income Tax:</u>		
Income tax variances	Flow-through deferral	Flow-through deferral
<u>Interest Expense/Cost of Debt:</u>		
Interest on RSAM/CCRA/MCRA/Gas Storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
All other interest variances	Flow-through deferral	Flow-through deferral

4 * Including items re-forecast outside of the formula such as insurance premiums, AMI, NGT stations, Biomethane, RS46 O&M

1 **REFERENCE: Undertaking 38 pdf page 51**

2
3 **PREAMBLE:** Undertaking 38 requests:

4
5 Undertaking to advise as to whether FortisBC Electric has a deferral or
6 contingency account (and if so, how such an account differs from YEC's
7 DCF) for changes in hydro generation from GRA forecasts due to
8 changes in forecast water levels, as such changes affect thermal
9 generation fuel costs, with the result that such cost variances are
10 ultimately borne by ratepayers. (underlining added)

11
12 **QUESTION:**

- 13
14 a) It appears that the submission for undertaking 38 is not responsive to the request.
15 The response does not comment on changing water levels and therefore changes
16 in hydro generation due to that variance in water levels, does not refer to a deferral
17 account that records variations in hydro generation due to water levels being
18 different from forecast, nor any affect [sic] on thermal generation costs. Please
19 explain how YEC is responsive to the undertaking.
20
21 b) If FBC does not have a deferral account similar or identical to YEC's DCF then
22 please confirm so.

23
24 **ANSWER:**

25
26 **(a) and (b)**

27
28 To be clear, FBC does not have a deferral account "similar or identical to YEC's DCF".
29 However, similar to YEC's situation with its DCF, FBC does not bear any cost risks related
30 to variations in hydro generation due to variances in water levels.

31
32 The response to Undertaking #38 notes at page 2:

33
34 "FBC's PPEVDA fully defers to customers all variances in resource unit prices
35 (similar to Rider F for YEC) as well as water variability (similar to the DCF for YEC).

1 The FBC PPEVDA also fully defers to customers both the cost and revenue
2 variance related to any impact from changes to load or sales.” (underlining added)

3

4 Please see the response to YUB-YEC-3-4 for a review of this specific quote. As reviewed
5 in that response, in addressing “variances due to water variability” for FBC it is necessary
6 to understand the context of this utility’s hydro power supply arrangements with BC Hydro
7 as well as the mechanisms as approved by BCUC for cost flow through to customers of
8 any FBC supply cost variances, and the extent collectively to which these arrangements
9 remove risk from FBC related to water variability cost impacts. See response to YUB-YEC-
10 3-4 for review of these two key factors, and review of BCUC’s decisions on the relevant
11 power supply flow through mechanisms. Many of these same details (particularly
12 regarding the BC Hydro arrangements) were included in the original Undertaking #38
13 response.

14

15 The key point is that FBC does not bear any risk related to water variability. Such risks are
16 borne either by BC Hydro or by FBC’s customers. Further, in the event that the specifics
17 of BC Hydro arrangements are not clear or understood, it remains clear that BCUC has
18 approved mechanisms to flow through to FBC customers any FBC power supply cost
19 variances that may actually occur.

20

21 Accordingly, due to its specific circumstances, FBC has no need for (and does not have)
22 a specific deferral account similar or equivalent to YEC’s DCF solely to address water
23 variability impacts. The absence of such an account with FBC in no way suggests that
24 FBC bears any added risk compared to YEC as regards water variability.

25

26 Additional information is provided below on FBC’s power supply context and
27 arrangements with BC Hydro.

28

29 **FBC Power Supply Context**

30

31 As noted in the response to Undertaking #38, the context for FBC is very different, and
32 less risky, than Yukon Energy. As FBC is not on an isolated grid, FBC is not exposed to
33 the same thermal cost risks that YEC is exposed to given FBC has access to renewable
34 generation resource options available on BC’s integrated grid system.

1 The FBC deferral account flow through of purchase power cost variances to ratepayers is
2 not associated with a need for the same rate stability elements as YEC's DCF - and
3 nothing suggests a need with FBC for such rate stability elements related to potential
4 variances in water availability.

5
6 The following were specifically noted in response to Undertaking #38 regarding the level
7 of water risk that FortisBC has relative to Yukon Energy:

- 8
- 9 • **FBC is insulated from hydrology risk under the CPA** – FBC's resource stack
10 includes four existing hydro plants operated under the CPA with BC Hydro directly
11 dispatching and FBC receiving guaranteed entitlement to energy and capacity
12 provided that the generating plants are available to be dispatched. FBC has a long-
13 term contract to purchase the whole output of the four hydro generating units of
14 the Brilliant Plant, which is also a CPA entitlement plant.
 - 15
16 • **FBC has other supply arrangements not available to Yukon Energy** – this
17 includes a Power Purchase Agreement with BC Hydro, capacity blocks from the
18 hydro Waneta Expansion project, and the ability to import electricity from the
19 Mid-C market via existing transmission connections.
- 20

21 In Yukon Energy's view, the above was responsive to the undertaking request. Further
22 information regarding the specific context for FortisBC and how it differs from the Yukon
23 grid is provided below. Additional information is available in FortisBC's Annual Information
24 Form For the Year Ended December 31, 2017 Dated March 14, 2018 provided as
25 Attachment 1 to this response [see pages 7 and 8].

26
27 In summary, FortisBC uses a combination of Company-owned generation entitlements,
28 firm contracted supply, and market purchases to meet its load requirements.

- 29
- 30 • The Canal Plant Agreement (see below) provides FortisBC with an annual
31 entitlement based on 50-year historical water flows. As a result, FortisBC does not
32 face any business risk related to water level variations at its hydro-electric
33 generation facilities.
 - 34
35 • Variations in purchased power expense for any reason are addressed through the
36 annual flow-through mechanism under FortisBC's current Performance Based

1 Regulation (PBR) plan. As a result, any variations in purchase power expense are
2 flowed through to customers annually and FortisBC does not retain any of the
3 business risk associated with variations in purchased power expense.¹
4

5 **Canal Plant Agreement**²
6

7 FortisBC's four hydroelectric generating plants are governed by the Canal Plant
8 Agreement (CPA). The CPA is a multi-party agreement that enables the six separate
9 owners of nine major hydroelectric generating plants (having a combined capacity of
10 approximately 1,900 MW and all located in relatively close proximity to each other) to
11 coordinate the operation and dispatch of their generating plants. The plants and their
12 respective capacity and owners are outlined in the table below:
13

Plant	Capacity	Owners
Canal Plant	580	BC Hydro
Waneta Dam	256	BC Hydro
Waneta Dam	237	Teck Metals Ltd.
Waneta Expansion	335	Waneta Expansion Limited
Kootenay River System (4 plants)	225	FBC
Brilliant Dam	149	Brilliant Power Corporation
Brilliant Expansion	120	Brilliant Expansion Power

14
15 The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water
16 flows, subject to the 1961 Columbia River Treaty between Canada and the United States,
17 and coordinated operation of storage reservoirs and generating plants, to generate more
18 power from their respective generating plants than they could if they operated
19 independently. Under the CPA, BC Hydro takes into its system all power actually
20 generated by the nine plants owned by the Entitlement Parties. In exchange for permitting
21 BC Hydro to determine the output of these plants, the Entitlement Parties are each
22 contractually entitled to their Entitlements, which are based on 50-year historical water

¹ See FBC's annual review for 2018 rates (YUB-YEC-3 Attachment 2), lines 13-16 at page 41 which states "Any variances in the costs of power supply, including any power purchase expense decrease due to further portfolio optimization, are recovered in the Flow-through deferral account and returned to or recovered from customers in the subsequent year." Items addressed in the Flow-through mechanism are set out in Table 12-4 of this same FBC annual review. The Flow-through mechanism was approved in BCUC Decision G-139-14 (see YUB-YEC-3-3 Attachment 1, pages 228-229).

² Based on FortisBC's Annual Information Form For the Year Ended December 31, 2017 Dated March 14, 2018 provided as Attachment 1 to this response [see pages 7 and 8].

1 flows. The Entitlement Parties receive their Entitlements irrespective of actual water flows
2 to the Entitlement Parties' generating plants.

3

4 BC Hydro enjoys the benefits of the additional power generated through coordinated
5 operation and optimal use of water flows. The Entitlement Parties benefit by knowing years
6 in advance the amount of power that they will receive from their generating plants and
7 therefore do not face hydrology variability in generation supply planning.

8

9 The Corporation, however, retains rights to its original water licenses and flows in
10 perpetuity. Should the CPA be terminated, the output of the Corporation's Kootenay River
11 system plants would, with the water and storage authorized under its existing licenses and
12 on a long-term average, be approximately the same power output as the Corporation
13 receives under the CPA. The CPA does not affect the Corporation's ownership of its
14 physical generation assets. The Corporation continues to own and operate its four
15 Kootenay River system generating plants, which are included in the Corporation's Rate
16 Base Assets. The CPA continues in force until terminated by any of the parties by giving
17 no less than five years' notice at any time on or after December 31, 2030.



FortisBC Inc.
An indirect subsidiary of Fortis Inc.

Annual Information Form
For the Year Ended December 31, 2017
Dated March 14, 2018

FortisBC Inc.

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All figures are expressed in Canadian dollars unless otherwise noted.

Except as otherwise stated, the information in this Annual Information Form is given as of December 31, 2017.

FortisBC Inc.

FORWARD-LOOKING INFORMATION

Certain statements contained in this Annual Information Form contain forward-looking information within the meaning of applicable securities laws in Canada (“forward-looking information”). The words “anticipates”, “believes”, “budgets”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “will”, “would” and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words.

The forward-looking information reflects management’s current beliefs and is based on information currently available to the Corporation’s management. The forward-looking information in the 2017 Annual Information Form and the information incorporated herein by reference includes, but is not limited to, statements regarding: expectations regarding the scheduled rehabilitation and life extension of FBC’s hydroelectric generation units, expectations regarding power output in the event that the CPA is terminated; expectations under take-or-pay contracts; and the Corporation’s expectation that compliance with environmental laws and regulations will not have a material effect on the Corporation’s capital expenditures, earnings or competitive position.

The forecasts and projections that make up the forward-looking information are based on assumptions, which include but are not limited to: receipt of applicable regulatory approvals and requested rate orders; absence of administrative monetary penalties; the ability to continue to report under United States generally accepted accounting principles (“US GAAP”) beyond the Canadian securities regulators exemption to the end of 2023 or earlier; absence of asset breakdown; absence of environmental damage and health and safety issues; absence of adverse weather conditions and natural disasters; ability to maintain and obtain applicable permits; the adequacy of the Corporation’s existing insurance arrangements; the First Nations’ settlement process does not adversely affect the Corporation; the ability to maintain and renew collective bargaining agreements on acceptable terms; no material change in employee future benefit costs; the ability of the Corporation to attract and retain skilled workforces; absence of information technology infrastructure failure; absence of cyber-security failure; continued electricity demand; the ability to arrange sufficient and cost effective financing; no material adverse ratings actions by credit rating agencies; that counterparties do not default on power supply contracts; and no weather related demand loss or significant and sustained loss of precipitation over the headwaters of the Kootenay River system.

The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory approval and rate orders risk (including the risk of imposition of administrative monetary penalties); continued reporting in accordance with US GAAP risk; asset breakdown, operation, maintenance, and expansion risk; environment, health and safety matters risk; weather and natural disasters risk; permits risk; underinsured and uninsured losses; risks involving First Nations; labour relations risk; employee future benefits risk; human resources risk; information technology infrastructure risk; cyber-security risk; interest rates risk; impact of changes in economic conditions risk; capital resources and liquidity risk; competitiveness and commodity price risk; power purchase and capacity sale contracts risk; weather related risk; and other risks described in this Annual Information Form. For additional information with respect to these risk factors, reference should be made to the section entitled “Risk Factors” in this Annual Information Form, the section entitled “Business Risk Management” in the Corporation’s Management Discussion & Analysis for the year ended December 31, 2017 and the other continuous disclosure materials filed from time to time on SEDAR at www.sedar.com, and which are incorporated herein by reference.

All forward-looking information in this Annual Information Form and the information incorporated herein by reference is qualified in its entirety by this cautionary statement and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

FortisBC Inc.

GLOSSARY

Except as otherwise defined, or unless the context otherwise requires, the following terms have the meanings set forth below.

“**ARO**” means asset retirement obligation;

“**BC Hydro**” means British Columbia Hydro and Power Authority, a British Columbia Crown corporation and electric utility serving the majority of British Columbia residents;

“**BC Hydro PPA**” means the 200 MW power purchase agreement between the Corporation and BC Hydro dated May 21, 2013;

“**BCUC**” or “**Commission**” means the British Columbia Utilities Commission;

“**Board**” means the Board of Directors of FBC;

“**Brilliant Plant**” means the 149 MW hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation;

“**Brilliant PPA**” means the 149 MW power purchase agreement between the Corporation and Brilliant Power Corporation terminating in 2056;

“**Canal Plant**” means the Kootenay Canal Plant, a hydroelectric generating plant on the Kootenay River system owned by BC Hydro;

“**CBT**” means Columbia Basin Trust;

“**COPE**” means Canadian Office and Professional Employees Union Local 378 (COPE operates as MoveUP);

“**Corporation**” or “**FBC**” means FortisBC Inc.;

“**CPA**” means the second amended and restated Canal Plant Agreement dated for reference November 15, 2011 among BC Hydro, the Corporation, Teck Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Corporation and Waneta Expansion Limited Partnership;

“**CPC**” means Columbia Power Corporation, a British Columbia Crown corporation;

“**DBRS**” means DBRS Limited;

“**EMS**” means environmental management system;

“**Entitlement**” means a generating facility’s fixed annual entitlement of capacity and energy under the CPA;

“**Entitlement Parties**” means, collectively, Brilliant Power Corporation, Brilliant Expansion Power Corporation, Teck Metals Ltd., Waneta Expansion Limited Partnership and FBC;

“**FEI**” means FortisBC Energy Inc.;

“**Fortis**” means Fortis Inc.;

“**FortisBC Pacific**” means FortisBC Pacific Holdings Inc.;

FortisBC Inc.

“**GWh**” means a gigawatt hour, which is a measure of energy that is equal to 1,000,000,000 watts used over a one-hour period;

“**IBEW**” means International Brotherhood of Electrical Workers Union, Local 213;

“**Moody’s**” means Moody’s Investors Service;

“**MW**” means a megawatt, which is a measure for power that is equal to 1,000,000 watts;

“**MWh**” means a megawatt hour, which is a measure of energy that is equal to 1,000,000 watts used over a one-hour period;

“**PBR**” means the performance based rate setting methodology for regulation of public utilities;

“**PCBs**” means polychlorinated biphenyls;

“**Powerex**” means Powerex Corp.;

“**Rate Base Assets**” means all generation, transmission, distribution and other utility assets that are used or required to be used to provide service to utility customers, which are included in the calculation of the Corporation’s revenue requirement for the applicable year and are subject to a regulated rate of return;

“**UCA**” or the “**Act**” means the *Utilities Commission Act* (British Columbia), as amended;

“**WECA**” means the capacity purchase agreement between Waneta Expansion Limited Partnership and FBC made as of October 1, 2010.

FortisBC Inc.

1.0 CORPORATE STRUCTURE

1.1 NAME AND INCORPORATION

FBC was incorporated as West Kootenay Power and Light Corporation, Limited pursuant to the *West Kootenay Power and Light Corporation, Limited, Act 1897* (British Columbia), as amended. The Corporation's name was changed to "West Kootenay Power Ltd." on September 1, 1988, to "UtiliCorp Networks Canada (British Columbia) Ltd." on October 22, 2001, to "Aquila Networks Canada (British Columbia) Ltd." on May 31, 2002 and to "FortisBC Inc." on June 1, 2004.

FBC's head office is located at Suite 100, 1975 Springfield Road, Kelowna, British Columbia ("BC"), V1Y 7V7 and its registered office is located at 2500 – 700 West Georgia Street, Vancouver, BC, V7Y 1B3.

1.2 INTER-CORPORATE RELATIONSHIPS

The Corporation is an indirect, wholly-owned subsidiary of Fortis. Fortis is a leader in the North American electric and gas utility business, serving customers across Canada, the United States and the Caribbean.

2.0 GENERAL DEVELOPMENT OF THE BUSINESS

2.1 THREE-YEAR HISTORY

Over the past three years the Corporation's Rate Base Assets have grown by approximately 6.7 per cent. This growth reflects the Corporation's capital expenditures necessary to ensure the ability to provide service, public and employee safety and reliability of supply of electricity to the Corporation's customer base.

3.0 THE BUSINESS OF FORTISBC INC.

3.1 GENERAL

FBC is an integrated, regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets, all of which are located in the southern interior of BC. The Corporation has been in continuous operation since 1897.

As at December 31, 2017 FBC served, directly and indirectly, a diverse base of approximately 172,300 customers. Customers are comprised of residential, commercial, wholesale and industrial consumers of electricity located in the cities and rural regions of the southern interior of BC. The majority of FBC's customers are located in urban centres. In 2017, the Corporation sold 3,305 GWh of electricity to its customers, 591 GWh of which was purchased by FBC's six wholesale customers. The Corporation had a peak demand of 731 MW in 2017, 15 MW lower than the historical peak demand of 746 MW.

The Corporation's regulated generation assets consist of four hydroelectric generating plants on the Kootenay River with an aggregate capacity of 225 MW and an annual gross energy entitlement of approximately 1,609 GWh. FBC meets the remainder of its customers' energy and capacity requirements through a portfolio of long-term and short-term power purchase contracts, the majority of which have been accepted by the BCUC and the costs of which are flowed through to customers. The Corporation's regulated transmission and distribution assets consist of approximately 7,260 kilometres of transmission and distribution power lines and 65 substations. With the exception of BC Hydro, FBC is the only integrated, regulated electric utility operating in BC. FBC also conducts a small amount of other activities relating primarily to the operation and management of third-party owned hydroelectric generation, transmission and distribution systems located within the FBC service area.

FBC operates in the southern interior of BC serving approximately 135,800 direct customers in communities including Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland. In addition, FBC indirectly serves approximately 36,500 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro at two points. The

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service territory is primarily residential but also contains key industries served by FBC including lumber, pulp and paper, mining, agriculture and manufacturing.

The following table compares 2017 and 2016 regulated electricity revenue, electricity sales, and number of customers by customer class:

	Electricity Revenue ⁽¹⁾				Electricity Sales ⁽¹⁾				Customers ⁽³⁾			
	2017		2016		2017		2016		2017		2016	
	\$ millions	%	\$ millions	%	GWh	%	GWh	%	#	%	#	%
Residential Service	186	51	168	50	1,371	41	1,260	40	117,748	87	115,772	87
Commercial ⁽²⁾	98	27	92	27	973	29	925	30	17,989	13	17,722	13
Wholesale	50	14	44	13	591	19	551	18	6	0	6	0
Industrial	31	8	31	10	370	11	383	12	50	0	50	0
Total	365	100	335	100	3,305	100	3,119	100	135,793	100	133,550	100

Notes:

1. Electricity revenue and electricity sales set out in this table reflect regulated amounts only. Including amounts from the Corporation's unregulated business, for the year ended December 31, 2016, total electricity sales were 3,121 GWh and total electricity revenue was \$335.3 million. On February 25, 2016, FBC and its subsidiaries completed the sale of the unregulated Walden Power Plant, a 16MW hydroelectric generating plant, and surrounding lands, to the Cayoose Creek Power Limited Partnership and the Cayoose Creek Development Corporation respectively. The Corporation had no un-regulated electricity sales and no un-regulated electricity revenue for the year ended December 31, 2017.
2. Commercial includes Street Light & Irrigation customers.
3. Direct customers.

3.2 GENERATION AND POWER SUPPLY

FBC meets the electricity supply requirements of its customers through a mix of owned-generation and short-term and long-term power purchase contracts. The Corporation owns four regulated hydroelectric generating plants with an aggregate capacity of 225 MW, which provide approximately 45 per cent of the energy and 30 per cent of the peak capacity needs of FBC. The four hydroelectric generation plants are located on the Kootenay River and contain fifteen separate generating units. Generation assets represent approximately 15 per cent of the Corporation's rate base assets. Under the CPA, as described below, these generating facilities are dispatched by BC Hydro in exchange for Entitlement. However, the generating units are required to be maintained and available for dispatch. Since 1998, eleven of fifteen FBC hydroelectric generation units have been subject to a life extension and upgrade program which substantially concluded in 2011. On January 20, 2017, the BCUC approved a complete rehabilitation and life extension of the remaining four units, which commenced in 2017 and is expected to be completed in 2021.

(a) Canal Plant Agreement

FBC's four hydroelectric generating plants are governed by the CPA. The CPA is a multi-party agreement that enables the six separate owners of nine major hydroelectric generating plants (having a combined capacity of approximately 1,900 MW and all located in relatively close proximity to each other) to coordinate the operation and dispatch of their generating plants. The plants and their respective capacity and owners are:

Plant	Capacity (MW)	Owners
Canal Plant	580	BC Hydro
Waneta Dam	256	BC Hydro
Waneta Dam	237	Teck Metals Ltd.
Waneta Expansion	335	Waneta Expansion Limited Partnership (WELP)
Kootenay River System (4 plants)	225	FBC
Brilliant Dam	149	Brilliant Power Corporation
Brilliant Expansion	120	Brilliant Expansion Power Corporation

The CPA enables BC Hydro and the Entitlement Parties, through coordinated use of water flows, subject to the

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1961 Columbia River Treaty between Canada and the United States, and coordinated operation of storage reservoirs and generating plants, to generate more power from their respective generating plants than they could if they operated independently. Under the CPA, BC Hydro takes into its system all power actually generated by the nine plants owned by the Entitlement Parties. In exchange for permitting BC Hydro to determine the output of these plants, the Entitlement Parties are each contractually entitled to their Entitlements, which are based on 50-year historical water flows. The Entitlement Parties receive their Entitlements irrespective of actual water flows to the Entitlement Parties' generating plants.

BC Hydro enjoys the benefits of the additional power generated through coordinated operation and optimal use of water flows. The Entitlement Parties benefit by knowing years in advance the amount of power that they will receive from their generating plants and therefore do not face hydrology variability in generation supply planning.

The Corporation, however, retains rights to its original water licenses and flows in perpetuity. Should the CPA be terminated, the output of the Corporation's Kootenay river system plants would, with the water and storage authorized under its existing licenses and on a long-term average, be approximately the same power output as the Corporation receives under the CPA. The CPA does not affect the Corporation's ownership of its physical generation assets. The Corporation continues to own and operate its four Kootenay river system generating plants, which are included in the Corporation's Rate Base Assets. The CPA continues in force until terminated by any of the parties by giving no less than five years' notice at any time on or after December 31, 2030.

(b) Power Purchase Agreements

The Corporation's electricity supply not supplied by its own generating plants is acquired through power purchase contracts consisting of the following:

- (i) the Brilliant PPA;
- (ii) the BC Hydro PPA;
- (iii) Brilliant Expansion Capacity and Energy Purchase Agreement;
- (iv) a number of small power purchase contracts with certain independent power producers;
- (v) spot market and contracted capacity purchases; and
- (vi) the WECA.

These power purchase contracts have been accepted by the BCUC and prudently incurred costs thereunder flow through to customers through electricity rates.

(i) Brilliant Power Purchase Agreement

The Brilliant Plant is a hydroelectric generating plant jointly owned by CPC and CBT through the Brilliant Power Corporation. The Brilliant Plant is allocated Entitlement energy of 985 GWh and capacity of 149 MW pursuant to the CPA. Under the Brilliant PPA, FBC has agreed to purchase from Brilliant Power Corporation, on a long-term basis (a) the Entitlement allocated to the Brilliant Plant and (b) after the expiration of the CPA, the actual electrical output generated by the Brilliant Plant. While the total Entitlement is 985 GWh, FBC does not purchase the approximately 60 GWh of regulated flow upgrade Entitlement under this agreement. However, FBC has entered into another agreement with CPC for this energy over a five year period as discussed below. The Brilliant PPA uses a take-or-pay contract structure which requires that FBC pay for the Brilliant Plant's Entitlement, irrespective of whether FBC actually takes it. FBC does not foresee any circumstances under which the Corporation would be required to pay for power that it does not require. During the first 30 years of the Brilliant PPA term, FBC pays to Brilliant Power Corporation an amount that covers the operation and maintenance costs of the Brilliant Plant and provides a return on capital, including original purchase costs, sustaining capital costs and any life extension investments. During the second 30 years of the Brilliant PPA term (commencing in 2026), an adjustment using a market price mechanism based on the depreciated value of the Brilliant Plant and then-prevailing operating costs will be made to the amounts payable by FBC. The

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Brilliant PPA provided FBC with approximately 24 per cent of its energy requirements in 2017.

(ii) Power Purchases from BC Hydro

FBC is a party to the BC Hydro PPA, which provides the Corporation with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW. Energy bought pursuant to the BC Hydro PPA provided approximately 17 per cent of FBC's energy requirements in 2017. The current BC Hydro PPA was approved by the BCUC in May 2014 and expires on September 30, 2033. The current agreement replaced a previous power purchase agreement with BC Hydro that had been in place since 1993.

(iii) Brilliant Expansion Capacity and Energy Purchase Agreement

In November 2012, FBC entered into an agreement to purchase CPC's unused Entitlements from 2013 to 2017. The Entitlements are from the Brilliant Plant and the Brilliant Expansion Plant, including the 60 GWh from the Brilliant Plant that is not included in the Brilliant Power Purchase Agreement. In July 2017, FBC renewed the agreement on similar terms for the period of 2018 to 2027. The agreement provided approximately 3 per cent of FBC's energy requirements in 2017.

(iv) Small Power Purchase Contracts

FBC has a number of small power purchase contracts with independent power producers, which collectively provided less than 1 per cent of the Corporation's energy supply requirements in 2017.

