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

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-156-10

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 a 2009 Rate Design and Cost of Service Analysis

BEFORE: A.J. Pullman, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commission

October 19, 2010

O R D E R

WHEREAS:

A. On October 30, 2009, pursuant to sections 58 and 61 of the *Utilities Commission Act* (the Act), FortisBC Inc. (FortisBC) filed its 2009 Rate Design and Cost of Service Analysis Application (Application) for approval by the British Columbia Utilities Commission (Commission);

B. On November 26, 2009, the Commission issued Order G-139-09 establishing an initial Regulatory Timetable for the proceeding to review the Application;

C. On December 15, 2009, a Procedural Conference was held in the City of Kelowna;

D. On December 21, 2009, the Commission issued Order G-166-09, amending the initial Regulatory Timetable. Order G-166-09 established that an Oral Public Hearing would be held in the City of Kelowna, commencing Monday, May 3, 2010;

E. By letter dated February 15, 2010, Zellstoff-Celgar Limited partnership (Celgar) applied for Commission determinations that establishing a Generation Baseline (GBL) for Celgar's Castlegar pulp mill would be appropriate within the scope of the rate design proceeding, and for procedural directions to accommodate addressing the GBL (the Celgar Application);

…/2

F. By letter dated February 18, 2010, the Commission invited FortisBC and registered Interveners to make written submissions on the Celgar Application. Responses supporting the Celgar Application were received from British Columbia Old Age Pensioners' organization *et al*. (BCOAPO), Mr. Andy Shadrack, and Mr. Alan Wait; submissions opposing the Celgar application were received from British Columbia Municipal Electric Utilities (BCMEU) and FortisBC. British Columbia Hydro and Power Authority (BC Hydro) took no position concerning the appropriateness and determination of a GBL between FortisBC and Celgar within the scope of the proceeding. However, BC Hydro submitted that the existing generation baseline specified in the Energy Purchase Agreement (EPA) between itself and Celgar and the Power Purchase Agreement between FortisBC and BC Hydro, as amended, should be outside the scope of the proceeding. In Reply, Celgar agreed with BC Hydro's position on excluding those two matters from the scope of the proceeding;

G. On March 3, 2010, the Commission issued Order G-35-10, with Reasons for Decision, with respect to the Celgar Application. The Regulatory Timetable was amended to permit Celgar to file evidence on establishing a GBL with FortisBC (the GBL Evidence), and to allow for a round of Information Requests (IRs) on the GBL Evidence. Celgar was directed to make a witness panel available for cross-examination on the GBL Evidence at the oral hearing. The contractual generation baseline established in the EPA between BC Hydro and Celgar was ruled outside the scope of this proceeding. The Commission would determine whether the GBL Evidence was ultimately relevant to the proceeding as part of the Rate Design Decision, and, if appropriate, determine a GBL between Celgar and FortisBC;

H. By letter dated March 22, 2010, FortisBC applied to the Commission (the Reply Application) for approval to file Reply Evidence to address certain matters raised in Intervener Evidence filed on March 15, 2010. FortisBC claimed that the Reply Evidence would minimize the new matters likely to arise during the oral hearing. By letter dated March 24, 2010, BCMEU filed an objection, requesting that, should the Reply Application be approved, parties would have a right to file IRs on the Reply Evidence. By letter dated March 26, 2010, the Commission invited other Interveners to comment on the Reply Application;

I. On April 12, 2010, after considering the Reply Application, submissions from BCMEU and other Interveners and a FortisBC reply, the Commission granted the Reply Application subject to the right of Interveners to make submissions on the admissibility of the Reply Evidence. Order G-69-10 was issued amending the Revised Regulatory Timetable to allow FortisBC to file Reply Evidence by Thursday, April 22, 2010;

J. The oral public hearing was held in the City of Kelowna, commencing Monday, May 3, 2010 and concluding Friday, May 7, 2010. The parties agreed on a preliminary schedule for Final Argument in light of an undertaking by FortisBC to file a revised Cost of Service Analysis (Revised COSA) by May 14, 2010. The Panel gave Interveners until May 21, 2010 to provide written submissions to the Commission on whether the Revised COSA required process beyond the preliminary schedule for Final Argument. The Commission left the evidentiary record open pending receipt of Intervener comments;

K. On May 14, 2010, FortisBC filed the Revised COSA (Exhibit B-35) containing summary tables showing various scenarios requested by the Commission and Interveners;

L. By May 21, 2010, the Commission had received submissions on further process from six Interveners. Big White, Mr. Shadrack, and BCOAPO supported further process with respect to the revised COSA; all other Interveners submitted that no further process was required. Big White proposed that the Commission assign no weight to the Revised COSA, using the existing evidence and timetable to set rates for FortisBC. As an alternative, Big White requested an extension of the evidentiary phase (possibly reconvening the oral hearing) to allow for a full and comprehensive review for the rates suggested by the Revised COSA;

M. On May 25, 2010, the Commission issued Order G-86-10, with a Supplementary Regulatory Timetable extending the evidentiary phase of the hearing to allow IRs on FortisBC Exhibits B-33 and B-35;

N. By letter dated June 7, 2010, Celgar advised the Commission of its objections concerning certain IRs submitted to FortisBC pursuant to Order G-86-10. Celgar identified the specific IRs it objected to (Contentious IRs), giving reasons for its objections;

O. By Letter L-44-10 the Commission invited FortisBC and Intervener submissions on Celgar's objections to the Contentious IRs. Parties were invited to comment on whether the Contentious IRs were in scope, raised new issues, necessitated further process, and if so, what further process would be necessary. The Commission received comments on Letter L-44-10 from the BCMEU, Big White, and FortisBC;

P. On June 18, 2010, the Commission issued Letter L-51-10 directing FortisBC to respond to all of the Contentious IRs. Letter L-51-10 also amended the Supplementary Regulatory Timetable specified in Order G-86-10;

Q. After considering the submissions received in response to Letter L-44-10 the Commission, by letter dated July 30, 2010, announced that an Oral Phase of Argument would be held in Vancouver on Tuesday, September 7, 2010;

R. The Oral Phase of Argument was held in Vancouver on September 7, 2010; and

S. The Commission Panel has considered the Application, including Celgar GBL proposal, and the submissions of Interveners.

…/4

NOW THEREFORE the Commission for the reasons stated in the Decision issued concurrently with this Order orders that:

1. FortisBC comply with all the directives of the Commission in the Decision that are not specifically mentioned below.

2. FortisBC's proposal to use contract demand or demand limits for some customer groups is denied.

3. FortisBC re-run and submit the COSA with all the adjustments described in the Decision within 30 days of this Order.

4. FortisBC submit a final set of rates based on the revised COSA within 60 days of the date of this Order.

5. FortisBC is directed to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and file an RIB rate application with the Commission no later than March 31, 2011.

6. FortisBC is directed to initiate consultations with its industrial customers with the goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro. FortisBC's action plan for this matter is to be included in the compliance filing within 60 days of the date of this Order.

7. FortisBC is directed to reconsider the concepts underpinning RS 33 that were approved by the Commission in Order G-15-98 and resubmit it in accordance with those principles. FortisBC is also directed in its compliance filing to set out how the wires charge components or its TOU rates were determined within 60 days of the date of this Order.

8. Celgar is ineligible to take service under RS 33. FortisBC is directed to provide Celgar service under RS 31 effective January 2, 2011.

9. FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved.

10. The appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside the range of reasonableness. FortisBC is directed to adjust its rates with the goal of achieving R/C ratios of one for each class.

11. FortisBC is directed to determine the nature of its Irrigation customers, to identify which of them are irrigation or drainage, and to ascertain their eligibility for service under RS 60 and RS 61. Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class, the Irrigation class is exempt from rate rebalancing and is subject only to base adjustments associated with FortisBC revenue requirements and BC Hydro flow-through.

12. FortisBC is directed to develop a new policy that demonstrates the management of credit risk through ongoing active monitoring of credit worthiness and which is non-discriminatory in nature.

13. FortisBC is to return the security deposit in respect of International Forest Products Ltd. forthwith.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of October 2010.

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair/Commissioner

IN THE MATTER OF

FORTISBC INC.

2009 RATE DESIGN AND
COST OF SERVICE ANALYSIS

DECISION

October 19, 2010

BEFORE:

A.J. Pullman, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commissioner

TABLE OF CONTENTS

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

TABLE OF CONTENTS

EXECUTIVE SUMMARY

FortisBC Inc. (FortisBC) has made an Application dated October 30, 2009 related to rate design. It included the results of a 2009 Cost of Service Analysis (COSA) and proposals to revise Rate Schedules of selected customer classes and general revisions to other tariff sheets. Zellstoff Celgar Limited Partnership (Celgar) has used the Application proceeding to request the Commission establish a Generation Baseline (GBL) between it and FortisBC. Several areas were examined extensively through the proceedings including:

- the COSA;
- Celgar's request for a GBL;
- rate structures;
- rate rebalancing; and
- Terms and Conditions of FortisBC's Electric Tariff.

The key issues associated with these areas and the related determinations are summarized below.

The COSA

Sections 59 and 60 of the *Utilities Commission Act (UCA)* provide guidance to rate setting, and require that due regard be given to ensuring that rates must not be unjust, unreasonable, unduly discriminatory, or unduly preferential. Rate setting proposed by FortisBC has also been guided by eight "Bonbright Principles" drawn from one of the seminal textbooks on rate design, "Principles of Public Utility Rates" by James C. Bonbright and his colleagues.

The cornerstone of fair rate setting is the comparison of revenues collected from each class of customer with the cost of providing service to them. The COSA is a means of equitably allocating the revenue requirement of the utility to the various customer classes and takes account of cost-causal factors of specific customer classes. The revenue-to-cost (R/C) ratio becomes an important measure used to assess the fairness of rates established for each customer class.

In assessing FortisBC's proposed COSA the Commission Panel has made the following key determinations:

- actual coincident peak demands should be used for all customers for COSA purposes rather than contract demands or demand limits;
- FortisBC's use of the 2CP method for allocating the demand portion of production and transmission costs is accepted;
- FortisBC is directed to rerun and submit the COSA with a single class for Wholesale customers except for Nelson, with Celgar taking service during the test year on RS 31, and using amended load factors for the Irrigation customers, all within 30 days of this Order.

Celgar's Request for a GBL

Celgar seeks a Commission Panel determination of a GBL with respect to the sale and purchase of power from FortisBC. It submits that FortisBC has an obligation to serve its full mill load at FortisBC's embedded cost, and it alone can relieve FortisBC of that obligation. The Commission Panel has made the following determinations with respect to Celgar's request:

- Celgar's request is prohibited by Commission Order G-48-09; and
- the Commission Panel declines to set a GBL between Celgar and FortisBC in this proceeding.

Rate Structure

Recent BC policy and legislative developments have strongly highlighted energy efficiency and conservation. FortisBC seeks approval of continuation of its current residential rates until the implementation of Advanced Metering Infrastructure and proposes no increase in the Basic Charge. Celgar raised concerns for the lack of incentives for conservation and efficiencies for industrial customers and believes there are opportunities in these areas through rate design and contractual obligations. The Commission Panel has made these determinations:

- FortisBC is directed to develop a plan for introducing residential inclining block rates for residential customers that also incorporates a lower Basic Charge in the immediate future, and to file a RIB application with the Commission no later than March 31, 2011;
- FortisBC is directed to initiate consultations with Industrial customers with a goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro; and
- FortisBC is directed to set out the billing determinants for Wholesale customers to be consistent with those to be set out for Large General service Transmission customers.

Rate Rebalancing

The Application has considered rebalancing of rates amongst rate classes and made several proposals that, in FortisBC's view, derive fair and just rate equity amongst rate classes. The Commission Panel has made the following determinations:

- FortisBC's range of reasonableness of R/C ratios of 95 percent to 105 percent is approved;
- the appropriate target for R/C ratios in each customer class is unity or one, and that rebalancing should only be required when a customer class falls outside the range of reasonableness;
- FortisBC is directed to adjust its rates with the goal of achieving R/C ratios of unity for each class; and
- FortisBC is directed to undertake load research to establish the load characteristics of the Irrigation class. Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class, the Irrigation class is exempt from rate rebalancing and is subject only to base adjustments associated with FortisBC's revenue requirement and BC Hydro flow-through.

Terms and Conditions

The principal issue that emerged during the proceeding related to Terms and Conditions contained in FortisBC's Electric Tariff dealt with security deposits. Interfor submits that Celgar's requirement for Interfor's security deposit is discriminatory because FortisBC's policy has been applied inconsistently and in a preferential manner. The Commission Panel has made the following determinations:

- FortisBC is directed to develop a new policy that demonstrates the management of credit risk through an active monitoring of credit worthiness and which is non-discriminatory in nature; and
- FortisBC is directed to return the security deposit in respect of Interfor forthwith.

1.0 INTRODUCTION

This Decision deals with the Application by FortisBC Inc. (FortisBC) dated October 30, 2009 related to rate design. The Application includes the results of a 2009 Cost of Service Analysis (COSA) and proposes revisions to Rate Schedules of selected customer classes and general revisions to other Tariff sheets.

The Decision encompasses the following:

- Section 1.0 introduces the subject of rate design, FortisBC, and the Application;
- Section 2.0 addresses FortisBC's 2009 COSA;
- Section 3.0 discusses matters related to rate structure;
- Section 4.0 deals with matters related to rate rebalancing arising from the COSA and initiatives around rate structures;
- Section 5.0 considers issues associated with Terms and Conditions contained in FortisBC's Electric tariff;
- Section 6.0 speaks to Celgar's request that the Commission establish a generation base line (GBL) between it and FortisBC; and
- Section 7.0 provides a summary of directives included in this Decision.

The following introduction first addresses relevant legislation, the general purpose of a rate design proceeding, the history of rate design at FortisBC and how that informs the current FortisBC Rate Design Application (RDA), and the cost of service analysis and its role in the RDA. The second part of the Section introduces the parties who intervened in this proceeding, the relief they seek, and the issues that arose during the course of the hearing.

1.1 Relevant Legislation

The British Columbia Utilities Commission (Commission or BCUC) is a regulatory agency of the Provincial Government operating under, and administering, the *Utilities Commission Act (UCA, the Act).* The Commission's primary responsibility is the regulation of public utilities under its jurisdiction to ensure that the rates charged for service are fair, just and reasonable, that utility operations are safe, that adequate and secure service is provided to customers, and that the opportunity for utilities to earn a fair and adequate financial return is preserved. It also approves construction of new facilities planned by utilities. The Commission's function is quasi-judicial, and its decisions and orders may be appealed to the Court of Appeal on questions of law or excess of jurisdiction with leave of a justice from the Court of Appeal.

The Commission receives guidance from provisions of the *UCA*, inclusive of Special Directions issued by order of the Lieutenant Governor in Council pursuant to Section 3 of the *UCA*. The following sections of the *UCA* are particularly applicable to the FortisBC RDA.

Section 60 (b) of the *UCA* requires the Commission to 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.

Section 59 (1) of *the UCA* states that "A public utility must not make, demand or receive a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia."

1.2 Rate Design: Overview

The purpose of a RDA is threefold: (i) to examine whether the structure of existing rates continue to promote an economically efficient consumption of electricity by the utility's customers; (ii) to assess whether the charges to customers that result from the application of these rates are fair and reasonable; and (iii) to provide an opportunity for all parties to examine the relevance of a utility's tariffs including its terms and conditions of service to ensure they remain relevant and valid.

An assessment of the fairness of rates is typically based on a comparison of the revenues collected from each class of customer with the cost of providing service to them. The cornerstone of this assessment is the COSA which attempts to equitably allocate the revenue requirement of the utility to the various customer classes of service (i.e., residential, commercial, etc.).

One of the seminal textbooks on rate design is "Principles of Public Utility Rates" by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, first published in 1961 by Public Utilities Reports, Inc.

FortisBC states that the COSA and RDA processes were guided by the eight "Bonbright Principles" which it describes as:

Principle 1: Recovery of the revenue requirement;

Principle 2: Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates);

Principle 3: Price signals that encourage efficient use and discourage inefficient use (consideration of social issues including environmental and energy policy);

Principle 4: Customer understanding and acceptance;

Principle 5: Practical and cost-effective to implement (sustainable and meet long-term objectives);

Principle 6: Rate stability (customer rate impact should be managed);

Principle 7: Revenue stability; and

Principle 8: Avoidance of undue discrimination (interclass equity must be enhanced and maintained).

Exhibit B-1, p. 33; Exhibit B-22

The three basic steps of a COSA are:

(i) functionalization which separates costs into major categories that reflect the utility's plant investment and different services provided to customers. The primary functional categories are production, transmission, distribution, and general;

(ii) classification which determines the portion of the cost that is related to specific cost-causal factors, such as those that are demand-related, energy-related, or customer-related; and

(iii) allocation of costs to specific customer classes which is based on the customer's contribution to the specific classifier selected.

1.3 The Applicant

FortisBC is an investor-owned utility engaged in the business of generation, transmission, distribution and sale of electricity in the southern interior of British Columbia. FortisBC currently serves more than 158,000 customers both directly and indirectly through sales to five municipally-owned electric utilities. The Company owns assets with a gross book value in excess of $1 billion, including four hydroelectric generating plants located on the Kootenay River with a combined capacity of 223 MW and approximately 7,000 circuit km of transmission and distribution power lines for the delivery of electricity to major load centers and customers in its service area.

Until 1988 the company was controlled by Cominco Ltd. and was known as West Kootenay Power Ltd. (WKPL). From 1988 to 2003 it was owned by Utilicorp Inc., after which it was purchased by Fortis Inc. and renamed FortisBC.

The Company had previously filed RDAs with the Commission in 1983 and 1997.

1.4 Interveners and Issues

The following parties intervened in the RDA proceeding, which is described in greater detail in Appendix A:

Municipalities:

- British Columbia Municipal Electric Utilities (BCMEU), being the Wholesale municipal customers of Kelowna, Penticton, Grand Forks, Summerland, and Nelson;
- Town of Osoyoos;
- Town Of Oliver;
- City of Rossland; and
- Town of Princeton.

Major Industrial Customers:

- British Columbia Hydro and Power Authority (BC Hydro):
- Rate Class 30 Customer Group (Rate 30 Group), comprising Atco Wood Products Ltd., Columbia Brewery, Greenwood Forest Products, Hawkeye Holdings Ltd., JH Huscroft Ltd., Kalesnikoff Lumber Co, Porcupine Wood Products, Springer Creek Forest Products, Weyerhaeuser Company Ltd., and Wynndel Box & Lumber;
- Zellstoff Celgar Limited Partnership (Celgar);
- Roxul Inc; and
- International Forest Products (Interfor).

Other:

- Irrigation Ratepayers Group (IRG), comprising Keremeos Irrigation District, Fairview Heights Irrigation District and Similkameen Improvement District, Kaleden Irrigation District, the Water Supply Association of B.C., the Okanagan/Kootenay Cherry Growers' Association, the British Columbia Fruit Growers' Association, the South Interior Stockmen's Association, the Osoyoos Indian Band, and Vincor Canada;
- Big White Ski Resort (Big White or BWSR);
- BC Old Age Pensioners’ Organization, BC Coalition of People with Disabilities, Council of Senior Citizens’ Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre (BCOAPO);

- Red Mountain Resort; and
- Okanagan Environmental Industry Alliance (OEIA), Natural Resource Industries and Hedley Improvement District.

Residential Customers:

- Alan Wait;
- Andy Shadrack;
- Norman Gabana; and
- Buryl Slack.

The following key issues were raised by the Interveners:

- Both BCMEU and Celgar took exception to FortisBC's proposed use of contract demand as a basis for allocation of transmission plant costs to customer classes. This is addressed in Section 2.0;
- Celgar requested the Commission to establish a GBL between it and Fortis BC. This is addressed in Section 6.0;
- Interfor submitted that FortisBC's proposed security deposit requirements were discriminatory. This is addressed in Section 5.0;
- Both Rate Group 30 and Big White requested that General Service rates rebalanced (downwards) more quickly than FortisBC proposed. This is addressed in Section 4.0;
- IRG asked for the Irrigation rate class to be exempted from rate rebalancing increases. This is addressed in Section 4.0; and
- Mr. Shadrack wanted a residential rate structure that rewarded conservation through a lower fixed charge and the introduction of an inclining block structure. This is addressed in Section 3. 0.

2.0 FORTISBC COST OF SERVICE ANALYSIS

This Section first presents an overview of FortisBC's COSA, followed by a discussion of the foundational aspects of the COSA – the revenue requirement, load data and the identification of customer classes. The Section then discusses the differences between the 1997 COSA and the 2009 COSA and the impact on the costs allocated to each customer class. Finally the Section reviews the major issues regarding the choice of Contract Demands to allocate transmission plant costs, the use of 2 Coincident Peaks (CP), and IRG's complaint that their members were disadvantaged by the COSA.

2.1 Overview of FortisBC's 2009 COSA

The COSA in the 2009 FortisBC Rate Design Application was prepared by EES Consulting (EES), which has been responsible for the preparation of several COSA studies for FortisBC and its predecessor companies, including the 1997 COSA which served as the starting point of the 2009 study, and also established the basis for the existing FortisBC tariff.

FortisBC states that a COSA is a process used to assign or allocate a fair share of total cost or revenue requirement of a utility to its various customer rate classes or schedules. The primary output of the study is the cost to be collected by rate class, which is used as a basic input for rate design (Exhibit B-1, p.36). The revenue from each class under prevailing rates is divided by the costs allocated to that class in order to compute Revenue-to-Cost (R/C) ratios. The R/C ratios for each class derived by the 2009 COSA as provided in the Application and as modified in subsequent errata filings are shown below:

Table 2-1
Revenue-to-Cost Ratios by Rate Class

Rate Class	Ratio
Residential	98.3%
Small General Service (20)	113.4%
General Service (21)	138.9%
Large General Service Primary (30)	122.4%
Large General Service Transmission (31)	109.9%
Large General Service Transmission TOU (33)	23.5%
Lighting	81.9%
Irrigation	78.6%
Kelowna Wholesale*	89.9%
Penticton Wholesale	78.0%
Summerland Wholesale	96.6%
Grand Forks Wholesale	68.1%
BC Hydro Lardeau Wholesale	101.8%
BC Hydro Yahk Wholesale	103.5%
Nelson Wholesale	80.0%
Total	**100.0%**

Source: Exhibit B-1-1, updated p. 43

* Note that in the table - Kelowna Wholesale through BC Hydro Yahk Wholesale currently belong to the same RS 40.

FortisBC states that Bonbright Principles 2 (fair apportionment of costs among customers) and 8 (interclass equity) are the primary considerations when developing the COSA. Using cost causation as the foundational principle of the COSA leads to the allocation of costs to each customer class that, when compared to revenues generated by each class (using the R/C ratio), indicates whether or not a cross-subsidization between rate classes exists. Interclass revenue adjustments can then be proposed to ensure that the amount of revenue collected from each customer class more appropriately recovers the costs of serving that class.

2.2 Foundational Aspects of the FortisBC COSA

2.2.1 Revenue Requirement, Rate Base, and Revenue Forecasts used in the COSA

FortisBC states that its COSA is based on the 2009 forecast revenue requirement approved by the Commission on December 11, 2008 by Order G-193-08. The total approved revenue requirement was $233.1 million, which includes an offset of $4.9 million in revenues from sources other than electric rates, to which was added an adjustment of $2.3 million to reflect the wholesale tariff increase from BC Hydro.

The rate base associated with the 2009 revenue requirement was $908 million, comprising gross plant of $1.2 billion, offset by accumulated depreciation and customer contributions. Gross plant comprised distribution assets (46 percent), transmission (29 percent), power production (13 percent) and general plant (12 percent).

FortisBC's projected customers and gross energy consumption are both consistent with its 2009 Resource Plan and are 111,913 at year-end 2009 and 3.4 million MWh for 2009, respectively (Exhibit B-1, Appendix A, p. 2).

FortisBC provided revenues by class for the 2009 Revenue Requirement. These revenues were calculated using an average rate for each class, consistent with the method used in past years.

For purposes of the COSA, revenues were calculated under each tariff based on the billing determinants for each class. Total revenues of $233.4 million were calculated in this manner. As a comparison, FortisBC calculated revenues at rates approved for the 2009 revenue requirement filing of $222.8 million and added the allowed 4.6 percent 2009 rate increase. The result of $233.1 million was 0.1 percent lower than the $233.4 million calculated for purposes of the COSA (Exhibit B-1, Appendix A, p. 9).

2.2.2 Customer Classes

The following customer classification issues were addressed during the proceeding.

2.2.2.1 Municipal Wholesale Customers

In a departure from the 1997 COSA, FortisBC treated each Wholesale customer as a distinct customer class, splitting the existing Rate Schedule (RS) 40 class into six classes; one for each of Kelowna, Penticton, Summerland, Grand Forks, BC Hydro Lardeau and BC Hydro Yahk and allocated costs to each based on their particular load characteristics. The City of Nelson was originally in its own rate class (RS 41). FortisBC submitted:

> "the municipal wholesalers have different operating characteristics, things like voltages, load profiles, size. And from the standpoint of FortisBC, they cause the utility to incur different costs" (T7:1335).

FortisBC, in responding to the Commission Panel's question during the Oral Phase of Argument regarding whether or not all municipal Wholesale customers should be aggregated into a single rate class for purposes of the COSA, stated that it would not object to such an aggregation since no other customers of FortisBC would be affected. FortisBC continues to propose that the City of Nelson remain in a separate rate class owing to the fact that it receives service at transmission voltages (T7:1336).

BCMEU argues in support of the continued use of a common class for municipal customers, stating that (i) they each have a customer mix which is primarily residential; (ii) the BCMEU members have similar revenue to cost ratios under standard COSA principles, although not under FortisBC's proposed COSA approach; (iii) each of the BCMEU members support retaining one customer class; and (iv) no other customer class is harmed by a consolidation approach and it is revenue neutral to FortisBC (BCMEU Argument, para. 106).

BCMEU reaffirmed its position during Oral Phase of Argument and agreed with FortisBC that Nelson would remain in its own rate class (T7:1345-46).

BCOAPA, Mr. Wait and Mr. Shadrack supported the BCMEU's position during the Oral Phase of Argument (T7:1345-48).

2.2.2.2 Large Industrial Customers

Industrial customers receiving power at transmission voltage and having loads exceeding 5,000 kVA are served under either Large General Service Transmission RS 31 or Large General Service Transmission Time-of-Use RS 33. FortisBC introduced RS 33 in the period after the completion of the 1997 COSA. The 2009 COSA allocates costs to the three customers receiving service under RS 31 and to Celgar, the sole RS 33 customer, separately, based on the load characteristics of each class.

FortisBC states that it allocated costs separately to RS 31 and RS 33 because RS 31 customers would be significantly negatively affected by the inclusion of the RS 33 customer:

> "... for COSA purposes the small number of customers in the class overall, and given that Zellstoff Celgar is the lone Schedule 33 customer, is also a self-generator, and has a significant impact on the class as a whole, a separation for cost allocation is necessary to avoid intra-class subsidization." (Exhibit B-3-4, Celgar 1.2.1)

and:

> "Zellstoff Celgar would be no better off having Rate 31 and Rate 33 combined, while the Rate 31 customers would be facing 5% per year rate increases they would otherwise not have received. This is precisely why FortisBC chose to separate Rate 31 and Rate 33 in the COSA. If Zellstoff Celgar were served under Rate 31 then it would be appropriate to include them with the three other customers in that rate class." (Exhibit B-7, Celgar 2.18.1)

According to FortisBC's tariff, RS 33 is "applicable to Customers with satisfactory, as determined by the Company, Load Factors". Counsel for Celgar describes his client's load factor as "terrible."

FortisBC states that “the load factor restriction was intended to prevent under-recovery of costs. Therefore, an acceptable load factor would be one that results in a revenue to cost ratio within the range of reasonableness. The Company cannot determine a universally applicable numerical load factor threshold that would indicate an acceptable revenue to cost ratio” (Exhibit B-7, BCUC 2.44.1).

Celgar testified that it transferred from RS 31 to RS 33 on October 1, 2006, in anticipation of executing a service agreement between the two parties that would replace the agreement executed in 2000. Although RS 33 requires a written agreement between customer and utility, one does not presently exist (T5:880).

During the Oral Phase of Argument and in response to the Commission Panel’s question regarding whether or not Rate Schedules 31 and 33 should be combined in order to improve Celgar’s R/C ratio, Celgar replies that, while this would reduce the inter-class subsidization that is currently occurring, it would increase the intra-class subsidization. Celgar states that it expects that the other transmission service customers would object to combining Rate Schedule 33 with Rate Schedule 31 since the resulting R/C ratio would result in a rate increase instead of a rate decrease for the combined class (T7:1223-25).

Celgar states that, while it initially objected to being segregated in a separate rate class, it abandoned its objection early in these proceedings because “it realized that subsidies, whether inter- or intra-class, were not the answer. And in fact they are the problem” (T7:1224).

IRG is the only Intervener to comment on the segregation of Celgar into a separate rate class. IRG agrees with FortisBC’s reasoning and strongly supports the use of a separate R/C ratio for Celgar (IRG Argument, para. 15).

2.2.2.3 Irrigation Customers

During the Oral Phase of Argument, the Commission Panel asked for submissions regarding whether the Irrigation class should be included in the General Service class for COSA purposes. FortisBC replied that it would not support the merging of the Irrigation and General Service classes unless the Irrigation customers apply to join and be served under the General Service rate year round. FortisBC stated that it believed that the Irrigation customers would be worse off as a result of joining the General Service class (T7:1338).

FortisBC stated that the Irrigation and General Service classes have different characteristics with respect to their power supply and infrastructure requirements that cause them to drive costs on FortisBC's system differently. FortisBC submitted that: “driving customers toward the 100 percent isn't an objective of the COSA process itself, which is really to obtain an accurate view of which customer classes are subsidizing others, or being subsidized, and which customers are causing the utility to incur what costs” (T7:1339).

IRG opposed the merging of the Irrigation and General Service rates, stating that the unique circumstances of the irrigators would not be suitably served by the General Service class. IRG stated that a distinct Irrigation class with competitive rates appears consistent with the direction provided by the Provincial Government in respect of B.C. Hydro's Irrigation class. Rolling Irrigation customers into the General Service schedules year-round would mask those important distinctions and send the wrong price signals to Irrigation customers (T7:1354-57).

BCOAPO opposed the merging of the Irrigation and General Service rates stating that this would lead to cross-subsidization (T7:1347). Mr. Shadrack opposes the inclusion of the Irrigation customers in the General Service Rate 21 class, but supports their inclusion in General Service Rate 20, stating that “irrigation falls more in line with small general service customers than it does with the larger general service customer” (T7:1348).

Commission Determination

The Commission Panel agrees with each of BCMEU's arguments in favour of a single class and determines that the Wholesale customers (other than Nelson which will remain its separate class) can be considered to be a single class for COSA purposes. The Commission Panel directs FortisBC to re-run the COSA on this basis.

So far as RS 33 is concerned it is clear to the Commission Panel that Celgar's load factor cannot be described as satisfactory as required by FortisBC's tariff. Accordingly the Commission Panel determines that Celgar is ineligible to take service under RS 33 and directs FortisBC to re-run the COSA using the assumption that Celgar was taking service during the test year on RS 31. The suitable allocation methodology for RS 31 will be determined later in this Section.

So far as concerns Irrigation customers the Commission Panel accepts the submissions of almost all parties that it should not direct FortisBC to combine Irrigation and Small General Service classes for COSA or rebalancing purposes.

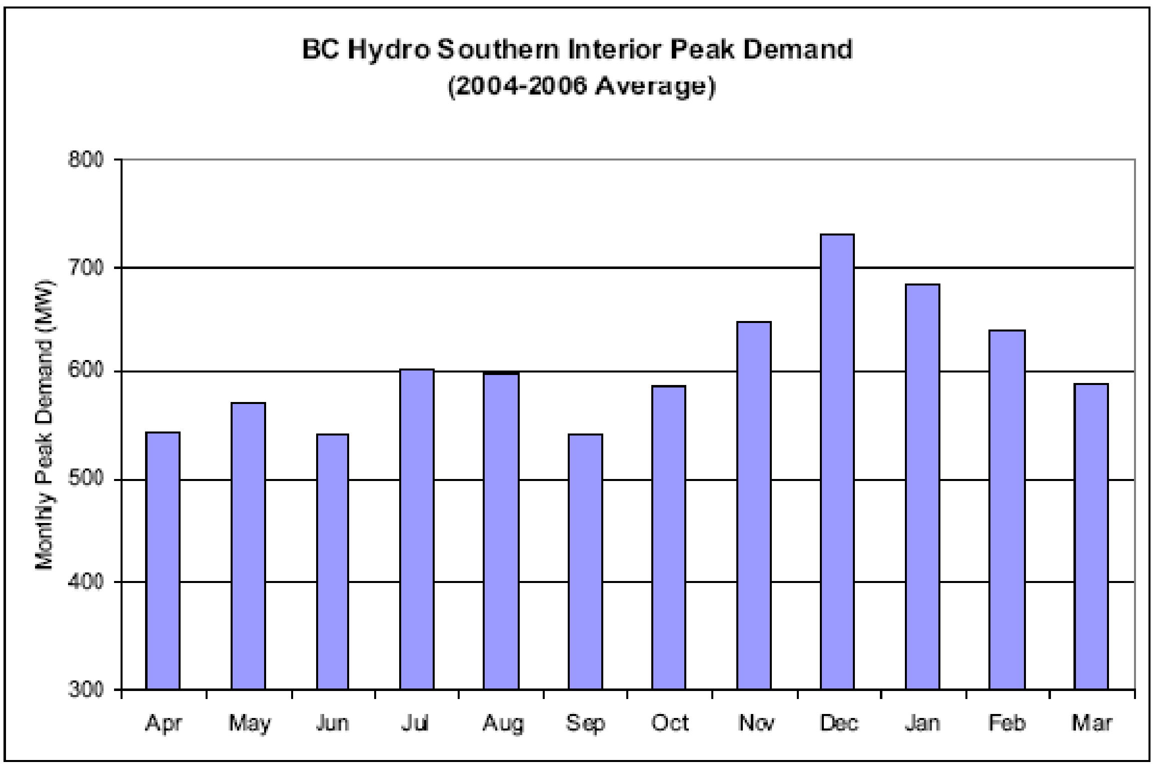
2.2.3 Load Data

FortisBC states that it forecasts system peak loads for revenue requirement and COSA purposes based on actual historical peaks plus forecast increases due to load growth (Exhibit B-3-1, BCUC 1.44.1). The contribution to the system peak of each customer class is determined either from actual metered customer load data, or from estimates based on metered consumption and available information.

Metered load data available to FortisBC is restricted to that from General Service customers on RS 21, Large General Primary and Transmission Service customers on RS 30, RS 31 and RS 33, and from Wholesale customers on RS 40 and RS 41.

