IN THE MATTER OF

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

AND

F2009 AND F2010 REVENUE REQUIREMENTS

DECISION

March 13, 2009

Before:

L.A. O'Hara, Panel Chair and Commissioner
R.J. Milbourne, Commissioner
A.A. Rhodes, Commissioner

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OVERVIEW

These Reasons for Decision are issued in respect of the Commission's Order G-16-09 issued on March 13, 2009. The Reasons are set out as follows:

Section 1.0 describes the procedural background to the Application and the regulatory and policy framework within which it was made. It also describes the conduct of the hearing which included several evidentiary updates which were caused by a drastic change in economic conditions between February 20, 2008 (filing date) and October 29, 2008 (closure of the record).

Section 2.0 addresses jurisdictional matters with emphasis on the scope of the Commission's discretion in reviewing BC Hydro's forecasts and planned expenditures as well as the role of prudency. The Commission Panel considers the overall legislative scheme provided by the Act and HC2 and finds that the submissions and authorities cited by BC Hydro do not fetter the Commission Panel's discretion in respect of making determinations to the extent claimed by BC Hydro. Furthermore, the Commission Panel finds that in the case of reviewing the cost consequences of BC Hydro's past management decisions a rebuttable presumption of prudency is relevant. However, with respect to planned and forecast expenditure for the test period the Commission Panel concludes that a presumption of prudency has little, if any, relevance to the matters reviewed.

Section 3.0 outlines the context of the Application, including key influences, key cost drivers as well as the goals and objectives defined as safety, reliability and low cost service over the long-term, and summarizes the specific approvals sought by BC Hydro. The Commission Panel makes no determinations in respect of BC Hydro's safety programs or reliability performance but requests BC Hydro to report on any progress towards a formalized safety management program and to provide more quantifiable links between its planned expenditures to the maintenance and/or improvement in its supply and distribution reliability to justify those measures and expenditures in its next RRA.

Section 4.0 examines all aspects of the revenue requirements for the F2009-F2010 test period. Determinations in both this and subsequent sections reflect the impacts of the downturn in the economy, uncertainty regarding the current economic conditions and volatility in the broader financial markets. First, the Commission Panel accepts BC Hydro's evidence as to the significant uncertainty surrounding its load forecast and its proposal to defer the net impact. Second, concerning the revenue forecast, the Commission Panel finds that BC Hydro has shown a significant tendency to underestimate its trade income from Powerex and directs BC Hydro to adjust its forecast net income from Powerex to $199 million in each of the test years. The Commission Panel requests that BC Hydro initiate discussions with the Province with a view to amending the current $200 million limit. Third, regarding the domestic energy costs, the Commission Panel accepts BC Hydro's forecasts subject to specific determinations regarding the G.M. Shrum Unit 3 failure, F2006 Call, load curtailment and use of "average water" to establish cost of energy.

In its review of operating costs in Section 4.4 the Commission Panel reviews BC Hydro's approach to budgeting vis-à-vis presentation of OMA costs in the Application, base operating costs, new on-going and fixed-term initiatives, resourcing strategies, capitalized overheads as well as trend analysis, benchmarking and productivity issues to test the overall reasonableness of the forecast.

The Commission Panel approves most of the planned initiatives but expresses concern regarding the Procurement Enhancement Initiative estimated to cost some $30 million, excluding the capital investments necessary. The reasonableness of this initiative is to be examined in a future proceeding once more information regarding the quantifiable benefits is available.

The Commission Panel also expresses concern over significant increases (32 percent over the test period) in net labour expense noting that the three key factors influencing BC Hydro's resourcing strategies, namely pre-hiring for knowledge transfer due to the "retirement bubble", load growth, and availability of skilled labour, may all be in turn impacted by the economic downturn in North America. A recognition of this unprecedented uncertainty is the Panel's direction to BC Hydro to segregate to the Employee Cost Regulatory Account any variance from its planned total employment costs for the test period with the balance in that account at the end of 2010 to be dealt with in the next revenue requirement application.

Section 5.0 addresses deferral and other regulatory accounts reflecting a temporary increase in the use of deferral mechanisms as a short-term transient measure to manage the prevailing uncertainty and volatility in the economy as well as to convey the desire of the Commission Panel to ensure that ratepayers enjoy rates based on realistic forecasts and have the benefit of symmetry in positive and negative variances. Examples of forecasts that will be temporarily dealt with by way of new deferral mechanisms include load forecast, finance costs, F2010 non-current pension costs and amortization.

Section 6.0 deals with miscellaneous other issues such as gas hedging, capital plan, risk sharing between BC Hydro and its ratepayers and insurance, deemed equity and reporting.

Section 7.0 reviews BC Hydro's revenue requirements in a summary fashion and to achieve balance amongst the matters in subsection 60(1)(b) of the *Act* the Commission Panel directs BC Hydro to establish rates for F2010 in its compliance filing that reflect its operating costs for that year at 97 percent of those applied-for, which approximates a reduction of some $20 million in the revenue requirements for F2010.

Section 8.0 deals with OIC No. 074 issued February 17, 2009 which further amends Heritage Special Direction No. HC2 as of that date.

Section 9.0 provides a summary of directives.

Section 10.0 records the dissenting view of Commissioner Rhodes in respect of the Commission Panel Majority Determination on the issue of Interest Rates.

1.0 INTRODUCTION

1.1 Procedural Background

On February 20, 2008 British Columbia Hydro and Power Authority ("BC Hydro") submitted its F2009/F2010 Revenue Requirements Application ("the F09/F10 RRA" or "the Application") seeking, among other things, a British Columbia Utilities Commission ("Commission") order for across-the-board rate increases of 6.56 percent and 8.21 percent effective April 1, 2008 for F2009 and April 1, 2009 for F2010, respectively. BC Hydro also sought an order to reduce the Deferral Account Rate Rider ("DARR") from 2.0 percent to 0.5 percent, effective April 1, 2008 (Exhibit B-1).

In the covering letter accompanying its Application, BC Hydro also sought interim orders effective April 1, 2008 in the F09/F10 RRA pursuant to sections 58 -61 and 90(2) of the Utilities Commission Act ("*UCA*" or "*Act*") for a refundable 6.56 percent across-the-board rate increase and a decrease in the Rate Rider from 2.0 percent to 0.5 percent. On March 14, 2008 by Order G-40-08, the Commission granted BC Hydro the interim rate relief it sought, to be applied as described in Appendix R of the Application.

In that letter BC Hydro also sought Commission determinations in respect of the process for dealing with certain other proceedings which were both imminent, and intersected with, the F09/F10 RRA. Specifically, BC Hydro filed its Transmission Service Re-pricing Application ("the TSRA") dated February 22, 2008, and its 2008 Residential Inclining Block Rate Application ("the 2008 RIB") on February 26, 2008. By Order G-28-08 dated February 28, 2008, the Commission established a Procedural Conference to be held April 28, 2008 to consider the process for dealing with these matters. By Order G-78-08 dated April 30, 2008, the Commission determined that the F09/F10 RRA would be reviewed by way of a Negotiated Settlement Process ("NSP") and ordered that:

> "The scope of the NSP will include all of the issues arising from the F09/F10 RRA, except for [DSM issues] including DSM expenditures during the test period, the anticipated demand response to those expenditures, and the appropriate

> amortization period for the expenditures. The revenue implications of the [TSRA] are to be included within the scope of the NSP."

In that Order, the Commission also established the regulatory timetable for the review of the Application, with provision for an oral public hearing commencing October 6, 2008 in the event that the NSP was unsuccessful in its totality, or if it was unable to reach a conclusion on some of the issues in the Application.

On July 2, 2008 BC Hydro filed an evidentiary update ("the July EU") that included, among other things, F2008 actual results, updated DSM savings and expenditures, and updated forecasts for energy sales, revenues, and cost of energy. In the aggregate, if approved, the permanent rates for F09 and F10 would give rise to increases of approximately 9 percent per year, respectively. To mitigate these increases, BC Hydro proposed a deferral mechanism which, if approved, would give rise to final rate increases of 5.96 percent and 8.12 percent for F09 and F10, respectively. BC Hydro further projected an increase in the Rate Rider from 0.5 percent for F09 to 1.0 percent for F10 (Exhibit B-10).

By letter dated August 13, 2008 the Joint Industry Electricity Steering Committee ("JIESC") advised the Commission and the parties that in light of the July EU it no longer supported the NSP and believed that a full public review of the Application was required (Exhibit C5-7). By letter dated August 14, 2008, the BC Old Age Pensioners' Organization et al. ("BCOAPO") essentially concurred with the JIESC position (Exhibit C12-5). In response, BC Hydro acknowledged that "without the willing participation of these two Intervenors, it is not worthwhile proceeding with the NSP" (Exhibit B-15).

In light of these developments, by Order G-119-08 dated August 15, 2008, the Commission established a further Procedural Conference to be held August 21, 2008 to consider the regulatory timetable for the balance of the review of the Application, as well as certain other matters which had recently arisen. These included the August 13, 2008 application by Local 378 of the Canadian Office and Professional Employees Union ("COPE") for leave to apply to file Intervenor evidence in the proceeding, and the July 30, 2008 Information Requests from Mr. Stuart Meade, an Intervenor (Exhibit A-15).

The Procedural Conference was held as scheduled. BC Hydro made extensive submissions to the effect that:

- given the extensive record established to date, the evidentiary record should be closed and the review proceed by way of a written hearing process; or, in the alternative;
- if an oral hearing process was determined to be required, the Application should be combined with BC Hydro's 2008 Long-term Acquisition Plan ("the 2008 LTAP") as applied for June 12, 2008, inasmuch as that proceeding would be considering the DSM issues, and that those determinations were necessary to establish the permanent rates for F09 and F10;
- there was insufficient information available to establish the relevance, if any, of the COPE evidence; and
- there was insufficient information to establish that Mr. Meade had a substantial interest in the proceeding.

By Order G-122-08 dated August 25, 2008, the Commission Panel determined that:

- the Oral Public Hearing scheduled for October 6, 2008 would proceed;
- the scope of the proceeding would remain as defined in Order G-78-08;
- leave was granted for COPE to file its application and proposed evidence by September 5, 2008, with submissions from BC Hydro and the parties by September 10, 2008 and COPE's reply by September 11, 2008; and
- BC Hydro did not have to respond in writing to Mr. Meade's Information Requests ("IRs") (Exhibit A-17).

By Order G-134-08 dated September 18, 2008, the Commission Panel accepted the COPE evidence as part of the evidentiary record. As well, BC Hydro was directed to file an evidentiary update to, among other things, reflect its current intentions in relation to its Accenture Business Services

British Columbia Limited Partnership ("ABSBC" or "Accenture") contract and future procurement policies by September 29, 2008 (Exhibit A-20).

1.2 Regulatory and Policy Framework

The Application gives rise to the third review of BC Hydro's revenue requirements since BC Hydro's rates were unfrozen in 2003 and returned to oversight by the Commission.

The first review, the F05/F06 RRA, was by way of an oral public hearing process, and took place in the context of the Heritage Contract, Special Directions relevant to it, and the 2002 Energy Plan. The results of that review are described in Order G-96-04 dated October 29, 2004 and the Reasons for Decision accompanying that Order.

The second review, the F07/F08 RRA, was by way of a Negotiated Settlement Process ("NSP"), and took place in a context materially unchanged from that of the first review. The outcome of that review is described in Order G-143-06. Numerous directives from the Commission to BC Hydro were made in Order G-96-04 and commitments made by BC Hydro were reflected in Order G-143-06. Many of these related to the impacts of the external policy framework on BC Hydro. As well, many are brought forward to this Application or to the 2008 LTAP proceeding. Tables 8.1 and 8.2 of Exhibit B-1 provide BC Hydro's summary of the disposition and/or current status of all as of the date of the Application.

In 2007, a second Provincial Energy Plan ("the 2007 Energy Plan") came into effect. The aspects of that Plan, its precursor, the 2002 Energy Plan, the Heritage Contract, and certain Special Directions to the Commission that impact on BC Hydro's rates were considered at length and summarized in Chapters 1 and 2 of the Reasons for Decision accompanying Order G-130-07 in the matter of BC Hydro's 2007 Rate Design Application ("the 2007 RDA"), and are incorporated here by reference.

Subsequent to the 2007 RDA Decision, amendments to the *UCA* came into effect which, among other things, set aside the Commission's determinations in the 2007 RDA in respect of rate re-balancing among BC Hydro's customer classes and, as well, gave certain directions to BC Hydro and the Commission in respect of matters such as "Smart Metering." Many aspects of these amendments that impact on BC Hydro were considered and summarized at Sections 1.2 and 1.3 of the Reasons for Decision accompanying Order G-124-08 in the matter of the 2008 Residential Inclining Block Rate Application ("the 2008 RIB") and are also incorporated here by reference. As well as the foregoing amendments to the *Act*, others, in particular those reflected in subsection 44.2(2) that relate to recovery of DSM expenditures, and those in the repealed subsections 45(6.1) and (6.2) that relate to BC Hydro's capital program, will be dealt with in Sections 4.10 and 6.2 of this Decision, respectively.

Other matters arising since the F07/F08 RRA Order also intersect with this Application. In particular, pursuant to applications by BC Hydro, Orders G-76-07, G-77-07, G-11-08 and G-17-08 established deferral mechanisms for costs arising from F2007 storm damage, First Nations matters, and BC Hydro's Purchasing Enhancement Initiative ("the PEI") respectively. These are dealt with in Section 5.0 of this Decision.

1.3 Conduct of the Hearing

1.3.1 Evidentiary Record

At the commencement of the oral public hearing phase on October 6, 2008, the record included three rounds of Information Requests ("IRs") and responses. As well, it included the Intervenor evidence filed by the JIESC (Exhibit C5-10) and IR responses to it, and the Direct Evidence of BC Hydro's witness panels (Exhibit B-21).

Further, the record included the COPE evidence as noted above (Exhibit C3-7) and BC Hydro's evidentiary update in that regard dated September 29, 2008 (Exhibit B-20).

In addition to its July EU to the Application as noted above, BC Hydro filed a further evidentiary update dated October 1, 2008 ("the October EU") which reflected, among other things, revised interest rate forecasts provided to it by BC Treasury Board Staff (Exhibit B-22). In respect of those revisions, BC Hydro amended its request for rate relief to seek permanent rates for F09 and F10 reflecting rate increases of 4.59 percent and 8.10 percent respectively. In Argument, BC Hydro further amended these increases to 6.56 percent and 7.50 percent for F09 and F10, respectively. No changes to the other requested final orders as set out in Section 1.9 of the Application were sought, nor was any change sought in the current interim rates that went into effect on April 1, 2008. The rates sought included the impact of the deferral mechanism as proposed in the July EU.

1.3.2 Issues List

Following receipt of submissions from the parties, by letter dated October 1, 2008 (Exhibit A-22) the Commission Panel determined that it would not issue an Issues List.

1.3.3 Commencement of the Oral Hearing Phase of the Review

The Oral Hearing commenced on October 6, 2008. BC Hydro and several Intervenors made opening statements which, in part, referred to the overall nature of the review and the current context. These aspects are summarized as follows:

- BC Hydro distinguished the Commission's discretion and jurisdiction in a RRA proceeding from that which it has in a rate design hearing (T3: 208). BC Hydro stated that sections 58 to 61 of the Act, and certain special directions under the BC Hydro Public Power Legacy and Heritage Contract Act and *UCA* collectively prescribe the Commission's rate setting powers in respect of BC Hydro, and that the key special direction affecting the Commission's jurisdiction with respect to BC Hydro's rates and revenue requirements is Heritage Special Direction No. HC2 ("HC2") at sections 4 through 7. In particular, BC Hydro stated that sections 4 and 5(d) require the Commission to set BC Hydro's rates to allow recovery of the cost of providing reliable electricity service, including an annual return on deemed equity.

- BC Hydro further stated that its cost of service reflects decisions that are the obligation and prerogative of its management to make, as set out in Section 5 of the Hydro Power and Authority Act. Accordingly, absent evidence of imprudence, BC Hydro stated that it would be inappropriate for the Commission, as constrained by its statutory framework, to substitute its opinion for how the utility should be managed or to otherwise impose upper bounds on its rates. BC Hydro stated that it anticipated these matters would be raised in the proceeding and would be addressed in its Argument (T3: 206-210).

- The Independent Power Producers of BC ("IPPBC") noted that the water usage rates paid by many of its members were linked to BC Hydro's rates, and further, that its members were impacted by the reliability of BC Hydro to accept and distribute its members' production. Accordingly it submitted that the review should be focused on selectively minimizing rates while maximizing reliability (T3: 214-215, 216-217).

- The JIESC questioned the rationale for the deferral approach advocated by BC Hydro in its July and October EU's, noting that the effect was to shift current period costs to the future. It also submitted that the onus was on BC Hydro to establish the necessity of its costs, not on the Commission or the Intervenors to prove otherwise. As well, JIESC noted that inasmuch as BC Hydro had submitted its costs in a formulaic or global format rather than on a line item basis, then the review should take a comparable approach to their approval (T3: 231, 223-226).

- The Commercial Energy Consumers of BC ("CEC") noted BC Hydro's role as an implementer of Government Energy Policy and stated that it was for BC Hydro to justify how it exercised its management discretion in the implementation of those policies and that that judgment is subject to Commission review (T3: 235).

- The CEC also noted the dynamic and challenging economic environment and the dramatic changes in it since the July EU (T3: 236).

- BCOAPO also noted the dramatic change in the economic context from the time of filing of the Application, expressing concern with both the formulaic approach to the presentation of BC Hydro's costs and its proposed deferral approach to short-term mitigation of rates (T3:253-256).

- The BC Sustainable Energy Association/Sierra Club of BC ("BCSEA") echoed other Intervenors' concerns with the deferral approach proposed by BC Hydro (T3: 259).

- COPE amplified the concern expressed by the CEC in respect of BC Hydro's implementation of Government Energy Policy, and emphasized the need for transparency in reviewing those costs (T3: 262).

- COPE also took issue with BC Hydro's position as to the limited jurisdiction of the Commission in respect of the review of the Application, characterizing the issue as not one of the Commission substituting its judgment for that of BC Hydro, but rather one of the Commission exercising its discretion to decide who should be bearing the regulatory risks of unnecessary or unjustifiable cost increases (T3:263).

- Mr. Alan Wait noted a “fundamental problem” where the owner of the Utility also can and does give direction to the Commission, and the costs must be absorbed by the ratepayers (T3: 266).

- Mr. Stuart Meade questioned whether the actions of BC Hydro in respect of service cut-offs and the conduct of its Fraud Office were appropriately within its jurisdiction (T3: 271).

1.3.4 Witness Panels

BC Hydro provided six witness panels for cross-examination. The panels were either chaired by or included a senior executive of BC Hydro. In the course of the hearing, a seventh panel was made available, for reasons described at Section 1.3.5 below. The scope of the Panels and their chairs are as follows:

Table 1.1

Panel 1	Policy:	Bob Elton Chief Executive Officer
Panel 2	Consolidated Finance Accounting Load and Revenue Forecast:	Charles Reid Executive VP Finance and CFO
Panel 3	Communications, Safety and Health, Environment and Human Resources:	Susan Yurkovich Senior VP Corporate Affairs
Panel 4	Procurement, Accenture Relationship, Information Technology and Property:	Tony Morris Strategic Procurement Manager
Panel 5	Customer Care, Conservation and Field Operations:	Bev Van Ruyven Executive VP Customer Care and Conservation (“CC&C”)
Panel 6	Engineering, Aboriginal Relations and Generation (“EARG”):	Chris O’Riley Senior VP EARG
Panel 7	Financial Management:	Charles Reid Executive VP Finance and CFO

Source: Exhibit B-21

Intervenor witnesses provided for cross examination were Lloyd Guenther, President, First Solutions Inc. (on behalf of the JIESC), and Gwenne Farrell, Vice President (on behalf of COPE).

1.3.5 Omnibus Economic Update

In the course of the proceeding, on October 10, 2008 the Panel Chair invited BC Hydro to reconsider its approach to updating its Application to account for more current forecast information, and its deferral account proposal, in light of current economic conditions and volatility in the broader financial markets (T7: 1064, 1128). In response, BC Hydro filed its omnibus economic update ("OEU") containing updated assumptions as to load, wholesale energy prices, trade income and foreign exchange rates as of October 17, 2008 (Exhibit B-64), noting that while it did not yet have a proposal as to how it should be addressed, that there were three options:

1. continue the review as scheduled and deal with the OEU in Argument; or
2. update the facts and amend the rate relief requested; or
3. make more use of Deferral Accounts;

and that it would provide a proposed approach for consideration by the parties in due course. The Intervenors generally agreed with BC Hydro's suggestion, with IPPBC noting that today's level of uncertainty was not unusual, and that a long-term view should be taken (T7: 1229-1230).

On October 17, 2008 BC Hydro proposed that the parties make submissions as to the process for dealing with the OEU, and that it would make a seventh witness panel available, to be chaired by Charles Reid, Executive VP Finance and CFO.

On October 20, 2008 submissions were received from the parties. The JIESC noted the materiality of the changes from the July EU with the potential for rate increases now being 3.75 percent for F09 and 10.17 percent for F10 with the elimination of the previously proposed deferral mechanism. It proposed an adjournment of the Oral Hearing to permit a fourth round of IRs to inquire further into the matters raised by the OEU, that the matters it raised relating to post-employment benefits ("PEBs") be spun out to a separate future proceeding, and that the Oral Hearing resume after the IR responses were received, with the Intervenor witness panels to be scheduled after cross examination of BC Hydro's Panel 7 (T12: 2109-2115).

BCOAPO generally supported the JIESC's approach, while taking no position on the separation of the PEB matters. The CEC generally supported the JIESC's approach, including separation of the PEB matters (T12: 2115-2117).

IPPBC did not support the JIESC proposal, noting that the numbers that had changed could just as easily change again, and suggested that the matters be dealt with by examination of Panel 7 without the need for the further round of IRs (T12: 2117-2119).

BCSEA emphasized the importance of procedural certainty, noting that changes can come up in any review. It endorsed the examination of Panel 7, and took no position on the separation of the PEB matters (T12: 2120-2121).

In response BC Hydro noted that volatility issues could be handled through deferral mechanisms, citing in particular the approach approved by the Commission for Terasen Utilities and FortisBC to deal with their PEBs. It noted that while a further round of IRs could be helpful, the timetable proposed by JIESC created witness scheduling problems for Panel 7, and introduced unnecessary delay. It did not support the separation of the PEB matters (T12: 2128-2132).

Following consideration of the parties' submissions, the Commission Panel determined that the Hearing would adjourn on October 21, 2008 after the examination of BC Hydro Panel 6, a fourth round of IRs would be scheduled with requests to BC Hydro by October 23, 2008 and the responses by BC Hydro by October 27, 2008, with the resumption of the Hearing on October 29, 2008 for the evidence of BC Hydro Panel 7, to be followed by the examinations of the Intervenors' witness panels. The PEB matters would remain within the scope of the review (T12: 2136-2137).

1.3.6 Closure of the Record of the Proceeding October 29, 2008

There was agreement among the parties as to the dates for filing outstanding Undertakings and Final Argument. BC Hydro undertook to file its Undertakings by November 21, 2008, with one particular exception involving benchmarks, which was to be filed by December 3, 2008 if information was available. The outstanding undertakings from the JIESC Panel were committed to be filed by November 7, 2008.

The schedule for Final Argument was established as:

- BC Hydro by November 21, 2008
- Intervenors by December 5, 2008
- BC Hydro Reply by December 19, 2008

An Oral Phase of Argument, if required, was scheduled for January 6, 2009.

The Commission Panel Chair indicated that the Commission Panel would consider whether a listing of matters on which it particularly wished to receive submissions in Argument would be of assistance in the review, and if so, would issue such a list in a timely fashion.

On motion from Commission Counsel, subject to the filing of outstanding undertakings, the Commission Panel Chair declared the evidentiary record closed on October 29, 2008.

1.3.7 Commission Panel List of Matters for Argument

By letter dated November 3, 2008, the Commission Panel provided the parties with a listing of matters where the Commission Panel believed that its determinations could be helpfully informed (Exhibit A-24, Appendix 1 to this Decision).

1.3.8 Oral Phase of Argument

By letter dated December 30, 2008, the Commission Panel advised the parties that it required an Oral Phase of Argument, and provided a list of seven matters on which it invited submissions (Exhibit A-26, Appendix 2 to this Decision). By agreement among the parties the oral phase was scheduled for 9:00 a.m. on January 16, 2009 and took place on that date, concluding on January 17, 2008.

Where the parties' submissions in the Oral Argument Phase are relevant to the Commission Panel's determinations, they are described in the relevant section of this Decision.

2.0 JURISDICTIONAL MATTERS

2.1 Scope of the Commission's Review and the Role of "Prudency"

The relevant statutory framework governing the Application is found in the *Utilities Commission Act*, R.S.B.C. 1996, c. 473 as amended (previously defined as "the *Act*", "*UCA*"), the *Hydro and Power Authority Act*, R.S.B.C. 1996, c. 212 as amended ("*Hydro Act*"), the *BC Hydro Public Power Legacy and Heritage Contract Act*, S.B.C. 2003 ("*Heritage Contract Act*"), and Heritage Special Direction No. HC2 as amended by Order in Council 028 dated January 17, 2008, made pursuant to sections 3 and 4 of the *Heritage Contract Act* ("HC2").

In addition to the statutory framework, the consideration of the prudency of the decisions of BC Hydro's management played a significant role in the proceedings.

2.1.1 Statutory Framework

The Commission's rate setting powers are found in sections 58-61 inclusive of the *Act*. The powers found in these sections are subject to certain limitations either found elsewhere in the *Act* (for example, section 44.2(2)) or in HC2. Section 3 of the *Act* requires the Commission to comply with special directions issued by the Lieutenant Governor in Council. HC2 is such a special direction.

In addition, sections 25 and 38 of the *Act* are relevant to the Application. Those sections respectively empower the Commission to determine whether a public utility is providing "reasonable, safe, adequate and fair service" and order the public utility to provide such service and to require a public utility to provide service that the Commission "considers is in all respects adequate, safe, efficient, just and reasonable."

The relevant sections of the *UCA*, the *Hydro Act*, sections 3 and 4 of the *Heritage Contract Act* and the operative sections of HC2 for the proceeding as they existed until February 17, 2009 follow:

UTILITIES COMMISSION ACT

Commission may order amendment of schedules

58 (1) The commission may,

(a) on its own motion, or

(b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable, insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,

after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

(2) If the commission makes a determination under subsection (1), it must, by order, set the rates.

(2.1) The commission must set rates for the authority in accordance with

(a) the prescribed requirements, if any, and

(b) the prescribed factors and guidelines, if any.

(2.2) A requirement prescribed for the purposes of subsection (2.1) (a) applies despite

(a) any other provision of

(i) this Act, including, for greater certainty, section 58.1, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

(3) The public utility affected by an order under this section must

(a) amend its schedules in conformity with the order, and

(b) file amended schedules with the commission.

Rate rebalancing

58.1 (1) In this section, **"revenue-cost ratio"** means the amount determined by dividing the authority's revenues from a class of customers during a period of time by the authority's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3 or 125.1 (4) (f), or

(b) any previous decision of the commission.

(3) The following decision and orders of the commission are of no force or effect to the extent that they require the authority to do anything for the purpose of changing revenue-cost ratios:

(a) 2007 RDA Phase 1 Decision, issued October 26, 2007;

(b) order G-111-07, issued September 7, 2007;

(c) order G-130-07, issued October 26, 2007;

(d) order G-10-08, issued January 21, 2008,

and the rates of the authority that applied immediately before this section comes into force continue to apply and are deemed to be just, reasonable and not unduly discriminatory.

(4) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission may not set rates for the authority for the purpose of changing the revenue-cost ratio for a class of customers.

(5) Subsection (4) is repealed on March 31, 2010.

(6) Nothing in subsection (3) prevents the commission from setting rates for the authority, but the commission, after March 31, 2010, may not set rates for the authority such that the revenue-cost ratio, expressed as a percentage, for any class of customers increases by more than 2 percentage points per year compared to the revenue-cost ratio for that class immediately before the increase.

Discrimination in rates

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

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

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

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

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

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

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

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

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

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

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

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

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

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

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

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

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

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

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

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

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

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

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

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

Rate schedules to be filed with commission

61 (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

(3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

(4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a rise in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.

(5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,

(a) on complaint of a person whose interests are affected, or

(b) on its own motion,

direct an inquiry into the new schedule of rates having regard to the fixing of a rate that is not unjust or unreasonable.

(6) After an inquiry under subsection (5), the commission may

(a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or

(b) confirm the increase or part of it.

HERITAGE SPECIAL DIRECTION NO. HC2 TO THE BRITISH COLUMBIA UTILITIES COMMISSION (AS AMENDED BY OIC 028, JANUARY 17, 2008)

Basis for establishing authority revenue requirements

4. Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) provide reliable electricity service,

(b) meet all of its debt service, tax and other financial obligations, despite the inclusion of debt in deemed equity,

(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and

(d) achieve an annual rate of return on deemed equity equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor owned energy utility regulated under the Utilities Commission Act.

Determining the cost of energy

5. In setting the authority's rates, the commission

(a) must treat the heritage contract as if it were a legally binding agreement between 2 arms-length parties,

(b) must determine the energy required by the authority to meet its domestic service obligations and must determine the cost to the authority of the portion of that required energy that is in excess of the energy supplied under the heritage contract,

(c) may employ any mechanism, formula or method referred to in section 60 (1) (b.1) of the Utilities Commission Act, and

(d) unless a different mechanism, formula or method is employed under paragraph (c), must ensure that electricity used by the authority to meet its domestic service obligations is provided to customers on a cost-of-service basis.

Return on equity

6. In setting the authority's rates, the commission must allow the authority an annual rate of return on deemed equity calculated using forecast consolidated operating income, which forecast consolidated operating income is calculated on the basis of forecast trade income.

Deferral accounts

7. When regulating and setting rates for the authority, the commission:

(a) must allow the authority to establish one or more accounts to reflect and record variances between

(i) the heritage payment obligation and the authority's forecast of the heritage payment obligation, and

(ii) the trade income and the authority's forecast of trade income,

(b) may allow the authority to establish one or more other deferral accounts for other purposes, and

(c) must set or regulate the authority's rates in such a way as to allow the deferral accounts to be cleared from time to time and within a reasonable period of time.

Note: On February 17, 2009 HC2 was further amended by Order in Council No. 074 (OIC 074).
This is addressed in Section 8.0

HYDRO AND POWER AUTHORITY ACT

Powers of directors

5 The directors must manage the affairs of the authority or supervise the management of those affairs, and may

(a) exercise the powers conferred on them under this Act,

(b) exercise the powers of the authority on behalf of the authority, and

(c) delegate the exercise or performance of a power or duty conferred or imposed on them to anyone employed by the authority.

Directors' proceedings

6 (1) The directors may, on behalf of the authority, pass resolutions thought by them necessary or advisable for the

(a) conduct of the affairs of the authority, and

(b) times, places, calling and regulation of meetings of directors and of committees of directors.

(2) The authority may exercise any of its powers or duties by resolution unless otherwise provided in this Act.

Appointment of employees

10 The authority may, without regard to the Public Service Act, appoint a secretary and executive officers, engineers, solicitors, accountants, employees, consultants and agents it thinks necessary for its business, and may define their duties, determine their compensation and provide a system of organization to establish responsibility and promote efficiency.

Powers

12 (1) Subject to the approval of the Lieutenant Governor in Council, which may be given by order of the Lieutenant Governor in Council, the authority has the power to do the following:

(a) generate, manufacture, distribute and supply power;

(b) develop power sites, power projects and power plants;

(c) [Repealed RS1996 (Supp)-212-1.]

(d) flood and overflow land, purchase, otherwise acquire, accumulate and store water, raise or lower the level of rivers, lakes, streams and other bodies of water, and purchase and otherwise acquire water records and water privileges;

(e) manufacture and deal in all articles and things required for exercising the powers and duties of the authority;

(f) acquire, maintain, develop, replace, alter, administer, manage, operate and dispose of property;

(g) build, make, construct and establish every kind of structure, excavation or installation and install every kind of equipment or facility;

(h) acquire and protect, prolong and renew patents, patent rights, trade marks, designs, licences, franchises, concessions, and use, exercise, develop, manufacture under or grant licences or privileges in respect of those acquisitions and experiment with, test and improve patents, rights, inventions, discoveries, processes or information;

(i) [Repealed 2004-23-14.]