(v) Spot Market and Contracted Capacity Purchases

During 2017, the Corporation purchased capacity and energy from the market to meet its peak energy requirements and optimize its overall power supply portfolio. To facilitate market transactions going forward, FBC entered into the Capacity and Energy Purchase and Sale Agreement (CEPSA) with Powerex, which was approved by the BCUC in April 2015. The CEPSA is a master agreement that sets the terms and conditions for future market transactions entered into by FBC with Powerex. The CEPSA became effective May 1, 2015 and expires on September 30, 2019, unless extended by a mutual agreement. Spot market and contracted purchases provided approximately 12 per cent of the Corporation's energy supply requirements in 2017.

(vi) WECA

The Corporation entered into the WECA to purchase capacity from the Waneta Expansion, a 335 MW hydroelectric generating facility adjacent to the existing Waneta Plant on the Pend d'Oreille River in BC. The Waneta Expansion is owned and operated by a limited partnership, the limited partners of which are FBC's ultimate parent corporation, Fortis, which owns a 51 per cent interest, and a wholly-owned subsidiary of each of CPC and CBT. The WECA allows FBC to purchase capacity over a 40 year period which commenced in April 2015. The WECA was accepted for filing as an energy supply contract by the BCUC in May 2012.

3.3 OPERATIONS

(a) Transmission

FBC's transmission system is a high voltage system that operates at the 230 kV, 161 kV, 138 kV and 63 kV levels while transmitting electricity to customers directly connected to the transmission grid. The transmission system is highly integrated and operates synchronously with the BC Hydro system. It consists of approximately 1,300 kilometres of transmission lines and includes major substations throughout the service territory. FBC has 9 terminal transmission substations, the components of which include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, together with site infrastructures such as buildings and security systems. There are also 4 additional substations with generator step-up transformers associated with the four generating plants.

(b) Distribution

Electricity produced at generating plants is moved across transmission lines to terminal stations and transformers and then distributed at lower voltages to customers. FBC's distribution system is comprised of 52 distribution substations and approximately 5,960 kilometres of overhead and underground distribution lines.

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The FBC distribution system is being upgraded in a number of locations over several years in order to renew obsolete components at or near the end of their useful life, and to accommodate load growth that has caused load on the existing system to approach design capacity.

(c) Major Capital Projects

The Corporation plans and implements programs for sustaining and enhancing its regulated generation, transmission and distribution assets. Capital projects are typically identified as being one of two types: (a) “sustaining”, which are directed at adequately maintaining asset condition and modernizing equipment; and (b) “growth” or “expansionary”, which are primarily required to accommodate customer and load growth within the FBC service area. Developing the priorities for the transmission and distribution system involves an assessment of both asset condition and maintenance needs and system contingency analysis. The latter involves a modeling and simulation of system impacts following several possible and different system event scenarios.

3.4 OTHER OPERATIONS, ASSETS AND ACTIVITIES

(a) Other Operations

FBC carries out monitoring, control and real-time management of its generation, transmission and distribution facilities through its centralized system control centre. The control centre coordinates with BC Hydro to ensure that appropriate monitoring and control of transmission equipment is maintained twenty-four hours a day.

(b) Other Assets

Other assets of the Corporation include those supporting the ongoing maintenance and operation of the system, such as office and service buildings, transport and work equipment and other office and information technology assets.

(c) Other Activities

FBC’s other activities are relatively small in comparison to its regulated electricity operations but provide an opportunity to leverage the utilization of FBC’s utility operation, maintenance and management resources under service contracts to third parties. FBC provides certain operations, maintenance and management services relating to the Waneta hydroelectric generation plant (jointly owned Teck Metals Ltd., and BC Hydro), and the Brilliant Plant.

FortisBC Pacific, the direct parent of the Corporation, provides services of a similar nature with respect to the Brilliant Expansion Plant, Waneta Expansion Plant and Arrow Lakes Generating Station. FBC provides staff and material resources to FortisBC Pacific in order for it to carry out the services required under the contracts and charges FortisBC Pacific its cost plus a mark-up as compensation.

3.5 OTHER MATERIAL CORPORATE ISSUES

(a) Insurance

The Corporation, through Fortis, maintains insurance coverage including liability, all risk property, boiler and machinery, and directors’ and officers’ liability insurance for the benefit of the Corporation. The Corporation self-insures against the risk of damage to transmission and distribution poles, wires and related equipment. FBC also maintains insurance coverage that is required by provincial statute, which covers automobile liability, firefighting expense and non-owned aircraft liability. Management believes that the coverage, amounts and terms of the Corporation’s insurance agreements are consistent with industry practices.

(b) Employees

The Corporation employed approximately 510 employees as at December 31, 2017. The organized employees of FBC are represented by the IBEW and COPE unions. IBEW represents employees in specified occupations in the areas of generation and transmission and distribution. The term of the current collective agreement with the IBEW is February 1, 2018 to January 31, 2021.

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There are two collective agreements between the Corporation and COPE. The term of the first collective agreement with COPE, representing employees in specified occupations in the areas of administration and operations support is January 1, 2014 to December 31, 2018. The term of the second collective agreement with COPE, representing customer service employees is April 1, 2017 to March 31, 2022.

(c) Specialized Skills and Knowledge

The skills and knowledge needed to operate and maintain electrical generation, transmission and distribution systems are key to the Corporation's success. These skills are currently available, and the Corporation has placed considerable focus in succession planning on ensuring that these skills are preserved as the Corporation's workforce ages and retires.

(d) Intellectual Property

Fortis owns the trademark "FortisBC", which it has licensed the Corporation to use. FBC owns the trademark "PowerSense", which has been used in the promotion by the Corporation of energy efficiency and energy awareness programs.

(e) Real Property

Certain of the Corporation's transmission and distribution facilities cross over land that is owned by the governments of Canada or BC. The Corporation believes it has obtained appropriate access rights from the relevant governments through Crown leases, statutory rights of way, land use permits, licenses of occupation and low voltage permits. Where transmission or distribution lines extend over waterways, various provincial and federal government bodies must approve the installation of those lines. Agreements and permits in this respect have been obtained from the appropriate government body.

The Corporation's transmission and distribution lines at times also cross over or run parallel to lands owned by various railway companies. In these circumstances, appropriate access rights, generally referred to as crossing agreements, have been obtained from the relevant railway company. Some of the Corporation's transmission and distribution lines are located on lands owned by other persons, including local governments, corporations, First Nations and individuals. The Corporation believes it has obtained or is in the process of obtaining the rights to use these lands through working with the property owner to come to an agreement (such as statutory rights of way) permitting land usage.

If the Corporation becomes aware of a situation in which it has not acquired the requisite usage rights, it will attempt to come to an agreement to secure usage rights with the landowner. The Corporation has the power to expropriate land if necessary.

(f) Seasonality

FBC's operations generally produce lower net earnings in the third quarter due to the timing of power purchases. The higher net earnings in the first and fourth quarters are due to increased customer load as a result of cooler weather, while certain expenses such as depreciation, interest and operating expenses remain more evenly distributed throughout the fiscal year.

(g) Competition

BC's traditional regulatory model does not support retail competition for customers, which would give customers the right to purchase electricity from suppliers other than the utility to which they are directly connected. FBC has a form of retail access for its wholesale and industrial customers supplied at transmission voltage. This retail access has not led to a loss of any of FBC's wholesale or industrial customers.

4.0 REGULATION

4.1 OVERVIEW

Public utilities in BC, such as FBC, are subject to the regulatory jurisdiction of the BCUC. The UCA is the legislation that defines the scope of the BCUC's jurisdiction regarding the regulation of public utilities and the responsibilities of those public utilities. The BCUC's primary responsibility is to establish just and reasonable

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utility rates, which include an opportunity for the public utilities to earn a fair return on the investments they have already made and will make in the future to provide customers with safe and reliable service.

4.2 REVENUE REQUIREMENT

The rate setting process generally has two main elements: revenue requirements and rate design.

The utility's revenue requirements represent the total revenues that are necessary for the utility to recover prudent costs for providing the utility services, to recover prudent investment, and to earn a fair return on and of its investments. The cost of providing service includes energy costs, operating and maintenance expenses, depreciation expenses, taxes, financing costs and a return on equity. Rate base is the book value of utility plant in service (plant less accumulated depreciation and customer contributions in aid of construction) and utility deferred charges, plus an allowance for working capital invested in the business, and is the investment base to which a rate of return is applied. The return on rate base is established by determining the cost of individual components of the capital structure, including equity, and weighting such costs to determine an aggregate return on rate base. Both the capital structure and rate of return on equity are determined by the BCUC.

The BCUC usually determines a public utility's revenue requirements based on the cost of service. Under the cost of service ratemaking, the Corporation forecasts the amount of electricity that will be delivered during normal weather, together with all of the other costs of providing service (including the return on rate base) in the test year(s). Variances between the forecast costs and the actual costs incurred, and variances in the actual amount of electricity delivered from what has been forecast, normally result in variances in FBC's return, except for variances that are captured by deferral accounts for future recovery or refund.

From 2014 to 2019, FBC is operating under a PBR Plan. The approved PBR Plan incorporates an incentive mechanism for improving operating and capital expenditure efficiencies. Operation and maintenance expenses and base capital expenditures during the PBR period are subject to an incentive formula reflecting incremental costs for inflation and half of customer growth, less a fixed productivity adjustment factor of 1.03 per cent each year. The PBR Plan also includes a 50/50 sharing of variances from the formula-driven operations and maintenance expenses and capital expenditures over the PBR period, and a number of service quality measures designed to ensure FBC maintains service levels. It also sets out the requirements for an annual review process which provides a forum for discussion between FBC and interested parties regarding its current performance and future activities.

When approved by the BCUC, FBC employs deferral accounts to address certain uncontrollable or non-routine items and to match costs incurred to the periods that the costs benefit. During the term of the PBR Plan, FBC has a deferral account to flow through variances in the majority of its costs and revenues, including revenue and power supply costs but excluding the formulaic operation and maintenance costs.

After revenue requirements have been established, costs are allocated among different classes of energy users/customers and rates are designed to reflect the cost of providing services to each rate class. Before any rate can be put into effect, it must be filed with and approved by the BCUC.

In BC, the regulatory process for revenue requirement determination and rate design involves participation of interested parties, such as customer representatives, other public groups or private individuals.

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4.3 KEY REGULATORY INFORMATION

Important regulatory information pertaining to decisions made by the BCUC with respect to FBC is summarized in the following table.

	2018	2017	2016	2015	2014
Rate Base Assets (\$ millions)	1,322	1,285	1,286	1,249	1,204
Deemed common equity component of total capital structure (%)	40.0	40.0	40.0	40.0	40.0
Allowed rate of return on common equity (%)	9.15	9.15	9.15	9.15	9.15

5.0 SAFETY AND ENVIRONMENTAL MATTERS

5.1 GENERAL

Canadian federal, provincial and municipal governments share jurisdiction over matters affecting safety and the environment. As a result, the Corporation is subject to provincial occupational health and safety legislation as well as federal, provincial and municipal requirements relating to the protection of the environment including, but not limited to, fish, wildlife, water, natural resource protection, and the proper storage, transportation, waste discharges, disposal and release of hazardous and non-hazardous substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better natural resource and land-use planning through the identification and mitigation of potential environmental impacts of projects or undertakings prior to and after commencement.

5.2 ENVIRONMENTAL MANAGEMENT SYSTEM

The environmental risks associated with the Corporation's activities and operations are managed under the framework of an EMS. FBC has an EMS in place to manage the impact of its activities on the environment and the design of the EMS is consistent with the guidelines of ISO 14001, an internationally recognized standard for EMS.

The Corporation's EMS includes an environmental policy, a summary of the environmental risks associated with the Corporation's business and operations, a summary of relevant environmental legislation, and an internal reporting process. The EMS also includes environmental training requirements for employees and contractors and reinforces environmental guidelines that serve to minimize the environmental impacts of FBC operations and ensure compliance with applicable environmental legislation. FBC has external audits of its EMS conducted on a regular cycle to ensure continued compliance with ISO 14001 standards and legal requirements.

5.3 PERMITS, LICENCES AND APPROVALS

Various federal and provincial statutes require the Corporation to obtain and comply with specific permits, licenses and approvals in the course of its operations. Pursuant to the *Water Sustainability Act* (British Columbia), water rental rates apply to the use of water for power generation. Water rental rates in BC are levied on the basis of both total station capacity and on total station generation. The Corporation is able to recover water rental costs through rates.

5.4 ENVIRONMENTAL EXPENDITURES

The Corporation incurs environmental compliance and environmental management system related operating and capital expenditures in connection with capital projects and in connection with ongoing operation and maintenance activities that are not reasonably quantifiable. The Corporation's cost of compliance with environmental laws and regulations did not have a material effect on the operating costs, capital expenditures, earnings or competitive position of the Corporation in 2017 and, based on current laws, facts and circumstances, is not expected to have a material effect on such matters in the future. Operating and capital costs associated

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with complying with environmental laws and regulations are generally recoverable by the Corporation through rates.

5.5 RELEASES

Federal, provincial and municipal environmental legislation regulate the release of substances into the environment through the regulation of discharges that have an adverse effect or a potentially adverse effect on the environment. FBC believes that the potential for spills, and resulting enforcement actions under existing environmental legislation, is reduced through the implementation of spill prevention, material handling, emergency response programs and spill response guidelines in conjunction with appropriate training. The potential for an adverse effect resulting from a spill is further reduced by the Corporation through the tracking of all incidents and potential incidents in an incident reporting database in order to facilitate continual learning and improvement.

5.6 HAZARDOUS SUBSTANCES

The Corporation manages hazardous substances used in its operations such as PCBs and herbicides. The Corporation has environmental management programs in place to deal with the hazardous substances including programs to deal with PCBs and herbicides:

- (a) *PCBs* - Current management plans for PCBs focus on the identification, safe handling, transportation, storage and ultimate disposal of PCB containing equipment. As equipment becomes obsolete and is taken out of service, FBC disposes of it in an environmentally sound manner and in compliance with applicable laws. Federal PCB regulations specify deadlines for the elimination of PCB containing equipment. With the exception of pole-top transformers and their auxiliary equipment, PCB containing equipment having levels of PCBs greater than 500 ppm or those with PCB levels between 50 ppm and 500 ppm located in sensitive areas were removed from service by the end of 2009. FBC believes it is compliant with the PCB regulation. For certain substation auxiliary equipment FBC had been granted an extension to the Federal PCB regulation deadline to 2014 and had mitigated the PCB concern for the majority of this substation equipment at year end. However, the regulation was subsequently amended to extend the deadline for removal from service of such substation auxiliary equipment to December 31, 2025. All other electrical equipment with PCB levels greater than 50 ppm must be removed from service by December 31, 2025. FBC is taking the necessary steps to meet these compliance deadlines and will recover the associated costs through rates as approved by BCUC.
- (b) *Herbicides* - The Corporation uses herbicides primarily for the control of incompatible vegetation on rights-of-way, along transmission and distribution lines and on station sites. The Corporation uses an integrated approach toward vegetation management using manual and mechanical cutting, natural competition from compatible vegetation, together with the selective use of herbicides. Patrols occur to monitor vegetation growth and assess appropriate maintenance activities. Site-specific conditions, including tree species, tree density, height, terrain, prevailing wind directions, and adjacent land uses, are considered by the Corporation in determining the appropriate overall vegetation management plan. Herbicides are applied in accordance with applicable federal and provincial legislation, which governs application, notification and reporting.
- (c) *Other* - In addition, some facilities and products used in operational activities contain substances that are designated for special treatment under occupational health and safety legislation, such as asbestos, lead and mercury. The Corporation has exposure control plans in place to address situations when these kinds of substances are encountered or utilized. In addition, the Corporation has programs in place to manage the disposal of materials and products containing hazardous substances in accordance with regulatory requirements.

5.7 SITE INVESTIGATION AND REMEDIATION

Spills and leaks of substances may occur in the normal course of the Corporation's operations and may result in future clean-up costs being incurred in connection with these releases. The Corporation has from time to

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time, investigated sites for potential contamination and remediated sites where appropriate. It is possible that remediation costs could be incurred in future due to contamination at sites and the Corporation expects that costs incurred for site remediation would be recovered through rates.

5.8 AIR EMISSIONS MANAGEMENT AND POLICY

BC government policy direction with respect to air emissions management regulation continues to unfold, but it remains to be determined to what extent a greenhouse gas emissions cap will impact the Corporation. To mitigate this uncertainty, BC is a participant in the Western Climate Initiative (“WCI”). Some members of WCI have implemented a cap and trade program to reduce greenhouse gas emissions. However, the government of British Columbia has delayed the implementation of this regulatory initiative. If British Columbia decides to participate in the WCI cap and trade program the specific details will be defined in regulation. If implemented the cap and trade program is expected to have a declining cap on emissions that all covered facilities must meet, either by reducing emissions internally or by purchasing allowances from other facilities for releases over the capped amount. In 2012, the Corporation began reporting its greenhouse gas emissions for electricity imports pursuant to the provincial greenhouse gas reporting regulation.

5.9 ASSET RETIREMENT OBLIGATIONS

During 2010 the Corporation obtained sufficient information to determine an estimate of the fair value and timing of the estimated future expenditures associated with the removal of PCB contaminated oil, as previously described in Section 5.6(a), from certain of its electrical equipment. As such, the Corporation has recorded an ARO of approximately \$2.2 million as at December 31, 2017. The determination of the ARO depends upon management’s best estimates relating to factors such as timing, amount and nature of future cash flows necessary to discharge the legal obligation and comply with existing legislation or regulations, as well as the use of a credit-adjusted risk-free rate for measurement purposes. There are uncertainties in estimating future asset retirement costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. It is possible that volumes of contaminated assets, inflation assumptions, cost estimates to perform the work and the assumed pattern of annual cash flows may differ significantly from the Corporation’s current assumptions. In addition, in order to remove certain PCB-contaminated oil, the ability to conduct maintenance outages in critical facilities may impact the timing of expenditures. The ARO may change from period to period because of the changes in the estimation of these uncertainties.

Excluding the ARO pertaining to PCBs, the nature, amount and timing of costs associated with land and other environmental remediation and/or removal of assets, cannot be reasonably estimated due to the nature of their operation; and applicable licences, permits and laws are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers. In the event that environmental issues are identified, or the applicable licences, permits, laws or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

5.10 EMERGENCY PREPAREDNESS AND SAFETY

FBC has detailed emergency preparedness plans in place to respond to natural disasters, accidents and emergencies, and regularly tests these plans in simulations involving employees and other emergency response organizations.

The Corporation is committed to monitoring and assessing its safety management system regularly. FBC incorporates safety performance measures into its employee compensation system, sets challenge levels and objectives for performance, and conducts safety and environmental audits regularly.

5.11 ELECTRO-MAGNETIC FIELDS

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and within every building that has electrical service. Scientists and public health experts in North America and abroad are studying the possibility that exposure to electro-magnetic fields may cause health problems. FBC understands there is no conclusive evidence of any harm caused by

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exposure at levels normally found in Canadian living and working environments. Electro-magnetic fields are not currently regulated by the federal or provincial governments and the Corporation is unaware of any plans to regulate electro-magnetic fields.

6.0 RISK FACTORS

For more information with respect to risks and uncertainties to which the Corporation is subject, see the section entitled “Business Risk Management” in the Corporation’s Management Discussion & Analysis for the year ended December 31, 2017, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

7.0 CAPITAL STRUCTURE

FBC’s business requires the Corporation to have ongoing access to capital to allow it to build and maintain the electrical systems in its service territory. In order to ensure that this access to capital is maintained and in accordance with BCUC requirements, the Corporation currently targets a long-term capital structure that includes 40 per cent equity and 60 per cent debt. This capital structure excludes the effects of goodwill and other items that do not impact the deemed capital structure. The cost of capital for regulated utilities in BC is reviewed periodically which can result in a change in the equity component for the Corporation.

7.1 SHARE CAPITAL

The Corporation is authorized to issue 500,000,000 common shares with a par value of \$100 each and 500,000,000 preferred shares with a par value of \$25 each, of which 20,000 shares have been designated as Preferred Shares - Series 1, and 480,000 shares have been designated as Cumulative Redeemable Retractable Preferred Shares - Series 2. The issued and outstanding share capital of FBC as at December 31, 2017 consists of 2,191,510 common shares and no preferred shares. Fortis owns all of the issued common shares through its indirect wholly-owned subsidiary, FortisBC Pacific.

Holder of common shares of the Corporation are entitled to receive dividends as and when declared by the Board, subject to the rights of holders of the preferred shares, and are entitled to one vote per share on all matters to be voted on at all meetings of shareholders except those meetings at which only the holders of shares of another class or of a particular series are entitled to vote. Upon the liquidation, dissolution or winding-up of the Corporation, the holders of common shares are entitled to share rateably in the remaining assets available for distribution, after payment of liabilities and subject to the rights of the holders of the preferred shares. The common shares do not have exchange, conversion, redemption or retraction rights.

Preferred shares may be issued from time to time in one or more series, each series comprising the number of shares, designation, rights and restrictions determined by the Board. Preferred shares are entitled to priority over the common shares with respect to the payment of dividends and distributions of assets in the event of the liquidation, dissolution or winding-up of the Corporation. Except in respect of a meeting of holders of the preferred shares or of a particular series of the preferred shares, or except as may otherwise be provided in the rights attached to any series of preferred shares, holders of the preferred shares will not be entitled to vote at any meetings of shareholders.

7.2 DIVIDEND POLICY

The declaration and payment of dividends is at the discretion of the Board and will be influenced by ongoing capital structure management. In 2017, FBC paid \$47 million in dividends, compared with \$53 million in 2016 and \$22 million in 2015.

Certain of the Corporation’s debt covenants contain restrictions on the payment of dividends if consolidated debt exceeds 75 per cent of consolidated capitalization, if the dividends are not in the ordinary course of business or if the cumulative dividends paid since the date that certain debt instruments were issued exceeds thresholds based on the cumulative net earnings of the Corporation.

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8.0 CREDIT RATINGS

The following table discloses the Corporation’s debenture credit ratings as at December 31, 2017.

Credit Ratings	DBRS	Moody’s
Unsecured Debentures	A (low), Stable Trend	Baa1, Stable Outlook
Secured Debentures	A (low), Stable Trend	-

In July 2017, Moody’s affirmed the long term credit rating for FBC of Baa1 for unsecured debentures. In March 2017, DBRS affirmed the long-term credit rating for FBC of A(low) for unsecured and secured debentures.

Ratings are not recommendations to purchase, hold, or sell debentures because ratings do not comment as to market price or suitability for a particular investor. The Corporation understands that ratings are based on, among other things, information furnished to the rating agencies by the Corporation and information obtained by the rating agencies from public sources. Ratings may be changed, suspended or withdrawn as a result of changes in, or unavailability of, that information.

Securities issued by FBC are rated by DBRS and Moody’s. FBC paid each of these agencies a maintenance fee to provide ratings during 2017 and 2016, but did not pay for or receive any other services from the agencies during those years. The ratings assigned to securities issued by FBC are reviewed by these agencies on an ongoing basis. Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. DBRS rates debt instruments by rating categories ranging from AAA which represents the highest quality of securities, to D which represents the lowest quality of securities rated. Moody’s rates debt instruments by rating categories ranging from Aaa which represents the highest quality of securities to C which represents the lowest quality of securities.

According to the DBRS rating system, debt securities rated A are of good credit quality. Protection of interest and principal is still substantial, but the degree of strength is less than with AA related entities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. “High” or “Low” are used to indicate the relative standing of a credit within a particular rating category. The lack of one of these designations indicates a rating which is essentially in the middle of the category.

According to the Moody’s rating system, debt securities rated Baa are considered to be subject to moderate credit risk, are medium grade obligations and as such may possess certain speculative characteristics. Moody’s applies numerical modifiers (1, 2 and 3) in each rating classification from Aa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category.

9.0 MARKET FOR SECURITIES

None of the issued and outstanding shares of the Corporation or any of its debentures are listed on any exchange.

On December 4, 2017, the Corporation issued \$75 million of 32-year medium term note debentures with an interest rate of 3.62 per cent.

10.0 DIRECTORS AND OFFICERS

10.1 DIRECTORS

The following table sets forth the name, province or state, and country of residence of each director of the Corporation, his or her respective position and office with the Corporation as at the date of filing of this Annual Information Form. In addition this table sets forth each director’s principal occupation during the five preceding years, and the period during which he or she has served as a director of the Corporation, and when his or her term expires:

FortisBC Inc.

NAME AND RESIDENCE	TERM AS A DIRECTOR ⁽⁴⁾	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Peter Blake ⁽¹⁾ British Columbia, Canada	Commencing 2017. Term expires at the next annual general meeting.	Chief Executive Officer of Western One Inc. since September 2014; prior thereto CEO of Ritchie Bros. Auctioneers.
Roger A. Dall'Antonia British Columbia, Canada	Commencing 2017. Term expires at the next annual general meeting.	President & CEO of the Corporation and additionally of FortisBC Energy Inc. since December 2017; prior thereto Executive Vice President, Customer Service & Technology of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Executive Vice President, Customer Service & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc. since August 2014; prior thereto Vice President, Strategic Planning, Corporate Development & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.
Phonse Delaney ⁽²⁾ Alberta, Canada	Commencing 2016. Term expires at the next annual general meeting.	Executive Vice President and Chief Information Officer of Fortis Inc. since June 2017; prior thereto President & CEO of FortisAlberta Inc. since June 2014; prior thereto Executive Vice President, Operations, Engineering and Information Technology of FortisAlberta Inc.
Brenda Eaton ⁽¹⁾ British Columbia, Canada	Commencing 2010. Term expires at the next annual general meeting.	Corporate Director.
Ida J. Goodreau ⁽²⁾⁽³⁾ British Columbia, Canada	Commencing 2010. Term expires at the next annual general meeting.	Corporate Director.
David G. Hutchens ⁽¹⁾ Arizona, USA	Commencing 2015. Term expires at the next annual general meeting.	Executive Vice President, Western Utility Operations of Fortis Inc. since January 2018; additionally and prior thereto President & Chief Executive Officer of UNS Energy Corporation since May 2014; prior thereto President and Chief Operating Officer of same since August 2013; prior thereto President of same.
K.M. Tracy Medve ⁽²⁾ British Columbia, Canada	Commencing 2016. Term expires at the next annual general meeting.	President of KF Aerospace since May 2013; prior thereto President of Canadian North Airlines.
Barry V. Perry ⁽²⁾ Newfoundland and Labrador, Canada	Commencing 2010. Term expires at the next annual general meeting.	President & CEO of Fortis Inc. since January 2015; prior thereto President of Fortis Inc. since June 2014; prior thereto Vice President, Finance & Chief Financial Officer of Fortis Inc.