FortisBC estimates the contribution to peak demand for each of its non-interval metered customer classes using a combination of individual load factors and group and system coincidence factors as described in Appendix C of the COSA Study (Exhibit B-1, Appendix A, pp. C-1 to C-3). FortisBC develops load and coincidence factors for those customer classes not having interval meters by using load research data from BC Hydro's Southern Interior service territory (Exhibit B-1, Appendix A, p. C-1) whose annual load curve is presented in the chart below:

Table 2-2
BC Hydro Southern Interior Peak Demand

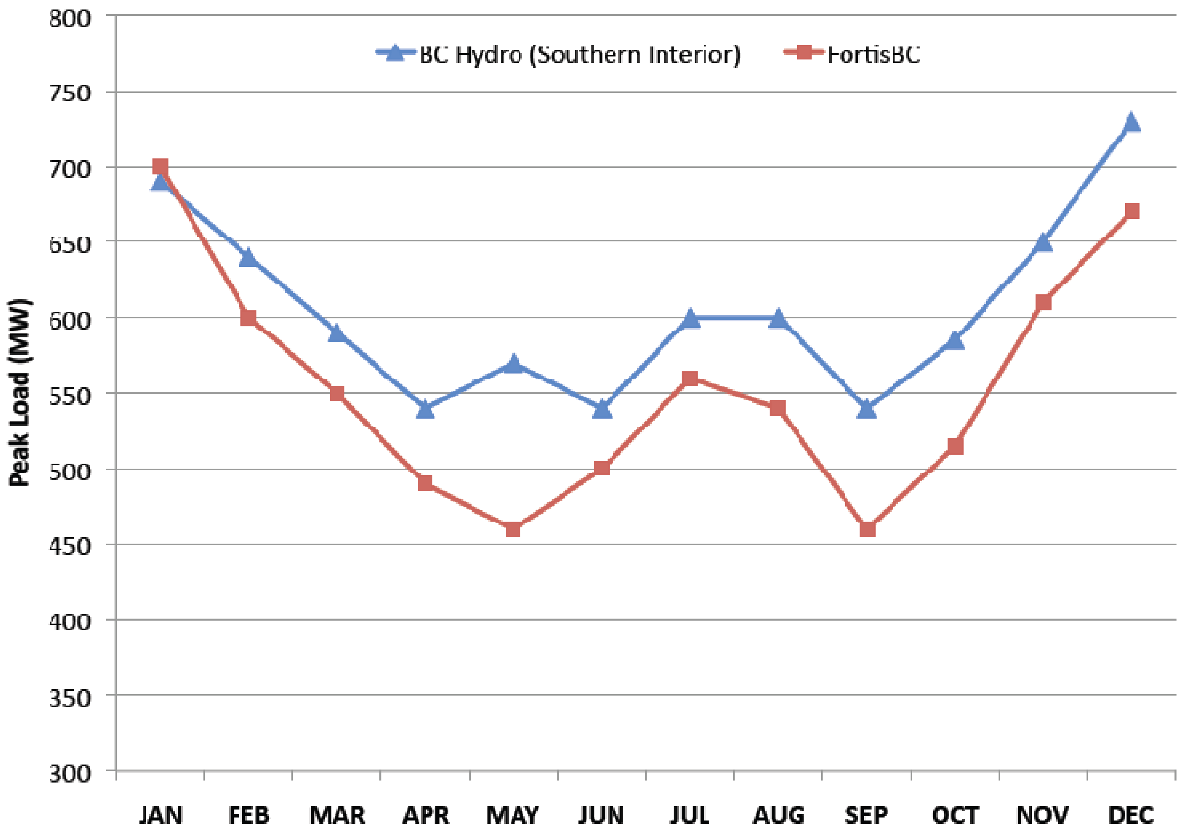


Source: Exhibit B-3-1, BCUC 1.90.2

IRG is the only Intervener to take issue with the use of BC Hydro's load research data and its complaint is considered later in this Section.

The monthly load profile of BC Hydro's Southern Interior Region aligns very closely with FortisBC's monthly load profile load profile, as the following table shows:

Table 2-3
Comparison of Load Profile Data



Sources: Exhibit B-3-1, BCUC 1.90.2 and Exhibit B-1, Appendix A, p. 30

Commission Determination

Given the close alignment of BC Hydro's Southern Interior load profile with that of FortisBC, the Commission Panel does not consider it necessary to direct FortisBC to carry out its own load research other than for its Irrigation customers as discussed below. **The Commission Panel accepts FortisBC's load data for COSA purposes, other than for its Irrigation customers as discussed below.**

2.3 Differences between the 1997 COSA and the 2009 COSA

FortisBC states that the methodology used in the 2009 COSA differs from that of the 1997 COSA in three regards:

1) the allocation of transmission costs on the basis of a two coincident peak allocator (2 CP) that uses contractual demand for Large General Service Transmission and Wholesale customers in place of actual demand;

2) the classification of generation plant to 80 percent energy and 20 percent demand, rather than to 100 percent energy as was done in the 1997 COSA; and

3) the classification of distribution plant using a minimum system approach that is subsequently adjusted for its Peak Load Carrying Capacity (PLCC).

In addition, the 2009 COSA includes an analysis reaffirming the appropriateness of the 2 CP method used in the 1997 COSA for allocating generation demand related and transmission costs (Exhibit B-1, Appendix A, p. 25). Items 1 and 3 and the 2CP analysis are considered below. Item 2 was not challenged by any of the parties to the proceeding and is not addressed further.

2.4 Use of Contract Demand in the Allocation of Transmission Plant

FortisBC proposes to use contract demand to allocate transmission costs to its Wholesale and Transmission customers in its 2009 COSA. This Section first summarizes the FortisBC's proposal and shows the difference between the 1997 and the 2009 approach, followed by the positions of the parties. The issue of renominations of contract demand for Wholesale customers and Celgar is addressed followed by the positions of the parties.

2.4.1 FortisBC Proposal

FortisBC states that it has negotiated supply service contracts with its RS 31, RS 33 and Wholesale customers which contain "demand limits" which represent the maximum load that FortisBC is contractually obligated to supply at each point of delivery. FortisBC states that these demand limits are capacity reservations on its transmission system and that it incurs a cost for the planning and constructing of infrastructure required to satisfy these contractual arrangements.

FortisBC refers varyingly to the obligation to meet the supply requirements at these points of delivery as contractual demand, contract demand, contracted demand, or demand limits, but states that, regardless of the nomenclature, it must have the ability at each supply point identified in the contracts to simultaneously provide electric service to the contractual limit specified, and to allocate the costs of doing so to those parties who see the benefit (Exhibit B-1, p. 40).

FortisBC states that the concept of cost causation as expressed in the second of Bonbright's Principles is supported through the use of contract, rather than actual demand in the determination of the 2CP demand allocator (Exhibit B-1, p. 40) and proposes to calculate the 2CP demand allocator of the RS 31, RS 33, RS 40 and RS 41 customers based on the higher of their contractual demand limits and their forecast actual demand. FortisBC recognizes that this is a departure from the 1997 COSA, which only took forecast demand into consideration but believes that the new approach better reflects the capacity costs associated with its contractual obligations, and prevents those costs from being inappropriately absorbed by the broader customer base.

FortisBC states that, since it is obligated to supply electric service at the contractual limits specified, it is appropriate to base cost allocation on contractual requirements:

> "These agreements contain "demand limits" which represent the load that FortisBC is contractually obligated to supply at each point of delivery. In effect, these demand limits are capacity reservations, and there is a cost attributable to the planning and constructing of infrastructure required to satisfy these contractual arrangements. The COSA utilizes these amounts as an allocation factor for transmission and distribution costs where these demand limits exceed the actual demand." (Exhibit B-1, p. 40)

FortisBC also states that its agreements with its Wholesale customers require it to "build new facilities once actual loads reach 95 percent of the contractual demand" (Exhibit B-1, Appendix A, p. 31). FortisBC expects that, should it not supply up to the demand limits specified in its service agreements, customers would hold the utility to those contractual obligations. FortisBC testified that BCMEU was clear on this point during the technical workshop that FortisBC held as part of its consultation (T2:223).

FortisBC addresses the National Electric Reliability Corporation (NERC) reliability standards and states that they require that not just forecast actual loads but contract demand (equivalent to “Firm Transmission Service Commitments”) be considered for system normal operations (N-0) compliance (Exhibit B-7, BCUC 2.38.2). FortisBC states that it began to consider the contractual obligations that are contained in the wholesale agreements in transmission planning in 2008 and that it can meet the coincident contractual demand of all of its Wholesale customers (Exhibit B-7, BCUC 2.39.1).

However, FortisBC also testified that its system planning is done on an N-1 basis (meaning that the loss of any of any one transmission element will not result in a loss of load, equipment overload or voltage violation) and that this planning relies on forecast rather than contract demand: “Again, for the purposes of N minus 1 planning, we always use forecasted actual demands” (T2:235).

FortisBC confirmed that its transmission system is “unable to supply full contract demand to all Wholesale customers under N-1 operations without experiencing some equipment loading violations” (Exhibit B-7, BCUC 2.39.2).

FortisBC states that use of contract demand as a basis for cost allocation ensures that RS 31, RS 33 and Wholesale customers are provided price signals reflecting the true cost of the facilities used to serve them and therefore ensures that future capacity nominations are efficient (Exhibit B-1, pp. 40-41).

FortisBC states that FERC supports the use of contract demands for rate making purposes, but qualifies the statement in saying that the approach is commonly used for natural gas transportation. The Alberta Electric System Operator (AESO) is cited as using 90 percent of contract demand for billing as part of a bulk system charge (Exhibit B-1, Appendix A, p. 32). Mr. Saleba of EES testified that the FERC cost allocation basis for network service customers is their load ratio, determined from actual coincident demands, and that contract demand is not used for network service but is used for point-to-point services (T2:188; T3:393-94).

2.4.2 The impact on R/C ratios of using contract demand

The following table compares the Peak Demands and Contract Demands/Demand Limits of customers in RS 40, 41 31 and 33:

Table 2-4
Comparison of Peak Demands and Contract Demands/Demand Limits

Customer Class	Coincident Peak Demand (kVA)	Contract Demand/ Demand Limit(kVA)
City of Grand Forks	8.6	24.0
City of Kelowna	60.9	91.8
City of Penticton	70.9	156.6
District of Summerland	21.9	30.0
BC Hydro Lardeau	2.0	n/a
BC Hydro Kingsgate	0.8	0.5
Subtotal RS 40	165.1	302.9
City of Nelson (RS 41)	29.2	45.0
RS 31	10.1	11.1
RS 33	12.2	40.0

Sources: Exhibits B-1, Appendix A, B-7, Celgar 2.8.1, B-3-3, BCMEU 1.2.1b

FortisBC testified that the use of contract demand in the development of the 2CP allocator results in an increase of $7 or $8 million in the costs allocated to the Wholesale customers over the course of the rate rebalancing period (T2:169).

The following table shows the impact on the R/C ratios of each customer class resulting from the use of contract, rather than actual, demand:

Table 2-5
Revenue-to-Cost Ratios with and without Contract Demand

	Contract Demands for Wholesale/Industrial (As Filed)	Actual Demands for Wholesale/Industrial (1997 Method)
Residential	98.3%	93.8%
Small General Service (20)	113.4%	107.9%
General Service (21)	138.9%	130.3%
Industrial Primary (30)	122.4%	114.6%
Industrial Transmission (31)	109.9%	111.7%
Industrial Transmission TOU (33)	23.5%	46.3%
Lighting	81.9%	81.0%
Irrigation	78.6%	74.1%
Kelowna Wholesale	89.9%	96.8%
Penticton Wholesale	78.0%	91.6%
Summerland Wholesale	96.6%	97.8%
Grand Forks Wholesale	68.1%	88.2%
BC Hydro Lardeau Wholesale	101.8%	93.5%
BC Hydro Yahk Wholesale	103.5%	98.1%
Nelson Wholesale	80.0%	95.4%
Total	100.0%	100.0%

Source: Exhibit B-3-1, BCUC 1.71.3

2.4.3 Positions of Parties

2.4.3.1 BCMEU

BCMEU characterizes the contract demand concept as "misguided and unprecedented", and asserts that neither FortisBC nor its consultants provided any credible precedent for using contract demand as a cost allocator in a COSA study (BCMEU Argument, para. 10). Dr. Rosenberg testified that he has consulted with his colleagues and associates who have been involved in over 500 cost of service studies and neither he, nor anyone in his firm, has ever come across the use of contract demands for the purpose of allocating the costs of a bulk transmission system (T6:1019).

Dr. Rosenberg further states that FortisBC's assertion that AESO uses contract demand to allocate the costs of the Alberta bulk transmission system is not correct and that the costs are in fact allocated on the basis of peak demand. Dr. Rosenberg submits that the differences between natural gas and electricity transmission systems are too significant to draw conclusions concerning the use of contract demand allocating costs (Exhibit C1-6, p. 13).

BCMEU accepts that Bonneville Power Authority (BPA), a transmission provider regulated by FERC, uses contract demand for point to point (PTP) transmission service but submits that the BPA and FortisBC are not similar utilities. BCMEU states that if the Commission Panel accepted the use of contract demand for allocating costs to the municipal Wholesale customers, then it would "need to accept the assumption that FortisBC provides network transmission service to its own (retail) customers, but PTP service to its Wholesale customers-when these customers are right across the street from each other" (BCMEU Argument, para. 46).

BCMEU observes that the COSA allocates bulk transmission and substation distribution costs to some customers on the basis of contract demand, while for other customers allocations are based on actual coincident peaks. BCMEU submits that, for consistency, an allocator analogous to contract demand was required for those rate classes without a contractual demand limit (Exhibit C1-9, BCUC 1.7.1). BCMEU points out that the term "contract demand" does not appear in the expired contracts which FortisBC proposes to rely on and that those contracts only use the term "Demand Limit" which is defined as "the capability of FortisBC's facilities at each Point of Delivery." BCMEU further notes that the proposed approach does not consider the differences in winter and summer demand limits (BCMEU Argument, para. 14).

Dr Rosenberg states that not all customers peak at the same time, and this factor is known as diversity. He considers that the highest level of diversity is reached at the generation and bulk transmission levels, where facilities are used to serve the entire system simultaneously. This means that the coincident demand is the only measure of demand that determines the amount of generation and bulk transmission the utility must plan and build. He states that "It would be inefficient and even wasteful for the utility to design or plan its system on the assumption that it must meet the sum of everyone's peaks, and ignore the reality that not all customers peak at the same time" (Exhibit C1-6, p.4).

2.4.3.2 Celgar

Celgar states:

> "One of the important characteristics of the Mill, for the purposes of rate design, is its firm load requirements. The Mill needs firm power of 8 MVA to meet the needs of its environmental systems. This is the Mill's only firm requirement."
> (Exhibit C13-7, p. 30)

Celgar points to FortisBC's statement that a change in rates would be unlikely to influence Celgar's peak demand since the peak tends to be set when there is an outage to Celgar's generator (Exhibit B-7, BCUC 48.2).

Celgar states that had FortisBC engaged Celgar in "meaningful consultation," it would have been better informed as to Celgar's ability to shift demand from the FortisBC system by reducing load, or, in some circumstances, by self-supply. Celgar states that it can manage the timing and duration of outages of its generator and will, once its new generator is installed, be able to manage it more easily. Also, Celgar states that it can manage the timing of self-supply by intra-day storage of its fuel, black liquor (Exhibit C13-7, p. 30).

Celgar takes "strong exception" to the contract demand cost allocation method, characterizing it as an inappropriate cost allocation measure. Celgar argues that contract demand is inappropriate for allocating transmission costs to a retail customer. Further, Celgar asserts that it has not agreed with FortisBC to set a contract demand for the purposes of cost allocation, or at all. Celgar disagrees with FortisBC that using demand limits aligns with ratemaking principles, and that there is any trend toward applying contractual obligations as a basis for allocating costs in a COSA for retail customers. Celgar submits that if the mandatory reliability standards that are the basis for system development planning and investment decisions are not based on contractual obligations, contract demands should not be used for allocating costs. Celgar notes that FortisBC testified that system planning is based on meeting N-l reliability criteria using forecast actual coincident peak demands rather than contract demands (Celgar Argument, para. 12, 137, 142). Celgar states that FERC hardly ever allows contract demand as a basis for allocating transmission costs, particularly for native load customers (Exhibit C13-7, p. 12).

Celgar submits that there has been no change in cost-causation since 1997 that supports a change in the cost allocators to be used. The justification for the use of contract demands as cost allocators is neither supported by the increased use of contract demands by EES in its COSA's completed for other utilities, nor by the increased use of contract demands in other jurisdictions (Celgar Argument, para. 155).

2.4.4 Renomination of Contract Demand

FortisBC states that the contract demands as set out in Appendix A of its agreements with its municipal Wholesale customers have, for the most part, reflected installed capacity as well as the demand reserved for the customer by the company and contracted for by the customer. FortisBC states that it did not received any indication from its Wholesale customers that these demands did not reflect what they required until just before the August technical workshop. When it did receive that indication, FortisBC decided to offer the opportunity for re-nominating transmission capacity. FortisBC recognizes that its Wholesale customers entered into contracts prior to FortisBC identifying contractual demands as a basis for allocating costs (FortisBC Argument, para. 22-24).

The Wholesale customers provided details of their transmission capacity requirements to FortisBC in emails during September 2009. FortisBC re-ran the COSA based on those "renominations," rather than the earlier amounts and provided the results in the following table:

Table 2-6
COSA Impact with Nominated Demand for Wholesale Customers

	Original RC Ratio	New RC Ratio
Total	100.0%	100.0%
Residential	98.6%	96.3%
Small General Service	113.3%	110.9%
General Service	139.8%	135.1%
Rate 33 Industrial	23.8%	21.5%
Industrial Primary	123.7%	118.9%
Rate 31 Industrial	110.3%	106.3%
Lighting	82.2%	81.5%
Irrigation	79.1%	76.6%
Kelowna Wholesale	87.9%	92.3%
Penticton Wholesale	77.2%	88.2%
Summerland Wholesale	95.6%	91.7%
Grand Forks Wholesale	68.1%	85.3%
BCH Lardeau Wholesale	101.1%	79.3%
BCH Yahk Wholesale	103.9%	89.6%
Nelson Wholesale	80.2%	90.0%

Source: Exhibit B-30

FortisBC confirmed that industrial transmission customers such as Celgar would have the opportunity to renominate on the same basis that had been offered to the Wholesale utilities (FortisBC Argument, para. 26).

Celgar testified that it would be prepared to renominate a contractual right to the greater of 43 MVA minus Celgar's GBL, or 8 MVA (T5:906-07). The 8 MVA is the minimum firm load required by the mill to run its “critical environmental systems” (Exhibit C13-7, p. 16).

BCMEU also testified that, if the contractual demand allocation approach proposed by FortisBC were accepted by the Commission, its members would stand by the renominations contained in the September 2009 emails for cost allocation purposes (T6:1036).

FortisBC filed the renominated contractual rights (contract demands), along with Celgar’s nomination of either 8 MVA or 41.5 MVA in the additional COSA scenarios “Case E” and “Case F”, respectively, along with “Cases A, B and C” (Exhibit B-35).

Regarding the renomination of contract demand and their reflection in the additional COSA scenarios Cases A through E, BCMEU urges the Commission Panel to give little weight to these five additional scenarios, submitting that the results presented in Exhibit B-35 are flawed because (i) FortisBC uses contract demands for the allocation of transmission plant despite evidence in this proceeding that FortisBC does not use contract demands in its N-1 contingency planning for transmission; (ii) contracts demands for cost allocation are not applied consistently across all customer classes; (iii) it uses the same contract demands for winter as it does for summer; contrary to FortisBC's position that both summer and winter contract demands should be used to allocate transmission plant; (iv) the contract demands assigned to the Wholesale customers reflect anticipated growth while the actual demands used for other classes do not; and (v) the "demand limits" from the expired contracts are still used as an allocator of the costs of distribution substations (BCMEU Argument, para. 80).

Regarding BCMEU's request that FortisBC be directed to negotiate new agreements with the municipalities once a determination on the Contract Demand concept is resolved, both Big White and IRG express concern regarding the effect that these renominations could have on the rates paid by those customers without contract nominations (Big White, Argument, para. 24; IRG Reply, para. 8).

BCOAPO believes that using the contract demand methodology could discourage contracting parties from engaging in energy conservation. BCOAPO observes that to some extent BCMEU's members have based their re-nominated contract demand values on forecast quantities. BCOAPO expects that, if BCMEU members are not permitted frequent re-nominations of their demand limits, the contract demand approach would discourage energy conservation (BCOAPO Reply, para. 3).

Commission Determination

The Commission Panel rejects FortisBC proposed allocation methodology of transmission costs to its Wholesale and major industrial customers for the following reasons:

- the Commission Panel finds that there is very little, if any, regulatory support for such a practice;
- the Commission Panel considers that such a practice ignores the diversity factor around coincident peak factors upon which electric systems are planned;
- the Commission Panel agrees with BCMEU that N-0 is not a reliability planning criterion for system planning purposes and should not be used for cost allocation purposes;
- the Commission Panel considers that the proposal is discriminatory in that it seeks to allocate costs to a small number of customer classes but ignores the principle for the remaining customer classes.

Accordingly, the Commission Panel accepts the use of actual coincident peak demands for COSA purposes, and directs FortisBC to re-run the COSA, using actual coincident peak demands for all customers rather than contract demands (or demand limits).

The Commission Panel rejects the possibility of using "renominated" values for COSA purposes, on the grounds that the concept more than anything demonstrated the weakness in FortisBC's proposal and would lead to unintended consequences if allowed to proceed.

2.5 2CP Allocation Method

FortisBC proposes to allocate demand related generation and all transmission costs on the basis of a winter/summer coincident peak method, consistent with the method it used in the 1997 COSA. This proposal is challenged by BCMEU, who led evidence on the matter in support of an allocation to customer classes based on the coincident peaks of three winter months, and by IRG, which describes it as "tremendously unfair to irrigation customers."

FortisBC states that production facilities in general are designed and operated to meet system peak demands as well as to supply the energy requirements of a utility. Transmission facilities are typically designed and operated to meet system peak demand requirements. The cost responsibility of each customer class is therefore typically allocated on the basis of the contribution of a class to the system coincident peak demand, or combination of coincident peak demands. FortisBC states that coincident peaks are typically used for allocating a portion of production costs related to meeting peak demand and all of transmission costs as they are generally sized for the system peak as a whole. FortisBC determined that an allocator based on the sum of the two highest summer and the two highest winter coincident peaks is the most appropriate to reflect system use and planning for generation and transmission facilities. FortisBC calls this allocation the 2CP method and states that it is consistent with the peak allocation method used in the 1997 COSA (Exhibit B-1, Appendix A, pp. 1, 25).

FortisBC states that its decision to continue to use the 2CP method is based on the following criteria:

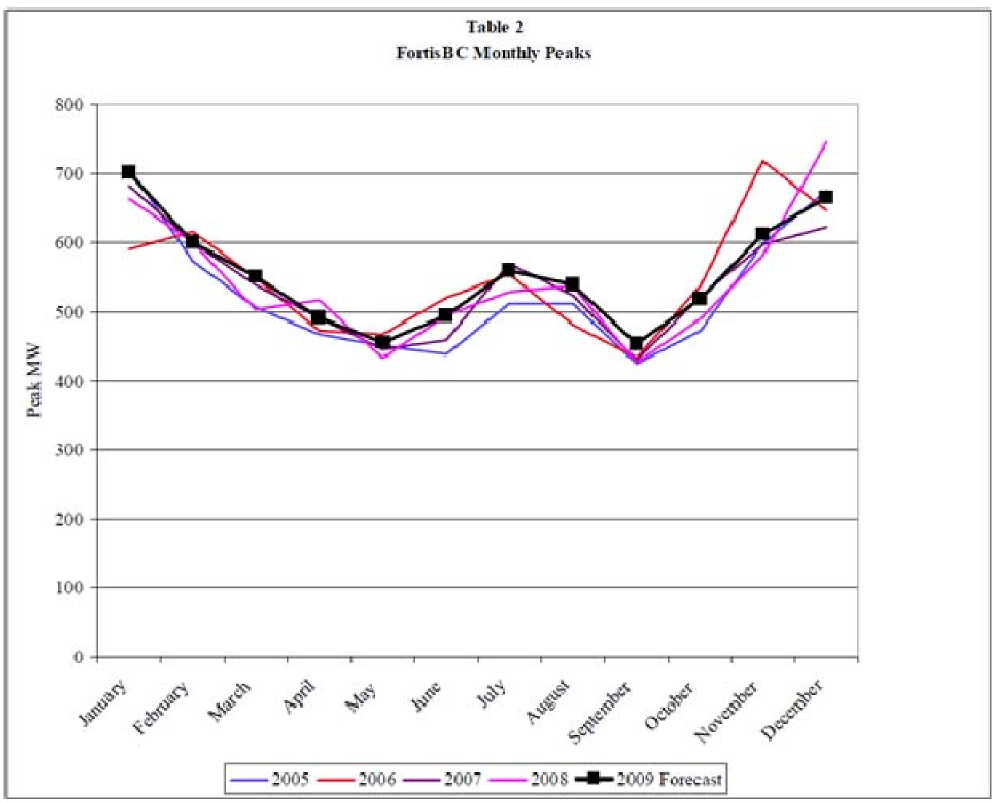
- the precedent for the allocation of transmission and demand-related production costs is the 2CP method used in the 1997 COSA study;
- whether circumstances at the utility had changed to warrant a different allocator;
- the consideration of the results of tests used by FERC and the Ontario Energy Board (OEB) in selecting a demand allocator;
- the relative rate of growth in the summer and winter demand peaks;
- the influence of the summer demand peak in planning for new facilities in some instances; and
- the recent Commission approval of a 4CP demand allocator for BC Hydro in Order G-111-07.

(Exhibit B-3-1, BCUC 1.68.4)

2.5.1 Relative Importance of the Winter and Summer Peaks in the FortisBC System

FortisBC states that the dual summer and winter peaking nature of its system is reflected in its decision to use the 2CP demand allocator, which is the sum of two winter and two summer peaks (Exhibit B-1, p. 41). The 2CP approach was selected because the summer demand peak experienced on the FortisBC system "is significant, particularly when the lower summer capacity of the electric infrastructure is considered" (FortisBC Argument, p. 44). FortisBC presented a graphical depiction of the actual annual load pattern over the period 2005 to 2008 as well as its forecast for 2009 that is reproduced below:

Table 2-7
FortisBC Monthly Peaks (MW)



Source: Exhibit B-1, Appendix A, p. 30

FortisBC states that the winter peak remains the primary consideration in planning for transmission capacity expansion and is expected to remain so within the current planning horizon (Exhibit B-3-1, BCUC 1.66.7). However, the summer peak is becoming a consideration when planning transmission system reinforcements in certain areas. FortisBC testified that the percent utilization of portions of its transmission system during the summer peak is approaching that of during the winter peak, especially in the Penticton-Osoyoos area of its South Okanagan region (T3:562 and T4:759)

FortisBC also considered the peak demand growth in the summer months relative to the growth in the winter months. When comparing the 2009 forecast peaks to 1997 actual peaks (the year of the last COSA), the summer peak is growing twice as fast as the winter peak. For that time period, the total growth was 61 MW in the winter, or about 0.8 percent per year. For the summer peak, the growth was 112 MW, or about 1.9 percent per year. FortisBC states that this indicates that the summer peak is moving closer to the level of the winter peak, and that FortisBC system planning will continue to need to recognize the growth in the summer peak (Exhibit B-1, Appendix A, p. 31).

2.5.2 Choice of Peak Data

FortisBC states that it used forecast peaks for 2009 for determining the 2CP allocator, which is consistent with the test year used for developing the revenue requirements (Exhibit B-7, BCUC 2.21.1). The forecast of system demand peaks are based on a total system peak taken from actual historical peaks plus a forecast to account for load growth (Exhibit B-3-1, BCUC 1.44.1). FortisBC forecasts the winter peak for the 2009 test year as 701 MW, and the summer peak as 560 MW (Exhibit B-1, Appendix A, p. 2). The magnitude of the winter peak is consistent with that presented as the January 2009 peak demand forecast on page 78 of the FortisBC 2009 Resource Plan (Exhibit B-3-3, BCMEU 1.44.1).

In determining the winter peak demand to use in the 2CP demand allocator, FortisBC uses the average of the January and December 2009 peak demands, and the average of the July and August 2009 peak demands to determine the summer peak demand (Exhibit B-1, Appendix A, Schedule 6.3).

2.5.3 Impact of the Allocation Method on the Results of the COSA

FortisBC estimates that the residential class contributes 44.7 percent to the highest annual system peak, while the RS 30, 31 and 33 customers contribute 6.8 percent. Under the 2CP method used for allocating costs within the COSA, the residential contribution is 40.6 percent compared to 7.2 percent for the RS 30, 31 and 33 customers (Exhibit B-1, Appendix A, Schedules 6.2 and 6.3, and Exhibit B-7, Wait 2.4). FortisBC also provides the impact on the revenue to cost ratios resulting from alternative choices of the peak allocation method. These results are reproduced in the table below:

Table 2-8
Revenue-to-Cost Ratios by Peak allocation Method

	2 CP (As Filed)	1CP	4CP	12 CP
Residential	98.3%	95.3%	97.7%	100.1%
Small General Service (20)	113.4%	115.9%	118.1%	117.0%
General Service (21)	138.9%	138.2%	141.2%	139.2%
Industrial Primary (30)	122.4%	121.9%	121.1%	120.8%
Industrial Transmission (31)	109.9%	112.5%	111.3%	108.3%
Industrial Transmission TOU (33)	23.5%	25.4%	24.4%	22.7%
Lighting	81.9%	78.2%	78.2%	80.2%
Irrigation	78.6%	92.8%	85.1%	78.5%
Kelowna Wholesale	89.9%	92.8%	91.3%	88.5%
Penticton Wholesale	78.0%	77.8%	76.1%	74.3%
Summerland Wholesale	96.6%	95.1%	93.4%	92.1%
Grand Forks Wholesale	68.1%	67.0%	65.4%	64.0%
BC Hydro Lardeau Wholesale	101.8%	85.0%	96.6%	104.1%
BC Hydro Yahk Wholesale	103.5%	102.2%	99.7%	99.7%
Nelson Wholesale	80.0%	83.4%	81.4%	78.2%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Source: Exhibit B-3-1, BCUC 1.67.2

2.5.4 Positions of Parties

2.5.4.1 BCMEU

BCMEU's expert, Dr. Rosenberg, objects to the use of the 2CP method, citing FortisBC's response to BCUC 1.66.7 stating that the winter peak remains the primary consideration in planning the bulk transmission network. Dr. Rosenberg states that a 3 Winter CP method, as used by Albertan utilities and by Nova Scotia Power, based on the three highest winter coincident peaks, is a more appropriate allocator from a cost causation perspective (Exhibit C1-6, pp. 17-18). Alternatively, Dr. Rosenberg also supports the use of a 4CP method (Exhibit C1-11, FortisBC 1.21.1).

Dr. Rosenberg points out that the 2CP allocator proposed by FortisBC was based on a maximum peak demand of 701 MW which was considerably less than the peak demand of 746 MW actually experienced by FortisBC on December 20th, 2008. The use of the lower number, Dr. Rosenberg goes on to state, results in less costs being allocated to the most weather sensitive classes, such as the residential class (Exhibit C1-6, Evidence of Dr. Rosenberg, p. 18).

FortisBC responds by stating that the December 2008 winter peak occurred after the winter peak forecast for 2009 had been developed and that the 746 MW peak reflects colder than average conditions, while the 2009 forecast reflects normal weather conditions (Exhibit B-16, p. 9).

BCMEU does not address the issue further in Argument.

2.5.4.2 Irrigation Ratepayers Group

IRG does not agree with the use of the 2CP demand allocator and states that the comparison has used the average winter months as October to March and the summer average as April to September. This does not coincide with the RS 60 seasonal rate, which is April to October. If the winter and summer averages were developed by moving October in to the summer average then both averages would be higher but the difference would still be almost 100 MW and all the 5 monthly winter month averages are still greater than the peak summer month of July (Exhibit C22-3).

IRG submits that the use of the 2CP methodology for cost allocation is “tremendously unfair to irrigation customers.” The load profile for Irrigation customers clearly shows that their demand makes no significant contribution to the two winter peaks (IRG Argument, para. 17).

Commission Determination

While the Commission Panel agrees that, based on the data presented in the Application and the 2009 Resource Plan, FortisBC is a winter peaking utility and is expected to remain so within the current planning horizon, it also notes that FortisBC does experience a pronounced summer peak. The Commission Panel accepts that the summer peak has been growing faster than the winter peak when the 1997 actual load data is compared to the 2009 forecast.

The Commission Panel recognizes that the load carrying capacity of transmission wires does diminish with increasing ambient temperatures and accepts FortisBC's position that, for certain parts of its system, the summer peak is becoming a consideration in the planning of transmission system reinforcements in certain areas.

The Commission Panel has considered Dr. Rosenberg's assertion that less costs are allocated to the most weather sensitive classes, such as the residential class, under the 2CP method as compared to an allocation based solely on winter peaks but agrees with FortisBC that the summer peak is an influencing factor in the available capacity of the transmission system.

The Commission Panel accepts the use of 2009 forecast load data in the determination of the 2CP allocator and considers FortisBC's adjustment of the data to account for normal weather patterns to be appropriate.

While the Commission Panel agrees that FortisBC's Irrigation class is the most disadvantaged by FortisBC's 2CP allocation methodology, it does not consider that a single class with approximately 1,000 customers should be determinative of the methodology used by FortisBC.

Accordingly, the Commission Panel accepts FortisBC's use of the 2CP method for allocating the demand portion of production costs as well as for allocating transmission costs.

2.6 IRG's Complaint

IRG states that the COSA methodology has been incorrectly applied to the Irrigation class because, for five months of the year, Irrigation customers are transferred to a General Service Rate (RS 20 or 21). Therefore cost allocations made on the basis of a full year of service under the Irrigation rate (RS 60) are inappropriate. Although IRG did not re-run the COSA to determine the appropriate allocations to the Irrigation rate, it states that the proper reduction of costs allocated to the Irrigation class by 5/12 to reflect the portion of the year during which the service is unavailable will result in a revenue to cost ratio that is much higher than that presented by FortisBC in its Application. IRG submits that the incorrect application of the COSA to the Irrigation class completely discredits the proposed rate rebalancing for the class (IRG Argument, pp. 12-15).

IRG states that the Irrigation class is "uniquely *self-balancing* across three different rate classes" and therefore the proposed rate rebalancing for Irrigation is not necessary (IRG Argument, para. 55). IRG submits that, because Irrigation customers are transferred to either General Service rates, the correct revenue to cost ratio for the Irrigation class is at least 110.3 percent:

> "FortisBC's evidence states R/C ratios of 78.6% for Irrigation, 113.4% for Small General Service (RS 20) and 138.9% for General Service (RS 21) (Exhibit B-1, p. 43). IRG is not aware of evidence anywhere in the record of this proceeding that sets out the breakdown of Irrigation customers transferred to either RS 20 or 21. Such evidence is another essential part of FortisBC's case in respect of the proposed rate rebalancing for Irrigation customers. In the absence of such evidence, for purposes of calculating the annual R/C ratio for Irrigation customers it is reasonable to assume a 50/50 split of Irrigation customers transferred to General Service RS 20 or 21. That results in an average annual R/C ratio of 110.3%, which is significantly above unity.
>
> The approach submitted above would otherwise result in a more accurate view of the true annual R/C ratio, which is exactly the same period used to calculate the ratios for all other rate classes (i.e. one year). In any event, even using the discredited R/C ratio for Irrigation confirms that the applicable rates on an annual basis are indeed self-balancing and already fall above FortisBC's range of reasonableness" IRG Argument, para. 56-57).

IRG describes the situation as one of either inter-class discrimination (where Irrigation customers subsidize other classes by paying for service that they don't receive under RS 60) or intra-class discrimination (where they pay twice for service they receive as General Service customers). IRG contends that the COSA unfairly treats Irrigation customers as General Service customers for purposes of collecting rates but ignores that status for purposes of determining the appropriate R/C ratios. IRG believes that the methodological error was inadvertent (IRG Argument, paras. 50-51).