(j) apply for and obtain and exercise any franchise, licence, right or privilege that may be conferred or obtained under any Act of Canada or of any province;

(k) acquire in accordance with a statute relating thereto the right to enter on roads, highways, railways, rivers, streams, waterways and other public places to erect on, over or under any of them anything for the generation or supply of power;

(l) integrate existing power plants;

(m) purchase power from or sell power to a firm or person;

(n) purchase, subscribe for, underwrite, guarantee the subscription of and otherwise acquire and deal in, sell and dispose of stock, shares, bonds, debentures, debenture stock, notes, securities and evidences of indebtedness, of any corporation and any stocks, funds and securities of any government, municipality or other authority;

(o) acquire or lease all or part of the property, assets and undertaking, and assume any of the obligations and liabilities of a firm or person carrying on or entitled to carry on any activities that the authority is authorized to carry on or that can be carried on incidental to or in connection with the exercise of the powers and duties of the authority;

(p) assume duties and obligations of a firm or person, reimburse others for payments made and liabilities incurred and indemnify others against liabilities;

(q) issue securities in exchange for obligations assumed by the authority or in exchange for securities of any other firm or person representing those obligations, and enter into any covenants or agreements considered necessary or desirable for that purpose;

(r) amalgamate in any manner with or enter into partnership with a firm or person;

(s) enter into a working arrangement with or cooperate with a firm or person carrying on or proposing to carry on an activity that the authority is empowered to carry on;

(t) by agreement or otherwise, take part in or take over all or part of the management, supervision or control of the business or operations of a firm or person;

(u) enter into agreements with a firm or person for any of the purposes of this Act;

(v) finance the operations of a corporation that has powers the exercise of which, in the opinion of the directors, would be beneficial to the authority;

(w) do immediately anything referred to in this section in contemplation of future requirements;

(x) do anything necessary or desirable for carrying out any of the powers and purposes in this section;

(y) exercise any of the powers in section 22 of the Companies Act, R.S.B.C. 1960, c. 67.

(2) If the authority

(a) acquires all of the property, assets or undertaking of a firm or person,

(b) assumes the obligations and liabilities of a firm or person,

(c) amalgamates in any manner with a firm or person, or

(d) takes over the management, supervision or control of the business of a firm or person,

the authority or the amalgamated corporation, if there is an amalgamation, may exercise and perform any power or duty conferred or imposed on it or on that other firm or person under this or any other Act for and on behalf of that other firm or person, or the amalgamated corporation, or with respect to the property or undertaking of that other firm or person, or the amalgamated corporation, with or without exercising or performing any other resulting power or duty.

(3) If the authority amalgamates with a firm or person, this Act applies as if the amalgamated corporation were the authority.

(4) The Lieutenant Governor in Council may, by order, prescribe the procedure to be followed in amalgamation of the authority with a firm or person.

(5) Despite the Land Title Act, if the authority acquires all of the property, assets or undertaking of, or amalgamates in any manner with, a firm or person,

(a) all of the interests of that firm or person that are registered in a land title office are deemed to be registered interests of the authority or the amalgamated corporation, as the case may be,

(b) the registrar of that land title office must accordingly make all necessary amendments to the register, and

(c) the amendments constitute registration of the interests under the Land Title Act in favour of the authority or the amalgamated corporation, as the case may be.

(6) The Lieutenant Governor in Council may make regulations necessary for carrying out subsection (5).

(7) Fees must not be paid for anything done under subsection (5) or (6).

(8) Nothing in this section relieves the authority from any requirement of the Utilities Commission Act that applies to the authority under section 32 (7).

(9) The Lieutenant Governor in Council, by order, may designate any agreement entered into or to be entered into by the authority that the Lieutenant Governor in Council considers relates to the provision of support services to or on behalf of the authority.

(10) For the purposes of subsection (9), "support services" means services that support or are ancillary to the activities of the authority from time to time, and includes services related to metering for, billing and collecting fees, charges, tariffs, rates and other compensation for electricity sold, delivered or provided by the authority, but does not include the production, generation, storage, transmission, sale, delivery or provision of electricity.

(11) Despite the common law and the provisions of this or any other enactment, if an agreement is designated under subsection (9),

(a) the authority is deemed to have, and to have always had, the power and capacity to enter into the agreement,

(b) the agreement and all actions of the authority taken in accordance with the provisions of the agreement are authorized, valid and deemed to be required for the public convenience and necessity,

(c) the authority is deemed to have, and to have always had, the power and capacity to carry out all of the obligations imposed under, and to exercise all of the rights, powers and privileges granted by, the agreement according to its terms,

(d) the agreement is binding on and enforceable by the authority, according to the agreement's terms, and

(e) subject to subsection (12), the authority is not required to obtain any approval, authorization, permit or order under the Utilities Commission Act in connection with the agreement or any actions taken in accordance with the terms of the agreement, and the commission must not prohibit the authority from taking any action that the authority is entitled or required to take under the terms of the agreement.

(12 Nothing in subsection (11) (e) precludes the commission from considering the costs incurred, or to be incurred, in relation to an agreement designated under subsection (9) when establishing the revenue requirements and setting the rates of the authority.

(13) [Repealed 2004-23-14.]

BC HYDRO PUBLIC POWER LEGACY AND HERITAGE CONTRACT ACT

Heritage contract

3 Without limiting any other obligation of the commission or the authority,

(a) the commission must, when setting rates of the authority, comply with any regulations, including, without limitation, any general or special directions, made by the Lieutenant Governor in Council under this Act, and

(b) the authority must provide the service required by the regulations made under this Act, in accordance with

(i) the terms and conditions specified in those regulations, and

(ii) the rates set by the commission in accordance with the regulations.

Power to make regulations

4 (1) The Lieutenant Governor in Council may make regulations referred to in section 41 of the Interpretation Act.

(2) Without limiting subsection (1) of this section, section 3 of the Utilities Commission Act or section 35 of the Hydro and Power Authority Act, the Lieutenant Governor in Council may make any regulations the Lieutenant Governor in Council considers necessary or advisable to respond to the recommendations made by the commission in response to the reference, including, without limitation, any of the following regulations:

(a) to amend any regulation made under any of the Utilities Commission Act, the Hydro and Power Authority Act and the Transmission Corporation Act;

(b) to issue directions to the commission specifying the factors, criteria and guidelines that the commission must or must not use in regulating and setting rates for the authority that are applicable to the service referred to in section 3 (b) of this Act.

UTILITIES COMMISSION ACT

Commission subject to direction

3 (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.

(2) The commission must comply with a direction issued under subsection (1), despite

(a) any other provision of

(i) this Act, except subsection (3) of this section, or

(ii) the regulations, or

(b) any previous decision of the commission.

(3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly

(a) declare an order or decision of the commission to be of no force or effect, or

(b) require the commission to rescind an order or a decision.

Expenditure schedule

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

(a) the expenditure is the subject of a schedule filed and accepted under this section, or

(b) the amendment or rescission is for the purpose of setting an interim rate.

In its Argument, BC Hydro submits that "Sections 58-61 of the *UCA specifically* establish the Commission's rate setting powers, and it is these powers BC Hydro invokes in this application (BC Hydro Argument, p. 7) [emphasis added]. BC Hydro also referenced section 3 and subsection 44.2(2) of the *Act* among others. It pointed to sections 4, 5, 6, and 7 of HC2 [as they existed at the time of its Argument] as operative in this proceeding (BC Hydro Argument, pp. 8-10).

BC Hydro submits that in a revenue requirements hearing the Commission has "relatively little scope of discretion, at least in regard to the establishment of across-the-board rate increases." BC Hydro relied upon *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1992), 66 B.C.L.R (2d) 1 (C.A.) ("*Hemlock Valley*") for the proposition that "once the Commission determines the revenue requirement, it is obliged under the *UCA* to allow the recovery of the revenue requirement" in support of its position (BC Hydro Argument, pp. 7-8).

BC Hydro further submits that the Commission has some discretion in determining the manner in which the revenue requirement is recovered, whether in current or in deferred charges once the revenue requirement is established. It also submitted that while *Hemlock Valley* suggests that the Commission is obliged to set rates that allow for recovery of the revenue requirement, it "has considerable discretion in designing rates to allow recovery of the revenue requirement as between customer classes, and over time." BC Hydro further expressed the view that it "did not believe that any issue before the Commission in this proceeding turns on the specific words of sections 58-61" (BC Hydro Argument, pp. 7-8, 28).

In its Argument, COPE challenged BC Hydro's position on the limitation of the Commission's discretion in setting rates. COPE submits that the language of subsection 60(1) of the *Act* "is clear and unambiguous" and that the Commission has "a broad discretion to determine what matters it considers relevant and proper in setting rates for BC Hydro." COPE acknowledges, however, that the Commission is constrained by the factors set out in the subsection and submits that they "have been interpreted as having primary importance in the fixing of rates and represent the interests that must be balanced in setting rates for BC Hydro." In this respect, COPE relies upon both *Hemlock Valley* and *British Columbia Electric Railway Co. v. British Columbia Public Utilities*

Commission, [1960] S.C.R. 837 ("*BC Electric Railway*"). COPE also refers to section 59 of the *Act* for the definition of an "unjust" or "unreasonable" rate (COPE Argument, pp. 3-5).

COPE submits that BC Hydro's position "ignores the fundamental question at issue in this hearing, namely what costs and expenditures are properly recoverable as part of BC Hydro's revenue requirements for the purposes of "rate setting". It submits that subsection 60(1)(b) requires the Commission to have due regard to more than setting a rate that provides a fair and reasonable return to BC Hydro and argues that subsection 60(1)(b)(iii) of the *Act* clearly and unambiguously directs the Commission to have due regard to the setting of a rate that encourages public utilities to increase efficiency, reduce costs and enhance performance, and that those constraints in subsection 60(i)(b)(iii) were added after the decision in *Hemlock Valley*.

COPE further submits that in order for the Commission to discharge that obligation, it must "look behind the rate request and examine the costs and other charges claimed by BC Hydro … [in order to] determine whether those costs are justified and reasonable, and, if not, they ought not to be recoverable in the rates set" and that "[t]o hold otherwise would be to ignore the clear language of s. 60(1)(b)(iii) and unreasonably fetter the Commission's broad discretion under s. 60" (COPE Argument, pp. 3-6).

In its reply to COPE, BC Hydro submits that the post-*Hemlock Valley* amendments to the *Act* cited by COPE "do not remove the obligation of the Commission to have "due regard" to the setting of a rate that allows a utility a reasonable opportunity to earn a return on its invested capital, as that expression was interpreted in *Hemlock* [*Valley*]", and further that the "due regard" requirement "may not be subordinated to other criteria" and, accordingly, "the other criteria, including those prescribed by the amendments to the *UCA*, simply provide an *additional* basis upon which rates may be found to be unjust or unreasonable, not an *alternative* basis" (BC Hydro Reply, p. 2; emphasis in original).

BC Hydro also characterizes COPE's position as implying that the post-*Hemlock Valley* amendments to the *Act* "empower the Commission to make arbitrary disallowances from otherwise prudent revenue requirements for the ostensible purpose of encouraging efficiency", and replies that, if that is in fact COPE's submission, then "such a course would be unlawful, [as] in BC Hydro's submission the logic of *Hemlock [Valley]* is not affected one whit by subsequent amendments to the *UCA*" and further that "BC Hydro's submissions in section 1.2 of its Final Argument can all be accepted by the Commission" (BC Hydro Reply, p. 3).

The issue of the effect of *Hemlock Valley* upon the Commission Panel's exercise of it rate setting functions under sections 59 and 60 of the *Act* was one of the matters for which the Commission Panel sought further submissions during the Oral Phase of Argument. The issue formed part of item 2 of Exhibit A-26, the letter informing the parties of the issues for which the Commission Panel was seeking submissions on for the Oral Argument Phase.

In response to an inquiry from the Panel Chair as to the reconciliation of BC Hydro's position in respect of "no trade-offs" with the post-*Hemlock Valley* addition of subsection 60(1)(b)(iii) of the *Act* requiring the Commission to give due regard in setting rates to promoting increased efficiency, reduced costs and enhanced performance, BC Hydro noted that, if given effect, to take otherwise prudent spending out if its revenue requirement would result in a conflict between that subsection and subsection 59(5)(b) which requires that the rate provide the utility with fair and reasonable compensation for the service provided, and a fair and reasonable return on the appraised value of its property. In BC Hydro's submission, that conflict can only be resolved by concluding that subsection 60(1)(b)(iii) is applicable only to rate design matters, not to the establishment of rates pursuant to a revenue requirements application (T15: 2692-2693, 2701-2703).

BCOAPO disagreed with BC Hydro's interpretation of *Hemlock Valley,* noting that that decision related to a narrowly defined issue wherein the Commission had established both the fair compensation for service provided and the fair and reasonable return, and then established rates which did not enable the utility to realize the aggregate revenue requirement. In BCOAPO's submission, *Hemlock Valley* stands for the proposition that the Commission may not make trade-offs that are extraneous to the decision making process dictated by the statute. In particular, BCOAPO highlighted the findings of the Court of Appeal in *Hemlock Valley* that: "The proper balancing of interests which the Commission carried out was done and completed when it settled the rate base, fixed the rate of return, and determined the costs of operation allowable for rate making purposes", inclusive of "… the Commission [making] substantial downward adjustments to many of HVES's estimates of its costs of operation." BCOAPO submitted that the requisite and proper balancing of interests can only be achieved by looking equally to all parts of subsections 60(1)(b) and 59(5) of the *Act* (T15: 2712-2725).

BCOAPO also noted the comments of Mr. Justice Martland, writing for the majority, in *BC Electric Railway* in support of its position that there is a necessary balancing of interests in determining just and reasonable rates. Justice Martland stated, in reference to an earlier version of the *Act* [*Public Utilities Act*, R.S.B.C. 1948, c. 277]:

> "Section 16 deals with the duties of the Commission in fixing rates. Clause (a) of subs. (1) states that the Commission shall consider all matters which it deems proper as affecting the rate. It confers on the Commission a discretion to determine the matters which it deems proper for consideration and it requires the Commission to consider such matters.
>
> Clause (b) of subs. (1) does not use the word "consider", which is used in clause (a), but directs that the Commission "shall have due regard", among other things, to two specific matters. These are:
>
> (i) The protection of the public from rates that are excessive as being more than a fair and reasonable charge for services of the nature and quality furnished by the public utility; and
> (ii) To giving to the public utility a fair and reasonable return upon the appraised value of its property used or prudently and reasonably acquired to enable the public utility to furnish the service.
>
> As I read them, the combined effect of the two clauses is that the Commission, when dealing with a rate case, has unlimited discretion as to the matters which it may consider as affecting the rate, but that it must, when actually setting the rate, meet the two requirements specifically mentioned in clause (b)" (T15: 2718-2720).

The JIESC, COPE, CEC, and IPPBC concurred with the essential elements of BCOAPO's argument and authorities, to the effect that the Commission had the jurisdiction to set rates and that the statutory scheme of the *Act* contemplated tradeoffs in order to balance the interests of the utility and its ratepayers.

The Terasen Utilities ("Terasen") submitted that insofar as the rates and balancing that had been discussed by other Intervenors were concerned, there could be no impingement on the right of the utility to have its rates set on the basis of the opportunity to earn a fair rate of return. Terasen also cited *BC Electric Railway,* which the Court of Appeal had relied on in *Hemlock Valley* - in particular the passage in *BC Electric Railway* from Justice Locke: "The obligation [of the Commission] to approve rates which will provide the fair return to which the utility has been found entitled is, in my opinion, absolute" (T15: 2772-2773). Terasen also noted part of the passage in *BC Electric Railway* from Justice Martland, relied upon by COPE and quoted above: "As I read them, the combined effect of the two clauses is that the Commission, when dealing with a rate case, has unlimited discretion as to the matters which it may consider in effect as affecting the rate, but that it must, when actually setting the rate, meet the two requirements specifically mentioned in clause (b)" and submitted clause (b) speaks to a fair and reasonable return to the utility (T15: 2773-2774). In response to an inquiry from the Commission Panel, Terasen confirmed that in its view, the "unlimited discretion" referenced above applied to the utility's operating costs as "matters which [the Commission] may consider in determining a rate" (T15:2779-2780).

2.1.2 Commission Panel Determination in Respect of Its Rate Setting Jurisdiction under sections 58-61 of the *Act*

The Commission Panel finds that its rate setting powers are not limited in the manner suggested by BC Hydro. In reaching this conclusion, the Commission Panel relies on the passages in *BC Electric Railway* and *Hemlock Valley* as cited by BCOAPO and Terasen, while at the same time recognizing that its rate setting powers on this Application are also subject to the limitations imposed by HC2 and subsection 44.2(2) of the *Act.* **Accordingly, the Commission Panel makes its**

determinations in this Decision based on the evidence and submissions before it, in a manner consistent with the overall scheme of the *Act* and HC2.

2.1.3 The Prudency Test

It was common ground among the parties to the hearing that the following paragraphs from the Ontario Court of Appeal decision in *Enbridge Gas Distribution Inc. v. Ontario(Energy Board)* [2006] O.J. No. 1355, 41 Admin L.R. (4th)69(C.A.) ("*Enbridge Gas*") represent the law on the proper approach to an examination of the prudency of a utility's expenses:

> **10** The approach of the OEB to the "prudence" inquiry is captured in the following extract from its reasons:
>
> > While the parties described it in somewhat varying terms, in the Board's view they were in substantial agreement on the general approach the Board should take to reviewing the prudence of a utility's decision.
> >
> > The Board agrees that a review of prudence involves the following:
> >
> > * Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
> > * To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
> > * Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
> > * Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.
>
> **11** Neither the Divisional Court nor either party to this appeal takes issue with the correctness of the above quoted passage from the OEB's reasons. The "prudence" inquiry described by the Board has two stages. At the first stage,

> the decision of Enbridge is presumed to have been made prudently unless those challenging the decision demonstrate reasonable grounds to question the prudence of that decision. At the second stage of the inquiry, reached only if the presumption of prudence is overcome, Enbridge must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, Enbridge at the time it made the decision.
>
> **12** In the above quoted extract from its reasons, the OEB expressly alluded to the limited role played by hindsight. Hindsight, that is knowledge of facts relevant to the prudence of the business decision gained after the decision was made, could not be used at the second stage of the "prudence" inquiry to determine the ultimate question of whether the decision was prudent. Those facts could, however, be taken into consideration at the first stage in determining whether the presumption of prudence had been rebutted.

BC Hydro submits that "[t]he correct approach to "prudency" has three elements: (1) a rebuttable presumption that utility decisions, and the resulting costs are prudent; (2) hindsight may not be used to assess whether decisions were prudent but may be used to rebut the presumption; and (3) decisions that are the subject of a prudency inquiry are prudent if they were objectively reasonable." It cited *Enbridge Gas* and the Alberta Court of Appeal decision in *ATCO Gas and Pipelines Ltd. v. Alberta Energy and Utilities Board* 2005 CarswellAlta 582, 2005 ABCA 122 ("*ATCO 2005"*) in support of its position (BC Hydro Argument, pp. 20-24). Based on those authorities, BC Hydro asserts that it is apparent that the scope of the prudency test "applies to all management decisions, and their cost consequences, that flow from management's obligations to manage the affairs of the company [and] all decisions with respect to expenditures … whether capital or operating," noting, however, that while "it does not apply to all elements in this proceeding such as, for example, amortization of regulatory accounts", it means that "[a]s is suggested in *Hemlock [Valley],* the Commission is obliged to set rates that allow for recovery of the revenue requirement as between customer classes, and over time…." (BC Hydro Argument, p. 26).

No Intervenor takes a contrary position in respect of the prudency aspect of expenditures that reflected BC Hydro's past decisions, or that the appropriate standard is that reflected in *Enbridge* Gas, and crystallized in *ATCO 2005* as the "two-part test." In essence, the onus to rebut the presumption of prudency is borne by the party seeking to impugn the decision of the utility, but once rebutted, the objective test of the utility's decision is the reasonableness of that decision in light of the facts known to it at the time the decision was made (BC Hydro Argument, p. 22).

However, in regard to other decisions that "prospectively" forecast expenses in the test period, BCOAPO submits that the presumption of prudency on the part of BC Hydro does not apply, and that the onus for establishing the reasonableness of such expenditures rests with BC Hydro (BCOAPO Argument, pp. 4-5). In reply, BC Hydro submits that no authority is cited for the BCOAPO view, that there is no basis for it in the authorities cited by BC Hydro, and that the position of the BCOAPO is "simply incorrect" (BC Hydro Reply, p. 6).

The JIESC makes a similar point to that of BCOAPO, submitting that BC Hydro bears the burden of proof that the requested rate and corollary relief ought to be granted (JIESC Argument, p. 4).

In reply, BC Hydro revisits the authorities cited in its Final Argument, and asserts that "BC Hydro's management has exercised its legal responsibilities in establishing capital and operating budgets for the F2009 and F2010 fiscal periods that will allow BC Hydro to meet its service obligations. All such decisions get the benefit of the presumption of prudence. The fact that some expenditures arising from management decision-making will happen at a future time does not make such decisions any less the responsibility of BC Hydro, or any more the responsibility of the Commission" (BC Hydro Reply, p.6).

Given the parties divergent positions on the scope of the Commission Panel's discretion in reviewing BC Hydro's forecasts and planned expenditures in its RRA, and the extent to which a presumption of prudency accrued to BC Hydro in respect of its decisions in determining its revenue requirements and the differing views as to which party bore the "onus of proof" in respect of rebutting, or establishing, that presumption of prudency, pursuant to item 3 of Exhibit A-26, the Commission Panel invited submissions from the parties in respect of a hypothesis that BC Hydro could be perceived as claiming "immunity" from Commission amendment or variation of any of its planned or forecast expenditures in the absence of a finding of imprudence on BC Hydro's part.

In its opening submissions on item 2, BC Hydro had distinguished between externally forecast components and its planned expenditure components of its revenue requirements. In particular, BC Hydro distinguished forecasted expenditures arising from the world at large, which it exemplified as matters such as interest rates and wholesale market prices for electricity, from operating costs, which it states are planned expenditures arising from its budgeting processes. On the former, BC Hydro states that it bears the balance of persuasion, and the Commission must satisfy itself on the evidence what, for example, interest rates should be for the purpose of setting BC Hydro's revenue requirement. It is only on the latter, which BC Hydro states reflect its managements' legal obligation to determine what is necessary to meet its obligations to provide service, that BC Hydro asserts that it receives a presumption of prudency (T15: 2689-2691).

BC Hydro further distinguished the planned expenditure components by identifying the basis on which they could be "forecasts" based on expected vs. approved spending in current but incomplete fiscal years (T15: 2090). BC Hydro summarized its position as being that not all of its forecast expenditures receive the benefit of the presumption of prudency, only those that result from the planning obligations on BC Hydro to meet its legal obligation to serve (T15: 2692). BC Hydro also clarified that *Hemlock Valley* was not cited by it in respect of any prudency related matters *per se*, but was tabled as authority for BC Hydro's position that the Commission may not trade-off other factors against BC Hydro's right to the opportunity to earn its allowed rate of return (T15: 2692).

BC Hydro rejected the notion that it was seeking immunity from review of its planned expenditures and stated that its "question" was "how are they to be reviewed and what is the burden that Hydro bears with respect to demonstrating that its planned expenditures ought to be recovered in rates" (T15: 2705).

BCOAPO characterized BC Hydro's position as "a direct challenge to the very notion of meaningful rate regulation," in that it meant that "the Commission must defer to the utility's word as to how much money it wants to spend on operations in the coming period unless the Commission or another party can meet an evidentiary onus to demonstrate that the utility's revenue should be less than applied for", characterizing that position as "a total reversal of the well established onus that rests on the shoulders of a utility to justify its applied-for revenue requirement." BCOAPO noted that if the burden were the other way around, strictly speaking in terms of a fair hearing, all that would be required for the utility to do is say "here's what we're entitled to", and if the evidentiary burden is on the Intervenors, we are the ones who would somehow have to muster all the evidence that probes into the reasonableness of those proposed expenditures." BCOAPO pointed to the Commission's publication "Understanding Utility Regulation: A Participants' Guide to the British Columbia Utilities Commission ("Participants' Guide")" and its guidance at page 26 " ... the burden of proof is on the utility to justify its application to the Commission" and, "[F]or this reason, the utility is expected to include written evidence necessary to support its application to the Commission." BCOAPO further referred to the statement at page 38 of the Participants' Guide: "When the utility applies for an increase in rates to be charged to its customers, it must justify the revenue requirement that supports the request for an increase" (T15: 2731-2734).

BCOAPO stated that "BC Hydro's effort to reverse the onus in establishing its approved prospective operational costs would presumptively insert the utility's managers above the judgment of the regulator and strip much of the substance out of the *Act* and the Commission itself." As authority for its position BCOAPO referenced a November 2008 Alberta Utilities Board ("AUB") Decision 2008-113 in respect of the 2008-2009 General Rate Application of ATCO Gas ("*ATCO 2008*"), noting at the outset that the statutory scheme in Alberta stipulates, as a matter of law, that the onus rests on the utility to justify rate increases, but that, in BCOAPO's view, was insufficient to distinguish the case from the BC Hydro situation (T15: 2739). BCOAPO characterized the Alberta statutory scheme as nothing more than a codification of a well understood regulatory principle.

BCOAPO quoted from page 13 of *ATCO 2008* where the AUB discussed both retrospective and prospective expenditures. In terms of past expenditure performance, the AUB stated: "Because the utility's rates in the base year and other past years had been approved by regulation as just and reasonable and because the quality of service of the utility had also been regulated, the interests of customers in receiving acceptable service at reasonable prices were protected by regulation. In that environment, any decisions made by the utility within those rates and quality guidelines can be presumed to be prudent insofar as the balance between the monopoly power of the utility and its customers is present." In terms of future expenditures the AUB stated: "Operating expenses and capital expenditures forecast by a utility to be incurred in the test years cannot be presumed to be prudent because the balance between customer and company interests that would be present in a competitive market is simply not present and no regulatory examination has yet occurred to counter balance the monopoly power of the utility" (T15: 2742-2743).

BCOAPO submitted that both "common sense" and the principle of the line of reasoning by the AUB in *ATCO 2008* are confirmatory of the legislative intent of the *Act,* and that BC Hydro's position seeking to reverse the onus with respect to an application for approval of forecast expenditures to be recovered in rates should be rejected (T15: 2744).

The JIESC, COPE, CEC, and IPPBC generally concurred with the essence of BCOAPO's arguments on this issue.

Terasen submitted that the AUB in *ATCO 2008* clearly relied on the statutory scheme in making its determinations, and that in B.C., the *Act* puts no such statutory obligation on a utility to justify its expenditures. Terasen further submitted that what might be in the Participants' Guide did not establish such a burden. Terasen argues that there is no such burden on either the applicant or the intervenor(s) because there is a statutory obligation on the Commission to set rates that are just and reasonable, which obliges the Commission to listen to all the evidence, apply its judgment to the evidence, and to establish the rates (T15: 2785-2786).

Terasen characterizes BC Hydro's position as saying that "the rates it has sought in its application, and in particular the operating expenses it has sought in its application must be accepted unless the Commission rules that its forecasts involve expenditures that the Commission determines are imprudent." Terasen does not support BC Hydro's position, on the basis that the *Act* does not establish a test of imprudency in determining rates in a revenue requirement proceeding, rather it adopts a standard of reasonableness and justness as a test of rates. In summary, Terasen submitted that rates should be determined on the basis of the evidence in the proceeding, that forecast expenditures should not be disallowed capriciously, and that the Commission should not substitute its views on how the utility should be operated for those of the management of the company. Terasen expresses particular concern that the imposition of a prudency test in respect of forecasts could lead to increasingly complex and burdensome revenue requirements proceedings (T15: 2795-2798).

Terasen also argued that it was appropriate to subject prior actions taken by utility management that become the subject of a retrospective review to a prudency test, and referenced the AUB's reasoning in the *ATCO 2008* decision in that regard (T15: 2799).

In reply, BC Hydro states its understanding of Terasen's position as being that "management's obligation is to decide what those (operating) expenses should be, and that they may not be simply substituted for by a different number by the Commission to achieve other objectives because that would then undermine the ability of the utility to earn a return on its investment." BC Hydro notes that the large volume of evidence on the record virtually all came from BC Hydro, and that unless the Commission found that evidence wanting, most of its revenue requirement is likely to be accepted so "the issue [of prudency] is really around the edges" (T15: 2814).

BC Hydro points out that in its view the presumption of prudency with respect to its decisions, whether retrospective, or prospective, did not mean that they could not be set aside, or that the onus had shifted, or that the evidentiary burden had shifted, and, at the end of the day "[it] isn't perhaps as big a deal as its being made out to be." BC Hydro describes the issue in terms of, having filed its application, what are the questions raised by intervenors, Commission Staff and the Commission Panel that perhaps rebut the presumption, asserting that this was not a wholesale change in the way things had been done, and was fundamentally unlikely to affect the substance of the Commissions decision "except for here or there on a few particular cost issues" (T15: 2815-2816).

BC Hydro also addresses the *ATCO 2008* decision, distinguishing it from BC Hydro's position, noting firstly that it dealt with a forecast of debenture rates, a matter typical of those to which BC Hydro said the presumption of prudency did not, in its view, apply. Secondly, BC Hydro points to the AUB legislative framework, which references a regulation requiring that a determination be made by the Commission as to the prudent costs incurred by a gas distributor, which discretion would be frustrated if the presumption of prudence claimed by ATCO prevailed, and submits that that is not the case with respect to BC Hydro's revenue requirement in this proceeding. BC Hydro contrasts the Alberta regulatory scheme with that of [HC2], noting that nothing in [HC2] section 4 fetters the Commission's ability to look at every single element of BC Hydro's cost structure (T15: 2826-2828).

In summary, BC Hydro states its position as "[it] does bear a burden of persuasion with respect to its case generally. But with respect to certain of its decisions […] which relate primarily to the decisions of management, it gets a presumption of prudence. It's a rebuttable presumption, and that's all it gets. And that doesn't shift the burden in the way that the Commission here seems to assume it does" (T15: 2830-2831). In an exchange with the Panel Chair, BC Hydro stated that its claimed presumption of prudency would be rebutted in any specific instance arising from the evidence in the proceeding by its witness' acknowledgement that the matter at issue could be accomplished in some alternative way that would be more efficient, regardless of the prudency test that the Commission applies or doesn't apply (T15: 2833-2834).

2.1.4 Commission Determination in Respect of Item 3 of Exhibit A-26

Having considered the extensive submissions and authorities cited by the parties, the Commission Panel determines that in the case of reviewing the cost consequences of BC Hydro's past management decisions a rebuttable presumption of prudency is relevant, and that the two-part test arising from the *Enbridge Gas* and *ATCO 2005* decisions applies.

In its review of BC Hydro's planned and forecast expenditures for the test period the Commission Panel finds that, as suggested by Terasen, BC Hydro's presumption of prudency has little, if any, relevance to the matters reviewed, and accordingly makes its determinations in this Decision

based on the evidence before it in a manner consistent with the overall scheme of the *Act* and HC2.

2.2 Other Matters

BC Hydro raised two matters in its Argument in which it advanced the proposition that the Commission's discretion was lawfully fettered. Firstly, in respect of the consideration of trend and benchmarking information in the Commission Panel's determinations, BC Hydro stated that "it would be unlawful for the Commission to reach any conclusions with respect to the Application on the basis of trend and benchmarking information, and the ratios in response to the Commission Panel IR (Exhibit B-33-A), without regard to BC Hydro's decisions that resulted in those trends and ratios." While it cites no statutory or legal authority for its position, it submits that "the Commission should base its final orders on the reasons for the changes to BC Hydro's cost structure over time, and the prudence of BC Hydro's decisions that resulted in the changes" (BC Hydro Argument, p. 30).

Secondly, in respect of consideration of the Commission Panel accepting final rate schedules for filing under subsection 61(1) of the *Act*, BC Hydro said that such an approach, despite its attractiveness, would be unlawful. It cites as statutory authority for its position the new subsection 44.2(2) of the amended *Act*, which precludes the Commission from so doing "'to the extent that the amendment … is for the purpose of recovering [DSM] expenditures' unless the DSM expenditures have been filed and accepted by the Commission – which will not happen until the 2008 LTAP is resolved" BC Hydro Argument, p. 129).

The above matters are dealt with at Section 4.10 and Section 5.5.6 of this Decision, respectively.

As well, BCOAPO in its Argument, in respect of the Commission Panel's requests for argument on certain matters (Exhibit B-24), takes the position that "The Commission has no jurisdiction to order BC Hydro to change its insurance arrangements in any way." While it cites no statutory authority for its position, it submits that "[t]he Commission's only purchase point on this question is in determining whether … the utility has imprudently under-insured (or alternatively over-insured) against a risk or set of risks" (BCOAPO Argument, p. 22). This matter is dealt with at Section 6.4 of this Decision.

In its reply, BC Hydro raises further issues in respect of which it submits that the Commission's jurisdiction is fettered. Firstly, it states that the Commission "may not lawfully" accept the JIESC submission that "it is open to the Commission to simply dismiss the Application …" (BC Hydro Reply, p. 13). The Commission Panel does not need to make a determination on this matter, inasmuch as the Commission Panel has approved, with some amendments, the Application.