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NAME AND RESIDENCE	TERM AS A DIRECTOR ⁽⁴⁾	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Christopher F. Scott ⁽²⁾ British Columbia, Canada	Commencing 2013. Term expires at the next annual general meeting.	Corporate Director; additionally Consultant to First Nations Bands; additionally Owner/Operator of Premium Varietal Vineyard.
Karl W. Smith ⁽¹⁾ Newfoundland and Labrador, Canada	Commencing 2014. Term expires at the next annual general meeting.	Executive Vice President & Chief Financial Officer of Fortis Inc. since June 2014; prior thereto President & CEO of FortisAlberta Inc.
Janet P. Woodruff ⁽¹⁾ British Columbia, Canada	Commencing 2013. Term expires at the next annual general meeting.	Corporate Director; additionally Consultant to June 2015.

Notes:

1. Member of the Audit and Risk Committee.
2. Member of the Governance Committee.
3. Chair of the Board.
4. The Articles of the Corporation provide that if the Corporation does not hold an annual general meeting in accordance with the *Business Corporations Act* (British Columbia), the Directors then in office shall be deemed to have been elected or appointed as Directors on the last day on which the annual general meeting could have been held pursuant to the *Business Corporations Act* (British Columbia), and they may hold office until other Directors are appointed or elected or until the day on which the next annual general meeting is held.

FortisBC Inc.

10.2 OFFICERS

The following table sets forth the name, province and country of residence of each executive officer of the Corporation, his or her respective position and office with the Corporation as at the date of filing of this Annual Information Form. In addition, this table sets forth each officer's principal occupation during the five preceding years:

NAME AND RESIDENCE	OFFICE HELD	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Roger A. Dall'Antonia British Columbia, Canada	President & CEO	President & CEO of the Corporation and additionally of FortisBC Energy Inc. since December 2017; prior thereto Executive Vice President, Customer Service & Technology of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Executive Vice President, Customer Service & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc. since August 2014; prior thereto Vice President, Strategic Planning, Corporate Development & Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.
Doyle Sam British Columbia, Canada	Executive Vice President, Operations & Engineering	Executive Vice President, Operations & Engineering of the Corporation and additionally of FortisBC Energy Inc. since February 2014; prior thereto Executive Vice President, Network Services, Engineering & Generation of the Corporation and additionally of FortisBC Energy Inc. since February 2013; prior thereto Vice President, Engineering & Generation of the Corporation and additionally of FortisBC Energy Inc.
Cynthia M. Des Brisay British Columbia, Canada	Vice President, Midstream Services	Vice President, Midstream Services of the Corporation and additionally of FortisBC Energy Inc. since August 2017; prior thereto Vice President, Midstream Services & Resource Development of the Corporation and additionally of FortisBC Energy Inc. since April 2016; additionally President of FortisBC Midstream Inc. since November 2015; prior thereto Vice President, Energy Supply & Resource Development of the Corporation and additionally of FortisBC Energy Inc.
Jody D. Drope British Columbia, Canada	Vice President, Human Resources & Environment, Health and Safety	Vice President, Human Resources & Environment, Health and Safety of the Corporation and additionally of FortisBC Energy Inc. since November 2014; prior thereto Chief Human Resources Officer of the Corporation and additionally of FortisBC Energy Inc.

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NAME AND RESIDENCE	OFFICE HELD	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Michael A. Leclair British Columbia, Canada	Vice President, Major Projects	Vice President, Major Projects of the Corporation and additionally of FortisBC Energy Inc. since February 2018; prior thereto Director, Generation & Compression of the Corporation since August 2016; prior thereto Director, Generation of the Corporation since January 2014; prior thereto Manager, Generation of the Corporation.
Ian G. Lorimer British Columbia, Canada	Vice President, Finance & CFO	Vice President, Finance & CFO of the Corporation and additionally of FortisBC Energy Inc. since June 2015; prior thereto Vice President, Finance & CFO of FortisAlberta Inc.
Dawn M. Mehrer British Columbia, Canada	Vice President, Customer Service and Information Systems	Vice President, Customer Service and Information Systems of the Corporation and additionally of FortisBC Energy Inc. since February 2018; prior thereto Director, Customer Contact Centres of FortisBC Energy Inc.
Diane E. Roy British Columbia, Canada	Vice President, Regulatory Affairs	Vice President, Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc. since October 2016; prior thereto Director, Regulatory Services of the Corporation and additionally of FortisBC Energy Inc. since November 2014; prior thereto Director, Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.
Douglas L. Stout British Columbia, Canada	Vice President, Market Development & External Relations	Vice President, Market Development & External Relations of the Corporation and additionally of FortisBC Energy Inc. since August 2014; prior thereto Vice President, Energy Solutions & External Relations of the Corporation and additionally of FortisBC Energy Inc.
Dennis A. Swanson British Columbia, Canada	Vice President, Energy Supply & Resource Development	Vice President, Energy Supply & Resource Development of the Corporation and additionally of FortisBC Energy Inc. since August 2017; prior thereto Vice President, Energy Supply of the Corporation and additionally of FortisBC Energy Inc. since May 2016; prior thereto Vice President, Corporate Services of the Corporation and additionally of FortisBC Energy Inc. since November 2014; prior thereto Director, Regulatory Affairs of the Corporation and additionally of FortisBC Energy Inc.

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NAME AND RESIDENCE	OFFICE HELD	PRINCIPAL OCCUPATION FOR THE FIVE PRECEDING YEARS
Monic D. Pratch British Columbia, Canada	Corporate Secretary	Chief Privacy Officer, Corporate Secretary & Senior Counsel of the Corporation and additionally of FortisBC Energy Inc. since April 1, 2017; prior thereto Chief Privacy Officer, Corporate Secretary & Counsel of the Corporation and additionally of FortisBC Energy Inc. since November 2014; prior thereto Chief Privacy Officer & Counsel of the Corporation and additionally of FortisBC Energy Inc.
Debra G. Nelson British Columbia, Canada	Assistant Corporate Secretary	Assistant Corporate Secretary and Manager, Corporate Compliance and Secretariat of the Corporation and additionally of FortisBC Energy Inc.

10.3 CONFLICTS OF INTEREST

Other than as disclosed herein, to the knowledge of management of the Corporation, there are no existing or potential material conflicts of interest among the Corporation or a subsidiary of the Corporation and any director or officer of the Corporation or such subsidiary.

11.0 EXECUTIVE COMPENSATION

The Corporation's Statement of Executive Compensation is attached as Schedule "A".

12.0 SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The Corporation does not have a compensation plan under which securities of the Corporation are authorized for issuance. See "Executive Compensation – Share Based Awards" in Schedule "A" of this Annual Information Form for a description of the Fortis 2012 Stock Option Plan.

13.0 INDEBTEDNESS OF EXECUTIVE OFFICERS, DIRECTORS, AND EMPLOYEES

The following table sets forth details of the aggregate indebtedness of all executive officers, directors, and employees and former executive officers, directors and employees outstanding at the date of this Annual Information Form to the Corporation or any of its subsidiaries in connection with (i) the purchase of securities and (ii) all other indebtedness, other than routine indebtedness.

Aggregate Indebtedness (\$)		
Purpose	To the Corporation or its Subsidiaries	To Another Entity
Share purchases	Nil	Nil
Other	Nil	Nil

14.0 INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Corporation, or person or Corporation that beneficially owns, or controls or directs, directly or indirectly, more than 10 per cent of any class or series of the Corporation's outstanding voting securities, nor any associate of the foregoing persons, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years of the Corporation or during the current financial year of the Corporation that has materially affected or is reasonably expected by the Corporation to materially affect the Corporation.

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For more information with respect to the Corporation's material transactions with related parties, see the section entitled "Related Party Transactions" in the Corporation's Management Discussion & Analysis for the year ended December 31, 2017, which is filed on SEDAR at www.sedar.com, and is incorporated herein by reference.

15.0 MATERIAL CONTRACTS

The following are the only material contracts, other than contracts entered into in the ordinary course of business and not required by applicable securities laws to be filed with a Canadian securities regulatory authority or those that were entered into before January 1, 2002, which have been entered into by the Corporation within the Corporation's most recently completed financial year, or before the most recently completed financial year but is still in effect:

- the trust indenture dated as of November 30, 2004 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time;
- the CPA (see "The Business of FortisBC Inc. – Generation and Power Supply"); and
- the trust indenture dated as of May 27, 2009 between the Corporation and Computershare Trust Corporation of Canada, as Trustee, as supplemented and amended from time to time.

Copies of the above noted agreements are contained on SEDAR at www.sedar.com.

16.0 LEGAL PROCEEDINGS

The Province of BC filed a claim in the BC Supreme Court on June 8, 2012 claiming on its behalf, and on behalf of approximately 17 homeowners, damages suffered as a result of a landslide caused by a dam failure in Oliver, BC in 2010. The Province alleges in its claim that the dam failure was caused by the defendants, including FBC, through the use of a road on top of the dam. The Province estimates its damages and the damages of the homeowners on whose behalf it is claiming, to be approximately \$15 million. FBC had notified its insurers of this claim. In December, 2017, FBC was advised by counsel for the Province that the Province is requesting that all defendants agree to a consent dismissal order which will dismiss the claim without costs to any party. FBC has agreed to the consent dismissal order and is waiting on confirmation that the other defendants will agree to the consent dismissal order. The outcome cannot be reasonably determined or estimated at this time and, accordingly, no amount has been accrued in the financial statements.

17.0 TRANSFER AGENTS AND REGISTRARS

Computershare Trust Corporation of Canada is the registrar and transfer agent and trustee for the Corporation's debentures. Transfers of these securities may be effected at Computershare Trust Corporation of Canada's offices in the city of Vancouver, BC.

18.0 INTEREST OF EXPERTS

Deloitte LLP Chartered Accountants is the auditor of the Corporation and was appointed effective as at May 15, 2017. Deloitte LLP, has prepared the audit report attached to the audited consolidated financial statements for the Corporation's financial year ended December 31, 2017. Deloitte LLP remains independent with respect of the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of British Columbia.

Prior to the appointment of Deloitte LLP as the auditor of the Corporation, Ernst & Young LLP Chartered Accountants was the auditor of the Corporation. Ernst & Young LLP prepared the audit report attached to the audited consolidated financial statements for the Corporation's financial year ended December 31, 2016 which were filed on February 16, 2017. Ernst & Young LLP remains independent with respect of the Corporation within the meaning of the Rules of Professional Conduct of the Chartered Professional Accountants of British Columbia.

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19.0 ADDITIONAL INFORMATION

Additional financial information is also provided in the Corporation's financial statements for the financial year ended December 31, 2017, and management's discussion and analysis of such financial results. A copy of such documents and additional information relating the Corporation is contained on SEDAR at www.sedar.com. Such information is not incorporated by reference into this document unless specifically stated herein.

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SCHEDULE “A” - EXECUTIVE COMPENSATION

A. COMPENSATION DISCUSSION AND ANALYSIS

It is the responsibility of the Governance Committee to review, recommend and administer the compensation policies in respect of the Corporation's executive officers. The Governance Committee's recommendations as to base salary, short term incentives and grants under the 2015 Performance Share Unit (“PSU”) Plan and the 2015 Restricted Share Unit (“RSU”) Plan are submitted to the Board of the Corporation for approval. Proposed grants to the Corporation’s executive officers under the Fortis Stock Option Plan are submitted by the Corporation’s Board to the Human Resources Committee of the Fortis Board of Directors for approval.

The Corporation’s executive compensation program is designed to provide competitive levels of compensation, a significant portion of which is dependent upon individual and corporate performance and contribution to increasing shareholder value. The Governance Committee recognizes the need to provide a total compensation package that will attract and retain qualified and experienced executives as well as align the compensation level of each executive to that executive’s level of responsibility.

The Corporation has a policy of compensating executive officers at approximately the median (50th percentile) of comparable Canadian commercial industrial companies. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. Annually, the Governance Committee uses the compensation data from this reference group to compare each executive officer to corresponding positions within the reference group. This framework serves as a guide for the Governance Committee’s deliberations. The actual total compensation and/or amount of each compensation component for an individual executive officer may be more or less than the median amount.

Total annual compensation for the executive officers is composed primarily of five main components:

- annual base salary;
- annual incentive plan that provides the opportunity to each to earn a cash bonus;
- share-based awards that provide the opportunity to earn cash at the end of a three-year period (RSU Plan);
- share-based awards that provide the opportunity to earn cash based on performance metrics at the end of a three-year period (PSU Plan);
- option-based awards to purchase Fortis Common Shares; and
- pension arrangements.

Each of the components is discussed further in the following sections of this Schedule “A”.

REPORT ON CORPORATE GOVERNANCE

Governance Committee

Specifically, the Governance Committee provides assistance to the Board by overseeing the Corporation’s policy and performance in matters of corporate governance, including the nomination of Directors, matters of environment and safety, and matters of human resource management, including compensation of executive officers and the Corporation’s pension plans.

With regards to executive compensation matters, the responsibilities of the Governance Committee include reviewing and making recommendations to the Board regarding:

- the adequacy and form of compensation of directors;
- the appointment and compensation of executive officers;
- the overall effectiveness of the senior management team including the CEO; and
- the development of policy for orderly succession to senior positions and targets used by the Corporation to measure performance for compensation purposes.

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Total annual compensation for the executive officers involves a significant proportion that is at risk due to the use of short-term and long-term incentive components. For 2017, approximately 65 per cent of the President & Chief Executive Officer's total annual compensation was designed to be at risk. Approximately 55 per cent of other executive officers' total annual compensation was designed to be at risk. Total annual compensation includes both the cash compensation paid to the executive officers in the year and the target compensation for the medium-term and long-term incentive components.

Additionally, the Governance Committee believes that the Corporation's compensation regime appropriately takes into account the performance of the Corporation and the contribution of the President & CEO and other executive officers of the Corporation toward that performance.

The mandate of the Governance Committee includes making recommendations to the Board with respect to the governance and management of the pension plans and designating executive officers for purposes of participation in supplemental pension plans. In regards to non-union pension matters, the Governance Committee appoints the auditor for the pension plan financial statements. The Board establishes or terminates pension plans, is the fiduciary and administrator for the plans and approves the governance structure, major plan design changes and the mandate of the Governance Committee.

The Corporation recognizes the importance of appointing knowledgeable and experienced individuals to the Governance Committee. The Governance Committee composition includes members that have the necessary background and skills to provide effective oversight of corporate governance and executive compensation, including adherence with sound risk management principles.

To enable the Governance Committee to fulfill its mandate, all Governance Committee members have significant senior leadership and/or governance experience. More specifically, a majority of the membership of the Governance Committee has direct operational or functional experience overseeing compensation policies and practices at large organizations similar in complexity to FBC.

The members of the Governance Committee are Christopher F. Scott, Ida J. Goodreau, Barry V. Perry, K. M. Tracy Medve and Phonse J. Delaney. These directors are independent directors with the exception of Barry V. Perry, President & CEO of Fortis Inc. and Phonse J. Delaney, Executive Vice President, Chief Information Officer of Fortis Inc.

In fulfilling its duties and responsibilities with respect to executive compensation, the Governance Committee seeks periodic input, advice, and recommendations from various sources, including the Board, executive officers, and external independent consultants. The Governance Committee retains discretion in its executive compensation decisions and is not bound by the input, advice, and/or recommendations received from the external independent consultant.

Compensation Review Framework

Annual Review

FBC monitors, reviews, and evaluates its executive compensation program annually to ensure that it provides reasonable compensation ranges at appropriate levels and remains competitive and effective.

As part of the annual review process, Fortis engages Hay Group Limited ("Hay Group"), its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian commercial industrial companies. Using this data, a detailed review is prepared to analyze the Corporation's competitive compensation positioning against its peer group is undertaken. Hay Group provides Fortis and its subsidiaries' management preliminary recommendations on the basis of pay competitiveness, emerging market trends and best practices. In addition, the Corporation may from time to time engage Hay Group to provide specific analysis of its executive compensation components.

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Management then takes into account the corporate performance against pre-determined objectives and together with the CEO recommends a set of new performance objectives for the following year. Individual performance reviews, incentive award payouts, and compensation adjustments, if any, are also determined at this stage. The CEO does not make recommendations to the Governance Committee with respect to his own compensation.

In the final step, the Governance Committee reviews the recommendations set forward by management and the compensation consultant prior to seeking approval from the Board regarding current year’s compensation payouts and next year’s performance objectives. The Governance Committee and the Board may exercise discretion when making compensation decisions in appropriate circumstances and make deviations from the prescribed incentive award formulas, if necessary.

Competitive Positioning

FBC does not measure performance against a particular reference group. However, as a general policy, FBC establishes base and incentive compensation targets so as to compensate executives and in particular, each person who served as the CEO or CFO during the most recently completed financial year and the most highly compensated executive officers of the Corporation during the most recently completed financial year (the “Named Executive Officers” or “NEOs”), at a level generally equivalent to the median of practice among a broad reference group of approximately 200 Canadian commercial industrial companies. This reference group, (The Commercial Industrial Comparator Group) is compiled by Hay Group. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It does include organizations from the energy, mining and manufacturing sectors. This reference group is formally reviewed as part of the Fortis biennial review of executive compensation policy.

Elements of Total Compensation

Total annual compensation for the executive officers involves a significant proportion that is at risk due to the use of short-term and long-term incentive components. The total annual compensation includes both the cash compensation paid to the executive officers in the year and an estimated compensation for the long-term incentive components.

The executive compensation regime is structured in a manner that recognizes the greater ability of the President & CEO to affect corporate performance by making a greater portion of that individual’s compensation dependent upon corporate performance.

The elements of compensation of the NEOs and their respective compensation objectives are set out below:

Compensation Element (<i>Eligibility</i>)	Description	Compensation Objectives
Annual Base Salary and Annual Incentive		
Annual Base Salary <i>(all NEOs)</i>	Salary is a market-competitive, fixed level of compensation.	Attract and retain highly qualified executives. Motivate strong business performance.
Annual Incentive <i>(all NEOs)</i>	Combined with salary, the target level of annual incentive is intended to provide executives with a market-competitive total cash opportunity. Annual incentive payout depends on individual and corporate performance.	Attract and retain highly qualified executives. Motivate strong business performance. Compensation dependent on individual and corporate performance. Simple to communicate and administer.

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Mid-term Equity Based Incentive		
<p>Share-Based Awards (PSUs) <i>(all NEOs)</i></p>	<p>Incentive is based on Fortis' performance over a three-year period against predetermined measures.</p> <p>The amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average price of Fortis' common shares for the five trading days immediately preceding the date of grant. The grant date is January 1 of each year.</p> <p>Cash payout upon completion of the three-year performance period, depending on Fortis' performance.</p>	<p>Align executive and shareholder interests.</p> <p>Attract and retain highly qualified executives.</p> <p>Encourage strong long-term business performance.</p> <p>Balance compensation for short and long-term strategic results.</p> <p>Compensation dependent on corporate performance.</p> <p>Encourages sustained long-term growth by linking a portion of compensation to long-term performance.</p> <p>Simple to communicate and administer.</p>
<p>Share Based Awards (RSUs) <i>(all NEOs)</i></p>	<p>The amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average price of Fortis' common shares for the five trading days immediately preceding the date of grant. The grant date is January 1 of each year.</p> <p>Cash payout upon completion of the three-year period.</p>	<p>Align executive and shareholder interests.</p> <p>Attract and retain highly qualified executives.</p> <p>Balance compensation for short and long-term strategic results.</p> <p>Simple to communicate and administer.</p>
Long-term Equity Based Incentive		
<p>Stock Options <i>(all NEOs)</i></p>	<p>Annual equity grants are made in the form of stock options to purchase common shares of Fortis.</p> <p>Beginning in 2015, the amount of annual grant is determined as a specified percentage of the participant's annual base salary divided by the binomial valuation of Fortis' share price.</p> <p>Options vest over a 4 year period and expire after 7 years (2006 Stock Option Plan) or 10 years (2012 Stock Option Plan).</p>	<p>Align executive and shareholder interests.</p> <p>Attract and retain highly qualified executives.</p> <p>Encourage strong long-term business performance.</p> <p>Balance compensation for short and long-term strategic results.</p> <p>Simple to communicate and administer.</p>

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Pension Plans		
Registered Retirement Savings Plan (“RRSP”) (<i>all NEOs</i>)	Contribution to a RRSP equal to 6.5 per cent of a member’s base salary which is matched by the member up to the maximum annual contribution limit allowed by the Canada Revenue Agency.	Attract and retain highly qualified executives. Simple to communicate and administer.
Defined Contribution: Supplemental Employee Retirement Plan (“SRP” or “SERP”) (<i>all NEOs</i>)	Accrual of 13 per cent of base salary and annual incentive in excess of the Canada Revenue Agency annual limit. At time of retirement, paid in one lump sum or in equal payments up to 15 years.	Attract and retain highly qualified executives. Simple to communicate and administer.

Annual Base Salary

Annual base salaries paid to the Corporation’s NEOs are determined by the Board upon recommendation by the Governance Committee and are established annually by reference to the range of salaries paid by comparable Canadian commercial industrial companies and are targeted to the median of the comparator group.

Annual Incentive

NEOs participate in an annual incentive plan that provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets approved by the Board upon recommendation by the Governance Committee. The Corporation’s annual earnings must reach a minimum threshold level before any payments are made. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Corporation.

Corporate performance is determined with reference to the performance of the Corporation relative to weighted targets in respect to financial, safety, customer satisfaction and regulatory performance. There were five targets in 2017 which included (i) net earnings (35.0 per cent weighting); (ii) sustainment and other capital execution (15.0 per cent weighting); (iii) an all injury frequency rate which measures how safely the Corporation operates (20.0 per cent weighting); (iv) customer satisfaction which measures a customer survey score (15.0 per cent weighting); and (v) field services score (15.0 per cent weighting). Net earnings are primarily based on regulated earnings which are representative of the achieved return on equity based on the allowed return on equity as approved by the BCUC.

Individual performance is determined with reference to individual contribution to corporate objectives, elements of which are subjective. For the President & CEO, 70 per cent of the annual cash bonus is based on corporate targets and 30 per cent is based upon personal targets. For each of the other NEOs, 50 per cent of the annual cash bonus is based upon corporate targets and 50 per cent is based upon personal targets. At the discretion of the Board, executives may be awarded up to an additional 50 per cent of target incentive pay in recognition of exceptional performance contributions.

Medium and Long-Term Incentive Plan

Effective 2015, the Corporation has changed its medium and long-term incentive granting practices to provide a target long-term incentive (“LTI”) value, expressed as a percentage of base salary, which is then granted in pre-determined proportions of PSUs, RSUs and stock options. The LTI value for the former President & CEO was 150 per cent of his base salary. The LTI value for the current President & CEO while in his former role of Executive Vice President, Customer Service and Technology was 70 per cent of his base salary. The Vice President, Finance & CFO was granted LTI having a market value at the time of grant equal to 60 per cent of his base salary. The Executive Vice President, Operations & Engineering was granted LTI having a market

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value at the time of grant equal to 70 per cent of his base salary. The LTI value is granted to all the executive officers through a combination of 50 per cent in PSUs, 25 per cent in RSUs and 25 per cent in stock options.

Share Based Awards

PSUs: Effective January 1, 2015, the Corporation adopted a PSU plan. Each PSU represents a unit with an underlying value equivalent to the value of a Fortis common share. Grants of PSUs are determined as a specified percentage of the participant's annual base salary divided by the volume-weighted average trading price of Fortis common shares for the five trading days immediately preceding the date of the grant. Notional dividends are assumed to accrue to the holder of the PSU and to be reinvested on the quarterly dividend payment dates of the common shares. Payment is made three years after the grant in an amount of 0-200 per cent of the number of PSUs accumulated, including reinvestment of notional dividends, times the volume-weighted average trading price of Fortis common shares, as determined appropriate by the Governance Committee upon measurement of Fortis' performance, as compared to a comparable group of utility holding companies, over such three-year period against predetermined measures. Previous grants of PSUs are not taken into consideration when new PSUs are awarded.

RSUs: Effective January 1, 2015, the Corporation adopted a RSU plan. Each RSU represents a unit with an underlying value equivalent to the value of a Fortis common share. Grants of RSUs and the accumulation of notional dividends are consistent with the PSU plan. Payment will be made three years after the grant in an amount of the number of RSUs accumulated, including reinvestment of notional dividends, times the volume-weighted average trading price of Fortis common shares.

Option-Based Awards: Long-term incentives take the form of grants of options under a Fortis Stock Option Plan, pursuant to which options to acquire Fortis common shares may be granted to executive officers, in order to encourage increased share ownership to participants as an incentive to maximize shareholder value. Grants of options are dependent upon the optionee's salary.

In February 2017, the former President & Chief Executive Officer of the Corporation was granted options entitling him to purchase that number of common shares of Fortis having a market value at the time of grant equal to 37.5 per cent of his base salary. The Chief Financial Officer of the Corporation was granted options entitling him to purchase that number of common shares of Fortis having a market value at the time of grant equal to 15.0 per cent of his base salary. The current President & Chief Executive Officer while in his previous role of Executive Vice President, Customer Service & Technology and the Executive Vice President, Operations & Engineering were granted options entitling the executive to purchase that number of common shares having a market value at the time of grant equal to 17.5 per cent of such executive's base salary. Previous grants of stock options are not taken into consideration when new options are awarded.