IRG submits that the Commission Panel should reject the revenue to cost ratio presented by FortisBC in its Application as incorrect; that FortisBC should be directed to re-run the COSA to properly allocate costs to reflect the transfer of Irrigation customers between rate classes; and that FortisBC should be required to make an application to approve rate rebalancing for the Irrigation/General Service class - the goal of which, as IRG states, would be to decrease rates for those customers (IRG Argument, para. 58).

FortisBC submits that IRG misunderstands the COSA model and its inputs, that the COSA correctly captures the Irrigation class, and that IRG's argument should not be given weight. FortisBC states that Irrigation customers are not transferred to the General Service class during the five winter months, but are charged the General Service rate in the winter creating, in effect, a seasonal rate. All summer and winter usage and revenues for Irrigation customers have been included in data for purposes of the COSA and the COSA already accounts for their lower loads and the switch to General Service rates in the winter (FortisBC Reply, para. 115). The COSA simply captures winter loads and revenues for Irrigation customers within the Irrigation class calculations, so they are never included in the General Service class and there is no double-counting. Further, Irrigation is charged less than customers with year-round loads because they are allocated very few costs other than power supply in the winter months when their usage is low (FortisBC Reply, para. 116).

Regarding IRG's statement that the Irrigation costs should be reduced by 42 percent to reflect that they do not take service during the winter months, FortisBC states that the revenues resulting from the switch to the General Service rates in the winter months are likely to recover more than the cost of service for Irrigation customers during those months since the revenue to cost ratio of the General Service class is above unity. FortisBC estimates that, if the winter revenues and costs were excluded from the Irrigation class for purposes of the COSA, there would likely be an even lower revenue to cost ratio for the remaining summer months (FortisBC Reply, para. 117).

IRG cites EES testimony that the BC Hydro load research data that informed the COSA did not include an Irrigation class (T3:506) and submits that "the evidence indicates that the load factors and coincidence factors attributed to Irrigation were merely estimates approximated using data for entirely different rate classes" (IRG Argument para. 35-36).

IRG states that the irrigation power consumption has very different and more consistent overall power consumption then most other power users within FortisBC's service area, and suggests that this should be taken into consideration by the COSA (Exhibit C22-3). IRG panel testified that most pumping equipment was installed when electric rates were determined by motor size and that the pumps were sized to run "24/7" (T6:1167).

FortisBC used the following monthly load factors for the Irrigation rate class:

Table 2-9
Irrigation Rate Class Load Factors

Month	Load Factor (%)
April	15
May	45
June	70
July	70
August	70
September	65
October	35
All other months	15

Source: Exhibit B-1, Appendix A Schedule 8.2

FortisBC gives no explanation for its selection of Irrigation class load factors.

The load factors for the Small General Service rate class ranged between 42 percent and 55 percent in the winter months. The group and system coincidence factors used by FortisBC for the Irrigation class was 80 percent and 90 percent respectively compared to the Small General Service of 75 percent and 70 percent (Exhibit B-1, Appendix A Schedule 8.2).

Commission Determination

The Commission Panel has considered the wording in FortisBC's tariff RS 60:

> "AVAILABLE: For an irrigation or drainage season commencing with the Customer's meter reading taken within 5 business days of April 1st each year and terminating with the Customer's meter reading taken within 5 business days of October 31st each year. During the non-irrigation season Customers will be automatically transferred to the applicable commercial Service rate and billings prorated for a partial first or final Service month when read dates are outside of the 5 day band."

The Commission Panel interprets this to mean that the RS 60 customers are billed at RS 20 or RS 21 during the five months outside the irrigation or drainage season, and considers that the COSA does reflect the tariff.

The Commission Panel considers that IRG's complaint is misplaced and that the issue is not with double counting but with the assumptions used by FortisBC in the COSA regarding the Irrigation class.

The Commission Panel is concerned with both the load factors and the group and system coincidence factors used by FortisBC in its COSA for the Irrigation rate class and considers that they were applied arbitrarily**. The Commission Panel considers that there is no basis for using different load factors in different months during the irrigation season, and that a single load factor should be applied. As for load factors in the non-irrigation season, the Commission Panel considers that**

the RS 20 load factors should be used in those months. Accordingly, the Commission Panel directs FortisBC to re-run the COSA using the following assumptions:

- **a 70 percent load factor for the irrigation season (being the load factor for June, July and August) and the Small General Service load factor for the remaining months; and**
- **the Small General Service group and system coincidence factors of 75 percent and 70 percent respectively for all 12 months.**

2.7 Minimum System Analysis/ Peak Load Carrying Capability

In its 2009 COSA study, FortisBC classifies distribution system costs as either customer or demand-related using a minimum system approach along with an offset to account for the peak load carrying capability (PLCC) of a minimum system.

As part of the total FortisBC electric system, the distribution system receives electricity from the transmission system, which operates at 35,000 volts (35 kV) and above, steps the transmission voltage down to lower primary distribution level voltages normally from 750 V to 35 kV, transports the electricity along a system of primary distribution lines, steps the primary voltages down to secondary voltages and then ultimately supplies customers through individual meters and services.

Components of a distribution system include substations, poles and towers, conductors, line transformers and services, and meters. In the 2009 COSA study, FortisBC classifies the components of its distribution system as either customer or demand-related to reflect the notions that the costs of certain components vary with the number of customers, while others vary with the size of the load. FortisBC states it classified these components as follows:

- substations as demand-related;
- services and meters as customer-related; and
- poles, towers, conductors and line transformers into customer and demand-related components as an outcome of the minimum system analysis.

The following table presents a comparison of the customer and demand related costs of the poles, conductors and transformers of the distribution plant resulting from the minimum system approach as conducted in the 1997 and 2009 COSA studies:

Table 2-10
Comparison of Allocation factors

Distribution Plant	1997 COSA	2009 COSA
Poles	76% customer/24% demand	96% customer/4% demand
Conductors	48% customer/52% demand	58% customer/42% demand
Transformers	72% customer/28% demand	73% customer/27% demand

Source: Exhibit B-1, Appendix A, p. 39

In its 2009 COSA study, FortisBC incorporates a PLCC adjustment to the results of the minimum system approach. This adjustment is to account for the fact that a distribution system built using minimum sized components is, in actuality, capable of serving some amount of demand. A portion of customer-related costs classified under the minimum system approach are, therefore, demand related. The PLCC adjustment determines how much demand for a customer class can be met by the minimum system and credits this amount against the class' non-coincident peak demand which is used to allocate demand related distribution costs amongst classes. The 2009 COSA study determined that the PLCC adjustment, that is the average customer load that can be serviced by a minimum system serving FortisBC's territory, is 1 kW per customer (Exhibit B-1, Appendix A, p. 21).

The resulting classification of costs associated with poles as done in the 2009 study differs from the resulting customer/demand split of the 1992 study, which had informed the 1997 COSA. For the minimum system study conducted in 2009, FortisBC engineers determined that the size of poles is a function of terrain as opposed to the size of the load at the specific location (Exhibit B-3-1, BCUC 1.89.3).

No Intervener takes issue with FortisBC's proposal.

Commission Determination

The Commission Panel accepts FortisBC's proposed classification of distribution system costs related to poles, conductors and transformers based on the minimum system method.

The Commission Panel also accepts that the PLCC adjustment compensates for changes in the minimum size and shifts the costs associated with the increased capacity of the minimum system to those customers having a higher than the average 1kW demand on the system. The Commission Panel therefore finds the use of the PLCC adjustment to the results of the minimum system method an appropriate refinement to the 1992 minimum system study.

The Commission Panel will consider the results of the COSA in this regard as part of its determination of the suitability of FortisBC's proposed RS 74 and system extensions.

3.0 RATE STRUCTURE

The *Clean Energy Act* (*CEA*,) received Royal Assent on June 3, 2010 and has given a renewed and heightened importance to energy efficiency, conservation, smart meters and smart grid, especially in sections 2 and 17. To set the policy context for the rate structure review, this Section first provides an overview of the Government's energy policy which sets out the more specific energy objectives and action items.

FortisBC's conservation and efficiency action plan, having the introduction of automated metering infrastructure and time-of-use rates as its corner stones, is then described. The fundamental issue from the Commission Panel's perspective is whether the FortisBC response is sufficiently comprehensive and proactive to result in increased conservation and energy efficiency in a timely manner. In other words, the Commission Panel will examine the proposed time frame; explore what the correct conservation signals are, and whether the response by FortisBC is sending those correct signals especially for the residential customers. The proposed rate structure for other customer groups is briefly reviewed as well.

The Section concludes with a review of other policy matters such as postage stamp rates compared with rates set on the basis of region or size of community served.

3.1 Background – Policy Context

3.1.1 2007 Energy Plan

The BC Energy Plan: A Vision for Clean Energy Leadership (2007 Energy Plan) was released by the Provincial Government in February 2007. The 2007 Energy Plan set out a large number of policy actions that placed emphasis on energy conservation, energy efficiency, clean energy and self - sufficiency. Specifically, the following four policy actions highlight the government's commitment to conservation:

- set an ambitious conservation target, to acquire 50 percent of BC Hydro's incremental resource needs through conservation by 2020;
- ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia;
- encourage utilities to pursue cost-effective and competitive demand side management opportunities; and
- explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.

The 2007 Energy Plan also listed the following future energy efficiency and conservation initiatives in more detail:

- continuing to remove barriers that prevent customers from reducing their consumption;
- building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume;
- exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times;
- employing new rate structures to help customers to implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices; and
- advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

3.1.2 Bill 15 and Amendments to the *UCA*

The amendments to the *Act* brought about by Bill 15 became effective May 1, 2008, except for the new s. 58.1, which was made effective as of March 31, 2008. Noteworthy for this proceeding is the introduction of s. 64.04 which obliged BC Hydro to put in place "smart meters" for all of its residential customers by December 31, 2012. Furthermore, the new s. 64.04(4) stated:

> "If a public utility, other than the authority, makes an application under the act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority."

This section was subsequently repealed on June 3, 2010 and replaced with a similar text in s. 17(6) of the *CEA*.

3.1.3 Bill 17 – 2010, Clean Energy *Act*

The *CEA*, tabled by the Provincial Government on April 28, 2010, advances sixteen specific energy objectives, and enshrines the previous key goals such as achievement of electricity self-sufficiency, as well as energy conservation and efficiency.

While the government's communications regarding Bill 17 focused on BC Hydro, a direct link can be drawn to FortisBC in the following statements:

- "Energy efficiency in the future will go beyond simply using energy efficient products. It will include a shift in behaviour to ensure we use electricity wisely and without waste." (emphasis added)
- BC Hydro will work towards achieving conservation and energy efficiency by introducing smart meters, new energy pricing tools, a Large General Service rate, a conservation rate and a Industrial Stepped Rate.

(www.powerofbc.ca Fact Sheet: Energy Efficiency)

A comparison of relevant sections of the *UCA* before and after June 3, 2010 and the *CEA* is provided in Appendix C.

3.1.4 Jurisdictional Matters

During the Oral Phase of Argument the Commission Panel sought submissions on its jurisdiction in relation to conservation by asking questions that included the following:

- Even though the Application was filed pursuant to sections 58 and 61 in particular of the *UCA*, does the Panel have the jurisdiction to consider conservation and energy efficiency in general, and DSM matters specifically in making its Decision?
- Is there any jurisdictional impediment to the Panel directing FortisBC to introduce inclining block rates?

FortisBC affirmed the Commission Panel's jurisdiction with regard to the first question by referring to s. 60(1) of the *UCA,* the 2007 Energy Plan (Action No. 3) and Bonbright Principles 3, 4 and 5 (T7:1371-1372). FortisBC submissions were supported by BCMEU, BCOAPO and BC Hydro. Mr. Shadrack provided some additional support while Celgar, Mr. Wait and Big White took no position.

With regard to the second question, FortisBC stated there is "no jurisdictional impediment" of which it is aware although it reminded the Panel of its opposition to the introduction of inclining block rates (T7:1374). BCOAPO, however, noted that there was no evidence put forward in relation to inclining block rates and that, therefore, the Commission does not have jurisdiction in this proceeding to direct FortisBC to introduce such rates. "For such a dramatic shift in rate structure a hearing in our view is needed, so that issues such as conservation effects, bill impacts, cut-off points to encourage conservation and other such things could be addressed", stated BCOAPO. To that end, BCOAPO suggested that the Commission would have jurisdiction to direct FortisBC to file an application for inclining block rates (T7:1376-77). BC Hydro supported BCOAPO's views by pointing out that "there is a potential jurisdiction impediment" which is that by s. 58(1) of the *UCA* the Commission may not set a rate until after a hearing. However, BC Hydro also noted that if the Panel has concerns about FortisBC's timeline, it can direct the Company to submit an application by a certain date (T7:1378-79).

3.1.5 BC Hydro's Residential Inclining Block Rate

During its 2007 rate design proceeding, BC Hydro already described a plan to examine rate options focused on conservation, including residential inclining block (RIB) rates, where the price rises as more electricity is consumed in order to more closely reflect marginal costs and encourage conservation. Towards the end of the proceeding BC Hydro, in fact, confirmed its intention to introduce an RIB rate structure "in the immediate future." The Commission Panel commended that decision and found it to be in accordance with Policy Action 4 of the 2007 Energy Plan.

Some Interveners perceived BC Hydro's proposed implementation schedule aiming at October 2008 as "aggressive" and premature in light of the Smart Meter Initiative BC Hydro was required by legislation to implement by 2012. BC Hydro argued that waiting until all residential customers are able to be on time-of-use rates before implementing RIB rate structures would delay the introduction of conservation rates by about four years – until 2013.

By Order G-124-08 the Commission approved BC Hydro's RIB rate effective October 1, 2008. Consistent with the approved pricing principles, BC Hydro plans to file an application for the price of Tier 2 energy before April 1, 2011, at which time it hopes to have sufficient evidence based on Energy Purchase Agreements from the 2008 Clean Power Call to support approval of a new long run marginal cost to adjust the second tier pricing (Reasons for Decision to Order G-124-08, BC Hydro F2011 Revenue Requirement Application, Appendix A1).

3.1.6 Encouraging Conservation and Efficiency

FortisBC states that in selecting the appropriate default rate design option for each customer class it considered and balanced the eight Bonbright Principles described previously. FortisBC further states it gave particular attention to Principle 3: *Price signals that encourage efficient use and discourage inefficient use* (consideration of social issues including environmental and energy policy). This principle is directly linked to the 2007 Energy Plan and the *UCA* which together encourage utilities develop rates that:

- conserve energy or promote energy efficiency;
- reduce the energy demand a public utility must serve; or
- shift the use of energy to periods of lower demand.

Finally, FortisBC submits that, in addition to above, its future conservation rate design plans "were strongly weighted when considering rate design changes" (Exhibit B-1, pp. 33, 53-54).

FortisBC's long term rate strategy for residential conservation rates, the residential Basic Charge, automated metering infrastructure and the proposed implementation timeframe are addressed below.

3.2. Residential Rate Design Strategy

FortisBC seeks approval of continuation of its current residential rate structures until the implementation of Advance Metering Infrastructure (AMI) and proposes no increase to the Basic Charge.

3.2.1 Residential Conservation Rates

FortisBC states it supports the provincial energy consumption conservation goals through increased investment in its DSM programs and the planned move towards time-based conservation rates. Given the growing capacity constraints in the FortisBC system, the Company submits it must consider the introduction of rates and other incentives that encourage customers to reduce their electric use particularly when the system is most constrained. In other words, FortisBC "must endeavour to reduce its customers overall energy consumption while also reducing peak demand."

FortisBC believes that only time-of-use (TOU) and critical peak pricing (CPP) rates, which charge higher rates for energy at times when the system loading is at its highest, can achieve this goal. In contrast, FortisBC states inclining block rates "would be expected to have only a minimal impact in reducing system demand while having a questionable effect on energy conservation." A modeling scenario with a 40 percent pricing differential between blocks is provided as an example. FortisBC states that this assumption results in an upper block rate that is some 17 percent higher than current flat rates and that based on a price elasticity ratio of 0.1, this price increase would reduce the energy consumption in the upper block only by 1.7 percent. Similarly, peak demand reduction could be expected to approximate the same percentage.

To support its case for time-based rates FortisBC refers to the following two studies:

- a 2007 OEB report which showed TOU rates resulting in 6.0 percent overall reduction in energy consumption and CPP rates reducing peak demand by 25.4 percent; and
- a 2008 Brattle Group study which concluded that for the average customer, TOU rates are likely to induce a drop in peak usage of under 5 percent while CPP tariffs induce a drop of around 10-25 percent.

Based on these findings, FortisBC submits that it plans to introduce mandatory time-based conservation rates for all metered customer classes, once electric usage interval data is made available through the implementation of the AMI. FortisBC also expects that this type of demand conservation has the added benefit of energy conservation "since a customer choosing to use less electricity during the more expensive peak periods, will likely not use more electricity during the off-peak period to compensate" (Exhibit B-1, pp. 22-23).

FortisBC also notes that given the relatively short time period between the decision on the RDA and the proposed implementation of AMI, it does not recommend introducing an interim rate such as an inclining block structure for the following reasons:

- the effective implementation of energy conservation rate structures requires that customers be provided with additional education allowing them to understand the new pricing signals. Since the Company intends to introduce time-based rates after the implementation of an AMI, customers would have to be re-educated in order to understand and adjust to the time-based pricing signals. This could cause customer confusion and stranded customer investment in conservation infrastructure;

- certain types of energy conservation rates, inclined block in particular, require real-time energy consumption information to be available to customers for maximum effectiveness. This information will not be available until AMI is implemented; and
- energy conservation rate structures do not directly address fundamental power supply issue at FortisBC, which is an increasing capacity constraint.

(Exhibit B-1, p. 16)

FortisBC agreed, however, that a RIB rate would have at least some impact on residential consumption in the transition period before the implementation of time-based rates. Yet, FortisBC repeated its concern that “any price signals arising out of an inclining block structure would not be time-based and therefore would not prepare customers to begin reducing power use at specific times and/or shifting their power use to off-peak periods” (Exhibit B-3, BCUC 1.6.4, 1.6.5).

3.2.2 Basic Charge

During its public consultation FortisBC presented three residential rate structure options in addition to the status quo:

- Option 1 – Reduce Basic Charge with an increased energy rate and minimum bill;
- Option 2 – Inclining block rate with a lower Basic Charge and higher energy rates; and
- Option 3 - Inclining block rate with higher Basic Charge and lower energy rates.

Both Option 1 and Option 2 resulted in bi-monthly bills to low end consumption customers that are lower than the status quo (Exhibit B-1, Appendix I, p. 64).

In addition, the Commission Panel requested that FortisBC model another inclining block rate option with a $6.00 monthly basic charge ($ 12.00 per two months), with a threshold of 600 kWh a month (1,200 kWh per two months), and a Tier 1 rate at current rates (T5:815-816). The calculation submitted by FortisBC results in a bi-monthly bill to low end consumption customers which is even lower than those modeled in earlier options (Exhibit B-34, p. 9).

Rather than considering a reduction in the Basic Charge, FortisBC explained why it determined not to increase it for residential customers: "Were the principle of cost causation strictly adhered to in rate design, the Basic Charge would have been considerably higher and the energy rate considerably lower, both arguably disincentives to conservation" (FortisBC Argument, p. 49).

FortisBC shows a comparison of basic charges at select Canadian utilities to demonstrate that its current basic charge is "lower than combined average basic charge of the other Canadian utilities" (Exhibit B-1, p. 58). In particular, BC Hydro's current basic charge is 13.41 cents per day or $ 4 per month, as compared to the $ 12 per month proposed by FortisBC, and its minimum charge equals the Basic Charge.

3.2.3 Automated Metering Infrastructure and Conservation Rates

FortisBC explains that the majority of meters installed throughout its service territory do not collect electric usage interval data. Instead, most meters installed continuously record total energy use and, for certain customer classes, the peak electrical consumption rate (peak demand) since the last meter reset. In comparison, the new AMI meters will take measurements of energy use at regular intervals. FortisBC states that due to the lack of electricity usage interval data, potential changes to existing rates are confined to adjustments to the Basic charge and the rate charged for total energy consumption between successive meter readings. In addition, for certain customer classes the rate charged for peak demand may also be considered. To address this matter, FortisBC intends to file an application in 2010 with the Commission requesting approval for the installation of AMI meters that will make interval data readily available and thereby permit the introduction of time-based conservation rates (Exhibit B-1, p. 24).

In December 2007 FortisBC applied to the Commission for a Certificate of Public Convenience and Necessity (CPCN) for the AMI Project for the first time. The Commission denied the application at that time mainly because the Panel found it as incomplete and premature. The Commission expressed concern that no overall vision of the complete program for the implementation and use of AMI had been adequately articulated and that there was insufficient evidence with respect to the feasibility and cost effectiveness of the ultimate end result of the program. However, the Commission encouraged FortisBC to continue its efforts to develop and, in due course, reapply for approval of a comprehensive program for the implementation of the AMI project. The Commission also noted that government had not yet issued any regulations concerning Smart Meters and their installation although they were referred to in the context of Bill 15 and section 64.04 (Order G-168-08).

3.2.3.1 FortisBC's Proposed Timeframe

FortisBC intends to prepare for the implementation of wide-scale time-based rates in the following four stages:

- conduct a study during 2009 and 2010 that examines the typical effects of time-based rates on energy and demand, as experienced by utilities that have already implemented or piloted them;
- file a CPCN application for Advanced Meter Infrastructure Project in 2010 (with an expectation that AMI be available to most residential customers by the end of 2013);
- conduct a study after the implementation of AMI to determine the extent to which education and real-time consumption information can best influence customer conservation behaviour; and
- submit a Rate Design Application supporting results of consultation and study.

(Exhibit B-1, p. 24; Exhibit B-3, BCUC 1.6.1)

More specifically, FortisBC indicated that its plan to file an AMI CPCN Application in the fourth quarter of 2010 was dependent on several factors, including the issuance of Smart Meter Regulations made pursuant to the *UCA* (Exhibit B-3, OEIA 1.5.1.2). FortisBC also testified that it is feasible, especially if the regulations are delayed, that the time-of-use rates would not be implemented until sometime after 2014, and that it does not have a fallback plan for development and earlier implementation of rates that would promote conservation and efficiency that do not rely on AMI. FortisBC added that "…anything other, at this point, than a time-based rate would in our circumstance ultimately be an interim measure, and we're concerned that that doesn't necessarily conserve the best interest of the customers in the long term" (T4:684-685).

FortisBC also testified that it assumed that its residential TOU rates would be mandatory, without any customer choice, unlike BC Hydro (T5:804-05).

3.2.4 Positions of Parties

In his Opening Statement Mr. Shadrack challenged FortisBC's single minded focus on time-based rates as follows: "While I agree that peak power usage can be shaved by TOU rates, so as to encourage, for example, when clothes are washed and when dishwasher is set to run, I want to challenge the notion of energy conservation through stand alone, eggs-in-one-basket TOU rates." In contrast, Mr. Shadrack asked FortisBC to explain "why an inclining block rate will not better encourage a residential customer to switch from incandescent bulbs to compact fluorescent or LED lights; more easily encourage them to switch from a top loading washing machine to a front loading one; better encourage a customer to install an energy efficient fridge, freezer and stove; and better encourage a customer to switch from electric heat to a ground source heat pump" (Exhibit C2-10, p. 3).

To strengthen his submissions, Mr. Shadrack recommends that "the Commission in its order require FortisBC to introduce an inclining block rate" (Shadrack Argument, pp. 4-5).

Mr. Shadrack also recommends that the Commission require FortisBC to replace the basic charge with a minimum charge based on a set minimum purchase of KWh per billing period and that the minimum purchase be set at 250 kWh. Mr. Shadrack demonstrates by way of his own consumption data that a higher basic charge actually favours higher consumption customers to the disadvantage of low consumption customers, rather than providing an incentive or a price signal to conserve. He further submits that "the current Basic Charge rate design is in fact providing a massive subsidy" to the high end consumption customers and that "in effect 70.6% of the residential load is being subsidized by a majority of residential customers" (Shadrack Argument, pp. 1-3).

BCOAPO *et al.* supports the FortisBC decision not to implement inclining block rates for residential customers at this time, "as changing rate structures could lead to customer confusion with little conservation benefits for the Company and its ratepayers" (BCOAPO Argument, p. 13).

Commission Determination

The Commission Panel finds that increasing the Basic Charge would be unacceptable, especially in view of the requirement for providing appropriate pricing signals for conservation and energy efficiency.

In the context of conservation and efficiency, the Commission Panel rejects FortisBC's position that no conservation rates should be introduced before the AMI implementation, for a number of reasons. First, the timeline for the implementation of AMI is subject to a number of factors with a potential outcome that introduction of wide spread time-of-use rates could be five years away which the Commission Panel believes is contrary to the intent of the government energy policy. Second, the Commission Panel finds that hourly customer consumption data is not necessary to the design of a residential inclining block rate structure. BC Hydro introduced RIB rates almost two years ago – long before its planned Smart Meter installation. Third, the Commission Panel disagrees with the FortisBC position that a customer choosing to use less electricity during the peak periods will not use more electricity during the off-peak period to compensate. Finally, the Commission Panel is not persuaded by the FortisBC argument that customers would be confused over introduction of two kinds of conservation rates over a short period of time and that customers may need to be re-educated. In today's world of heightened awareness of the need for conservation, customers are more receptive to new price signals.

The Commission Panel considers that, while TOU rates may result in a reduction in peak demand, residential inclining block rates can provide price signals for reducing the overall energy consumption. The Commission Panel is especially concerned that backing away from the RIB rate structure in the FortisBC service area today, in anticipation of TOU rates being implemented in five years time, would represent a foregone opportunity for energy efficiency and conservation. Similarly, the Commission Panel is concerned that the existing relatively high basic charge gives wrong pricing signals and believes that Bonbright Principle 3 regarding the price signals encouraging conservation should trump Principle 2 which seems to support a higher basic charge. Specifically, the Commission Panel agrees with the observations of Mr. Shadrack. **Accordingly, the Commission Panel directs FortisBC to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and to file an RIB rate application with the Commission no later than March 31, 2011.**

3.3 Rate Structure for Other Customer Groups

After considering and balancing the eight Bonbright Principles, FortisBC brought forward the following proposal:

- default (i.e. non-TOU) rate schedules for each customer class will remain, become, or move closer to a flat rate;
- the Basic Charge will be unchanged;
- demand charges will be increased (as a proportion of the bill) for customers not subject to contract demand (General Service and Large General Service – Primary);
- demand charges will be split into power supply-related demand charges using actual demand as the billing determinant and wires-based demand charges using contract demand as the billing determinant for customers with a contract demand (Large General Service – Transmission and Wholesale); and
- Time-of-Use rate schedules for customers subject to contract demand will be modified to include a wires-based contract demand charge.

(Exhibit B-1, p. 54)

Specifically, FortisBC submits it has adjusted its General Service rates such "that disincentives to conservation have been reduced." Regarding the new "wires" portion, FortisBC believes "such rates will promote conservation by creating more appropriate price signals" and that "slowing increases in contract demand would in turn reduce the need for additional infrastructure" (FortisBC Argument, pp. 46-47).

3.3.1 Submissions of Parties on Rate Structure Changes

Celgar accepts that rates designed to meet the Government's energy objectives "are an important means to advance Government policy and to implement Commission directives." However, Celgar submits it believes that "further and more meaningful consultation, and further consideration by FortisBC of opportunities through rate design and contractual obligations to incent conservation and efficiencies, would have resulted in an RDA that better meets such objectives, at least as they relate to the treatment of Zellstoff Celgar's self-generation."

Specifically, Celgar states that there are opportunities at its mill for over 5 MW of load reduction representing 42 GWh of annual energy savings, and expresses concern about the low level of DSM incentives FortisBC has offered its Industrial Customers. Celgar also highlights the lack of progress by FortisBC in rate design since 1997 (Exhibit 13-7, p. 26 as revised).

Rate 30 Group expresses concern over FortisBC's proposal to increase the RS 30 demand charge, to reduce the energy rate charge, and to apply rebalancing adjustments to the energy charges only. It submits "if FortisBC wants to promote conservation (a guiding principle in COSA and the *CEA*), then increasing the demand charge does not achieve this goal. No change to the demand charge is necessary at this time" (Rate 30 Group Argument, p. 5).

3.3.2 Billing Determinants for Rate Schedule 31

The primary change to RS 31 (Large General Service – Transmission) proposed by FortisBC is in the determination of the amount of billed demand. Currently, customers on this rate are billed a single demand charge based on the greatest of:

- 80 percent of the Contract Demand; or
- the maximum demand in kVA for the current billing month; or
- 80 percent of the maximum demand in kVA recorded during the previous eleven month period.

The proposed revision to RS 31 will separate the demand component into a charge related to power supply and a charge related to transmission infrastructure cost as follows:

Wires Charge

The greatest of:

- 100 percent of the Contract Demand; or
- the maximum demand in kVA for the current billing month; or
- 100 percent of the maximum demand in kVA recorded during the previous eleven month period.

Power Supply Charge

The maximum demand in kVA for the current billing month (Exhibit B-1, p. 68).

3.3.3 Billing Determinants for Rate Schedule 33

The current RS 33 (Large General Service Transmission, TOU) includes a Customer Charge but no Demand Charge. The proposed revision, not unlike the RS 31, is as follows:

Wires Charge $ 0.00 per kVA determined by:

The greatest of:

- 100% of the contract Demand Limit; or

- the maximum demand in kVA for the current billing month; or
- 100% of the maximum demand in kVA recorded during the previous eleven month period.

FortisBC submits that RS 33 has been modified to gain consistency of treatment with other rate schedules subject to the use of Contract Demand in their billing treatment. Because of its nature as a TOU rate, RS 33 is not subject to the power supply portion of the Demand Charge – only the Wires Charge is applicable. FortisBC further submits the R/C ratio for this rate class is very low largely due to significant under collection of wires-related costs. “Therefore, the introduction of full-cost wires-based demand charge with a corresponding downward adjustment of TOU energy rates was not deemed to be in compliance with cost-based or energy efficiency principles.” As a result, FortisBC proposes to “price the wires-based demand charge at $0 per kVA to begin, with all rebalancing increases for this rate schedule to be applied solely by increasing this demand charge. The current Basic Charge and TOU energy rates will be left unchanged to begin with then subject only to any annual general rate increases” (Exhibit B-1, p. 73).

The calculation of the billing demand for the Wires Charge under RS33 differs from that under RS31. Under RS33, billing demand is based on “Contract Demand Limit” while under RS 31, it is based on “Contract Demand”. Celgar submits that pro forma contracts for both RS 31 and RS 33 industrial customers include a Demand Limit and either a contract demand or capacity reservation (Exhibit B-7, BCUC IR2, Appendix 34.7). Accordingly, “RS 33 should also be revised so as to be billed on the contractual obligation equivalent to contract demand and that is capacity reservation” (Celgar Argument, p. 69).

In its 1997 COSA FortisBC described how the TOU rates were designed. This was done by determining the six timeframes (Winter, Summer and Shoulder, on peak and off peak) and carrying out a cost of service analysis by month. To ensure that customers would be indifferent or unable to game the system the class R/C ratio had to be applied to each set of numbers. To send the appropriate signal to the customers, the on-peak summer and winter charges had to reflect all the transmission charges while the other periods attracted none. The proposed RS 33 comprised the following elements:

Table 3-1
Rate Schedule 33 Elements

	Commodity	Transmission	Total
Winter On Peak	5.193	3.427	8.620
Winter Off Peak	2.437		2.437
Summer On Peak	2.998	8.500	11.498
Summer Off Peak	1.898		1.898
Shoulder On Peak	2.762		2.762
Shoulder Off Peak	1.452		1.452

Source: Exhibit B-3-3, BCMEU 1.34.1 Appendix A, p. 95

With regard to the 100 percent "ratchet" included in the Wires Charge, Mr. Linxwiler testified that "this ratchet has not been shown to be justified and, in fact, is unreasonable in part because it is inconsistent with the 2CP demand allocation method. A 75 percent or 80 percent ratchet is more traditional and would be more consistent with the 2CP allocation. Also, such a ratchet that "looks back" only six months would be more reasonable because it would be more consistent with the 2CP allocation method." Finally, Mr. Linxwiler noted that consistency between rate design and cost allocation is necessary to avoid or minimize over- and under-recovery of revenue requirements and to avoid discrimination within a customer class (Exhibit C13-7, Testimony of Joe N. Linxwiler, Jr., pp. 14-15).

Celgar submits that the evidence of Mr. Linxwiler was neither challenged during the proceeding nor commented on in Argument by FortisBC and that therefore the Panel should accept this evidence, and change the ratchets used in both RS 31 and RS 33 from 100 percent to 80 percent. Furthermore, Celgar submits that the time period on which the demand ratchet is based should be set to the preceding six months rather than eleven months. For clarity, Celgar submits that the wires charge should be based on:

The greatest of:

- 80% of "the capacity reservation as stated in the GSA (general service agreement) that applies to the pricing period with the highest rate"; or
- the maximum demand in kVA "of firm purchases" for the current billing month; or
- 80% of the maximum Demand in kVA "of firm purchases" recorded during the previous "six" month period.

(Celgar Argument, p. 69)

In Reply, FortisBC cited Mr. Saleba's testimony during cross-examination regarding 75 percent or 80 percent ratchet as a traditional industry standard as follows:

> "Again, it depends on the requirement that the customer puts on the utility. It may be that if the utility got a situation where they can curtail load to somebody occasionally, maybe that's not bad. 75 to 80 percent is not bad. But in this specific situation, FortisBC is on the hook for a hundred percent of that contract demand every month. So, if there is no relief there, that we know of, in the planning or the operational standpoint, and it follows to us, then that if Fortis has to provide contract demand every month, that the customer should pay for that contract demand every month" (T2:310).

3.3.4 Billing Determinants for Wholesale Customers

Currently customers on RS 40 and RS 41 are also billed a single demand charge based on the greatest of:

- 25 percent of the Contract Demand; or
- the maximum demand in kVA for the current billing month; or
- 75 percent of the maximum demand in kVA registered during the previous eleven month period.

FortisBC is proposing to follow the same rationale and process as with the Large General Service Transmission customer class by separating the demand component into a Wires Charge and a Power Supply Charge. Accordingly the Wires Charges is proposed as the greatest of:

- 100 percent of the Contract Demand Limit; or
- the maximum demand in kVA for the current billing months; or
- 100 percent of the maximum demand in kVA recorded during the previous eleven month period.

While BCMEU did not specifically express concern over Billing Determinants in its Argument, it took issue with interpretation of contracts and the “renominations” matter. Specifically, BCMEU submits that the existing agreements were not drafted with any consideration of the Demand Limit in place for the customer for the purpose of setting a Contract Demand. “The Demand Limit provisions essentially set the nameplate capacity of the substations” (BCMEU Argument, p. 38).

3.3.5 General Service Rate Restructuring

FortisBC proposes to flatten the RS 20 energy rate, which currently has a three-step declining block rate structure. FortisBC states that almost 97 percent of RS 20 bills are entirely within the first energy block which implies the transition to a completely flat rate would not result in excessive bill impacts.

For RS 21 FortisBC proposes moving from a three-step to a two-step declining block rate in which the first block rate (up to 8,000 kWh monthly) and the flat rate of RS 20 are the same, while second block of consumption attracts a lower rate.

FortisBC stats that this will allow the customers who receive service under this rate to transition more smoothly to the time-based rates that FortisBC foresees will become the standard under its future plans.