Secondly, in response to the JIESC submission that "the Commission should tell BC Hydro that they must simply do more with less," BC Hydro asserts that that "would not be a proper or lawful way for the Commission to exercise its discretion in a revenue requirements proceeding" (BC Hydro Argument, p. 30). BC Hydro provides no authority for its position. The Commission Panel's Determinations in this Decision make specific amendments to BC Hydro's RRA. The Commission's jurisdiction is dealt with earlier in this Section and is further addressed in Section 7.0.

Lastly, in response to the JIESC submission that "BC Hydro's proposal [for interim rate increases without any consideration of refund to its customers] would be inconsistent with the Commission's approval of interim rates in Order G-40-08 …", BC Hydro asserts that such "would only be the case if the Commission's approval of [different] interim rates unlawfully fettered its discretion to establish, in this proceeding, the appropriate level of the Deferral Account balances for F2009." (ibid p. 53) Here again, BC Hydro provides no authority for its position. However, the Commission Panel determined that this matter was of sufficient import to warrant further submissions in the Oral Phase of Argument, as described at item 1.(ii) of Exhibit A-26, which are considered in Section 4.10 of this Decision.

3.0 APPLICATION AND ORDERS SOUGHT

As of the commencement of the Oral Hearing BC Hydro was requesting rate relief by way of across-the-board increases of 4.59 percent for F09 and 8.10 percent for F10, with rate riders of 0.5 percent and 1.0 percent for those respective years, and a deferral mechanism to mitigate the impact of the rate increases during the test years. All other requested relief in the Application remained unchanged (T3: 194).

In consequence of matters raised during the Oral Hearing, particularly those flowing from the OEU, BC Hydro amended its requested rate relief. In particular, it requested in Argument:

- an across the board interim rate increase of 7.5 percent effective April 1, 2009 for F2010;
- approval of the Rate Rider at 0.5 percent for F2009;
- approval to establish the Rate Rider for F2010 and beyond in accordance with its proposed formula; and
- that the rate increases of 6.56 percent and 7.50 percent respectively for F2009 and F2010 remain interim pending a compliance filing by it following the Commission's determination in the F2008 LTAP (BC Hydro Argument, pp. 181-182).

BC Hydro also asked for a determination by the Commission that its forecast of non-current post-employment expense for F2010 as provided in the OEU be dealt with in a Deferral Account, or, in the alternative, that that expense be included in its revenue requirement for F2010. Further, BC Hydro requested that any difference between the interim rate for F2009 and the otherwise lower rate that could be determined not be refunded to its customers but be applied to the Non-Heritage Deferral Account ("NHDA") in order to mitigate the higher increase for F2010 that would otherwise arise.

The remaining requested relief sought in its Application remained unchanged, and is described at Section 3.4 of this Decision.

3.1 Context

To explain the need for rate increases at this time, BC Hydro states that to meet its long-term goals and short-term priorities it must invest in its electric system assets, maintaining and upgrading them as necessary. As well it must respond to the ever increasing demand for energy by managing and adding to the system to ensure sufficient capacity and by acquiring any additional needed supply from Independent Power Producers ("IPPs") – all within the context of government policy and many other external and market influences,

3.1.1 Key Influences

BC Hydro states that the key influences that have a bearing on its plans during the test period are:

- aging generation assets and supporting facilities, and older distribution infrastructure;
- capacity constraints on many parts of the system;
- labour market pressures;
- high and escalating construction costs;
- B.C. Government policy;
- First Nations relationship building; and
- Economic and population growth outlook.

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

3.1.2 Key Cost Drivers

BC Hydro states that the above contextual factors individually or in combination drive the primary changes to its cost structure that gives rise to the requested rate relief. It identified these "key drivers" of its costs as:

- increasing cost of domestic energy due to an increasing reliance on higher cost non-heritage energy sources as well as the impact of increased water rental rates on the cost of heritage energy production;

- increased capital investment in its system both to meet new demand and to replace and upgrade older facilities leading to increasing amortization and finance charges over the test period; and

- rising operating and maintenance costs reflecting the growing number of customers to serve and the higher costs of labour, materials and contractors and the need for additional initiatives to address reliability and security concerns, its aging workforce and the scarce labour situation, First Nations relationships, and the need to maintain a system with many components nearing the end of their life.

(Exhibit B-1, pp. 1-11 to 1-12)

BC Hydro summarizes the rate increase impacts of these key cost drivers in its Application as follows:

Table 3.1
Rate increase Impacts of Key Cost Drivers

	F2009 increase from F08 RRA	Impact on Rates	F2010 increase from F2009	Impact on Rates	2-Year increase from F08 RRA	Impact on Rates
	$ million	%	$ million	%	$ million	%
Domestic Energy Costs (net of Subsidiary Income)	42.0	1.47%	125.6	4.02%	167.6	5.78%
Operating Costs	55.4	1.94%	44.3	1.42%	99.7	3.43%
Amortization	30.2	1.06%	37.9	1.21%	68.1	2.35%
Finance Charges	43.4	1.52%	37.8	1.21%	81.3	2.80%
ROE	(18.7)	-0.66%	44.1	1.41%	25.4	0.87%
Other	35.2	1.23%	(33.1)	-1.06%	2.1	0.07%
Total	187.5	6.56%	256.7	8.21%	444.2	15.31%

Source: Exhibit B-1, p. 1-13, Table 1-2

In the course of the proceeding, it became apparent that the categories of expense in the Table were not the same as those employed by BC Hydro in its F2007/F2008 RRA proceeding. In response to a request from the Commission Panel, BC Hydro provided the rate increase impacts for the test period in the same category format as had been used in the F2007/F2008 RRA as shown in the following table:

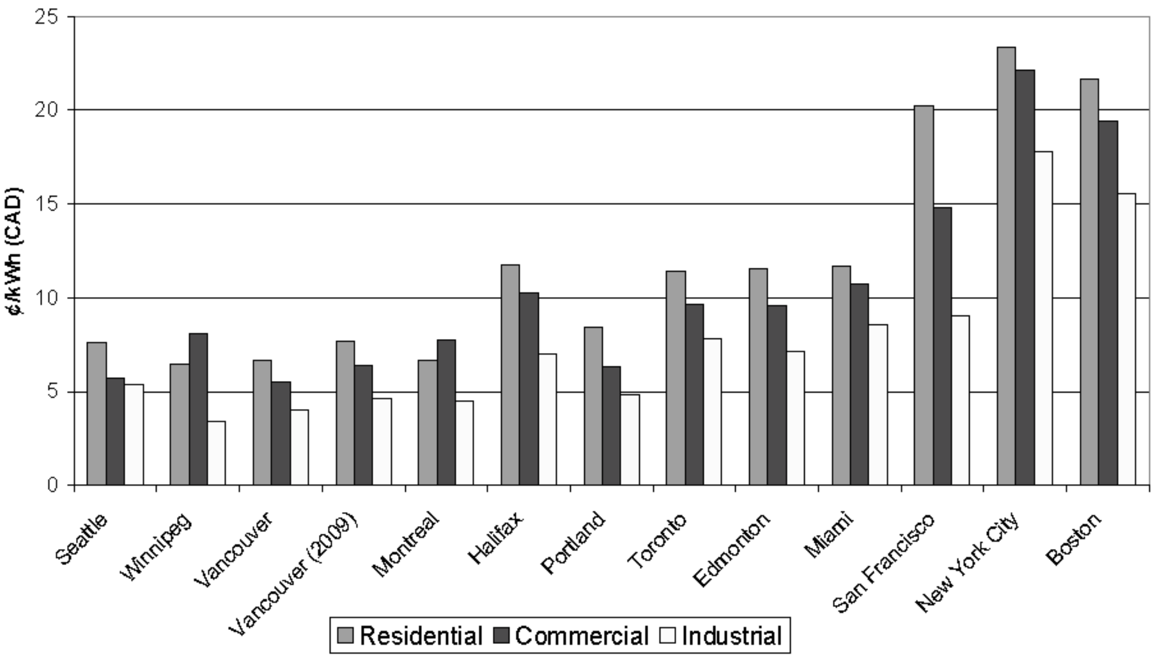
Table 3.2
Revenue Requirement Increases by Component, F2007, F2008, F2009 and F2010

($ million)	F2007 Plan	Impact on Rates (%)	F2008 Plan	Impact on Rates (%)	F2009 Plan	Impact on Rates (%)	F2010 Plan	Impact on Rates (%)
Energy Costs - Load Growth 1	51.0	1.87	13.0	0.44	(12.9)	(0.46)	18.2	0.62
Energy Costs - Existing Load 2	73.0	2.67	(70.0)	(2.37)	86.0	3.07	53.0	1.80
New Investment 3	32.0	1.17	74.0	2.51	73.0	2.61	101.2	3.45
Operating Costs	52.0	1.90	12.0	0.41	55.0	1.96	40.2	1.37
Depreciating Study Impacts 4	(29.0)	(1.06)	(12.0)	(0.41)	-	-	-	-
Trade Income	(44.0)	(1.61)	(2.0)	(0.07)	-	-	-	-
Other	(8.0)	(0.29)	(11.0)	(0.37)	-	-	-	-
Deferral Account Amortization 5	n/a	n/a	76.0	2.57	-	-	-	-
Amortization 6	-	-	-	-	4.4	0.16	(14.6)	(0.50)
Subsidiary Net Income	-	-	-	-	(22.8)	(0.82)	4.4	0.15
Other 7					(54.2)	(1.94)	35.4	1.21
Total	**127.0**	**4.65**	**80.0**	**2.71**	**128.5**	**4.59**	**237.9**	**8.10**

Source: Table 1-3 F2007/F2008 RRA and Exhibit B-37

BC Hydro positions its requested rate relief in the context of April 2007 rates for Vancouver and other North American cities as follows:

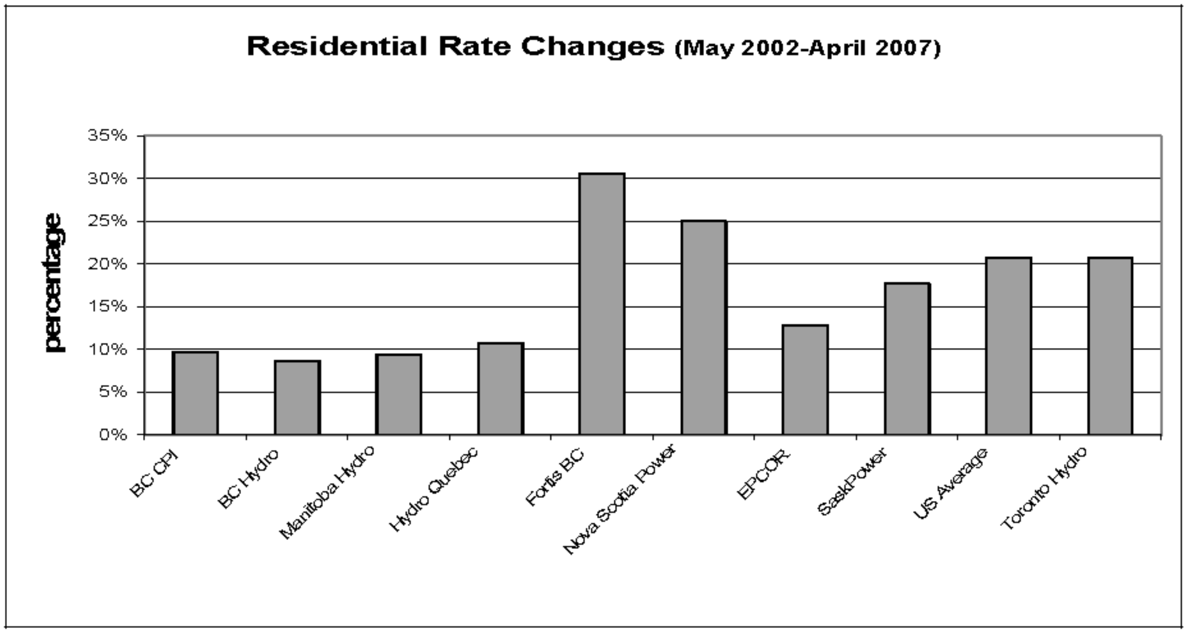
Figure 3.1
Average Rate Comparison as of April 1, 2007
across North American Cities



Source: Exhibit B-1, p. 1-14

As well, BC Hydro illustrates that over the period 2002 to 2007 its cumulative rate increase was the lowest among other major Canadian utilities and well below that of the average for US utilities.

Figure 3.2
Residential Rate Changes
(May 2002 to April 2007)



Source: Exhibit B-1, p. 1-15

3.1.3 Goals and Objectives

BC Hydro submits that its Application ought to be considered not only in the context of its key influences and key cost drivers described above, but also that the Commission ought to consider as well the nature of BC Hydro's goals and objectives. With reference to its Service Plan, provided as Appendix C to its Application, BC Hydro describes its "over-arching objective" as "the provision of safe, reliable, and low-cost service, over the long-term" (BC Hydro Argument, p. 11).

To complement the regulatory and policy framework described previously, this Section addresses the nature of BC Hydro's goals and objectives, which are a part of the foundation on which the review of the RRA will be based.

The remainder of this Section summarizes BC Hydro's submissions in respect of those identified goals and objectives and includes Intervenor comments as appropriate.

3.1.3.1 Safety

BC Hydro summarizes its safety record, in terms of key safety performance measures employed by it, as follows:

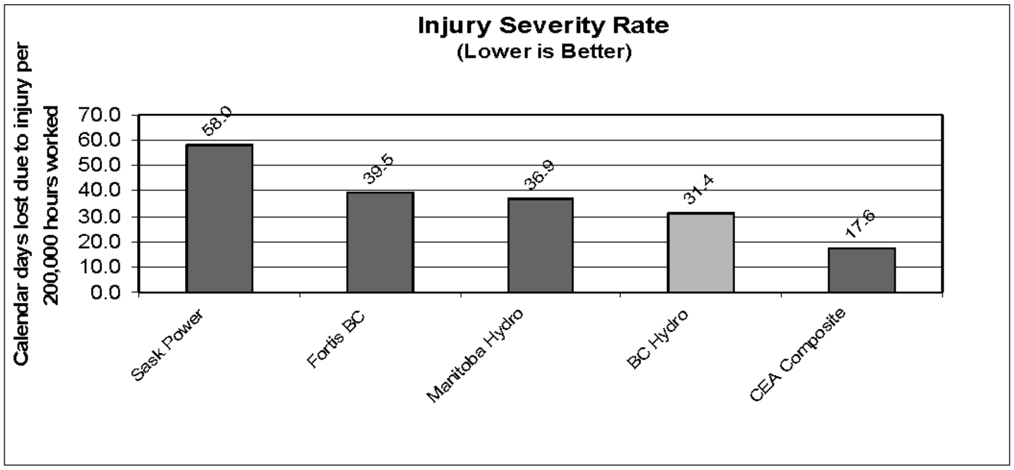
- **Injury Severity Rate:** Injury Severity Rate is a standard Canadian Electricity Association (CEA) measure defined as the number of calendar days lost due to injury, per 200,000 hours worked.
- **All Injury Frequency:** All Injury Frequency is also a standard CEA measure defined as the total number of employee medical aid and disabling injuries occurring in the last 12 months per 200,000 hours worked. Medical aid injuries are those where a medical practitioner has rendered services beyond the level defined as first aid and the employee was not absent from work after the day of the injury. Disabling injuries are those where the employee is absent beyond the day of injury.

Table 3.3
Safety Performance Measures

	Actual	Actual	Actual	Target	Forecast	Target	Target
Performance Measure	**F2005**	**F2006**	**F2007**	**F2008**	**F2008**	**F2009**	**F2010**
Severity (Number of days lost due to injury per 200,000 hours worked)	36	57	31	25	30	25	23
All Injury Frequency (Number of injuries per 200,000 hours worked)	2.6	2.6	2.4	1.9	2.4	2.4	2.3

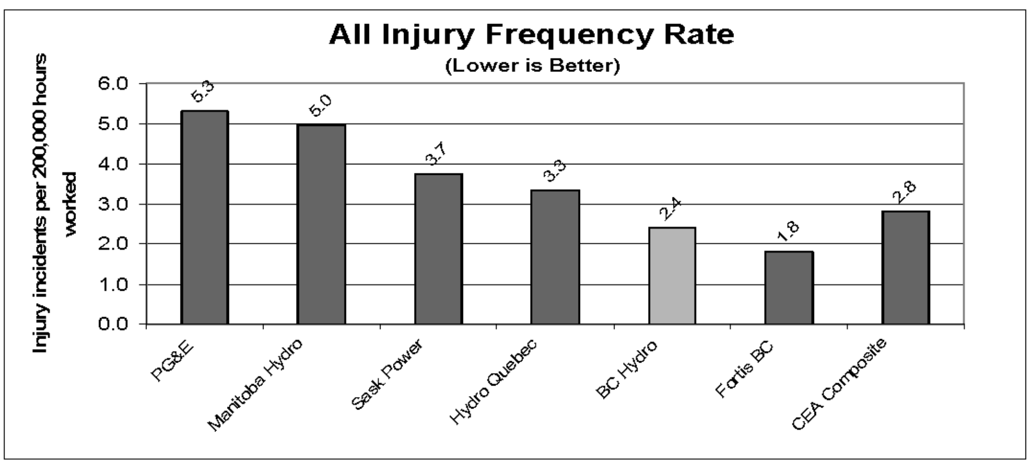
Source: Exhibit B-1, Appendix O, p. 3

Figure 3.3
Injury Severity Rate – Comparable Performance



Source: Exhibit B-1, Appendix O, p. 4

Figure 3.4
All Injury Frequency Rate – Comparable Performance



Source: Exhibit B-1, Appendix O, p. 4

BC Hydro testified that safety is an "over arching concern" in the organization but that its focus on safety would not be expected to improve productivity in the short-term. However, in the long-term, providing the work and projects are designed better, BC Hydro expects productivity improvements due to reduction of costly safety incidents (T4: 531-532, 508-509).

With respect to BC Hydro's safety objective relative to its peers BC Hydro testified that:

> "In terms of safety, I would like us to be world-class, which means that we have a better safety record than other companies, full stop. Not just a better record than other utilities. I am told that we do have a better record than many utilities, but I don't think the safety record of utilities generally is acceptable." T4:589-590.

No Intervenors commented specifically as to BC Hydro's safety programs or its management thereof.

Commission Determination

The Commission Panel makes no determinations in respect of BC Hydro's safety programs, except to register its concern that BC Hydro does not, as yet, have a comprehensive safety management program in place (BC Hydro Argument, p. 12). The Commission Panel notes BC Hydro's characterization of safety as an "over-arching objective," and while it regards the designation of an executive management position of responsibility for the functional aspects of its safety initiatives as a positive development, it also encourages BC Hydro to implement a management system in safety management comparable in scope and rigor to that which it has achieved in the environmental management area with its ISO 14,000 program accreditation**. BC Hydro is requested to report on any progress towards a formalized safety management program in its next RRA**.

3.1.3.2 Reliability

BC Hydro submits that reliability is also a priority for BC Hydro in terms of both reliability for customers and reliability of supply, and that the former refers to the delivery of an uninterrupted supply of electricity to customers, and the latter refers to ensuring all the infrastructure components are available and ready to generate electricity for customers (BC Hydro Argument, p. 12).

BC Hydro summarizes its reliability performance record, in terms of its customer reliability performance measures, as follows:

- **Customer Average Interruption Duration Index (CAIDI):** CAIDI is the average interruption in hours per interrupted customer, in a year.
- **System Average Interruption Frequency Index (SAIFI):** SAIFI is the average number of times that a customer experiences an outage during a year.
- **CEMI–4** (**Customers Experiencing Multiple Interruptions**)**:** CEMI-4 is the percentage of customers experiencing four or more outages during a year.

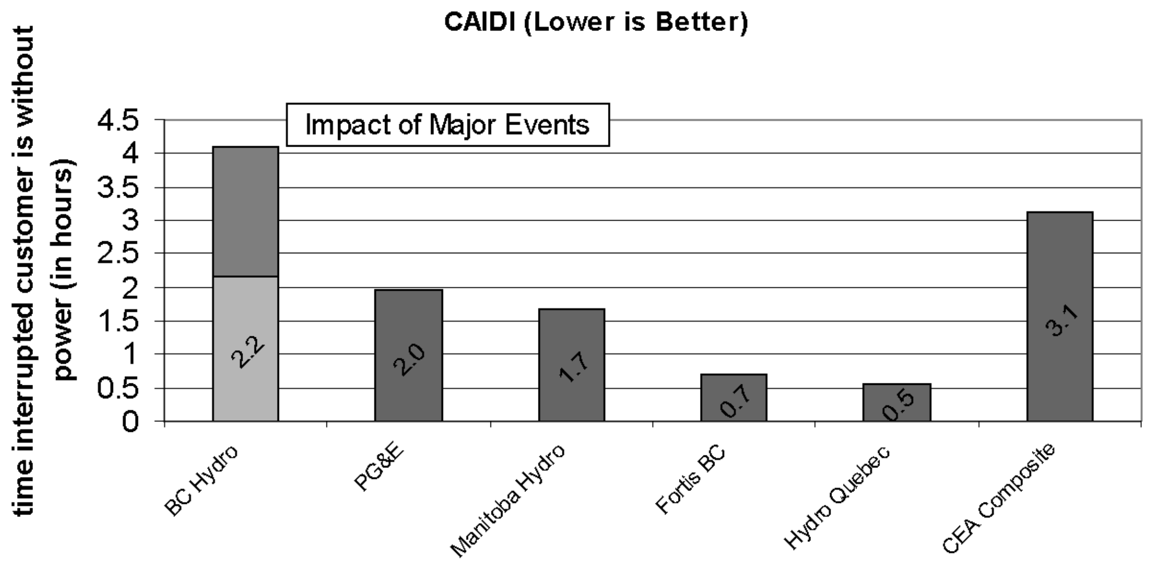
All three of these performance measures assess reliability performance during normal operating conditions, and are normalized to exclude major events such as storms and forest fires. BC Hydro defines a major event, for this purpose, as a single uncontrollable event causing more than 70,000 customer hours lost or ≥ 1 percent of annual customer hours lost for the distribution system.

Table 3.4
Customer Reliability Performance Measures

	Actual	Actual	Actual	Target	Forecast	Target	Target
Performance Measure	**F2005**	**F2006**	**F2007**	**F2008**	**F2008**	**F2009**	**F2010**
CAIDI (interruption hours/year)	2.27	1.82	2.16	2.15	2.15	2.15	2.15
SAIFI (outages/year)	1.30	1.45	1.33	1.22	1.35	1.31	1.27
CEMI-4 (% of customers with 4 or more outages/year)	14	14	7.3	10	10	9	8

Source: Exhibit B-1, Appendix O, p. 5

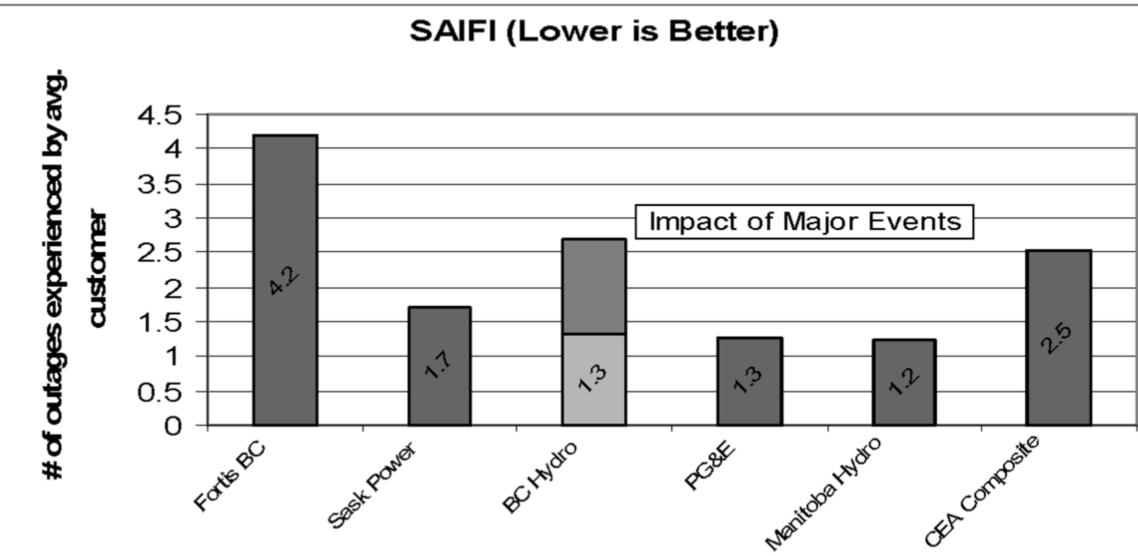
Figure 3.5
CAIDI – Comparable Performance



Note: Reference data did not state whether major events were included or not.
CEA data includes major events.

Source: Exhibit B-1, Appendix O, p. 6

Figure 3.6
SAIFI – Comparable Performance



Note: Reference data did not state whether major events were included or not.
CEA data includes major events.

Source: Exhibit B-1, Appendix O, p. 6

With respect to its reliability objectives vis-à-vis its peers, as distinguished from safety, BC Hydro testified as follows:

> "In terms of reliability, I think this is a different question, because I think the question of trade-offs is one that customers logically should weigh in on, in a different way…. what matters is that reliability is very, very satisfactory to our customers. I think that might change, depending on the types of customers, but I think that the more over time we can talk to our customers, in whatever form, and understand maybe more discretely what each group of customers really wants in terms of reliability, and what the financial implications are, that would be very helpful." (T4: 590)

In light of the potential downturn in the British Columbia economy, BC Hydro also testified that its obligation to serve is not dependant on the overall state of the economy, but on the number of customers, their electricity demand and their reliability expectations (T3: 396-397). Finally, BC Hydro submits that reliability of supply has been about economics (maximizing the value of the generation system for the benefit of customers) but recently, and ultimately, it is about providing reliable service to customers (BC Hydro Argument, p. 15).

Intervenor Positions

Other than the commentary from IPPBC as recorded at Section 1.3.3 above, no Intervenors commented specifically with respect to BC Hydro's reliability performance or its targets for the test period as reflected in Table 1.2 above.

Commission Determination

The Commission Panel makes no specific determinations in respect of BC Hydro's reliability performance. The Commission Panel notes that, based on the industry comparables BC Hydro provided, its performance could be characterized as "average," absent the impact of major events.

However, the Commission Panel also notes that while of BC Hydro's three performance metrics only CEMI-4 is targeted for improvement over recent years' experience, the justification for many of its initiatives, as reflected in both operational and capital spending over the test period and beyond, is driven by or predicated on, "reliability." The Commission Panel agrees with BC Hydro that "… reliability is a different question [than safety], because … the question of trade-offs is one that customers logically should weigh in on, in a different way" (BC Hydro Argument, p. 19).

Given the pervasive (and large) role of reliability in BC Hydro's expenditure programs for the test period, its limited expectation for quantifiable improvements in its reliability metrics for the test period, and the difficulty in linking Intervenors' concerns in respect of BC Hydro's costs to what is clearly a major cost driver, the Commission Panel encourages BC Hydro to view the identified reliability aspects of its business as "quality " matters, and deal with them as such under its submitted "objective to have management systems for quality that are compatible with ISO and other quality management standards" (Exhibit B-54, p. 2). **BC Hydro is requested to report on progress in this regard in its next RRA.**

The Commission Panel also notes that subsection 4(a) of HC2 requires the Commission, in regulating and setting rates for BC Hydro, to ensure that such rates allow BC Hydro to collect sufficient revenue in each year to enable it to provide "reliable electricity service." **Accordingly, BC Hydro is directed to transparently and quantifiably link, in dollar amounts, its planned expenditures to the maintenance of and/or improvement in, its supply and distribution reliability measures and to justify those measures and expenditures in its next RRA.**

3.1.3.3 Low-Cost Service Over the Long-Term

BC Hydro stated that public utilities have an obligation to take a long-term perspective in their decision-making process. Specifically, BC Hydro stated that "the obligation to serve is a long-term commitment" and that "every decision BC Hydro makes must be considered in light of its long-term effects, particularly on cost, reliability of service and safety" (Exhibit B-23).

With regard to its cost structure, BC Hydro testified as to the importance its shareholder, and therefore BC Hydro itself, puts on maintaining rates that are competitive with other jurisdictions (T4: 582-583, 577). BC Hydro further submits "that in the context of a public utility a focus on low-cost does not inevitably mean that costs will decrease in absolute terms. Rather, low-cost means that costs should, over the long-term, be lower than they otherwise would be; that is, low-cost means that costs may only be relatively lower, where the baseline against which actual costs are measured is to some degree speculative. The acknowledged difficulty in measuring impacts of such efficiency and productivity does not mean that they do not exist, or that they are of no value to customers." Accordingly, BC Hydro submits that it would be "overly simplistic and unrealistic to infer that low-cost service is not a priority of BC Hydro" simply because its costs are increasing in the test period in absolute terms (BC Hydro Argument, p. 16).

Finally, BC Hydro submits that unlike unregulated businesses and, perhaps investor-owned utilities, it "does not have a shareholder interested in earning more than its allowed return on equity", and that its shareholder is instead primarily interested in recovering only that return on equity that BC Hydro is given the reasonable opportunity to earn. BC Hydro submits that this ownership feature is relevant because "it implies little or no tension between the goals of its shareholder and its customers and therefore no motivation within BC Hydro to act in a manner inconsistent with ratepayer interests (BC Hydro Argument, pp. 19-20).

Positions of the Parties

BC Hydro submits in its Application that its costs are prudent, necessary and reasonable.

Many Intervenors took issue with respect to various aspects of BC Hydro's cost structure as well as its costs for particular activities, as described at other sections of this Decision.

In its Argument and Reply, BC Hydro maintains that the evidence does not justify any findings of imprudence, lack of necessity or unreasonableness in respect of its applied for costs.

Commission Determination

The Commission Panel has dealt with the general application of the prudency test to BC Hydro's costs in Section 2.1.3 of this Decision. Its determinations in respect of other particulars of BC Hydro's cost matters are as described at other sections of this Decision.

3.2 Operating Costs

BC Hydro states that since this Application is the third such RRA in the space of five years that the Commission and the Intervenors have become familiar with the contextual issues impacting its business, noting that the previous two applications have generated responses to 3,700 IRs and an estimated 28,000 pages of evidence, all of which is publicly available. Accordingly it states that in the interests of regulatory efficiency it has presented its Application on the basis of what is incrementally changing since the last test period, rather than presenting its entire portfolio of costs and activities. This approach includes a "growth and inflation" formula for BC Hydro's base operating costs along with details and justifications of significant initiatives (Exhibit B-1, pp. 1-15, 1-16). These matters are considered in Section 4.4 of this Decision.

3.3 Intersection with 2008 LTAP

In its Application BC Hydro summarizes the issues that are common to both this proceeding and the 2008 LTAP proceeding in the following table:

Table 3.5

RRA and LTAP Interrelationships

	F09/F10 RRA	2008 LTAP
	Operating/Deferred Operating/Capital	**Determinations to cover**
DSM Expenditures	Operating & Deferred Operating	Definition and Implementation phase expenditures.
Mica 5 & Mica 6	Capital	Definition phase expenditures.
Site C Stages 2 & 3 (Consultation/Project Definition and Regulatory Stages)	Deferred Operating	F09-F10 expenditures.
Burrard	Operating & Capital	Sustaining capital (longer term, beyond the test period).

Source: Exhibit B-1, p. 1-17, Table 1-3

To deal with any consequential changes in its revenue requirements during the test period from the Commission's decision on the LTAP proceeding, BC Hydro proposes that any such changes be reflected its F09/F10 RRA compliance filing, and that the rates determined in this proceeding be carried forward pending the 2008 LTAP Decision. These matters are considered in Section 4.10.1 of this Decision.

3.4 Approvals Sought

In addition to the rate relief as described earlier, BC Hydro initially sought the following:

(i) A final order that the Heritage Payment Obligation ("HPO") include the costs of all current load curtailment contracts rather than the current Vancouver Island only contracts.

(ii) Final orders allowing deferral for later amortization through the NHDA of variances between forecast and actual cost of energy arising from variances between forecast and actual customer load; variances between forecast and allowed return on equity ("ROE") for F10, and, the F07 and F08 costs associated with major storm restoration as already deferred by Orders G-76-07 and G-77-07 as well as future such costs on the basis as described at Section 5.4.2 of the Application.

(iii) Final orders allowing the continuation of Order G-143-06 deferring all Site C related development costs at least until the time of a decision as to whether to proceed or not, and, the continuation of Order G-17-08 deferring the F08 costs related to the PEI as well as expected expenditures for F09 and F10.