The stock option plan in place for 2017 was the 2012 Stock Option Plan. The 2012 Stock Option Plan became effective May 4, 2012. The provisions of the 2012 Stock Option Plan dealing with the eligibility, grant and terms of options are similar to the 2006 Stock Option Plan; however, the exercise period of options granted under the 2012 Stock Option Plan has been increased from seven (7) to ten (10) years from the date the option is granted, subject to any accelerated termination. In addition, options granted under the 2012 Stock Option Plan will vest and become exercisable at such time or times as may be determined by Fortis. Under the terms of this plan, all options granted, vesting rights, and financing provisions under previous plans continue to exist and remain in force as long as any options granted under former plans are outstanding. No consolidation of options granted previous to May 4, 2012 will be made into the 2012 Stock Option Plan and Fortis has ceased to grant options under previous stock option plans.

The stock option plan in place for 2011 and prior years was the 2006 Stock Option Plan which became effective May 2, 2006. Under this plan, options are exercisable for seven years from the date of the option grant subject to a vesting requirement whereby options vest at a rate of 25 per cent per year over the four year period commencing on the first anniversary of the date of grant. The Corporation does not provide financial assistance to the optionee on the exercise of options granted after May 2, 2006.

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Pension Plans – see “Executive Compensation – Pension Plan Benefits”.

Director Compensation

The Governance Committee reviews director compensation on a periodic basis by reviewing director fees paid by organization of similar size and complexity to FBC.

Director compensation is comprised solely of retainer and meeting fees. There are no compensation securities issued to Directors. In 2017, each director of the Corporation, other than the President & CEO who does not receive director compensation, was paid an annual retainer of \$50,000 and a meeting fee of \$1,250 for attending each meeting of the Board or any Committee thereof, in person or by telephone. An additional annual retainer of \$8,000 was paid to the Chair of the Audit & Risk Committee and an additional annual retainer of \$4,000 was paid to the Chair of Governance Committee. The Chair of the Board was paid an annual retainer of \$85,000, inclusive of the basic annual director’s retainer. The Corporation also paid an additional \$1,000 in respect of travel time for directors that attended a group of meetings outside of their regional area of residence.

Directors of FBC also serve on the respective board of FEI, and the companies share the total board compensation costs proportionately.

The President & Chief Executive Officer receives no fees for his services as a director.

B. TABLE OF COMPENSATION

The following table sets forth information concerning the compensation earned for services rendered in respect of each of the individuals who served as the President & CEO, the Vice President, Finance & CFO and the Corporation’s other most highly compensated executive officer during the most recently completed financial year. The table also details individual director compensation.

Name and position	Year	Salary or Retainer ⁽¹⁾ (\$)	Bonus ⁽²⁾ (\$)	Committee or meeting fees ⁽³⁾ (\$)	Value of all other compensation ⁽⁴⁾ (\$)	Total Compensation ⁽⁵⁾⁽⁶⁾⁽⁷⁾ (\$)
Roger A. Dall’Antonia President & CEO Director ⁽⁸⁾ FortisBC Holdings Inc.	2017	345,789	319,100	-	70,075	734,964
	2016	314,000	264,000	-	60,628	638,628
Michael A. Mulcahy President & CEO Director ⁽⁹⁾⁽¹⁰⁾ FortisBC Inc.	2017	454,519	428,000	-	227,244	1,109,763
	2016	460,000	470,000	-	146,761	1,076,761
Ian G. Lorimer Vice President, Finance & CFO FortisBC Energy Inc.	2017	312,000	196,000	-	81,469	589,469
	2016	299,000	203,000	-	82,488	584,488
Doyle Sam Executive Vice President, Operations & Engineering	2017	344,000	247,000	-	66,457	657,457
	2016	330,000	241,000	-	58,243	629,243
Peter Blake Director ⁽¹¹⁾	2017	37,500	-	10,000	2,000	49,500
	2016	-	-	-	-	-
Phonse Delaney Director ⁽¹²⁾	2017	50,000	-	13,750	4,000	67,750
	2016	25,000	-	8,750	3,000	36,750

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Name and position	Year	Salary or Retainer ⁽¹⁾ (\$)	Bonus ⁽²⁾ (\$)	Committee or meeting fees ⁽³⁾ (\$)	Value of all other compensation ⁽⁴⁾ (\$)	Total Compensation ⁽⁵⁾⁽⁶⁾⁽⁷⁾ (\$)
Brenda Eaton	2017	58,000	-	13,750	5,000	76,750
Director ⁽¹³⁾	2016	56,000	-	17,500	3,000	76,500
Ida J. Goodreau	2017	77,250	-	15,000	6,000	98,250
Director ⁽¹⁴⁾	2016	54,000	-	18,750	5,000	77,750
David G. Hutchens	2017	50,000	-	12,500	4,000	66,500
Director ⁽¹⁵⁾	2016	50,000	-	17,500	5,000	72,750
K.M. Tracy Medve	2017	50,000	-	15,000	4,000	69,000
Director	2016	37,500	-	12,500	3,000	53,000
Barry V. Perry	2017	50,000	-	13,750	4,000	67,750
Director ⁽¹⁶⁾	2016	50,000	-	17,500	5,000	72,500
David R. Podmore	2017	21,250	-	5,000	-	26,250
Director ⁽¹⁷⁾	2016	85,000	-	22,500	1,000	108,500
Christopher F. Scott	2017	53,000	-	15,000	1,000	72,000
Director ⁽¹⁸⁾	2016	50,000	-	18,750	5,000	73,750
Karl W. Smith	2017	50,000	-	12,500	4,000	66,500
Director ⁽¹⁹⁾	2016	50,000	-	15,000	5,000	70,000
Janet P. Woodruff	2017	50,000	-	13,750	2,000	65,750
Director	2016	50,000	-	16,250	1,000	67,250

Notes:

1. Represents the annual salary for the NEOs and the retainer paid to each of the Directors. See **Director Compensation** for a description of fees paid to Directors.
2. Represents performance bonus and amounts awarded under the Corporation's short-term non-equity incentive program in recognition of FEI and FBC's respective corporate performances and the individual's performance for the reported year and paid in the following year.
3. See **Director Compensation** for a description of retainers and other fees paid to Directors.
4. Includes, where applicable the aggregate of amounts paid by FEI or FBC for (i) payment in lieu of vacation, (ii) the dollar value of insurance premiums paid by the Corporation with respect to term life insurance, (iii) 10 per cent match by the Corporation on contributions made to purchase Fortis Common Shares through the Employee Share Purchase Plan (ESPP), (iv) interest benefit from ESPP loans, (v) Director travel reimbursement and (vi) all compensation paid or accrued to Named Executive Officers relating to defined contribution pension plans, including contributions to the Named Executive Officer's self-directed RRSF and SERP. See **Pension Plan Benefits**. Perquisites are not disclosed as they did not exceed the minimum disclosure threshold of the lesser of 10 per cent of the total annual salary of the Named Executive Officer.
5. Amounts reported represent amounts paid by FHI for Mr. Dall'Antonia's service to FBC and other FortisBC companies. FBC proportionately reimburses FHI for his service.
6. Amounts reported represent amounts payable by FBC for Mr. Mulcahy's, and Mr. Sam's service to FEI and other FortisBC companies. FEI proportionately reimburses FBC for their services.
7. Amounts reported represent amounts paid by FEI for Mr. Lorimer's service to FBC and other FortisBC companies. FBC proportionately reimburses FEI for his service.

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8. Mr. Dall'Antonia was appointed to President & CEO December 7, 2017. Mr. Dall'Antonia was also appointed to the position of Director for which no additional compensation was earned or received. Amounts reflect compensation Mr. Dall'Antonia earned in his previous role of Executive Vice President, Customer Service & Technology up to December 6, 2017 and his compensation as President & CEO, effective December 7, 2017.
9. As a result of Mr. Mulcahy's passing, his employment ended November 12, 2017.
10. In addition to his previous role of President and CEO, Mr. Mulcahy also held the position of Director for which no additional compensation was earned or received.
11. Appointed to the Board of Directors April 1, 2017.
12. Mr. Delaney also held the position of Vice President with Fortis Inc. for which Fortis Inc. provided executive compensation.
13. Chair of the Audit & Risk Committee.
14. Chair of the Board of Directors.
15. Mr. Hutchens also held the position of President & CEO of UNS Energy for which UNS Energy provided executive compensation.
16. Mr. Perry also held the position of President & CEO of Fortis Inc. for which Fortis Inc. provided executive compensation.
17. Director to March 31, 2017.
18. Chair of the Governance Committee.
19. Mr. Smith also held the position of Vice President with Fortis Inc. for which Fortis Inc. provided executive compensation.

C. COMPENSATION SECURITIES

The following table sets forth details of the securities granted to each NEO in the most recently completed financial year. There are no compensation securities issued to Directors.

Name & Position	Type of compensation security	Number of compensation securities ⁽¹⁾	Date of grant	Issue or exercise price (\$) ⁽²⁾	Closing price of underlying security on date of grant (\$) ⁽³⁾	Closing price of underlying security at year end (\$) ⁽³⁾	Expiry Date
Roger A. Dall'Antonia President & CEO Director ⁽⁴⁾	Stock Options	12,580	15-Feb-17	42.36	41.93	46.11	15-Feb-27
	PSU	2,828	1-Jan-17	41.46	41.46	46.11	1-Jan-20
	RSU	1,414	1-Jan-17	41.46	41.46	46.11	1-Jan-20
Michael A. Mulcahy President & CEO Director ⁽⁵⁾	Stock Options	41,444	15-Feb-17	42.36	41.93	46.11	12-Nov-20
	PSU	9,316	1-Jan-17	41.46	41.46	46.11	1-Jan-20
	RSU	4,658	1-Jan-17	41.46	41.46	46.11	12-Nov-17
Ian G. Lorimer Vice President, Finance & CFO ⁽⁶⁾	Stock Options	10,044	15-Feb-17	42.36	41.93	46.11	15-Feb-27
	PSU	2,258	1-Jan-17	41.46	41.46	46.11	1-Jan-20
	RSU	1,129	1-Jan-17	41.46	41.46	46.11	1-Jan-20
Doyle Sam Executive Vice President, Operations & Engineering ⁽⁷⁾	Stock Options	12,920	15-Feb-17	42.36	41.93	46.11	15-Feb-27
	PSU	2,904	1-Jan-17	41.46	41.46	46.11	1-Jan-20
	RSU	1,452	1-Jan-17	41.46	41.46	46.11	1-Jan-20

Notes:

1. Each unit of stock option, PSU and RSU is equivalent to one common share of Fortis. The compensation securities granted in 2017 represent less than 1 per cent of the total number of common shares issued and outstanding of Fortis.
2. The exercise price for stock options and issue price for PSUs and RSUs is the volume weighted average price of the common shares of Fortis traded on the Toronto Stock Exchange (TSX) for the five (5) trading days immediately preceding the date of grant.
3. Represents the closing price of Fortis Common Shares on the TSX on the applicable dates.
4. At December 31, 2017, Mr. Dall'Antonia held 71,632 unexercised stock options, of which 39,507 were fully vested. Options vest at a rate of 25 per cent, per year over the four year period commencing on the first anniversary of the date of grant. Mr.

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- Dall’Antonia also held 15,079 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.
5. At December 31, 2017, Mr. Mulcahy’s estate held 149,736 unexercised stock options, of which 61,695 were fully vested. Options vest at a rate of 25 per cent, per year over the four year period commencing on the first anniversary of the date of grant. However, in the event of death, all options not vested at the date which is the 2nd annual anniversary of the death shall immediately become vested and exercisable. Mr. Mulcahy also held 24,323 PSUs, of which 6,791 were fully vested. PSUs vest upon the completion of the three-year period from the date of grant. RSUs were vested and payable immediately upon death.
 6. At December 31, 2017, Mr. Lorimer held 59,528 unexercised stock options, of which 35,711 were fully vested. Options vest at a rate of 25 per cent, per year over the four year period commencing on the first anniversary of the date of grant. Mr. Lorimer also held 8,971 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.
 7. At December 31, 2017, Mr. Sam held 83,001 unexercised stock options, of which 48,589 were fully vested. Options vest at a rate of 25 per cent, per year over the four year period commencing on the first anniversary of the date of grant. Mr. Sam also held 15,734 PSUs and RSUs. PSUs and RSUs vest upon the completion of the three-year period from the date of grant.

The following table sets forth details of the securities exercised by each NEO in the most recently completed financial year.

Name & Position	Type of compensation security ⁽¹⁾⁽²⁾	Number of underlying securities exercised	Exercise price per security (\$)	Date of exercise	Closing price per security on date of exercise (\$)	Difference between exercise price and closing price on date of exercise (\$)	Total value on exercise date (\$)
Roger A. Dall’Antonia President & CEO Director	Stock Options	10,700	32.95	30-Aug-17	46.00	13.05	139,635
	PSUs	993	30.42	1-Jan-17	41.46	11.04	46,451
Michael A. Mulcahy President & CEO Director ⁽³⁾	RSUs	4,658	41.46	12-Nov-17	48.027	6.57	229,856
		3,040	38.90	12-Nov-17	48.027	9.13	161,638
		3,658	37.72	12-Nov-17	48.027	10.31	187,438
	PSUs	2,281	30.42	1-Jan-17	41.46	11.04	106,666
Ian G. Lorimer Vice President, Finance & CFO	Stock Options	5,000	32.95	10-Nov-17	48.01	15.06	75,288
		5,152	32.95	15-Nov-17	47.98	15.03	77,445
	PSUs	920	30.42	1-Jan-17	41.46	11.04	43,010
Doyle Sam Executive Vice President, Operations & Engineering ⁽⁴⁾	PSUs	2,281	30.42	1-Jan-17	41.46	11.04	106,666

Notes:

1. PSUs represent the 2014 PSU values that were realized and paid in 2017 in respect of the three-year period. The value of the PSUs at the payment date is dependent on meeting the payment criteria and corporate performance.
2. RSU’s awarded in 2015 will vest January 1, 2018 and be paid in early 2018.
3. In the case of death, Mr. Mulcahy’s RSUs were immediately vested and exercised.
4. Mr. Sam did not exercise Stock Options in 2017.

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D. PENSION PLAN BENEFITS

The following table sets forth the details of the defined contribution amounts and supplemental employee retirement plan for the respective NEOs.

Name	Accumulated value at start of year (\$)	Compensatory (\$)	Accumulated value at year end (\$) ⁽¹⁾
Roger A. Dall'Antonia	289,484	51,860	352,153
Michael A. Mulcahy ⁽²⁾	683,804	94,178	808,170
Ian G. Lorimer	211,837	40,940	263,211
Doyle Sam	388,590	50,040	452,581

Notes:

1. Includes non-compensatory amount, including regular investment earnings on contributions, which are not included as a separate column in the table above.
2. Mr. Mulcahy participated in the RRSP and DC SERP plans described below until November 12, 2017.

Each of Mr. Dall'Antonia, Mr. Lorimer and Mr. Sam participate in an RRSP which requires the NEO to contribute to a self-directed RRSP equal to 6.5 per cent of the individual's annual base salary and bonus which is matched by the corporation that employs them, up to the maximum contribution limit allowed by the Canada Revenue Agency. In 2017, the respective corporations that employ each of the NEOs contributed \$13,005 for each of the NEO's participating in the executive RRSP arrangement.

In addition, Mr. Dall'Antonia, Mr. Lorimer and Mr. Sam participate in a defined contribution supplemental employee retirement plan (the "DC SERP"). The DC SERP provides for the accrual by the respective corporations who employ each of the NEOs of an amount equal to 13 per cent of the annual base salary and bonus paid to the NEO. This amount which is in excess of the maximum contribution limit allowed by the Canada Revenue Agency to an RRSP, is tracked in a notional account which accrues interest equal to the rate of a 10-year Government of Canada Bond plus a premium of 0 per cent to 3 per cent dependent upon years of service. At the time of retirement, the notional amounts accumulated under the DC SERP may be paid to the NEO in one lump sum or in equal payments up to 15 years.

E. TERMINATION AND CHANGE OF CONTROL BENEFITS

There are no contracts, agreements, plans or arrangements that provide for payments to Mr. Lorimer and Mr. Sam at, following or in connection with any termination. There is a written employment agreement between FEI and Mr. Dall'Antonia that sets out the terms of his employment and provides for certain benefits in the event that employment is terminated other than for cause. The terms of the agreements are based on competitive practices and include non-competition, non-solicitation and confidentiality provisions.

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The table below sets out the key severance, termination and change of control provisions for Mr. Dall'Antonia.

	Retirement (early or normal)	Termination with Cause	Termination without cause	Change of Control
Annual base salary	Ceases on the termination date.	Ceases on the termination date.	Ceases on the termination date.	Ceases on the termination date.
Annual STI for applicable year	Target annual incentive for the fiscal year is pro-rated to the date of retirement.	Forfeited.	Target annual incentive for the fiscal year is pro-rated to the date of termination.	Target annual incentive for the fiscal year in which the termination date occurs (or if greater, the fiscal year immediately preceding the fiscal year in which the change of control occurs).
	Retirement (early or normal)	Termination with Cause	Termination without cause	Change of Control
Cash severance	None.	None.	The greater of: A lump sum payment to one million five hundred thousand dollars (\$1,500,000) or a lump sum payment equal to one and a half (1.5) times the sum of the base salary and target incentive for the fiscal year in which the termination date occurs.	A lump sum payment equal to one and a half (1.5) times the sum of the base salary and target incentive for the fiscal year in which the termination date occurs (or if greater, the fiscal year immediately preceding the fiscal year in which the change of control occurs).
Performance share units	Continue per normal schedule.	All PSUs are cancelled.	PSUs that have a payment date prior to the expiry of the notice period are paid. Other PSUs are cancelled.	All PSUs are redeemed at 100% on the date immediately before the change of control.
Restricted share units	Continue per normal schedule.	All RSUs are cancelled.	RSUs that have a payment date prior to the expiry of the notice period are paid. Other RSUs are cancelled.	All RSUs are redeemed at 100% on the date immediately before the change of control.
Stock Options	All unvested options continue to vest per normal schedule for two years after retirement, and all remaining unvested options after the second year vest immediately. Options expire on the original expiry date or three years from the date of retirement, whichever is earlier.	All vested and unvested options expire immediately and are forfeited on the termination date.	All unexercised options expire after 90 days from the termination date. All unvested options expire immediately and are forfeited.	All unvested options vest immediately and become exercisable.
Retirement benefits	Entitled to accrued pension and retiree health benefits.	Entitled to accrued pension.	Entitled to accrued pension and retiree health benefits.	Entitled to accrued pension and retiree health benefits.
Perquisites	Ceases immediately.	Ceases immediately.	Ceases immediately.	Ceases immediately.

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The next table shows the estimated incremental amounts that would be paid to Mr. Dall’Antonia if his employment had been terminated on December 31, 2017.

	Retirement (early or normal)⁽¹⁾	Termination with Cause	Termination without cause⁽²⁾	Change of Control⁽³⁾
Cash Severance	-	-	1,500,000	1,146,000
Annual Incentive	319,100	-	176,163	264,000
Restricted share units	-	-	-	297,963
Performance share units	-	-	-	397,330
Stock options	-	-	-	693,172

Notes:

1. PSUs continue to vest according to the normal schedule.
2. PSU payments depend on the notice period.
3. Market or payout value of share-based awards is the market value of outstanding PSUs and RSUs based on \$46.11, the closing price of Fortis common shares on the TSX on December 31, 2017.

1 **REFERENCE: Undertaking 38 pdf page 52**

2
3 **QUOTE:** Overall, FBC's existing resource stack offers a lot of options and
4 protections not available to YEC, given FBC's location adjacent to BC
5 Hydro and other power supply sources. The FBC deferral account flow
6 through of purchase power cost variances to ratepayers is not
7 associated with a need for the same rate stability elements of the DCF
8 contingency fund - and no analysis has been provided in the FBC
9 resource plans to suggest a need for such rate stability elements related
10 to potential variances in water availability. (underlining added)

11
12 **QUESTION:**

- 13
14 a) How does the underlined section provide evidence as to differences between the
15 PPEVDA and the DCF as opposed to similarities?

16
17 **ANSWER:**

18
19 **(a)**

20
21 Please see response to YUB-YEC-3-4 and YUB-YEC-3-5 for review and elaboration on
22 the initial response to Undertaking #38.

23
24 The central point is that FBC is not exposed to water risks that would merit or require a
25 specific and separate deferral or contingency account mechanism similar to the DCF. FBC
26 has a general flow through deferral account mechanism to capture power supply and other
27 cost variances from forecast. In addition, prior to any such deferral account being
28 established, FBC does not have the same thermal cost or water variance risk exposure
29 as YEC due to its CPA with BC Hydro. As a result of these two factors, a specific and
30 separate DCF-type deferral or contingency account model is not required or appropriate.

31
32 Accordingly, the absence of a specific FBC deferral account similar to the DCF is of no
33 importance when comparing risks for FBC relative to YEC, i.e., the central point is that
34 FBC, unlike YEC, is not exposed to any of the risks that would lead to a need for such a
35 specific deferral account. Customers of each utility (FBC and YEC) also bear any risks

1 related to water variability that the utility may otherwise be exposed to - even if the nature
2 of the deferral account used in each case is quite different.

3

4 Looking beyond impacts of water variability from forecast, the FBC deferral account shifts
5 other risks from the utility to customers beyond what is approved for YEC with the DCF.

6 Overall, the FBC deferral account mechanism shifts a range of other cost variances from
7 the utility to its customers, and also shifts related revenue variances from the utility to its
8 customers.

1 **REFERENCE: Undertaking 39 pdf page 53**

2
3 **QUOTE:** The response varies depending on the time period addressed for
4 FortisBC Electric (FBC) as regards determination of its Planning
5 Reserve Margin (PRM). The current risk premium assessment for FBC
6 relevant to YEC's current GRA is based on the earlier Resource Plan
7 and revenue requirement BCUC decision from 2012.¹ However, FBC's
8 subsequent 2016 Resource Plan has updated its capacity planning
9 criterion.

10
11 **QUESTION:**

- 12
13 a) Please confirm that footnote 1 refers to BCUC Decision G-110-12.
14
15 b) Please confirm that BCUC Decision G-110-12 did not make any determination on
16 FBC's risk premium but deferred such matters to a future GCOC proceeding.
17

18 **ANSWER:**

19
20 **(a)**

21
22 Confirmed. See YUB-YEC-3-1 Attachment 1 for copy of that Order. This Order was
23 referenced as per the footnote in BCUC Order G-47-14 when addressing "Short-Term
24 Risks and Deferral Accounts", Section 3.2.6, page 97 of 168 (see YUB-YEC-1-52
25 Attachment 3 for a copy of BCUC Order G-47-14).
26

27 **(b)**

28
29 In Decision G-110-12 the panel reaffirms its Decision of November 30, 2011, to maintain
30 the current ROE and capital structure pending determinations made in the GCOC
31 proceeding.
32

33 Page 26 of Decision G-110-12 notes:

34
35 In the Reasons for Decision accompanying Order G-199-11 dated November 30,
36 2011, the Commission Panel addressed, among other things, the ICG's position

1 on ROE and capital structure. The Panel noted that subsequent to the Procedural
2 Conference on November 28, 2011, the Commission had issued a letter
3 expressing its intent to conduct a Generic Cost of Capital (GCOC) Hearing
4 designed to deal with capital structure and ROE with application to all utilities. In
5 view of this, the Commission Panel concluded that there was little to be gained in
6 terms of value or efficiency by considering the issue of capital structure and return
7 on equity as part of this proceeding. The Panel's determination was as follows:

8
9 “Accordingly, the Commission Panel has determined there is no need to
10 expand this hearing to include a comprehensive review of FortisBC's
11 capital structure and ROE. Therefore, the Commission Panel has
12 determined that given the Commission announcement regarding a generic
13 hearing process, it would be appropriate to maintain the current ROE and
14 capital structure pending determinations made in the Generic Cost of
15 Capital Hearing.”

16
17 At page 31 of Decision G-110-12 the Panel also notes the following in support of its
18 determination:

19
20 In the Panel's view, the rate for the first year of the test period is not insufficient to
21 yield a fair and reasonable compensation to the utility for its service. This
22 conclusion flows from the following:

- 23
- 24 ○ FortisBC has not sought to challenge the existing capital structure
25 or ROE as yielding an insufficient return.
 - 26
 - 27 ○ The NSA for the previous test period arrived at rates which were
28 approved by the Commission as not being “unjust” or
29 “unreasonable”. The rates for the first year of this test period are
30 basically the same, when inflation is considered, and there has
31 been no degradation in the nature and quality of the service
32 provided as is indicated by the SAIDI and SAIFI statistics.
 - 33
 - 34 ● The GCOC proceeding has been initiated to deal with the issues of ROE and
35 capital structure for all utilities at the same time. This will ensure all of the utilities
36 taking part in the GCOC proceeding are treated in a consistent manner. The

- 1 Commission Panel considers this to be just and reasonable for both the utilities
2 and the ratepayers.
3
- 4 • Reviewing cost of capital in a single process is an efficient and cost effective
5 approach. The Commission Panel is of the view that holding a separate hearing
6 process to examine cost of capital issues for FortisBC alone, for only one year in
7 the test period, would result in significant additional costs which would be borne by
8 FortisBC's ratepayers.
9
 - 10 • For these reasons the Commission Panel reaffirms its Decision of November 30,
11 2011, to maintain the current ROE and capital structure pending determinations
12 made in the GCOC proceeding.

1 **REFERENCE: Undertaking 39 pdf page 53-54, footnote 5**

2

3 **QUOTE:** Available information indicates that FBC has currently (2016) adopted
4 LOLE (Loss-Of-Load-Expectation) as the reliability metric for
5 assessment of PRM adequacy, and targets a 1 day in 10 years or 0.1
6 day (or 2.4 hours) per year threshold. Further, FBC currently meets this
7 criteria. (footnote omitted)

8

9 **QUESTION:**

10

11 a) Has FBC's Long Term Electric Response Plan (LTERP) been accepted by the
12 BCUC? If so, please provide the BCUC decision, in its entirety, that accepts the
13 LTERP.