FortisBC stats that the majority of both RS 20 and RS 21 customers will see a modest bill decrease as a result of the change (Exhibit B-1, pp. 61-63).

No Intervener comments on FortisBC's proposal.

3.3.6 Specific Celgar Rate Structure Matters

In addition to the issue of consistency for Billing Determinants, other matters concerning a suitable Celgar rate structure surfaced during the proceeding, such as the eligibility of Celgar to receive service under RS 33 and the rates for similar service offered by the BC Hydro tariff.

RS 33 is applicable to industrial customers with loads of 5,000 kVA or more, "subject to written agreement" and "with satisfactory, as determined by the Company, load factors." As addressed in Section 2.0, FortisBC defined an acceptable load factor as "one that results in a R/C ratio within the range of reasonableness" but could not state "a universally applicable numerical load factor threshold" that would indicate an acceptable R/C ratio (Exhibit B-7, BCUC 2.44.1).

FortisBC stated that Celgar transferred from RS 31 to RS 33 on October 1, 2006, in anticipation of executing a service agreement between the two parties that would replace the agreement executed in 2000. Although RS 33 explicitly requires a written agreement between a customer and the utility, one does not presently exist (Exhibit B-1, Appendix B, RS 33; T5:891).

Celgar states that all of the electricity purchases currently made by Celgar are for the purpose of back-up power. Celgar further points out that elsewhere in the Province, Celgar's competitors have access to BC Hydro Rate Schedule 1880 – Transmission Service- Standby and Maintenance, which has no demand charge. Celgar also notes that BC Hydro has not utilized the demand taken by customers under this tariff as part of its cost of service analysis (Exhibit C13-7, p. 22).

During the Oral Phase of Argument, the Commission Panel sought submissions concerning alternative methods to address Celgar's low R/C ratio, such as the introduction of a Rate Schedule comparable to BC Hydro's RS 1880 as suggested by Celgar in its evidence. In response, Celgar explained that it did not mean to suggest that it was seeking solely standby power but wanted service under RS 31 or RS 33, as it elects, for service of its full load (T7:1227). FortisBC stated that it does not currently offer a standby service rate that could be applied either as means for billing Celgar or as a basis for allocating costs in the COSA. FortisBC further stated that in its view BC Hydro's RS 1880 is not a standard standby rate (T7:1260).

Commission Determination

The Commission Panel shares Celgar's concerns regarding lack of incentives for conservation and efficiencies for industrial customers and agrees that a further consideration of opportunities through rate design and contractual obligations would have resulted in a rate design proposal that better meets the Government's energy objectives. The Commission Panel also notes that for quite some time BC Hydro has had a stepped rate for transmission service customers and that, with the introduction of the *CEA,* it will be expected to do even more in terms of conservation rates. In light of the heightened importance of energy efficiency and conservation in the province, it is somewhat disappointing that FortisBC merely chose to "reduce disincentives." **Accordingly, the Commission Panel directs FortisBC to initiate consultations with its industrial customers with a goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro. FortisBC's action plan for this matter is to be included in the compliance filing.**

The Commission Panel approves FortisBC's proposed restructuring of the RS 20 and RS 21 energy rates.

With regard to Billing Determinants for Large General Service Transmission Customers, the Commission Panel accepts the FortisBC proposal to separate the demand component into the Wires Charge and Power Supply Charge in order to send better price signals. However, the Commission Panel finds that there should be consistency between rate design and cost allocation. As explained in Section 2.0, the Commission Panel rejected the use of Contract Demand for transmission cost allocation purposes. Accordingly, it finds that using 100 percent of the Contract

Demand or 100 percent of the maximum demand recorded during the previous eleven month period for Billing Determinants is not acceptable either. The Panel was especially persuaded by submissions of Mr. Linxwiler in this regard. **Therefore, the Commission Panel directs FortisBC to return to its previously used parameters for the purpose of setting the Wires Charge for RS 31 and RS 33.** For greater clarity, the Wires Charge should be set as the greatest of: a) 80 percent of the Contract Demand; or b) the maximum demand in kVA for the current billing month; or c) 80 percent of the maximum demand in kVA recorded during the previous eleven month period.

Finally, on the basis of the pro-forma contracts provided by FortisBC, the Commission Panel sees no reason for the differentiation between RS 31 and RS 33 and directs that RS 33 should also be revised so as to be billed on the basis of Contract Demand as opposed to contract Demand Limit.

In addition, the Commission Panel rejects FortisBC's proposed changes to RS 33 that establish a new wires charge component as part of the rate, starting it at $0.00 per KVA/month and appling all the rebalancing increases to it. The Commission Panel considers that RS 33 already has a wires component inherent in it, as is apparent from the 1997 RDA, and the Commission Panel determines that there is no justification for introducing a second wires charge**. FortisBC is directed to reconsider the concepts underpinning RS 33 that were approved by the Commission in Order G-15-98 and resubmit it in accordance with those principles. FortisBC is also directed in its compliance filing to set out how the wires charge components of its other TOU rates were determined.**

A ratchet provides a mechanism for the utility to recover the costs of the system from the customer who is responsible for those costs. In case of FortisBC's customer classes that currently have demand ratchets, the Commission Panel finds there does not appear to be a single class that contributes a significantly larger portion to the system peak demand as measured by the 2CP allocator. In other words, there is enough diversity in loads contributing to the system peak to justify an 80 percent demand ratchet for the Wholesale Customers as well. The Panel notes that the existing Wholesale contracts are unclear on what is the Contract Demand versus the Demand Limit and what are FortisBC obligations to the customers. The Commission Panel accepts the

BCMEU view that the Demand Limit provisions essentially set the nameplate capacity of the substation and rejects Mr. Saleba's arguments in support of 100 percent ratchet. **Accordingly, the Commission Panel directs FortisBC to set the billing determinants for the Wholesale Customers to be consistent with those to be set for the Large General Service Transmission Customers.**

With regard to the specific Celgar rate schedule matters, the Commission Panel finds that under the current circumstances Celgar is ineligible to take service under RS 33 and directs FortisBC to provide Celgar service under RS 31 effective January 2, 2011. This ineligibility is primarily due to the following:

- there is no current signed agreement as stipulated by the Electric Tariff, RS 33; and
- FortisBC has failed to explain how the current low load factor could qualify as "satisfactory" as stipulated by the Electric Tariff.

Based on evidence and determinations related to Celgar, as addressed in Sections 2.0 and 6.0, the Commission Panel also recommend that FortisBC and Celgar reconsider the options available for designing a practical and workable rate schedule for Celgar. For instance, a stand-by rate similar to that offered by BC Hydro might still be an option regardless of the submissions made during the Oral Phase of Argument.

3.4 Postage Stamp Rates

3.4.1 General Policy

The concept of postage stamp rates refers to the practice of charging every customer within each class of service the same rate, regardless of the geographical region in the province in which service is provided, even though this may entail some cross-subsidies between customers in a class. In British Columbia, in addition to FortisBC, BC Hydro and a few municipal and small private utilities also distribute electricity. Accordingly, the entire Province is not covered by postage stamp rates for electricity.

3.4.2 Positions of Parties

FortisBC states it considered and consulted on seasonal rates and urban/rural rates, but rejected these options since it felt they were unduly discriminatory to electric heat customers (in the case of seasonal rates) or rural customers (in the case of urban/rural rates) (Exhibit B-1, p. 55).

Mr. Shadrack questioned the postage stamp principle for allocating transmission and distribution costs. He pointed to FortisBC evidence that North Okanagan's percentage share of the total load will increase by 20.8 percent while Kootenay's share is forecast to decline by a further 20.4 percent. He asks: "Why … should all classes of West Kootenay customers participate in paying for purchase of wheeling from BCTC for customers in the Okanagan and Creston?" (Exhibit C2-10).

At the request of the Commission Panel, Commission Counsel filed a 2003 letter from the Minister of Energy, Mines and Petroleum Resources to the President of the Union of British Columbia Municipalities indicating his support for postage stamp rates:

> *"Electricity rates will be set on a postage stamp basis. This means all customers within a particular customer class will receive the same rate, regardless of their location in the Province."* (Exhibit A2-1)

FortisBC acknowledges that there may be some inequity in having one single rate but believes that the continuation of the postage stamp rate provides an overall benefit to customers. FortisBC submits the following key reasons to support its position:

- postage stamp rates reduce the price fluctuations that would otherwise occur for regional subgroups due to new regional infrastructure projects and, therefore, the cost impediments to growth in rural areas and/or areas needing infrastructure; and

- postage stamp rates take into account the fact that although high density customers are generally less expensive to serve, they also generally receive higher levels of service, particularly with respect to reliability, whereas low density customers are generally more expensive to serve but may receive lower levels of service.

(FortisBC Argument, pp. 55-56)

Commission Determination

The Commission Panel notes that while regional rates may have some merit, more detailed, regionally distinguished cost of service studies would be required for a proper analysis. Accordingly, the Commission Panel concludes that it has insufficient evidence to justify a departure from the current postage stamp principle followed by FortisBC, which is also supported by current government policy.

The Commission Panel further notes that the current policy, supporting same rates to all members of a customer class regardless of their location in the Province, can also be interpreted to support the idea that the FortisBC residential customer rate structure should more closely resemble the BC Hydro residential rate structure.

4.0 RATE REBALANCING

Section 4.0 addresses matters related to rate rebalancing arising from the COSA and initiatives around rate structures. It also includes particular rebalancing concerns regarding Irrigation rates resulting from the treatment of Irrigation rate payers within the COSA.

Sections 59 and 60 of the *UCA* address the setting of rates for service. They require that the Commission have due regard in setting a rate that is not unjust or unreasonable, unduly discriminatory, or unduly preferential. One consideration in assessing this is the R/C ratio for different classes of customer. That is, there must be a fair apportionment of costs amongst customers and there must be a reasonable recovery of costs allocated to different customer groups to avoid rates being set that would be unjust, unreasonable, unduly discriminatory, or unduly preferential.

FortisBC states that its Application has considered a rebalancing of rates amongst rate classes and made proposals intended, in FortisBC's view, to derive fair and just rate equity amongst rate classes. It has concluded that adjustments to current cost recovery rates are required (Exhibit B-1, p. 45).

4.1 Range of Reasonableness

In its Application FortisBC proposes a range of reasonableness for the class R/C ratios resulting from the COSA study of 95 to 105 percent. Customer classes, whose resulting R/C ratios fall within this range would not be subject to the rebalancing mechanism proposed by FortisBC. Generally speaking, customer classes that fall within the range of reasonableness are considered to be paying an appropriate share of their costs.

FortisBC states that it has adopted a range of reasonableness to underpin its rate rebalancing approach to reflect a number of assumptions made within the COSA including the use of a test year using a forecast of revenues, costs and customer loads, the lack of complete load data for all customers, and the choice of the COSA methodology itself (Exhibit B-7, BWSR 2.2.2, BCOAPO 2.13.2; FortisBC Argument, p. 62).

FortisBC states that it has sufficient metering data to support a goal of 100 percent R/C ratio for the Large General Service and Wholesale classes (Exhibit B-16, p. 15; Exhibit B-3-6, p. 13; Exhibit C1-11, p. 78). However, meters deployed to other customer classes are not capable of recording the interval data required to support a similar level of load analysis (Exhibit B-3-6, p. 39; Exhibit B-7, BCUC p. 18, and FortisBC Argument, pp. 62-63). For those customer classes lacking interval meters, EES used load research data from BC Hydro's Southern Interior delivery area for guidance in determining load and coincidence factors (Exhibit B-3-3, p. 36 and FortisBC Argument, p. 63).

FortisBC specifically confirmed that it is not aware of any systematic bias in its load data (Exhibit B-7, BWSR, p. 5).

FortisBC testified that the accuracy of its load data was not the sole determinant of its choice of a range of reasonableness, explaining that policy considerations were reflected as well:

> "MR. SINCLAIR: A: Ultimately, ultimately the company has to decide what range of reasonableness they put forward in the application. Those things are certainly a large part.
>
> MR. LUSZTIG: Q: Okay.
>
> MR. SWANSON: A: And we look to things like provincial policy, prior Commission decisions on us and on other utilities, and 95 to 105 seem to be right now not only supported by the data side of it but supported by the policy side of it." (T3:539)

In the event that the Commission Panel determines that a broader range is appropriate, FortisBC submits that having different ranges for different customer groups would be a possibility and that, given the greater accuracy of the load data of the Large General Service and Wholesale classes, these customers could have a narrower range than other, non-hourly-metered, customers (Exhibit B-16, p. 15; FortisBC Argument, p. 63).

FortisBC states that it discussed the concept of the range of reasonableness during public consultations and received little feedback (Exhibit B-1, Appendix I; Exhibit B-3-1, BCUC 1.98.1).

4.1.1 Positions of Parties on Range of Reasonableness

BCMEU agrees that a tolerance band is necessary to appropriately account for the level of precision in a COSA resulting from its underlying assumptions, estimates, and generalizations. Dr. Rosenberg goes on to state that, in general, the less confidence one has in the assumptions and the accuracy of the data, the wider the range of reasonableness should be. In the case of the FortisBC COSA, Dr. Rosenberg recommends a range of reasonableness of 90 to 110 percent to reflect the "lack of any statistical sampling or load data specific to FortisBC" (Exhibit C6-1, p. 26).

Dr. Rosenberg admits that his recommendation is not based on any empirical evidence concerning the accuracy of the load sampling data used by FortisBC, nor that it is based on any calculations. Rather, Dr. Rosenberg states that, by extending the range of reasonableness by another five percent in either direction, "we can be more comfortable that we are circumscribing a realistic result" (Exhibit C1-10, BWSR 1.1.2 and 1.1.3, p. 2).

The BCMEU also states that the Commission accepted a 90 to 110 percent range of reasonableness in its decision related to the 1997 COSA and that "continuity supports this approach" (BCMEU Reply, p. 5).

BCOAPO supports BCMEU's proposal for a range of reasonableness of 90 to 110 percent (BCOAPO Reply, p. 2). It states that FortisBC has provided no empirical evidence to support the range it is proposing. Since FortisBC must rely on BC Hydro load data, BCOAPO submits that the accuracy FortisBC's load data cannot be as great as BC Hydro's and, therefore, rebalancing warrants the use of a wider tolerance range (BCOAPO Argument, para. 66).

IRG agrees with FortisBC on the need for a range of reasonableness and that a 95 to 105 percent range is a reasonable target for rate balancing (IRG Argument, p. 11). However, IRG goes on to state that:

> "if the classes with more accurate load data are only subject to a 95% - 105% range of reasonableness, then it would be equitable to apply a broader range for classes with less accurate load data – particularly the Irrigation class."
> (IRG Argument, p. 12)

Big White submits that a range of reasonableness approach, used in conjunction with FortisBC's rebalancing proposal, should be rejected by the Commission Panel:

> "It is right to understand and accept that a calculated revenue-to-cost ratio of 100 percent does not mean with certainty that every customer class is paying exactly its true cost of service. It is wrong to derive from that a policy that targets the edges of a range of reasonableness, rather than targeting its centre (unity)" (Big White Argument, para. 12).

Big White further submits that aiming for unity during rebalancing does not make or imply a claim of certainty or accuracy and that customers are more likely to be paying an amount appropriate to their level of service, following a re-balancing that targets unity rather than one that that targets a range (Big White Argument, para. 7, 9).

In reply, BCMEU submits that there is no statistical support for choosing unity, stating that it is an arbitrary point with a range of reasonable results (BCMEU Reply, p. 5).

The Rate 30 Group states that the target for the revenue to cost ratio should be 100 percent, rather than the extremities of the range of reasonableness. The Rate 30 Group acknowledges the imprecision of the revenue to cost ratios resulting from the 2009 COSA and states that a rebalancing method targeting the centre of the range has the best chance of reducing the effects of the imprecision (Rate 30 Group Argument, p. 2).

Mr. Shadrack agrees with the position taken by Big White that FortisBC should target a R/C ratio of 100 percent for all customer classes, rather than use a range of reasonableness. If the Commission Panel were to accept the range of reasonableness approach, then Mr. Shadrack proposes that the range be narrowed further to 97.5 to 102.5 percent (Shadrack Reply, pp. 3-4).

4.1.2 Implementing Rate Rebalancing

In its Application FortisBC proposes to apply a series of adjustments to customers' rates over a five year period in order to bring the associated revenue to cost ratios for most classes to within the range of reasonableness. With regard to limiting billing impacts to an acceptable level, FortisBC intends to cap annual increases resulting from increases to the revenue requirement and the rebalancing to no more than 10 percent, unless the increase due to the revenue requirement alone exceeds 10 percent. This cap is exclusive of any BC Hydro increases that FortisBC may apply on a flow-through basis. FortisBC also proposes to cap rate increases due to rebalancing alone to five percent.

The purpose of the rate rebalancing approach by FortisBC is to bring the R/C ratios of most customer classes to within the range of reasonableness. Specifically, FortisBC states that, assuming that the revenue requirement increase is less than 10 percent, the rebalancing would result in each class with a R/C ratio below 95 percent receiving a combined rebalancing/revenue requirement increase up to the lesser of 10 percent or the amount required to achieve a 95 percent R/C ratio.

The excess revenue that results from these increases is then applied to those classes that have R/C ratios above 105 percent. Each of these classes would receive the same percentage rate reduction unless doing so would result in a R/C ratio below 105 percent. FortisBC also states that: "If, in any year, a customer class achieves a R/C ratio within the range of reasonableness, no further adjustments would be made in subsequent years if the ratio again fell outside of the range" (Exhibit B-1, p. 47).

In its Application, FortisBC provides an example of the rate increases resulting from the rate rebalancing assuming a five percent general rate increase (Exhibit B-1, p. 48). FortisBC also includes a forecast of the resulting R/C ratios over the five year period (Exhibit B-1, p. 49). FortisBC notes that, at the end of the five year period, four classes remain outside of the range of reasonableness of 95 to 105 percent, but that this situation cannot be remedied without exceeding the 10 percent cap.

With regards to the exclusion of the BC Hydro increases from the cap, FortisBC states that the BC Hydro rate increases are not known at the time that FortisBC set its own rates (Exhibit B-3-2, BCOAPO p. 17; Exhibit B-7, BCOAPO p. 12; FortisBC Argument, p. 65). FortisBC also states that "Factoring in potential sources of rate increases beyond revenue requirements lessens the chances that rebalancing will occur in a timely fashion" (FortisBC Argument, p. 66).

FortisBC testified that the weighted impact to its own rates of BC Hydro's rate increases can be estimated by using a factor of 0.2. Therefore, a 10 percent BC Hydro rate increase would result in about a two percent increase to the rates charged to FortisBC's customers (T2:152).

FortisBC states that it received a high degree of support from feedback received through its consultations with customers, with a majority of responses indicating support for rebalancing in general. As well, most participants of the Super Group consultations agreed that a five percent cap applied to the rebalancing related increases is reasonable (Exhibit B-1, pp. 31-32).

4.1.3 Positions of Parties on Implementing Rate Rebalancing

BCMEU supports the FortisBC rebalancing proposal. However, it expresses concerns about committing to a five year plan without re-evaluating changing circumstances. The BCMEU "urges that no more than two annual rebalancing occur without requiring FBC to submit an updated rate base" (BCMEU Argument, p. 30).

FortisBC interprets the BCMEU reference to an "updated rate base" as being a new COSA and responds that it intends to file a new COSA in three to five years as part of its adoption of time-based rates. FortisBC states that having customers incur the cost of another COSA process after two years "seems excessive" (FortisBC Reply, p. 50).

BCOAPO also supports FortisBC's proposal to cap rate increases to 10 percent. It goes on to state that the impact of the flow through of BC Hydro costs will be that the actual rate increases will likely be significantly higher for FortisBC customers who are currently underpaying according to the COSA (BCOAPO Reply, p. 2).

The Rate 30 Group generally supports the FortisBC proposal to rebalance customer rates but expresses concern regarding the five year time before the rates of its customers are brought to within the range of reasonableness. The Rate 30 Group states that the five year time frame is too long; that its members will continue to over-contribute during the five year period; and that there is "no good reason based in fairness to delay adjusting the rates to the 'fair' level" (Rate 30 Group Argument, p. 1).

In addition, the Rate 30 Group would like to ensure that the full rate decrease projected for its members' rate class is actually implemented, stating that the five-year rebalancing period runs the risk that the proposed adjustments will be adjusted again before the full reduction is achieved (Rate 30 Group Argument, p. 1).

Big White states that FortisBC's Application using the target 95-105 percent range of reasonableness approach does not produce just and reasonable rates for Big White. However, by rebalancing to a target of unity, the resulting rates almost uniformly fall into the range of reasonableness (BWSR Argument, para. 15). As evidence of the difference that rebalancing to unity makes in the R/C ratios of all customer classes, Big White references Cases E and F of Exhibit B35-2 that FortisBC provided in response to undertakings arising from the oral hearing. Big White also notes, however, that the Year 5 R/C ratio of the general service class is 123.2 percent in Case E and 118.2 percent in Case F, both of which are outside the range of reasonableness proposed by FortisBC.

Big White goes on to note that the Year 5 results under the Cases E and F, but with the target of the rebalancing set to unity rather than the end points of the range, results in a "vast improvement in those classes that, under FortisBC's approach, remain far outside of results that sound ratemaking would consider as just and reasonable" (Exhibit B-37, BWSR 3.2.2; BWSR Argument, para. 14).

Finally, Big White asks that, if the Commission Panel does not accept a rate rebalancing approach that targets unity, the Commission Panel should consider instructing FortisBC to "design a deferral mechanism that resolves in a reasonable time the overpayment by general service customers, without causing the rate of rebalancing to be too swift for other classes to manage" (BWSR Argument, para. 23).

FortisBC, in reply, states that implementing such a deferral mechanism is problematic; that it would take 26 years to rebalance all rate classes; and that there would be approximately $5.2 million (or a net present value of $2.0 million) of carrying costs associated with the deferral that would have to be collected from customers as part of the annual revenue requirement (FortisBC Reply, para. 110; Exhibit B-7, BWSR 2.4.2.4).

IRG supports the inclusion of a cap to the annual rate increases resulting from the rebalancing proposal, but submits that the 10 percent annual cap as applied to Celgar is unreasonable. IRG cites Mr. Saleba's testimony that confirmed that if a 10 percent annual cap is applied to Celgar, then it will take over 20 years before Celgar's revenue to cost ratio falls within the proposed range of reasonableness, while most other classes would complete their rebalancing adjustments within five years (T3:484–85; IRG Argument, p. 12).

Commission Determination

The Commission Panel notes BCMEU and BCOAPO's comments concerning the relative accuracy of FortisBC's load data as compared to BC Hydro's but also notes that neither party presented empirical evidence justifying their position that the range of reasonableness should be increased to 90 to 110 percent. The Commission Panel accepts FortisBC's assessment that there is no indication of systematic bias in the COSA. The Commission Panel also accepts FortisBC's position that the range of reasonableness is based not only on the accuracy of its data, but also on policy considerations such as the Commission's prior decision regarding the range of reasonableness for

BC Hydro.

In addition the Commission Panel considers that the load profiles of FortisBC and BC Hydro's Southern Interior delivery area are sufficiently comparable to give a degree of confidence in FortisBC's use of the latter's load research data.

Accordingly, the Commission Panel finds that the range of reasonableness of 95 percent to 105 percent is the correct range for the purpose of future rebalancing in the circumstances of FortisBC. **FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved.**

The Commission Panel recognizes that FortisBC's rate rebalancing approach that limits rate changes due to rebalancing to five percent per year is a compromise intended to accommodate the opposing positions of those customers whose R/C ratios are above the range of reasonableness, and those whose ratios are below it.

The Commission Panel is further persuaded by Big White's argument that targeting unity in the rate rebalancing, rather than the end points of the range of reasonableness, will result in a more equitable distribution of revenue to cost ratios amongst customer classes at the end of five years.

Accordingly, the Commission Panel finds that the appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.

The Commission Panel has considered the requests of Big White for the introduction of a deferral mechanism to manage the rebalancing process, and the reply of FortisBC in this regard. The Commission Panel agrees with FortisBC that such a mechanism would indeed be problematic and would result in additional cost to all ratepayers which the Commission Panel does not consider warranted.

FortisBC is directed to adjust its rates with the goal of achieving revenue-to-cost ratios of one for each class. Rate increases due to rebalancing alone are capped at five percent annually, with a 10 percent cap on increases resulting from rebalancing and revenue requirement increases combined, exclusive of increases to BC Hydro rates flowed through to FortisBC customers. The 10 percent cap does not apply to increases due solely to revenue requirements. Rebalancing will be determined on the basis of the updated COSA.

4.2 Rebalancing of Irrigation Rates

FortisBC testified that its typical customers in the Irrigation rate class are irrigation districts, wineries, golf courses, and farms, but that it had not undertaken an analysis of its Irrigation customers by those categories (T5:801). In fact, when asked how many of its customer were farmers, FortisBC testified that "we don't, other than the count of irrigation customers, which are not all going to be farmers…We don't have a good way to estimate that number, I'm afraid." (T5:799).

Furthermore, FortisBC does not have a comprehensive assessment of the various components of the members of the irrigation rate class, including their load profiles. For example, when contemplating various customer studies for time-based rates, FortisBC testified "None of the studies we have referenced thus for…have studied anything but residential and commercial customers, they would have been studied, but not specifically for the irrigation season: (T3:465). Similarly, when examined on growth in air-conditioning load since 1997, FortisBC was unable to determine if irrigation load contributed to the growth in the period:

> "MR. WIESBERG: Q: Can you agree with me though that substantial growth in the irrigation load is not a change over that period?
>
> MR. SALEBA: A: I don't know one way or the other." (T3:468)

In Section 2 the Commission Panel addressed the concerns of the IRG with respect to its perceived incorrect application of the COSA methodology to it, and the apparent related intra- or inter-class rate discrimination. The Commission Panel also addressed the IRG's claim that it is uniquely self balancing across three different rate classes and, therefore, the proposed rebalancing for irrigation customers is not necessary. While the Commission Panel has not accepted the IRG arguments in this regard, it has concluded that there is no basis for the load factors used by FortisBC in rate setting and has directed that FortisBC rerun the COSA using different load factors impacting irrigation customers. This will likely have implications on rate rebalancing for the IRG.

4.2.1 Intervener Perspectives

BCOAPO is sensitive to the concerns of small farmers trying to cope with difficult economic times. Nonetheless, BCOAPO does not believe that the Irrigation customer class should avoid paying their fair share of the costs of electric service provision (BCOAPO Argument, para. 68).

Mr. Gabana sympathizes with IRG's requests for relief. However, like BCOAPO, he believes that Irrigation customers should pay their fair share of costs; anything less is a subsidy from other FortisBC ratepayers. He believes that any economic support to agriculture should come from the province.

No other Interveners expressed support for excluding Irrigation customers from rate rebalancing or commented upon IRG's position.

Commission Determination

In Section 2.0 the Commission Panel made a number of determinations concerning the Irrigation class, which should result in a more reasonable assessment of the costs associated with providing service to the Irrigation class.

The Commission Panel is concerned that FortisBC has not performed an analysis of the composition of its Irrigation rate class and that FortisBC does not appear to have consulted effectively with its Irrigation customers.

FortisBC is directed to determine the nature of its Irrigation customers, to identify which of them are irrigation or drainage, and to ascertain their eligibility for service under RS 60 and RS 61.

The Commission Panel further directs FortisBC to consult with its bona fide Irrigation customers to determine the conditions it should attach to RS 60 and RS 61. Finally, the Commission Panel directs FortisBC to undertake load research to establish the load characteristics of the Irrigation class.

Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class and reflect these in its COSA, the Commission Panel determines that the Irrigation class should be exempt from rate rebalancing, and subject only to base adjustments associated with FortisBC revenue requirements and BC Hydro flow-through.

In making this determination, the Commission Panel has placed no weight on the IRG arguments related to economic hardships of agricultural customers and agrees with other Interveners that submit that the Irrigation customers should pay their fair share of costs.

5.0 TERMS AND CONDITIONS

In this Section the Commission Panel addresses issues associated with the Terms and Conditions contained in FortisBC's Electric Tariff. These govern the relationship between the company and its customers, including the provisions under which the customer receives service from the company. Issues addressed in this Section include security deposits, system extension charges, and the equal payment plan.

5.1 Security Deposits

The Application includes proposed changes to provisions of the Terms and Conditions related to security deposit requirements contained in Section 2.3 of the Terms and Conditions.

5.1.1 Current Status of Security Deposits

FortisBC states that security deposits are intended to protect ratepayers and FortisBC shareholders from the risk of write offs associated with customers failing to pay outstanding charges for service. Currently the company requires residential customers with pre-existing addresses to pay a deposit based on three months estimated consumption with a $100 minimum, and a $200 minimum for customers with no or insufficient billing history. This security deposit may be waived if the customer can provide an adequate credit report, or credit reference from another energy utility.

FortisBC states that with effect from April 1, 2007 its policy requires a security deposit from customers with a demand over 200 kVA. This policy was not applied retroactively and applies only to new customers. Prior to that time security deposits from such customers were only required at the company's discretion. These customers are typically industrial. FortisBC views that such customers represent a larger risk to the company relative to other customer classes on the basis that their outstanding balances represent larger amounts. This policy is not documented or written (Exhibit B3-5, p. 1).

FortisBC acknowledges that it has not applied this policy consistently. Indeed, since implementing this policy six of sixteen such new customers were not charged security deposits (Exhibit B-3, Interfor 1.1(e) (ii)).

FortisBC states that as of October 14, 2008 there were 139 accounts with demands in excess of 200 kVA that had not been required to pay any security deposit (Exhibit B-3, Interfor 1.2(a)), including four customers with demands that ranged from 17 to 60 MVA (Exhibit B-7, Interfor 2.2(a)).

5.1.2 Proposed Changes to Section 2.3 of the Terms and Conditions

The Application proposes amendments to Section 2.3 of the Terms and Conditions that would make security deposits mandatory for customers with demand in excess of 200 kVA and returning such deposits only when the account is discontinued and paid in full. There would be no changes to the basis upon which security deposits are calculated. FortisBC testified that such security deposits are calculated on the basis of estimated monthly charges for three months, plus a six month minimum charge (T4:611).

Interest is payable on the security deposit as outlined in the Terms and Conditions (Exhibit B -1, Appendix H, p. 30).

5.1.3 Interfor Intervention

Interfor seeks relief from the Commission to disallow the amendments proposed by FortisBC to the Terms and Conditions and further that:

> “(i) Interfor not be required to pay any security deposit in order to continue to obtain electric service for its sawmill premises at Grand Forks and Castlegar provided it continues to be financially sound and has a good credit history;
>
> (ii) FortisBC return the security deposits that FortisBC required to be provided by Interfor to date; and

(iii) FortisBC cease requiring security deposits which are discriminatory or provide preferential treatment to customers; or

In the alternative, Interfor asks that the Commission amend Section 2.3 of FortisBC's Terms and Conditions to provide that:

(i) security deposits not be required in circumstances where a customer is financially sound and has a good credit history;

(ii) the requirement for security deposits not be applied in a discriminatory or preferential manner; and

(iii) where security deposits are required, they are returned to the customer after 12 months of prompt and full payment of its invoices, with interest, where applicable."

Interfor became a new customer of FortisBC when it acquired mills in Castlegar and Grand Forks in 2008, which had previously been operated by Pope & Talbot before its bankruptcy. Interfor's demand is in excess of 200 kVA. It is currently required to have a security deposit of $438,654 provided by an irrevocable letter of credit with an annual cost to Interfor of $19,739. Interfor's security deposit amount is 15 times greater than the next largest security deposit ($25,835).

Interfor maintains that it does not pose a credit risk to FortisBC and its ratepayers and that FortisBC's requirement for the security deposit from Interfor is prejudicial, discriminatory, and inconsistent with the *UCA.* It submits that mandatory security deposits are only justified where there are identified credit issues with a customer (Interfor Argument, p. 5).

Interfor submits that sections 39 and 59 of the *UCA* preclude undue discrimination of customers in service provision and in rates. Further, it submits that FortisBC's requirement for Interfor's security deposit is discriminatory because FortisBC's policy has been applied inconsistently and in a preferential manner. It submits that:

- the security deposit policy does not apply to FortisBC's largest customers;

- the policy does not apply to all new customers;
- the policy is not applied consistently to all new customers;
- existing customers are allowed to bypass security deposit requirements when increasing demand above the 200 kVA threshold; and
- existing customers with proven financial problems pay a fraction of the deposit required from new customers.

(Interfor Argument, pp. 10-16)

It indicates that:

- Interfor's demand is substantially less than many customers who are not required to provide security deposits;
- six of sixteen new customers were not required to pay a security deposit as required by FortisBC's policy;
- not all deposits paid by new customers were calculated based on the formula set out in the tariff;
- several customers with demand increasing to over 200 kVA escaped the requirement for security deposits; and
- many customers who have encountered financial difficulty and missed payments have negotiated favourable security deposit requirements in relation to what is required from new customers.

Interfor submits that FortisBC provides its competitors service without the requirement for a mandatory security deposit, thereby placing it at a disadvantage (Interfor Argument, p. 18).

It also suggests that the high default rate among Residential Class customers poses a greater risk of financial loss than the risk associated with large customers because of FortisBC's approach and procedures related to account monitoring and management. Indeed, FortisBC concurred that residential customers represented the highest amount of write-offs (T4:662).

In reply to FortisBC's argument that the large loss it incurred with a write-off associated with the bankruptcy of Pope & Talbot demonstrates the need for its security deposit policy, Interfor submits that this loss took place even after the FortisBC security deposit policy was in place, and that the security deposit paid by Pope &Talbot was considerably less than what it would have been if calculated in a manner consistent with its policy (T4:653-58). Interfor further submits that the Pope &Talbot loss could have been mitigated by "proper credit management, including reviewing its customers' credit worthiness on a regular basis, monitoring payment histories, reviewing publicly available financial statements, reliance on its contractual terms, attending industry credit meetings, etc." (Interfor Argument, p. 22).

Finally, Interfor submits that FortisBC's security deposit policy is inconsistent with other major electrical utility service providers in Western Canada who do not require security deposits from their customers where those customers have good credit, and where security deposits are required there are provisions to return them on evidence of prompt payment over a period of time (Exhibit C8-4, p. 5). It provides the security deposit policies of BC Hydro, SaskPower, and EPCOR as evidence (Exhibit C8-4 Appendices P, Q, and R).

5.1.4 Positions of Other Interveners

BCOAPO, IRG, and Mr. Wait all argue for supporting the amendments proposed by FortisBC's security deposit policy, citing concerns of potential losses similar to those suffered with the Pope & Talbot bankruptcy. None of these Interveners, however, addressed the issues of inconsistent treatment of different customers, nor provided evidence that FortisBC's proposed approach would adequately protect ratepayers without active monitoring of credit worthiness of different customers.

BCOAPO did identify that active credit monitoring and management would require additional and dedicated resources, but did not provide evidence to this effect (BCOAPO Argument, p. 13).

Commission Determination

The Commission Panel is not persuaded that the proposed FortisBC policy amendments will adequately protect ratepayers against write offs associated with delinquent customer accounts. **Furthermore, the Commission Panel finds that the proposed policy and existing security deposit practices are discriminatory and unfair. The Commission Panel directs FortisBC to develop a new policy that demonstrates the management of credit risk through ongoing active monitoring of credit worthiness and credit risk associated with all classes of customer, rather than be based solely on the size of the customer.** Credit risk can be monitored by individual account or class of account, but there should be consistent treatment based on assessed credit worthiness. The Commission Panel considers that such a program would help identify risky accounts at an early stage to minimize the risk of events similar to those with Pope &Talbot.