(iv) A final order to establish a Capital Project Investigation regulatory account ("RA") to formalize and continue its practice of capitalizing capital project investigation costs, a Tax RA to defer and amortize differences between forecast and actual taxes and grants in lieu for the reasons as described at Section 5.5.3 of the Application, and, a Future Storm Damage RA to defer incremental costs to restore service as well as to transfer approved deferred costs plus interest to the NHDA for reasons as described at section 5.5.4 of the Application.

(v) For Deferral Account purposes, Commission determinations of BC Hydro's *baseline* forecasts for certain such accounts for the test period.

(vi) Commission determinations that BC Hydro's forecast costs for British Columbia Transmission Corporation ("BCTC") Service Level Agreements under the Field Services Agreement of $111.1 million and $114.9 million for F09 and F10 respectively are appropriate, and, that its forecast costs under the Engineering Service Agreement of $58.1 million and $61.1 million for F09 and F10 respectively are appropriate.

(vii) With regard to the Capital Plan, a final order that the filing at Chapter 5 of the Application and its related Appendices satisfies both BC Hydro's obligations pursuant to section 45(6.1) (a) of the *Act*, and paragraph 19 of the F07/F08 RRA NSP agreement.

(viii) With regard to gas hedging, a final order pursuant to paragraph 29 of the F07/F08 RRA Negotiated Settlement Agreement ("NSA") to approve BC Hydro engaging in natural gas hedging purchases as a complementary activity to its electricity hedging purchases. These matters are dealt with at Section 6.1 of this Decision.

Source: Exhibit B-1, pp. 1-21 to 1-24

These matters are dealt with in Sections 5 and 6 of this Decision.

4.0 REVENUE REQUIREMENTS

4.1 Load Forecast

BC Hydro's "load" forecast is made up of its energy sales and peak demand forecasts. At the time of filing of the Application in February, 2008, BC Hydro noted actual domestic energy sales of 52,911 GWh for F2007, which was 0.4 percent less than had been predicted in its F07/08 RRA. It also showed a reduction in its forecast of domestic energy sales for F2008 of 1.1 percent to 53,588 GWh and planned domestic energy sales for F2009 and F2010 of 54,791 GWh and 55,594 GWh respectively, representing increases of 2.2 percent and 1.5 percent over each of the prior years.

Domestic energy sales include sales to residential, light industrial and commercial and large industrial customers as well as sales for irrigation, street lighting, and to the City of New Westminster, FortisBC and other utilities (Exhibit B-1, Appendix A, Schedule 14). Forecasts for domestic energy sales are based on historical sales and forecasts of economic drivers which are assumed to affect sales, both of which are factor inputs into models designed to reflect the relationship between the two (Exhibit B-1, p. 2-1).

The peak demand forecast includes peak demand for all domestic distribution substations and transmission customers, peak demand supply arrangements with other utilities and peak demand supply obligations to Seattle City Light pursuant to the Skagit Valley Treaty as well as total transmission losses (Exhibit B-1, p. 2-4).

Peak demand in F2007 was 10,449 MW, which represented an increase of 1.2 percent over the RRA forecast for that period. The updated forecast for F2008 was 2.2 percent above the F07/08 RRA amount. The forecasts for F2009 and F2010 are 10,871 MW and 11,078 MW respectively, representing increases of 1.0 percent and 1.9 percent over each of the prior years (Exhibit B-1, Appendix A, Schedule 14).

In its July EU, BC Hydro provided the actual domestic energy sales figure for F2008 of 53,299 GWh (0.5 percent less than the updated forecast contained in the Application) and updated forecasts for F2009 and F2010 as set out in the two tables below:

Load Table 4.1
Domestic Energy Sales, F2009

(GWh)	F2009 Plan 1	DSM Update 2	Industrial Update 3	Price Elasticity 4	F2009 Update 5=1+2+3+4
Residential	17,430	(261)	0	(61)	17,108
Light Industrial and Commercial	18,936	(18)	0	(45)	18,872
Large Industrial	16,369	(47)	(307)	(33)	15,981
Other	2,056	0	(96)	(3)	1,957
Total	54,791	(327)	(403)	(142)	53,919

Load Table 4.2
Domestic Energy Sales, F2010

(GWh)	F2010 Plan 1	DSM Update 2	Industrial Update 3	Price Elasticity 4	F2010 Update 5=1+2+3+4
Residential	17,701	(529)	0	(105)	17,067
Light Industrial and Commercial	19,167	(55)	0	(99)	19,013
Large Industrial	16,597	(63)	(457)	(83)	15,994
Other	2,128	0	(100)	(7)	2,021
Total	55,594	(647)	(557)	(295)	54,095

Source: Exhibit B-10, p. 9, Tables 5 and 6

BC Hydro attributes the decline in forecast domestic energy sales in its July EU to: DSM programs, reduced industrial sales and sales to other utilities (FortisBC) largely due to economic conditions resulting in shutdowns in the forestry sector, and price elasticity of demand (where sales decrease in response to an increase in price-i.e. the applied for increases of 6.56 percent and 8.21 percent for F2009 and F2010, respectively) (Exhibit B-10, pp. 7-8). Its forecasts remained unchanged for domestic energy sales in BC Hydro's October EU (Exhibit B-22, Schedule 14).

The July EU also includes revised figures for peak demand. Actual peak demand for F2008 was 10,462 MW (0.7 percent less than F2008 RRA estimate of 10,534 MW and an increase of 0.12 percent over the prior year). The forecasts for peak demand for F2009 and F2010 were reduced slightly from the estimates in the Application to 10,835 MW and 10,866 MW respectively, representing increases of 3.6 percent and 0.5 percent over each of the prior years (Exhibit B-10, Appendix 1, Schedule 14). These numbers were unchanged in the October EU Exhibit B-22, Schedule 14).

BC Hydro further revised its forecasts for domestic energy sales in response to a request from BCOAPO during the hearing to update this information to incorporate the anticipated effect of the RIB rate structure which came into effect in the fall of 2008. BC Hydro's updated forecasts for domestic energy sales for F2009 and F2010 were 54,088 GWh and 54,290 GWh, respectively, representing modest increases over the forecasts contained in the July EU (Exhibit B-46).

A further update to the domestic energy sales forecasts was provided in the OEU, indicating that energy sales would be reduced by 1,217 GWh for F2009 and 1,473 GWh for F2010 from the forecasts contained in the October EU, which would translate into total energy sales of 52,702 GWh and 52,622 GWh, both of which are below sales for F2007 (Exhibit B-64, p. 3).

The Table below shows Domestic Energy Sales, actual and forecast, for F2007 to F2010 in GWh.

Load Table 4.3
Domestic Energy sales F2007 – F2010

		F2009			F2010		
F2007 Actual	F2008 Actual	App.	July/Oct EU	OEU	App.	July/Oct EU	OEU
52,911	53,299	54,791	53,919	52,702	55,594	54,095	52,622

Derived from Exhibit B-1, Appendix A, Schedule 14;
Exhibit B-10, Appendix 1, Schedule 14; and
Exhibit B-22, Schedule 14; Exhibit B-64, p. 3

Positions of the Parties

BC Hydro submits that “the Commission should accept BC Hydro’s projections of load for F2009 and F2010 as included in the October 17 [OEU] update as the best information available for setting rates.” BC Hydro noted that its projection of year-to-date load as set out in the OEU was based on a “simple extrapolation process” rather than a full load forecast, which “leads to some significant uncertainty in terms of what could be the load, particularly in F2010” and further noted that the “load in F2010 could … easily [vary by] plus or minus 1,500 GWh from the projection as a result of changing economic conditions.” BC Hydro submits that the volatility and uncertainty relating to load makes the net impact of its variance a candidate for inclusion in the NHDA (BC Hydro Argument, p. 42).

BCOAPO notes the fact that the final load forecast put forward by BC Hydro was based on a “simple, year-to-date trend adjustment to the forecast originally filed” but agrees with BC Hydro that it was likely the best estimate available, given the rapidly changing economic circumstances and should therefore be used to set F2009 rates. BCOAPO also noted that the load forecast remains subject to revision to account for DSM and rate design effects which will be dealt with in the LTAP proceeding (BCOAPO Argument, p .7).

The CEC comments on the methodology used by BC Hydro to update its load forecast and takes the position that the methodology was unlikely to reflect the full impact of the economic downturn, suggesting that "there is a significant likelihood that the actual results will be less than those in the evidentiary updates." The CEC prepared a table (as set out below) showing the forecast load changes from the original projections as reflected in the OEU, on a percentage basis, by customer class.

Load Table 4.4
Changes in Load Forecast

% Change	F2008	F2009	F2010
Residential	5.4%	-1.6%	-1.7%
Commercial	.8%	.2%	.8%
Industrial	-3.8%	-1%	.1%
Other	-2%	-10%	7%
Total	.7%	-1.1%	-.2%

Source: CEC Argument, p. 13

The CEC notes that the updated BC Hydro load projections "show a decline in residential load continuing into F2010. However, there is no continued reduction in load for commercial and industrial customers." The CEC submits that the Commission should direct BC Hydro to reduce its load forecast by 1 percent for all customer classes into F2010 based on the likelihood that economic conditions will continue to deteriorate beyond the OEU, citing BC Hydro's CFO's views that things will likely get worse before they get better. The CEC calculated that a one percent decrease in 2010 forecast load across the board would equate to 445 GWh, which is less than one third of the possible downward load variance of 1,500 GWh noted by BC Hydro (CEC Argument, pp. 14-15).

No other Intervenor made submissions on load.

In reply, BC Hydro notes that the "arbitrary" reductions of either 750 GWh or 1,500 GWh proposed by the CEC are within the potential variation in load for F2010 testified to by its witness, and that there is no evidence to support a further reduction to that load forecast. BC Hydro further notes that if its proposal to defer the net impact of load forecasts is approved, there would be no impact on customers of any difference between forecast and actual load. Accordingly, BC Hydro submits that the Commission should accept its load forecasts as included in the OEU (BC Hydro Reply, pp. 16-17).

Commission Determination

The Commission Panel accepts BC Hydro's evidence on the significant uncertainty surrounding its load forecasts. **Inasmuch as the Commission Panel accepts BC Hydro's proposal to defer the net impact of load forecasts as described and for reasons given at Section 5.2.2 of this Decision, BC Hydro's load forecast of October 17, 2008 is approved, as there should be no material impact on customers due to variance from that forecast.**

4.2 Revenue Forecast

BC Hydro's domestic revenues are made up of its sales to customers within the province as well as outside the province pursuant to long-term contracts or treaty. As discussed above, BC Hydro has a number of different classes of customer, such as industrial, commercial, residential, other utilities, street lights, and irrigation customers, which are subject to different rates and rate structures (Exhibit B-1, Appendix A, Schedule 14).

BC Hydro also has miscellaneous revenues from various corporate activities, income from its subsidiaries Powerex Corp. ("Powerex") and Powertech Sales Inc. ("Powertech"), and may collect additional revenue through a deferral rate rider which is a percentage charge applied to the total balance of the Heritage Deferral Account ("HDA"), NHDA, Trade Income Deferral Account ("TIDA") and BCTC Deferral Account ("BCTCDA") combined, assuming a positive balance. These four deferral accounts accumulate the differences between forecast and actual costs and revenues and so do not relate to current consumption (Exhibit B-1, pp. 6-1 to 6-2; 6-7 to 6-8; Appendix A, Schedules 1, 2.1, 3, 14, 15).

For F2008 BC Hydro had $2.857 billion in total domestic electricity sales revenues including $66.9 million from sales to other utilities and $55.7 million collected by way of the Rate Rider. Subsidiary net income represented a further $83.2 million and miscellaneous revenues accounted for $31.4 million (Exhibit B-22, Schedules 1, 14, 15).

Forecast domestic sales revenues for F2009 and F2010 are $2.958 billion and $3.224 billion, respectively (Exhibit B-24, Panel IR 1.1.1). In the OEU, BC Hydro amended its revenue forecast to $2.963 billion and $2.957 billion for F2009 and F2010, respectively (Exhibit B-64, Schedule 14.0, p. 1). As noted above, domestic revenue forecasts vary with load forecasts and applicable rates.

BC Hydro's revenue forecasts are also impacted by projections of income for its subsidiaries and inter-segment transfers of costs, as described in more detail in the following sections.

4.2.1 Subsidiary Net Income

BC Hydro's subsidiary net income consists of forecast income from its subsidiaries, Powertech and Powerex. Powertech's net income is forecast to be $1.7 million in F2009 and $1.9 million in F2010. No issues have arisen in regard to Powertech's forecast net income.

Powerex, which is involved in electricity trading activity, has forecast net income of $190.0 Million and $154.8 Million for F2009 and F2010, respectively (BC Hydro Argument, p. 121). Its energy purchase and sale transactions with BC Hydro are governed by the Transfer Pricing Agreement ("TPA"), which came into effect in April, 2003 (BC Hydro Argument, p. 123).

HC2, section 1 defines "trade income" as:

> "…the audited net income of Powerex Corp., according to generally accepted accounting principles, adjusted by,
>
> (a) if the audited net income is less than zero, adding the amount necessary to make it zero, and
>
> (b) where audited net income is greater than $200 million, subtracting any amounts in excess of $200 million."

This definition provides a "cap" and "floor" for trade income accruing to the benefit of ratepayers. Variances between forecast and actual trade income are captured in the TIDA and amortized by the rate rider mechanism.

BC Hydro notes two issues which typically arise: (i) whether forecast trade income should be increased, which would result in a reduction to BC Hydro's revenue requirements and, hence, rates; and (ii) whether the TPA between BC Hydro and Powerex should be modified so as to increase the benefits accruing to ratepayers. BC Hydro takes the position that its forecasts for trade income in the test period are based on the best available information and that the TPA, as designed, allocates costs and risks so as to maximize the value of the system to the benefit of ratepayers, and that any changes would thus undermine that scheme (BC Hydro Argument, pp. 122, 124).

The JIESC expresses concern that the $200 million cap on trade income is now likely to be exceeded on regular basis, depriving customers of a portion of the benefit of the natural hedge which exists due to the reverse effect of currency fluctuations on import costs and export revenues. The JIESC also argues that the cap deprives customers of the benefit of export-enabling facilities for which they paid. The JIESC asks that the Commission recognize the cap's negative impacts in its decision (JIESC Argument, pp. 24-25).

The CEC comments extensively on the performance of Powerex over the most recent 5 year period, in terms of differences in BC Hydro's forecast and actual results for trade income.

Trade Income Table 4.1
Trade Income – Capped ($ millions)

	2005[35]	2006	2007	2008	2009[36]	Average
Plan	$ 89.5	$ 91.0	$ 179.0	$ 136.9	$ 136.7	$ 126.6
Actual	$ 200.0	$ 179.0	$ 200.0	$ 83.0	$ 190.0	$ 170.4
Difference	$ 110.5	$ 88.0	$ 21.0	$ -53.9	$ 53.3	$ 43.8

Source: CEC Argument, p. 20
FN35 Exhibit B-77, C.4.6.10
FN36 F2009 Estimate as of October based on actual earned to September 30, 2008

Trade Income Table 4.2
Trade Income – Uncapped ($ millions)

2003	2004	2005	2006	2007	2008	2009
$ 138	$158	$256	$179	$259	$83	$190

FN36 F2009 estimate as of October based on actual earned to September 30, 2008
Source: CEC Argument, p. 28

The CEC notes that in all but one of the last four fiscal periods BC Hydro has significantly underestimated its trade income and submits that the Commission should “require BC Hydro to forecast Trade Income for F2009 and F2010 at $200 million”, thereby increasing the F2009 forecast by $8.3 million and the F2009 forecast by $43.7 million based on the average past experience” based on this clear evidence of [BC Hydro’s] under-forecasting.” The CEC further points to the actual trade income realized in F2005 and F2007 being well in excess of the cap. The CEC submits that the record supports the Commission substituting its own judgment in place of that of BC Hydro to increase forecast trade income (CEC Argument, p. 20).

The CEC also advocates that BC Hydro renegotiate its TPA with Powerex in order to reduce the probability of trade income beyond the cap being lost to customers (CEC Argument, pp. 29, 105).

The CEC further "contends that Powerex does not pay for its access to and use of … BC Hydro's electric system capabilities, and in particular for storage capabilities." The CEC suggests that BC Hydro should "better defend its customers' interest" and amend the TPA (CEC Argument, pp. 100-101). The CEC also suggests that BC Hydro should charge Powerex for its appropriate share of overheads (CEC Argument, p. 102).

The CEC observes that "[t]he TPA allows for changes to the pricing to be negotiated between the parties and allows for amendments to the agreement" and further states that it is not aware of any legislative impediments impacting the TPA. The CEC does not, however, propose any specific amendments (CEC Argument, pp. 29-30).

Alan Wait notes that Powerex exceeded the $200 million cap in F2001, F2002 and F2005 and submits that, with the falling value of the Canadian dollar in relation to that of the U.S., Powerex is on track to exceed the limit in F2009 and will probably also do so in F2010. He states that the cap was put into place in 1992 and has remained constant with no allowance for increased trading volumes or inflation. He also argues that Powerex's trading "creates increased line losses and inefficiencies in the BC Hydro system…" He submits that the $200 million cap should be eliminated, or, alternatively, increased as a "poor second choice". He argues that if a cap remains, the domestic losses caused by the export trade should be charged to Powerex (Wait Argument, pp. 4-6).

BC Hydro does not directly address the CEC proposal to increase the trade income forecast for the test years in its Reply. With respect to CEC's and Alan Wait's submissions concerning modifying the transfer pricing and or cost allocation between BC Hydro and Powerex by charging additional costs and fees to Powerex, BC Hydro submits that that would undermine the purpose of the Heritage Contract scheme and decrease the benefits of trade for customers (BC Hydro Reply, p. 47).

Commission Determination

The Commission Panel notes that, on average, over last five years, the actual trade income has exceeded BC Hydro's forecast by $43.8 million per annum. **Accordingly, the Commission Panel finds that the evidentiary record confirms that BC Hydro has shown a significant tendency to underestimate its trade income from Powerex, and directs BC Hydro to adjust its forecast net income from Powerex to $199 million in each of the test years.**

The Commission Panel notes BC Hydro's response in testimony to Intervenors' concerns in respect of the $200 million cap, to the effect that "… if we felt that raising the $200 million limit was a good idea, we could not say that in public, and we would have a private discussion with government" (T3: 408).

The Commission Panel requests that BC Hydro initiate discussions with the Province with a view to increasing the cap on trade income beyond the current $200 million limit, or, in the alternative, removing both the cap and the floor that currently limit the ratepayers' participation in Powerex's performance, and to report to the Commission as to the progress and outcome of those discussions on a regular basis.

4.2.2 Inter-Segment Revenue

Inter-segment revenue reflects the BC Hydro side of its TPA transactions with Powerex. Schedule 3 of Appendix 1 of the October EU (Exhibit B-22) shows the components of inter-segment revenue: Powerex – Corporate Allocation, Mark to Market Losses/Gains, Other, Powerex Net Sales, Powerex PTP Charges and BC Hydro PTP Charges. There are only amounts shown for PTP Charges in the test years. All other components are reflected at zero. Forecast inter-segment revenue is $56.6 million for F2009 and $60.5 million for F2010 (Exhibit B-64, Table 2).

The CEC notes that in prior years, Powerex had been allocated a portion of BC Hydro's corporate overhead costs, known as the "corporate allocation" in amounts in the range of $4.0 to $5.0 million, which has not been allocated to it for the test years. Specifically, the actual allocated amounts totaled $4.6 million and $4.0 million in F2007 and F2008, respectively (Exhibit B-1, Appendix A, Schedule 3.1).

The CEC also notes that BC Hydro has under-estimated its forecast inter-segment revenues in the past 2 years by an average of $2.35 million. The CEC asks the Commission to instruct BC Hydro to increase its forecast of inter-segment revenue by $7.35 million, reflecting a corporate allocation of $5.0 million and increased revenues of $2.35 million calculated as the average amount of the under forecasts from the prior two years (CEC Argument, p. 23). As noted by BC Hydro, the CEC position is somewhat inconsistent in that it states later in its argument that the inter-segment revenue forecast consists solely of estimated PTP charges, which estimate it accepts (CEC Argument, p. 102).

BC Hydro makes no submissions as to reasons for its elimination of the corporate allocation to Powerex, but submits that as long as the Powerex net income forecast is equal to or less than the $200 million cap, allocating overhead to Powerex will simply serve to reduce its income forecast by an equivalent amount and serve no purpose. BC Hydro further submits that there is "no evidentiary basis to support a change to the forecast of these [inter- segment] revenues for the current test period, and in particular that an average forecast variance over a single two-year test period does not on its own constitute such evidence." It further submits that as the variances between forecast and actual inter-segment revenues from PTP charges are subject to deferral through the BCTC Deferral Account, positive differences will accrue to customers in the ordinary course. It therefore submits that its forecast of inter-segment revenues from PTP charges should be accepted as filed (BC Hydro Reply, pp. 48-49).

Commission Determination

The Commission Panel recognizes that as long as the Powerex net income forecast is equal to or less than the $200 million cap, no purpose is served by allocating a portion of corporate overhead to Powerex. However, BC Hydro has given no reasons for its planned change in practice. In Section 4.2.1 of this Decision, the Commission Panel directed BC Hydro to increase its forecast for net income from Powerex to $199 million for each of the test years. The Commission Panel notes the past practice of BC Hydro allocating some $4.0 to $5.0 million of corporate overheads to Powerex and the absence of any rationale for the change. **Accordingly, the Commission Panel finds that allocating a portion of corporate overhead to Powerex is reasonable, and is consistent with past practice. The Commission Panel therefore directs BC Hydro to continue the corporate allocation charge to Powerex in the amount of $4.3 million per year for the test years, being the average of the allocations for F07 and F08. The Commission Panel also clarifies that the $199 million forecast for Powerex net income is net of that $4.3 million corporate allocation.**

With respect to the CEC request for relief in respect of the PTP charges, the Commission Panel finds that there is insufficient evidence before it to grant the requested relief, and accepts BC Hydro's forecast of those charges.

4.3 Domestic Energy Costs

BC Hydro's Domestic Energy Cost (i.e. the cost to supply electricity to its domestic customers, including its obligations under the Skagit Valley Treaty) is made up of the sum of its "Consolidated Cost of Heritage Energy" and "Cost of Non-Heritage Energy" (Exhibit B-1, p. 3-1).

The Consolidated Cost of Heritage Energy is BC Hydro's cost to provide up to 49,000 GWh per year to serve domestic load under the Heritage Contract. This cost is made up of water rental costs payable to the provincial government, market electricity purchases (if required to obtain 49,000

GWh), the cost of natural gas for thermal generation and certain transmission costs, less any surplus sales (Exhibit B-1, pp. 3-1 to 3-2).

The Cost of Non-Heritage Energy is BC Hydro's cost to provide amounts in excess of 49,000 GWh per year to serve domestic load. This cost is primarily composed of market purchases, purchases from IPPs, energy costs for Non-Integrated Areas ("NIAs"), natural gas transportation costs, and the net cost of transmission in B.C., and is adjusted for net purchases from Powerex (Exhibit B-1, p. 3-2). Non-Heritage energy has historically made up less than 20 percent of the total energy supply.

BC Hydro's major source of supply is from hydro-electric generation (a Heritage Resource), and BC Hydro states that in any year it can vary from 42,700 to 53,400 GWh depending on water conditions. The Peace and Columbia River systems represent approximately 75 percent of BC Hydro's generation capability and approximately 90 percent of its storage capacity. BC Hydro states that it employs a Marginal Cost Model ("MCM") suite of in-house models to co-ordinate and optimize its hydro-electric generation, IPP purchases, market purchases and thermal generation. BC Hydro views the marginal cost of hydro-electric generation from the Peace and Columbia River systems as being "generally reflective of the marginal value of generation from the Peace and Columbia systems" and is used to support decisions on storage, thermal dispatch and market purchases and sales (Exhibit B-1, p. 3-3).

BC Hydro's actual domestic energy costs were $1,091.2 million for F2007 and $1,096 million for F2008. Both of these amounts were well below its F07/08 RRA forecast estimates for those years (Exhibit B-22, Schedule 4, p. 16). The lower costs in 2007 resulted from drawing down of reservoir levels in anticipation of higher inflows in 2008 and lower market energy prices. BC Hydro attributes the lower costs in 2008 to large water inflows to the system resulting in reduced market purchases, as well as lower market prices. BC Hydro states that it was also able to sell surplus electricity under its TPA with Powerex (Exhibit B-1, p. 3-4).

BC Hydro's total domestic energy costs forecasts for F2009 and F2010 were revised three times in the course of the review as shown in the table below:

Energy Table 4.1
Domestic Energy Costs – Forecasts ($Millions)

	Application	July EU	October EU	OEU
F2009	1,252.4	1,273.2	1,272.1	1,142.7
F2010	1,430.8	1,386.3	1,381.7	1,231.4

Derived from Exhibit B-1, Appendix A, Schedule 4, p.16;
Exhibit B-10, Appendix 1, Schedule 4, p.16;
Exhibit B-22, Table 3; and Exhibit B-64, Table 2

Unit costs for the various components of the Consolidated Heritage and Non-Heritage energy accounts vary substantially, as shown in the following table of unit costs ($/MWh) for each of the main components of the total cost of domestic energy.

Energy Table 4.2
Domestic Energy Costs – $(MWh)

$per MWh	F2007 Actual	F2008 Actual	F2009 Application	F2009 July 02 EU	F2010 Application	F2010 July 02 EU
Water Rental	5.8	6.0	6.9	7.0	6.9	7.4
IPP and Long-term Contracts	60.3	61.8	64.7	68.2	68.3	69.7
Market	43.8	67.9	53.8	66.7	57.9	68.7
Natural Gas	76.7	116.1	139.2	170.3	151.3	166.4
NIA	181.9	187.7	192.6	228.7	194.0	229.8
Weighted	**20.6**	**20.6**	**22.9**	**23.6**	**25.7**	**25.6**

Derived from: Exhibit B-1, Appendix A, Schedule 4.0, p.17; and
Exhibit B-10, Appendix 1, Schedule 4.0, p. 17
Note: Impact of Proposed Rates not included as updated information not available for October.

In conclusion, after the evidentiary updates BC Hydro submits that forecast domestic energy costs for F2009 and F2010 are in the order of $1.1 billion and $1.2 billion, respectively (BC Hydro Argument, p. 43).

Positions of the Parties

BC Hydro submits that the Commission should accept BC Hydro's forecasts for domestic energy costs in each of the test years. It notes possible areas for challenge as being:

- Heritage Energy cost increases due to the failure of the G.M. Shrum Unit 3 turbine runner in March 2008;
- the cost of energy purchases from IPPs pursuant to the F2006 Call for Energy;
- load curtailment; and
- the use of forecast water levels.

(BC Hydro Argument, pp. 43-45)

The CEC proposes a reduction in BC Hydro's forecast cost of energy on the basis that the economic downturn would be more significant than assumed by BC Hydro, resulting in reduced market purchases. It provided a calculation assuming market purchases were reduced by 405 GWh and line losses by 60 GWh which resulted in an estimated energy cost saving of approximately $24.4 million (assuming an average unit cost for market purchases of $54.7/MWh) (CEC Argument, p. 32).

BCOAPO submits that, although energy costs are highly uncertain in today's economic climate, BC Hydro's estimates are likely the most reliable (BCOAPO Argument, p. 7).

No other party took an overall position on the cost of energy forecasts; however, specific submissions were made in the areas of challenge identified by BC Hydro.

In reply, BC Hydro addresses the matters described above as raised by the CEC and BCOAPO in general terms, and submits that, given the circumstances, its forecast cost of energy should not be arbitrarily amended. It then deals, in order, with the areas of challenge it has identified, and submits that none of the challenges should be accepted as valid by the Commission.

Commission Determination

The Commission Panel notes that the variances from BC Hydro's forecast energy costs are captured in either the HDA or NHDA as the case may be, and further that its approval to defer the impact of load variation on the cost of energy as described in Section 4.1 above of this Decision should mitigate the concern raised by the CEC. **Accordingly, subject to modification by the Commission Panel's determinations below in the areas of challenge identified by BC Hydro, BC Hydro's forecast of domestic energy costs is approved.**

The balance of this Section deals in turn with each of the areas of challenge.

4.3.1 G.M. Shrum Unit 3 Failure

In its July EU, BC Hydro reported that on March 2, 2008, the turbine runner on Unit 3 at the G.M. Shrum (GMS) Generating Station experienced a catastrophic failure and is expected to be out of service for a year. In combination with other factors this outage led to forecast shortfalls of 340 GWh and 482 GWh for F09 and F10, respectively, from the hydroelectric generation forecast in the Application (Exhibit B-10, p. 16).

While the final cost of returning the unit to service was not available, pursuant to Order G-96-04, BC Hydro noted that it has approval to, and would defer those costs in the HDA (Exhibit B-10, p. 17).

BC Hydro filed two reports concerning the GMS Unit 3 failure. These were its internal "Technical Report" (Exhibit B-25), and a "Root Cause Report" provided by a third party consultant (Exhibit B-50). During the Oral Hearing, BC Hydro's EARG Panel was examined at length by both Intervenors and the Commission Panel as to the foreseeability and preventability of the catastrophic failure as well as its revenue and cost implications.

In an exchange with the Commission Panel, BC Hydro disclosed that it carried insurance with a deductible of $5.0 million against the currently estimated $24 to $28 million cost to return the unit to service, but that the additional total impact on the cost of energy, currently estimated at $17 million was not covered. The matters related to BC Hydro's practices with respect to insurance coverage are described in Section 6.4 of this Decision.

In terms of the failure itself, inquiries of BC Hydro's witnesses focused on such matters as BC Hydro's maintenance personnel replacing a previously failed shear pin with a shear pin from a bin labeled "do not use," inasmuch as it was the failure of this latter pin that triggered the series of events that led to the catastrophic failure. Other matters pursued included the apparent failure of BC Hydro to implement preventative measures that had been recommended to it by its engineering personnel that would, if implemented, have detected the failure of the shear pin and/or the vibration level accompanying the ensuing cascading failure and taken the unit off-line without the consequent catastrophic damage.

In its witnesses' responses, and as summarized in its Argument, BC Hydro takes and maintains the position that the failure was neither foreseeable nor preventable in that:

> "The evidence is that the failure of shear pins, and [this] pin in particular, was not an uncommon occurrence, and had occurred numerous times in the history of the unit without causing the cascading failure that had led to the unit outage. Indeed, units were run with broken shear pins to allow for replacements at opportune times without incident. Nothing in either report suggests that the specific shear pin …. was a primary or even secondary cause of the cascading failure … . Crucially, the design limitation and failure mode was unknown until it occurred even though the turbines have been the subject of extensive engineering analysis over a period of 40

years. It is for these reasons that the actions identified in the two reports that *could* have been taken, and which *might* have prevented the failure, provide no basis on which a finding of imprudence can be made." (BC Hydro Argument, p. 48; emphasis in original)

The JIESC takes issue with BC Hydro's position and submits that "BC Hydro's imprudence was not that it did not know of a latent defect, it was in allowing faulty parts to be used and not having normal recommended safeguards in place for detecting shear pin failure and monitoring vibration", and further that "the responsibility for the associated costs …. must be borne by BC Hydro and its shareholder" (JIESC Argument, p. 38).

In support of its position, the JIESC quotes extensively from the two technical reports entered and adopted without qualification as evidence by BC Hydro, which establish that:

(i) the failed shear pin that triggered the cascading failure was date stamped with " …the same date stamped on several pins found in GMS stores tagged "do not use, emergency use only"; and

(ii) risks associated with shear pin failures were not fully recognized, despite failures which continued through to March 2008; and

(iii) Unit 3 was not equipped with a shear pin failure detection system as "In 2000 the "GMS G1 – G10 V*ibration Monitors Replacement Project Definition Phase" was initiated, which included shear pin failure detection. However the project was not implemented";* and

(iv) "*improved vibration monitoring was proposed in the mid 1990's by Generation Engineering with extensive studies and recommendations presented in 2000.",* but no action was taken; and

(v) "the costs of installing shear pin detection and vibration monitoring for GMS Units 1-5 was estimated to be under $1.5 million."

(JIESC Argument, pp.42-43, emphasis in original)

The only other Intervenor to comment directly on the GMS Unit 3 failure was the CEC, who submits that " … in the case of the G.M. Shrum failure, [CEC] does not believe on balance that BC Hydro was imprudent but rather the evidence is that it was unaware of a potential failure sequence" (CEC Argument, p. 122).