14

15 **ANSWER:**

16

17 **(a)**

18

19 Please see YUB-YEC-3-8 Attachment 1 for a copy of BCUC Decision G-117-18 dated
20 June 28, 2018.

21

22 The Executive Summary notes key findings and determinations made by the BCUC
23 regarding the LTERP which indicate that the LTERP was not accepted in its entirety.
24 Specifically, it notes "we find the LTERP for the period through 2024 as being in the public
25 interest and accept it. For the period from 2025 through to the end of the planning horizon,
26 the Panel finds that the plan is not in the public interest and, therefore, the Panel does not
27 accept that portion of the LTERP." Other key findings of the BCUC are summarized in the
28 Executive Summary.

29

30 With regard to the PRM, which was the focus of discussion in Undertaking #39, Decision
31 G-117-18 notes as follows at page 26, "FBC's PRM methodology is consistent with
32 industry practice, and the Panel finds the PRM methodology used in this LTERP is
33 acceptable."



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FortisBC Inc.

2016 Long Term Electric Resource Plan and Long Term Demand Side Management Plan

Decision and Order G-117-18

June 28, 2018

Before:
H. G. Harowitz, Panel Chair
D. J. Enns, Commissioner
M. Kresivo, QC, Commissioner

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**COMMISSION ORDER
 APPENDICES**

Executive summary

FortisBC Inc. (FBC) submitted its 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand-Side Management (DSM) Plan (LTDSM Plan) Application (2016 LTERP & LTDSM Plan, Application) in November of 2016, seeking acceptance of its 2016 LTERP & LTDSM Plan and approval to rescind Electric Tariff No. 2 Schedule 90, Energy Management Services (RS90).

Eleven entities registered as interveners in the proceeding. Development of the evidentiary record included two rounds of information requests (IRs) on FBC's Application, submission of intervener evidence and a round of IRs thereon, submission of amended application material from FBC addressing errors in the original Application, and arguments from parties.

The Panel makes the following key findings and determinations:

- We find that FBC's overarching objectives to ensure cost-effective, secure and reliable power for customers; to provide cost-effective demand side management; and to ensure consistency with provincial energy objectives, such as the applicable *Clean Energy Act* (CEA) objectives (Overarching Objectives) are in the public interest, and we accept them.
- We find that FBC's objective to achieve self-sufficiency is not in the public interest, and the Panel rejects self-sufficiency as a valid planning objective. The Panel is not persuaded that a provincial target of electricity self-sufficiency logically translates into a case for FBC to be self-sufficient. Further, the Panel does not accept the line of reasoning that expected market conditions require the pursuit of a self-sufficiency objective at this time.
- We accept the demand forecast. To the extent that there may be a risk that the demand forecast is overstated, it is of limited material consequence since the forecast does not indicate any resource gaps until well after the next LTERP & LTDSM Plan will be filed.
- We find the LTDSM Plan, recommending adoption of the High DSM scenario, to be adequate and in the public interest, and we accept it. Noting that the Max DSM plan is also cost-effective, the Panel agrees with FBC's position that FBC is not compelled to adopt all DSM initiatives that are cost-effective, but rather to adequately explain its preferred DSM portfolio.
- We find the LTERP for the period through 2024 as being in the public interest and accept it. For the period from 2025 through to the end of the planning horizon, the Panel finds that the plan is not in the public interest and, therefore, the Panel does not accept that portion of the LTERP. In reaching these determinations, the Panel notes that the four portfolios put forward by FBC are identical through 2024, and are largely a continuation of recent/current plans. Beyond 2024, FBC's objective of achieving self-sufficiency, which the Panel does not accept as a valid objective, plays a large role in the ultimate selection of FBC's preferred portfolio. FBC's preferred portfolio has a Long Run Marginal Cost (LRMC) that is \$21/MWh (28 percent) higher than A1 portfolio and the Panel has not been persuaded that this increase in costs is justified as being in the public interest.
- Given these findings, the Panel determines that the next LTERP & LTDSM Plan should be developed and filed by no later than December 1, 2021.
- The Panel finds that RS90 is no longer of use, and approves the request to rescind it.

The Panel also provides comments in five additional areas: calculation of LRMC and its use; incremental cost evaluation of DSM scenarios; the framework for resource portfolio evaluation/selection; distributed generation; and the planning reserve margin.

1.0 Introduction

1.1 Application at a glance

Date of Application	November 30, 2016
Approvals sought	<ul style="list-style-type: none"> • Acceptance of the FortisBC (FBC) 2016 Long Term Electric Resource Plan (LTERP), including the 2016 Long Term Demand-Side Management Plan (LTDSM Plan); and • Approval to rescind Electric Tariff No. 2 Schedule 90, Energy Management Services (Rate Schedule [RS] 90) (collectively, the Application)
British Columbia Utilities Commission (BCUC) Panel	<ul style="list-style-type: none"> • Howard Harowitz (Chair) • Douglas Enns • Miriam Kresivo
Registered Interveners	<ul style="list-style-type: none"> • Andy Shadrack (Shadrack) • B.C. Sustainable Energy Association and Sierra Club B.C.(BCSEA) • British Columbia Hydro and Power Authority (BC Hydro) • British Columbia Old Age Pensioners' Organization <i>et al.</i> (BCOAPO) • Commercial Energy Consumers Association of BC (CEC) • Donald Scarlett (Scarlett) • Industrial Customers Group (ICG) • Jerrilynn DeCock (DeCock) • Nicholas Marty (Marty) • Norman Gabana (Gabana); and • Zellstoff Celgar Partnership Limited (Celgar)
Regulatory process	<ul style="list-style-type: none"> • Two rounds of Information Requests (IRs) on FBC's Application • Intervener Evidence • One round of IRs on Intervener Evidence • Panel IRs • Application Errata • FBC Final Argument • Intervener Final Argument • FBC Reply Argument
Date of Decision	June 28, 2018

1.2 Legislative and policy framework

FBC seeks acceptance of the 2016 LTERP under section 44.1 of the *Utilities Commission Act* (UCA). Subsection 44.1(2) of the UCA sets out that a public utility is to file with the BCUC “in the form and at the times the commission requires” a long-term resource plan which includes:

- an estimate of the demand for energy the public utility would expect to serve if it does not take new DSM measures during the period addressed by the plan;
- a plan of how the public utility intends to reduce its demand by taking cost-effective DSM measures and an estimate of the demand for energy that the public utility expects to serve after it has taken those measures;
- a description of the facilities that the public utility intends to construct or extend, and information regarding the energy purchases from other persons the public utility intends to make, to serve demand after all cost-effective DSM measures⁴ are taken;
- an explanation as to why the demand for energy to be served by facilities the utility intends to construct or extend and energy purchases the utility intends to make cannot be met with DSM; and
- any other information required by the BCUC.

The LTERP must also meet the test of adequacy as set out in the BCUC Resource Planning Guidelines (RP Guidelines)¹.

This Panel must determine if carrying out the LTERP would be in the public interest and, therefore, whether it should be accepted.

1.2.1 Public interest

Subsection 44.1(6) of the UCA gives the BCUC the discretion to either accept the LTERP, if the BCUC determines that to carry it out would “be in the public interest,” or to reject it, subject to the discretion given to the BCUC in subsection 44.1(7) to accept or reject “a part” of an LTERP.

Pursuant to subsection 44.1(8) of the UCA, in determining whether to accept an LTERP, the factors that the BCUC “must consider” include:

- (a) the applicable BC energy objectives;
- (b) BC’s energy objective to achieve electricity self-sufficiency (section 6 of the *Clean Energy Act*);
- (c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and
- (d) the interests of persons in BC who receive or may receive service from the public utility.

As required by section 44.1(8)(a) of the UCA, the BCUC must consider the applicable British Columbia energy objectives in reviewing resource plans filed by utilities under its jurisdiction. Section 2 of the *Clean Energy Act* (CEA) sets out BC’s energy objectives for the province as a whole. Those most relevant to this proceeding include:

- to achieve electricity self-sufficiency;
- to take demand-side measures and to conserve energy;

¹ British Columbia Utilities Commission Resource Planning Guidelines, retrieved from http://www.b cuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf.

- to generate at least 93 percent of the electricity in BC from clean or renewable resources; and
- to reduce BC greenhouse gas (GHG) emissions.

The Demand-Side Measures Regulation, BC Reg. 326/2008 (DSM Regulation), defines the adequacy requirements and cost-effectiveness tests to be used by the BCUC in evaluating a DSM Application under subsection 44.1(8)(c) of the UCA.

It is important to note that a lack of comment by the Panel on any specific initiative provided in the LTERP does not indicate the Panel's acceptance of that initiative. Any specific projects proposed by FBC in the future must be appropriately evaluated in accordance with the requirements of the UCA and the BCUC.

2.0 2016 Long Term Electric Resource Plan objectives and planning inputs

The resource planning process involves a number of steps in identifying and evaluating resource options to meet expected load requirements. The long-term resource planning objectives set out by the utility set a foundation upon which the planning process is built and, in particular, how alternative portfolios are evaluated. Hence, the Panel first turns its attention to assessing the objectives that form the basis of this LTERP.

2.1 Overarching Long Term Electric Resource Plan objectives

Relevant evidence

FBC's 2016 LTERP presents a long-term plan for meeting the forecast peak demand and energy requirements of customers with demand-side and supply-side resources over the 20-year planning horizon (2016 to 2035). FBC states that its resource planning objectives form the basis for meeting any potential future load-resource balance gaps and for identifying and evaluating potential resource options and portfolios in the LTERP.² The objectives of its 2016 LTERP are to: "ensure cost-effective, secure and reliable power for customers; provide cost-effective demand side management, and ensure consistency with provincial energy objectives (for example the applicable CEA objectives"³ (collectively, the Overarching Objectives).

FBC argues that the 2016 LTERP objectives are consistent with the BCUC's mandate in assessing long-term resource plans as stated in the decision regarding the FBC 2012 LTERP.⁴ In FBC's 2012 LTERP decision, the BCUC stated: "The BCUC's mandate in assessing the resource plans of energy utilities is intended to assure the cost-effective delivery of secure and reliable energy services in a manner congruent with British Columbia's energy objectives."⁵

Positions of the parties

The CEC submits that "a consideration of the interests of persons in British Columbia who receive or may receive service from the public utility would weigh heavily towards ensuring the lowest appropriate cost of energy supply to enable the most affordable energy for its customers."⁶

BCOAPO supports FBC's planning objectives stating that they "are appropriate and reflect the broader applicable legislative requirements."⁷

² Exhibit B-1, p. 5.

³ Exhibit B-1, p. 5; FBC Final Argument, p. 1.

⁴ FBC Final Argument, pp. 1-2.

⁵ FBC 2012-2013 Revenue Requirements and 2012 Integrated System Plan, Decision and Order G-110-12, p. 143.

⁶ CEC Final Argument, p. 4.

⁷ BCOAPO Final Argument, p. 5.

FBC addresses the CEC's final argument in Reply Argument stating that in determining whether to accept a long-term resource plan, the BCUC must consider the interests of persons in British Columbia who receive or may receive service from the public utility but also states that contrary to the CEC's suggestion, the BCUC must also consider the applicable British Columbia energy objectives.

FBC submits that "the interests of FBC's ratepayers should not be interpreted in a manner that is inconsistent or incompatible with BC's energy objectives as expressed in the CEA. The energy objectives, like all statute law, are an expression of or were enacted to further the public interest. FBC's ratepayers must have an interest in the province's energy objectives being pursued and achieved."⁸

BCUC determination

The Panel finds that FBC's Overarching Objectives are consistent with the 2012 LTERP objectives, which have been accepted by the BCUC in the past. Further, the Overarching Objectives include due consideration for the provincial energy objectives.

Therefore, **the Panel accepts FBC's 2016 LTERP Overarching Objectives as being in the public interest.**

2.2 Self-sufficiency

In addition to the Overarching Objectives discussed above, FBC sets out an additional objective of achieving self-sufficiency in the long term. The goal of self-sufficiency plays a central role in this Application in terms of FBC's evaluation of alternative resource portfolios and the ultimate selection of the preferred portfolio.

Relevant evidence

FBC submits that the portfolio it ultimately selected is "predicated on achieving electricity self-sufficiency by 2025, after which time incremental supply will come from FBC's own generation and/or energy purchases from BC suppliers."⁹

FBC has assumed that it will be able to access low-cost reliable market supply for the next 10 years, out to 2025. After this time, FBC has assumed that it will become self-sufficient, with incremental supply coming from its own generation and/or long-term contracts from BC suppliers.¹⁰ FBC is of the view that self-sufficiency at some point in the planning horizon is a more prudent approach to resource planning as it could mitigate market risks and it also provides consistency with the CEA objective of achieving electricity self-sufficiency.¹¹

FBC makes numerous references in this proceeding to the CEA as a foundational basis for achieving self-sufficiency, summarized in Reply Argument as follows.

[The BCUC must consider], under section 44.1(8)(b) "the extent to which the [LTERP] is consistent with the applicable requirements under sections 6 and 19 of the Clean Energy Act". Section 6(4) of the CEA provides that: (4) A public utility, in planning in accordance with section 44.1 of the Utilities Commission Act for (a) the construction or extension of generation facilities, and (b) energy purchases, must consider British Columbia's energy objective to achieve electricity self-sufficiency.

⁸ FBC Reply Argument, p. 7.

⁹ FBC Final Argument, p. 54.

¹⁰ Exhibit B-1, p. 117.

¹¹ *Ibid.*, p. 120.

While these provisions do not establish an express legislative requirement for FBC to achieve self-sufficiency, it is also clear that FBC cannot simply ignore self-sufficiency in favour of cost-based objectives. FBC “must consider” the objective of achieving self-sufficiency in its long term planning and the Commission’s public interest review of the LTERP includes the extent to which it is consistent with this provincial energy objective.¹²

FBC notes that the British Columbia Hydro and Power Authority (BC Hydro) is acquiring additional energy and capacity through electricity purchase agreements and the development of new and existing generation sites including Mica Unit 5, Revelstoke Unit 6 and Site C. FBC considers that some of this power may be surplus and could be available to FBC at potentially attractive prices.¹³ However, FBC states that it has not considered the possibility of meeting all of its energy and capacity needs over the planning period with surplus power from BC Hydro as part of this LTERP.¹⁴

For the long-term resource planning process FBC compares the forecast price of market purchases to the forecast price of the Power Purchase Agreement (PPA) and other resources to evaluate market purchases within the resource options portfolio. FBC states that based on current base forecasts for market prices, some reliance on market purchases of energy and capacity is more cost-effective than other resource options over the short to medium term.¹⁵

FBC states that relying on market purchases over the long-term can be risky in terms of price and supply availability. FBC elaborates that:

[W]hile there are market price forecasts for future electricity prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the marketplace....There is also no guarantee that FBC will be able to access market supply reliably, especially if there is no access to long term firm transmission.¹⁶

In FBC’s view, market supply is relied upon as a Planning Reserve Margin (PRM) resource to meet unforeseen increases in demand or forced plant outages, and if increased amounts of market supply were also relied upon as a base resource in the preferred portfolio to meet expected gaps, then the PRM test could fail. Specifically, FBC states in its PRM report that it only has 150 MW (225 MW in June) of reliable access to the US market over Line 71, however the PRM report did not specify whether there was a similar limit on purchases of BC Hydro surplus energy.¹⁷

FBC comments that it may consider delaying its self-sufficiency target of 2025 in the next long-term resource plan if the delay of self-sufficiency can be accomplished while meeting the objectives of the long-term resource plan at that time.¹⁸ Market conditions such as reduced transmission availability, increased market costs or reduced liquidity in the market would support FBC’s plan to become self-sufficient by 2025, while favourable market conditions such as the availability of cost-effective, secure and reliable power would support continued reliance on market supply beyond 2025.¹⁹

¹² FBC Reply Argument, p. 6-7

¹³ Exhibit B-1, pp. 36, 37.

¹⁴ Exhibit B-14, CEC 36.3.

¹⁵ Exhibit B-1, p. 111.

¹⁶ Exhibit B-1, pp. 111–112.

¹⁷ FBC Reply Argument, p. 22; Exhibit B-1, Appendix L, pp. 10, 16.

¹⁸ Exhibit B-5, CEC IR 21.1.

¹⁹ Exhibit B-5, CEC IR 21.2, 21.3, 24.2.

Position of the parties

The CEC argues that FBC has “unreasonably established a criterion of self-sufficiency” which is not included in section 44.1(8) of the UCA²⁰ and states that according to section 6(2) of the UCA, the electricity self-sufficiency requirement applies only to BC Hydro and is only a consideration, not a requirement, for FBC.²¹ The CEC submits that FBC has prioritized this self-sufficiency criterion over the interests of persons in British Columbia who receive or may receive service from FBC.²² The CEC further submits that a consideration of the interests of persons in British Columbia who receive or may receive service from FBC would weigh heavily towards ensuring the lowest appropriate cost of energy supply to enable the most affordable energy for its customers.²³

The CEC notes that FBC may consider extending the self-sufficiency target further out in time if FBC can continue to purchase market power cost-effectively, securely and reliably beyond 2025.²⁴ The CEC submits that FBC's pursuit of self-sufficiency would result in additional, unnecessary costs to FBC ratepayers and calculates the difference between portfolio A1 (no self-sufficiency) and FBC's preferred portfolio (A4) to be \$19.8 million in 2035 depending on the cost of other planned resources.²⁵ In conclusion, the CEC submits that “the BCUC should deny FBC's objective of self-sufficiency and recommend that FBC resubmit its LTERP using Portfolio A1.”²⁶ The CEC supports a full review of FBC's self-sufficiency target in the next LTERP to be filed in 2021, or before.²⁷

BCOAPO notes that if PPA Tranche 2 energy is included in FBC's resources, new resources are not truly needed for most, if not all, of the planning period and submits that the decision to build new resources during the period should be based on cost and market supply risk considerations.²⁸ BCOAPO submits that FBC should be directed to critically assess the cost and risks of continuing to rely on market purchases as an alternative to acquiring new resources as preparation for its next long-term resource plan.²⁹

FBC counters in its Reply Argument and disagrees with the CEC's statutory interpretation of the UCA and the CEA. FBC states that the self-sufficiency objective does not only apply to BC Hydro and also states that FBC must consider BC's energy objectives as required by section 6(4) of the CEA.³⁰ FBC states that while these provisions “do not establish an express legislative requirement for FBC to achieve self-sufficiency, it is also clear that FBC cannot simply ignore self-sufficiency in favour of cost-based objectives.”³¹

FBC argues that “the interests of FBC's ratepayers should not be interpreted in a manner that is inconsistent or incompatible with BC's energy objectives as expressed in the CEA. The energy objectives, like all statute law, are an expression of or were enacted to further the public interest.”³² FBC further states that its ratepayers must have an interest in the province's energy objectives being pursued and achieved. FBC concludes by stating that “its consideration of and decision to pursue a self-sufficiency target date by the end of 2025 in the LTERP is consistent with the applicable legislative and regulatory framework.”³³

²⁰ CEC Final Argument, p. 4.

²¹ CEC Final Argument, p. 5.

²² CEC Final Argument, p. 4.

²³ CEC Final Argument, p. 4.

²⁴ CEC Final Argument, p. 5.

²⁵ CEC Final Argument, p. 7.

²⁶ CEC Final Argument, p. 8.

²⁷ CEC Final Argument, p. 21.

²⁸ BCOAPO Final Argument, p. 16.

²⁹ BCOAPO Final Argument, p. 17.

³⁰ FBC Reply Argument, pp. 6–7.

³¹ FBC Reply Argument, p. 6.

³² FBC Reply Argument, p. 7.

³³ FBC Reply Argument, p. 7.

BCUC determination

FBC's position in support of its self-sufficiency objective rests on two principal lines of argument: alignment with the CEA objectives; and market conditions. The Panel addresses each in the comments that follow.

With regard to the CEA objective of electricity self-sufficiency, the Panel draws a sharp distinction between an objective for the Province as a whole and an objective for FBC in particular. The CEA speaks to self-sufficiency for British Columbia. Notably, while specific reference is made to BC Hydro's mandatory role in respect of that objective, there is no such explicit mention of any other utility (including FBC). The Panel notes that if the lawmakers had intended for this objective to apply specifically to FBC as well as to BC Hydro, they would have provided that clarity.

Thus, the Panel views the imperative for FBC to consider the energy self-sufficiency objective to obligate FBC to evaluate the extent to which its plan furthers or impedes achieving the provincial objective, but does not obligate FBC to actively pursue its own self-sufficiency.

For the reasons above, the Panel does not accept the line of reasoning that the CEA objectives support the case for FBC to pursue self-sufficiency.

Turning to the line of reasoning regarding market conditions, FBC acknowledges that market purchases have been a reliable strategy in the recent past, and further argues that it is FBC's preferred strategy through 2024. FBC comments that markets could change in ways that compromise a continuation of that strategy beyond 2024 and/or that the PRP test could fail at some time in the future. That said, the Panel has not been persuaded that events are likely to unfold in a way that produces either of these potential outcomes and, therefore, compromises a continuation of the current strategy. For these reasons, the Panel does not accept the line of reasoning that expected market conditions require the pursuit of a self-sufficiency objective at this time.

Thus, the Panel finds that FBC's objective of achieving electricity self-sufficiency is not in the public interest, and therefore does not accept it as a valid planning objective against which portfolio options should be evaluated.

3.0 Demand forecast

Relevant evidence

FBC produced reference case forecasts, before incorporating the effects of DSM, for annual energy and peak demand over the 20-year planning horizon (2016-2035). The annual energy forecast represents annual consumption while the peak demand forecast provides an estimate of the maximum hourly electricity demand under expected peak summer and winter conditions.³⁴

FBC produces forecasts by customer groups (residential, commercial, wholesale, industrial, lighting and irrigation) using a different method for each group, and then aggregates the customer group forecasts into a total forecast. The reference case load forecast after load savings is used to determine the load-resource balance before assessing incremental demand- and supply-side resources.³⁵

FBC's reference case load forecast anticipates an increase in total gross load after-savings from 3,544 GWh in 2016 to 4,334 GWh by 2035 and an increase in total net load after-savings from 3,264 GWh in 2016 to 4,003

³⁴ Exhibit B-1, Appendix E, p. 1.

³⁵ Exhibit B-1, Appendix E, pp. 2-15

GWh by 2035.³⁶ Both the gross load and net load forecasts represent a compound annual growth rate of 1.1 percent over the twenty year planning horizon. Gross load forecasts include system losses, while net load forecasts exclude system losses. FBC assumes system losses of 8 percent of gross load.³⁷

To account for future variability in the load forecast inputs, FBC employed a Monte Carlo (MC) simulation; employed Navigant Consulting Ltd. (Navigant) to assist in identifying emerging trends and technologies not reflected in the reference case load forecast that could drive future load requirements; and discussed the load scenarios with the Resource Planning Advisory Group (RPAG) stakeholders.³⁸

FBC considers that there are no “significant issues that would call into question its long term load forecasts in a material way....”³⁹ FBC submits that “the load forecasts presented in the LTERP are adequate to satisfy the legislative requirement found at section 44.1(2)(a) of the UCA and the MC range and alternative load scenarios developed for the LTERP conform with the direction in the RP Guidelines to include multiple load forecasts in a long term resource plan to account for future load uncertainty.”⁴⁰

Position of the parties

BCOAPO addressed each customer group and submits that the forecasts for each customer group and the aggregate forecast are reasonable for the purposes of Section 44.1(2)(a) of the UCA and the FBC’s 2016 LTERP.⁴¹

ICG submit that FBC’s load forecast is appropriate for the purposes of this LTERP.⁴²

The CEC submits that the BCUC should request FBC to reconsider its Load Forecast and to resubmit it in a manner that more accurately reflects historical load increases.⁴³ The CEC submits that both FBC’s gross and net load forecasts anticipate a compound annual growth rate of 1.1 percent over 20 years while FBC’s actual growth rates data shows that the actual growth rate averaged 0.14 percent for the ten years between 2006 and 2015 and was 0.75 percent over the twenty years between 1996 and 2015.⁴⁴ The CEC submits that FBC’s load forecast is likely to be overstated given the lower rates historically. The CEC concludes that over-forecasting of load in the LTERP could lead to a planned requirement for more resources than necessary which would increase cost to ratepayers, especially when the utility is relying upon non-flexible resources.⁴⁵

BCSEA observes that “under the 2016 LTERP and LTDSM Plan FBC requires no new supply-side resources in the next ten years...the accuracy of FBC’s pre-DSM load forecast will be an important consideration in the review of FBC’s next long term plan, anticipated in 2021, when the prospect of new supply-side resources is more imminent.”⁴⁶

In reply to the CEC, FBC notes that the compound annual growth rate of 1.1 percent for both gross and net load forecasts provided in the LTERP is a before-DSM forecast, while the historical growth rates on which the CEC refers to in its final argument includes the effects of DSM savings.⁴⁷ FBC further states that “when the savings

³⁶ Exhibit B-1, pp. 53-54.

³⁷ Exhibit B-1, pp. 53-54; Appendix E, p. 1 (System losses definition).

³⁸ Exhibit B-1, p. 70.

³⁹ FBC Final Argument, p. 13

⁴⁰ FBC Final Argument, pp. 15-16.

⁴¹ BCOAPO Final Argument, p. 9

⁴² ICG Final Argument, p. 10.

⁴³ CEC Final Argument, p. 1.

⁴⁴ CEC Final Argument, p. 10.

⁴⁵ CEC Final Argument, pp. 10-11.

⁴⁶ BCSEA Final Argument, p. 5.

⁴⁷ FBC Reply Argument, p. 11.

associated with the High DSM scenario are applied to the reference case forecast, the reduction in load growth over the 20-year planning horizon reflects a CAGR of 0.26 percent (compared to 1.1 percent without DSM).⁴⁸

FBC submits that this 0.26 percent after-DSM savings is roughly consistent with the averages the CEC calculated for the actual growth rate over the last 10 and 20-year periods.⁴⁹ FBC concludes that the CEC has not demonstrated any issues or inaccuracies with FBC's long term forecast and that they should not be directed to reconsider, revise or resubmit its load forecast.⁵⁰

In reply to BCSEA's comment about load scenarios, FBC states that it will continue to monitor the situation and will determine, taking into account input from the RPAG, what level of scenario development is appropriate as the next LTERP is prepared.⁵¹

BCUC determination

The Panel notes the CEC's concern with regard to the possibility of FBC's forecasts being overstated in the light of recent demand trends, but notes that even if the forecast is overstated, it still does not precipitate the need for new resources until comfortably beyond the timing of the anticipated filing of FBC's next LTERP. By then, FBC will have additional years of history with which to evaluate whether there has been a shift in longer term demand growth trends.