Further, the Commission Panel directs that the application of such policy be done so as not to discriminate against individual or specific accounts. The level of security deposit should be tied to the assessed level of risk of a customer based on its credit worthiness. The size of an account could be one of many factors taken into account in determining the security deposit requirements, but the demonstrated level of risk based on active monitoring should be the foundation for extending credit. The policy would be applied uniformly against all accounts.

Furthermore, in those instances where security deposits are required, they should be returned to those customers after twelve consecutive months of prompt and full payment of its invoices. The Commission Panel considers that holding deposits when credit worthiness has been consistently demonstrated is unjust, unreasonable, and inconsistent with section 59 of the *Act*. Since Interfor has demonstrated such a payment history and FortisBC has not demonstrated that Interfor's financial position currently represents a credit risk, the Commission Panel directs FortisBC to return the security deposit in respect to Interfor forthwith.

The Commission Panel accepts Interfor's view that "all customers would share the costs of monitoring credit" and that there are credit risks associated with all classes of customer. An active program of credit management benefits all customers and the costs, therefore, should be borne by all.

Security deposits are one (passive) means of protecting ratepayers against risks associated with write-offs. Active credit monitoring is another. The Commission Panel believes that both are needed and that they should be applied in a consistent manner across all customers and customer groups.

5.2 System Extension Charges

5.2.1 System Extensions-Proposal

FortisBC proposes a revised RS 74 – Extensions, which specifies the respective contributions for utilities and customers for distribution system extensions. The revision is intended to make the schedule easier to apply and understand. It uses a new methodology for calculating the utility contribution towards the construction which is intended to better reflect current costs and the impacts of customer additions.

5.2.2 System Extensions - Background

FortisBC states that its proposed RS 74 specifies a capital credit or allowance for each customer class. The capital credit or allowance is based on the investment in distribution poles, conductors, and transformers for each rate class covered in the applicable retail rate. A new customer is required to pay for the additional investment in poles, conductors, and transformers required for the new service, less FortisBC's capital contribution, as set out in the following table:

Table 5-1
Extension Credits

Rate Schedule	Maximum FortisBC Contribution
RS 1, 2A,	$1,765
RS 20, 21	$158 per kW
RS 50 (Type I, Type II)	$19.43 per fixture
RS 60, 61	$1,390

Source: Exhibit B-1, p. 76

The objective is for the charges paid by a new customer to hold harmless all existing customers, allowing for growth on the distribution system without subsidy from existing accounts. The charge to the new customer is the actual cost of new poles, conductors, and transformers needed to provide service, less any capital allowance or credit. The allowance is based on costs allocations to the existing customers (Exhibit B-1, pp. 76-77). The distribution system extension charges are intended to be equitable to all customers within a rate class, and across rate classes (T3:426).

FortisBC used the 2009 COSA to calculate the line extension credit for each customer class. The relevant rate-base amounts for distribution were summed for each rate class, minus the associated accumulated depreciation and contributions in aid of construction to provide the net distribution investment by class. This net amount was divided by either the number of customers in the class or the non-coincident kW for the class to determine the appropriate level of credit (Exhibit B-1, p. 77).

The line extension credit applies only to distribution facilities. Transmission expenditures will be paid for through rates, except in the case of Large General Service and Industrial Applicants as provided for in RS 74, Special Contracts (Exhibit B-3-2, BCOAPO 1.21.3).

5.2.3 Positions of Parties

No Intervener commented on FortisBC's proposed amendments to RS 74.

Commission Determination

The Commission Panel considers that FortisBC has calculated its system extension test in a manner that is comparable to the other utilities in BC and approves in principle FortisBC's proposed RS 74. However, as the proposed amendments to RS 74 rely upon output from the COSA, the contributions set out in RS 74 may need to be modified to be consistent with the final version of the COSA resulting from directives in this Decision.

5.3 Equal Payment Plan

5.3.1 Proposed Changes

FortisBC proposes changes to Section 11.5 of its Tariff Terms and Conditions regarding the Equal Payment Plan (Exhibit B-1, p. 18). For clarity and ease of administration the modifications are intended to allow reconciliation of the Equal Payment Plan on the anniversary date of the plan, clarification of customer obligations to establish satisfactory credit arrangements with the company, and permission for the company to modify or cancel the Plan at any time (Exhibit B-1, p. 85).

5.3.2 Positions of Parties

No Intervener commented on the proposed changes regarding the Equal Payment Plan.

Commission Determination

The Commission Panel supports FortisBC's proposals to clarify language and simplify administration of the Equal Payment Plan and accepts the proposed changes, and directs FortisBC to insert the following clause into the Terms and Conditions related to the Equal Payment Plan:

“If a customer on an Equal Payment Plan credit balance closes the account, the Company will refund the amount regardless of the size of the balance. If the customer has not terminated their account, and the credit balance is small, it will be carried forward.”

6.0 CELGAR'S GENERATION BASELINE

In this Section the Commission Panel considers Celgar's request that it establish a GBL between it and FortisBC. The Commission Panel will first determine whether Celgar's evidence might be relevant to the RDA, and once it has determined that it might be relevant it will proceed to address the three issues in the following order:

1. will increased power purchases from FortisBC increase Celgar's R/C Ratio and thus benefit all FortisBC's customers (See Section 6.3);
2. does Commission Order G-48-09 render Celgar's request invalid (See Section 6.4); and
3. is Celgar's assertion that it is entitled to have its full mill load served by FortisBC at embedded rates justified (See Section 6.5)?

6.1 What Celgar's Request Really Means

This is not a typical topic for a RDA and the Commission Panel will first set out the full import of Celgar's request.

BC Hydro cites Celgar's testimony: "from our perspective, the obligation to serve self-generation customers is one of the central issues in this proceeding" and describes what it considers to be the issue as follows:

> "Although Zellstoff Celgar seeks determination of a "FortisBC GBL", its issue is really about the extent of FortisBC's obligation to serve the Mill load at embedded cost of service rates at times when Zellstoff Celgar is using its existing self- generating capability for sales into available markets. Therefore, it is probably more accurate to describe what Zellstoff Celgar seeks as a BCUC determination that FortisBC has the obligation to serve all but 13,474 MWh and 1.5 MW of the Mill load at average embedded cost rates notwithstanding the fact that FortisBC has historically served a much smaller portion of the Mill load because Zellstoff Celgar has served the Mill load from self-generation. If the BCUC were to make such a determination, Zellstoff Celgar would then be able to sell all of its generation output in excess of 13,474 MWh and 1.5 aMW into available markets for market prices, and replace approximately 40 MW of electricity required to serve the Mill load with purchases

from FortisBC at low, embedded cost rates" (BC Hydro Argument, pp. 13-14).

It is important to note that FortisBC was not a protagonist in this portion of the proceeding. In negotiating with Celgar in 2008 it had in effect assented to Celgar's position and appeared quite content to sell Celgar the power it requested so long as its access to power from BC Hydro under RS 3808 was not affected (T3:318 et passim). The main protagonists on this issue are BC Hydro and Celgar.

6.2 Context

The background to Celgar's request is described in Appendix A to this Decision, as well as the regulatory process the Commission went through to determine whether Celgar's requested relief was within the scope of the 2009 RDA proceeding.

In Order G-35-10 the Commission stated:

> "At this stage in the proceedings, the Commission Panel is prepared to accept, without finally deciding the issue that the determination of a GBL between Celgar and FortisBC may have an impact on the latter's COSA and the revenue-to-cost ratios that may flow from it and also may have an impact on the tariffs or the terms and conditions of FortisBC, all of which fall clearly within the scope of the RDA" and
>
> "The Commission Panel will therefore allow Celgar to file evidence concerning the establishment of a GBL with FortisBC, for this evidence to be tested by a round of Information Requests from all parties to the proceeding and through cross-examination and for all parties to make submissions concerning it. As part of its Decision on the RDA, the Commission Panel will determine whether Celgar's evidence is, in fact, ultimately relevant to the RDA, and, if appropriate, may make determinations in respect of a GBL between Celgar and FortisBC."

6.2.1 Celgar's Position

Celgar summarizes its four reasons why it feels it is appropriate for the Commission to establish a GBL between it and FortisBC:

- doing so would be consistent with the direction of the Commission in Order G-38-01, the principles of which have been expressly extended to FortisBC customers by Order G-48-09;
- doing so would be the only approach that is consistent with, and follows, that taken by BC Hydro in relation to its self-generation customers;
- doing so would be in the best interests of other FortisBC ratepayers as increased power purchases from FortisBC would increase Zellstoff Celgar's R/C Ratio; and
- Zellstoff Celgar will not arbitrage between embedded-cost utility service and market prices and the conditions associated with the establishment of a FortisBC GBL will ensure that Zellstoff Celgar is not able to do so.

(Exhibit C13-7, p. 5)

Celgar seeks the Commission Panel's determination of its requested GBL with respect to the sale and purchase of power from FortisBC (the FortisBC GBL). Celgar submits that the Commission Panel should accept Celgar's election of a FortisBC GBL having an annual energy component of 13,474 MWh and an average capacity component of 1.5 MW. Celgar's reasons are that only it, and not the Commission, can relieve FortisBC of the obligation to serve and that the establishment of a FortisBC GBL by Celgar determines that portion of its load that FortisBC is not obligated to serve. Celgar submits that, in addition, the establishment of a FortisBC GBL is in the public interest and consistent with the legislative policy direction of the *CEA*. Finally, Celgar submits that a FortisBC GBL will address concerns of inter-class subsidization and is therefore in the interests of other customers (Celgar Argument, para. 16).

In its Argument, Celgar submitted that:

> "These numbers tell the story. Absent an appropriate GBL, Celgar is, and shall continue to be, forced by regulation into an untenable and, in the long-term, unsustainable, position - one where it is the only pulp mill in the Province forced to accept an abysmal load factor and long-term upward pressure on its electricity rates. It will remain a drag on other Rate classes." (Celgar Argument, para. 116)

In the Oral Phase of Argument the Commission Panel sought submissions on the question: In what respect is Celgar's GBL evidence relevant to the RDA proceeding?

Celgar submitted that it was indeed its R/C ratio that made the GBL relevant and submitted "If this RDA proceeds on the assumption that Celgar will start from an R/C ratio of 23.5 percent rather than 127 percent, the difference is significant. If the RDA goes ahead at a 23.5 percent revenue-to-cost ratio and Celgar is subsequently awarded a GBL by FortisBC, or pursues further proceedings to enforce the obligation to serve and is successful, the RDA will subsequently be skewed to the detriment of all ratepayers" (T7:1212).

6.2.2 Positions of Parties on the Relevance of Celgar's Evidence

BC Hydro takes no position on the relevance. Both BCMEU and BCOAPO reiterate the position they took on Celgar's original submission. BCMEU reminds the Commission of the risks of loss of access to RS 3808 and of increased costs to other ratepayers that the establishment of an inappropriate GBL creates (T7:1239-40), and BCOAPO favours the issue being addressed at a "separate generic GBL proceeding" (T7:1241).

FortisBC submits that the nature and magnitude of the impact that the GBL evidence would have on this proceeding depends on three Commission determinations:

- the level of the GBL;
- the extent to which FortisBC can use RS 3808 power to supply Celgar when Celgar is selling electricity; and
- who pays for the costs of non RS 3808 power that FortisBC must use?

(T7:1243 et seq.)

Commission Determination

The Commission rejects the submissions of those parties who suggested that this is not the forum for a determination on Celgar's GBL, that some of the necessary parties may not "be at the table" or that the whole issue should be the subject of a generic hearing. The Commission Panel considers that adequate notice was given, that BC Hydro did take part in the proceeding (although it did not file evidence), and that a generic hearing for what is the only pulp mill in BC without a GBL would be unlikely to materialize.

The Commission Panel considers that of Celgar's original four reasons, and its fifth reason, namely that it would enable FortisBC to comply with the legislated intent of the *Clean Energy Act*, which came into law after the oral hearing had finished, the third reason (that increased power purchases from FortisBC would increase Celgar's R/C Ratio and thus benefit all FortisBC's customers) could be relevant to the RDA and it will therefore proceed to determine whether a GBL between Celgar and FortisBC would be in the public interest.

6.3 Will increased power purchases from FortisBC increase Celgar's R/C Ratio and thus benefit all FortisBC's customers?

FortisBC files Exhibit B-35 which sets out the R/C ratios of its customer classes under different scenarios, the relevant of which are Cases C and F. In these two cases FortisBC assumed that that a 1.5 MVA GBL had been established and that FortisBC was supplying almost the entire mill load of 41.5 MVA at embedded rates, having purchased the bulk of the energy required from BC Hydro under RS 3808 (assuming continued access to RS 3808 power at embedded cost rates) up to its 200 MW limit and having gone to the open market for the balance.

FortisBC states that these assumptions resulted in $12.2 million of additional power supply costs being incurred to meet the increased load for Celgar, made up of $8.9 million in additional energy purchases from BC Hydro under RS 3808, $2.1 million in additional spot market purchases, a reduction in surplus revenues of $0.8 million and an increase in Balance Pool charges of $0.4 million. The amount was recovered from Celgar ($9.2 million), and from FortisBC's remaining customers ($3.0 million) (Exhibit B-37, BCUC 4.5.1).

By assigning an additional $9.2 million to Celgar, Case C and F showed a R/C ratio for RS 33 of 127.8 percent and 124.0 percent.

Commission Determination

Elsewhere in this Decision the Commission Panel has found that Celgar is not eligible to take service on RS 33 and has directed FortisBC to re-run the COSA on the basis that Celgar took service during the test year on RS 31. Notwithstanding, the Commission Panel considers that it must still test Celgar's assertion that increasing Celgar's R/C ratio would benefit FortisBC's remaining customers.

It is clear from FortisBC's calculations that the rest of its customers would be charged an extra $3.1 million under the scenario set out in Case C and F, and thus cannot be said to have received a benefit. It is also clear that BC Hydro's ratepayers would most likely have been disadvantaged by BC Hydro having to supply FortisBC with $8.9 million of power at embedded rates.

It is also clear to the Commission Panel that the only way FortisBC's customers could benefit is by FortisBC being able to sell the extra energy to Celgar at a price that exceeded FortisBC's opportunity value of the extra energy. That is certainly not the case in this instance. Furthermore, the Commission Panel considers that if such a benefit can be created, it can only come at the expense of BC Hydro's ratepayers. This brings the Commission Panel to consider the second issue.

6.4 Does Commission Order G-48-09 render Celgar's request invalid?

In this Section, the Commission Panel addresses the issue of arbitrage. In the decision attached to Order G-48-09, the Commission had quoted BC Hydro's definition of arbitrage as "the simultaneous purchase and sale of the same securities, commodities or foreign exchange in different markets to profit from unequal prices." It also quoted Celgar, which had considered that arbitrage means the simultaneous purchase and sale of the same item, with a view to taking advantage of different prices in different markets" (G-48-09 Decision, pp. 8-9).

Celgar submits that it will not arbitrage between embedded-cost utility service and market prices and that the conditions associated with the establishment of a FortisBC GBL will ensure that it is not able to do so (T7:1319).

6.4.1 Background

On September 16, 2008, BC Hydro applied to the Commission pursuant to subsections 58(1) and (2) of the *UCA* for approval to amend its Power Purchase Agreement with FortisBC Inc. to clarify that electricity purchased by FortisBC under the RS 3808 cannot be sold to a FortisBC customer with self-generation who wished to displace its self-generation with utility service for the purpose of selling its self-generation to market. BC Hydro stated that if it is required to provide incremental energy to FortisBC at embedded cost based rates for the purpose of supporting the export activities of FortisBC's customers, BC Hydro and its ratepayers would incur an annual estimated loss of $16.7 million, an amount based on BC Hydro's assertion that provision of the incremental energy to FortisBC would require it to either purchase the energy from the market at a price "that is almost certainly greater than the sale price to FortisBC" or to "use its own generation and lose the opportunity to sell that energy in the market or store it for later use" (G-48-09 Decision, p. 2).

Following a written process, the Commission issued Order G-48-09 and reasons for decision for BC Hydro's PPA Amendment Application. The Commission ordered the amendment of section 2.1 of the BC Hydro PPA to read as follows:

> "(a) The electricity purchased under this agreement is solely for the purpose of supplementing FortisBC's resources to enable it to meet its service area load requirements and, shall not be exported or stored, provided that nothing contained herein shall prohibit FortisBC from storing its entitlement resources in its entitlement account pursuant to the Canal Plant Agreement; and
>
> (b) shall not be sold to any FortisBC customer when such customer is selling generated electricity which is not in excess of load.

> For greater certainty, paragraph (b) above is to prevent FortisBC self-generating customers from purchasing power at regulated embedded cost rates and simultaneously selling an equivalent amount of power into available domestic and export markets" (G-48-09 Decision, p. 31).

In the Decision, the Commission clarified what constitutes "excess self-generated electricity" as set out in Order G-38-01, Section 1:

> "In the end, the Commission Panel has decided that there must be a simple definition of what constitutes "excess power" and we define that term to mean power "net of load on a dynamic basis." The Commission Panel determines that any self-generators, as owners of the generation facilities, should have the flexibility to reduce domestic load as they see fit in the commercial circumstances at hand in order to optimize the export of self-generated power. What will not be permitted is the supply of embedded cost power to service the domestic load, at any time when the self-generator is selling power into the market" (G-48-09 Decision, p. 29).

Under the terms of its PPA with BC Hydro, FortisBC purchases power from BC Hydro under a contract for up to 200 MW of power, with prices set under RS 3808, currently $5.313 per kW-month plus 3.114 cents per kWh (Exhibit B-1, p. 23). The power purchased by FortisBC from BC Hydro under RS 3808 provides approximately 27 percent of FortisBC's capacity requirements, and 24 percent of its energy (Exhibit B-3-1, BCUC 1.7.1, p. 85).

6.4.2 Positions of the Parties

FortisBC states that it has analysed the issue and has concluded that, if a GBL incorporated into an energy purchase agreement were set lower than Celgar's mill load, with the result that FortisBC sells power to Celgar to serve a portion of its load while Celgar in turn sells power from its self-generation into the market, then such a GBL may have an adverse effect on FortisBC's rights and obligations under the terms of its PPA with BC Hydro (FortisBC Argument, para. 49).

BC Hydro states that paragraph 2.1(b) of its amended PPA with FortisBC makes it clear that FortisBC shall not sell electricity purchased under the agreement to any FortisBC customer who is selling its self-generation that is not in excess of its own load requirements (BC Hydro Argument, pp. 10-11). BC Hydro goes on to state that, if the Commission were to decide to grant Celgar's request of a FortisBC GBL that is less than the mill load, and to the extent that FortisBC's resource requirements increase as a result, FortisBC could not use RS 3808 power, accessed under the terms of the BC Hydro PPA, to meet the increase. The BC Hydro PPA would not be amended as requested by Celgar (BC Hydro Argument, p. 26).

Celgar agrees that it is reasonable that FortisBC has concerns about its access to RS 3808 power (T5:993). Celgar accepts that there will be financial consequences to BC Hydro if BC Hydro "loses the benefit of Celgar's investment in cogeneration" and supplies at embedded cost power to its customers, which include FortisBC, that it could otherwise sell power on the open market (Celgar Reply, para. 51).

Celgar also submits that BC Hydro's customers will benefit from Celgar's investment in cogeneration if BC Hydro's arguments in this proceeding prevail, in that Celgar will be "required to displace its load requirements with its cogeneration in perpetuity. Such displacement will result in BC Hydro's customers receiving the benefits of Celgar's investment, without paying for it" (Celgar Reply, para. 9).

Celgar submits that, in the G-48-09 proceeding, the most relevant issue before the Commission was whether or not FortisBC was a customer of BC Hydro (Celgar Reply, para. 37). In the PPA Amendment Decision, the Commission concluded that:

> "In the Commission's view, B.C. Hydro has an ongoing obligation to serve [FortisBC]. This relationship is, however, best characterized as a hybrid in which [FortisBC] is to be treated partly as a customer of B.C. Hydro and partly as an independent utility" (G-48-09 Decision, pp. 25-26).

Celgar submits that In Order G-48-09, BC Hydro's obligation to serve FortisBC was established at the current capacity of the RS 3808 contract of 200 MW. Therefore, BC Hydro has an obligation to serve FortisBC just as it must serve any other customer (Celgar Reply, para. 38).

Celgar also submits that its request in this proceeding should not be denied even if the Commission Panel concludes that FortisBC will not be able to purchase from BC Hydro while Celgar is selling its self-generation power (Celgar Argument, para. 125).

Celgar states that the result of the PPA Amendment Decision and Order G-48-09 is to proscribe purchases of power from FortisBC by customers who are at the same time selling power from their own generation. Celgar submits that such an interpretation of Order G-48-09 relieves FortisBC from its obligation to serve the full load of Celgar without consent of Celgar to that relief. Those types of proscriptions are not permitted by law, nor are they consistent with the policy direction established by the CEA (Celgar Argument, para. 73).

Celgar also submits that the "net of load on a dynamic basis" approach embedded in the PPA Amendment Decision is inappropriate and inconsistent with the *CEA*. A decision of the Commission Panel that would relieve FortisBC of the obligation to serve Celgar, when Celgar sells power, requires the Commission to oversee power sales by Celgar from its cogeneration. Celgar submits that oversight role would be inconsistent with the legislative direction established by the *CEA*. Under the *CEA*, allowing or disallowing the sale of power by self-generators in most cases is now beyond the jurisdiction of the Commission (Celgar Argument, para. 74).

BC Hydro replies that the *CEA* does not affect the Commission's discretion in relation to the matters raised by the Celgar GBL Application. BC Hydro submits that Celgar made its arguments in the proceeding to review the PPA Amendment Application and, in BC Hydro's view, nothing material has changed since Order G-48-09 was issued. There are therefore no grounds for reconsideration (BC Hydro Reply, p. 8).

Celgar goes on to state that, if the Commission Panel does accept Celgar's submissions regarding the obligation to serve, then in Celgar's opinion, the Commission Panel must revise Section 2.1 of the BC Hydro PPA (Celgar Argument, para. 123).

Celgar proposes a revision to Section 2.1 of the BC Hydro PPA as follows:

> *"(b) shall not be sold to any FortisBC customer that is self-supplying its load requirement that has been designated to be served by FortisBC"* (Celgar Argument, para. 77).

Referring to the two phase process for the reconsideration of decisions established by the Commission, Celgar submits that the usual process should not be followed in this case for two reasons:

> "(i) the merits and justice of this case require a variance of the Decision; and
>
> (ii) the Decision is incorrect as a matter of law."

Celgar submits that, if the Commission Panel concludes that it would be inappropriate to vary Order G-48-09 at this time, then the Commission Panel could direct a reconsideration of the Decision, effectively moving the matter to Phase II of the reconsideration process (Celgar Argument, para. 125).

BC Hydro submits that Celgar should bring an application for reconsideration of Order G-48-09 as a separate matter rather than in final argument of this proceeding (BC Hydro Reply, p. 8).

Commission Determination

The Commission Panel has considered the submissions on the issue of RS 3808 and Order G-48-09. The Commission Panel is of the view that the Commission's determination at page 31 of Order G-48-09 is clear, and sets out to prevent exactly what Celgar is proposing to do.

Accordingly, the Commission Panel considers that defining what is precisely meant by "arbitrage" is irrelevant. It is clear from Exhibits B-35 and B-37 that the effect of Celgar's proposal that it be allowed to purchase the full mill load at embedded rates from FortisBC will require FortisBC to purchase an additional $8.9 million of power from BC Hydro under RS 3808 at embedded (heritage) rates.

While FortisBC might be indifferent financially to this proposal, it is clear that BC Hydro and its ratepayers would not be indifferent as it would oblige BC Hydro to pay incremental prices for the power or lose export opportunities. The Commission Panel considers that this would not be in the public interest.

The Commission Panel considers that what Celgar proposes is expressly prohibited by Order G-48-09 and that, as long as the Order is in full force and effect, and as long as the PPA between FortisBC and BC Hydro is in effect, FortisBC will be unable to buy any power from BC Hydro under RS 3808 for sale to Celgar when Celgar is exporting power from the mill.

6.5 Is Celgar's assertion that it is entitled to have its full mill load served by FortisBC at embedded rates justified?

The Commission Panel considers that since the PPA between BC Hydro and FortisBC has a termination date, the Commission Panel should address the third issue, namely Celgar's assertion that it is entitled to have its full mill load served by FortisBC at embedded rates.

Accordingly, this section reviews the Arguments of Celgar and BC Hydro regarding a utility's obligation to provide service to any customer that requests it. The issue for the Commission Panel to decide upon is the extent of the obligation to serve: whether it extends solely to providing a connection to a customer, irrespective of the rate charged that customer; or whether the obligation also prescribes the rate that the utility is allowed to charge for the service. In short, whether the obligation to serve extends to providing service at embedded cost rates without regard for any other considerations, such as the impact on existing customers.

Celgar states that one of the central issues in this proceeding is FortisBC's obligation to serve Celgar:

> "While Zellstoff Celgar has invested in electricity generation, in our view a customer with self-generation is just as much a customer as any other customer. Why is customer status important? Well, it's important because FortisBC has an obligation to serve its customers at average embedded costs. From our perspective, the obligation to serve self-generation customers is one of the central issues in this proceeding." (T5:853)

In Argument, Celgar requests that the Commission Panel "ensure that FortisBC fulfills its obligation to serve the full load requirements of Celgar" (Celgar Argument, para. 30). This obligation is a matter of law and therefore the only evidence required to support Celgar's submission is that FortisBC is a public utility within the meaning of the *Act*, and that the mill is in the service territory of FortisBC (Celgar Argument, para. 122). Celgar goes on to state that the Commission Panel cannot relieve FortisBC from the obligation to serve, but that Celgar may choose to relieve the utility from the obligation to serve all or part of its load through the election of a GBL (T5:931-33; Celgar Argument, para. 40).

Celgar's original position is that the GBL should be established at 1.5 MW, based on the average annual output of the mill's original generator, installed in 1961 and decommissioned in 1993, between the years 1991-1992. Celgar's position during the proceeding moved towards a GBL of zero MW, based on its assertion that FortisBC had an obligation to supply its entire mill load at embedded costs.

Celgar derives its position from the following sources:

- the *Utilities Commission Ac*t;
- the Supreme Court of Canada in *ATCO*;
- the *Clean Energy Act*;
- Commission Order G-38-01; and
- FortisBC's Access Principles Agreement approved by the Commission in Order G-27-99.

6.5.1 The *Utilities Commission Act*

In Argument, Celgar refers to sections 38 and 39 of the *Act* as providing an explicit statutory obligation on public utilities in BC to serve their customers:

> **38** A public utility must
>
> a) provide, and
>
> b) maintain its property and equipment in a condition to enable it to provide, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.
>
> **39** On reasonable notice, a public utility must provide suitable service without undue discrimination or undue delay to all persons who:
>
> a) apply for service,
>
> b) are reasonably entitled to it, and
>
> c) pay or agree to pay the rates established for that service under this *Act*.

Celgar interprets section 38 as that a public utility is obligated to provide adequate service as meaning that the utility provides enough electricity to meet all of its customers' needs, and states that the obligation to serve, as set out in sections 38 and 39 of the *UCA*, is limited only by the availability of the utility's infrastructure, which is set out in section 28 of the *UCA*:

> **28**(1) On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.
>
> (Celgar Argument, para. 31-31)

BC Hydro submits that the obligation to serve is not absolute and that section 28(3) of the *Act* provides for the Commission to relieve a utility from the obligation to serve a customer's load as follows:

> **28**(3) After a hearing and for proper cause, the commission may relieve a public utility from the obligation to supply service under this Act on terms the commission considers proper and in the public interest.
>
> (BC Hydro Argument, p. 15)

FortisBC agrees with BC Hydro's interpretation of section 28(3) of the *Act* (FortisBC Reply, para. 80).

Celgar replies that section 28(3) has no application in the determination of FortisBC's obligation to serve. Celgar submits that section 28(3) deals only with a utility's duty to interconnect to a customer and the establishing of a service connection. The Commission may rely upon section 28(3) only to relieve a utility from the obligation to provide service based on factors such as the customer's proximity to the utility's infrastructure (Celgar Reply, para. 42).

In the Oral Phase of Argument Celgar submits that section 39 follows section 28, and that one of the statutory interpretation techniques when one is looking at whether a provision is meant to qualify another is it seems unusual to put the qualifying provision ahead of the provision that it qualifies.

Celgar also points out that section 28.3 really seems to speak in language of a show-cause hearing. The utility should show cause why the service should not be provided, and submits that that has not been the case in the RDA (T7:1220).

6.5.2 The Supreme Court of Canada in *ATCO Gas* & *Pipelines Ltd.* v. *Alberta (Energy & Utilities Board)*

Celgar submits that a public utility's obligation to serve has its origins in common law principles, forming part of what it terms "the regulatory compact" and notes that the regulatory compact was recently considered by the Supreme Court of Canada in *ATCO Gas* & *Pipelines Ltd.* v. *Alberta (Energy & Utilities Board),* [2006]1 S.C.R. 140, 2006 SCC 4 (*ATCO*).

Celgar considers *ATCO* to be a seminal case on the regulatory compact and provides jurisprudence that is relevant to the issues to be considered by the Commission in this proceeding, and submits that, in *ATCO*, the Supreme Court of Canada clarified the law as it relates to the "economic and social arrangement" between a utility (FortisBC) and its customers (Celgar), albeit, on a different aspect of the "regulatory compact" than is before the Commission in this proceeding.

Nevertheless, Celgar cites *ATCO* and submits that the decision makes it clear that the law requires that *“utilities assume a duty to adequately and reliably serve all customers”* and that “*all customers have access to the utility at a fair price***.”** Just as *ATCO* makes it clear that the law requires that shareholders receive the entire proceeds from the sale of assets used to serve customers, Celgar submits that “the law ensures that the economic benefits of the obligation to serve accrue to all customers” (Celgar Argument, para. 33-36).

The Supreme Court of Canada addressed the issue of the regulatory compact in its decision where it stated at para. 135:

> “The Board referred in its decision to the 'regulatory compact' which is a loose expression suggesting that in exchange for a statutory monopoly and receipt of revenue on a cost plus basis, the utility accepts limitations on its rate of return and its freedom to do as it wishes with property whose cost is reflected in its rate base.”

No party addresses *ATCO* in reply.

6.5.3 *Clean Energy Act*

Celgar submits that, on a policy level, the *CEA* is relevant to the issue of a utility’s obligation to serve. Celgar states that its investment in cogeneration is consistent with the direction set by the *CEA*. A decision by the Commission Panel to relieve FortisBC from serving the full load requirements of the mill, and thereby reduce the economic benefits to Celgar of its investment, would be inconsistent with one of the British Columbia energy objectives as set out in the *CEA*, that being “to use and foster the development of innovative technologies that support energy conservation and efficiency and to maximize the value of resources (*CEA* Sections 2(d) and 2(m))" (Celgar Argument, paras. 49, 54, 56).

BC Hydro submits that none of the sections of the *CEA* cited by Celgar affect the Commission's discretion to relieve a public utility from the obligation to provide service to a customer with existing self-generating capability if the customer chooses to divert the self-generation from its historical mill load-serving use, to a market-sales use (BC Hydro Reply, p. 6).

BC Hydro further submits that the *Act*, as amended by the *CEA*, prescribes the matters for which the Commission must consider the British Columbia energy objectives and that none of these sections are relevant to the issue of the obligation to serve (BC Hydro Reply, p. 7).

6.5.4 Order G-38-01

Celgar submits that in Order G-38-01 the Commission did not prohibit sales of self-generation while purchasing power from a utility and did not qualify the obligation to serve (Celgar Argument, para. 66). The order required BC Hydro to attempt to agree on a customer baseline, based either on the historical energy consumption of the customer or the historical output of the customer's own generation. Where the parties cannot agree on an appropriate baseline, the order called for an affidavit from the self-generation customer that it will "not adjust its consumption of electricity under Rate Schedule 1821 to take advantage of market sales from its self-generation." Celgar submits that, because the order requires either that a baseline be established with the consent of the customer, or a commitment from the customer that it will not adjust its consumption to take advantage of market conditions, Order G-38-01 does not qualify the obligation of BC Hydro to serve its customers (Celgar Argument, para. 66, 71). Celgar submits that, in this case, the customer, Howe Sound Pulp and Paper Ltd., relieved BC Hydro of the obligation to serve (Celgar Argument, para. 63).

Celgar submits that Order G-38-01 and the PPA Amendment Decision cannot be reconciled with the law relating to the obligation to serve. The practical result of the Order is to prohibit purchases of power from FortisBC by Celgar to serve its mill load at times when Celgar is simultaneously selling power from its own generation. Such a result relieves FortisBC from its obligation to serve to the extent requested by Celgar and is therefore inconsistent with the statutory obligation to serve (Celgar Argument, para. 72-73).

FortisBC submits that it "cannot have an obligation to serve Celgar in a manner that would contravene Order G-48-09" (FortisBC Reply, para. 80). FortisBC goes on to point out that the definition of "the full load requirements of Celgar" that Fortis BC is obligated to serve (which Celgar states at para. 30 of its Argument) is unclear. FortisBC submits that the appropriate load to be served by FortisBC is what is "manifested at the meter, as is the case for other customers. Any regulatory obligation to provide service should not be in excess of what the customer needs" (FortisBC Reply, para. 80).

6.5.5 Access Principles Application

Celgar states that the obligation to serve was central to the Access Principles Application (APA) filed by FortisBC's predecessor, West Kootenay Power Ltd. (WKPL) and accepted by the Commission in Order G-27-99 (Celgar Argument, para. 45). Celgar paraphrases portions of the APA to illustrate that the principle of the obligation to serve has been recognized in the APA:

> "the purpose of the APA is to ensure that [open access to the transmission system] results in the Fair Treatment ... of customers who remain with Utility supply and of Eligible Customers who choose to obtain some or all supply from non-Utility resources."
>
> "'Fair Treatment' of 'Eligible Customers' is defined to mean that the maintenance of [FortisBC's] obligation to serve continues for an Eligible Customer as long as the Eligible Customer elects to receive embedded cost service from [FortisBC] for all or part of its load."

> "[FortisBC] retains the obligation to serve every customer until that customer elects to leave the embedded cost power services of [FortisBC]",
>
> "[FortisBC] also retains the obligation to serve at embedded cost rates any new load entering its service territory, any additional load attributable to its existing customers and returning Eligible Customers ..."
>
> "[FortisBC] will enter into good faith negotiations with any Eligible Customer desiring to enter into a new contract at embedded cost rates."
>
> (Order G-27-99, Appendix A, pp. 1-2)

The entire APA is attached as Appendix B to this Decision.

Celgar states that it considers a GBL with FortisBC to be an election by it, as provided for in the APA, to reduce the obligation to serve to that portion of the load requirement that exceeds the FortisBC GBL, and that the APA would provide Celgar an election to return to embedded cost rates for its entire load requirement (Exhibit C13-11, FortisBC 1.3.1).

Included in the APA principles are re-entry provisions that state:

> "An Eligible Customer that has previously taken bundled service may, at any time, return to power service from West Kootenay Power at a rate calculated to ensure Fair Treatment." (Order G-27-99, Appendix A, p. 4)

While the "Fair Treatment" provision as related to customers remaining with the utility states that:

> "For customers who remain with Utility supply, the exit, partial exit or re-entry of Eligible Customers must, at a minimum, make them no worse off than if Eligible Customers had always remained with the Utility." (Order G-27-99, Appendix A, p. 1)

At the Oral Phase of Argument, the Commission Panel sought further submissions on this part of Celgar's Argument on the following:

a. Order G-27-99 and its relevance in 2010 to this Application; and

b. Celgar's relationship with its electricity suppliers and whether the Commission Panel can be informed by any other decisions the Commission may have made concerning Celgar (and its previous operating entities) and Cominco/WKPL etc.