In reply, BC Hydro reiterates much of its Argument in this matter and submits that neither of the reports support the JIESC thesis that BC Hydro ought to have known of the defect, even with the benefit of hindsight. Specifically, BC Hydro notes that:

(i) "shear pin failures had occurred many times previously without incident and without even necessitating an immediate shutdown"; and

(ii) the use of a faulty shear pin is irrelevant inasmuch as "a shear pin is intended to be the weak link that breaks first when a mechanical problem arises, to prevent further more extensive damage"; and

(iii) "In this case the failure of a shear pin actually caused, rather than prevented, extensive damage …"; and

(iv) "the turbine units at the G.M. Shrum station had been the subject of extensive engineering analysis for many years without the defect being discovered"; and

(v) "… because the latent defect and failure mode were not known, and not reasonably knowable, each and every one of the safeguards could only have prevented the failure by dumb luck – and under any meaning of the word it can not be "imprudent" to not get lucky"; and

(vi) "the small cost of the safeguards relative to the cost of the failure is irrelevant in light of the unknown failure mode [i.e.] management and engineers simply could not have considered the relative costs and benefits of the safeguards in light of the costs of the failure because there was no knowledge of the latter"; and

(vii) "The Root Cause Report was not intended to, and does not address … whether the unit failure was the consequence of imprudence. Instead its focus is entirely about what contributed to the failure, and how future performance can be improved."

(BC Hydro Reply, pp.18 –19)

Given the magnitude and uncertainty of the cost and the unknown return to service date of the failed unit, the Commission Panel invited further submissions in Oral Argument in respect of the regulatory accounting treatment for the direct and indirect costs of the failure, pursuant to item 4 of Exhibit A-26.

BC Hydro argues that the determination as to the prudency of its management decisions should be made based on the evidentiary record in this proceeding. It also submits that it expects all of the costs to be recovered from its insurance, except for a “relatively small” $5.0 million deductible. In response to clarification from the Panel Chair that the costs being considered by the Commission Panel as “indirect” included an increase in the cost of energy, BC Hydro acknowledged that, given that that cost was not known, and that it could be relatively large, it might be better put into a deferral account or, depending on the circumstances, taken as an expense in one year. BC Hydro suggests that it could identify all of the failure related costs in its existing deferral accounts and provide the total in its deferral account reporting without setting up a specific deferral account - which could be done if required (T15: 2840-2844).

BCOAPO took no position in respect of the recoverability of the costs of the failure by BC Hydro, but submits that “concerns that customers will pay the right amount trump concerns that the correct generation of customers are paying that amount” (T15: 2849).

The JIESC agrees with BC Hydro that the determination as to the prudency matter should be settled now, but that if a deferral account were created to allow for the quantification of the direct and indirect costs that would not raise any particular concerns (T15: 2851).

The CEC supports the use of a deferral account to assess the quantum of the impact of the failure prior to determination of any amortization periods (T15: 2853).

No other Intervenor made submissions on the matter. BC Hydro made no submissions in reply.

Commission Determination

The Commission Panel accepts BC Hydro's argument that it was unaware of the potential for the exact mechanism of failure that took place in the present case. It does not, however, accept BC Hydro's argument that inasmuch as it did not know of the precise mechanism of failure, that it was not in its and its ratepayers best interests to put in place its own engineering staff's recommendations for shear pin failure detection systems and enhanced vibration monitoring of the GMS Units.

The Commission Panel notes that the recommendations for those safeguards as referenced in the Root Cause Report are contained in certain BC Hydro internal studies and reports, which were not filed in this proceeding. The Commission Panel infers that those arose from concerns that BC Hydro's qualified technical staff had in respect of the integrity and security of the units. BC Hydro's operational and maintenance management saw fit to not accept and implement the recommended safeguards, despite their modest cost and the virtual certainty that if implemented they would have secured the units against a suite of possible failure events which would have included the particular mechanism of the GMS Unit 3 failure. The Commission Panel does not accept BC Hydro's linkage of its decision to not implement the safeguards to its engineering and maintenance personnel's inability to do a cost-benefit analysis against the particular failure mode of GMS Unit 3.

The Commission Panel finds that the evidentiary record is sufficient to overcome a presumption of prudency claimed by BC Hydro in respect of its past decisions regarding its management of the GMS units. The Commission Panel finds, however, that any determination as to the reasonableness of BC Hydro's management of the GMS units and hence its ability to recover the costs associated with the Unit 3 failure must of necessity consider a more complete evidentiary record than that available to this proceeding. **Accordingly, given the seriousness and materiality of the GMS Unit 3 failure, BC Hydro is directed to segregate all of the incurred-to-date and future direct and indirect costs of the outage and repair, inclusive of the impact on its cost of energy, in a separate regulatory account ("the GMS3 RA"), and to apply, at its discretion, to the Commission**

for recovery of those costs at such time as all of the costs are known and can be appropriately allocated by the Commission. At such time BC Hydro is expected to include in its application the studies and reports which recommended the installation of the safeguards, and its reasons for not responding constructively to them, in order that a determination as to the reasonableness of its management's decisions at that time can be made.

4.3.2 F2006 Call for Energy (the "F2006 Call")

Electricity purchased under the F2006 Call is at issue in this proceeding due to the fact that BC Hydro made the decision to purchase 5,725 GWh per year of Firm Electrical Energy from large IPP projects and 1,400 GWh per year of Non-Firm Electrical Energy from large and small IPP projects when the NSP Agreement approved by the Commission in the 2005 REAP proceeding contemplated purchases of 2,500 GWh per year of firm electrical energy, together with associated non-firm electrical energy from large projects and 200 GWh per year of non-firm electrical energy from IPP projects "at relatively high prices" (F2006 Call Decision, pp. 8, 20).

In its opening statement COPE indicated that it would question whether the incremental costs (Electricity Purchase Agreement ("EPA") vs. market cost of electricity) of the F2006 Call energy coming on stream in the test period should be allowed as a recoverable expense, noting that when the Commission accepted the F2006 contract awards in its September 21, 2006 Decision it stated that BC Hydro would bear the regulatory risk of the Commission not accepting BC Hydro's estimated load requirements and, in particular, the Commission's decisions regarding the non-firm allowance that BC Hydro should use in determining its requirements – the deficits BC Hydro presented in support of the need for additional resources as soon as 2009 assumed no market allowance. In its subsequent 2006 IEP Decision (Exhibit C-3-11) the Commission indicated that BC Hydro should continue to rely on the 2,500 GWh market allowance and that the market allowance should not necessarily be restricted to domestic resources (T3: 264-265).

BC Hydro submits that the total cost of energy to be purchased from IPPs pursuant to the F2006 Call during the test period is properly recoverable in rates on the basis that “the Commission has already concluded that BC Hydro’s decisions to acquire the F2006 Call volumes and costs for delivery in F2009 and F2010 were prudent” (BC Hydro Argument, p. 56).

In particular, BC Hydro submits that the Commission in its F2006 Call Decision accepted that the Call process was competitive and “provided a reasonable indicator of near-term market prices for independently produced power in British Columbia”, and that contracts for volumes up to the volumes which were originally approved in the 2005 REAP NSP proceeding by Order G-103-05 are cost-effective. The NSP included approval of the F2006 Call for a target of some 2,400 GWh/yr of firm energy (BC Hydro Argument, pp. 53-54).

In the F2006 Call Decision which considered the EPA’s, the Commission concluded, among other things, that: “the 2006 [Call] process was competitive and has provided a reasonable indicator of near-term market prices for independently produced power in [BC]”; and, “that this conclusion alone is not sufficient to determine the cost effectiveness of the increased volume of contract awards in these circumstances, particularly in light of the higher prices associated with the greater volume of awards than originally contemplated in the NSP.” BC Hydro submits that this supports the cost-effectiveness of the volume up to that approved by the NSP (BC Hydro Argument, p. 54).

BC Hydro also points to its witness’ testimony that the volumes of IPP energy expected to be acquired in the test years are 65 GWh and 831 GWh respectively, which are well below the NSP approved volumes. Further, BC Hydro’s witness testified that the products are not comparable i.e. “You cannot compare spot market pricing to long-term fixed price contracts.” BC Hydro submits that “ … it would be completely unfair to conduct an “after the fact “review of prices from the 2006 Call that have been found to be cost effective (and are within the volumes approved by Order G-103-05) based on spot market prices (for a product that is not comparable) during the test period, and that the costs for IPP purchases pursuant to the call ought to be recovered in rates. (BC Hydro Argument, p. 56)

In its Argument, COPE characterizes BC Hydro's differentiation of the products as "a distinction without a difference," and notes BC Hydro's responses to IRs and its admissions in the oral hearing that:

- market supply at lower cost is available during the test period;
- that BC Hydro could have acquired electricity from the market at fixed prices during the test period;
- that BC Hydro could have avoided the problem through structuring the F2006 call by requiring staggered implementation dates or power deliveries commencing after a certain date; and,
- if the F2006 Call power was replaced by market sources during the test period the revenue requirement would be reduced by some $36 million.

(COPE Argument, pp. 11-12)

COPE submits that the incremental costs of power from the F2006 call over the cost of equivalent spot market purchases during the test period should be disallowed on the basis that BC Hydro embarked on the F2006 call without engaging in appropriate or sufficient analysis of the true benefits of this course of action in advance (COPE Argument, p. 36).

The CEC takes the position that the F2006 Call purchases could have been contested at the time of the section 71 decision on the F2006 Call and were not and does not believe they can now be contested. The CEC submits that the Commission "concluded that these acquisitions were prudent" and submitted that there is no basis to disallow these costs (CEC Argument, p. 81).

IPPBC agrees with BC Hydro's response to COPE's apparent position on IPP purchases, adding its view that market electricity purchases are not directly comparable to long-term firm electricity supply contracts (IPPBC Argument, p. 20).

No other Intervenor made submissions on this matter.

In reply, BC Hydro re-states and amplifies the regulatory history that led to the deliveries of F2006 Call electricity in the test period, emphasizing that only IPP volumes in excess of those approved by the 2006 NSP were confirmed by the Commission as being the subject of residual risk. BC Hydro further argues that COPE provides no evidence to support its assertions that electricity purchased under the EPAs and spot market purchases are substantially similar if not the same product, and further notes that no Intervenor representing ratepayers in this proceeding that participated in the NSP supports COPE's position (BC Hydro Reply, pp. 20-25)

Given the materiality of this matter, and the seeming reliance of both BC Hydro and COPE on the same regulatory record, the Commission invited further argument pursuant to item 6 of Exhibit A-26.

BC Hydro distinguished the regulatory record on which it relies from that of COPE, noting that BC Hydro's submissions referenced the 2005 REAP NSP settlement and Order G-103-05 as confirming the prudence of its decision to undertake the F2006 Call, whereas that proceeding was not referred to in COPE's submissions. BC Hydro submits that COPE goes beyond an inappropriate use of hindsight by not considering that aspect of the regulatory record. In support of its position that the regulatory record as referenced in its Final Argument and Reply confirmed the prudence of its decisions, BC Hydro cites the decisions, referred to in Exhibit A-26, of the Nova Scotia Utility Board ("NSUB"), both regarding Nova Scotia Power Inc. ("NSPI") and its coal resource planning strategy. In the first of those related cases, NSPI was found to have been imprudent in its fuel procurement practices since, despite an earlier warning from the NSUB on the issue, NSPI was faced with a material increase in its forecast cost of coal fuel and purchased power for F2005, some three years later, as a result of becoming over-exposed to the spot market. BC Hydro submits that the circumstances in that Nova Scotia case are the opposite of its management's decisions in respect of the F2006 Call in which, with review and approval by Commission, it has managed its exposure to the spot market for electricity purchases (T16: 2858 – 2865).

The CEC affirmed its support of BC Hydro's argument, as described in the CEC's Final Argument (T16: 2866).

IPPBC agreed with BC Hydro with respect to its submissions and arguments and also its Reply Argument (T16: 2866).

COPE submits that had BC Hydro limited its awards in the F2006 Call to the agreed-to volumes, the cost overruns in the test period would have been lower, as the power deliveries that BC Hydro would have been obliged to take would have been proportionately lower, and that BC Hydro's decision to award contracts in amounts of more than double what was agreed to in the 2005 NSP was imprudent in the circumstances (T16: 2873).

COPE further argued that the NSUB decision in fact supports its position that BC Hydro's reliance on the Commission's Decision in the F2006 Call proceeding is ill-founded. Specifically, COPE points to the finding of the NSUB in its 2002 proceeding that NSPI's coal procurement strategy was prudent at that time, but that as a result of NSPI's subsequent decisions in the face of changed circumstances and the prior direction from the NSUB, the strategy was no longer prudent in 2005. COPE draws an analogy with BC Hydro's circumstances, having awarded greater than approved volumes in the F2006 Call, at higher prices, it has now imprudently limited its procurement options during the test period, thus leaving its ratepayers facing significantly increased costs (T16: 2873-2874).

In further amplification of its position, COPE referenced the Commission's Decision in the 2006 IEP/LTAP proceeding which said, "Therefore the market risk issue for BC Hydro is primarily one of price. The issue is […] balancing the certain costs of firm long-term contracts against the uncertain costs of future market purchases"; and further, "[…] BC Hydro has placed undue weight on its objective of reducing market exposure despite its submissions that the portfolios with 3,000 or 6,000 [GWh] are both less sensitive to gas price forecasts than other scenarios" (T16: 2877-2879).

COPE submits that "BC Hydro made a decision to make what is essentially a market call. They had forecasts and an RE[A]P that said X volume is what the Call should be. They chose, at their own decision to award far in excess of that," and have locked themselves into take or pay contracts, the result of which is excessive cost to ratepayers. COPE argues that the Commission should either find, along the lines of the NSUB decision, that BC Hydro's actions and decisions were imprudent and disallow the excess costs in their entirety, or, in the alternative, it should look to Section 59(5) of the *Act* and exercise its discretion under subsection 59(5)(c) to ensure that the rate it determines is not "unjust or unreasonable for any other reason" (T16: 2778-2880).

In reply, BC Hydro notes that the 2005 REAP NSP approved commencement of delivery dates for power pursuant to the F2006 Call between October, 2007 and November 1, 2010, and that if BC Hydro had given other instructions to the IPPs it would have been inconsistent with the NSP. BC Hydro submits that the matter of prudency was determined in the F2006 Call Decision, subject only to the additional volume issue which was addressed in the 2006 IEP/LTAP proceeding.

Commission Determination

The Commission Panel finds that the regulatory record confirms that BC Hydro acted reasonably in respect of that portion of the EPAs awarded in the F2006 Call that met the requirements of the 2005 REAP NSP Agreement. Inasmuch as the deliveries from IPPs in the test years are within the 2005 REAP NSP agreement volume, the Commission Panel determines that there is no basis on which to make any adjustment to BC Hydro's revenue requirements for the test years as requested by COPE.

The Commission Panel makes no express or implied determination in respect of the recoverability by BC Hydro of any "excess cost" that may arise in future test periods from the F2006 call volumes that may be delivered in excess of the 2005 REAP NSP approved volume, as it does not regard the Commission's 2006 IEP/LTAP Decision as determinative of the reasonableness of BC Hydro's F2006 Call EPA awards in excess of the NSP approved volume.

4.3.3 Load Curtailment Costs

Load curtailment costs are the costs which BC Hydro pays to certain of its large transmission-voltage customers on Vancouver Island to reduce their consumption, at BC Hydro's request, to manage peak load on its system during the winter. The Vancouver Island load curtailment costs are currently included in the cost of Heritage Energy. BC Hydro now seeks to expand the scope of load curtailment costs it includes in the HPO to cover existing load curtailment contracts with its large customers anywhere in its service area, and to record any differences between forecast and actual costs in the HDA, as is now being done with the Vancouver Island load curtailment costs (Exhibit B-1, pp. 3-10 to 3-12).

BC Hydro submits that, given its expertise with system operation and optimization, there is no basis upon which to second-guess BC Hydro's decisions on load curtailment volumes (BC Hydro Argument, pp. 56-57).

Positions of Parties

The CEC submits that load curtailment costs are related to the cost of energy and may become more significant in the future if BC Hydro should use load curtailment to free up capacity to earn additional income (CEC Argument, p. 54). The CEC also suggests that it would agree to the inclusion of load curtailment cost variances in the HDA so long as the curtailment was used to support domestic load. To the extent that load curtailment is used to support Powerex trade income, the CEC submits that "load curtailment cost variance should more properly be included in the TIDA account" (CEC Argument, p. 110).

BCOAPO supports BC Hydro's request to include the costs of existing load curtailment contracts (and renewal of existing Evergreen Agreements) in the calculation of the HPO (BCOAPO Argument, p. 15).

The JIESC supports the inclusion of load curtailment costs in the calculation of the HPO. It also submits that BC Hydro should increase its use of load curtailment as it is a relatively economical way to meet peak load requirements and can come on stream quickly. The JIESC further submits that BC Hydro's reasons for not using load curtailment more – i.e. because BC Hydro does not want to disturb its customers and because the resource is relatively new and BC Hydro is not comfortable with it – are not valid. The JIESC argues that customers that sign load curtailment contracts expect to be called upon and further that BC Hydro has tested protocols in place which can be enforced. JIESC further notes that "[c]urtailment programs work and are used by other utilities in Canada and the United States." It submits that "BC Hydro should be comfortable with both the current level of contract curtailment capacity and with the potential for increased curtailments" (JIESC Argument, pp. 22-23).

In reply, BC Hydro submits that there is no evidence on the record of what the cost of energy would be, or what system impacts there would be, if BC Hydro had contracted for more or exercised more readily its load curtailment rights. Accordingly, BC Hydro submits that there is no basis for a finding of imprudence regarding load curtailment costs (BC Hydro Reply, p. 25).

Commission Determination

The Commission Panel accepts that load curtailment costs are an integral part of the cost of energy and the costs should be included in the HPO. However, if and when BC Hydro increases its use of load curtailment, and to the extent that load curtailment is used to free up capacity for trade, then the inclusion of such load curtailment costs in the HPO will need to be re-visited. The Commission Panel is not prepared to direct BC Hydro to increase load curtailment beyond its comfort level at this time. The Commission Panel's determination in respect of deferral account treatment of load curtailment can be found in Section 5.2.1.

4.3.4 Use of Average Water to Establish Cost of Energy

BC Hydro forecasts its cost of energy for the test period based on its estimated percentage of the long-term average inflows to its reservoirs, and its most recent, or otherwise current reservoir levels. BC Hydro takes the position that the matter of basing the forecast cost of energy on "average" or "normal" water conditions has already been reviewed by the Commission in its 2004 Decision regarding BC Hydro's F05/F06 RRA, with the conclusion that the forecast should use the best known information available at the time. BC Hydro also notes that, in its view, "there is nothing normal about reservoir levels" and submits that the Commission should reject the notion that the forecast cost of energy should be based on "average" or "normal" water conditions (BC Hydro Argument, pp. 57-58).

The CEC canvassed this matter at length with BC Hydro's witness and makes extensive submissions in its Argument. Based on BC Hydro's responses to IRs, CEC describes its understanding as:

- BC Hydro forecasts future inflows on the assumption they will be 100 percent of normal;
- BC Hydro indicates that the 10 year long-term average reservoir level is 11,600, GWh;
- reservoir levels were about 800 GWh above that long-term average as of March 31, 2008;
- reservoir levels are expected to be 300 GWh above that long-term average at the end of F2010;
- the value of changes in water inflow levels of 1 percent, or about 530 GWh is about $40 million;
- the value of changes in water inflows can vary non-linearly with the level of inflows; and
- under current water inflow and market prices that 1 percent variation works out to be approximately $75/MWh.

(CEC Argument, p. 33)

The CEC submits that the problem with allowing reservoir level forecasts to be made as part of determining the revenue requirements for a period is that they will result in timing differences in rate responsibility for the revenue requirements beyond normal water inflows and normal loads, and that it is appropriate to establish rates based on normal water inflows, weather normalized load forecasts, and a normal reservoir level forecast (CEC Argument, pp. 34-35).

The CEC further submits that it is appropriate to bring the reservoir level forecast down to the 10 year long-term average of 11,600 GWh for the purpose of rate setting and then record variances from that level into the deferral account, assuming an ending reservoir water level of 11,600 GWh. The result of this would be to reduce the requirement for forecast energy purchases by 300 GWh for F2010, with a corresponding reduction to the revenue requirement of $16.4 million as the displaced cost of those purchases as forecast (CEC Argument, p. 36).

The CEC responds to BC Hydro's Argument that this matter was settled in the F05/F06 RRA by pointing to the changed economic circumstances for ratepayers since that Decision, submitting that steps to mitigate inappropriate costs to customers should be pursued wherever possible, and that nothing precludes the Commission from reviewing the issue in this proceeding (CEC Argument, p. 35).

No other Intervenor took a position in this matter.

In reply, BC Hydro "notes that forecasting on an assumption of average inflows could be done, but that forecasting on the basis of average reservoir levels makes no sense at all because reservoir levels do not have an a normal distribution", and BC Hydro submits that there is therefore no reason to believe that the variances between actual and forecast cost of energy based on such averages will themselves average to zero over time (BC Hydro Reply, pp. 25-26).

BC Hydro characterizes the CEC's submissions as "suggest[ing] that "forecasts" of cost of energy based on average water conditions for revenue requirements and rate-setting might somehow have an effect on actual operations" to which BC Hydro responds that such would not be the case.

BC Hydro points out that a consequence of the CEC's approach would, however, be that "BC Hydro would never be able to make a witness available to testify to the manner in which the operation of the system results in the forecast cost of energy in a revenue requirement proceeding" (BC Hydro Reply, p. 26).

BC Hydro agrees with the CEC that the matter can be reconsidered in this proceeding, but submits that there is "an onus [on CEC] to address head-on the reasons that the Commission gave at first instance", which it submits the CEC has failed to do (BC Hydro Reply, pp. 26-27).

Commission Determination

The Commission Panel notes that the circumstances in this proceeding are fundamentally different from those at the time of the F05/F06 RRA proceeding. That proceeding was in many respects "foundational" in that, in large part, it was concerned with the re-regulation of BC Hydro, the implementation of the Heritage Contract and the regulatory account structures associated with it, as well as the disaggregation of BC Hydro into BC Hydro and BCTC as "arms-length" entities. Given the intervening years and the maturation of the HDA, NHDA, and other regulatory account structures that were settled in that proceeding, the Commission Panel finds BC Hydro's Reply that the intersection of the use of average water levels with all of that needs to be revisited in order to make a determination in respect of the CEC's proposed relief to be unpersuasive.

The Commission Panel finds the CEC's proposal could be a straightforward, more certain, and more transparent method to provide a basis against which the variances in the actual vs. forecast cost of energy can be established, and that it is in concordance with the basic principle underpinning the "Heritage Benefit" i.e., the heritage generation capacity itself is based on a defined set of assets under a defined, fixed, set of water conditions. **However, in consideration of all of the circumstances, based on the evidence before it the Commission Panel declines to grant the CEC the relief it requests.** In particular, the Commission Panel is concerned as to the long-term impacts of the CEC proposal on the alignment of cost causation with cost recovery.

The Commission Panel directs BC Hydro to file with its next RRA a comparison of the economic impacts in terms of its annual costs and deferral account balances with and without the CEC proposal in place for the eight years preceding and the forecasts for the test years covered by that RRA.

4.4 Operating Costs

4.4.1 BC Hydro's Position

BC Hydro notes that a large portion of the proposed increase in its operations, maintenance and administration ("OMA") costs is attributed to maintaining, refurbishing and increasing the resiliency and security of its electrical assets, as well as an increase in investment in the buildings and other civil infrastructure that support the company's employees and operations. Further, BC Hydro states that operating expenditures are being increased in the areas of training, development and recruitment as the labour market and aging workforce "present continuing challenges" (Exhibit B-1, p. 4-2).

To add further context to its increase in staffing levels, BC Hydro stated:

> "In rough numbers, BC Hydro now employs as many people as it did prior to the creation of the BCTC and the advent of the outsourcing arrangement with Accenture. BC Hydro does not see this as a failure, or a problem to be rectified. In fact, quite the opposite. The required reinvestment into BC Hydro's Heritage Resources, and the new challengers facing BC Hydro, require those staffing levels. In the past, BC Hydro has had difficulty in actually delivering its annual capital plan. One of the reasons has been the lack of human resources to do the work. The lack of human resources has been a structural issue for BC Hydro, in that it has not simply been a matter of opening a "hiring tap". With a significant number of our employees at retirement age; with the need for specialized skills that are not readily obtainable; with the tight labour market in BC Hydro [sic] and the North American demand for certain utility expertise, there has been no "tap" to turn to. Instead, BC Hydro has made human resources management a strategic issue."
> (Exhibit B-23, p. 3)

With regard to the concern raised by the Commission Panel that the RRA Decision will not be available until towards the end of F2009, BC Hydro testified that they have instructed Management to "be careful", to try to tilt spending towards the end of the year and that the Government is "very well aware of the situation, and they will apply their own thoughts to what they think the risk is on their revenue, of which we, of course, are part" (T4: 584-585).

The following sections address in more detail issues such as BC Hydro's approach to budgeting, base operating costs, new on-going and fixed-term initiatives, resourcing strategies, and capitalized overhead, as well as trend analysis, benchmarking and productivity.

4.4.2 BC Hydro's Approach to Budgeting

In the Application, BC Hydro states that its planning and budgeting process, which took several months, consisted of both top-down and bottom-up processes, but that to improve the efficiency of the regulatory review process it decided to adopt a formula-based approach in preparing its F2009/2010 RRA. BC Hydro further submits that given that its operating costs were thoroughly reviewed in the F05/F06 RRA and F07/F08 RRA, it considers that the approved F2008 revenue requirement is a reasonable starting point to allow for a formula-based approach to budgeting of its operating costs over the test period.

BC Hydro used the following formula to determine what it describes as its "base OMA growth" (T4: 610) for each of the two fiscal years of the test period:

> Increase for fiscal year N = Operating costs for fiscal year (N-1) x (inflation rate + customer growth rate – productivity factor).

For purposes of the calculation, BC Hydro bases its inflation forecast on the B.C. consumer price index ("B.C. CPI"), which the B.C. Ministry of Finance has forecast at 2.1 percent per year over the test period. The customer growth rate is forecast to be 1.7 percent per annum. The productivity factor at one-half B.C. CPI or 1.05 percent per year is as specified by BC Hydro.

BC Hydro states that as well as the base OMA growth, there are costs that it is incurring that are larger than those numbers, such as labor cost increases. In addition to those increased costs it has eleven fixed-term initiatives, four areas of on-going work and two productivity initiatives that must be addressed but cannot be accommodated within the budget allowance determined by the formula-based approach (Exhibit B-1, pp. 4-9 to 4-12; T4: 610).

BC Hydro submits that it used the formula approach because it was quantitative and transparent, and that its approach to budgeting in this proceeding was never intended to exclude the review of its base costs since there is sufficient information on the record to compare increases in the operating costs of each business group for F2007 through F2010 (BC Hydro Argument, pp. 61-64).

Table 4.1 below summarizes the proposed operating costs resulting from BC Hydro's approach.

Table 4.1
Proposed Operating Costs

($ million)	RRA F2008	F2009	F2010
Operating Costs (F08 per RRA NSA)	556		
Previous Year Formula Base Operating Costs		**556**	**572**
Inflation Factor = BC CPI %		2.10%	2.10%
Average Customer Growth %		1.70%	1.70%
Productivity Target		-1.05%	-1.05%
Increase per Formula		16	16
Formula Base Operating Costs		572	588
On Going Initiatives F09 to F10		12	17
Less: Incremental Capitalized Overhead		(12)	(12)
BCTC Fees Increase		9	11
Proposed Base Operating Costs		**582**	**604**
Fixed Term Initiatives F09 to F10		28	45

Source: Exhibit B-1, Table 4-1, p. 4-14

BC Hydro clarified that it is not proposing performance-based ratemaking ("PBR"), but is simply using the formula approach to manage the increase in its on-going base operating costs, which are only a component of the total operating cost budget. BC Hydro further points out that its approach does not include an incentive mechanism to share earnings variances between BC Hydro and its customer as its shareholder, the Province, "does not expect more (or less) than the annual return on deemed equity prescribed by [HC2]" (Exhibit B-5, BCUC 1.43.1).

BC Hydro also points out that it has implemented specific performance requirements, which are outlined in its F2009 Service Plan, and that variable pay and gain-sharing contracts for the Executive Team ("ET") and all employees include specific Safety, Customer Satisfaction and Financial metrics to ensure alignment with the goals and objectives identified in the Service Plan (Exhibit B-1, Appendix C; Exhibit B-5, BCUC 1.43.1).

BC Hydro explains that it decided to use the formula approach to base OMA growth for the following four reasons:

1. it provides a quantitative and transparent method to manage the on-going base operating cost increase;
2. the productivity factor component drives cost containment;
3. it supports budgetary efficiency by providing a high-level way to manage costs as opposed to a line by line build-up; and
4. it supports regulatory efficiency by providing a high level way to review costs.

BC Hydro further stated that its formula is similar to those used by FortisBC and Terasen in that it incorporates customer growth, inflation and productivity against a base operating value. BC Hydro notes that the customer growth component of the formula was used as a transparent proxy for the multiple drivers that influence its costs, while the productivity factor was based on management judgment and a review of the Terasen and FortisBC formulas, as well as "known cost increases faced by the organization." Finally, BC Hydro notes that Terasen used a productivity factor of 50 percent of CPI for the first two years of its 2004-2007 NSA while FortisBC negotiated a productivity factor of two percent for 2008 and three percent for 2009, provided its PBR settlement is extended (Exhibit B-5, BCUC 1.43.1, pp. 3-4).

In terms of the process leading to finalization of its planned OMA expenditures for the test period, BC Hydro's witnesses testified that:

- BC Hydro went through a bottom-up process to determine the activities and costs that were required during the test period;
- BC Hydro's business units were unable to fully comply with initial instructions to stay within their '08 amounts;
- it took the overall revenue requirement and used the formula methodology as a proxy to manage budgets, to keep cost containment in light of labor and contactor costs rising at a rate much higher than inflation plus customer growth minus productivity, that it was not an exact science but a methodology applied to the budgeting process;
- any increases resulting from costs included in the 2008 base that were escalated by the formula to calculate growth in base OMA and separately identified in the Application, such as initiatives or BCTC pass-through items, were allocated to areas of cost pressure within the business units;
- the aggregate planned OMA expenditure increases for F2009 and F2010 vs. F2008 are \$40.5 million and \$61.8 million; and
- not all of the details of the bottom-up budgeting process are provided in the Application, only the process is provided, while some of the details are in the IRs.

(T4: 648-656)

BCOAPO submits that setting rates for the test period is difficult because of the opacity of the Application, especially with the formulaic justification provided for OMA expenditures. BCOAPO further submits that "whatever the outcome in the present Application, we ask that the Commission direct BC Hydro to present a more rigorous, bottom-up account of its projected expenses in future revenue requirements" (BCOAPO Argument, p. 3).

The CEC submits that the formula approach is a prudent management approach but notes that the process of setting the formula is reasonably generous in terms of “not putting too much pressure on the management”, especially when compared to the tight management of the Accenture Business Services for Utilities Limited (“ABSU”) contract. Further, CEC submits that it would be concerned about any action at this stage that might be aimed at “slashing costs” because there are issues that BC Hydro needs to deal with regarding reliability, security of supply, safety, environment, First Nations and organization transition. Regardless, the CEC submits that “some marginal increase in productivity of 0.5 percent in each year would be warranted and expresses a view that productivity management at BC Hydro is somewhat deficient because the management does not appear to have measures in place to track productivity improvement. Finally, the CEC submits that the Commission should set rates on the basis of sending a signal for a requirement for increased productivity which would reduce OMA expenses by approximately $6 million in F2010 (CEC Argument, pp. 83-85).

The JIESC submits that it has found this RRA both frustrating and difficult because of “the high degree of aggregation” BC Hydro has used for reporting its historic data and because of BC Hydro’s “global approach to future requirements” rather than a line by line approach. While in its opening statement the JIESC suggested the Application should be rejected, in its Final Argument it seeks, among other things, orders from the Commission to: reduce OMA expenses by $55.9 million and $62.9 million in the respective test years in order to “properly base BC Hydro’s formulaic approach on approved F2008 OMA costs”, and, to reduce BC Hydro’s Forecast OMA On-going Initiatives by 50 percent and its Fixed Term Initiatives by 25 percent “to recognize that BC Hydro’s formulaic approach provides room for growth in costs and shifting initiatives” (JIESC Argument, pp. 4-6).

In reply to the CEC Argument, BC Hydro submits that “it included a reasonable productivity factor in its formulaic approach to budgeting, and that it did not believe that a higher productivity factor is achievable, as evidenced by the formula’s inability to accommodate initiative spending. In response to BCOAPO, BC Hydro submits that the formulaic approach was one of the tools that were used in a budgeting process over several months (BC Hydro Reply, pp. 27-29).