The Panel is satisfied with the approach taken by FBC in developing its demand forecasts, and **the Panel accepts the load forecast for purposes of this 2016 LTERP & LTDSM Plan.**

4.0 2016 Long Term Demand-Side Management Plan

FBC submits that the 2016 Long Term Demand-Side Management Plan (LTDSM Plan) is in the public interest pursuant to section 44.1(6) of the UCA.⁵² FBC notes that it is not seeking approval of the pro-forma DSM expenditures listed in section 3.3 of the LTDSM Plan.⁵³

FBC partnered with three other BC utilities to perform a provincial, dual-fuel conservation potential review (CPR), to determine the energy efficiency potential for electricity and natural gas across British Columbia in the residential, commercial, and industrial sectors over the planning horizon of 2016 to 2035.⁵⁴

FBC presents four DSM scenarios, which are based on increasing targets for load growth offset over the 20-year period of the LTERP, summarized in the table below.⁵⁵

⁴⁸ FBC Reply Argument, p. 11.

⁴⁹ FBC Reply Argument, p. 11.

⁵⁰ FBC Reply Argument, p. 12.

⁵¹ FBC Reply Argument, p. 10.

⁵² Exhibit B-1, Volume 1, p. 14.

⁵³ Exhibit B-1, Volume 2, p. 1.

⁵⁴ Exhibit B-1, Volume 2, p. 7.

⁵⁵ Exhibit B-2, BCUC IR 33.1.

Table 1 – Summary of DSM Scenarios

	Low	Base	High	Max
2017 – 2021 period				
Total Dollars (\$millions)	\$28	\$39	\$40	\$40
Average Annual GWh Savings	21	26	27	27
2017 – 2031 period				
Total Dollars (\$millions)	\$45	\$88	\$104	\$114
Average Annual GWh Savings	20	26	31	36

There are three key requirements relating to the adequacy of the LTDSM Plan. It must:

- indicate how the public utility intends to reduce the anticipated pre-DSM demand by taking cost-effective demand-side measures (Cost Effectiveness);⁵⁶
- explain why the demand for energy to be served by the supply-side facilities and/or market purchases are not planned to be replaced by demand-side measures (Explanation);⁵⁷ and
- contain, at a minimum, programs in three specific areas of low-income households, rental accommodation, and education programming for students (Completeness).⁵⁸

4.1 Cost-effectiveness

Relevant evidence

The key indicator of cost effectiveness is the Total Resource Cost (TRC) ratio, which compares total benefits against total costs (i.e. a TRC value greater than 1.0 delivers positive benefits, and the higher the value above 1.0, the more cost effective the portfolio). FBC submits that the BCUC has consistently applied the TRC at the portfolio level, and this approach is appropriate for FBC's current LTDSM plan.⁵⁹ The average costs and the TRC values of each DSM scenario is shown in the table below.

Table 2 – Average Costs and TRC Benefit/Cost Ratios of DSM Scenarios

	Low DSM	Base DSM	High DSM	Max DSM
Average cost incl. program costs (\$2016/MWh)⁶⁰	\$42	\$52	\$58	\$64
TRC Benefit/Cost Ratios⁶¹	3.4	2.6	2.2	2.0

⁵⁶ UCA s.44.1(2)(b)

⁵⁷ UCA s. 44.1(2)(f)

⁵⁸ DSM Regulation 326/2008, Section 3

⁵⁹ FBC Final Argument, pp. 9–10.

⁶⁰ Exhibit B-1-1, p. 166.

⁶¹ Exhibit B-1-1, p. 3.

BCUC determination

The analysis presented indicates that each of the four scenarios are cost effective as indicated by TRC values greater than 1.0 in each case. **The Panel finds the High DSM scenario to be cost effective.**

4.2 Explanation

Relevant evidence

FBC puts forward the High DSM portfolio as its preferred option. In explaining its choice, FBC provides the following comments:

The high level of DSM under the scenario proposed in FBC’s LTDSM Plan has an average incremental cost of \$98/MWh. This is closely comparable to FBC’s LRMC for BC clean or renewable resources (approximately \$100/MWh) that is used in the cost-effectiveness test under the *DSM Regulation*.⁶²

...

[The Max scenario] would require higher-cost DSM measures with marginal costs averaging \$108/MWh. This is significantly more than the cost of the proposed DSM scenario. It is also materially higher than the \$100/MWh LRMC of BC clean or renewable resources, and would result in rate increases for customers if implemented.⁶³

...

FBC considered the higher levels of DSM under the Max scenario to be sub-optimal for a number of other reasons, including the inherently non-firm, non-dispatchable nature of DSM savings compared to supply side options. DSM requires voluntary participation by customers and the Max scenario therefore creates risks in managing the [load-resource balance] if DSM program uptake does not materialize as planned.⁶⁴

Position of the parties

BCSEA submits that “the requirement that a public utility’s long-term resources plan must provide an explanation of why planned supply-side resources are not instead planned to be replaced by demand-side measures, evinces a clear legislative direction that DSM resources are to be considered the first and best approach to meeting anticipated shortfalls in meeting energy needs, ahead of supply-side resources.”⁶⁵

FBC disagrees with BCSEA, and submits that “for utilities other than BC Hydro, section 44.1(2)(f) simply reflects a neutral approach in which utilities are required to give adequate consideration of both supply and demand resources to meet gaps in their long-term LRB, based on their own unique circumstances, and to provide a reasoned explanation for the decision ultimately made.”⁶⁶ FBC submits that the LTERP includes an adequate explanation for its decision not to pursue additional levels of DSM that meets the standard BCSEA proposes, and that the BCUC should accept its explanation.⁶⁷

⁶² FBC Final Argument, pp. 43–44.

⁶³ FBC Final Argument, p. 44.

⁶⁴ FBC Final Argument, p. 45.

⁶⁵ BCSEA Final Argument, p. 22.

⁶⁶ FBC Reply Argument, p. 9.

⁶⁷ FBC Reply Argument, p. 5.

BCOAPO submits that comparing the incremental cost of the additional DSM measures (i.e. Max compared to High) is problematic, and the TRC test indicates that the Max scenario is cost-effective. Having said that, the BCOAPO goes on to say that it agrees with FBC that the Company is not required to include all cost-effective DSM, but rather provide an adequate explanation of its choice.⁶⁸

BCUC determination

The Panel agrees with FBC that the UCA does not compel FBC to pursue any and all DSM resources that are cost effective, but rather to provide an explanation for its choice of DSM scenarios.

The Panel notes BCOAPO’s comments that FBC’s use of the incremental cost of the Max scenario is problematic, and more will be said on that issue later in this Decision in Section 8.2.

FBC has set out in some detail the basis on which it constructed the alternative DSM scenarios, evaluated the pros and cons of each, and ultimately selected the High DSM scenario. The Panel is satisfied that, whether or not all parties agree that the High DSM is their preferred scenario, FBC has adequately explained why it is FBC’s preferred scenario.

Thus, the Panel finds that FBC has provided an adequate explanation as to why it prefers the High DSM scenario.

The Panel notes that FBC did not model a range of DSM scenarios for the period 2017–2021. Looking to FBC’s next 2016 LTERP & LTDSM Plan filing, the Panel expects that FBC will update its short-term market assumptions and develop a richer analysis of DSM alternatives for the first five years of the LTDSM Plan.

4.3 Completeness

With regard to requirements to include specific programs, the table below summarizes the programs where FBC submits that the LTDSM Plan meets the adequacy requirements of the DSM Regulation.

Table 3 – DSM Regulation Section 3 Adequacy Requirements - LTDSM Plan Programs

Section of DSM Regulation	Adequacy Requirement	Summary of Programs in LTDSM Plan
3(a)	a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption	Low-Income Households Program: Energy Saving Kits (ESK), Energy Conservation Assistance Program, rebates for multi-unit residential buildings (MURBs) ⁶⁹
3(b)	a demand-side measure intended specifically to improve the energy efficiency of rental accommodations	Rental Apartment Program: ESK installation for rental MURBs, energy audits and technical support ⁷⁰
3(c)	an education program for students enrolled in schools in the public utility's service area	Education Programs: online education program, funding support for third party educational organizations ⁷¹
3(d)	an education program for students enrolled in post-secondary institutions in the public utility's service area	Education Programs: financial and in-kind support for post-secondary curriculum and behaviour change initiatives ⁷²

⁶⁸ BCOAPO Argument p. 14.
⁶⁹ Exhibit B-1, Volume 2, p. 19.
⁷⁰ Exhibit B-1, Volume 2, p. 19.
⁷¹ Exhibit B-1, Volume 2, p. 23.

On March 24, 2017, the DSM Regulation was amended adding additional adequacy requirements under section 3, including measure(s) to address local government and First Nations step codes.⁷³ FBC submits that the amendments were not passed or in effect until well after the LTERP was filed on November 30, 2016, and that the BCUC's review of the LTERP should be based on the pre-amendment version of the *DSM Regulation*, as it read at the time the LTERP was filed.⁷⁴

Position of the parties

The CEC submits that the amendment took place within the time period of the proceedings for the LTERP. The CEC also notes that the amended DSM Regulation will be in effect during the period covered by the LTERP, and therefore the BCUC is entitled to and should weigh all the evidence before it and to make a determination on the matter.⁷⁵

BCSEA submits the amendment to the *DSM Regulation* must be construed as “always speaking”, and the BCUC's determination as to whether carrying out the plan would be in the public interest is made in accordance with the law as it stands at the time of the determination.⁷⁶

In its Reply Argument, FBC counters that the LTERP and LTDSM Plan could and should be accepted on the basis that FBC's plan shows it intends to pursue adequate, cost effective demand-side measures. Further, FBC states the adequacy requirements set out in section 3 of the DSM Regulation are in practice met through FBC's DSM expenditure schedule application and its 2018 DSM expenditure schedule application notes that its existing Community Energy Planning program already meets the new requirement in section 3(f) of the amended DSM regulation.⁷⁷

BCUC determination

The Panel is satisfied that FBC has included programs that meet each of the requirements set out in Section 3 of the DSM Regulation, and therefore **the Panel finds the LTDSM Plan to be adequate for the purposes of Section 3 of DSM Regulation 326/2008**. The Panel is assured by FBC's statement that it intends to pursue adequate, cost-effective demand-side measures. Further, the adequacy requirements set out in section 3 of the DSM Regulation will be assessed with each future DSM expenditure schedule filing.

The Panel finds that the High DSM scenario is complete in terms of containing the necessary specific programs.

Having found the High DSM scenario to be cost effective (section 4.1), adequately explained (section 4.2), and complete (section 4.3), **the Panel finds that FBC intends to pursue adequate, cost effective DSM measures, and accepts the LTDSM plan as being in the public interest.**

5.0 Resource planning

Relevant evidence

FBC applies the High DSM portfolio to the reference case load forecast to produce an analysis of LRB over the forecast horizon.

⁷² Exhibit B-1, Volume 2, p. 23.

⁷³ B.C. Reg. 117/2017.

⁷⁴ FBC Final Argument, pp. 7–9.

⁷⁵ CEC Final Argument, p. 14.

⁷⁶ BCSEA Final Argument, pp. 3–4.

⁷⁷ FBC Final Argument, p. 8.

Key assumptions factoring into the Energy LRB include:

- the Brilliant Expansion contract is extended to 2027 and discontinues after that;
- the PPA with BC Hydro is renewed and continues beyond the September 2033 expiration date; and,
- FBC uses only the Power Purchase Agreement (PPA) Tranche 1 Energy amount, as FBC expects that it would be able to build or contract for new energy resources at a cost lower than the PPA Tranche 2 Energy cost.⁷⁸

A key assumption factoring into the Capacity LRB is whether the Brilliant Expansion contract is renewed until 2027 after which it expires. The capacity LRB also assumes that 200 MW of capacity is available to FBC from the PPA but can be reduced if not required to meet the load forecast. As with the energy LRB, FBC also assumes the renewal of the BC Hydro PPA in 2033.⁷⁹

The results of this analysis are summarized by FBC in the following charts:

Figure 1 – Energy LRB (After DSM)⁸⁰

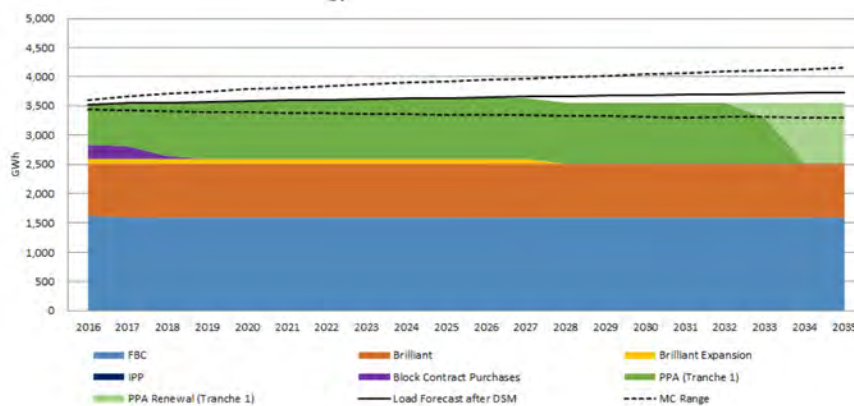
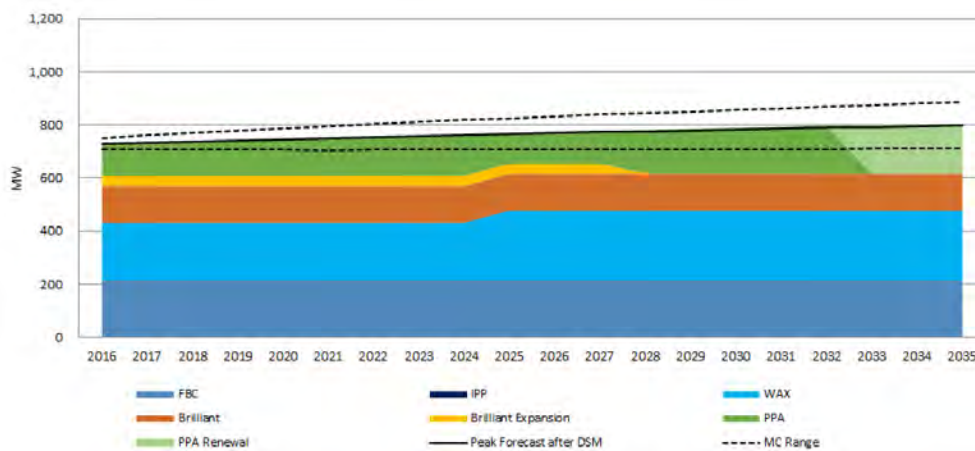


Figure 2 – Capacity LRB (After DSM)⁸¹



⁷⁸ Exhibit B-1, p. 93.

⁷⁹ Exhibit B-1, p. 94.

⁸⁰ Exhibit B-1, p. 101.

⁸¹ Exhibit B-1, p. 102.

The charts show that with the high level of DSM applied to the reference case (solid black line) there are no energy gaps (spread between anticipated demand and supply) out to 2024. Slight gaps start in 2025, which increase to almost 200 GWh by 2035 if the PPA is renewed.⁸²

For the capacity, the figure above shows that with the High scenario level of DSM offsetting about 56 percent of future peak load growth, there are no gaps that need to be filled if the PPA is renewed based on the reference load forecast peak after DSM. FBC notes that based on the peak load forecast after DSM, there would be surpluses of capacity for most years if the PPA is assumed to provide its full peak supply of 200 MW. However, the figure reflects the reduction in the PPA to match what is required to meet the peak demand forecast.⁸³

FBC states that there are minimal gaps for peak capacity if the PPA is renewed beyond 2033 and therefore, the main focus for FBC is to fill any gaps related to energy.⁸⁴

FBC presented 16 possible resource portfolios for evaluation based on several different base characteristics and then explored sensitivities around these base characteristics (as shown in table 4). The portfolios were then analysed across a range of attributes (technical, financial, environmental and socio-economic).

Table 4 – Portfolio Analysis Base Characteristics and Sensitivity Cases⁸⁵

Portfolio Base Characteristics	Sensitivity Cases
DSM Level <ul style="list-style-type: none"> • Proposed High level 	<ul style="list-style-type: none"> • No DSM • Max DSM • Low DSM
Reliance on Market Purchases <ul style="list-style-type: none"> • Self-sufficiency by 2025 	<ul style="list-style-type: none"> • No self-sufficiency • Self-sufficiency by 2020 • High market and carbon prices
Percent Clean or Renewable <ul style="list-style-type: none"> • 93 percent clean or renewable 	<ul style="list-style-type: none"> • 100 percent clean or renewable • High market and carbon prices
Load Requirements <ul style="list-style-type: none"> • Reference case load forecast 	<ul style="list-style-type: none"> • High load scenario • Low load scenario
PPA Renewal <ul style="list-style-type: none"> • PPA renewed in 2033 	<ul style="list-style-type: none"> • PPA not renewed

FBC also conducted online discussion boards to survey customers about their views regarding the ranking of FBC’s resource planning objectives. When presented with choosing among resource planning objectives, the majority of residential and commercial customers surveyed ranked “cost effective secure and reliable power” as “the most critical” objective for LTERP planning.⁸⁶ The reported findings state the following:

- [Residential] Customers who view this objective as critical tend to focus on the importance of maintaining reasonable costs for the everyday customer. They either believe that current costs are already too high or that, given that costs will inevitably increase in the future, the focus has to be on affordability.⁸⁷
- [Commercial] Customers who view this objective as critical cite the central role of electricity in everyday life – “everything revolves around electricity” – and the need to contain costs so that electricity can be an affordable option.⁸⁸

⁸² Exhibit B-1, p. 101.

⁸³ Exhibit B-1, p. 102.

⁸⁴ Exhibit B-1, p. 103.

⁸⁵ Exhibit B1, p.116.

⁸⁶ Exhibit B-11, BCUC IR 65.1.2; Exhibit B-1, LTDSM Plan Appendix B, pp. 14, 24.

⁸⁷ Exhibit B-1, LTDSM Plan Appendix B, p. 14.

⁸⁸ Exhibit B-1, LTDSM Plan Appendix B, p. 24.

Four of the portfolios were brought forward as the short list for final consideration as the preferred resource portfolio. FBC states that it “believes that [these four portfolios] best meet the LTERP’s objectives of cost-effectiveness, reliability, inclusion of cost-effective DSM and consideration of BC’s energy objectives.”⁸⁹ The composition of the four portfolios is summarized in the following table:⁹⁰

Table 5 – Incremental Resources Included in Each Resource Portfolio

A1 No Self-Sufficiency	C1 93% Clean with CCGT	A4 93% Clean with SCGT	C4 100% Clean BC Resources
Market (97%)	Market (51%)	Market (31%)	Market (31%)
Biogas (3%)	CCGT (48%)	Wind (65%)	Wind (65%)
	Biogas (1%)	Biogas (3%)	Biogas (3%)
		SCGT (1%)	Biomass, Solar (1%)

FBC’s submissions show that for each year from 2016 through to 2024 the incremental resources used in each of the above portfolios are identical,⁹¹ and the differences in incremental resources between each of the four portfolios occur only from 2025 through to 2035.⁹² From 2016 through to 2024, the incremental resources used are PPA Tranche 1 Energy and Capacity, Market Purchases and DSM.⁹³ FBC further states “For portfolio A1 with no self-sufficiency, market purchases are selected throughout the 20 years [planning horizon] because market power is lower cost than the other resource options.”⁹⁴

FBC states three out of the four alternative portfolios FBC considered for the preferred portfolio and the portfolio it ultimately selected are predicated on achieving electricity self-sufficiency. From 2026 onwards, portfolios C1, A4 and C4 do not utilize market purchases as an incremental resource, instead relying on Simple Cycle Gas Turbine (SCGT), Combined Cycle Gas Turbine (CCGT), biogas, solar or wind resources as determined by the selected portfolio.⁹⁵

FBC uses the criteria listed below to assess each of the four portfolios and to determine the preferred portfolio:⁹⁶

1. Cost (using the LRMC of each portfolio);
2. Reliability;
3. Geographic diversity of generation resources; and
4. Consistency with the CEA objectives of:
 - a. encouraging socio-economic development and the creation and retention of jobs, and
 - b. reducing environmental impacts in terms of GHG emissions.

The table below shows the results of FBC’s analysis of each of the portfolios using the above criteria as metrics.

⁸⁹ Exhibit B-1, p. 125.

⁹⁰ Exhibit B-1, p. 125.

⁹¹ Exhibit B-1-1, FBC Errata, Revised Responses to BCOAPO IR No. 1, pp. 4, 6, 13, 15.

⁹² Ibid.

⁹³ Ibid.

⁹⁴ Exhibit B-1, p. 125.

⁹⁵ Exhibit B-1-1, FBC Errata, Revised Responses to BCOAPO IR No. 1, pp. 4, 6, 13, 15.

⁹⁶ Exhibit B-1, p. 125.

Table 6 – Attributes of Portfolios Considered for Preferred Portfolio⁹⁷

Portfolio	Incremental Resources	LRMC (\$/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO ₂ e)	Full-Time Equivalents per year	Geographic Resource Diversity	
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	\$75	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	\$90	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	\$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3%) Biomass, Solar (1%)	\$97	0.0%	0	216	Medium

FBC determined portfolio A4 (93 percent clean with SCGT) to be its preferred portfolio stating that it was determined to best meet the LTERP objectives in terms of balancing cost, reliability, socio-economic benefits, geographic resource diversity, as well as BC’s energy objectives.⁹⁸ FBC states that this portfolio produces minimal GHG emissions, only 3,000 CO₂ equivalents over twenty years, because the SCGT resource is not required until 2033 and is only required to run during peak demand periods, unlike a CCGT plant that would run more frequently as a base load resource. FBC points out that a SCGT plant in the portfolio provides FBC with additional reliability and flexibility for unforeseen capacity and/or energy requirements because it can be used to run more frequently than required for peak demand periods. FBC noted A4’s socioeconomic benefits of 145 full time equivalent employees (FTEs) per year and states that A4 provides high geographic resource diversity with the wind energy and the SCGT resources likely being located in the Okanagan.

FBC concludes that portfolio A4 “best meets the LTERP objectives in terms of balancing cost, reliability and geographic resource diversity with BC’s energy objectives as relates to its preferred portfolio.”⁹⁹

FBC notes that the inclusion of the SCGT in the preferred portfolio offers flexibility for contingency planning if market prices are higher than forecast, if new large loads arise, or as a backup resource due to the uncertain nature of wind generation.¹⁰⁰ FBC states that the preferred portfolio also satisfies planning reserve margin requirements without the need for incremental resource requirements or additional costs.¹⁰¹

Position of the parties

The CEC, BCSEA and ICG oppose FBC’s preferred portfolio and each propose an alternative from the four portfolios considered by FBC.¹⁰² BCOAPO does not support FBC’s preferred portfolio but notes that the Action Plan for this current LTERP will be the same regardless which of the four portfolios is chosen. BCOAPO further notes that the time at which a decision must be made regarding the preferred portfolio does not occur prior to the preparation of FBC’s next long term resource plan.¹⁰³

⁹⁷ Exhibit B-1-1, Table 9-2, p. 126.

⁹⁸ FBC Final Argument, p. 39.

⁹⁹ Exhibit B-1, p. 127.

¹⁰⁰ FBC Final Argument, p. 40.

¹⁰¹ FBC Final Argument, p. 40.

¹⁰² CEC Final Argument, p. 1; BCSEA Final Argument, p. 19; ICG Final Argument, p. 11.

¹⁰³ BCOAPO Final Argument, p. 18.

The CEC submits that that the BCUC “should deny FBC’s objective of self-sufficiency and recommend that FBC resubmit its LTERP using Portfolio A1.”¹⁰⁴ Portfolio A1 is a market-based portfolio that comprises of 97 percent market supply and 3 percent biogas with a LRMC of \$75 per MWh.

The CEC disputes FBC’s stated goal of self-sufficiency and submits that FBC’s discussion of uncertainty of access to market power in the LTERP is overstated. The CEC provides several reasons in support of market supply including a reference to an information request where FBC assumes that “the market will be available 99.84 percent of the time and that transmission to the market will be available 99.45% of the time.”¹⁰⁵ The CEC also argues that FBC and BC Hydro have an Imbalance Agreement whereby BC Hydro provides FBC with imbalance energy as needed, during unexpected conditions or circumstances, and the only consequence to FBC is a financial penalty.¹⁰⁶

The CEC refers to the updated PPA Tranche 2 energy price of \$85 per MWh and further recommends that “to the extent the Commission does not wish to rely on market energy, the Commission recommend that FBC maximize the use of PPA Tranche 2 energy wherever it is the most cost-effective option.”¹⁰⁷

BCOAPO submits that additional new resources are “not truly needed” because FBC already has existing resources, such as PPA Tranche 2 energy, to meet the energy gap that arises in 2024.¹⁰⁸ BCOAPO submits that one alternative approach would be to continue to use market supply and “rely on PPA Tranche 2 energy simply as insurance.”¹⁰⁹ BCOAPO acknowledges that this may increase costs but reiterates that it would only be required in case market supply was inaccessible or too costly.¹¹⁰ BCOAPO concludes that the Action Plan for this current LTERP will be the same regardless of which of the four portfolios is chosen and submits that it is appropriate for the BCUC to accept FBC’s 2016 LTERP in the public interest.¹¹¹

BCSEA strongly opposes any new gas-fired generation as a supply resource and states that this precludes portfolios C1 and A4 which have a CCGT and a SCGT respectively.¹¹² BCSEA also opposes portfolio A1 stating that “market power is more carbon intensive than clean or renewable BC power or DSM resources.”¹¹³ BCSEA states its preference for portfolio C4, however BCSEA concludes by highlighting that FBC will not need to consider whether to build or acquire new generation resources until its next LTERP.¹¹⁴

ICG opposes FBC’s selection of preferred portfolio A4. ICG submits that portfolio C1 should be chosen as the preferred portfolio because it meets the 93 percent clean energy target, does not rely on the market, and has a lower LRMC of \$90 per MWh versus 96 per MWh for portfolio A4.¹¹⁵ ICG also states that FBC should include in its action plan “opportunities for contracts with self-generation customers based on an LRMC from portfolio C1” and further submits that the incentives for purchases from self-generation should be “to advance BC energy objectives and for more prudent resource planning.”¹¹⁶

¹⁰⁴ CEC Final Argument, p. 8.