Under matter (b) the Commission Panel also sought submissions on how Order G-39-99, dated April 15, 1999, might inform the Commission Panel on FortisBC's obligation to provide service to the pulp mill, given the fact that the application to which the Order relates was filed with the Commission on the day after the Commission issued Order G-27-99 (Exhibits A-29 and A-30).

Celgar submits that the APA remains in effect and is as relevant in 2010 as it was in 1997, and that it applies no less to an eligible customer with the option of self-generating as it would to one with the option of taking service from a third-party supplier (T7:1276).

Celgar submits that, while the 1999 service agreement may indicate that Celgar relieved FortisBC of its obligation to serve all but 16MVA at embedded rates, the APA still gave eligible customers the right of return to service at embedded rates, and it submits that it gave FortisBC notice of the exercise of that right when negotiating its 2008 service agreement (T7:1285).

On the timing of the issue of G-27-99 and FortisBC's filing of the service agreement with Celgar, Celgar has no submission to offer.

BC Hydro submits that the APA set out principles to be applied in situations where West Kootenay Power customers wished to purchase electricity from the market, and was not designed to address the principles to be applied when a self-generating customer wished to sell electricity to the market (T7:1291).

FortisBC submits Order G-27-99, is not relevant to the RDA, and the facts are different than were being considered when the APA was before the Commission.

FortisBC agrees with BC Hydro that the APA was directed toward the ability of customers to access to import power from other suppliers, not the ability of self-generating customers to export power and find a market elsewhere.

FortisBC submits that Order G-27-99 does not address such issues as i) whether an obligation to serve might be affected by self-generation by a customer, ii) the sources of power that FortisBC would have to access in serving that customer, iii) the cost of that supply, or iv) the arbitrage concerns that have been raised by BC Hydro, since G-27-99 predated Orders G-38-01 and G-48-09 (T7:1302-04).

6.6 Other Relief sought by Celgar

Celgar also asks the Commission Panel to order that section 7.4(b) of the BC Hydro EPA in its present form shall have no force or effect, and submits that a direction from the Commission Panel regarding section 7.4(b) will result in a more efficient regulatory process, at least from Celgar's perspective, than if no order is granted at this time. However, if the Commission Panel decides to not give the direction that Celgar is seeking, then Celgar will seek the Section 7.4(b) direction in a future proceeding, if necessary. Celgar submits that it is important that the Commission Panel give direction to FortisBC to enter into a service agreement with Celgar with the GBL requested in this proceeding.

BC Hydro replies that the Commission does not have the power to make such an order because it has already determined that the Zellstoff Celgar EPA is in the public interest and has already accepted it pursuant to section 71 of the *UCA.* Unlike a "rate" under the *UCA*, the Commission does not have on-going jurisdiction to order an amendment to, or otherwise change an energy supply contract, after it has accepted the contract.

BC Hydro states that if the Commission upholds Celgar's GBL application, then BC Hydro will fulfill its commitment to amend the EPA by replacing paragraph 7.4(b) with the "alternate 7.4(b)" in accordance with the EPA Side Letter. The amended EPA would be filed with the Commission pursuant to section 71 of the *UCA.* The filing of the amended contract would once again engage the BCUC's jurisdiction under section 71 of the *UCA*.

Commission Determination

The Commission Panel agrees with Celgar that section 28 of the *UCA* does not necessarily relieve a utility of the obligation to provide service that Celgar finds in sections 38 and 39 of the *UCA*, as was suggested by BC Hydro and others. The Commission Panel agrees that an interpretation of a piece of legislation does not look to a section that precedes a second section to qualify the latter section.

By the same token, the Commission Panel does not find an unconditional obligation on a utility to provide service to all persons <u>at embedded costs</u>. It is clear to the Commission Panel that FortisBC is a public utility and that Celgar is in FortisBC's service area. It is also clear that since 1980 FortisBC has provided adequate, safe, and efficient service to the Celgar mill at just and reasonable rates. The Commission Panel considers that section 39(i) of the *UCA* gives the Commission the power to establish rates for service to FortisBC's customers, and that sections 60-61 give the Commission the power to set rates that may not necessarily be based on embedded costs.

Celgar looks to the Supreme Court of Canada in *ATCO* to find a reference to the "regulatory compact." The Commission Panel does not consider *ATCO* to be germane to the RDA as it contemplated proceeds from the disposal of a utility asset, rather than the obligation to serve at embedded cost. The Commission Panel notes that the Supreme Court describes "regulatory compact" as a loose expression. The Commission Panel considers that such a "loose expression" can only give directional guidance as to the need to balance the rights of the utility and of its customers as a group, rather than of a single customer.

The Commission Panel has considered Celgar's submissions that the *Clean Energy Act* is relevant to the issue of a utility's obligation to serve in that its objectives include "to use and foster the development of innovative technologies that support energy conservation and efficiency and to maximize the value of resources". In the Commission Panel's view a piece of legislation enacted in

2010 cannot be relevant to a decision taken in 1992 to install a new steam turbine to meet the needs of the modernized and enlarged pulp mill. Accordingly, the Commission Panel rejects Celgar's submissions in this regard.

The Commission Panel considers that the APA of 1999 might provide Celgar with its most compelling argument concerning its right to purchase its full mill load from FortisBC at embedded rates.

The Commission Panel has considered the submissions of FortisBC and BC Hydro in respect to the APA, that since the APA dealt with the ability of Eligible Customers to access power from other sources rather than the ability of self-generating customers to export power, the APA is therefore irrelevant to these proceedings.

Nevertheless, the Commission Panel considers that the APA remains in effect and that some of the principles established in the APA and found by the Commission to be in the public interest in 1997 might be relevant to these proceedings.

The Commission Panel considers that hypothetically, an eligible customer that had chosen in 1997 to receive service from a third party and was now looking to "come back into the fold" and take service from FortisBC in 2010, would be entitled to receive service at embedded cost, but this must address the Fair Treatment principles to minimize the harm to existing ratepayers.

Similarly, Celgar's mill might be considered in 1997 to have made the decision to take some of its service from FortisBC and to self-generate the rest. The Commission Panel finds it informative that immediately after the issue of G-27-99, FortisBC and the mill filed an agreement that had the mill taking service on the basis of 16 MVA firm service with the balance of its needs being met by FortisBC on a reasonable efforts basis from the open market.

On the basis of its historical agreements with FortisBC the Commission Panel considers it possible that Celgar may have established a right to 16 MVA of service from FortisBC at embedded rates.

Should it wish to establish any higher obligation from FortisBC, the Fair Treatment principles will have to be addressed, which will presumably require negotiation between the two parties, followed by confirmation from the Commission after some form of public process.

The Commission Panel considers that its Order G-48-09 was issued in response to concerns raised by BC Hydro as to the possibility that heritage hydro was being sold to FortisBC customers with self-generation facilities to enable the latter to sell the output of their own generation facilities.

That being said, the Commission Panel notes that the PPA between the two utilities has a termination date and there may come a time when Order G-48-09 no longer has any relevance. Therefore, the Commission Panel declines to establish a GBL between FortisBC and Celgar. The parties are at liberty to establish their own GBL and, should they desire, to incorporate it into a general service agreement and submit it to the Commission for approval. The Commission Panel also notes that counsel for BC Hydro's announced at the Oral Phase of Argument that BC Hydro proposes to engage in Stakeholder consultation around the establishment of GBLs, which may inform Celgar and FortisBC as to the mechanics of establishing a GBL.

For these reasons, the Commission Panel declines to set a GBL between Celgar and FortisBC in this proceeding.

Should FortisBC propose to provide Celgar with some or all of the mill load from non-RS 3808 sources, the parties remain at liberty to negotiate terms and conditions and submit them to the Commission for approval.

The Commission Panel has considered Celgar's submission that the establishment of a GBL between it and FortisBC "would be the only approach that is consistent with, and follows, that taken by BC Hydro in relation to its self-generation customers."

In the Commission Panel's view, which was shared by all parties (including Celgar) to the proceeding, the issue of equity between pulp mills in BC falls outside the Commission's jurisdiction.

The Commission Panel will not address the issue further.

Finally for the reasons stated above the Commission Panel need make no finding with regard to Celgar’s request that it determine that section 7.4(b) of the BC Hydro EPA in its present form shall have no force or effect.

7.0 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.	The Commission Panel agrees with each of BCMEU's arguments in favour of a single class and determines that the Wholesale customers (other than Nelson which will remain its separate class) can be considered to be a single class for COSA purposes. The Commission Panel directs FortisBC to re-run the COSA on this basis.	18
2.	So far as RS 33 is concerned it is clear to the Commission Panel that Celgar's load factor cannot be described as satisfactory as required by FortisBC's tariff. Accordingly the Commission Panel determines that Celgar is ineligible to take service under RS 33 and directs FortisBC to re-run the COSA using the assumption that Celgar was taking service during the test year on RS 31.	18
3.	The Commission Panel accepts FortisBC's load data for COSA purposes, other than for its Irrigation customers as discussed below.	20
4.	The Commission Panel accepts the use of actual coincident peak demands for COSA purposes, and directs FortisBC to re-run the COSA, using actual coincident peak demands for all customers rather than contract demands (or demand limits).	31
5.	The Commission Panel accepts FortisBC's use of the 2CP method for allocating the demand portion of production costs as well as for allocating transmission costs.	37
6.	The Commission Panel considers that there is no basis for using different load factors in different months during the irrigation season, and that a single load factor should be applied. As for load factors in the non-irrigation season, the Commission Panel considers that the RS 20 load factors should be used in those months. Accordingly, the Commission Panel directs FortisBC to re-run the COSA using the following assumptions: • a 70 percent load factor for the irrigation season (being the load factor for June, July and August) and the Small General Service load factor for the remaining months; and • the Small General Service group and system coincidence factors of 75 percent and 70 percent respectively for all 12 months.	41

7.	The Commission Panel accepts FortisBC's proposed classification of distribution system costs related to poles, conductors and transformers based on the minimum system method.	44
8.	The Commission Panel also accepts that the PLCC adjustment compensates for changes in the minimum size and shifts the costs associated with the increased capacity of the minimum system to those customers having a higher than the average 1kW demand on the system. The Commission Panel therefore finds the use of the PLCC adjustment to the results of the minimum system method an appropriate refinement to the 1992 minimum system study.	44
9.	The Commission Panel finds that increasing the Basic Charge would be unacceptable, especially in view of the requirement for providing appropriate pricing signals for conservation and energy efficiency.	56
10.	The Commission Panel directs FortisBC to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and to file an RIB rate application with the Commission no later than March 31, 2011.	57
11.	The Commission Panel directs FortisBC to initiate consultations with its industrial customers with a goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro. FortisBC's action plan for this matter is to be included in the compliance filing.	65
12.	The Commission Panel approves FortisBC's proposed restructuring of the RS 20 and RS 21 energy rates.	65
13.	The Commission Panel directs FortisBC to return to its previously used parameters for the purpose of setting the Wires Charge for RS 31 and RS 33.	66
14.	On the basis of the pro-forma contracts provided by FortisBC, the Commission Panel sees no reason for the differentiation between RS 31 and RS 33 and directs that RS 33 should also be revised so as to be billed on the basis of Contract Demand as opposed to contract Demand Limit.	66
15.	FortisBC is directed to reconsider the concepts underpinning RS 33 that were approved by the Commission in Order G-15-98 and resubmit it in accordance with those principles. FortisBC is also directed in its compliance filing to set out how the wires charge components of its other TOU rates were determined.	66
16.	The Commission Panel directs FortisBC to set the billing determinants for the Wholesale Customers to be consistent with those to be set for the Large General Service Transmission Customers.	67

17.	The Commission Panel finds that under the current circumstances Celgar is ineligible to take service under RS 33 and directs FortisBC to provide Celgar service under RS 31 effective January 2, 2011.	67
18.	FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved.	78
19.	The Commission Panel finds that the appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside of the range of reasonableness.	78
20.	FortisBC is directed to adjust its rates with the goal of achieving revenue-to-cost ratios of one for each class. Rate increases due to rebalancing alone are capped at five percent annually, with a 10 percent cap on increases resulting from rebalancing and revenue requirement increases combined, exclusive of increases to BC Hydro rates flowed through to FortisBC customers. The 10 percent cap does not apply to increases due solely to revenue requirements.	79
21.	FortisBC is directed to determine the nature of its Irrigation customers, to identify which of them are irrigation or drainage, and to ascertain their eligibility for service under RS 60 and RS 61.	81
22.	The Commission Panel further directs FortisBC to consult with its bona fide Irrigation customers to determine the conditions it should attach to RS 60 and RS 61. Finally, the Commission Panel directs FortisBC to undertake load research to establish the load characteristics of the Irrigation class.	81
23.	Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class and reflect these in its COSA, the Commission Panel determines that the Irrigation class should be exempt from rate rebalancing, and subject only to base adjustments associated with FortisBC revenue requirements and BC Hydro flow-through.	81
24.	The Commission Panel finds that the proposed policy and existing security deposit practices are discriminatory and unfair. The Commission Panel directs FortisBC to develop a new policy that demonstrates the management of credit risk through ongoing active monitoring of credit worthiness and credit risk associated with all classes of customer, rather than be based solely on the size of the customer.	87
25.	The Commission Panel directs that the application of such policy be done so as not to discriminate against individual or specific accounts.	87

26.	In those instances where security deposits are required, they should be returned to those customers after twelve consecutive months of prompt and full payment of its invoices. The Commission Panel considers that holding deposits when credit worthiness has been consistently demonstrated is unjust, unreasonable, and inconsistent with section 59 of the *Act*. Since Interfor has demonstrated such a payment history and FortisBC has not demonstrated that Interfor's financial position currently represents a credit risk, the Commission Panel directs FortisBC to return the security deposit in respect to Interfor forthwith.	87
27.	The Commission Panel considers that FortisBC has calculated its system extension test in a manner that is comparable to the other utilities in BC and approves in principle FortisBC's proposed RS 74.	90
28.	The Commission Panel supports FortisBC's proposals to clarify language and simplify administration of the Equal Payment Plan and accepts the proposed changes, and directs FortisBC to insert the following clause into the Terms and Conditions related to the Equal Payment Plan: "If a customer on an Equal Payment Plan credit balance closes the account, the Company will refund the amount regardless of the size of the balance. If the customer has not terminated their account, and the credit balance is small, it will be carried forward."	91
29.	The Commission Panel declines to set a GBL between Celgar and FortisBC in this proceeding.	115

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of October 2010.

Original signed by:

A.J. (TONY) PULLMAN
PANEL CHAIR

Original signed by:

LIISA A. O'HARA
COMMISSIONER

Original signed by:

MICHAEL R. HARLE
COMMISSIONER

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

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-156-10

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 a 2009 Rate Design and Cost of Service Analysis

BEFORE: A.J. Pullman, Panel Chair/Commissioner
L.A. O'Hara, Commissioner
M.R. Harle, Commission

October 19, 2010

O R D E R

WHEREAS:

A. On October 30, 2009, pursuant to sections 58 and 61 of the *Utilities Commission Act* (the Act), FortisBC Inc. (FortisBC) filed its 2009 Rate Design and Cost of Service Analysis Application (Application) for approval by the British Columbia Utilities Commission (Commission);

B. On November 26, 2009, the Commission issued Order G-139-09 establishing an initial Regulatory Timetable for the proceeding to review the Application;

C. On December 15, 2009, a Procedural Conference was held in the City of Kelowna;

D. On December 21, 2009, the Commission issued Order G-166-09, amending the initial Regulatory Timetable. Order G-166-09 established that an Oral Public Hearing would be held in the City of Kelowna, commencing Monday, May 3, 2010;

E. By letter dated February 15, 2010, Zellstoff-Celgar Limited partnership (Celgar) applied for Commission determinations that establishing a Generation Baseline (GBL) for Celgar's Castlegar pulp mill would be appropriate within the scope of the rate design proceeding, and for procedural directions to accommodate addressing the GBL (the Celgar Application);

F. By letter dated February 18, 2010, the Commission invited FortisBC and registered Interveners to make written submissions on the Celgar Application. Responses supporting the Celgar Application were received from British Columbia Old Age Pensioners' organization *et al*. (BCOAPO), Mr. Andy Shadrack, and Mr. Alan Wait; submissions opposing the Celgar application were received from British Columbia Municipal Electric Utilities (BCMEU) and FortisBC. British Columbia Hydro and Power Authority (BC Hydro) took no position concerning the appropriateness and determination of a GBL between FortisBC and Celgar within the scope of the proceeding. However, BC Hydro submitted that the existing generation baseline specified in the Energy Purchase Agreement (EPA) between itself and Celgar and the Power Purchase Agreement between FortisBC and BC Hydro, as amended, should be outside the scope of the proceeding. In Reply, Celgar agreed with BC Hydro's position on excluding those two matters from the scope of the proceeding;

G. On March 3, 2010, the Commission issued Order G-35-10, with Reasons for Decision, with respect to the Celgar Application. The Regulatory Timetable was amended to permit Celgar to file evidence on establishing a GBL with FortisBC (the GBL Evidence), and to allow for a round of Information Requests (IRs) on the GBL Evidence. Celgar was directed to make a witness panel available for cross-examination on the GBL Evidence at the oral hearing. The contractual generation baseline established in the EPA between BC Hydro and Celgar was ruled outside the scope of this proceeding. The Commission would determine whether the GBL Evidence was ultimately relevant to the proceeding as part of the Rate Design Decision, and, if appropriate, determine a GBL between Celgar and FortisBC;

H. By letter dated March 22, 2010, FortisBC applied to the Commission (the Reply Application) for approval to file Reply Evidence to address certain matters raised in Intervener Evidence filed on March 15, 2010. FortisBC claimed that the Reply Evidence would minimize the new matters likely to arise during the oral hearing. By letter dated March 24, 2010, BCMEU filed an objection, requesting that, should the Reply Application be approved, parties would have a right to file IRs on the Reply Evidence. By letter dated March 26, 2010, the Commission invited other Interveners to comment on the Reply Application;

I. On April 12, 2010, after considering the Reply Application, submissions from BCMEU and other Interveners and a FortisBC reply, the Commission granted the Reply Application subject to the right of Interveners to make submissions on the admissibility of the Reply Evidence. Order G-69-10 was issued amending the Revised Regulatory Timetable to allow FortisBC to file Reply Evidence by Thursday, April 22, 2010;

J. The oral public hearing was held in the City of Kelowna, commencing Monday, May 3, 2010 and concluding Friday, May 7, 2010. The parties agreed on a preliminary schedule for Final Argument in light of an undertaking by FortisBC to file a revised Cost of Service Analysis (Revised COSA) by May 14, 2010. The Panel gave Interveners until May 21, 2010 to provide written submissions to the Commission on whether the Revised COSA required process beyond the preliminary schedule for Final Argument. The Commission left the evidentiary record open pending receipt of Intervener comments;

…/3

K. On May 14, 2010, FortisBC filed the Revised COSA (Exhibit B-35) containing summary tables showing various scenarios requested by the Commission and Interveners;

L. By May 21, 2010, the Commission had received submissions on further process from six Interveners. Big White, Mr. Shadrack, and BCOAPO supported further process with respect to the revised COSA; all other Interveners submitted that no further process was required. Big White proposed that the Commission assign no weight to the Revised COSA, using the existing evidence and timetable to set rates for FortisBC. As an alternative, Big White requested an extension of the evidentiary phase (possibly reconvening the oral hearing) to allow for a full and comprehensive review for the rates suggested by the Revised COSA;

M. On May 25, 2010, the Commission issued Order G-86-10, with a Supplementary Regulatory Timetable extending the evidentiary phase of the hearing to allow IRs on FortisBC Exhibits B-33 and B-35;

N. By letter dated June 7, 2010, Celgar advised the Commission of its objections concerning certain IRs submitted to FortisBC pursuant to Order G-86-10. Celgar identified the specific IRs it objected to (Contentious IRs), giving reasons for its objections;

O. By Letter L-44-10 the Commission invited FortisBC and Intervener submissions on Celgar's objections to the Contentious IRs. Parties were invited to comment on whether the Contentious IRs were in scope, raised new issues, necessitated further process, and if so, what further process would be necessary. The Commission received comments on Letter L-44-10 from the BCMEU, Big White, and FortisBC;

P. On June 18, 2010, the Commission issued Letter L-51-10 directing FortisBC to respond to all of the Contentious IRs. Letter L-51-10 also amended the Supplementary Regulatory Timetable specified in Order G-86-10;

Q. After considering the submissions received in response to Letter L-44-10 the Commission, by letter dated July 30, 2010, announced that an Oral Phase of Argument would be held in Vancouver on Tuesday, September 7, 2010;

R. The Oral Phase of Argument was held in Vancouver on September 7, 2010; and

S. The Commission Panel has considered the Application, including Celgar GBL proposal, and the submissions of Interveners.

NOW THEREFORE the Commission for the reasons stated in the Decision issued concurrently with this Order orders that:

1. FortisBC comply with all the directives of the Commission in the Decision that are not specifically mentioned below.

2. FortisBC's proposal to use contract demand or demand limits for some customer groups is denied.

3. FortisBC re-run and submit the COSA with all the adjustments described in the Decision within 30 days of this Order.

4. FortisBC submit a final set of rates based on the revised COSA within 60 days of the date of this Order.

5. FortisBC is directed to develop a plan for introducing residential inclining block rates that also incorporate a lower Basic Charge in the immediate future and file an RIB rate application with the Commission no later than March 31, 2011.

6. FortisBC is directed to initiate consultations with its industrial customers with the goal to introduce a stepped rate for transmission service similar to RS 1823 of BC Hydro. FortisBC's action plan for this matter is to be included in the compliance filing within 60 days of the date of this Order.

7. FortisBC is directed to reconsider the concepts underpinning RS 33 that were approved by the Commission in Order G-15-98 and resubmit it in accordance with those principles. FortisBC is also directed in its compliance filing to set out how the wires charge components or its TOU rates were determined within 60 days of the date of this Order.

8. Celgar is ineligible to take service under RS 33. FortisBC is directed to provide Celgar service under RS 31 effective January 2, 2011.

9. FortisBC's proposed range of reasonableness of 95 percent to 105 percent is approved.

10. The appropriate target for revenue-to-cost ratios in each class is unity or one, and that future rebalancing should only be required when a customer class falls outside the range of reasonableness. FortisBC is directed to adjust its rates with the goal of achieving R/C ratios of one for each class.

…/5

11. FortisBC is directed to determine the nature of its Irrigation customers, to identify which of them are irrigation or drainage, and to ascertain their eligibility for service under RS 60 and RS 61. Until FortisBC is better able to demonstrate the load characteristics of the Irrigation class, the Irrigation class is exempt from rate rebalancing and is subject only to base adjustments associated with FortisBC revenue requirements and BC Hydro flow-through.

12. FortisBC is directed to develop a new policy that demonstrates the management of credit risk through ongoing active monitoring of credit worthiness and which is non-discriminatory in nature.

13. FortisBC is to return the security deposit in respect of International Forest Products Ltd. forthwith.

DATED at the City of Vancouver, in the Province of British Columbia, this 19th day of October 2010.

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair/Commissioner

REGULATORY PROCESS

By Order G-115-07 dated September 21, 2007, the Commission directed FortisBC to file a cost of service study by June 30th, 2008 and a Rate Design Application by September 1st 2008.

FortisBC applied on two occasions to extend these deadlines, which the Commission granted by Orders G-147-08 and G-164-08.

FortisBC filed a draft COSA on June 30th, 2009, and by letter dated September 28th, 2009, advised the Commission that it was consulting with BCMEU, and requested an extension to the deadline to file its RDA until the end of October, 2009.

Fortis filed its RDA on October 30th, 2009. By letter dated November 26th, 2009, the Commission issued Order G-139-09, which established a procedural conference, instructed FortisBC to give notice of the conference in local newspapers, and established a provisional timetable to deal with the application.

The Procedural Conference took place on December 15, 2009 in Kelowna. At the Procedural Conference, Commission Staff and FortisBC presented alternative Regulatory Timetables for consideration by the Commission Panel. The Parties present at the Procedural Conference were invited to make submissions on, among other matters, the two alternatives.

FortisBC submitted that the process should comprise a negotiated settlement procedure (NSP) followed by a written process. The NSP would cover any issues parties wished to negotiate, but FortisBC considered that allocation of Contract Demand was an issue which it wished to be addressed in the NSP (T1:7-10).

All eight Interveners except Roxul Inc (which took no position) were generally unsupportive of a NSP, although some acknowledged that such a process could be used for some parts of the Application. BCMEU was in favour of a NSP except on rate rebalancing issues (T1:12).

By Order G-166-09, the Commission Panel determined that, to ensure that the Application was heard in a process that was transparent, efficient and above all fair, an oral hearing process was the appropriate method of hearing the Application and ordered that the Application proceed by way of an Oral Public Hearing commencing on May 3, 2010 at 9:00 a.m. in Kelowna. It also established an amended timetable.

By the deadline for intervener registrations had been received from: British Columbia Municipal Electric Utilities, Big White Ski Resort, Roxul Inc., British Columbia Old Age Pensioners Organization *et al,* Zellstoff Celgar Limited partnership, Okanagan Environmental Industry Alliance, Hedley Improvement District, Town Of Oliver, City of Rossland ,International Forest Products, Town of Osoyoos ,Town of Princeton, Atco Wood Products Ltd, Weyerhaeuser Canada Ltd, Red Mountain Resort, Nelson Hydro, Alan Wait, Andy Shadrack, Norman Gabana, and Buryl Slack.

Keremeos Irrigation District, Fairview Heights Irrigation District and Similkameen Improvement District applied for leave to intervene after the deadline had expired. They were joined by the following: Kaleden Irrigation District, the Water Supply Association of B.C., the Okanagan/Kootenay Cherry Growers' Association, the British Columbia Fruit Growers' Association, the South Interior Stockmen's Association, the Osoyoos Indian Band, and Vincor Canada.

Weyerhaeuser Canada Ltd informed the Commission that it would represent the interests of a Rate Class 30 customers' coalition, the members of which were: Atco Wood Products Ltd., Columbia Brewery, Greenwood Forest Products, Hawkeye Holdings Ltd., JH Huscroft Ltd., Kalesnikoff Lumber Co, Porcupine Wood Products, Springer Creek Forest Products, Weyerhaeuser Canada Ltd., and Wynndel Box & Lumber.

By letter dated February 15, 2010 Zellstoff Celgar requested the Commission to:

1. Issue a decision that the appropriateness, and determination, of a Generation Baseline (GBL) for Celgar's Castlegar pulp mill is within the scope of the Rate Design Application; and

2. Provide procedural directions for establishing the GBL within the hearing Process.

Having sought parties submissions and Celgar's reply thereto the Commission issued Order G-35-10, in which it determined that i) Celgar might file evidence concerning the establishment of a generation baseline with FortisBC (the GBL Evidence), ii) all parties might deliver Information Requests on the GBL Evidence, and iii) Celgar was to respond to the Information Requests and make a witness panel available for cross-examination on the GBL Evidence at the oral hearing.

The Commission also determined that neither the contractual generation baseline established in the EPA between BC Hydro and Celgar nor the PPA, as amended, [between BC Hydro and FortisBC] were within the scope of the RDA proceeding.

The Commission stated that, as part of its Decision on the Application, it would determine whether the GBL Evidence was ultimately relevant to the proceeding and, if appropriate, might make determinations in respect of a GBL between Celgar and FortisBC.

The oral phase of the Hearing took place in Kelowna on May 3-7, 2010. At the conclusion of the oral hearing there remained a number of outstanding undertakings given by Fortis BC in respect of requests from the Commission Panel, BCMEU, Zellstoff Celgar and BCOAPO, which were responded to by FortisBC in Exhibit B-34. In addition FortisBC responded to an Information Request from the Commission Panel in respect of testimony given by IRG's witness panel (Exhibit B-33).

Six interveners made submissions addressing further process: Big White, Mr. Shadrack, BCMEU, IRG, BCOAPO, and Celgar and while Big White, Mr. Shadrack and BCOAPO supported a further process with respect to revised COSA, all other Interveners submitted that no further process was required.

By letter dated May 18, 2010, Big White submitted that the Commission should assign no weight to the evidence provided in the revised COSA, and proceed on the existing evidence and timetable to set rates for FortisBC. In the alternative, Big White requested that the Commission extend the evidentiary phase of the proceeding (possibly reconvening the oral hearing) to allow for a full and comprehensive review of the rates suggested by the revised COSA results (Exhibit C4-4).

By letter dated May 18, 2010, Mr. Shadrack stated that he supported the" basic premise" of the Big White submission. In its submission, dated May 21, 2010, BCOAPO took issue with aspects of Big White's submission, and proposed a further round of information requests rather than the reconvening the oral hearing. BCOAPO also proposed the revision of dates for final submissions to allow for the further information requests and responses.

By letter dated May 21, 2010, IRG submitted that that no further process was required for the revised COSA, but also commented that some of the submitted figures concerning irrigation customers in another exhibit, Exhibit B-33, may be inaccurate.

By Order G-86-10 the Commission extended the evidentiary phase of the hearing to allow one round of information requests on FortisBC Exhibits B-33 and B-35, established the following schedule for Final Argument:

FortisBC	Final Argument	June 30, 2010
Interveners	Final Argument	July 14, 2010
FortisBC	Reply	July 23, 2010
Interveners	Reply to other Interveners	July 23, 2010
FortisBC	Reply on reply	July 27, 2010

(Exhibit A-24)

By letter dated June 7, 2010 concerning some of the IRs submitted to FortisBC with respect to hearing Exhibits B-33 and B-35, Celgar identified specific IRs it objected to (the Contentious IRs), and gave reasons for its objections (Exhibit C13-21).

The Commission in Letter L-44-10 invited FortisBC and Interveners to comment on the letter from Celgar, and specified that the Commission Panel would issue a determination on further process concurrently with its determination on the Contentious IRs.

The Commission received comments from BCMEU, Big White and FortisBC and determined that FortisBC should respond to all of the Contentious IRs by June 23, 2010 (Exhibit A-27).

By letter dated July 30, 2010 the Commission confirmed the Oral Phase of Argument and set it down for September 7, 2010 (Exhibit A-28).

By letters dated August 31, 2010 and September 2, 2010 the Commission advised all parties that it would like to hear submissions concerning the following:

1. Generation Baseline
2. The Obligation to provide service at embedded cost rates
3. Arbitrage
4. Rate Rebalancing
5. Demand Side Management (DSM)
6. Supply Agreement and Curtailment Agreement
7. Waneta Expansion Project

(Exhibits A-29and A-30)

The Oral Phase of Argument took place in Vancouver on September 7, 2007.

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-27-99

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

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 West Kootenay Power Ltd.
for Approval of Access Principles

BEFORE: P. Ostergaard, Chair)
L.R. Barr, Deputy Chair)
K.L. Hall, Commissioner) March 10, 1998
P.G. Bradley, Commissioner)

O R D E R

WHEREAS:

A. On July 31, 1998, West Kootenay Power Ltd. ("WKP") filed an Access Principles Application ("APA") for Commission approval; and

B. On August 13, 1998, the Commission issued Order No. G-73-98 establishing that the APA would proceed through the use of an Negotiated Settlement Process to be held September 23 and 24, 1998; and

C. On September 23 and 24, 1998, the negotiations were held, resulting in a proposal to which there was limited agreement; and

D. By letter dated October 15, 1998, the Commission determined that the public hearing into WKP's Transmission Access Application was to commence with an examination of evidence concerning the Utility's APA; and

E. At the outset of the public hearing on October 19, 1998, several submissions were heard concerning the disposition of the APA, including suggestions that the negotiations be resumed; and

F. On October 21, 1998, the Commission ordered, from the bench, that the APA negotiations be continued on November 3, 1998, in Vancouver; and

G. The negotiations were held as ordered, resulting in a Proposed Settlement Agreement ("PSA"); and

H. Parties to the negotiations were canvassed as to whether they endorsed or dissented from the PSA; and

I. A letter of dissent was received from Columbia Basin Trust; and

J. A letter was received from the British Columbia Hydro and Power Authority ("B.C. Hydro") stating that it did not oppose the PSA provided that it was not seen as setting a precedent for B.C. Hydro; and

K. On November 16, 1998, the PSA was circulated to all Registered Intervenors as well as the Commission Panel. In the cover letter attached to the PSA, parties were canvassed as to the acceptability of the PSA, the desirability of a hearing, and, if held, whether that hearing should be oral or written; and

. . ./2

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-27-99

L. In response to this letter, the Association for the Advancement of Sustainable Energy Policy indicated that the PSA was not acceptable. In addition, certain parties indicated a preference for an oral hearing; and

M. On November 30, 1998, the Commission canvassed Registered Intervenors as to their level of participation if an oral hearing were held; and

N. On December 10, 1998, the Commission reviewed the responses; and

O. On December 14, 1998, the Commission issued Order No. G-113-98 setting down an oral hearing into the PSA to commence February 10, 1999, in Kelowna; and

P. The hearing was held as ordered.

NOW THEREFORE the Commission orders as follows:

1. The PSA with respect to WKP's Access Principles Application is accepted with the notice deadline of March 1, 1999, on page 2 amended to read April 1, 1999 and is attached as Appendix A to this Order. Nothing in the PSA provides a precedent for other utilities or circumstances.

2. WKP is directed to file a report by December 31, 1999, that discusses, at a minimum, the progress made in consultations with interested parties concerning alternative rate structures or arrangements that will foster the development of the most efficient supply sources and encourage conservation measures, the Utility's views on possible amendments to the principles embodied in the PSA, and the merit of using rate design measures to promote a competitive generation market in the WKP supply area.

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of March, 1999.

BY ORDER

Original signed by:

Peter Ostergaard
Chair

Attachment

West Kootenay Power Ltd. Access Principles Application ("APA")
Proposed Settlement Agreement

PURPOSE

Through its Transmission Access Application, West Kootenay Power proposes to open its transmission system to all Eligible Customers. The goal of open access is to encourage the development of a competitive generation market resulting in efficient resource allocation. The purpose of the APA is to ensure that this occurs in a way that results in the Fair Treatment of Utility shareholders, of customers who remain with Utility supply and of Eligible Customers who choose to obtain some or all supply from non-Utility resources.

DEFINITIONS

Commission means:

The British Columbia Utilities Commission.

Eligible Customer means:

Those West Kootenay Power bundled service customers eligible for transmission access as determined by the Commission from time to time.

Embedded Cost of Power means:

West Kootenay Power's cost of generation related transmission assets, generation assets, power purchase contracts, market purchases and other costs of power as determined by the Commission from time to time.

Fair Treatment means:

(i) For shareholders, the opportunity to earn a rate of return on equity does not change as a result of the exit, partial exit or re-entry of Eligible Customers;

(ii) For customers who remain with Utility supply, the exit, partial exit or re-entry of Eligible Customers must, at a minimum, make them no worse off than if Eligible Customers had always remained with the Utility. Any payments, made by Eligible Customers to ensure that those customers who remain with Utility supply are made no worse off, will be allocated by the Utility in such a way that no customer class is made worse off. Each remaining customer class is made no worse off if their rates for bundled service are no higher after an Eligible Customer makes its election. The rates before election are determined by a prospective calculation of the Utility's total net revenue requirement allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time. Similarly, the rates after election are calculated prospectively considering the change in total net revenue requirement due to the change in load, again allocated to customer classes using embedded cost methodologies as accepted by the Commission from time to time;

(iii) For Eligible Customers,

a) the maintenance of West Kootenay Power's obligation to serve continues for an Eligible Customer as long as the Eligible Customer elects to receive embedded cost service from West Kootenay Power for all or part of its load;

b) the right to elect to leave the embedded cost service of West Kootenay Power in whole or in part;
c) the right to return to West Kootenay Power's embedded cost service as set out under the Re-entry Provisions; and
d) notwithstanding the general principle that remaining customers are to be made no worse off by the exit of Eligible Customers, the right to take with them any benefits accruing from their load characteristics (that is, size and load factor), without additional payment or compensation to customers who remain on Utility supply.