In reply to the JIESC Argument, BC Hydro submits that JIESC "mischaracterizes" BC Hydro's approach to budgeting operating costs in that the "amount provided by the formula and the amount associated with the cost of activities in 2008 that do not continue in the test period were considered as a whole in the budgeting process and were allocated to the business groups to manage cost pressures." Further, BC Hydro reaffirms that it "used the formula as one of the tools to manage cost pressures related to the base budgets" and that JIESC has provided no evidence from the record that any of BC Hydro's planned activities are unnecessary, optional, or otherwise imprudent (BC Hydro Reply, pp. 30-32).

Commission Determination

The Commission Panel understands Intervenors' frustrations and concerns with attempting to understand BC Hydro's approach to establishing its planned OMA expenditures in this Application. The perhaps unintended consequences of BC Hydro's approach have been to send Intervenors and Commission staff on numerous, and in many cases seemingly fruitless searches through IRs and requests for undertakings to gain insight into where, and by what amount, and on what basis BC Hydro is determining and allocating the increase in planned OMA expenditures for which it seeks approval. The Commission Panel also finds that BC Hydro's seeming inability to quantifiably and transparently link its increases in planned OMA expenditure to what it has identified as its key influences, key cost drivers, and objectives is, at a minimum, troubling.

The Commission Panel accepts that BC Hydro's "formula approach" is but one element in the process by which it determined its planned OMA expenditures for the test period, and does not find it determinative in any respect, or to be of any particular assistance in the review process. While such an approach may be of value to parties in determining base revenue requirements in a PBR setting involving risk sharing between a utility and its ratepayers, that clearly is not the case with BC Hydro.

Stated differently, while BC Hydro is free to use whatever methodology it deems appropriate in managing its budgeting processes internally, the Commission Panel finds that the review process is not assisted by BC Hydro's reliance on those "tools" – as it describes them - as a basis for justification of its planned expenditures.

For its next RRA, BC Hydro is directed to submit its OMA forecast on a line item basis for each business unit, consistent with the system of accounts it employs to hold its managers accountable for budgetary performance, with a four year history for each expenditure category. Further, it is to quantifiably and transparently link the planned levels of expenditures to its key influences, key cost drivers, and objectives. In this latter regard, BC Hydro is referred to the Commission Panel's determination at Section 3.1.3.2 of this Decision.

4.4.3 Base Operating Costs

This Section addresses the base operating costs as well as certain cost items that were reviewed more extensively during the proceeding including the non-current Post Employment Benefit costs ("PEBs") and the Accenture costs. By way of background, a summary of Current and Planned Operating Costs for BC Hydro's Business Groups is provided in the following table:

Table 4.2

Current OMA by Business Group F2007 – F2010 ($millions)

	F2007 Actual	F2008 RRA	F2008 Actual	F2009 RRA	F2010 RRA
Corporate					
Base – New	141.3	139.4	98.3	124.1	127.7
Initiatives				7.5	11.2
Total				131.6	138.9
EARG					
Base – New	106.7	112.4	123.4	134.2	138.3
Initiatives				11.9	14.8
Total				146.1	153.1
CC&C					
Base – New	95.7	95.9	107.5	93.6	96.2
Initiatives				2.2	1.8
Total				95.8	98.0
Transmission	**93.4**	**93.1**	**94.7**	**94.4**	**95.9**
Field Operations					
Base – New	114.7	115.5	129.9	135.0	145.5
Initiatives				6.7	17.4
Total				141.7	162.9
Total Before Regulatory Accounts	**551.8**	**556.3**	**553.8**	**609.6**	**648.8**
Regulatory Account Recoveries	4.2	4.5	2.9	6.2	7.2
Total Current Operating	**556.0**	**560.8**	**556.7**	**615.8**	**656.0**
Increase over prior year		**.9%**	**.1%**	**9.8%**	**6.5%**
Cumulative increase over F2007		**.9%**	**.1%**	**10.8**	**18.0%**

Source: Exhibit B-10, Appendix A, Schedule 5.0, pp. 18-20)

4.4.3.1 Non-Current PEB Costs in F2008

The base costs in the foregoing table reflect the cost of BC Hydro providing health care and other benefits to its active and retired employees, including

- a defined benefit pension plan to substantially all its employees (the basic pension plan);

- supplemental pension benefits in excess of the statutory maximum allowable for qualifying employees.
- cost-of-living increases to retirees or their beneficiaries to the extent that funds are available in a separately funded indexing plan.
- non - pension benefits to current employees and to retirees – other post-employment benefits ("OPEB") - which are unfunded.

BC Hydro identifies its non-current PEB costs as the sum of its unfunded OPEB costs and the non-current service portion of its pension plan funding costs. Two principal issues of contention arose in the course of the proceeding in respect of these costs, triggered by the OEU.

The first such issue raised during the Oral Hearing with respect to BC Hydro's base OMA costs was the impact of the change in non-current PEB costs between the approved F2008 RRA amount and the F2008 actual amount, and those costs as estimated for the test period. The approved F2008 RRA included non-current PEB costs of $30.8 million, however, an "unplanned gain" of some $36-million arose and was allocated by management to deal with cost pressures among the EARG, CC&C and Field Operations Groups, "which [amounts] were kept within their budgets for fiscal 2009 and 2010" (BC Hydro Argument, pp. 65-67).

The impact of inclusion of the non-current PEB costs in the current operating costs is shown in Table 4.3 below.

Table 4.3

BC Hydro Net OMA Without Pension

($ millions)	2008 Approved	2009 Plan	Difference	% Increase	2010 Plan	Difference	% Increase
1	2	3	4	5	6	7	8
			=3-2	=4/2		=6-3	=7/3
1 Operations	$137.0	$158.9	$21.9	16.0%	$179.7	$20.8	13.1%
2 Maintenance	250.0	304.8	54.8	21.9%	337.1	32.3	10.6%
3 Admin & General	169.3	145.5	(23.8)	-14.1%	132.3	(13.2)	-9.1%
4 **Total Net**	**$556.3**	**$609.2**	**$52.9**	**9.5%**	**$649.1**	**$39.9**	**6.5%**
5							
6 less:							
7 Pension expense *	$30.8	($9.7)			($9.4)		
8							
9 Total Net without Pension expense	$525.5	$618.9	**$93.4**	**17.8%**	$658.5	**$39.6**	**6.4%**
10							
11 * Source Pension expense: BCUC IR 1.47.5 and 2.135.1							
12							
13							
14							

15 **Operating Costs without Pension including Regulatory Account Additions**

16

17 ($ millions)	2008	2009		%	2010		%
18	Approved	Plan	Difference	Increase	Plan	Difference	Increase
19 1	2	3	4	5	6	7	8
20			=3-2	=4/2		=6-3	=7/3
21							
22 Operating Costs	$621.4	$800.5	$179.1	28.8%	$833.1	$32.6	4.1%
23							
24 less:							
25 Pension expense	$30.8	($9.7)			($9.4)		
26							
27 Total Operating Costs							
28 without Pension Expense	$590.6	$810.2	**$219.6**	**37.2%**	$842.5	**$32.3**	**4.0%**

Source: Exhibit A2-8

<u>Positions of the Parties</u>

BC Hydro submits that the evidentiary record establishes that the difference between the F2008 RRA and actual non-current PEB costs was used to address cost pressures related to maintenance, safety, reliability, and other critical areas of the business, and that the cost pressures related to maintenance, safety, and reliability continue through the test period (BC Hydro Argument, p. 70).

The JIESC does not accept BC Hydro's "suggestion that [it] saved money on the pension and spent it elsewhere for good purposes", noting that "the pension change was an accounting entry, not a "saving" and furthermore, "even if the money was spent, it was not an <u>approved</u> expenditure under the F2008 RRA […] and accordingly has no place in the formulaic approach adopted by BC Hydro" (JIESC Argument, p. 20; emphasis in original).

As described in Section 4.4.2, the JIESC seeks an Order from the Commission requiring BC Hydro to reduce its OMA expense in F2009 by $55.9 million, and in F2010 by $62.9 million, based in large part on BC Hydro's inclusion of the difference in its non-current PEB costs from the 2008 RRA approved level in its base OMA costs for 2008 (JIESC Argument, p. 6).

BCOAPO notes that while BC Hydro represented the formula driven increase in base operating costs as some $16 million, the non-current PEB cost difference in the F2008 base year was the principal factor (at $40.5 million) in the formula effectively providing an increase of some $60 million for F2009 over the F2008 base operating costs. BCOAPO submits that "the incremental cost increases provided by the formula are substantial and exceed any reasonable expectation of the increase that should be required to carry on the same base activities in F2009 – even in the face of mounting cost pressures (BCOAPO Argument, p. 10).

The CEC proposes that no change be made to BC Hydro's base OMA expenditures in the test period as result of the allocation of the non-current PEB cost difference in F2008 to operating requirements, but that for improved transparency, volatility in the non-current PEB costs be dealt with through a deferral mechanism (CEC Argument, pp. 86-87).

In reply, BC Hydro submits that "even though the difference between forecast and actual non-current [PEB costs for F2008] was a non-cash accounting item, all else being equal, the difference would have reduced actual operating expenses (and increased net income) dollar-for-dollar in F2008. However, actual current operating expenses in F2008 were only $4.1 million below the F2008 RRA forecast, confirming that the difference [in non-current PEB costs] was offset by increased spending in other areas", and that those cost pressures continue through the test period (BC Hydro Reply, p. 33).

Commission Determination

As described in Section 4.4.2 of this Decision, the Commission Panel finds that BC Hydro's formula based approach to establishing its forecast OMA expenditures for the test period to not be determinative of the amounts of those expenditures and accordingly declines to grant JIESC the relief requested.

4.4.3.2 Non-Current PEB Costs in the Test Period

The second matter that arose in the course of the Oral Hearing which involved non–current PEB costs was the impact of financial market volatility on BC Hydro's forecast pension expenditure for the test period. The following table summarizes BC Hydro's experience for the most recent period, and its forecast for these costs over test the period.

Table 4.4
Non-Current Service Post-Employment Benefit Costs (Recoveries)
($millions)

F2007 RRA	F2007 Actual	F2008 RRA		F2008 Actual	F2009 RRA	F2010 RRA
33.4	26.2	30.8		(15.0)	(9.7)	(9.4)

Source: Exhibit B-5-4, BCUC 1.47.5; Exhibit B-8, BCUC 2.135.1; Exhibit B-33

The approved F2008 amount of $30.8 million when combined with the forecast credit of $9.7 million for F2009 totals the $40.5 million figure referred to by BCOAPO. BC Hydro also provided the following breakdown of its forecast non-current PEB costs:

Table 4.5
($Million)

	F2009	F2010
Non-Current Pension Costs	(51.3)	(51.4)
Other Post-Employment Benefits	41.6	42.0
Total	**(9.7)**	**(9.4)**

Source: Exhibit B-75, Undertaking 30

BC Hydro testified that its OPEB costs are not subject to the same volatility as its non-current pension costs and that the potential variances are much smaller (T14: 2552-2554). As well, in accordance with Generally Accepted Accounting Principles ("GAAP"), the costs for OPEB are expensed as incurred, whereas the non- current pension cost component is not booked on a cash basis but is "smoothed out over time (like the amortization of capital assets)" (BC Hydro Argument, p. 71).

BC Hydro explained that "Cash contributions to the pension plan are based on tri-annual actuarial going-concern and solvency valuations. … [and that] the solvency valuation usually governs the required cash contribution and solvency payments are made over a five year period." BC Hydro further states that the GAAP entries for non-current pension costs are updated in the intervening years based on the valuation of the pension plan assets and liabilities as of the prior December 31st and that accounting adjustments are amortized over the expected average remaining service life of active plan employees (currently 11 years for BC Hydro) (BC Hydro Argument, p. 72). As well, BC Hydro testified that "over the entire life of a pension plan, the GAAP entries and the cash contributions to the pension plan should even out" (BC Hydro Argument, pp. 71-72).

The most recent actuarial funding valuation for the basic pension plan was performed at December 31, 2006 with the next valuation for funding purposes taking place as of December 31, 2009 (BC Hydro 2008 Annual Report, Note 14 to Consolidated Financial Statements, p. 91).

Pursuant to the 2006 actuarial valuations on the going concern and solvency bases, BC Hydro is required to contribute 9.60 percent of Plan earnings in respect of the current service cost of basic pension benefits and 1.10 percent of Plan Earnings to the Index Reserve Account (“IRA”) annually, in addition to annually providing for the non-current post retirement pension costs. Furthermore, in 2007 BC Hydro made a one time contribution of $18 million plus interest to eliminate the unfunded solvency liability (Exhibit B-75, Undertaking No. 30, Attachment 1, p. 7).

In the OEU, BC Hydro states that if it “had to book its F2010 non-current PEB cost based on the value of the pension plan assets and liabilities as of October 10, 2008 the non-current PEB cost in F2010 would be $71 million, an increase in its F2010 OMA revenue requirement of approximately $80 million from its forecast recovery of $9.4 million for that test year in the F09/F10 RRA” (Exhibit B-22, p. 4). BC Hydro stated that:

> “non-current post-employment benefits expense is significantly driven by the market value of securities; the market value of securities across virtually all asset classes has plunged in recent weeks; and while security markets remain extremely volatile, there is no indication that their value will return to levels approaching what they were at the time of the July Evidentiary Update.”
>
> (BC Hydro Argument, p. 74)

BC Hydro also notes that “ … given the on-going volatility in the financial markets, it does not consider the valuation at October 10, 2008 to be an accurate forecast of what the [GAAP] valuation of the plan will be as of December 31, 2008.” Accordingly, to deal with this uncertainty BC Hydro proposes a new deferral mechanism that would defer the difference between the present forecast and the RRA forecast of non-current PEB costs for F2010 of some $80 million, as the actual F2009 non-current post-employment benefits expense has already been accrued based on final performance to the end of F2008. In the alternative, BC Hydro requests that “if the Commission is disinclined to allow the proposed deferral mechanism, BC Hydro seeks to have its current forecast of a F2010 $71 million expense reflected in its revenue requirement” (BC Hydro Argument, p. 74).

BC Hydro's proposed deferral mechanism would see the $80 million variance become part of the NHDA for "administrative simplicity" and to achieve a "4 to 6 year amortization period." BC Hydro stated that it would be opposed to a separate deferral account, but that it could be accommodated (Exhibit B-77, BCUC 4.206.1.2).

In summary, BC Hydro takes the position that:

(a) The uncertainty and volatility with respect to non-current post-employment benefits should be addressed using a deferral account, and the baseline for the deferral account should be the forecasts included in the Application;

(b) The deferral treatment should be limited to the non-current pension component of the non-current post-employment benefits costs (i.e. the deferral treatment should not apply to OPEB); and

(c) The non-current post-employment benefits costs included in the revenue requirements should continue to reflect the annual accounting adjustments as required under GAAP

(BC Hydro Argument, p. 166)

Intervenor Positions

The JIESC takes issue with BC Hydro's proposal on the basis that the amount forecast is only BC Hydro's best guess, is subject to further high volatility and that the accounting rules driving BC Hydro's proposed treatment are, or will likely be under review by the accounting bodies, and that a regulatory deferral account is unfair and inappropriate in light of BC Hydro's treatment of previous positive balances in the same account. In regard to the latter item the JIESC points to the $25.3 million positive change from the RRA approved amount for F2008 (the subject of section 4.4.3.2 above) where BC Hydro did not ask, and is not now asking, for a deferral account to return the positive balance to the ratepayers (JIESC Argument, pp. 31-32).

The JIESC requests that if the Commission allows a deferral account for this item, it should leave the question of recovery of the account balance open and subject to an order of the Commission at the time recovery of the balance is sought by BC Hydro, and urges the Commission "not to make a decision until one has a better understanding of what the accounting rules are and what the December 31, 2009 funding requirement is based on the [next] tri-annual actuarial valuations." Further, JIESC requests that if any deferral account for non-current PEB costs is granted, that it have an "opening credit balance of $25.3 million in order to ensure that the F2008 change in costs is treated in a manner consistent with the treatment being sought for F2009 and F2010" (JIESC Argument, pp. 31-33).

BCOAPO agrees with BC Hydro that a deferral of the differences that may occur during the test period between forecast and actual GAAP non-current PEB costs is preferable, and that it should only apply to F2010 variances as those for F2009 are already known. BCOAPO "strongly opposes any suggestion that this cost be permanently treated as deferrable." (BCOAPO Argument, p. 19)

The CEC "proposed to have this non-cash item removed from the operating costs for revenue requirement purposes and placed in a regulatory account", potentially to be offset by changes in the market value of equities in the plan and/or by cash contributions BC Hydro may have to make to the pension fund. The CEC submits "it is not appropriate for rate making purposes to have the valuation swings of the market securities in the pension plan determining rates", and proposes that:

- the actual cash recognition of the pension fund issues as required by the [tri-annual] actuarial valuations become the basis for recognizing expense to customers in revenue requirements; and
- once cash contributions are required the impact should be amortized to ratepayers over the period permitted in the actuarial valuations for the tests which drive the requirement for cash contributions (CEC Argument, p. 65).

Terasen submits that a deferral treatment is appropriate for variances in both current and non-current portions of pension expenses in that it would be simpler to administer and easier to understand (Terasen Argument, p. 4).

In reply to Terasen, BC Hydro submits that there is no evidence on the record regarding implications of such an approach and that the Commission should not accept it (BC Hydro Reply, p. 68).

In further reply, BC Hydro notes that no Intervenor opposes the creation of a regulatory account to defer differences between actual and forecast non-current pension benefits expenses (or, in fact argues against deferring the entirety of non-current PEB expense). It characterizes both the CEC and JIESC as "recommending that non-current pension costs should be based on cash contributions required pursuant to the tri-annual actuarial valuations, rather than on GAAP entries." BC Hydro acknowledges that this approach could be implemented, but would require Commission approval of a regulatory account to capture and defer the difference between the cash contributions and the GAAP entries for non-current pension costs. BC Hydro notes that while this approach would have "the superficial appeal of tracking the cash rather than tracking the GAAP entries", it would also require the Commission to approve deferral of the differences between forecast and actual cash contributions given the potential large and volatile nature of the cash contributions (BC Hydro Reply, pp. 34-35).

BC Hydro submits that since pension accounting is already highly regulated, and since GAAP already provides a smoothing of the cash contributions to the pension fund, "there would be little gained by setting up additional regulatory accounts to allow a new approach to pension accounting in the hopes of achieving a better smoothing of the impacts of cash contributions than is already achieved under GAAP" (BC Hydro Reply, pp. 34-35).

Commission Determination

The Commission Panel finds that the OPEB portion of the non-current PEB costs is not a material source of volatility, and that there is nothing to be gained by considering deferral account treatment for that portion of the expense, and accordingly it is to remain in BC Hydro's OMA expenditures for the test period.

In consideration of the non-current pension cost, the Commission Panel finds that the evidence is sufficient to warrant a deferral mechanism to remove that source of volatility from BC Hydro's revenue requirements for the remainder of the test period, i.e., for F2010. The Commission Panel deals with the specifics of that deferral mechanism in Section 5.5.5 of this Decision.

In respect of the particular relief sought by the JIESC and CEC concerning setting planned non-current pension expenses only on the basis of tri-annual actuarial valuations (JIESC), and on a cash vs. a GAAP basis (CEC), the Commission Panel finds that while these approaches could have merit in both reducing volatility and better aligning actual expenditures to planned expenses within the test period, the evidentiary record is insufficient to enable any such determination to be made in this proceeding. **For its next RRA BC Hydro is directed to provide documentation, covering a five year actual history and the next test period as to what the planned and actual expenditures would be under these combined scenarios, and, assuming a deferral mechanism had been in place for the five year reference period, what the closing balances would be for each of the years.**

4.4.3.3 Accenture Costs, COPE Evidence and Termination of the "Purchasing Tower"

In 2003, BC Hydro entered into a number of agreements with Accenture, the most significant of which committed BC Hydro to outsource a number of back-office services to ABSBC. These services fell into six main categories which are referred to as "towers" and include Customer care, Information Technology ("IT"), Finance, Human resources, Building and Office, and Purchasing. As described at sections 1.1 and 1.3.1 of this Decision, COPE filed evidence in respect of its concerns as to the costs BC Hydro was incurring under these arrangements, and BC Hydro filed an evidentiary update to explain the reasons behind the changes it had made to discontinue the purchasing tower arrangement on September 29, 2008 (Exhibit B-20).

The COPE evidence relates solely to BC Hydro's Accenture contract. COPE summarizes it as follows:

1. BC Hydro's operating costs and related revenue requirements are unjustified because of the extra services under the Accenture contract that remain unreported by BC Hydro. The day-to-day implementation of these extra services has created inefficiencies and decreased productivity.

2. Procurement Enhancement as outlined in the current RRA is a contractual responsibility of Accenture and BC Hydro has not justified why it should bear the costs of what is essentially a duplication of services (Exhibit C3-7, p. 1).

BC Hydro stated that pursuant to its notice to ABSBC, it will take responsibility for all its procurement functions commencing December 1, 2008. BC Hydro further noted that it will not pay a fee for the termination of the purchasing tower but will pay modest stranded demobilization and transition costs, which are not included in its revenue requirements for the test period. BC Hydro estimates an annual net cost increase due to the termination in F2009 as follows:

Table 4.6

	$000
ABSBC fees for purchasing services	(2,375)
Cost for incremental 27 FTE's	2,542
Net annual increase in costs	**$165**

Finally, BC Hydro stated that the change has no material impact upon the requested rate relief (Exhibit B-20, pp. 4-5).

The COPE witness testified that given BC Hydro's submission on September 29, 2008, (summarized above), COPE's concern regarding the duplication of procurement services "has been somewhat muted". COPE states, however, that its concern regarding "the inefficiencies and unjustified costs under the Amended MSA [Master Services Agreement] remain[s]" (T14: 2564). In particular, COPE testified that the practice of billing extra and/or discretionary services through a "variable rate card" creates inefficiencies and the use of "statements of work" results in both decreased productivity and inefficiencies (T14: 2577-2479).

With regard to the overall Accenture contract, BC Hydro submits that it originally expected that it would save approximately $250 million over the ten-year life of the Accenture arrangements and that it is on-track to fully realize those savings, having saved approximately $100 million to the end of F2008. In addition, BC Hydro submits that Accenture has met or exceeded over 98 percent of required service level metrics since the commencement of the arrangement, that external customer satisfaction with the Accenture-run call centre is at record high levels, and internal customer satisfaction is higher now than it was prior to the outsourcing arrangements in four of the five non-purchasing towers. Finally, BC Hydro submits that for the reasons stated there is no basis upon which to conclude that the costs incurred by BC Hydro related to the Accenture arrangements are imprudent (BC Hydro Argument, pp. 76-77).

COPE submits that the evidence given by BC Hydro’s witnesses regarding the Accenture contract fails to challenge the material elements of COPE’s testimony regarding the inefficiencies created by the Statement of Work (“SOW”) and the variable rate card. COPE further submits that its evidence on this issue ought to be accepted by the Commission (COPE Argument, p. 17).

The only other Intervenor to comment on the issue of the Accenture arrangements was the CEC, which supports BC Hydro’s submissions (CEC Argument, p. 85).

In reply, BC Hydro submits that regardless of whether the Commission gives any weight to COPE evidence, it does not support a conclusion that BC Hydro was imprudent in entering into or has been imprudent in managing the Accenture arrangements (BC Hydro Reply, p. 36).

Commission Determination

The Commission Panel has considered the evidence and submissions of COPE and BC Hydro and concludes that even if it gave considerable weight to the potential inefficiencies highlighted by COPE it cannot disallow any costs related to the Accenture contract as the evidence indicates that

BC Hydro has been effective in the overall management of the contract. **Accordingly, the Commission Panel declines to disallow any costs related to the Accenture contract and to grant COPE the relief it requests.**

4.4.3.4 Corporate Donations

BC Hydro's corporate donations totaled $1.2 million in F2008 and BC Hydro plans to spend the same amount in F2009 and F2010 (Exhibit B-8, BCUC 2.133.1).

BC Hydro testified that it undertakes a modest corporate donations program "because we believe that it helps to build and maintain public support" and noted the importance of public support in communities in which it operates, especially at the time when a significant infrastructure program is underway. BC Hydro further testified that it supports programs in the area of environment and sustainability, youth and education, people and leadership as well as community initiatives and that it also gives preference to those programs that have a safety focus and that benefit the First Nations communities where BC Hydro has operations. Finally, BC Hydro testified that through the corporate donations program it can mitigate the risk of opposition to its necessary activities in the communities and thereby reduce project approval times, which in turn allows BC Hydro to undertake programs in the least cost way. By way of justification, BC Hydro stated that "because undertaking those activities is to the benefit of the customers, we believe it's appropriate that the costs are also borne by the customers" (T8: 1291-1293).

BC Hydro confirmed that it consults with BCTC to ensure that there is no duplication in the donations programs of the two crown corporations (T9: 1388-1389). BC Hydro also provided a complete list of the corporate donations provided by BC Hydro in F2008. In addition to a large number of small donations in different communities related to activities described above, the program also includes more substantial donations to causes that are of a more general nature, such as donations to hospital foundations, the United Way provincial campaign and the Minerva Foundation (Exhibit B-71).

No other party made submissions in respect of BC Hydro's donations program.

Commission Determination

The Commission Panel is cognizant of the requirement to link the cost of corporate donations to the benefit to the ratepayer as the ratepayers should only pay for those costs that are related to the nature and quality of service provided by BC Hydro. While BC Hydro's donations on the F2008 list appear to have gone to worthy and commendable causes, the Commission Panel has some concern regarding the sufficiency of their direct linkage to ratepayer benefits, in particular, reliability. The Commission Panel is also concerned, as a matter of principle, that there now are two "related" crown corporations in the province making corporate donations for similar causes, which are in the main funded by the same group of ratepayers. However, the Commission Panel also notes that no Intervenor took issue with this planned expenditure in this proceeding.

To ensure that this issue will be further reviewed, the Commission Panel directs BC Hydro to provide a specific and more fulsome justification of the linkage between its donation program and its key influences, key cost drivers and objectives in its next RRA if it intends to continue to request that 100 percent of corporate donations be included in its revenue requirement, rather than having the costs shared between its shareholder and ratepayers.

4.4.4 New On-going and Fixed-Term Initiatives

As described in Section 4.4.2, BC Hydro states that certain incremental activities that are additional to its basic operations, need to be undertaken in the test period. These initiatives are summarized in Table 4.5 below.

Table 4.7

BC Hydro On-going and Fixed Term Operating Initiatives

($ million)	Description	Proposed F2009	Proposed F2010
Ongoing			
	First Nations	5.7	7.2
	Labour Strategies	4.8	7.1
	Remote Community Electrification	0.5	1.5
	NERC Compliance	1.2	0.9
Total Ongoing		**12.2**	**16.7**
Fixed Term			
Reliability Initiatives	Storm Response		
	- System Resiliency	4.8	5.8
	- Outage Communications	2.0	1.6
	Asset Maintenance		
	- Burrard	3.2	3.9
	- Civil Maintenance – Generation	3.5	5.5
	- Field and Corporate Facility Improvements	6.0	9.0
	- Distribution Asset Maintenance (Autosplice/Mountain Pine Beetle)	1.5	8.0
	- General Asset Maintenance and Security Improvement	3.4	4.1
	2010 Critical Infrastructure Security	1.1	6.0
Productivity Initiatives	Procurement Enhancement Initiative	19.5	3.0
	EARG Capital Improvement Process	1.8	0.3
	Site C	17.5	14.7
	Less transfers to regulatory accounts:		
	Procurement Enhancement Initiative	(18.5)	(2.0)
	Site C	(17.5)	(14.7)
Total Fixed Term Initiatives		**28.3**	**45.1**
Total Ongoing and Fixed Term Initiatives		**40.5**	**61.8**

Source: Exhibit B-1, p. 4-16

4.4.4.1 New On-going Initiatives

BC Hydro states that it has four areas of new on-going work that are expected to increase operating costs over and above the baseline on an on-going basis: (i) First Nations engagement; (ii) labour strategies; (iii) Remote Community Electrification ("RCE"), and (iv) North American Electric Reliability Corporation ("NERC") compliance. These on-going initiatives are addressed in further detail below:

(i) First Nations Engagement

BC Hydro mentions securing the necessary approvals to build additional generation and transmission infrastructure, obtaining water licenses and ensuring access to facilities as examples of business risks posed by First Nations' issues. BC Hydro states that it manages these business risks by addressing BC Hydro's and First Nations' interests through meaningful engagement processes, resolving historical grievances, effectively implementing agreements, and addressing key priorities for First Nations (Exhibit B-1, p. 4-17).

BC Hydro submits that investing in First Nations relationships now will inevitably avoid more costly operations and project development in the future and that these expenditures are a prime example of the result of the long-term view that BC Hydro brings to bear on its decision-making processes. BC Hydro also notes that there are no settlement costs in its RRA and submits that it will seek approval from the Commission with regard to any actual, future settlement costs it believes should be covered in rates (BC Hydro Argument, p. 81).

(ii) Labour Strategies

BC Hydro states that approximately 30 percent of its current workforce will be eligible to retire within the next five years and that at the same time, it faces a labour force supply shortage in many skilled occupations and increasing capital and maintenance programs. Because other utilities in North America are experiencing similar labour shortages, BC Hydro submits that it has been compelled to increase its focus on "growing and training from within", to go outside normal labour market sources to find the required skills, and to consider a more diversified non-traditional labour pool. Specifically, "BC Hydro plans to increase the number of apprentices and trainees to compensate for shortages in the market and to hire early replacements for key roles to allow adequate time for training and knowledge transfer." BC Hydro states that the operating expenditures associated with this on-going initiative will address increased training, development and recruitment costs aimed at enabling BC Hydro to achieve its objectives (Exhibit B-1, p. 4-18).

This initiative is dealt with in Section 4.4.5 of this Decision.

(iii) Remote Community Electrification

BC Hydro states that although this initiative involves primarily capital investment there are some incremental operating costs involved as well (Exhibit B-1, p. 4-19). BC Hydro submits that the RCE initiative has been discussed in previous filings with the Commission and that there is nothing on the record that justifies a finding of imprudence in regard to this initiative (BC Hydro Argument, p. 84).

(iv) NERC Compliance

BC Hydro notes that this initiative will allow it to implement and comply with NERC Electric Reliability Organization ("ERO") standards and anticipates that the Commission will approve NERC ERO standards during the test period. Further, BC Hydro states that this initiative will involve development of a work plan to maintain compliance and implementation of a process for documenting standards to demonstrate compliance (Exhibit B-1, p. 4-20). BC Hydro submits that there is no reasonable basis on the record that justifies a finding of imprudence (BC Hydro Argument, p. 84).

4.4.4.2 Fixed-Term Reliability Initiatives

The nine fixed-term reliability initiatives shown in Table 7-3 are summarized as follows.

(i) Storm Response Initiatives

BC Hydro plans System Resiliency and Outage Communications initiatives as a part of its storm response plan. BC Hydro states that it has identified 256 circuits that serve 40 BC Hydro districts within its service area that are most vulnerable to the impact of severe weather-related outages and plans to “harden” the system to reduce the number of outages, and to “build flexibility into the system to reduce outage restoration times.” While the System Resiliency initiative is primarily capital-related, it also involves operating costs, primarily for increased vegetation management (Exhibit B-1, p. 4-20, Appendix F, p. 8).

BC Hydro’s Winter Storm Report also identified the customer service call system and the quality of outage information provided to customers as areas that required improvements before the onset of the F2008 storm season. BC Hydro states that the Outage Communication Initiative (“OCI”) was launched in F2008 to improve outage communication capabilities and to undertake pro-active communication with customers. BC Hydro identifies the following goals as key to achieving effective outage communication with customers: increased customer contact capacity, improved quality and delivery of outage information, and better customer and community awareness and preparedness for outage events (Exhibit B-1, p. 5-30, Appendix F, p. 8). In continuing the OCI during the test period, BC Hydro plans expenditures of $2.0 million and $1.9 million in F09 and F10, respectively, to increase its customer contact capacity to handle up to 40,000 calls per hour during significant outage events, with less than 5 percent of customers receiving busy signals on a sustainable basis (Exhibit B-1, pp. 5-30 to 5-31; T10: 1734-1737).

<u>Position of the Parties</u>

BC Hydro submits that its evidence and testimony demonstrate the value of its storm response initiative, that the expenditures are required for the test period and that any finding of imprudence is precluded (BC Hydro Argument, p.85).

No Intervenor commented specifically in respect to BC Hydro’s storm response initiative.

Commission Determination

With respect to the OCI portion of BC Hydro's continuing storm response initiative planned expenditure, the Commission Panel is concerned that expenditures in this area could be characterized as "nice, but not necessary." In particular, the Commission Panel notes the evidence of BC Hydro's CEO that "every decision BC Hydro makes must be considered in light of its long-term effects, particularly on safety, costs and reliability of service" (T3: 276) and his further evidence that customer satisfaction ratings are already "astonishingly high" (T3: 592).