¹⁰⁵ CEC Final Argument, p. 8; Exhibit B-14, CEC IR 2.33.1

¹⁰⁶ CEC Final Argument, p. 8.

¹⁰⁷ CEC Final Argument, p. 13.

¹⁰⁸ BCOAPO Final Argument, p. 16

¹⁰⁹ BCOAPO Final Argument, p. 16.

¹¹⁰ BCOAPO Final Argument, p. 17.

¹¹¹ BCOAPO Final Argument, p. 18.

¹¹² BCSEA Final Argument, p. 19.

¹¹³ BCSEA Final Argument, p. 20.

¹¹⁴ BCSEA Final Argument, pp. 19–20.

¹¹⁵ ICG Final Argument, p. 11.

¹¹⁶ ICG Final Argument, p. 11.

Panel discussion

The Panel takes particular note of the fact that the incremental resources contained in each of the four portfolios (A1, C1, A4, C4) are identical through to 2024, and the portfolios only begin to diverge in composition beginning thereafter. Further to that point, no interveners have raised concern over the proposed resource portfolio out to 2024. The Panel considers the portfolio strategy through 2024 to be largely a continuation of current practice, and finds it to be a reasonable approach for that time span.

Looking beyond 2024, the LRM for the preferred portfolio A4 is \$21/MWh more expensive than A1 (a 28 percent increase), and the third-highest LRM of the four portfolios presented as final candidates. This is in sharp opposition to FBC's customer consultation process that indicated customers ranked cost as the most critical planning objective for the LTERP process.

Despite the significant cost differential, FBC recommends A4. The justification for A4 rests in large measure on the fact that it achieves FBC's electricity self-sufficiency objective, an objective that the Panel has rejected as a valid planning objective for this exercise.

Thus, having indicated that the final four portfolios best meet the LTERP's objectives of cost-effectiveness, reliability, inclusion of cost-effective DSM and consideration of BC's energy objectives, the Panel has not been persuaded that A4 is, in fact, the best of the four.

It is also noteworthy that FBC contemplates a more thorough review of its longer-term portfolio strategy as part of its next LTERP submission. Therefore, no aspect of the shorter-term plan is compromised by not committing to any specific trajectory beyond 2024.

BCUC determination

For these reasons, the Panel finds the LTERP for the years up to 2024 is in the public interest and accepts it. Given the concerns identified, the Panel finds the recommended portfolio plan for years beyond 2024 not to be in the public interest, and rejects that portion of the plan.

6.0 Timing of the next filing

FBC expects it will file its next long term resource plan in 2021, given that it requires no new supply-side resources in the next ten years.¹¹⁷ FBC submits that this is approximately five years from the filing of this LTERP, which is consistent with five year interval the BCUC directed following acceptance of FBC's 2012 LTERP.¹¹⁸

Position of the parties

BCSEA submit that the BCUC should direct FBC to file its next LTERP in 2021 and not later.¹¹⁹
The CEC supports a full review of FBC's self-sufficiency target in the next LTERP to be filed in 2021, or before.¹²⁰

BCUC determination

The Panel agrees with FBC that the appropriate timing for filing the next LTERP and LTDSM plan is 2021, and therefore **directs FBC to file its next LTERP and LTDSM plan by no later than December 1, 2021.**

¹¹⁷ Exhibit B-1, Vol. 1, p. 141; FBC Final Argument 64; Exhibit B-5, p.74

¹¹⁸ FBC Final Argument, p. 64.

¹¹⁹ BCSEA Final Argument, p. 28.

¹²⁰ CEC Final Argument, p. 21.

7.0 Rate Schedule 90

In this Application, FBC requests approval to rescind Electric Tariff No. 2 Schedule 90, Energy Management Services (RS90).

RS90 was introduced in 1990, pursuant to BCUC Order G-47-89. At that time, the purpose of RS90 was to describe each of the Company's specific programs, including the associated offers and financial incentives, and the overall program terms and conditions. Any revisions or extensions to a specific DSM program required an application to and order from the BCUC. In 2010 a major revision to RS90 removed much of the program specific pages and reduced RS90 to a generic high-level outline of program attributes.¹²¹

FBC is proposing to rescind RS 90 from its Electric Tariff to increase the Company's flexibility in DSM program design, to allow the Company to respond to market trends and new technologies more quickly and effectively, and to better align FBC's DSM programs with similar DSM programs and best practices from other utilities, including BC Hydro and FortisBC Energy Inc. (FEI). FBC submits that services offered under RS90 have been essentially made redundant by the specific DSM programs in FBC's approved DSM Plan portfolios, and that parts of RS90 conflict with the Company's offers or practices.¹²²

The CEC has no objections to RS90 being rescinded,¹²³ and BCSEA supports FBC's request for BCUC approval of rescission of RS90.¹²⁴

BCUC determination

The Panel agrees that RS90 currently serves no useful purpose, and that rescinding it would provide added flexibility in DSM program design. **The Panel approves FBC's request to rescind FBC's Electric Tariff No. 2 Schedule 90, Energy Management Services (RS90).**

8.0 Issues arising

In addition to the matters discussed above, the following issues arose during the proceeding and will be addressed in the following sections:

- Calculation of LRMC and its use;
- Incremental cost evaluation of DSM scenarios;
- Framework for resource portfolio evaluation/selection;
- Distributed generation; and
- Planning reserve margin.

8.1 Calculation of LRMC and its use

Two matters relating to LRMC arose during this proceeding: inclusion of DSM in calculating the value; and the manner in which the LRMC is then used in other contexts.

¹²¹ Exhibit B-1, Volume 2, p. 24.

¹²² Exhibit B-1, Volume 2, p. 25.

¹²³ CEC Final Argument, p. 22.

¹²⁴ BCSEA Final Argument, p. 29.

8.1.1 Inclusion of DSM

FBC's calculation of the LRM value includes DSM costs.¹²⁵ FBC indicated that the exclusion of DSM from the portfolio A4 would reduce the LRM value from \$95.52 to \$94.00/MWh.¹²⁶

FBC also does not consider that the LRM estimate of portfolio A4 (which includes DSM) is useful in informing future applications, but instead proposes an alternative LRM based on the avoided cost of supply side resources only that excludes DSM.

FBC states that it is not anticipating a requirement for additional resources for a considerable period of time and does not anticipate using the LRM to justify obtaining new resources to meet either load or planning reserve margin requirements at this time.¹²⁷

FBC further states, "If the resource provides little to no winter energy, such as solar PV, then it will have little to no impact on the LTERP required resources in the preferred portfolio A4, meaning that any energy produced at best only displaces BC Hydro PPA energy costs."¹²⁸ In addition, FBC indicated that it considers that the most reasonable proxy for its avoided cost of power is the rate at which it is able to purchase power under its PPA with BC Hydro.¹²⁹

FBC also states that the levelized unit energy cost for market purchases is about \$51 per MWh including transmission costs and losses from Mid-C, and submits that this is similar to the base case scenario for the PPA Tranche 1 Energy rate, with a levelized value of about \$50 per MWh over twenty years.¹³⁰

Panel discussion

FBC has not previously included DSM as a component of its LRM estimate, and it is not an approach currently used by other utilities in British Columbia. The Panel is not persuaded of the benefit of including DSM in the estimate of FBC's LRM, and encourages FBC to consider revising its LRM calculation method in its next LTERP filing.

8.1.2 Purpose and application of LRM beyond this Application

Interveners in both the recent FBC Net Metering proceeding and this proceeding have raised the issue that FBC's estimate of avoided energy cost in the Net Metering proceeding (BC Hydro's RS 3808 Tranche 1 rate) differs from its LRM estimate put forward in the FBC's LTERP.

Subsequent to the filing of this LTERP Application, FBC has put forward the following LRM values.

¹²⁵ Exhibit B-1, pp. 125, 127; Exhibit B-1-1, IR Responses, p. 7.

¹²⁶ Exhibit B-1-1, IR Responses, p. 9.

¹²⁷ Exhibit B-11, BCUC IR 55.1.

¹²⁸ Exhibit B-2, BCUC IR 36.3.

¹²⁹ Exhibit B-18, Shadrack IR.2.7.

¹³⁰ Exhibit B-1, Appendix J, p. 42.

Table 7 – LRM Values Used in FBC Subsequent Proceedings

Proceeding		LRMC
1	FBC Community Solar Pilot Project Application	FBC proposed: \$46.99/MWh (BC Hydro PPA Tranche 1 rate for F2017) ¹³¹
2	FBC Net Metering reconsideration	FBC proposed: \$43.03/MWh plus 5% rate rider (BC Hydro PPA Tranche 1 rate) ¹³²
3	FBC Electric Vehicle (EV) Rate	FBC proposed: \$50/MWh (levelized market purchase price). ¹³³

The FBC Rate Design and Rates of Electric Vehicle (EV) Direct Current Fast Charging Service (DCFC) Application, dated December 22, 2017, specifically refers the 2016 LTERP for guidance on FBC’s avoided cost. However, the LRM guidance referred to is the levelized unit energy cost for market purchases of about \$51/MWh included in Appendix J to the LTERP, and not the \$96/MWh stated as the LRM for Portfolio A4.¹³⁴

In the LTERP Application, FBC states that it “considers the long run marginal cost to be a price signal and is one of many considerations when assessing the cost-effectiveness of different resource options. FBC does not expect to acquire all available resources up to the LRM, nor should the LRM be viewed as a clearing price in isolation from other prudent resource planning considerations, such as energy or capacity profiles or environmental factors.”¹³⁵

FBC further explains that, while a particular resource option may be cost effective relative to a given LRM value, it may not fit the energy or capacity requirements of customers in the future. For this reason, FBC believes the LRM values presented should be viewed as price signals, rather than threshold targets, for resource options.¹³⁶

Panel discussion

For regulatory efficiency, the long-run marginal cost(s) developed in the LTERP should be a key input in future FBC proceedings.

The Panel agrees with FBC that a single calculation of the LRM is not necessarily applicable in all situations: adjustments are sometimes warranted in respect of different circumstances surrounding such characteristics as the time horizons, shape, intermittency, and firmness of the energy being considered. That said, while agreeing that the LRM needs to be adapted to specific situations, the Panel is of the view that this argues for starting with the LRM developed in the LTERP as the jumping-off point for making appropriate adjustments at the margin, but not for abandoning the (LTERP’s) LRM altogether and substituting an entirely different value.

FBC is encouraged to develop an LRM framework that provides more consistency (and hence regulatory efficiency and clarity) across its future applications.

¹³¹ FBC Community Solar Pilot Project Application proceeding, Exhibit B-1, pp. 11, 12.

¹³² FBC Application for Reconsideration and Variance of Order G-199-16 FBC Net Metering Program Tariff Update Decision proceeding, Phase 2, Application dated March 17, 2017, p. 20; FBC Net Metering Update Application, dated April 15, 2016, p. 11.

¹³³ FBC Rate Design and Rates of Electric Vehicle Direct Current Fast Charging Service Application, dated December 22, 2017, p. 14.

¹³⁴ FBC Rate Design and Rates of Electric Vehicle Direct Current Fast Charging Service Application, dated December 22, 2017, p. 14.

¹³⁵ Exhibit B-1, Appendix K, p. 10.

¹³⁶ Exhibit B-1, p. 118.

8.2 Incremental cost evaluation of DSM scenarios

BCOAPO submits that, while the incremental cost analysis provides some insights, comparing the incremental cost of the additional DSM measures in each scenario to the average avoided cost of Portfolio B1 is problematic, as the two “cost” definitions are fundamentally different. The appropriate approach would compare the average to average (i.e. the average LRMC for Portfolio B1, and the average cost of each DSM scenario including programming costs). BCOAPO notes that on this basis, the Max DSM scenario would also be cost-effective¹³⁷.

FBC asserts that presenting the incremental costs of each DSM portfolio clearly illustrates the increased cost, i.e. declining economics, of obtaining higher load growth offsets. FBC submits that use of average Total Resource Cost (TRC) has the effect of blending lower and higher cost resources and thereby obscuring the marginal measures that likely should not be pursued.¹³⁸ FBC also submits that DSM programs can have a cost of energy above the LRMC of \$100/MWh and still be considered cost effective on a TRC basis.¹³⁹

In its Reply Argument, FBC agrees with BCOAPO that “the ‘incremental cost’, including program costs, of the DSM scenarios...is not directly comparable to the \$100 per MWh LRMC estimate for clean or renewable BC resources calculated pursuant to Portfolio B1. FBC submits that while it does not dispute that the Max scenario is cost-effective, this is only one of the factors that go into the analysis as between the different DSM scenarios and does not signify that the Max scenario is appropriate to pursue.”¹⁴⁰

Panel discussion

The Panel does not consider the comparison of the incremental costs of DSM scenarios to be an appropriate metric for comparison and ultimate selection of FBC’s preferred DSM scenario.

The portfolio approach (i.e. as opposed to program-by-program approach) to assess cost-effectiveness of DSM has as its foundation an approach that measures and compares entire portfolios against one another as opposed to comparing the ‘top slice’ of one against the aggregate of the other. Said another way, breaking the portfolio into distinct parts is essentially a departure from the portfolio method, towards using the program-by-program (or arbitrary groupings thereof) approach.

The determining cost metric for a DSM plan as prescribed by regulation is the cost-effectiveness test pursuant to section 4 of the DSM Regulation. The Panel notes that while a discussion of incremental costs does arguably add some information, it does not in itself satisfy the regulatory requirements of the cost-effectiveness test. Further, it creates a problem of ‘apples to oranges’ comparisons by juxtaposing the average TRC of one DSM scenario with the marginal TRC of another grouping of DSM programs.

For these reasons, the Panel does not place weight on FBC’s use in this Application of the incremental DSM costs in its rationale for selecting its preferred DSM scenario. Going forward, the Panel encourages FBC to use the average cost approach outlined in the DSM Regulation as the basis for its comparative analysis of portfolios.

¹³⁷ BCOAPO Final Argument, p. 14

¹³⁸ Exhibit B-2, BCUC IR 35.2.1.

¹³⁹ Exhibit B-3, BCOAPO IR 4.3.

¹⁴⁰ FBC Reply Argument, p. 30.

8.3 Framework for resource portfolio evaluation/selection

In Sections 5 of this Decision, the Panel made a determination on the acceptability of FBC’s preferred portfolio option. This section deals with a related but different aspect of the portfolio analysis presented by FBC: the nature of the decision-making framework (i.e. as opposed to the resulting decision itself).

As noted in Section 5, FBC has identified four portfolios (A1, C1, A4, C4) for final consideration, stating that each meets the LTERP’s objectives. FBC presents the evaluation framework for comparison among the four in the following table.

Table 8 – Attributes of Portfolios Considered for Preferred Portfolio¹⁴¹

Portfolio	Incremental Resources	LRMC (\$/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO2e)	Full-Time Equivalents per year	Geographic Resource Diversity	
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	\$75	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	\$90	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	\$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3%) Biomass, Solar (1%)	\$97	0.0%	0	216	Medium

FBC’s submits that its selection of Portfolio A4 reflects a reasonable balance and compromise among differing objectives, such as: cost-effective and reliable supply to meet its customers’ energy requirements, consistency with provincial energy objectives (including self-sufficiency, pursuing adequate, cost effective DSM, and providing socio-economic benefits), and geographic resource diversity¹⁴². The other portfolios that Interveners prefer, all rank lower on important planning objectives compared to Portfolio A4, for example, as FBC states:

- Portfolio A1 (No Self Sufficiency), which is the CEC’s preference, ranks lowest in terms of socio-economic benefits and geographic resource diversity, in addition to the reliability concerns with over-reliance on market supply and inconsistency with the BC energy objective of achieving electricity self-sufficiency;
- Portfolio C1 (93 percent clean with CCGT), which is ICG’s preference, includes the most non-clean resources and produces the most GHG emissions while also generating lower socio-economic benefits and having less geographic resource diversity than Portfolio A4; and
- Portfolio C4 (100 percent clean or renewable), which is BCSEA’s preference, has the highest LRMC of the four portfolios, has less geographic resource diversity than Portfolio A4, and its resource composition offers less reliability and flexibility than Portfolio A4 based on the inclusion of the SCGT in that portfolio.¹⁴³

¹⁴¹ Exhibit B-1-1, Table 9-2, p. 126.

¹⁴² Exhibit B-1, p. 127.

¹⁴³ FBC Reply Argument, p.36.

Panel discussion

The Panel has concerns relating to the evaluation framework in two respects. First, it has concerns with the specific columns set out in the framework and how they are applied. Two examples illustrate the point.

- While energy self-sufficiency is put forward as a key planning objective, this objective does not explicitly show up as a rating column. Rather, it appears to have been applied outside of the framework (both to formulate portfolios in the first instance, and in narrative outside of, and subsequent to, application of the evaluation framework).
- Geographic Resource Diversity appears to be based on a hyper-sensitive rating paradigm. More specifically, the difference in valuation scores between A4 (High) and C4 (Medium) appears to arise singularly from the swapping out of one percent of the incremental resources from SCGT to Biomass/Solar.

The second concern relates to the apparent selectivity of comparisons made between alternative portfolios. FBC justifies its choice by referencing only the shortcomings of each of the alternatives in comparison to its preferred portfolio, while making no mention of their respective advantages. FBC dismisses A1 vs. A4 on the grounds of self-sufficiency and FTEs while remaining silent on the significant cost advantage of A1 (a difference of \$21, or 28 percent), but then dismisses C4 vs. A4 on the grounds of cost (albeit an LRMC difference of \$1, or 1 percent) while staying silent on its advantages on environment and FTEs. In short, FBC's explanation suffers from the appearance of being an exercise in starting from a portfolio preference (i.e. A4) and then justifying the selection after the fact.

Looking to the next LTERP filing, the Panel encourages FBC to develop and apply a more transparent and balanced rating framework that consistently subjects all portfolio alternatives to the same evaluation rigor.

8.4 Distributed generation

FBC defines distributed generation (DG) as an individual-use generation resource, such as solar or small wind turbines, distributed among and utilized by customers.¹⁴⁴

Issues were raised in this proceeding by BCSEA, ICG and Shadrack related to how DG should be defined, where it fits within the LTERP (a supply-side resource, demand-side resource, load forecast adjustment or a combination), and if FBC had appropriately considered DG in the LTERP.

FBC states that “the LTERP does reflect and has accounted for the potential future proliferation of DG as a load reducing driver within the alternative load scenarios.”¹⁴⁵ In addition, FBC states that DG can be considered both a supply-side or demand-side resource.¹⁴⁶ However, FBC states that it did not include power supply from DG or purchases from self-generating customers as resource options to be considered in the portfolio analysis as the availability of DG supply is not within FBC's control and FBC does not have any information at present regarding available energy, capacity, timing or cost of supply from self-generators.¹⁴⁷

FBC submits that it “views DG from the same perspective as it does any potential resource that may be considered within the resource planning process [and that it] seeks to neither advantage nor disadvantage DG regardless of size, type or ownership.”¹⁴⁸

¹⁴⁴ Exhibit B-2, BCUC IR 10.1.

¹⁴⁵ FBC Final Argument, p. 32.

¹⁴⁶ Exhibit B-1, Appendix J, p. 41.

¹⁴⁷ FBC Final Argument, p. 31-33.

¹⁴⁸ Exhibit B-2, BCUC IR 10.2.

Panel discussion

The Panel is satisfied that FBC has appropriately factored DG into this LTERP planning framework.

Looking at the broader policy issues relating to the extent to which DG should be encouraged, the Panel notes that a proceeding is currently underway, in which FBC is seeking approval of a policy that will guide self-generation in the future.

8.5 Planning Reserve Margin

In its Decision on FBC's 2012 Integrated System Plan (ISP), the BCUC found FBC's planning reserve margin (PRM) methodology to be under-developed and agreed with FBC's suggestion to complete its PRM methodology study and file it with the BCUC at a later date.¹⁴⁹ The BCUC accepted the resource supply/demand analysis provided by FBC (with the exception of the PRM) as FBC had no capacity gap forecast until sometime in the 2021–2040 period, however the BCUC directed FBC to include a full portfolio analysis in the next LTERP.¹⁵⁰

FBC states, "The Planning Reserve Margin (PRM) is conceptually the capacity above-expected load necessary to maintain a certain resource adequacy level." The PRM's role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system.¹⁵¹

FBC has since adopted a loss-of-load expectation (LOLE) methodology as the reliability metric for the assessment of PRM adequacy and targets a one day in ten years threshold.¹⁵² This is the same methodology and target used by BC Hydro and has widespread use in the industry.¹⁵³

There were no objections from Registered Interveners to FBC's proposed PRM methodology.

BCUC determination

FBC's PRM methodology is consistent with industry practice, and **the Panel finds the PRM methodology used in this LTERP is acceptable.**

¹⁴⁹ FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Decision dated August 15, 2012 (G-110-12), p. 41.

¹⁵⁰ *Ibid.*, p. 147.

¹⁵¹ Exhibit B-1, Appendix L, p. 1.

¹⁵² *Ibid.*, p. ES-1.

¹⁵³ Exhibit B-2, preamble to BCUC IR 29.0.

DATED at the City of Vancouver, in the Province of British Columbia, this 28th day of June 2018.

Original signed by:

H. G. Harowitz
Panel Chair / Commissioner

Original signed by:

D. J. Enns
Commissioner

Original signed by:

M. Kresivo, QC
Commissioner



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ORDER NUMBER
G-117-18

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2016 Long Term Electric Resource Plan and
2016 Long Term Demand Side Management Plan

BEFORE:

H. G. Harowitz, Panel Chair/Commissioner
D. J. Enns, Commissioner
M. Kresivo, QC, Commissioner

on June 28, 2018

ORDER

WHEREAS:

- A. On November 30, 2016, FortisBC Inc. (FBC) applied to the British Columbia Utilities Commission (BCUC) pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA) for acceptance of its 2016 Long Term Electric Resource Plan (2016 LTERP) and Long Term Demand-Side Management Plan (2016 LTDSM Plan) (Application);
- B. In the Application, FBC also applies to rescind Electric Tariff No. 2 Schedule 90, Energy Management Services (Rate Schedule 90);
- C. The 2016 LTERP sets out a long term plan for meeting the forecast peak and energy requirements of FBC customers with demand-side and supply-side resources over the next 20 years;
- D. The 2016 LTDSM Plan includes an assessment of the energy efficiency and conservation potential for FBC customers and identifies FBC's preferred DSM scenario for long term planning purposes;
- E. By Orders G-197-16, G-102-17 and G-107-17 dated December 22, 2016, June 30, 2017 and July 13, 2017 respectively, the BCUC established a regulatory timetable and written hearing process for the review of the Application, which included: two rounds of Information Requests (IR) to FBC, Intervener Evidence and IR's on that evidence, and one round of Panel IRs;
- F. On August 25, 2017, FBC filed for a suspension of the regulatory timetable. By Order G-134-17 dated August 29, 2017, the BCUC suspended the regulatory timetable until further notice;
- G. On September 8, 2017, FBC filed a letter indicating its intent to file errata to its Application;

Order G-117-18

- H. By Order G-139-17 dated September 13, 2017, the BCUC established a regulatory timetable setting out dates for FBC to file the errata, and interveners to review the errata and to comment on further process;
- I. On September 15, 2017, FBC filed the errata to its Application;
- J. By Order G-155-17, dated October 6, 2018, the BCUC ordered that the proceeding proceed to the Final Argument stage;
- K. FBC's Final Argument and Intervener Final Arguments were submitted on October 20, 2017 and November 9 -10, 2017 respectively, followed by a Reply Argument from FBC on November 24, 2017; and
- L. The BCUC has reviewed and considered the evidence and submissions and makes the following determinations.

NOW THEREFORE the British Columbia Utilities Commission orders as follows:

1. The 2016 LTERP for the years up to 2024 is in the public interest and is accepted. For years beyond 2024 the 2016 LTERP is not in the public interest and is rejected;
2. The 2016 LTDSM Plan is in the public interest and is accepted;
3. Rate Schedule 90 is rescinded from FBC's Tariff. FBC is directed to submit revised tariff pages in respect of Rate Schedule 90 no later than 30 days of the date of this order;
4. FBC is directed to file its next Long Term Resource Plan and Long Term Demand-Side Management Plan no later than December 1, 2021.

DATED at the City of Vancouver, in the Province of British Columbia, this 28th day of June 2018.