OBLIGATION TO SERVE

West Kootenay Power retains the obligation to serve every customer until that customer elects to leave the embedded cost power service of West Kootenay Power. In the event of partial supply customers, West Kootenay Power retains an obligation to serve the portion of a customer's load that remains with the Utility (subject to the provisions set out below under the section entitled Partial Supply). West Kootenay Power retains the obligation to provide transmission and distribution service to all customers within its service territory.

West Kootenay Power also retains the obligation to serve at embedded cost rates any new load entering its service territory, any additional load attributable to its existing customers, and returning Eligible Customers, under the Re-entry Provisions outlined below.

West Kootenay Power will provide short term backup service on a reasonable-efforts basis to Eligible Customers within its service territory for the period required by those Eligible Customers for the unanticipated loss of firm supply. For this service, West Kootenay Power will charge the higher of the market buy price or the cost of the marginal unit in West Kootenay Power's supply portfolio if West Kootenay Power supplies from its portfolio. The price charged will be determined retrospectively and will apply to the full period of service. In addition, West Kootenay Power may charge additional administrative costs reasonably incurred by the Utility to provide this power supply.

It is acknowledged that existing contracts between the Utility and Eligible Customers will not be abrogated. However, it is recognized that West Kootenay Power has a need for notice before the departure of any Eligible Customer and, therefore, it will be desirable if contracts are renegotiated in a timely fashion. In this regard, the City of Kelowna and the City of Nelson will provide notice of intent to leave the Utility or to enter into a new contract for bundled service by April 1, 1999. All other Eligible Customers that have contracts with an expiry date beyond 1999 will provide notice of intent to leave or to enter into a new contract for bundled service at least two years prior to the expiration of their bundled service contracts. Failure to provide such notice of intent to leave will expose these Eligible Customers to any costs imposed on remaining customers, as defined in the Re-entry Provisions below. If after giving notice of intent to stay, the Eligible Customer and West Kootenay Power are unable to conclude a mutually satisfactory contract and one or both parties believes this to be the result of the conduct of the other party, the Commission may be asked to grant protection from any costs implied by other parts of this agreement.

West Kootenay Power will enter into good faith negotiations with any Eligible Customer desiring to enter into a new contract at embedded cost rates. Any new contract will be subject to Commission approval. In any case, West Kootenay Power will include in all new contracts a condition that any Eligible Customer must provide at least two years' notice of early termination, West Kootenay Power will use reasonable efforts to accommodate, in a manner that results in Fair Treatment, a departure such that no stranded cost payment is required.

If such an accommodation cannot be found, Eligible Customers that leave West Kootenay Power during the notice period, taking with them 25% of their prior year's load or less, will pay mitigated stranded costs, if any, for the lesser of the remaining term of the notice period or two years. If an Eligible Customer takes with it more than 25% of its prior year's load, or if an Eligible Customer's monthly load factor in any month decreases by more than 20% as a result of going to market, or if the combined departure of all Eligible Customers' load exceeds 10% in any year of the Eligible Customers' total aggregate load at the end of the previous year, the Eligible Customer will pay mitigated stranded costs, if any, for a period of five years less any part of the notice period during which the Eligible Customer remained with West Kootenay Power for its total load. Within 15 business days of a request, West Kootenay Power will calculate for both a two-year and a five-year period the payments required to ensure that the revenue requirement of remaining customers is not increased from that which is expected to have occurred if the Eligible Customer had not departed early.

New Eligible Customers have the right to be served entirely through an alternate supplier without attracting any of the stranded cost provisions described above.

PARTIAL SUPPLY

An Eligible Customer may elect to meet any or all of its load requirements from West Kootenay Power. If any Eligible Customer elects to meet part of its load requirements from West Kootenay Power, then the rate for partial supply requirements shall be determined so as to ensure that all other customers receive Fair Treatment. For example, if by taking part of its load to market, an Eligible Customer materially worsens the load factor of that portion of its load which remains with the Utility, the Eligible Customer will compensate for these costs consistent with Fair Treatment. In contrast, if an Eligible Customer materially improves its load factor for the portion of its load remaining with the Utility – for example, by taking its peaking requirements to market - the Eligible Customer will realize the benefits of this in the price it pays for its remaining load (to the extent that this can be accomplished in a manner consistent with Fair Treatment and recovery of the embedded cost of service).

In order to satisfy the informational needs of potential partial load Eligible Customers, West Kootenay Power will respond within 15 business days to an Eligible Customer's inquiry about Utility rate changes (both generation and transmission) that the Eligible Customer will face as a result of its partial load election. New rates will be incorporated by reference in a new contract, and subject to Commission approval.

STRANDED COSTS AND BENEFITS

West Kootenay Power is not seeking any specific compensation for stranded costs as part of this agreement. Any person may raise the issue of Fair Treatment in any future stranded cost application before the Commission. However, before asking for stranded cost relief, West Kootenay Power is expected to have exhausted all reasonable avenues of stranded cost mitigation. In addition, the amount of any stranded costs attributable to an Eligible Customer's departure will be reduced by any benefits to remaining customers which result from that departure. However, in no case will this confer to a departing Eligible Customer a claim to stranded benefits.

Where a stranded cost or benefit determination is required, the amount of the stranded costs or benefits will be calculated by West Kootenay Power, disclosed to all interested parties, and submitted to the Commission for approval.

West Kootenay Power acknowledges the likelihood that open access may produce stranded benefits. If this is the case, these benefits will accrue to those customers that remain with the Utility. Departing Eligible Customers may not take these benefits with them, either in the form of exit payments or generation entitlements. Departing Eligible Customers retain claim to the inherent benefits implied by West Kootenay Power's low cost power, as provided for in the Re-entry Provisions.

Where a market opportunity to obtain power is available to an Eligible Customer which would not be viable without additional incentives, the Eligible Customer may seek to negotiate a sharing of stranded benefits under the auspices of the Commission. Such negotiations will be conducted pursuant to the Commission's Alternate Dispute Resolution Guidelines as they may exist from time to time.

Stranding caused by transmission or distribution bypass will be the subject of Commission consideration if and when it arises. As in other stranded cost recovery scenarios, West Kootenay Power will be required to have taken all reasonable steps to protect its assets from stranding and such steps will not create obligations or create a greater burden on the Utility than arises from regulatory principles, including prudent investment obligations.

RE-ENTRY PROVISIONS

An Eligible Customer that has previously taken bundled service may, at any time, return to power service from West Kootenay Power at a rate calculated to ensure Fair Treatment, subject to the conditions set out below, West Kootenay Power will make reasonable efforts to accommodate returning Eligible Customers as quickly as possible.

Returning Eligible Customers and new Eligible Customers who initially chose an alternative supplier should receive rates reflecting the embedded cost of service within the lesser of:

- the period in which West Kootenay Power can adjust its supply portfolio to serve these Eligible Customers, consistent with Fair Treatment; or
- two years from the date of their notice to return to West Kootenay Power's supply.

For the interim period (that is, the lesser of the time it takes West Kootenay Power to adjust its supply portfolio or two years) West Kootenay Power may charge rates reflective of its additional cost of serving these Eligible Customers over the interim period, while maintaining Fair Treatment. If market circumstances are such that market energy is reasonably anticipated to be less expensive than West Kootenay Power's embedded cost of power for the interim period, then the Eligible Customers will return to embedded cost tariffs immediately.

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

West Kootenay Power Ltd.

ACCESS PRINCIPLES
APPLICATION

DECISION

March 10, 1999

Before:

Peter Ostergaard, Chair
Lorna R. Barr, Deputy Chair
Kenneth L. Hall, P.Eng., Commissioner
Paul G. Bradley, Commissioner

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Background

West Kootenay Power ("WKP", “the Applicant”, “the Company”, “the Utility”) is an investor-owned electric utility that provides wholesale and retail service in the Kootenay and South Okanagan areas of British Columbia. The Company’s headquarters are in Trail, B.C., in the eastern part of the service territory. The more heavily populated Okanagan Valley, in the western portion of the service territory, includes the cities of Kelowna and Penticton. WKP is subject to regulation by the British Columbia Utilities Commission (“the Commission”, “the BCUC”).

WKP has an annual system peak of over 600 megawatts. The Utility owns four hydro-electric plants on the Kootenay River with a combined rated capacity of 205 megawatts. The remaining energy and capacity requirements are met through a combination of long-term contracts – with Washington Water Power, British Columbia Hydro and Power Authority (“B.C. Hydro”), Cominco Limited, and a joint venture of the Columbia Power Corporation (“CPC”) and the Columbia Basin Trust Power Corporation (“CBT”) – and short-term market purchases.

On July 31, 1998, WKP filed two distinct applications pertaining to electricity market reform: the Access Principles Application (“APA”) and the Transmission Access Application (“TAA”). The APA was very brief, and related primarily to the treatment of generation assets in an open access environment. The TAA concerned the terms and conditions of non-discriminatory access to the transmission system, and the pricing of transmission services.

Commission Order No. G-73-98, dated August 20, 1998, established regulatory agendas for both the APA and TAA. The TAA was reviewed at a public hearing, which began on October 19, 1998, in Kelowna, B.C. The evidentiary portion of the hearing ended on October 21, 1998, with written final argument received thereafter.

The APA became the subject of a Negotiated Settlement Process, held on September 23 and 24, 1998, in Kelowna. These negotiations produced a proposal on which Commission staff sought the final comments of parties to the negotiations by September 30, 1998. On October 2, 1998, this proposal, amended to reflect the comments received, was again sent to negotiation participants, this time seeking their statements of endorsement or dissent. On October 9, 1998, this proposal, along with the letters of endorsement and dissent, were sent to all Registered Intervenors and the Commission Panel.

Following a review of these submissions, the Commission determined (in a letter dated October 15, 1998) that while significant progress had been made in defining access principles, there remained substantive issues on which agreement had not been reached. Therefore, the Commission directed that the October 19, 1998, hearing into the TAA would begin with a WKP witness panel to address, and be cross-examined on, the Utility's views with respect to access principles.

At the outset of the October 19, 1998, hearing, however, several submissions were heard concerning the disposition of the APA, including suggestions that negotiations could be profitably resumed. No APA evidence was then heard as part of the TAA public hearing process and, on October 21, 1998, the Commission ruled from the bench (T: 441) that negotiations should recommence on November 3, 1998.

These negotiations lasted two days and produced a revised Proposed Settlement Agreement ("PSA") (Exhibit 12). At the conclusion of the negotiations, participants were asked to submit letters of endorsement for, or dissent from, the PSA by November 6, 1998. A single letter of dissent was received from CBT.

As a result of this dissent, Commission staff wrote to participants on November 10, 1998, seeking their input on how best to proceed. All parties that responded to that letter, except CBT, recommended proceeding with the PSA according to the Commission's Negotiated Settlement Guidelines. CBT recommended a written hearing.

On November 16, 1998, the PSA was sent to all Registered Intervenors and the Commission Panel, along with copies of the letters of endorsement and dissent, and participants' responses to Commission staff's letter of November 10, 1998. A proposed covering letter to the PSA, which had been developed as part of the negotiation process, was also included (Exhibit 23). A letter from Commission staff covering this package sought input from all Registered Intervenors on the most appropriate way to proceed with the APA.

On November 24, 1998, the Association for the Advancement of Sustainable Energy Policy ("AASEP") responded to Commission staff's November 16, 1998, letter, indicating that it supported the position of CBT and requesting that the PSA not be approved. This, and a division of opinion about the merits of proceeding with an oral versus a written hearing, prompted the Commission to issue a letter on November 30, 1998, seeking comments from Intervenors on the role that they would anticipate playing in an oral hearing. The Commission stated that it would use this input to determine if an oral hearing would be an efficacious manner in which to proceed.

In light of the comments received in response to both the November 16 and 30, 1998, correspondence, the Commission issued Order No. G-113-98, setting the APA down for a public hearing to commence on February 10, 1999. That hearing, which considered whether the Commission should accept or reject the PSA, lasted one and one-half days and closed with oral argument.

2.0 THE PROPOSED SETTLEMENT AGREEMENT ("PSA")

The PSA, underlined to signify one minor change to Exhibit 12 made by the Commission as a result of this Decision, is attached to Order No. G-27-99 as Appendix A.

2.1 Description of the PSA

WKP's Transmission Access tariffs define the terms, conditions, and prices of open access on the Utility's transmission system. The purpose of the PSA is to develop a fair enabling framework for open access.

To achieve this purpose, the PSA explicitly defines the meaning of Fair Treatment for each of Utility shareholders, customers who remain with bundled supply, and Eligible Customers. Eligible Customers are those customers who have the right to take unbundled transmission service, as defined in Section 1.2 of the Commission's Decision on the TAA, released concurrently with this Decision.

More specifically, the PSA identifies four key areas where policy definitions are needed to ensure Fair Treatment. These are: (1) the Utility's obligation to serve Eligible Customers; (2) an Eligible Customer's rights should it choose to take only part of its load from non-Utility sources; (3) the treatment of any stranded costs or benefits that may result from an Eligible Customer's partial or total departure from Utility supply; and (4) the re-entry provisions governing an Eligible Customer's return to bundled Utility supply.

In assessing the PSA, Intervenors raised issues which may be considered under four broad categories: (1) the pricing of Utility supply; (2) the treatment of stranded benefits; (3) the recovery of stranded Demand-Side Management ("DSM") assets; and (4) issues of general merit and practical application. These will be considered in turn as Sections 2.2 to 2.5.

In addition, B.C. Hydro asked the Commission to make clear that the PSA was made in specific reference to WKP's APA and that nothing in the PSA provides a precedent for other utilities or circumstances (Exhibits 13 and 23).

2.2 Pricing of Utility Supply

The PSA contains several provisions with respect to the pricing of Utility supply. These provisions make plain that Utility supply will normally be priced to reflect the Utility's embedded cost of service.

WKP supported the pricing of Utility supply at embedded rates, stating that current cost-of-service principles should continue to determine rates before and after customers leave Utility supply and that rates for all customers should be based on the average cost of supply (T: 455 and 456).

Both AASEP and CBT opposed the pricing of Utility supply at embedded rates. AASEP's opposition was based on a concern that the pricing of Utility supply at embedded cost rates means that there will be a less-than-desirable amount invested in DSM resources. CBT stated that the pricing of Utility supply at embedded cost rates means that customers and potential competitive suppliers will fail to receive a clear price signal (i.e., one which reflects the Utility's cost of supplying marginal demand) and that this will inhibit the development of a competitive generation market (Exhibit 19, p. 3). CBT stated that this would be unfair to independent power producers, marketers and developers attempting to serve the market (Exhibit 20, p. 2).

To overcome its concerns, AASEP proposed a model which would see current load served at embedded cost rates and incremental load growth by Eligible Customers priced at the Utility's cost of serving the incremental load (Exhibit 10, pp. 11 and 12, T: 689). AASEP stated that this would require that current embedded cost resources be allocated amongst all customer classes and, for those classes with access to third-party suppliers, allocated within customer classes. Those customers who wished to access market supply could do so for only their incremental load, with current load served at embedded cost rates, or could choose to have some greater portion of their load, up to 100 percent, served at market rates. AASEP proposed that if a customer were to leave Utility supply entirely, the customer would leave behind all rights to the embedded cost power. If the customer later were to decide to return to Utility supply, the customer would not return to the embedded cost rates but would be charged the Utility's incremental cost (T: 689 and 690). AASEP stated that this proposal results in efficient price signals which ensure an efficient allocation of resources and an incentive to invest in all DSM which is cheaper than the Utility's marginal cost of power (T: 689 and 690).

CBT also proposed two-tier pricing of Utility supply and suggested that this could be accomplished in one of two ways. Under CBT's first proposal, the demand for power would be split into two tiers for any customer wishing to leave WKP supply. The price from WKP for supplying the first tier would reflect any system stranded costs or benefits. The price for the second tier would reflect WKP's avoided cost of power. In order to ensure that a customer whose consumption does not change is charged the same overall cost of electricity as under embedded cost rates, CBT proposed to adjust the first tier price and quantity to produce a revenue neutral outcome at the historical consumption level of the Eligible Customer at the time of departure from WKP supply (Exhibit 19, p. 6).

Alternatively, CBT suggested that WKP could establish a first tier consisting of only existing WKP resources and long-term purchases. The amount of power available from these resources would be prorated among all customer classes, and customers within these classes, with the price reflecting the cost of these resources. The second tier would contain all other resources necessary to meet the expected load and would reflect the cost of these resources (Exhibit 19, p. 7). Customers with access to market supply would then be able to compare the cost of market supply with WKP's price for second tier power. CBT stated that the second approach would be administratively easier and would provide some pricing predictability (Exhibit 21, p. 1).

CBT acknowledged that neither of their proposals is ready for implementation but suggested that the two-tier rate structure should be the focus of a revised application by WKP, based on direction from the Commission (Exhibit 19, p. 7).

Although as noted above, WKP supported the pricing of Utility supply at embedded cost rates (T: 455 and 456), the Utility accepted that consideration of two-tier pricing might be an appropriate topic for some future regulatory proceeding (T: 626). Nonetheless, the Utility identified several problems that would need to be overcome before such a scheme could be successfully implemented. First, the Utility indicated that their analysis suggests that a two-tier pricing system would result in rates for customers who choose to remain with Utility supply that are higher than the average embedded cost of supply (T: 628). Second, WKP stated that a two-tier pricing system would impose additional administrative burdens, including frequent re-estimation of stranded costs in order to determine rates (T: 631) and the establishment of a unique rate for each customer requesting access (T: 632).

In response to the latter issue, CBT maintained that the calculation of a unique rate for each customer is no different in concept from the current situation in which different energy and capacity charges result in a different average rate for each customer (Exhibit 20, p. 3).

2.3 Stranded Benefits

The PSA acknowledges that open transmission access may produce stranded benefits and requires that these benefits accrue to those customers that remain with Utility supply.

WKP supported the retention of stranded benefits by those customers who remain with Utility supply, stating that it would be unfair to permit departing customers to have the opportunity to benefit from market purchases and at the same time give those same customers all the benefits of the low embedded costs of Utility supply (T: 455). More specifically, WKP stated that if a customer chooses to purchase from the market, instead of from WKP at the embedded cost of its resource portfolio, the customer does so accepting all the risks and benefits of market purchase and that customers who decide to continue to rely on WKP's resource portfolio should receive the full benefit of that portfolio (T: 456).

Both AASEP and CBT took exception to the provisions of the PSA relating to stranded benefits. AASEP indicated that it does not accept that the PSA provides sufficient protection of the stranded benefits for core market customers and fears that these protections will be eroded over time (T: 692 and 697). As a result, AASEP indicated that it believes a mechanism that explicitly shares the stranded benefits between remaining and departing customers would be preferable (T: 693 and 697). AASEP maintained that an example of such a mechanism is the pricing model which it proposed and which is discussed in Section 2.2.

CBT stated that it is unfair to deny market access customers stranded benefits while requiring the same customers to pay stranded costs (Exhibit 19, p. 3). More specifically, CBT maintained that market access customers should have the right to continue to consume power from the resources acquired on their behalf that have a higher value (lower cost) than the market (Exhibit 21, p. 7). CBT proposed that Eligible Customers receive these stranded benefits through the purchase of first tier energy from WKP. However, if a customer takes less than its share of first tier electricity, CBT accepted that the customer would leave any stranded benefits behind (Exhibit 19, p. 8). CBT maintained that the loss of stranded benefits in this situation is not unfair since the customer is making the choice to abandon the benefits (T: 583). In addition, CBT indicated that it has not identified any practical way for a customer leaving Utility supply in its entirety to retain its stranded benefits (T: 584).

CBT was unable to identify any jurisdictions where departing customers are allowed to take stranded benefits with them, but noted that in Alberta the distribution companies have been assigned their customers' historical share of resources in place at the time the electricity market restructuring legislation came into effect (Exhibit 21, pp. 7 and 8).

2.4 Demand-Side Management ("DSM")

The PSA does not specifically address issues surrounding the provision of DSM programs by the Utility. WKP indicated that it does not consider this to be a flaw with the PSA, stating that the hearing into the PSA is not the appropriate proceeding for evaluating mechanisms to address DSM concerns (T: 459).

In contrast, AASEP indicated that it views the PSA as not being in the public interest because it does not adequately address stranding of past DSM investments and does not encourage the efficient allocation of resources, including future DSM investment and renewables (T: 671). In addition, AASEP stated that the PSA predetermines issues before the Commission as part of the Transmission Access Application (T: 671). Specifically, as discussed in Section 2.2, AASEP objected to provisions in the PSA which would allow a customer who left WKP supply to return to Utility supply at embedded cost rates (T. 674), recommending that the customer instead be charged the Utility's incremental cost of providing power.

AASEP suggested that its public interest concerns could be overcome if the Commission either imposes a two-tier pricing system similar to that proposed in the testimony of AASEP's witness, discussed in Section 2.2, or requires 100 percent of DSM costs to be recovered through the transmission revenue requirement (T: 681). AASEP's evidence and arguments with respect to the recovery of DSM costs form part of the record with respect to WKP's Transmission Access Application. This issue is discussed fully in Section 3.4 of the Commission's Decision with respect to WKP's TAA, dated March 10, 1999.

2.5 General Merit and Practical Application

In addition to discussion on the issues described above, the Commission heard from a number of Intervenors on more general issues. Some endorsed the PSA, even while acknowledging that it may be a little-used first step. These parties emphasized the many issues to which the PSA brings clarity, its value as a symbol of market development, and its use as a vehicle to deliver the inherent benefits of customer choice. They also noted that there is unanimous support for the PSA among customer groups.

Dissenters from the PSA argued that merit requires usefulness, and that markets need real, not symbolic, access to achieve the benefits of competition. These parties took this argument further, suggesting that the PSA is not simply benign, but would impose additional costs on Utility customers, may damage the environment, and could stand as an obstacle to further market development.

The Interior Municipal Electrical Utilities ("IMEU") listed 40 ways in which the PSA brings clarity to the operation and conduct of open access for WKP and its customers (T: 642). The IMEU argued that these 40 points of clarity, in and of themselves, offer a very substantial argument in favour of Commission approval for the PSA (T: 645).

The IMEU also noted that the PSA emerged from negotiations between the Utility and its customers, and urged the Commission to assign considerable weight to that fact (T: 645). WKP also emphasized this point in their final argument, calling the endorsement of the PSA by all customers “almost determinative” of the issue (T: 620).

WKP used the phrase “almost determinative”, it said, because it recognized that the Commission holds a legislative responsibility to determine if the PSA is in the public interest (T: 620). However, WKP sought to define public interest by suggesting that, from the Commission’s perspective and considering only the issues in this hearing, it should be irrelevant that the PSA does not create competitive opportunities for third party suppliers and improved opportunities for energy efficiency measures (T: 622).

Customer consensus was also used by WKP to address claims by CBT (Exhibit 19, Evidence of J. Smienk, Q. 8) that the PSA, if approved, would be harmful or regressive. WKP argued that it would be “hard to imagine” how an agreement reached between the Utility and all of its customer groups could be regressive (T: 622). And since the PSA is not regressive, this is further reason for the Commission to approve it, WKP argued (T: 623).

Indeed, WKP stated that rejection of the PSA would be a regressive step that would restrict the options of wholesale customers whose contracts will be expiring in the coming years. The Utility argued that the regulatory certainty provided by the PSA is critical to fair and efficient negotiations with these customers and that providing that certainty now does nothing to restrict future proceedings designed explicitly to seek opportunities for third party suppliers or energy efficiency measures (T: 623).

In a related argument, the Consumers Association of Canada (B.C. Branch) et. al. [“CAC (B.C.) et. al.”] argued that efforts to create open access are fine, but that efforts to create a competitive market risk adverse impacts for residential and other captive customers (T: 667 and 668).

A more abstract argument in favour of the PSA was presented by the Joint Industry Electrical Steering Committee ("the Committee"). The Committee conceded that the PSA would create access, not competition, and that access without competition is of little practical value. Nonetheless, the Committee argued that the PSA provides important symbolic value and it consolidates and rewards the efforts of WKP and its customers. It also provides a basis from which to move forward (T: 656 and 657).

In dissenting from the PSA, CBT disputed WKP's position that customer support for the PSA should be almost sufficient for the Commission to approve it. CBT argued that if customer agreement were sufficient for approval of the PSA, then this hearing – or certainly CBT’s presence at it – was unnecessary (T: 710). Moreover, CBT challenged the strength of customer support for the PSA – describing the endorsements as 'hollow', and noting that most customers see the PSA only as a starting point (T: 711).

Expectations that the PSA will have little practical effect were also seized upon by CBT. While acknowledging that the Commission is not a court, CBT noted that courts have a general practice of refusing to grant opinions on general matters, or considering matters that are moot (T: 715). CBT stated that since the PSA would not actually lead to use of WKP's open access tariffs, any benefits which might be derived from the IMEU's 40 points of clarification are purely notional and serve only to make people feel that they are accomplishing some kind of market reform (T: 718).

Referring to the arguments of the Committee, CBT argued that the Commission should not approve the PSA simply to reward effort. Instead, the Commission should only reward results that are clearly in the public interest (T: 732).

Like CBT, AASEP raised concerns that the APA would represent an impediment to future market development. These concerns, the organization argued, are sufficient to militate against approving the APA now, with a view to investigating improvements in the future.

AASEP's first concern in this regard is that rights, once vested, can be extremely difficult to revoke. AASEP cited the PSA's re-entry provisions as a possible area of concern in this respect (T: 675). In addition, AASEP argued that the PSA's two year notice period to depart Utility supply would lead to a short-range planning horizon for the Utility, at the expense of both the environment and captive rate payers (T: 678 and 679).

2.6 Commission Determinations

The Commission notes that the PSA is the fruit of negotiations between WKP and its customers as to the rights and obligations of WKP and its customers in an era of increased market access and is supported by all WKP's customers. While the Commission agrees with those parties who argued that the endorsement of the PSA by all customer groups is not sufficient grounds to find that the PSA is in the public interest, in the absence of evidence indicating a clear harm to ratepayers, it is supportive of such a finding.

The Commission does not believe that the parties opposing the approval of the PSA have demonstrated that such approval will lead to rate payer harm either by impeding future market developments or entrenching rights and obligations which may prove difficult to change in the future. This is not to suggest that the Commission believes that the PSA represents an end point with respect to market development. Several parties have indicated desires to see further restructuring of the market – either broadly within the province as a whole or more narrowly within WKP's service area. If this occurs, the Commission expects that further refinements of the rights and obligations of utilities and their customers will need to be undertaken and that repudiation of the PSA in whole or in part is possible. In this regard, the Commission notes that the PSA was made in specific reference to WKP's APA and that nothing in the PSA provides a precedent for other utilities or circumstances. Nonetheless, by defining the current agreement between WKP and its Eligible Customers as to their respective rights and obligations, the PSA provides a framework in which decisions regarding suppliers may be made by Eligible Customers within WKP's service area.

With respect to the particular concern raised by CBT and AASEP over the pricing of WKP supply, the Commission believes that there is merit to a further examination of two-tier pricing. This is discussed more fully in Chapter 3.0.

With respect to the recovery of DSM costs, this issue is dealt with in full in the Commission's Decision regarding WKP's Transmission Access Application, dated March 10, 1999.

Based on the evidence and argument adduced at the hearing, the Commission is persuaded that the PSA is in the interest of WKP ratepayers. **Therefore, the Commission accepts the PSA, but amends the notice deadline of March 1, 1999, on page 2 to read April 1, 1999.**

3.0 NEXT STEPS

3.1 Further Consultations, Hearings, or Applications

Several Intervenors to this proceeding indicated that they viewed the PSA as encapsulating a transitional set of principles that will need to be re-visited in the future. The IMEU, for example, called the PSA a "useful step forward" in developing open access, but added that not much will have been achieved if it is also the last step. To ensure that further progress is made, the IMEU encouraged the Commission to endorse specific next-steps as part of a direction approving the PSA (T: 648 and 649).

The nature of what, if anything, the Commission should direct by way of next-steps was the subject of considerable comment by both WKP and Intervenors. CBT asked that the Commission reject the PSA and direct WKP to submit an amended application that incorporates access principles based on two-tier pricing. CBT suggested, as well, that this new application's development should proceed using an Open Access Council ("OAC"), as proposed in WKP's TAA. CBT has indicated a willingness to participate in such a process (T: 729).

AASEP argued that under any reasonable assumptions, there would be no need for access principles within the next two years. In the meantime, AASEP proposed that the status quo is acceptable, while work proceeds on a "marginal costing proposal" (T: 704).

WKP argued that the broad issue for further consideration is whether or not utility rate structures are the appropriate means to create opportunities for third party suppliers and energy efficiency measures. WKP characterized such decisions as embodying fundamental changes to rate design principles in current use (such as basing rates on the cost of service) and argued that such changes should be explored in the context of a distinct proceeding with clear terms of reference to examine these issues (T: 736).

WKP supported these comments by arguing that any further process directed by the Commission in approving or rejecting the PSA should include all utilities in B.C. The Utility noted that CBT and AASEP did not argue in this proceeding for the approval of any specific mechanisms. As a result, WKP stated, the Commission could, at most, direct the Utility to file another application designed to foster opportunities for third-party suppliers and energy efficiency measures. However, WKP further asserted that the record before the Commission is inadequate to allow such a direction (T: 624).

WKP did, however, indicate that it would support further development work aimed at finding a mechanism to create opportunities for third party suppliers and energy efficiency measures. It also suggested that an OAC may be an appropriate vehicle for this work, and recommended that funding should be available for participants if an OAC is used to review rate design mechanisms (T: 737 and 738). The CAC (B.C.) et. al. saw competitive opportunities of the type supported by CBT as coming at the expense of residential customers. For that reason, CAC (B.C.) et. al. "[did] not urge the Commission to create a new generic process" (T: 668 and 669).

However, to the extent that the Commission sees merit in pursuing the general proposals of CBT and AASEP, the CAC (B.C.) et. al. agreed with the Utility position on future proceedings, arguing that the only appropriate process is a generic public hearing (T: 666). A generic process is also appropriate, the CAC (B.C.) et. al. suggested, since it would be unproductive to require WKP to bring forward an application based on principles that it has, to date, rejected (T: 540). In the event that such a proceeding were to take place, then the CAC (B.C.) et. al. has said that they will fully participate in it (T: 669).

British Columbia Hydro and Power Authority ("B.C. Hydro") disputed the need for a generic hearing, although its comments were made in reference to a two-part rate in particular, rather than referring to general mechanisms aimed at creating competitive opportunities for third party suppliers and energy efficiency measures. Specifically, B.C. Hydro argued that a generic hearing would be impractical, since "the type of two tier rate is informed by and determined by the type of market access available in the service area in which the two tier rate would be offered" (T: 640).

Other Intervenors took similar positions. While arguing that there is a need to move forward with "full inquiry, including ADR" on how best to create competition, the Committee suggested that this process should be limited to the WKP service territory. The Committee argued that the circumstances and policy issues of WKP are different from those of a Crown Corporation, and that a generic hearing would risk getting these issues "muddled up". The Committee also stated that, in its view, the benefits of competition could be achieved in the WKP service area without too much difficulty (T: 659).

The IMEU also argued against a generic hearing which involved broad restructuring questions, recalling that such efforts have been unsuccessful in the past, and suggesting that the Commission would be doing a "disservice" if it embarked down that path again. Nevertheless, the IMEU did indicate that, in its view, it would be extremely valuable for the Commission to direct WKP to meet with interested parties using the Utility's proposed OAC. This process could develop a series of principles and mechanisms for the Commission's consideration that might be used to facilitate "marginal cost pricing in the context of open access" (T: 654).

3.2 Commission Determinations

As noted in Section 2.6, the Commission is persuaded that the PSA represents a useful step toward open access. However, the Commission also acknowledges that the current pricing structure imposes a substantial barrier for alternative suppliers as well as discouraging certain DSM options. As a result, the Commission believes that further exploration into the use of rate structure to foster supply competition and to encourage DSM and other conservation measures is appropriate. The Commission believes that this exploration should be directed narrowly at the WKP service area. For the reasons stated by the IMEU, the Committee and B.C. Hydro, the Commission feels that a generic hearing would be both inefficient and inappropriate.

The Commission is, however, unprepared at this time to direct WKP to file an application based on principles which both it and this Commission have not thoroughly explored. The Commission is also not in a position to direct consultation between the Utility and interested parties under the auspices of an Open Access Council, since the Commission declined to direct the creation of an OAC in its Decision on WKP's Transmission Access Application, released concurrently with this Decision.

Therefore, the Commission requests WKP to work with interested parties to examine alternative rate structures or arrangements that will foster the development of the most efficient supply sources and encourage conservation measures. **In addition, the Commission directs WKP to file a report by December 31, 1999, that discusses, at a minimum, the progress made in these consultations, the Utility's views on possible amendments to the principles embodied in the PSA, and the merit of using rate design measures to promote a competitive generation market in the WKP supply area.**

Dated at the City of Vancouver, in the Province of British Columbia, this 10th day of March, 1999.

Original signed by:
Peter Ostergaard
Chair

Original signed by:
Lorna R. Barr
Deputy Chair

Original signed by:
Kenneth L. Hall, P. Eng
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

COMPARISON OF RELEVANT SECTIONS OF THE
UTILITIES COMMISSION ACT COMPARISON AND CLEAN ENERGY ACT

Sect.	UCA pre-June 3, 2010	UCA after June 3, 2010	Sect.	Clean Energy Act
1	"**demand-side measure**" means a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand;	"**demand-side measure**" has the same meaning as in section 1 (1) of the *Clean Energy Act*; (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand,	**1**	"**demand-side measure**" means a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand, but does not include, (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed;
1	"**government's energy objectives**" means the following objectives of the government: .... (b) to encourage public utilities to take demand-side measures;	"**British Columbia's energy objectives**" has the same meaning as in section 1 (1) of the *Clean Energy Act*.	**1** **2**	"**British Columbia's energy objectives**" means the objectives set out in section2; The following comprises British Columbia's energy objectives: … (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%; … (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently; …
64.4	(4) If a public utility, other than the authority, makes an application under the Act in relation to advanced meters, the commission, in considering that application, must consider the government's goal of having advanced meters and associated infrastructure in use with respect to customers other than those of the authority.	Repealed.	**17**	(6) If a public utility, other than the authority, makes an application under the *Utilities Commission Act* in relation to smart meters other advanced meters or a smart grid, the commission, in considering the application, must consider the government's goal of having smart meters, other advanced meters and a smart grid in use with respect to customers other than those of the authority.

LIST OF ACRONYMS

2CP	two coincident peak allocator
2007 Energy Plan	BC Energy Plan: A Vision for Clean Energy Leadership
AESO	Alberta Electric System Operator
AMI	Advanced Metering Infrastructure
APA	Access Principles Application
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electric Utilities
BCOAPO	BC Old Age Pensioners’ Organization, BC Coalition of People with Disabilities, Council of Senior Citizens’ Organizations of BC, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre
Big White or BWSR	Big White Ski Resort
BPA	Bonneville Power Authority
CEA	*Clean Energy Act*
Celgar	Zellstoff Celgar Limited Partnership
Commission	British Columbia Utilities Commission
COSA	cost of service analysis
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical peak pricing
EES	EES Consulting Inc
EPA	Energy Purchase Agreement
FERC	U.S. Federal Energy Regulatory Commission
FortisBC	FortisBC Inc.