The Commission Panel further notes the evidence of BC Hydro that, although it has good media relationships, it apparently does not currently liaise with radio stations on a proactive basis to report on anticipated outage times, but that would be something that could be considered (T11: 1934-1935).

The Commission Panel finds that BC Hydro has not explored alternatives to further expanding its call handling capacity, which is not a key area in terms of safety or reliability and accordingly, disallows the OCI-related amounts of $2.0 million in F2009 and $1.9 million in F2010 in BC Hydro's revenue requirements.

(ii) Asset Maintenance Initiatives

Asset Maintenance related initiatives involve Burrard Generating Station, generation civil maintenance, field and corporate facility improvements, distribution asset maintenance and generation asset maintenance and security improvements.

BC Hydro states that expenditures earmarked for the Burrard Generating Station initiative will cover incremental maintenance costs associated with adding 150 MW of dependable capacity by making the sixth unit available for service and sustaining the 300 MW made available for service in F2007 and F2008 as well the costs associated with repairing cracks in the super heater tubes of all six units and inspections of the power boiler (Exhibit B-1, p. 4-21).

BC Hydro explains that its civil maintenance initiative for generation includes: "maintenance of civil assets that has not been completed in recent years; establishing a plan for the efficient on-going maintenance of civil assets; and developing fleet-wide maintenance standards and instructions for civil assets." BC Hydro further submits that "the civil maintenance initiative is driven by reliability of supply risks and safety risks" and addresses reservoirs, dams, power conduits, outlet and spillway works, powerhouses, auxiliary buildings and site access (Exhibit B-1, pp. 4-21 to 4-22).

Its Field Building Rebuilding program, Revitalization program and Corporate Facility Improvement program, notes BC Hydro, involve primarily capital expenditures but also include an operating cost component with the majority of the dollars to be spent on the Building Revitalization program (Exhibit B-1, p. 4-23).

BC Hydro's distribution asset maintenance initiative involves continuation of the autosplice replacement and mountain pine beetle ("MPB") programs during the test years. BC Hydro states that F2009 will be the third year of the 12-year program to replace approximately 120,000 autosplice connectors in wet coastal areas to "mitigate worker and public safety, reliability and financial risks." BC Hydro plans to remove 9,000 autosplices in F2009 and 15,000 in F2010. BC Hydro further notes that the MPB program to remove trees impacted by the MPB infestation, is a multi-year program initiated in F2005 that will continue beyond the test period. In further support of this program BC Hydro submits:

> "A recent study undertaken by Aquafor Consulting and the University of Northern B.C. found that absent this program about 20,000 trees are expected to fall on BC Hydro distribution lines in F2009, and the peak fall-down period is expected to be 2013-2017 (at 80,000 to 100,000 trees falling on the lines per year). This would cause an incremental 20,000 to 35,000 outages per year, with an estimated repair cost of $2,800 per outage related to tree damage."
>
> (Exhibit B-1, pp. 4-23 to 4-24)

BC Hydro states that its generation assets maintenance and security improvements initiative will address needed maintenance of older generation equipment and security maintenance requirements at generation facility sites, as well as provide plant planning support to complete maintenance and capital work. BC Hydro further explains that the majority of the expenditures associated with this initiative are for the completion of condition-based and corrective maintenance work that has not been completed in recent years because maintenance resources were reallocated to capital work and unplanned repair of equipment forced out of service. BC Hydro also notes that seven maintenance planning positions are being created to coordinate and support delivery of maintenance. Finally, BC Hydro states that the security maintenance requirements relate to: security equipment at the generation facilities, including cameras, thermal imagers and CCTV; fences, barriers and gates; personnel access control; and the operation of off-site, central control of security with alarm and video monitoring (Exhibit B-1, pp. 4-25 to 4-26).

(iii) 2010 Critical Infrastructure Security

BC Hydro states that "the objective of this initiative is to ensure reliable, secure and safe electrical power to BC Hydro customers during an unprecedented period in British Columbia of increased threat level, risk and world-wide attention in 2010." BC Hydro further notes that the activities and measures under this initiative will augment the proactive security risk reduction strategy that BC Hydro normally employs to protect its critical infrastructure, "in recognition of the heightened risk over the period of time immediately preceding and during the 2010 Winter Olympic Games" (Exhibit B-1, pp. 4-26 to 4-27).

BC Hydro submits that its evidence and testimony demonstrate the prudence of implementing increased security measures during the 2010 Olympic Games, that it is responsible for the costs of making its own assets secure during the event and that no conclusion of imprudence can be justified, on the evidence, in regard to this initiative (BC Hydro Argument, p. 93).

4.4.4.3 Fixed-Term Productivity Initiatives

BC Hydro introduces two productivity initiatives, the PEI and the EARG Capital Improvement Process, which are summarized as follows.

BC Hydro states that because it spends more than $1 billion per year on goods and services, "it has identified procurement as an area for productivity improvement and managing future costs to customers." The PEI comprises of two projects: Procure-to-Pay ("P2P") and Strategic Sourcing ("SS"). BC Hydro submits that:

> "completion of the P2P project will result in a significant change in the way goods and services are purchased. BC Hydro will shift from labour and administratively intensive paper-based manual processes to leading practices that are automated, scaleable, streamlined and allow end-users to focus on operational responsibilities."

The SS employs a strategic approach in determining how goods and services are to be purchased and the sources that BC Hydro purchases them from. BC Hydro states that SS also leverages its purchasing power to enhance the value of BC Hydro's procurement activities and builds relationships with suppliers (Exhibit B-1, pp. 4-27 to 4-29, Appendix H, pp. 2-3).

BC Hydro submits that its planned F2009 and F2010 expenditures on the PEI are not included in the revenue requirement as BC Hydro is seeking an order that would allow the expenditures to be deferred and amortized over a time period that corresponds to the period over which the benefits will be realized (BC Hydro Argument, p. 93). However, BC Hydro notes that it does not seek the deferral of $1 million per annum in operating costs relating to the establishment of the Office of the Chief Procurement Officer, which were absorbed into the base operating costs, nor does it seek the deferral of $4.8 million in capital costs related to this initiative (BC Hydro Argument, p. 153; Exhibit B-1, Appendix A, Schedule 5). The PEI initiative was examined at length in the proceeding, and is dealt with in Section 5.4.3 of this Decision.

BC Hydro states that initiative improvements by the EARG business group include streamlining and simplifying the management of capital projects through their complete lifecycle including project initiation, planning, business case review and approval, execution, and monitoring through project completion (Exhibit B-1, p. 4-29).

4.4.4.4 Site C

BC Hydro states that Stage 1, a feasibility review of the Site C project, was completed in F2007. Stage 2, focusing on extensive consultation and on project definition analysis, will take all of F2009 and part of F2010 to complete. BC Hydro further notes that if a decision is made by the Province to proceed to Stage 3, this next phase would include a formal regulatory process to obtain the necessary facility and environmental assessment approvals for the project, which would continue beyond the test period. This project will be reviewed more extensively during the 2008 LTAP review (Exhibit B-1, p. 4-30).

Intervenor Submissions Regarding On-going and Fixed-Term Initiatives

The BCOAPO submits that no issues were identified with these initiatives (BCOAPO Argument, p. 10).

The CEC submits that almost all of the initiatives BC Hydro proposes to undertake "need to be undertaken and are relevant for customers". However, the CEC submits that virtually all of these initiatives will have future benefits for many years and therefore they should be treated as investments by placing them in regulatory accounts (CEC Argument, p. 88).

The JIESC submits that increasing the amounts forecast for initiatives from $4 million in F2008 to $40.5 million in F2009 and $61.8 million in F2010 is a "thinly veiled attempt to increase OMA beyond the bounds of the formulistic approach to OMA". The JIESC further submits that every organization faces new challenges each year and takes on new initiatives but without increasing their OMA significantly. Instead, the JIESC submits, other organizations cut in areas no longer required and "innovate and increase productivity". Accordingly, the JIESC submits that the Commission must tell BC Hydro also to do so, requesting that the allowance for On-going Initiatives should be reduced by 50 percent to "recognize much of this work has origins in existing OMA cost levels". Similarly, the JIESC submits, the Commission should also cut the allowance for Fixed Term Initiatives by 25 percent, "a lesser cut because some are more arguably incremental responses to non-recurrent situations" (JIESC Argument, pp. 20-21).

In reply, BC Hydro submits that its "initiatives are not optional, they are necessary activities that must be undertaken in this test period" (BC Hydro Reply, p. 38).

Commission Determination

The Commission Panel has considered the evidence and the submissions of parties and finds that although the amounts could have been presented in the Application in a different manner, the evidence is, in general, sufficient to establish that the initiatives that BC Hydro plans to undertake in the F2009/F2010 test period are reasonable**. Accordingly, and for the same reasons as given in its determination at Section 4.4.3.1 of this Decision, the Commission Panel declines to grant the relief requested by the JIESC.**

4.4.5 Resourcing Strategies

For purposes of convenience and clarity this section groups and addresses a number of related issues such as pre-hiring, recruitment, staff growth, labour costs, vacancy rates and overtime under the umbrella of "Resourcing Strategies".

4.4.5.1 Employee Growth and Labour Costs

BC Hydro submits that its work load is increasing significantly over the test period and that the bulk of the incremental work is related to operating, maintaining and improving the generation and distribution systems. BC Hydro further submits that this work includes both capital and operating components, and is performed within the EARG and Field Operations business groups, which use a variety of resources to perform their work, including full-time, part-time and temporary employees, as well as contractors and consultants (BC Hydro Argument, p. 94).

Concerning overall compensation, BC Hydro submits that the overall compensation of its employees is reasonable and prudent because BC Hydro competes at the 50th percentile for total compensation as compared to appropriate comparable industries, and that its compensation plan has been reviewed and approved by the BC Government's Public Sector Employer's Council ("PSEC") (BC Hydro Argument, p. 95).

BC Hydro confirmed that while the actual retirement of eligible employees has averaged between 20 percent and 25 percent of those eligible over the past eight fiscal years, the aggregate number of retirement eligible employees continues to grow, with nearly 30 percent of BC Hydro's current, regular status workforce eligible to retire within next five fiscal years. BC Hydro further stated that as such, this reality continues to present BC Hydro with a "retirement bubble" and corresponding significant attrition, recruitment and retention issues (Exhibit B-75, Undertaking No. 86).

Labour Analysis

BC Hydro explained that it budgets in terms of full-time equivalents ("FTEs") for all capital and operating work. FTE is a measure of hours worked in a year, which in the BC Hydro organization equals 1,537.5 hours. BC Hydro stated that its labour costs are tracked in its financial systems on a gross basis and include amounts that are transferred subsequently to capital overhead or recovered through external recoveries. As a result, BC Hydro noted that it does not have the ability to isolate labour costs directly in the operating costs; therefore, the labour expense in net operating costs is being calculated based on the percentage of gross labour in gross operating costs (T7: 1176; Exhibit B-5-4, BCUC 1.4.2, 1.26.2)

BC Hydro states that its actual Vacancy Rate in F2007 was 9.0 percent with a target of 9.9 percent for F2009, decreasing to 9.6 percent by F2010 (Exhibit B-1, Appendix C, p. 26). BC Hydro provided its target and actual Vacancy Rates for F2008 which were 10.2 percent and 9.0 percent respectively and noted that this key performance metric for recruitment is calculated as follows:

$$\text{Vacancy Rate \%} = \frac{\text{Open Recruitment Cases}}{\text{Headcount + Open Recruitment Cases}}$$

(Exhibit B-5, BCUC 1.54.1)

BC Hydro further stated that it has forecast labour costs by assuming that:

> (i) "New positions are phased in throughout the course of the year (and are therefore vacant for part of the year); and
>
> (ii) Vacancies arising from turnover of employees in existing positions are offset by increased overtime or increased use of contractors.
>
> As a result, no adjustments to the F2009 and F2010 operating costs in the Application are required in respect of vacancies." (Exhibit B-5, BCUC 1.57.1)

Consequently, BC Hydro asserted that because FTE is a measure of hours worked, there is no such information as filled and vacant FTE positions (Exhibit B-5-4, BCUC 1.4.2).

Table 4.6 below shows the growth in FTEs as compared to the annual percentage change in customers and domestic sales with some other related relevant information.

Table 4.8

	F2004 Actual	F2005 Actual	F2006 Actual	F2007 Actual	F2008 Forecast	F2009 Plan	F2010 Plan
BC CPI (% change)	2.0	2.0	1.7	1.8	1.8	2.1	2.1
Cumulative CPI (% change)	2.0	4.0	5.8	7.7	9.7	12.0	14.3
Total Customers (thousands)	1,650.5	1,675.1	1,704.7	1.736.7	1,767.4	1,798.3	1,829.4
% Change in Customers		1.5%	1.8%	1.9%	1.8%	1.7%	1.7%
Net Customer Additions		24,573	29,616	32,070	30,647	30,917	31,115
Gross OMG&A ($millions)[1]	n/a	N/a	n/a	964.9	936.1	1,033.1	1,096.3
Gross OMG&A/Customer $	n/a	N/a	n/a	556	530	574	599
Net OMG&A ($millions)[2]	563.0	563.4	564.5	551.8	563.0	609.2	649.1
Net OMG&A/Customer $	341	336	331	318	319	339	355
Total FTEs	4,425	4,303	4,359	4,670	5,163	5,974	6,104
Total Sources of Supply (GWh)	55,120	55,865	57,796	58,240	58,781	60,181	61,068
Less Line Losses and System Use (GWh)	4,969	4,660	5,356	5,329	5,193	5,390	5,474
Total Domestic Sales (GWh)	50,151	51,205	52,440	52,911	53,588	54,791	55,594
% change in Domestic Sales		2.1%	2.4%	0.9%	1.3%	2.2%	1.5%

1 Gross OMG&A is Net OMG&A plus capital overhead and recoveries.
2 Net OMG&A refers to line 37 on Appendix A, Schedule 5.0.

Source: Exhibit B-5-4, BCUC 1.4.2 modified

BC Hydro also provided the following data for its labour expense component of net OMA costs:

Table 4.9

	Actual F2005	Actual F2006	Actual F2007	Actual F2008	Plan F2009	Plan F2010
$Millions	174.6	184.4	234.7	225.6	282.1	298.3
Increase over prior year (%)		5.6	27.3	(3.9)	25.0	5.7

Source: Derived from Exhibit B-78, Undertaking No. 36

4.4.5.2 Field Operations and IBEW Overtime

With regard to the management of the resource pools available to perform the operating, maintenance and capital work on the distribution system, BC Hydro testified that it bases its choices on the particular skills of the different resource pools and the availability of resources (T11: 1945-1951). Furthermore, BC Hydro submitted that it costs less to use its internal Power Line Technicians ("PLTs") and IBEW staff to perform work compared to using contractor resources (Exhibit B-75, Undertaking No. 87).

BC Hydro reported that the average overtime hours worked by Field Operations IBEW personnel were 408 and 429 hours for F2007 and F2008, respectively. BC Hydro further reports that average overtime hours worked by PLTs who worked all pay periods in the fiscal year, were 766 and 713 hours for F2007 and F2008, respectively, which compares to the "average" hours worked by an FTE, regardless of affiliation or position, of 1537.5 hours per annum (Exhibit B-5-1, BCUC 1.58.2). BC Hydro also reported for F2008 that the average IBEW overtime hours worked were composed of 398 scheduled hours and 73 unscheduled hours (Exhibit B-76, Undertaking No. 75).

BC Hydro stated that it has been successful in hiring contractors to complement its existing crews, based on need, location, qualifications and cost/benefit analysis, and that it has also entered into strategic alliances with contractors to secure dedicated resources for an extended period of time. However, BC Hydro noted that contractors are facing market conditions and competition for resources similar to BC Hydro and that there is a finite pool of contractors from which BC Hydro is able to draw resources in the local markets. Finally, BC Hydro states that B.C. certification requirements for PLTs constrain its ability to add qualified resources from outside B.C. (Exhibit B-8, BCUC 2.149.3.1).

BC Hydro admitted that there is concern within BC Hydro that excessive levels of overtime could be a safety concern but notes that the impact of higher levels of overtime on safety is dependant on the working conditions during which overtime is worked (Exhibit B-8, 2.149.1). BC Hydro stated that it does not have a formal overtime policy but that it relies on a practice to encourage employees to stop work if they have any safety or other concerns. BC Hydro also noted that the IBEW collective agreement ("CA") limits any one shift to 16 hours with an eight hour rest period between shifts (Exhibit B-8, BCUC 1.149.2).

In summary, BC Hydro submits that it is cost-effectively increasing staffing levels in its Field Operations business group to address increasing work plans, shortages of skilled resources in the marketplace and contractor communities and high levels of overtime as well as retirement risks. BC Hydro submits that there is no basis to conclude that more cost-effective staffing strategies are available to it in the current demographic and market conditions (BC Hydro Argument, p. 100).

4.4.5.3 Engineering, Aboriginal Relations and Generation

BC Hydro testified that its recent experience with engineering service consultants and contractors in the generation area is similar to the experience in the power line area; i.e. it is difficult to find good consultants/contractors and they are expensive (T13: 2455-2457).

BC Hydro submits that, consistent with the Field Operations approach, EARG is using a flexible approach to address resourcing needs in light of increasing work plans, shortages of skilled resources in the consulting and contractor communities, and retirement risks (BC Hydro Argument, p. 103).

Intervenor Submissions Regarding Resourcing Strategies

The CEC notes that the tight labour markets situation is unlikely to remain so indefinitely and submits that, given the events of October, 2008, there will be some considerable improvement. However, the CEC submits that this will not provide a complete solution to the issue faced by BC Hydro because "[t]ransitioning an aging work force of in some cases highly skilled employees will remain a demographic challenge because utilities all over North America are facing similar problems". Accordingly, the CEC submits that it supports the labour strategies BC Hydro is undertaking (CEC Argument, pp. 90-92, 94).

With regard to the further projected growth in overtime the CEC submits that BC Hydro provided only the explanation that “the increase in overtime was related to planning for the expanded staffing at the same level as was expected for employees in previous years” and that there was no direct connection between a specific work requirement and staffing shortages; in fact, the evidence is that the staffing is expected to increase significantly. The CEC also submits that because overtime is planned for at these high levels it is possible that it may not be required, or will be deferred if used in responding to major storms, and therefore requests that that the Commission require BC Hydro to transfer any variance with respect to the use of overtime to a regulatory account for recovery in the next RRA (CEC Argument, pp. 44-47).

IPPBC submits that the forecast increase in FTEs is not as important as the analysis BC Hydro uses to decide whether to hire an FTE as opposed to using other resourcing strategies, because hiring an FTE implies a long-term commitment and investment. The IPPBC further submits that while the hiring of an FTE is not identical to making a capital investment, there are enough similarities to suggest BC Hydro’s Project Evaluation Methodology could be used as the starting point for the preparation of its “FTE Hire Methodology”. Finally, the IPPBC submits that there is too much emphasis on the short-term in BC Hydro’s approach to hiring without any discernable link to the medium to long-term aspects of its load forecast, which illustrates the urgent need for development of an “FTE Methodology” or “manpower plan” (IPPBC Argument, pp. 14-19).

The JIESC, after conducting cross-examination along the corollary lines of long-term commitments, submits that the ratio of customers to FTEs has gone from 401 in F2005 to 301 in F2009 and that “given the relatively stable number of customers this is an inexplicable and unacceptable decline in productivity” and that "the growth in employees is a significant factor in the rise in OMA costs and is not simply related to capital expenditures” (JIESC Argument, p. 16).

In reply, BC Hydro notes that IPPBC does not recognize in its submissions the impacts of BC Hydro’s aging workforce and the large percentage of its current workforce that is eligible to retire. BC Hydro submits that a major focus of its strategies is to overlap retiring and new employees to allow for the transfer of knowledge and that, therefore, IPPBC's assumption of BC Hydro being "stuck" with increased staff as the workload might decline over time is not correct (BC Hydro Reply, p. 39).

In further reply, BC Hydro also addresses the overtime forecasting concern of the CEC and submits that since changes in the use of overtime would be offset either by changes in the use of contractors or by additional employees at a similar cost to overtime and since there is no double counting with respect to the deferred costs of major storm restoration, there is no reason to introduce a new regulatory account to defer the difference between forecast and actual overtime costs (BC Hydro Reply, pp. 76-78).

Commission Determination

The Commission Panel notes that the three key factors influencing BC Hydro's Resourcing Strategies, namely its claimed "retirement bubble", load growth, and availability of skilled employees, may all be in turn impacted by the economic downturn in North America in general and British Columbia, specifically. Among other things, the Commission Panel questions whether BC Hydro's plans for international recruitment are still necessary or reasonable.

Similarly, the extent of pre-hiring for knowledge transfer should be re-assessed by BC Hydro. The Commission notes that even with 30 percent of its workforce eligible to retire, given that, at its highest, the recent uptake of retirement amongst those eligible is only some 25 percent, the potential for retirements in the test period is likely to be 7.5 percent or less per year. The Commission Panel is further concerned that BC Hydro's operating plans and budgets reflect management's best estimates of what was expected to occur based on knowledge available in 2007, and that BC Hydro chose not to provide any updates in October 2008 to reflect the subsequent change in economic conditions and outlook. Nevertheless, since the onset of the economic volatility has been quite sudden, it is difficult to quantify what that impact will be and to what extent changing economic circumstances or government policy initiatives will ameliorate labour market pressures or otherwise affect BC Hydro's employment costs.

To find a balance in accommodating BC Hydro's challenges while ensuring that the ratepayers will not be burdened by unnecessary labour costs or exposed to over-collection by BC Hydro should its planned total expenditures on employee compensation not materialize, the Commission Panel directs BC Hydro to segregate to a regulatory account any variance from its planned total net employment costs in OMA for the test years (the Employment Cost Regulatory Account), with the balance in that account at the end of F2010 to be dealt with in its next RRA.

More specifically, the Commission Panel notes that for F2008 BC Hydro was able to lower the Vacancy Rate from a target of 10.2 percent to the actual of 9.0 percent. However, for F2009 BC Hydro is forecasting a higher Vacancy Rate of 9.9 percent. A higher Vacancy Rate would imply a greater need for overtime and use of contractors if BC Hydro's thesis that all of the work it budgets for in fact is necessary and is done one way or the other (Exhibit B-5, BCUC 1.57.1). BC Hydro's IBEW employees in F2008 worked a disproportionate amount of scheduled overtime versus unscheduled overtime. The Commission Panel is concerned that this heavy reliance on scheduled overtime to complete work activities is costly and inefficient.

The Commission Panel is further concerned by the high levels of overtime in general and that the overtime forecasts at its expanded staffing levels are proportionately unchanged from those based on previous years' high levels. BC Hydro provided insufficient evidence to refute the CEC's contention that it is unreasonable to expect the planned, increased staff complement to incur overtime at the same rate as the current cohort. Further, the higher target F2009 Vacancy Rate at 9.9 percent compared to the actual F2008 rate of 9.0 percent could indicate an inefficient use of overtime and contractors. **For greater clarity, the Commission Panel directs BC Hydro to include overtime paid in its calculation of total net employment costs as directed above.**

In light of its concerns as described above, the Commission Panel also directs BC Hydro to submit a comprehensive Resourcing Strategies Plan, addressing FTEs, headcounts, Vacancy Rates, part-time staff & contractors, status of retirement uptake, overtime statistics by business group for all non-executive personnel categories, and to provide four years of actual data supporting

projections for the test period in its next RRA. The report should clearly address the linkage of employment growth to and between base operating and capital expenditure related activities, as well as to reliability matters in particular.

4.4.6 Capitalized Overheads

The Application proposes to increase capitalized overhead costs from $149.9 million in Actual F2007 to $200.7 million in F2009 and $209.1 million in F2010 (Exhibit B-8-1, BCUC 2.143.1, Attachment 1). This increases capitalized overhead as a percentage of Gross OMA from 15.5 percent in Actual F2007 to 19.1 percent in F2010 (Exhibit B-5-4, BCUC 1.47.2). As part of its budgeting process, BC Hydro performs a capital overhead analysis to determine the ratio of costs allocated to capital overhead (T7: 1182-1184). The costs allocated to capital are reviewed on an annual basis (T13: 2450).

BC Hydro states that the percentage of support costs capitalized has increased due to the relative increase in capital work effort compared to non-capital work (planned labour and contractor costs to be charged to capital and non-capital work). Furthermore, BC Hydro submits that the overall increase in the capital support costs from F2007 to F2010 is the result of the higher support capacity needed to execute on the significant increase in capital expenditures and cost escalation. The increase in support costs includes costs of a direct capital nature that are charged to operating expense and capitalized via the capital overhead transfer (Exhibit B-8-1, BCUC 2.139.1.1).

Change in Capitalized Overhead Methodology

As part of its financial simplification process, BC Hydro implemented an accounting model change that eliminated internal billing in 2007. This resulted in capitalized overhead as a percentage of Gross OMA rising from 4.6 percent in Actual F2006 to 15.5 percent in Actual F2007 (Exhibit B-5-4, BCUC 1.47.2 Revised; T7: 1095). Capital overhead costs increased by $93.6 million from $56.3 million in Actual F2006 to $149.9 million Actual F2007, primarily due to the inclusion of an additional $73 million of support costs. Prior to F2007, these costs were assigned directly to capital by loading the support costs onto direct capital costs. The change in BC Hydro's capitalization policy was not discussed in the Application and BC Hydro did not respond to the Commission's request to provide documentation on the old and new capitalization methodology and the supporting calculations (Exhibit B-8-1, BCUC 2.138.1.3.2).

The Commission Panel questioned the applicability of the current overhead capitalization methodology given BC Hydro's environment of sustained increases in capital work (T13: 2446). BC Hydro stated that the overhead capitalization rate is set at the beginning of the year and does not change. Given the static overhead capitalization rate, BC Hydro submits that there is a potential disconnect if support costs incurred are different from forecast. The variances between forecast and actual overhead costs are trued up on a prospective basis (T13: 2446-2247). If capital support costs are greater than expected, the variance is absorbed by BC Hydro. Conversely, if capital support costs are less than expected, the benefit accrues to BC Hydro (T13: 2448).

Fixed Capital Overhead Rate

BC Hydro's overhead capitalization rate changes annually, but BC Hydro acknowledges that the fixed percentage methodology used by Terasen Gas and FortisBC may be more transparent and easier to understand (T6: 1023-1024; Exhibit B-8-1, BCUC 2.139.2.1). BC Hydro is of the opinion that it is inappropriate, at this time, to change to a fixed overhead capitalization rate given the continuing simplification of BC Hydro's accounting model and the potential changes under International Financial Reporting Standards ("IFRS"). BC Hydro submits that the accounting rules regarding capitalization of overheads will change under IFRS and that a percentage based method may be appropriate in that context. To ensure appropriate matching of the support costs with the benefits of the capital work, BC Hydro states that a detailed analysis of the IFRS impacts is required to assess the appropriateness of the methodology to be used. (Exhibit B-8-1, BCUC 2.139.2.1)

Capitalized Labour

When the Commission Panel requested that BC Hydro provide employment costs on a net basis, BC Hydro stated that it could only provide total employment costs. Furthermore, BC Hydro submitted that it could not supply a breakdown of labour cost between current OMA, capital and deferred OMA (T4: 551-554). After discussing BC Hydro's labour capitalization process with the Commission Panel, BC Hydro concluded that it could provide employment costs on a net basis (T7: 1184).

Intervenor Submissions

The CEC submits that BC Hydro's operating costs are increasing in part in response to regulatory account activity for which overhead costs are not being capitalized and that overhead costs should be capitalized to the regulatory accounts as well as the capital expenditure accounts (CEC Argument, p. 39). Specifically, the CEC contends that the costs for Site C, PEI, Capital Project Investigations and certain initiatives should attract overheads to the additions to the accounts for the years in question. The CEC estimates that this accounting change would transfer from F2009 and F2010 OMA $10.9 and $10.5 million respectively to regulatory accounts. The CEC also requests that the Commission direct BC Hydro to reassess its allocation of overheads such that it may identify additional overheads that may be appropriately allocated to the initiatives and Regulatory Account projects (CEC Argument, p. 71).

In reply, BC Hydro submits that it does defer overheads associated with regulatory accounts where it is appropriate to do so and that, in particular, the overheads associated with DSM, Site C and capital project investigations are already deferred while no similar overheads are incurred for the PEI project because of the nature of that initiative (BC Hydro Reply, p. 74).

Commission Determination

The Commission Panel notes the change in the Capitalized Overhead Methodology resulting from elimination of internal billing in 2007 and the absence of any description of this change in the Application. The Commission Panel has concerns regarding the accuracy of this methodology in the projected environment of sustained increases in annual capital programs, increased use of regulatory accounts and significant growth in FTEs, and the consequences on the correctness of the forecast net OMA costs in revenue requirements. At the same time, the Commission Panel notes BC Hydro's submissions regarding further changes in accounting rules for capitalization of overhead due to IFRS. The status of IFRS is further addressed in Section 6.6.1. **Accordingly, the Commission Panel directs BC Hydro to prepare a report providing documentation on the existing and new Capitalized Overhead Methodology under IFRS and file it with its next RRA. Similarly, BC Hydro is also directed to provide its employment costs for its OMA forecasts on a net basis, excluding amounts that are either charged directly to capital, transferred to capital overhead or recovered through external recoveries, in its next RRA.**

4.4.7 Trend Analysis, Benchmarking, Productivity and Cost Consciousness at BC Hydro

During the proceeding, both BC Hydro and Intervenors addressed a number of tangentially related issues such as trend analysis, benchmarking, cost consciousness and productivity.

4.4.7.1 Trend Analysis and Benchmarking

BC Hydro provided a schedule comparing its and the Canadian Electricity Association ("CEA") trends for certain capital and OMA costs from 2004 through 2006 (Exhibit B-8, JIESC 2.27.1). BC Hydro testified that making comparisons based on high level composite trends can be of limited value because "it is not known whether the benchmarking participants are reasonably comparable to BC Hydro, nor is it known what is driving changes in their costs" (T3: 343-344; BC Hydro Argument, p. 27). In response to a Commission Panel IR BC Hydro also provided additional related information in terms of actual data and ratios from F2001 to F2008 and forecast data for F2009 and F2010 (Exhibit B-33).

BC Hydro states that it has complied with Commission Directive No. 29 in the F05/F06 RRA Decision to "update its benchmark studies for its next RRA" and that "no further action is required" and justifies that conclusion on the basis of its understanding that the benchmarks were only required for the F07/F08 RRA (Exhibit B-1, Appendix N; Exhibit B-5, BCUC 1.101.1). BC Hydro also provided a list of benchmarking studies it used to set and assess its performance targets for F2006, F2007 and F2008 (Exhibit B-5, BCUC 1.27.1).

BC Hydro testified that it uses benchmarking data for absolute comparisons, to identify industry trends and, most importantly, to identify best practices (T11: 1858-1859). BC Hydro submits that, in its view, trend and benchmarking information, including the ratios in Exhibit B-33, are all helpful to understand the trends in BC Hydro's cost structure but "it is the reasons for the changes behind the trends that must be understood." BC Hydro further submits that the Commission should base its final orders on the reasons for the changes to its cost structure and the prudence of BC Hydro's decisions that resulted in those changes, and that it would be unlawful for the Commission to reach any conclusions with respect to the Application on the basis of trend, ratio and benchmarking information, "without regard to BC Hydro's decisions that resulted in those trends and ratios" (BC Hydro Argument, p. 30).

BCOAPO submits that it generally agrees with BC Hydro and states “analyses based on cross-utility or cross-jurisdictional comparisons require sufficient contextual information to be useful”. However, BCOAPO submits that its position should not be taken to mean that benchmarking should be abandoned, or that benchmarking results are not useful within the context of an RRA proceeding. BCOAPO further submits that benchmarking helps parties to identify areas or issues that require closer scrutiny and that “if BC Hydro is unable to satisfactorily explain trends, then it has not sufficiently supported its Application” (BCOAPO Argument, p. 5).

The CEC submits that trend analysis and benchmarking are useful for the purpose of learning from the process of making comparisons and building understanding, and that they can be useful in concert with specific assessment of the adequacy of performance (CEC Argument, p. 75).

The JIESC submits that it is concerned by the lack of data and what appears to be a “dismissal of the relevance of the benchmarking information by BC Hydro.” The JIESC further submits that it rejects the Total Factor Productivity Test (“TFP”) (described at section 4.4.7.4 of this Decision) as being too general and having only limited value without comparison of the individual factors. The JIESC also submits that useful benchmarking information can be obtained from regulatory filings and annual reports of other utilities and that the process would be assisted if BC Hydro was following the Uniform System of Accounts and reported its revenue requirement line items net of regulatory transfers. Finally, the JIESC submits that the Commission should require BC Hydro to undertake benchmarking studies in preparation for the next RRA and make the studies available to Intervenors (JIESC Argument, p. 17).