BY ORDER

Original signed by:

H. G. Harowitz
Commissioner

APPENDIX A

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Inc.
2016 Long Term Electric Resource Plan (LTERP)
and Long Term Demand Side Management Plan (LT DSM) Plan Application

EXHIBIT LIST

Exhibit No.	Description
<i>COMMISSION DOCUMENTS</i>	
A-1	Letter dated December 8, 2016 – Appointing the Panel for the review of FortisBC Inc.’s Long Term Electric Resource Plan & Long Term Demand Side Management Plan
A-2	Letter dated December 22, 2016 – Commission Order G-197-16 establishing a Regulatory Timetable with Public Notice
A-3	Letter dated February 28, 2017 – Commission Information Request No. 1 to FBC
A-4	Letter dated March 7, 2017 – Commission response to Mr. Gabana’s Extension Request
A-5	Letter dated April 19, 2017 – Confirming Regulatory Timetable with Intervener Evidence as set out in Order G-197-16
A-6	Letter dated April 27, 2017 – Commission Information Request No. 2 to FBC
A-7	Letter dated May 12, 2017 – Commission response to FBC and Mr. Shadrack regarding Questions Out of Scope
A-8	Letter dated June 8, 2017 – Commission Information Request No. 1 on BCSEA’s Evidence
A-9	Letter dated June 8, 2017 - Commission Information Request No. 1 on ICG’s Evidence
A-10	Letter dated June 8, 2017 - Commission Information Request No. 1 on Shadrack’s Evidence
A-11	Letter dated June 30, 2017 – Commission Order G-102-17 Amending the Regulatory Timetable
A-12	Letter dated July 13, 2017 –Commission Order G-107-17 Accepting Late Intervener Evidence and Amending the Regulatory Timetable

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- A-13 Letter dated July 27, 2017 – Commission Information Request No. 1 to Mr. Shadrack regarding Shadrack Late Intervener Evidence
- A-14 Letter dated July 27, 2017 – Panel Information Request No. 1 to FortisBC Inc.
- A-15 Letter dated July 7, 2017 – Commission Correspondence to Mr. Shadrack Regarding Confidential Responses to IR No. 1 on Intervener Evidence
- A-16 Letter dated July 31, 2017 – Commission Correspondence Regarding Request to Withdraw Exhibit B-23
- A-17 Letter dated August 18, 2017 – Commission Panel Denying Mr. Shadrack’s Request to Withdraw Exhibit B-23
- A-18 Letter dated August 29, 2017 – Commission Order G-134-17 Suspending the Regulatory Timetable
- A-19 Letter dated September 13, 2017 – Commission Order G-137-17 Establishing a Regulatory Timetable
- A-20 Letter dated October 6, 2017 – Commission Order G-155-17 Establishing a Regulatory Timetable

APPLICANT DOCUMENTS

- B-1 **FORTISBC INC. (FBC)** Letter dated November 30, 2016 - 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) Application
- B-1-1 Letter dated September 15, 2017 – FBC Filing Errata
- B-2 Letter dated April 6, 2017 - FBC Response to BCUC IR No.1
- B-2-1 **CONFIDENTIAL** Letter dated April 6, 2017 - FBC Confidential Response to BCUC IR No.1
- B-3 Letter dated April 6, 2017 - FBC Response to BCOAPO IR No.1
- B-4 Letter dated April 6, 2017 - FBC Response to BCSEA IR No.1
- B-5 Letter dated April 6, 2017 - FBC Response to CEC IR No.1
- B-6 Letter dated April 6, 2017 - FBC Response to Gabana IR No.1
- B-6-1 Letter dated April 18, 2017 - FBC Response to Gabana IR 1.11 Supplemental Information
- B-7 Letter dated April 6, 2017 - FBC Response to ICG IR No.1
- B-7-1 Letter dated May 18, 2017 – FBC Response to ICG IR 1.1.2 Erratum

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- B-8 Letter dated April 6, 2017 - FBC Response to Scarlett IR No.1
- B-9 Letter dated April 6, 2017 - FBC Response to Shadrack IR No.1
- B-10 Letter dated May 3, 2017 – FBC Submitting comments regarding Questions Out of Scope Shadrack IR No. 2
- B-11 Letter dated May 18, 2017 – FBC Response to BCUC IR No. 2
- B-12 Letter dated May 18, 2017 – FBC Response to BCOAPO IR No. 2
- B-13 Letter dated May 18, 2017 – FBC Response to BCSEA IR No. 2
- B-14 Letter dated May 18, 2017 – FBC Response to CEC IR No. 2
- B-15 Letter dated May 18, 2017 – FBC Response to Gabana IR No. 2
- B-16 Letter dated May 18, 2017 – FBC Response to ICG IR No. 2
- B-17 Letter dated May 18, 2017 – FBC Response to Scarlett IR No. 2
- B-18 Letter dated May 18, 2017 – FBC Response to Shadrack IR No. 2
- B-19 Letter dated June 8, 2017 – FBC Information Request No. 1 on BCSEA’s Evidence
- B-20 Letter dated June 8, 2017 - FBC Information Request No. 1 on ICG’s Evidence
- B-21 Letter dated June 8, 2017 - FBC Information Request No. 1 on Shadrack’s Evidence
- B-22 Letter dated July 17, 2017 – FBC Comments on Order G-107-17 – Shadrack Filing of Late Evidence
- B-23 Letter dated July 21, 2017 – FBC Comments on Mr. Shadrack’s Late IR Responses
- B-24 Letter dated August 1, 2017 - FBC Submitting Comments on Mr. Shadrack’s Request to Withdraw Exhibit B-23
- B-25 Letter dated August 24, 2017 – FBC Submitting Response to Panel Information Request No. 1
- B-26 Letter dated August 25, 2017 – FBC Submitting Request for Suspension of Regulatory Timetable
- B-27 Letter dated September 8, 2017 – FBC Submitting Proposed Timetable
- B-28 Letter dated September 26, 2017 – FBC Submitting Response to Mr. Shadrack’s Carbon Tax Query Exhibit C10-15
- B-29 Letter dated October 2, 2017 - FBC Reply Submission on Process

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INTERVENER DOCUMENTS

- C1-1 **NICHOLAS MARTY (MARTY)** – Form dated January 17, 2017 Request to Intervene by Nicholas Marty
- C2-1 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO)** – Form dated January 24, 2017 Request to Intervene by Fred James
- C3-1 **JERRILYNN DECOCK (DECOCK)** – Form dated January 17, 2017 Request to Intervene by Jerrilynn DeCock
- C4-1 **COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CEC)** – Form dated January 26, 2017 Request to Intervene by David Craig
- C4-2 Letter dated March 7, 2017 – CEC Submitting Information Request No. 1
- C4-3 Letter dated April 27, 2017 - CEC Submitting Information Request No. 2
- C4-4 Letter dated June 8, 2017 - CEC Submitting Information Request No. 1 on ICG’s Evidence
- C4-5 Letter dated June 8, 2017 - CEC Submitting Information Request No. 1 on BCSEA Evidence
- C4-6 Letter dated September 28, 2017 - CEC Submitting Comments on Further Process
- C5-1 **BC SUSTAINABLE ENERGY ASSOCIATION AND SIERRA CLUB OF BC (BCSEA)** – Form dated January 26, 2017 Request to Intervene by Thomas Hackney
- C5-2 Letter dated March 7, 2017 – BCSEA Submitting Information Request No. 1
- C5-3 Letter dated April 9, 2017 – BCSEA Submitting Notice on Filing Intervener Evidence
- C5-4 Letter dated April 27, 2017 - BCSEA Submitting Information Request No. 2
- C5-5 Letter dated May 25, 2017 - BCSEA Submitting Intervener Evidence
- C5-6 Letter dated June 8, 2017 - BCSEA Submitting Information Request No. 1 on ICG’s Evidence
- C5-7 Letter dated June 8, 2017 - BCSEA Submitting Information Request No. 1 on Shadrack’s Evidence
- C5-8 Letter dated June 29, 2017 - BCSEA Submitting Response to BCUC Information Request No. 1
- C5-9 Letter dated June 29, 2017 - BCSEA Submitting Response to BCOAPO Information Request No. 1
- C5-10 Letter dated June 29, 2017 - BCSEA Submitting Response to CEC Information Request No. 1
- C5-11 Letter dated June 29, 2017 - BCSEA Submitting Response to FBC Information Request No. 1

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- C5-12 Letter dated June 29, 2017 - BCSEA Submitting Response to Shadrack Information Request No. 1
- C5-13 Letter dated July 17, 2017 – BCSEA Submitting Information Request No 2. to Shadrack
- C5-14 Letter dated September 26, 2017 – BCSEA Submitting Reply to FortisBC Inc proposed timetable
- C6-1 **ZELLSTOFF CELGAR PARTNERSHIP LIMITED (CELGAR)** – Form dated January 26, 2017 Request to Intervene by Robert Hobbs
- C6-2 Letter dated April 13, 2017 - Celgar Submitting Notice of Intervener Evidence
- C7-1 **INDUSTRIAL CUSTOMERS GROUP (ICG)** – Form dated January 26, 2017 Request to Intervene by Robert Hobbs
- C7-2 Letter dated March 7, 2017 – ICG Submitting Information Request No. 1
- C7-3 Letter dated April 27, 2017 - ICG Submitting Information Request No. 2
- C7-4 Letter dated May 25, 2017 - ICG Submitting Intervener Evidence
- C7-5 Letter dated June 29, 2017 - ICG Submitting Response to BCUC Information Request No. 1
- C7-6 Letter dated June 29, 2017 - ICG Submitting Response to BCOAPO Information Request No. 1
- C7-7 Letter dated June 29, 2017 - ICG Submitting Response to BCSEA Information Request No. 1
- C7-8 Letter dated June 29, 2017 - ICG Submitting Response to CEC Information Request No. 1
- C7-9 Letter dated June 29, 2017 - ICG Submitting Response to FBC Information Request No. 1
- C7-10 Letter dated September 29, 2017 - ICG Submitting Comments on Further Process
- C8-1 **BRITISH COLUMBIA OLD AGE PENSIONERS’ ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, COUNCIL OF SENIOR CITIZENS’ ORGANIZATIONS OF BC, DISABILITY ALLIANCE BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE, (BCOAPO)** – Form dated January 26, 2017 Request to Intervene by Michael Seaborn and Kate Feeney
- C8-2 Letter dated March 7, 2017 – BCOAPO Submitting Information Request No. 1
- C8-3 Letter dated April 27, 2017 - BCOAPO Submitting Information Request No. 2
- C8-4 Letter dated June 8, 2017 - BCOAPO Submitting Information Request No. 1 on ICG’s Evidence
- C8-5 Letter dated June 8, 2017 - BCOAPO Submitting Information Request No. 1 on BCSEA Evidence
- C8-6 Letter dated September 27, 2017 - BCOAPO Submitting Comments on Further Process

APPENDIX A

- C9-1 **DONALD SCARLETT (SCARLETT)** – Form dated January 27, 2017 Request to Intervene by Donald Scarlett
- C9-2 Letter dated March 7, 2017 – Scarlett Submitting Information Request No. 1
- C9-3 Letter dated April 27, 2017 - Scarlett Submitting Information Request No. 2
- C9-4 Letter dated August 2, 2017 - Scarlett Submitting Comments on Request to Withdraw Exhibit B-23
- C10-1 **ANDY SHADRACK (SHADRACK)** – Form dated January 26, 2017 Request to Intervene by Andy Shadrack
- C10-2 Letter dated March 7, 2017 – Shadrack Submitting Information Request No. 1
- C10-3 Letter dated April 7, 2017 – Shadrack Submitting Notice on Filing Intervener Evidence
- C10-4 Letter dated April 27, 2017 - Shadrack Submitting Information Request No. 2
- C10-5 Letter dated May 8, 2017 - Shadrack Submitting Comments regarding Out of Scope Issue
- C10-6 Letter dated May 23, 2017 - Shadrack Submitting Intervener Evidence
- C10-7 Letter dated June 6, 2017 – Shadrack Submitting Information Request No. 1 on Intervener Evidence
- C10-8 Letter dated June 29, 2017 – Shadrack Submitting IR No.1 Response
- C10-8-1 Letter dated July 13, 2017 – Shadrack Submitting Supplemental Background Information on IR No.1 Response
- C10-9 Letter dated July 7, 2017 – Shadrack Submitting Late Intervener Evidence
- C10-10 Letter dated July 21, 2017 – Shadrack Submitting comments on Late Intervener Evidence
- C10-11 Letter dated August 4, 2017 – Shadrack Submitting Reply Submission Regarding Withdrawal of Exhibit B-23
- C10-12 Letter dated August 4, 2017 - Shadrack Submitting Notice of Legal Counsel Update
- C10-13 Letter dated August 10, 2017 - Shadrack Submitting Response to Commission Information Request No. 1 on Late Intervener Evidence
- C10-14 Letter dated August 10, 2017 - Shadrack Submitting Response to BCSEA Information Request No 2.
- C10-15 Letter dated September 12, 2017 - Shadrack Submitting Reply to FortisBC Inc proposed timetable
- C10-16 Letter dated September 28, 2017 - Shadrack Submitting Comments on Further Process

APPENDIX A

- C11-1 **GABANA, NORMAN (GABANA)** – Form dated January 27, 2017 Request to Intervene by Norman Gabana
- C11-2 Letter dated March 5, 2017 – Gabana Submitting Request for Filing Extension
- C11-3 Letter dated March 14, 2017 – Gabana Submitting Information Request No. 1
- C11-4 Letter dated April 27, 2017 - Gabana Submitting Information Request No. 2

INTERESTED PARTY DOCUMENTS

LETTERS OF COMMENT

1 **REFERENCE: Undertaking 30 pdf pages 39-40**

2
3 **PREAMBLE:** YEC provided details of its deferred cost amortization amounts for Tab
4 7, Schedule 5, Line 7 amounts noting that, “No feasibility contributions
5 were deducted in 2017 and 2018; however, feasibility contributions
6 were deducted in 2016.”

7
8 YEC provided similar details for its deferred cost contributions for
9 Tab 7, Schedule 5, Line 10 amounts and additionally, provided
10 details with respect to its 2017 actual results. The Board observes
11 there are actual 2017 feasibility contributions and proposed
12 feasibility contribution amounts identified for the years 2017 and
13 2018.

14
15 **QUESTION:**

- 16
17 a) Please explain what is meant by contributions being “deducted” from deferred cost
18 amortization.
19
20 b) Please explain why YEC’s Tab 7, Schedule 5, Line 7 reconciliation discloses
21 feasibility contributions for the year 2016 differently from the years 2017-2018. For
22 example, 2016 Actual deferred cost amortization is shown net of contributions,
23 whereas 2017-2018 Proposed deferred cost amortization is shown before
24 contributions.
25
26 c) Please explain why 2017 Actual feasibility contribution in the amount of \$1,325K is
27 significantly larger than the 2017 Proposed feasibility contribution in the amount of
28 \$786K.
29
30 d) For completeness, please provide the corresponding Tab 7, Schedule 5, Line 7
31 detail for YEC’s 2017 Actual results.

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 Amortization of deferred cost contributions does occur each year.

6
7 With regard to the explanation for what is meant by contributions being “deducted” from
8 deferred cost amortization – the following are noted:

- 9
- 10 • YEC first calculates the amortization of deferred costs on an asset by asset basis
11 in accordance with the Planning Cost Accounting Policy.
 - 12
 - 13 • If there was a contribution specifically for that deferred cost asset, then the
14 amortization of that contribution is “deducted” from the amortization of the deferred
15 cost asset. For example, YEC completed a Waste-to-Energy project at a cost of
16 \$1.667 million and received a contribution for this project in the amount of \$0.783
17 million. As this project is over \$1 million, YEC amortizes the cost of the project over
18 ten years (\$0.167 million per year). For consistency, YEC amortizes the
19 contribution for this project over the same period of ten years (\$0.078 million per
20 year).
 - 21
 - 22 • The net amortization of this project after “deducting” amortization of the
23 contribution is \$0.089 million per year (\$0.167 million less \$0.078 million).
- 24

25 In the GRA filing, amortization of deferred cost contributions has been shown as a
26 reduction of amortization of deferred costs (Tab 7, Schedule 5, Line 7) and also separately
27 under amortization of contributions (Tab 7, Schedule 5, Line 10). In addition, as noted in
28 the question, Line 7 reconciliation disclosed feasibility contributions for the year 2016
29 differently from the years 2017-2018.

30
31 It is acknowledged that this inconsistent presentation in the GRA filing is without any
32 specific rationale and has caused confusion; however, the amortization of deferred cost
33 contributions is ultimately treated in the same manner in each case, i.e., they offset
34 expenses for the calculation of income and therefore have no impact on revenue
35 requirement or customer rates.

1 Internally, YEC accounts for amortization of deferred cost contributions as a reduction of
2 amortization of deferred cost assets. This is the most appropriate treatment and is
3 consistent with accounting practices for Canadian regulated utilities.

4
5 To address and resolve the above confusions, Part (d) below provides updated tables
6 where amortization of all deferred cost contributions are shown consistently as a reduction
7 of amortization of deferred costs.

8
9 **(c)**

10
11 The difference between Actual and Proposed for 2017 in this instance reflects differences
12 in what was included.

13
14 The 2017 Actual feasibility contribution includes the amortization of the costs incurred and
15 contribution received for the Stewart-Keno Transmission Line study (note contribution in
16 this case equaled costs incurred). However, the 2017 proposed feasibility contribution in
17 the filing did not include amortization of the contribution or the cost.

18
19 As the project contribution was equal to the project costs, there is no net impact from the
20 above differences. The actual amortization of the study costs is fully offset by the actual
21 amortization of the contribution. The Proposed 2017 numbers in Schedule 5 did not break
22 this out, whereas the Actual 2017 numbers did break this out.

23
24 **(d)**

25
26 As described in response to (a) and (b) above, Tables 1-3 below provide updated tables
27 that show amortization of all deferred cost contributions consistently as a reduction of
28 amortization of deferred costs. YEC's 2017 Actual results are shown for completeness.

1 **Table 1: Consistent presentation of amortization of all deferred cost contributions**
2 **(Update to Tab 7, Schedule 5, Line 7)**

(\$000's)	Actual 2016	Actual 2017	Forecast		Forecast	
			Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Regulatory						
Pre contribution	425	593	153	622	88	577
Contributions	-	99	-	99	-	99
Net Regulatory	425	495	153	523	88	479
Hearing Cost Reserve Account	550	55	550	55	550	55
Feasibility						
Pre contribution	1,209	2,606	867	2,372	852	2,492
Contributions	-	1,325	-	786	-	705
Net Feasibility	25	1,282	84	1,586	150	1,787
Relicensing						
Pre contribution	582	582	582	582	515	515
Contributions	-	-	-	-	-	-
Net Relicensing	582	582	582	582	515	515
Dam Safety						
Pre contribution	-	30	-	30	-	30
Contributions	-	-	-	-	-	-
Net Dam Safety	-	30	-	30	-	30
Brushing	-	222	-	222	-	222
Amortization of deferred costs	1,581	2,666	1,369	2,998	1,304	3,088

3
4
5 Table 1 above shows a re-classification of amounts in Tab 7, Schedule 5, Line 7; Table 2
6 below updates Tab 7, Schedule 5, Line 10.

7
8
9

Table 2: Update to Tab 7, Schedule 5, Line 10

(\$000's)	Actual 2016	Actual 2017	Forecast		Forecast	
			Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
Customer contributions and government funding	4,102	4,115	4,119	4,122	4,130	4,135
Fire insurance recoveries	262	262	262	262	262	262
Amortization of Contributions and Fire Insurance Recoveries	4,364	4,377	4,381	4,384	4,392	4,397

10

1 To provide support that the above re-classification does not impact results, Table 3 below
2 provides a reconciliation.

3

4 **Table 3: Reconciliation of Tab 7, Schedule 5, Line 7 and Tab 7, Schedule 5 Line 10**

5

(\$000's)	Actual 2016	Actual 2017	Forecast		Forecast	
			Existing 2017	Proposed 2017	Existing 2018	Proposed 2018
As filed in GRA						
Amortization of deferred costs (line 7)	1,581		2,152	3,883	2,006	3,891
Amortization of contributions and fire insurance recoveries (line 10)	- 4,364		- 5,164	- 5,269	- 5,094	- 5,200
Total	- 2,783	-	- 3,012	- 1,386	- 3,088	- 1,309
As updated						
Amortization of deferred costs (line 7)	1,581	2,666	1,369	2,998	1,304	3,088
Amortization of contributions and fire insurance recoveries (line 10)	- 4,364	- 4,377	- 4,381	- 4,384	- 4,392	- 4,397
Total	- 2,783	- 1,711	- 3,012	- 1,386	- 3,088	- 1,309

6

1 **REFERENCE:** Transcript, Volume 3, PDF page 522, lines 23-25; Undertaking 31 pdf
2 page 41.

3
4 **QUOTE:** Transcript:

5
6 ... Regulatory, again, that's proceedings such as this. PPAs, reviews,
7 Part 3s, that sort of thing goes through our regulatory accounts...

8 Undertaking 31:

9 The response to YUB-YEC-2-26 Attachment 1 shows amortization
10 of proposed *Regulatory Costs* of \$0.622 million in 2017 and \$0.578
11 million in 2018 (prior to deduction of contributions).

12 ...

13 *Rate case amortization* is part of the net change in *Rate Case Assets* in
14 Table 4 of YUB-YEC-1-12; the related balance sheet account is
15 separately tracked from Deferred Studies (Tab 7, Schedule 1 –
16 Deferred studies is displayed on lines 8-12 while Rate Case is
17 separately disclosed under line 18). [emphasis added]

18
19 **QUESTION:**

20
21 a) Please provide detail of the remaining “part of the net change in Rate Case Assets
22 in Table 4 of YUB-YEC-1-12” which the Board observes is a total of \$493K in 2017
23 and -\$972K in 2018.

24
25 b) Please explain the nature of and differences between the types of costs
26 associated with the amortization of “regulatory costs” identified in YUB-YEC-2-
27 26 and Undertaking 31 which YEC describes as being related to the “rate case
28 amortization” of “rate case assets” as opposed to the “amortization of hearing
29 cost reserve account” identified in YUB-YEC-2-26.

30
31 c) With respect to “regulatory costs”, please explain the nature and source of the
32 associated contributions which were identified in YEC's response to
33 Undertaking 30 in the amount of \$99K in each of the years 2017 and 2018.

34
35 **ANSWER:**

1 (a)

2

3 The net change in Rate Case Assets in Table 4 of YUB-YEC-1-12 of \$493K in 2017 and
 4 -\$972K in 2018 is detailed below.

5

6

Table 1: Net change in Rate Case Assets

7

(\$000's)	2017	2018
Additions	713	-
Transfer to Hearing Reserve	- -	818
Amortization	- 221 -	155
Amortization of Contributions	1	1
Net Change	493 -	972

8

9

10 (b)

11

12 The YUB approved the Hearing Reserve Account in Order 2013-1 and Order 2013-3
 13 following YEC's 2012-13 GRA.

14

15 • Costs related to hearings before the YUB are added to this account. For example,
 16 the \$818K Transfer to Hearing Reserve in the table in answer (a) above reflects
 17 forecast costs of the 2017-2018 GRA proceeding.

18

19 • An annual appropriation of \$550k was established for the account following the
 20 2012/13 GRA. For the 2017-18 test years, YEC has proposed reducing the annual
 21 appropriation to \$250k.

22

23 Rate Case Assets are regulatory costs other than DSM costs or costs transferred to the
 24 Hearing Reserve Account. Rate Case assets include costs relating to YUB proceedings
 25 until completion of the hearing process, when approved costs are transferred to the
 26 Hearing Reserve Account.

27

28 • The \$713K of Additions 2017 in the answer to (a) above reflects costs forecast in
 29 2017 for the 2017-18 GRA.

1 • Subsequent to the YUB approval of the Hearing Reserve Account as part of the
2 2012-13, significant costs in the Rate Case Asset category other than costs
3 relating to YUB proceedings are not anticipated.

4

5 • An example of a regulatory cost not related to hearings is the study on International
6 Financial Reporting Standards that was completed in 2017 totaling \$0.181 million.
7 YEC is amortizing the cost of this project over a five year period.

8

9 **(c)**

10

11 To December 31, 2016, YEC had received \$975K of contributions relating to DSM. YEC
12 is amortizing these costs over ten years (\$97.5K per year). The majority of the
13 contributions came from Yukon Development Corporation to assist with DSM
14 investigations and program design (\$500K); as well, ATCO contributed approximately
15 \$300K to program delivery. The residual amounts were contributions from various third
16 parties for specific program elements.

1 **REFERENCE: Undertaking 29 pdf pages 33-37**

2
3 **QUOTE:** 2.1 The following planning and study costs will be recorded as an
4 expense of the period in which they are incurred:
5 a. Planning and study costs which are pure research in nature. It should
6 be noted that costs of this type, if any, are not expected to be significant.
7
8 b. Planning and study costs related to ongoing operations that, unless it
9 can be demonstrated that these costs provide long-term or multi-year
10 benefits to the system which will be deferred.

11
12 **QUESTION:**

- 13
14 a) Please clarify whether any of the changes to the proposed Planning Cost
15 Accounting Policy (PCAP) have been implemented or taken into account during
16 the 2017-2018 test years.
17
18 b) If part (a) is confirmed, please identify the PCAP provisions that YEC has adopted.
19
20 c) Please provide a dollar value threshold for a planning and study cost YEC would
21 consider is “significant.”
22
23 d) Please identify any study and its associated cost that would have been expensed
24 under section 2.1 (a-b) of the PCAP during the years 2012-2018.

25
26 **ANSWER:**

27
28 **(a) and (b)**

29
30 Yukon Energy has adopted the provisions of the Planning Cost Accounting Policy provided
31 as Appendix 5.1 of the Application for the test years; as such, all of the provisions of the
32 policy have been implemented or taken into account in the test years.

33
34 Note that some of the edits to this Policy are simply to codify existing practice e.g. the
35 requirement in S.2.4 to keep planning projects in WIP only as long as economically viable
36 has always been a YEC practice, and the policy update simply formalizes the practice.

1 **(c)**

2

3 “Significant” is used in the amended policy as a reference to pure research studies in
4 Section 2.1a.

5

6 The concept of expensing costs that are considered pure research in nature originated
7 with the original planning cost accounting policy adopted in the early 1990’s. This original
8 policy noted with regard to pure research that costs of this type, if any, are not expected
9 to be significant. Yukon Energy considers such costs to relate to negligible research or
10 operations work that does not provide enduring or multi-year benefits.

11

12 Given the above approach, YEC has not specifically assessed research activities for a
13 \$ value threshold.

14

15 **(d)**

16

17 In the 2012/13 GRA Yukon Energy noted that it could not provide any recent examples of
18 such costs, and that all research or studies related to ongoing operations in recent years
19 had been considered to provide longer term benefits to the system and has been
20 amortized over 5 years once the study is complete. In the 2012/13 GRA Yukon Energy
21 noted that no such costs were expensed in the 2012/13 test years.¹

22

23 YEC is not aware of any studies written off since 2012 that would be considered under
24 this criteria.

¹ 2012/13 GRA, T36, lines 2 to 13.