List of Acronyms

GBL	Generator Baseline
Interfor	International Forest Products
IRG	Irrigation Ratepayers Group
kVA	kilovoltampere
kW	kilowatt
MVA	Megavolt-amperes
MW	Megawatts
NERC	National Electric Reliability Corporation
OEB	Ontario Energy Board
OEIA	Okanagan Environmental Industry Alliance
PLCC	Peak Load Carrying Capacity
PPA	Power Purchase Agreement
PTP	point to point
R/C	Revenue to Cost
Rate 30 Group	Rate Class 30 Customer Group
RDA	Rate Design Application
RS	Rate Schedule
RIB	Residential Inclining Block
TOU	time-of-use
the *Act or UCA*	*Utilities Commission Act*
WKPL	West Kootenay Power Limited

LIST OF APPEARANCES/WITNESS PANELS

G. FULTON, Q.C.	Commission Counsel
G.K. MACINTOSH, Q.C. L.B. HERBST	FortisBC Inc.
C. WEAFER	British Columbia Municipal Electric Utilities
C. LUSZTIG	Big White Ski Resort
R. WILLIAMS	International Forest Products Ltd.
F. BRADY	Roxul Inc.
K. MOLLER M. LEE	Zellstoff Celgar Limited Partnership
S. KHAN	B.C. Old Age Pensioners' Organization B.C. Coalition of People with Disabilities Tenants' Rights Advisory Centre Council of Senior Citizens' Organizations of B.C.
A. SHADRACK	His own behalf
A. WAIT	His own behalf
N. GABANA	His own behalf
D. BURSEY	ATCO Wood Products Ltd. Weyerhaeuser Company Ltd. Columbia Brewery Greenwood Forest Products Hawkeye Holdings Ltd. JH Huscroft Limited Kaleshnikoff Lumber Co. Porcupine Wood Products Springer Creek Forest Products Wynndel Box & Lumber

F.J. WEISBERG	Keremeos Irrigation District Fairview Heights Irrigation District Similkameen Improvement District Kaleden Irrigation District Water Supply Association of B.C. Okanagan/Kootenay Cherry Growers' Association British Columbia Fruit Growers' Association South Interior Stockmen's Association Osoyoos Indian Band Vincor Canada

WITNESS PANELS

FortisBC Inc.

Michael Mulcahy, Vice President, Customer and Corporate Services
Dennis Swanson, Director, Regulatory Affairs
Paul Chernikhowsky, Director, Engineering Services
Mark Warren, Director, Customer Service
Corey Sinclair, Manager, Regulatory Affairs
Gary Saleba, President, EES Consulting
Gail Tabone, Principal, EES Consulting

British Columbia Municipal Electric Utilities

Alan Rosenberg, Managing Principal, Brubaker & Associates, Inc.
Rod Carle, General Manager, Electric Utilities Commission, City of New Westminster

International Forest Products Ltd.

Stephen Williams, Vice President & Corporate Treasurer

Zellstoff Celgar Limited Partnership

Brian Merwin, Vice President Strategic Initiatives, Mercer International Inc.
Robert Hobbs, Consultant
Joe Linxwiler, President, Linxwiler Consulting Services Inc.

Irrigation Ratepayers Group

Linda Allison, Fourth generation rancher
Brian Mennell, Chairman, Fairview Heights Irrigation District
Joe Sardinha, President, BC Fruit Growers’ Association
Ian Walters, Chairman, Keremeos Irrigation District
Neil Lougheed, Owner, Interior Powertech Services

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

and

FortisBC Inc.
2009 Rate Design and Cost of Service

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated November 23, 2009 - Appointing the Commission Panel for FortisBC Inc. 2009 Rate Design and Cost of Service Application
A-2	Letter dated November 26, 2009 - Regulatory Timetable, Notice of Application and Procedural Conference
A-3	Letter dated December 18, 2009 - Issuing Commission Information Request No. 1 to FortisBC
A-4	Letter dated December 21, 2009 – issuing Order G-166-09, Reasons for Decision and Revised Regulatory Timetable
A-5	Letter dated December 29, 2009 – Issuing response to BCOAPO regarding Late Submission of Supplemental Information Requests
A-6	Letter dated February 1, 2010 - Issuing Commission Information Request No. 2 to FortisBC
A-7	Letter dated February 17, 2010 – Notice regarding Expiry of Commissioner Pullman's Order in Council appointment
A-8	Letter dated February 17, 2010 – Commission Order G-22-10 announcing venue for the oral public hearing
A-9	Letter dated February 18, 2010 – Request to submit written comment on Celgar's requests described in Exhibit C13-4
A-10	Letter dated March 3, 2010 – Order G-35-10 with Reasons for Decision regarding Celgar's Generator Baseline Load

Exhibit No.	Description
A-11	Letter dated March 12, 2010 –FHID Information Request to FBC
A-12	Letter dated March 19, 2010 – Response to Interfor regarding Oral Hearing Appearance request
A-13	Letter dated March 22, 2010 – Response to Shadrack complaint on FBC IR responses
A-14	Letter dated March 26, 2010 – Request Intervener comments with respect to Reply Evidence Requests from FortisBC and BCMEU
A-15	Letter dated March 29, 2010 - Issuing Commission Information Request to Interfor
A-16	Letter dated March 29, 2010 - Issuing Commission Information Request to BCMEU
A-17	Letter dated March 29, 2010 - Issuing Commission Information Request to Zelstoff Celgar
A-18	Letter dated April 6, 2010 – Response to Mr. Shadrack regarding oral hearing procedures
A-19	Letter dated April 12, 2010 – Order G-69-10 amending the Regulatory Timetable to allow for Reply Evidence
A-20	Letter dated April 15, 2010 – Hearing Procedures Information to Participants
A-21	Letter dated April 19, 2010 – Response to FHID request extension for filing information request responses
A-22	Letter dated April 21, 2010 - Commission request to Interfor regarding Information Request Response Exhibit C8-8
A-23	Letter dated May 10, 2010 - Commission Panel Information Request to FortisBC regarding the Irrigation Ratepayers Group testimony
A-24	Letter dated May 25, 2010 - Order G-86-10 Supplementary Regulatory Timetable
A-25	Letter dated June 2, 1010 - Issuing Commission Information Request No. 4 to FortisBC
A-26	Letter dated June 9, 2010 – Issuing Letter No. L-44-10 regarding Information Requests to FortisBC

Exhibit No.	Description
A-27	Letter L-51-10 dated June 18, 2010 – Responses to Contentious Information Requests and Amended Timetable for Argument
A-28	Letter dated July 30, 2010 – Confirmation on Oral Phase of Argument
A-29	Letter dated August 31, 2010 - Oral Phase of Argument: Panel Questions and Topics for Submissions
A-30	Letter dated September 2, 2010 - Additional Panel Questions and Issues
A2-1	**COMMISSION COUNCIL SUBMITTED AT HEARING** May 04, 2010 – LETTER DATED MAY 27, 2003 FROM MINISTER NEUFELD TO PATRICIA WALLACE
A2-2	**SUBMITTED AT HEARING** May 05, 2010 – EXHIBIT B-3 FROM B.C. HYDRO 2007 RATE DESIGN APPLICATION INFORMATION RESPONSE TO IR NO. 1.25.1
A2-3	**SUBMITTED AT HEARING** May 05, 2010 – SCHEMATIC HEADED "EXHIBIT B-7, BCUC IR NO. 2 - APPENDIX A34.1
A2-4	**SUBMITTED AT HEARING** May 05, 2010 – DOCUMENT ENTITLED "FORTISBC - 2009 RATE DESIGN & COST OF SERVICE, COMMISSION STAFF WITNESS AID"
A2-5	**SUBMITTED AT HEARING** May 05, 2010 – DOCUMENT HEADED "EX. B-14, CELGAR IR#2 APPENDIX A8.1, TAB 2009
A2-6	**SUBMITTED AT HEARING** May 05, 2010 – DOCUMENT ENTITLED "BCMEU APPENDIX A15.1A, 2009 SDP UPDATE", WITH THREE PAGES ATTACHED
A2-7	**SUBMITTED AT HEARING** May 06, 2010 – INTERFOR PRESS RELEASE DATED DECEMBER 14, 2009
A2-8	**SUBMITTED AT HEARING** May 06, 2010 – LETTER L-106-09, DATED NOVEMBER 27, 2009, FROM BCUC TO BC HYDRO
A2-9	**SUBMITTED AT HEARING** May 06, 2010 – EXCERPT FROM GLOSSARY FROM B.C. HYDRO REVENUE REQUIREMENTS 2004/05 AND 2005/06 APPLICATION

Exhibit No.	Description
	APPLICANT DOCUMENTS- FORTISBC INC.
B-1	**FORTISBC INC. (FBC)** – Letter dated October 30, 2009 Rate Design and Cost of Service Application
B-1-1	Letter dated December 14, 2009 Via Email – FortisBC Erratum to Application
B-1-2	Letter dated January 18, 2010 - FortisBC submitting Errata No. 2 to Application
B-2	Letter dated December 16, 2009 – FortisBC Clarification of comments made in transcript, Volume 1, page 35, line 21
B-3	Letter dated January 18, 2010 – FortisBC's responses to Information Requests from BCUC, BCOAPO, BCMEU, Zellstoff Celgar, IFP, OEIA et al, RI, Mr. Andy Shadrack, and Mr. Alan Wait. **NOTE**: IR No.1 letter only. The file has been broken down to its component parts due to large file size.
B-3-1	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCUC
B-3-2	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCOAPO
B-3-3	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCMEU
B-3-3-1	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCMEU Appendix-A21.1
B-3-3-2	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCMEU Appendix-A15.1a
B-3-3-3	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to BCMEU Appendix-A18.1
B-3-3-4	Letter dated March 2, 2010 - FortisBC's Supplemental Filing to BCMEU IR No. 1 Q34.3 - Appendix BMEU A34.3
B-3-4	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to Zellstoff Celgar
B-3-4-1	Letter dated January 28, 2010 - Errata to FortisBC's response to Zellstoff Celgar Information Request No. 1 Q32.3
B-3-5	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to IFP

Exhibit No.	Description
B-3-6	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to OEIA et al
B-3-7	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to RI
B-3-8	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to A. Shadrack
B-3-9	Letter dated January 18, 2010 – FortisBC's IR No. 1 responses to A. Wait
B-4	Letter dated February 24, 2010 Via Email - FortisBC's Response to Celgar Application for the inclusion of GBL in the Oral Hearing
B-5	Letter dated February 26, 2010 - FortisBC's further correspondence regarding Celgar Application
B-6	Letter dated March 2, 2010 - FortisBC's Errata 4 to the Application and IR Responses No. 1
B-7	Letter dated March 2, 2010 - FortisBC's Responses to Information Request No. 2 from BCUC, BCOAPO, BCMEU, Celgar, IFP, OEIA, A. Shadrack, A Wait, and Big White
B-8	Letter dated March 12, 2010 Via email – FortisBC response to KIFHSI information Request No. 1
B-9	Letter dated March 22, 2010 Via email – FortisBC request to file reply evidence
B-10	Letter dated March 24, 2010 Via email – FortisBC response to BCMEU Exhibit C1-7
B-11	Letter dated March 29, 2010 – FortisBC Response to Letter from A. Shadrack dated Mar 14 2010 regarding Information Request No. 2
B-12	Letter dated March 29, 2010 – FortisBC's Information Requests to BCMEU, Zellstoff Celgar, KIFHSI and IFP Note: The file has been broken down to its component parts due to large file size
B-12-1	Letter dated March 29, 2010 – FortisBC's Information Request No. 1 to BCMEU
B-12-2	Letter dated March 29, 2010 – FortisBC's Information Request No. 1 to Zellstoff Celgar
B-12-3	Letter dated March 29, 2010 – FortisBC's Information Request No. 1 to IFP
B-12-4	Letter dated March 29, 2010 – FortisBC's Information Request No. 1 to KIFHSI
B-12-5	Letter dated March 29, 2010 – FortisBC's Book of Authorities

Exhibit No.	Description
B-13	Letter Dated April 6, 2010 Via Email – FortisBC's comments on BCMEU objection to FortisBC's proposed filing being made
B-14	Letter Dated April 8, 2010 - FortisBC submitting **ERRATA** to its Application and Information Request No. 2 Responses
B-15	Letter Dated April 16, 2010 - FortisBC submitting errata to its Information Request No. 1
B-16	Letter Dated April 22, 2010 – FortisBC submitting reply evidence
B-17	Letter dated April 26, 2010 – FortisBC submitting Errata No. 7 to Application
B-18	Letter dated April 27, 2010 – FortisBC Confirming reply evidence through initial witness panel
B-19	Letter dated April 29, 2010 – FortisBC Opening statement
B-20	Letter dated April 29, 2010 – FortisBC Witness Panel
B-21	Letter dated April 29, 2010 – FortisBC Witness Panel opening statement
B-22	**SUBMITTED AT HEARING** May 03, 2010 – EXTRACT FROM PRINCIPLES OF PUBLIC UTILITY RATES" BY BONBRIGHT, DANIELSEN AND KAMERSCHEN
B-23	**SUBMITTED AT HEARING** May 04, 2010 – RESPONSES TO UNDERTAKINGS 1 TO 5
B-23-A	**SUBMITTED AT HEARING** May 04, 2010 – ADDITIONAL RESPONSES TO UNDERTAKINGS, WITH FIRST PAGE COLOUR CHART AND GRAPH
B-24	**SUBMITTED AT HEARING** May 04, 2010 – ONE-PAGE DOCUMENT HEADED 'FORTISBC CLARIFICATION OF MAY 3, 2010 TRANSCRIPT VOLUME 2'
B-25	**SUBMITTED AT HEARING** May 05, 2010 – FORTISBC'S TEXT RESPONSE TO UNDERTAKINGS 8 AND 12 TO 17
B-25-A	**SUBMITTED AT HEARING** May 05, 2010 – DOCUMENT HEADED "RESIDENTIAL BILL FREQUENCY, UNDERTAKING 13 - ATTACHMENT"
B-25-B	**SUBMITTED AT HEARING** May 05, 2010 – UNDERTAKING 14 - ATTACHMENT, "DRAFT FORTISBC 2009 CUSTOMER END USE STUDY…AUGUST 2009"
B-26	**SUBMITTED AT HEARING** May 06, 2010 – FORTISBC INC. ELECTRIC TARIFF B.C.U.C. NO. 1 FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS

Exhibit No.	Description
B-27	**SUBMITTED AT HEARING** May 06, 2010 – EXCERPT FROM "GLOSSARY OF TERMS USED IN NERC RELIABILITY STANDARDS, UPDATED APRIL 20, 2010"
B-28	**SUBMITTED AT HEARING** May 06, 2010 – GROUP OF RESPONSES TO UNDERTAKINGS, FIRST PAGE HEADED "FORTISBC 2009 RATE DESIGN APPLICATION, ORAL HEARING UNDERTAKINGS FROM MAY 4, 2010"
B-28-A	**SUBMITTED AT HEARING** May 06, 2010 – INFORMATION RESPONSE, FIRST PAGE HEADED "UNDERTAKING 28 - ATTACHMENT"
B-28-B	**SUBMITTED AT HEARING** May 06, 2010 – INFORMATION RESPONSE, FIRST PAGE HEADED "UNDERTAKING 32 - ATTACHMENT"
B-29	**SUBMITTED AT HEARING** May 07, 2010 – FORTISBC ELECTRIC TARIFF BCUC NO. 1 FOR SERVICE IN THE WEST KOOTENAY AND OKANAGAN AREAS RE. "SCHEDULE 40 - WHOLESALE SERVICE - PRIMARY"
B-30	**SUBMITTED AT HEARING** May 07, 2010 – DOCUMENT HEADED "COSA IMPACT WITH NOMINATED DEMAND FOR WHOLESALE CUSTOMERS"
B-31	**SUBMITTED AT HEARING** May 07, 2010 – GROUP OF RESPONSES TO UNDERTAKINGS, FIRST PAGE RE: UNDERTAKING 18
B-32	**SUBMITTED AT HEARING** May 07, 2010 – ERRATA FOR FORTISBC RESPONSE TO INTERFOR ROUND 2 IR
B-33	Letter Dated May 14, 2010 – FortisBC responses to Information Requests from BCUC
B-33-1	Letter Dated June 16, 2010 – FortisBC Filing Errata to Information Requests
B-34	Letter Dated May 14, 2010 - FortisBC responses to undertaking requests from BCUC, BCMEU, Celgar and BCOAPO
B-35	Letter Dated May 14, 2010 – FortisBC submitting Revised COSA scenarios
B-35-1	Letter Dated May 27, 2010 – FortisBC Erratum to the Revised COSA scenarios
B-35-2	Letter Dated June 16, 2010 – FortisBC Filing Erratum 2 to the Revised COSA scenarios
B-36	Letter Dated June 14, 2010 Via Email - FortisBC responses to Letter No. L-44-10

Exhibit No.	Description
B-37	Letter Dated June 16, 2010 – FortisBC response to Information Requests from BCUC, BCOAPO, BCMEU, BSM, NG and Irrigation Ratepayers Group
B-38	Letter Dated June 23, 2010 – FortisBC's responses to Contentious IRs from BCUC IR No. 4, BCMEU IR No. 3 and Big White IR No. 3
B-3	Letter Dated June 23, 2010 – FortisBC's Erratum No. 11 to the application

INTERVENOR DOCUMENTS

C1-1	**BRITISH COLUMBIA MUNICIPAL ELECTRIC UTILITIES (BCMEU)** –Letter dated November 6, 2009 - Commenting on FortisBC's October 30, 2009 Application
C1-2	Letter Dated November 27, 2009 - Filing request by Christopher Weafer, Owen Bird Law Corporation council for Intervenor Status
C1-3	Letter Dated December 18, 2009 Via Email – BCMEU Information Request No. 1
C1-4	Letter Dated February 1, 2010 Via Email – BCMEU Information Request No. 2
C1-5	Letter Dated February 24, 2010 Via email – BCMEU Comments on Celgar submission Exhibit C-13-4
C1-6	Letter Dated March 15, 2010 - BCMEU Filing Evidence of Dr. Alan Rosenberg
C1-6-1	Letter Dated April 21, 2010 - BCMEU Filing Erratum to evidence of Dr. Alan Rosenberg
C1-7	Letter Dated March 24, 2010 Via Email – BCMEU Comments on FBC reply evidence request
C1-8	Letter Dated April 15, 2010 Via Email – BCMEU Responses to IR No1 from BCOAPO
C1-9	Letter Dated April 15, 2010 Via Email – BCMEU Responses to IR No1 from BCUC
C1-10	Letter Dated April 15, 2010 Via Email – BCMEU Responses to IR No1 from BWSR
C1-11	Letter Dated April 15, 2010 Via Email – BCMEU Responses to IR No1 from FBC
C1-12	Letter Dated April 26, 2010 Via Email – BCMEU Comments on FortisBC rebuttal evidence
C1-13	Letter Dated April 29, 2010 Via Email – BCMEU Supplemental responses to FBC Rosenberg evidence

Exhibit No.	**Description**
C1-14	Letter Dated April 29, 2010 Via Email – BCMEU Witness Panel
C1-15	**SUBMITTED AT HEARING** May 03, 2010 – HARDCOPY OF OPENING REMARKS OF C. WEAFER FOR BCMEU
C1-16	**SUBMITTED AT HEARING** May 03, 2010 – DOCUMENT ENTITLED "BONNEVILLE POWER ADMINISTRATION, 2008 BPA FACTS"
C1-17	**SUBMITTED AT HEARING** May 03, 2010 – ONE-PAGE DOCUMENT, STARTING "PROJECT NO. 3698570:APPLICATION FOR 2010 REVENUE REQUIREMENT"
C1-18	**SUBMITTED AT HEARING** May 03, 2010 – BCMEU EXCERPT FROM FORTISBC 2006 ANNUAL REPORT
C1-19	**SUBMITTED AT HEARING** May 03, 2010 – EXCERPT FROM FORTISBC 2007 ANNUAL REPORT
C1-20	**SUBMITTED AT HEARING** May 03, 2010 – LETTER DATED AUGUST 18, 2006 FROM D. BENNETT, FORTISBC, TO B.C.U.C., WITH ATTACHED APPLICATION RE: PRINCETON LIGHT AND POWER
C1-21	**SUBMITTED AT HEARING** May 03, 2010 – ONE-PAGE DOCUMENT HEADED "BCMEU WITNESS AID"
C1-22	Letter Dated May 12, 2010 Via Email – BCMEU Filing the undertaking response of the BCMEU's expert witness, Dr. Alan Rosenberg
C1-23	Letter Dated May 13, 2010 Via Email – BCMEU Filing the undertaking response to Irrigation Ratepayers Group
C1-24	Letter Dated May 21, 2010 Via Email – BCMEU Filing comments on FBC revised COSA
C1-25	Letter Dated June 1, 2010 – BCMEU Comments on proposed schedule and Information Request
C1-26	Letter Dated June 14, 2010 Via Email - BCMEU responses to Letter No. L-44-10
C2-1	**ANDY SHADRACK (AS)** Letter dated November 18, 2009 - Filing request for Registered Intervenor status
C2-2	Letter Dated December 18, 2009 Via Email – AS Information Request No. 1

Exhibit No.	Description
C2-3	Letter Dated February 24, 2010 Via email – AS Comments on Celgar submission Exhibit C-13-4
C2-4	Letter Dated March 14, 2010 Via Email – AS comments on FortisBC responses to IR No. 2
C2-5	Letter received March 15, 2010 – AS submission of document titled FortisBC Rate Design: Use Less, Pay More
C2-6	Letter received March 15, 2010 – AS submission of document titled Residential Electricity Costs Compared in the West Kootenay
C2-7	Letter received March 15, 2010 – AS submission of document titled Residential Electricity Costs Compared in the Okanagan-Boundary
C2-8	Letter dated January 31, 2010 – AS Information Request No. 2
C2-9	Letter dated March 22, 2010 – AS request regarding oral hearing
C2-10	Letter dated April 28, 2010 – AS Opening statement
C2-11	Letter dated May 18, 2010 – AS Comments on FBC submission on new evidence
C3-1	**HEDLEY IMPROVEMENT DISTRICT (HID)** Letter dated November 24, 2009 - Filing request for Registered Intervenor status by Richard Tarnoff
C3-2	Letter dated January 11, 2010 – HID confirming that Mr. Richard Tarnoff to represent the Hedley Improvement District
C4-1	**BIG WHITE SKI RESORT (BWSR)** Online Registration dated November 25, 2009 - Filing request for Registered Intervenor status by Cameron Lusztig
C4-2	Letter dated February 1, 2010 – BWSR Information Request No. 1
C4-3	Letter received March 29, 2010 – BWSR Information Request No. 1 to BCMEU
C4-4	Letter received May 18, 2010 – BWSR Comments on FBC submission on new evidence
C4-5	Letter Dated June 1, 2010 – BWSR Comments on Proposed Schedule for Final Argument
C4-6	Letter Dated June 2, 2010 – BWSR Information Request No. 2

Exhibit No.	Description
C4-7	Letter Dated June 14, 2010 Via Email - BWSR responses to Exhibit A-26 and, by extension, in response to Exhibit C13-21
C5-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION (BCOAPO) VIA EMAIL** Letter Dated November 24, 2009 - Filing request by and for Sarah Khan andBill Harper for Intervenor Status
C5-2	Email dated December 20, 2009 – BCOAPO filing Information Request No. 1
C5-3	Letter dated December 22, 2009 – BCOAPO filing IR No. 1 Supplemental
C5-4	Letter Dated February 1, 2010 – BCOAPO Information Request No. 2
C5-5	Letter Dated February 24, 2010 – BCOAPO Comments on Zellstoff-Celgar application to add the issue of the appropriateness and determination of a GeneraUon Baseline
C5-6	Letter Dated March 29, 2010 - BCOAPO Information Request No.1 to BCMEU
C5-7	Letter Dated March 29, 2010 - BCOAPO Information Request No.1 to Celgar
C5-8	Letter Dated March 29, 2010 - BCOAPO Information Request No.1 to IFP
C5-9	Letter Dated May 21, 2010 – BCOAPO Comments regarding FortisBC's revised COSA filings
C5-10	Letter Dated June 1, 2010 – BCOAPO Comments on Proposed Schedule for Final Argument
C5-11	Letter Dated June 1, 2010 – BCOAPO Information Request No. 3
C6-1	**TOWN OF OLIVER (TOO)** Online Registration dated November 25, 2009 - Filing request for Registered Intervenor status by Warren Everton
C7-1	**CITY OF ROSSLAND (COR) VIA EMAIL** Letter Dated November 26, 2009 - Filing request by Victor Kumar for Intervenor Status
C8-1	**INTERNATIONAL FOREST PRODUCTS (IFP) VIA EMAIL -** Letter Dated November 30, 2009 - Filing request by Rick Williams for Intervenor Status
C8-2	Letter Dated December 18, 2009 – IFP Information Request No. 1
C8-3	Letter Dated February 1, 2010 Via Email – IFP Information Request No. 2
C8-4	Letter Dated March 15, 2010 – IFP filing the evidence of Mr. Stephen Williams

Exhibit No.	Description
C8-5	Letter Dated March 16, 2010 – IFP Request to be excused from attending portions of the hearing
C8-6	Letter Dated March 30, 2010 – IFP Comments of FBC reply evidence
C8-7	Letter Dated April 8, 2010 – IFP requests clarification of quote from BCUC IR No. 1
C8-8	Letter Dated April 15, 2010 – IFP Response to Information Requests from BCUC, BCOAPO and FBC
C8-9	Letter Dated April 22, 2010 – IFP Resubmitting response to Information Requests from BCOAPO, FortisBC and BCUC
C8-10	Letter Dated April 29, 2010 – IFP Witness opening statement
C8-11	Letter Dated May 28, 2010 – IFP Comments on Proposed Schedule of Final Argument
C9-1	**ROXUL INC (RI) -** Letter Dated December 1, 2009- Filing request by Deighton Jarrett of En-Pro International Inc (Energy and Commodity Consultants) for Intervenor Status
C9-2	Letter Dated December 18, 2009 – RI Notice of new council McCarthy Tetrault LLP
C9-3	Letter Dated December 18, 2009 – RI Information Request No. 1
C9-4	Letter Dated April 30, 2010 – RI Comments on Application
C10-1	**NORMAN GABANA (NG)** Online Registration dated December 3, 2009 - Filing request by Norman Gabana for Intervenor Status
C10-2	Letter received June 3, 2010 – NG Information Request
C11-1	**ALAN WAIT (AW)** Online Registration dated December 9, 2009 - Filing request by Alan Wait for Intervenor Status
C11-2	Letter Dated December 18, 2009 – AW Information Request No. 1
C11-3	Letter Dated February 1, 2010 - AW Information Request No. 2
C11-4	Letter Dated February 24, 2010 – Response to Celgar request
C11-5	Letter Dated June 1, 2010 – AW Comments on Proposed Schedule for Final Argument

Exhibit No.	Description
C12-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH) –**December 9, 2009 requesting Intervenor status
C12-2	Letter Dated February 24, 2010 – BC Hydro's comments on Celgar request
C12-3	Letter Dated March 31, 2010 – BC Hydro's submissions regarding FortisBC7s Reply Application
C13-1	**ZELLSTOFF CELGAR LIMITED PARTNERSHIP (CELGAR)** – Filing request for Intervenor status by Mr. K.C. Moller of Sangra Moller LLP, legal counsel for Celgar
C13-2	Letter Dated December 18, 2009 – Celgar Information Request No. 1
C13-3	Letter Dated February 1, 2010 Via Email – Celgar Information Request No. 2
C13-4	Letter Dated February 15, 2010 – Celgar seeking decision from the Commission Panel
C13-5	Letter Dated February 22, 2010 Via Email – Celgar Filing additional contacts
C13-6	Letter Dated February 25, 2010 Via Email – Celgar Further comments and reply to Exhibit C13-4
C13-7	Letter Dated March 15, 2010 – Celgar submission of evidence
C13-7-1	Letter Dated March 15, 2010 – Celgar Errata to submission of evidence
C13-8	Letter Dated March 26, 2010 – Celgar submission support for Reply Evidence
C13-9	Letter Dated April 15, 2010 – Celgar Response to Information Request from BCOAPO
C13-10	Letter Dated April 15, 2010 – Celgar Response to Information Request from BCUC
C13-11	Letter Dated April 15, 2010 – Celgar Response to Information Request from FBC
C13-12	Letter Dated April 27, 2010 – Celgar Submitting witness panel
C13-13	**SUBMITTED AT HEARING** May 03, 2010 – HARDCOPY OF OPENING STATEMENT OF K. MOLLER FOR ZELLSTOFF CELGAR
C13-14	**SUBMITTED AT HEARING** May 03, 2010 – HARDCOPY OF OPENING STATEMENT OF THE ZELLSTOFF CELGAR WITNESS PANEL

Exhibit No.	Description
C13-15	**SUBMITTED AT HEARING** May 03, 2010 – BCUC COMMISSION PANEL INFORMATION REQUEST NO. 1 RE: "B.C. HYDRO BIOENERGY CALL PHASE 1 - EPA'S
C13-16	**SUBMITTED AT HEARING** May 03, 2010 – ONE-PAGE DOCUMENT HEADED "ZELLSTOFF CELGAR EPA"
C13-17	**SUBMITTED AT HEARING** May 04, 2010 – Celgar CHART ENTITLED "ACCOUNTING AND METERING OF ENERGY FROM CELGAR"
C13-18	Letter Dated May 13, 2010 Via Email – Celgar Filing Undertaking responses
C13-19	Letter Dated May 21, 2010 Via Email – Celgar Filing comments on FBC revised COSA
C13-20	Letter Dated June 1, 2010 – Celgar Comments on Proposed Schedule for Final Argument
C13-21	Letter Dated June 7, 2010 – Celgar Comments regarding Information Requests relating to Exhibits B-33 and B-35
C14-1	**TOWN OF OSOYOOS (TO)** Online Registration Dated December 14, 2009 - Filing request by Stu Wells for Intervenor Status
C15-1	**TOWN OF PRINCETON (TP)** Online Registration Dated December 14, 2009 - Filing request by Randy McLean for Intervenor Status
C16-1	**ATCO WOOD PRODUCTS LTD (ATCO)** Online Registration Dated December 14, 2009 - Filing request by Scott Weatherford for Intervenor Status
C17-1	**OKANAGAN ENVIRONMENTAL INDUSTRY ALLIANCE (OEIA)** Online Registration Dated December 14, 2009 - Filing request by Ludo Bertsch for Intervenor Status
C17-2	Email dated December 19, 2009 – OEIA/Bertsch filing Information Request No. 1
C17-3	Letter Dated February 1, 2010 – OEIA Information Request No. 2
C18-1	**WEYERHAEUSER LTD (WH)** Online Registration Dated December 14, 2009 - Filing request by Jeff Larsen for Intervenor Status
C18-2	Letter Dated April 26, 2010 – WH Notice of retained council David Burset of Bull, Housser & Tupper
C19-1	**RED MOUNTAIN RESORT (RMR)** Online Registration Dated December 14, 2009 - Filing request by Don Thompson for Intervenor Status

Exhibit No.	Description
C20-1	**BERYL SLACK** Letter dated December 12, 2009 - Filing request by Beryl Slack for Intervenor status
C20-2	Letter dated April 22, 2010 Via Fax – B. Slack's comments on Oral Public Hearing
C21-1	**NELSON HYDRO (NH)** Letter dated December 9, 2009 - Filing request by Heather Grant for Intervenor status
	****Part of BCMEU – See Intervenor Exhibit C1 for filings****
C22-1	**KEREMEOS IRRIGATION DISTRICT, FAIRVIEW HEIGHTS IRRIGATION DISTRICT AND SIMILKAMEEN IMPROVEMENT DISTRICT (IRRIGATION RATEPAYERS GROUP)** Letter dated March 1, 2010 - Filing request for Late Intervener Status by Brian Mennell
C22-2	KIFHSI Facsimile dated March 10, 2010 – Information Request No. 1
C22-3	Letter dated March 15, 2010 – Irrigation Ratepayers Group Filing comments and letters of support
C22-4	Letter dated April 14, 2010 – Irrigation Ratepayers Group Filing notice of Fred Weisberg, Weisberg Law Corporation as counsel
C22-5	Letter dated April 15, 2010 – Irrigation Ratepayers Group Filing extension request for Information Request Responses from FortisBC Inc.
C22-6	Letter dated April 19, 2010 – Irrigation Ratepayers Group Responses to Information Request No. 1 from FortisBC
C22-7	Letter dated April 29, 2010 – Irrigation Ratepayers Group Witness Panel and direct evidence
C22-8	Letter dated April 30, 2010 – Irrigation Ratepayers Group Addition to Witness Panel
C22-9	**SUBMITTED AT HEARING** May 03, 2010 – LETTER DATED MAY 1, 2010 FROM F.J. WEISBERG TO BCUC WITH ATTACHMENTS
C22-10	**SUBMITTED AT HEARING** May 03, 2010 – HARDCOPY OF OPENING STATEMENT BY MR. F.J. WEISBERG FOR THE IRRIGATION RATEPAYERS GROUP
C22-11	**SUBMITTED AT HEARING** May 04, 2010 – BCUC DECISION DATED OCTOBER 5, 1984, RE. "WEST KOOTENAY POWER AND LIGHT"
C22-12	**SUBMITTED AT HEARING** MAY 06, 2010 – HARDCOPY OF OPENING STATEMENT OF IRRIGATION RATEPAYERS GROUP WITNESS PANEL

Exhibit No.	Description
C22-13	**SUBMITTED AT HEARING** MAY 07, 2010 – ONE-PAGE UNDATED LETTER FROM F. HELLWIG OF VINCOR CANADA TO THE BCUC
C22-14	**SUBMITTED AT HEARING** MAY 07, 2010 – BC HYDRO RATE SCHEDULES EFFECTIVE 01 APRIL 2010, RE. SCHEDULE 1401 – IRRIGATION
C22-15	Letter dated May 21, 2010 – Irrigation Ratepayers Group Filing comments on FBC revised COSA
C22-16	Letter dated June 2, 2010 - Irrigation Ratepayers Group Filing Information Request No. 1 to FortisBC
C22-17	Letter dated June 4, 2010 - Irrigation Ratepayers Group Submission regarding Proposed Schedule of Final Argument

INTERESTED PARTY DOCUMENTS

D-1	**LILA PARSONS (LP)** Letter dated December 10, 2009 - Filing request by Lila Parsons for Interested Party status and comments on application

LETTERS OF COMMENT

E-1	**CROCKET, SID -** Letter of Comment dated December 11, 2009
E-2	**FIPKE, WAYNE -** Letter of Comment dated May 8, 2010
E-3	**HUTCHEON, IAN AND MCMECHAN, COLLEEN -** Letter of Comment dated May 8, 2010
E-4	**FOSSEN RANCH-** Letter of Comment dated May 8, 2010 Via Fax
E-5	**KETTLE RIVER STOCKMEN'S ASSOCIATION -** Letter of Comment dated May 10, 2010
E-6	**SOUTHERN INTERIOR STOCKMEN'S ASSOCIATION – L**etter of Comment dated May 27, 2010