In reply, BC Hydro submits that it has responsibility to explain its performance, in particular with respect to the performance measures it uses in the management of its business, including those in its Service Plan. BC Hydro further submits that “it does not dismiss the relevance of benchmarking as suggested by the JIESC, but it is important to make clear the limitations of trend and benchmarking information, and the dangers of putting too much weight on such information whether it appears to be favourable to BC Hydro or not.” With regard to the JIESC request for a Commission order to direct BC Hydro to undertake benchmarking studies, BC Hydro submits that "it can not compel performance data from its peers" and that benchmarking studies are usually proprietary and subject to non-disclosure conditions and that therefore "BC Hydro may not be able to comply" in a manner that is amenable to a public process (BC Hydro Reply, pp. 7-9).

4.4.7.2 JIESC Evidence

The JIESC's expert witness states that a broader trend analysis is required to review BC Hydro's proposed operating expense levels for the test period for the following reasons:

- Over the recent years, BC Hydro has undergone a number of organizational and reporting changes. "Most recently, the reporting of total OMA expenses with regulatory Account Transfers that are not identified by Revenue Requirement line item has made comparison of OMA and functional and departmental costs over time difficult if not impossible for BC Hydro and hearing participants." (Exhibit C5-10, p. 2)
- In the F2009/F2010 RRA BC Hydro has employed a formulaic approach.

The JIESC also escalates base year costs by using customer growth, inflation and an allowance for productivity but it uses as base years both F1998 and F2003. Based on its analysis, the JIESC concludes that BC Hydro's forecast is "clearly well above those projections and has a significant productivity gap" (Exhibit C5-10, p. 6). Accordingly, the JIESC recommends that F2009 OMA should be reduced by 50 percent of the "gap" it identifies, based on the F2003 base line projections, of $33 to $37 million, with a further $33 to $37 million reduction in F2010. Further, the JIESC recommends that "freezing OMA for some period of time would further reduce the productivity gap" and notes that the excess OMA over the trend line should provide adequate funding for reliability expenditures "in a measured and sustained manner" (Exhibit C5-10, p. 7).

BC Hydro submits that nothing in the JIESC evidence can justify a conclusion that BC Hydro's planned operating costs are imprudent and that the Commission should give no weight to the evidence regarding operating costs in the test period (BC Hydro Argument, p. 105).

The CEC submits that, while it is sympathetic to the JIESC's objectives in providing evidence regarding cost control at BC Hydro, it is "inclined to look for other alternatives to achieve them" (CEC Argument, p. 95).

The JIESC submits that it prepared its evidence before the Pension Expense adjustment issue surfaced which resulted in the JIESC recommended OMA reduction being lower than the base adjustment resulting from the pension adjustment. Accordingly, the JIESC submits that clearly its recommendation was conservative, "and too low", as indicated by the more direct approach of looking at the F2008 approved RRA and adjusting it for the pension expense (JIESC Argument, p. 21).

In reply, BC Hydro submits that no Intervenor has attempted to rely on the JIESC evidence and that even the JIESC only relies on its expert's numerical analysis, not on any of the conclusions drawn from such analysis (BC Hydro Reply, p. 40).

4.4.7.3 Cost Consciousness at BC Hydro

BC Hydro summarized the discrete activities it has taken or intends to take with regard to containing costs, maximizing revenues from non-load sources, increasing productivity and efficiency, and otherwise serving the "low cost" element of its over-arching objective to provide safe, reliable service at low cost, over the long-term. Examples of these activities include the optimization of the value of the generation system and the arrangements with Accenture (BC Hydro Argument, pp. 131-135). With respect to the issue of whether deferral accounts have any impact on cost control within BC Hydro, BC Hydro submits that the existence and use of deferral accounts has no impact on its cost control philosophy and approach (T13: 2237-2239; T7: 1174-1175; BC Hydro Argument, p. 141).

The JIESC submits that BC Hydro does not demonstrate any awareness of the detrimental impact the proposed rate increases may have on the British Columbia economy and, to the contrary, that "BC Hydro appears ready to take on any and every project or initiative it feels is beneficial without regard to priorities, resources or concern for the customers' ability to pay" (JIESC Argument, p. 3).

In reply, BC Hydro submits that the JIESC submission has no basis on the evidentiary record or in law and that the Commission has no basis to conclude "that BC Hydro is not as cost conscious as it should be, in light of its objectives and the challenges it faces in achieving those objectives (BC Hydro Reply, pp. 54-55).

4.4.7.4 Total Factor Productivity

BC Hydro indicates that it plans to use TFP as a new performance measure for operational efficiency and has established a target of 1.0 percent for the test period. BC Hydro defines the TFP as "the increase, period over period, of the ratio of a predefined set of outputs and inputs" and notes that TFP is an integrated performance measure used in the electricity sector in the UK, USA and Australia, and that it is not aware of any utility in Canada using TFP. BC Hydro further explains that the 1.0 percent TFP target was established based on the overall estimated TFP results achieved by Pacific Gas and Electric Company over a number of years and an overall comparison with utilities in the UK and Australia (Exhibit B-1, Appendix C, pp. 22-23; Exhibit B-5, BCUC 1.3.2, 1.3.3).

BC Hydro also notes that the use of this metric, TFP = Output Index/Input Index, is in the preliminary stages and that the formula may need to be reviewed. It shows the calculation of the indices as follows:

Table 4.10

	Weights	
INPUT	**UNITS**	**MODEL (%)**
Operating, maintenance and general & administration costs	CDN $	34.0
Generation capacity	MW	33.0
Transformer capacity	MVa	16.5
Network length	Km	16.5
OUTPUTS	**UNITS**	**MODEL (%)**
Number of customers	No	30.0
Peak demand	MW	5.0
Total energy delivered	GWh	35.0
Green energy delivered	GWh	5.0
System reliability index (SAIDI)	-	15.0
Utilization - % generation	%	10.0

Source: Exhibit B-5-1, BCUC 1.3.4

BC Hydro estimated the year over year change in TFP for the last ten years as shown in Table 4.11 below.

Table 4.11

	F1999	**F2000**	**F2001**	**F2002**	**F2003**	**F2004**	**F2005**	**F2006**	**F2007**	**F2008**
TFP (%)	2.6	0.8	-3.3	-3.3	-3.6	-3.0	1.6	0.6	-1.4	0.3

Source: Exhibit B-75, Undertaking No. 28

The JIESC rejects the TFP test because it is too general, it is not applied consistently, and "as a result has very limited value without comparison of the individual factors." JIESC requests that the Commission require BC Hydro to undertake benchmarking studies in preparation for the next RRA, and to make those studies available to Intervenors (JIESC Argument, p. 17).

No other Intervenor commented specifically on the TFP.

BC Hydro made no specific reply in respect of the JIESC's submissions.

Commission Determination

The Commission Panel has earlier noted the dissatisfaction expressed by several Intervenors in their attempts to understand the cost structure as it relates to efficiency and productivity matters at BC Hydro. The Commission Panel further notes the concerns of Intervenors regarding lack of cost consciousness at BC Hydro.

With regard to the culture of cost consciousness at BC Hydro, the Commission Panel believes that results will speak for themselves more clearly than any words, and expects that continuation of benchmarking studies and analysis of BC Hydro internal cost trends over a period of time will assist BC Hydro with its future rate applications. The Commission Panel finds that such studies provide informative trends both regarding BC Hydro's performance over time and its comparative performance against other utilities. The Commission Panel is concerned that BC Hydro only reported selected benchmarking studies in the Application and has not recently performed more comprehensive benchmarking. The Commission Panel believes that any confidentiality aspects of proprietary studies can be managed as in the past. **Accordingly, the Commission Panel directs BC Hydro to conduct a comprehensive and informative benchmarking study such as the PA Consulting Group study and/or the Haddon Jackson generation indexing study it submitted in the F05/F06 RRA Proceeding and update its other benchmarking studies for its next RRA.**

With respect to BC Hydro's use of TFP as a performance indicator, the Commission Panel finds that while TFP may be useful to BC Hydro as an internal management tool, it adds little value to the revenue requirement review process given its macro level approach and because other Canadian utilities do not appear to have embraced the TFP.

4.5 Taxes

BC Hydro's forecast of school taxes and grants-in-lieu is $167 million and $177 million for F2009 and F2010, respectively. BC Hydro submits that while the *Hydro Act* exempts BC Hydro from all property taxes other than those levied in respect of schools it also authorizes BC Hydro to pay grants-in-lieu of general municipal, regional district and local improvement taxes. Orders-in-Council set out the formula used to calculate the grant payments. BC Hydro is seeking Commission approval to establish a regulatory account to collect and defer variances between forecast and actual taxes plus interest during the test period because a review of the valuation of the distribution system by the B.C. Assessment Authority is still pending (BC Hydro Argument, p. 108).

BC Hydro testified that it has an active role in the review and that it will evaluate whether it will challenge the assessment results once the current review is complete (T10: 1668-1771).

Intervenor Submissions

The CEC submits that it is satisfied with BC Hydro's management of property taxes and supports BC Hydro's proposal for a regulatory account to capture variances in school taxes and grants-in-lieu (CEC Argument, p. 97). Similarly, the JIESC also submits that it supports the establishment of a regulatory account (JIESC Argument, p. 29) and BCOAPO submits that it has no issues regarding taxes (BCOAPO Argument, p.10).

Commission Determination

The Commission Panel finds BC Hydro's management of taxes acceptable, including the proposal for a regulatory account to capture variances in school taxes and grants-in-lieu, which is further addressed in Section 5.5.3.

4.6 Amortization and Finance Charges

Total amortization charges are forecast to be approximately $390.7 million in F2009 and $422.5 million in F2010. Finance charges are estimated to be $449.0 million and $501.2 million over the same fiscal years, respectively (Exhibit B-64, p. 7, Table 2). Incremental increases in amortization and finance charges are due to actual capital additions in F2008 and planned capital additions in F2009 and F2010. Planned capital additions in the test period are roughly $1.5 billion in each year (BC Hydro Argument p. 109).

Actual amortization and finance charges are determined by the number and cost of capital additions and applicable interest and depreciation rates. BC Hydro took the position that its depreciation rates have already been the subject "of extensive inquiry during the F07/08 RRA" and therefore proposed no changes to that cost component (BC Hydro Argument, pp. 109-110).

4.6.1 Planned Capital Additions

BC Hydro provides its detailed capital plan for F2009 to F2010 in Chapter 5 and Appendices I and J of the Application. BC Hydro states that its capital expenditures (excluding transmission) are forecast to increase by almost 60 percent from F2008 to F2010 (Exhibit B-1, pp. 5-9).

BC Hydro describes the "key drivers" behind the significant projected increase in its capital expenditures in the test period as being: aging assets, both in their own right and in relation to changing environmental and safety standards, capacity constraints, labour market pressures, and high construction costs (Exhibit B-1, pp. 5-1 to 5-2).

BC Hydro notes that it is "not seeking any relief with respect to its capital plan in the current application", and also observes that the statutory basis for it to file a capital plan has changed. BC Hydro proposes to address the effect of the new legislation on the capital plan review process in the 2008 LTAP proceeding (Exhibit B-19). It submits that its capital plan remains available to satisfy its obligations under the F2007/F2008 RRA NSP agreement, which was approved by Commission Order G-143-06 (BCH Argument, p. 109-110).

BC Hydro also submits that its "planned capital additions arise from management's views on what is required to provide safe, reliable and low cost service over the long- term, and accordingly have the benefit of the rebuttable presumption of prudency" (BCH Argument, p. 111). As noted by BC Hydro, no Intervenor took particular issue with its forecast of capital additions (BC Hydro Reply, p. 41).

4.6.1.1 Timing and Ability to Deliver Capital Plan

BC Hydro's evidence was that in the past it has had difficulty in delivering its annual capital plan, due, in part to the "lack of people to do the work" but that "…in fiscal 2008, BC Hydro, for the first time in a number of years, was able to deliver on its capital plan of about $1.1 billion" (T3: 280-281). In fact, "in F2008 BC Hydro delivered a capital expenditure plan of $1,126 million compared to a forecast of $1,076 million", an increase over forecast of $50.0 million. BC Hydro argues that this "increasing ability to deliver on capital expenditure plans can be relied on as evidence of [its] ability to deliver on its planned capital additions" (BC Hydro Argument, pp. 112-113).

The JIESC takes the position that whether BC Hydro can achieve the "substantial capital projects" it has forecast is subject to many forces beyond its control and that if it does not actually require the funds as scheduled and no interest expense is incurred it should not receive compensation as if the expense was incurred (JIESC Argument, p. 28).

BC Hydro argues that although some elements of the EARG group's capital plans are behind schedule and at risk of not coming into service, other elements are ahead of schedule, and that being behind or ahead of schedule may not necessarily reflect either a delay or advancement of an in-service date. BC Hydro submits that "[w]ithout evidence on each element of the planned capital additions the Commission can only speculate or, worse, "cherry-pick" those elements of the planned capital additions that are behind schedule." It submits that "the totality of the evidence on timing and ability to deliver capital additions does not support a conclusion that, on a net basis, taking account of both advancements and delays, that any material amount of BC Hydro's test period capital additions is not likely to come into service as planned." (BC Hydro Argument, p. 113) BC Hydro submits that "there is no reason to defer any portion of the difference between forecast and actual capital additions" (BC Hydro Reply, p. 41).

Commission Determination

The Commission Panel has dealt with this matter in its Determination at Sections 4.6.1.2 and 5.5.2 of this Decision.

4.6.1.2 Depreciation Commencing at the Start of the Following Fiscal Year

By Order G-143-06 the Commission approved the NSP agreement for BC Hydro's F2007 and F2008 revenue requirements, in which agreement Commitment 32(iv) states:

> "In its next revenue requirement application BC Hydro shall:
>
> iv. consider and address the appropriateness of an accounting policy change that would delay the recording of depreciation arising from some or all capital additions until the beginning of the fiscal period following the period in which the capital additions go into service;"

BC Hydro's current practice, consistent with GAAP, is to commence amortization in the month after an asset is placed into service. For revenue requirement purposes, the amortization is forecast to commence in the month after the asset is forecast to be placed into service.

BC Hydro argues that an accounting policy change to commence depreciation at the start of the following fiscal year would not be appropriate because there would be no difference in the present value of the impact on ratepayers and because delaying depreciation beyond when an asset goes into service is not supportable under GAAP. Also, BC Hydro argues that it would require an accounting order from the Commission to establish a regulatory account to provide for the delayed recovery from customers of the depreciation and interest expense that would be booked under GAAP in the year in which the project is completed. Each capital project that is recorded under the change would need to be tracked for the life of the asset, which could result in a significant administrative burden depending on the threshold used for non-GAAP treatment (BC Hydro Argument, p. 115).

BC Hydro has a “dual presentation” for its financial statements. BC Hydro presents its financial statements in accordance with GAAP on a gross basis before regulatory accounts and then applies regulatory accounting. However, this two step methodology appears to prevent or make it difficult for BC Hydro to accommodate regulated rate recovery adjustments. BC Hydro confirms that Terasen Gas Inc. and FortisBC Inc. do not have this “dual presentation” and present their GAAP financial statements on a net basis. BC Hydro does not know of other companies following the practice adopted by BC Hydro and confirms that this “dual presentation” is not a requirement by the auditors or GAAP (T6: 986; T7: 1117-1118).

BC Hydro testified that CICA Handbook Section 3061.28 (Exhibit A2-14) indicated that depreciation should start the month after it is placed into service (T7: 1124). CICA Handbook Section 3061.28 states: “Amortization should be recognized in a rational and systematic manner appropriate to the nature of an item of property and equipment with a limited life and its use by the enterprise.”

BC Hydro confirms that Terasen Gas Inc. and FortisBC Inc. calculated depreciation on assets based on plant in service at the beginning of the year and both of these companies received unqualified audit opinions from their external auditor, Ernst & Young, in 2007. BC Hydro also confirms that for fiscal year 2007 its auditor was also Ernst & Young. BC Hydro was also able to confirm that FortisBC Inc. does not have a regulatory account in its financial statements for the depreciation difference between commencing the following year and commencing the following month (Exhibit B-5-1, BCUC IR 1.97.1 to IR 1.97.3).

Alan Wait expresses concern with depreciation and amortization being budgeted to start from the month of scheduled completion for a capital project. He submits that projects are delayed far more often than they are completed ahead of schedule. Because of possible delays he argues that if depreciation and amortization commenced the following year it would be more accurate when preparing the budget. Alan Wait also argues that the change would assure ratepayers that they are not being charged twice for a portion of the depreciation and amortization of capital projects (Wait Argument, p. 6).

As the forecast variances impact both amortization and finance charges, some Intervenors addressed this issue from the interest expense perspective in their arguments as shown in Sections 4.6.1.1 and 5.5.2.

In reply, BC Hydro submits that no Intervenor proposed a change to the forecast of capital additions while the CEC, JIESC and Alan Wait each made proposals that would defer a different portion of the impact on revenue requirements of a difference between forecast and actual capital additions (BC Hydro Reply, p. 41).

Commission Determination

The Commission Panel finds that the CICA Handbook is not prescriptive as to how a company should depreciate its assets. Canadian GAAP does allow utilities to commence depreciation either the month following the asset is placed into service or at the beginning of the fiscal period as evidenced by an auditor, Ernst & Young, providing unqualified audit opinions for utilities adopting either accounting policy. It should be noted that both of these practices do not contemplate carrying interest during construction or allowance for funds used during construction into the gross cost of plant assets. The estimated carrying costs of new plant can be included in the test year's revenue requirements. The prime benefit of delaying the commencement of depreciation until the following year is that, for rate setting purposes, the forecast revenues associated with the capital recovery of plant assets (calculated from the depreciation charge) would better match the actual depreciation charge incurred.

In the case where forecast depreciation is based on actual test year beginning balances there would be no depreciation difference between forecast and actual. A potential problem arises when assets placed into service in the test year include a depreciation charge in the test year. If the value of the actual assets placed into service in the test year was less than forecast then the utility would be recovering in revenues a capital recovery of depreciation that is greater than the forecast capital recovery of depreciation. Depreciation commencing at the start of the fiscal year reduces the forecast error between the expected revenue capital recovery of depreciation and actual depreciation.

In light of BC Hydro's past track record of not completing capital work as planned, the Commission Panel finds that changing the accounting policy to calculate depreciation on assets based on plant at the beginning of the year would be an effective solution to mitigating any revenue requirement impact of forecasting errors. However, it is cognizant of the upcoming changeover to IFRS and the potential impact on depreciation policies and practices of regulated public utilities. **The Commission Panel finds that an alternate solution is to establish a new regulatory account for any differences between the forecast and actual amortization expense resulting from forecast variances in capital additions, and accordingly directs BC Hydro to establish such an account to be dealt with in its next RRA.**

4.6.2 Interest Rates

BC Hydro submits that the presumption of prudence does not apply to interest rate forecasts and that the task of the Commission is to select a forecast interest rate based on the evidence before it. BC Hydro confirmed in its OEU that: "… since the outset of the oral phase of the hearing a global financial crisis has emerged that has caused considerably more uncertainty over a number of BC Hydro's forecasts than would otherwise be the case" (Exhibit B-64, p. 1). BC Hydro then submitted in argument that the best evidence was the interest rate forecast contained in the October EU (which it received from the Treasury Board as of July 28, 2008) and which shows rates of 2.92 percent and 4.49 percent in F2009 and 3.65 percent and 4.92 percent in F2010 for short-term and long-term interest rates, respectively (BC Hydro Argument, p. 113).

The CEC takes the position that BC Hydro has historically taken a very conservative approach to interest rates and has consistently demonstrated an under forecasting of its short-term interest rates. The CEC argues that the forecasts contained in the Evidentiary Updates "are very likely greater than they will turn out to be and …should be reduced further by the Commission" (CEC Argument, pp. 49-50). The CEC suggests that "it is highly probable that there will be further interest rate reductions as a stimulus response to significant impacts on the global economy which are evident and continuing and requests that the Commission order BC Hydro to determine rates based on an additional rate reduction of 0.25 percent for F2009 and a further 0.5 percent for F2010 (CEC Argument, p. 51).

Alan Wait also notes that the short-term interest rate projections provided by the BC Government are conservative and "appear to be too high" (Wait Argument, p. 3).

BCOAPO expresses dissatisfaction that interest rates were not updated in the October 17th Update but notes that the proposed deferral account for finance costs would mitigate the impact (BCOAPO Argument, p. 11).

BC Hydro submits in reply that "the Commission is obliged to make its decision on the basis of the record before it, and may not simply substitute an arbitrary figure for a forecast, *no matter how tenuous in the current circumstances that forecast is*." It submits that the "principled solution to the *admitted problem* is the creation of a regulatory account…" (emphasis added) (BC Hydro Reply, p. 41).

Commission Determination

The Commission Panel finds that it would not be in the interest of ratepayers to approve a RRA which contains an "admitted problem" as attested to by BC Hydro. That notwithstanding, the Commission Panel has no evidence before it in this proceeding as to any forecast of short-term interest rates for the two test years other than that provided by the BC Government in July of 2008, which is reflected in BC Hydro's RRA by way of the OEU. **Accordingly, the Commission Panel finds that the appropriate manner to resolve the issues concerning the short-term interest rate forecast for the test years is through the deferral mechanism applied for by BC Hydro, as amended, as is described and determined at Section 5.5.2 of this Decision.**

4.6.3 Management of Debt Portfolio

BC Hydro has both short- and long-term debt. According to its Responses to IRs of July 22, 2007 (Exhibit B-11) BC Hydro's maximum short-term debt, by agreement with the Province, which supplies it with commercial paper loans, is $1.4 billion. It uses short-term debt to smooth differences in cash inflows and outflows and to provide liquidity. BC Hydro issues long-term bonds to coincide with significant cash outflows which are not likely to be replenished through cash inflows in the short-term and also uses long-term debt to maintain a cushion to protect it from unexpected variances in its short-term debt portfolio (Exhibit B-11, BCUC 3.200.3.1). BC Hydro also submits that the management of its debt attracts the presumption of prudence and that there "is no basis upon which the Commission could conclude that BC Hydro's management of its debt portfolio is imprudent" (BC Hydro Argument, p. 114).

The CEC does not dispute BC Hydro's management of its debt portfolio but suggests that there might be additional savings available with increased use of short-term financing (CEC Argument, p. 115) The CEC also suggests that BC Hydro's swap and derivative positions may not be incorporated in the schedules setting out finance charges (CEC Argument, p. 47).

BC Hydro has taken the position that it is not able to increase its short-term borrowings beyond the year end balances of approximately $1.25 billion and $1.27 billion in each of F2009 and F2010, respectively, citing the $1.4 billion limit on short-term commercial paper loans from the Province (Exhibit B-11, BCUC IR 3.200.3.2.) During the Oral Hearing, however, BC Hydro's CFO testified that that limit had been increased earlier in the year from $1.2 billion to $1.7 billion (T5: 812-813, 814). He also testified that the use of interest rate swaps has enabled BC Hydro to increase its effective short-term debt to approximately $3.0 billion out of a total of $8.0 billion (T5: 811-812).

BC Hydro testified that the effect of its interest rate swaps is reflected in the schedule appended to its Application dealing with "Finance Charges" (T5: 813). More specifically, the effect of interest rate swaps is subsumed in "other income" in this schedule (Exhibit B-11, Wait IR 3.5.0).

Alan Wait argues that "[w]ith interest rate swaps, BC Hydro is basically betting against the Banks, gambling" and recommends that "BC Hydro should, in a prudent manner, eliminate its position in interest rate swaps and then stay out of swap activity" (Wait Argument, pp.2-3).

BC Hydro submits in reply that a prohibition on the use of interest rate swaps would hamper its ability to maintain an appropriate mix of short and long term debt in its portfolio which would, in turn, increase costs (BC Hydro Reply, p. 43).

Commission Determination

The Commission Panel finds that there is no evidentiary basis before it that would support any of the relief sought by Intervenors with respect to BC Hydro's management of its debt portfolio. However, the Commission Panel does find that the effect of interest rate swaps, subsumed in BC Hydro's Other Income has a material impact on BC Hydro's finance costs. Accordingly, the Commission Panel has recognized that impact in its Determination on BC Hydro's application for deferral treatment of its finance costs as described at Section 5.5.2 of this Decision.

4.7 Return on Equity

The Commission Panel has dealt with this issue in Section 5.2.3.

4.8 Non-Tariff Revenues

BC Hydro earns additional miscellaneous revenues from its operations such as: rental income, net gains on the sale of its properties, meter reading, meter rents, lease revenue from BCTC, fleet revenue and other miscellaneous revenue items as identified in Exhibit B-1, Appendix A, Schedule 15. These revenues are expected to stay relatively constant over the test period (Exhibit B-1, p. 7-5).

BC Hydro submits that its forecast of non-tariff revenue, as updated in its July EU in part to include forecast profit from external engineering consulting contracts of $1.2 million and $1.5 million in F2009 and F2010, respectively, should be accepted as filed (BC Hydro Argument, pp. 119-121).

BC Hydro notes as well, in support of this submission, that the only other issue raised in the proceeding in terms of non-tariff revenues relates to BC Hydro's decision not to attempt to forecast revenues which it could potentially receive from Accenture for "founding partner benefits" or "CIS credits" (BC Hydro Argument, p. 119). Founding partner benefits are payable when Accenture obtains a new utility client with the assistance of BC Hydro, possibly through BC Hydro hosting a potential new client at one of its facilities or through BC Hydro providing a reference for Accenture (T9: 1501-1502). Customer information system ("CIS") credits are payable when Accenture is able to implement a CIS similar to that used by BC Hydro in either a new or existing utility client (T9: 1505). BC Hydro's position is that it should not attempt to forecast these potential revenues and credits as they result from the actions of Accenture, independent of BC Hydro, such that BC Hydro has no ability to predict whether or not Accenture will be successful in obtaining a new client/CIS client. In fact, BC Hydro has never received any revenues in respect of CIS credits (BC Hydro Argument, p. 119). BC Hydro therefore argues that it is appropriate to record only actual revenues received from Accenture as part of non-tariff revenues (BC Hydro Reply, pp. 46-47).

The CEC disagrees with BC Hydro's approach of not recognizing potential income from Accenture. The CEC submits that "if there is a reasonable probability of income being derived from this source then there is an obligation to forecast what that might be and deal with any variance in an appropriate regulatory account" and requests the Commission "to require BC Hydro to incorporate an estimate of these income sources into its revenue requirements" (CEC Argument, p. 99). The CEC notes that in the past 3 years, BC Hydro has received approximately $500,000 each year in founding partner benefits (CEC Argument, pp. 99-100).

Commission Determination

The Commission Panel notes the evidence of BC Hydro that it has received a total of $1.6 million in founding partner benefits and no CIS benefits to date (Exhibit B-5-1, BCUC IR 1.49.1.1). The Commission Panel acknowledges BC Hydro's position that it is difficult to predict potential revenues which might accrue due to another party's efforts to obtain new clients, but notes as well that, to the extent that BC Hydro is entitled to be rewarded, that reward is due to its efforts in promoting and facilitating Accenture's efforts.

Based on the evidence before it, the Commission Panel declines to grant the CEC the relief requested in this proceeding. That notwithstanding, Commission Panel finds that BC Hydro can and should provide its best estimate in terms of a forecast for this potential revenue stream from the Accenture relationship in future revenue requirement applications and is directed to do so for its next RRA.

4.9 Regulatory Account Transfers

Transfers to deferral and other regulatory accounts are made up of additions to, recoveries from and interest charged on the outstanding balances in each of the accounts. The applicable interest rate is BC Hydro's weighted average cost of debt, based on its most recent fiscal year. BC Hydro proposes that there be no change to the method of determining the applicable interest rate (BC Hydro Argument, p. 125). No parties took issue with this position.

When BC Hydro filed its OEU on October 17, 2009 it requested across-the-board increases of 3.75 percent and 10.17 percent, effective each of April 1, 2008 and April 1, 2009, based on the assumption that it would be preferable to issue refunds for the difference between the interim F2009 rate increase of 6.56 percent and a final rate increase of 3.75 percent. During the course of preparing its Argument, BC Hydro re-visited the relative merits of issuing a refund for the difference between interim F2009 rates and final F2009 rates and the process of addressing the impact of DSM that are the subject of the 2008 LTAP (BC Hydro Argument, p. 1).

BC Hydro concluded that it would seek final rate increases of 6.56 percent, effective April 1, 2008, and 7.50 percent, effective April 1, 2009, necessarily subject to the resolution of the 2008 LTAP (BC Hydro Argument, pp. 1-2). BC Hydro proposes for F2009 a credit addition of $75.3 million to the NHDA in order to achieve a final F2009 rate increase of 6.56 percent (BC Hydro Argument, p. 125).

Commission Determination

The Commission Panel does not accept that any transfers should be made to deferral accounts for the sole purpose of affecting rates at this time. **The BC Hydro proposal to credit the NHDA for $75.3 in order to achieve a final F2009 rate increase of 6.56 percent is denied.** The Commission Panel believes that the OEU proposal (Exhibit B-64, p. 6) is more appropriate to set rates, subject to adjustments arising from this Decision. Further, the Commission Panel has determined that a refund is to be made, as described at Section 4.10.2 of this Decision. The Commission Panel agrees that no change is needed to the method of determining the interest rate applicable to deferral accounts proposed in this Application.

4.10 Revenue Deficiency and Requested Rate Relief

This Section addresses how the revenue deficiency should be reflected in the requested rate relief with the following specific questions identified:

(i) Whether or not the F2009 and F2010 rates should remain interim until after the Commission decision regarding the 2008 LTAP proceeding: and

(ii) How to deal with the difference between interim and permanent rates for F2009.

4.10.1 Accounting for DSM Determinations in 2008 LTAP

BC Hydro proposed that DSM-related matters, which include the DSM electricity savings, the DSM expenditures and the amortization period for DSM expenditures be reviewed for the RRA test period as part of the 2008 LTAP proceeding. This proposal was accepted by Commission Order G-78-08 which defined the scope for the RRA (Exhibit A-8). BC Hydro submits that it now estimates that the 2008 LTAP decision will not be available until June 2009, which raises the issue with respect to the mechanism by which the DSM determinations of the Commission ought to be reflected in F2009 and F2010 rates (BC Hydro Argument, p. 128).

The options considered in the RRA proceeding included the following:

- BC Hydro rates for F2009 and F2010 remain interim until the Commission renders its decision on the 2008 LTAP (Exhibit B -5, BCUC 1.74.2).
- BC Hydro rates for F2009 and F2010 are finalized prior to the LTAP Decision with a regulatory account being established to defer the impact of the DSM matters that are subject to adjustment after the 2008 LTAP decision (Exhibit B-77, BCOAPO 4.84.0(a)).

In reference to subsection 44.2(2) of the *UCA*, BC Hydro submits that "despite the attractiveness of establishing final orders and a regulatory account in light of the current expectations regarding the timing of a final decision regarding the 2008 LTAP, BC Hydro has now concluded that such an approach would be unlawful" (BC Hydro Argument, p. 129).

BCOAPO submits that its clients strongly prefer finalized 2009 rates based on the outcome of the current proceeding and that "we do not agree that there is no mechanism available to the Commission to make this possible." BCOAPO further submits that:

> "on its face, 44.2(2)(a) is a procedural, not a substantive, requirement. It prohibits the Commission from consenting to BC Hydro amending its rate schedule on a final basis until a certain process of filing and acceptance is complete. However, nothing in the legislation prevents the Commission from arriving at a finding that a particular rate is just and reasonable for fiscal 2009 in this proceeding. All it cannot do is to authorize the amendment of the schedule."

Accordingly, BCOAPO submits that the Commission should determine what the just and reasonable rate would be for the current year, but indicate that it is withholding its consent under section 61(1) to incorporate that rate in the tariff on a permanent basis. Specifically, BCOAPO submits that the Commission should amend the interim rate which is now in place to reflect the "right" F2009 rate which it finds would be just and reasonable, and indicate that it will consent to the final rate amendment in the schedule once the LTAP process is complete (BCOAPO Argument, pp. 12-13).

In reply, BC Hydro submits that it believes that the mechanism proposed by BCOAPO in substance is no different than what BC Hydro already has proposed and because of the complexity of the issue sets out in more detail the steps contemplated. The essential steps include:

- the F09/F10 RRA Decision addressing rates for the two test years;
- filing of new tariff sheets establishing new interim rates effective April 1, 2009 regarding F2010;

- confirmation that the rates established are just and reasonable, subject only to the resolution of the DSM issues in the 2008 LTAP and the subsequent compliance filing; and
- establishment of a deferral account for the DSM reconciliation.

Lastly, BC Hydro submits that although the rates would remain interim until the resolution of the 2008 LTAP, the advantage would be that "despite being interim for a significant period, the F2009 and F2010 rates faced by customers would not be subject to further change in the test period. In this way rates would remain final in the sense that they would remain unchanged, although they would not be final insofar as they would be established by interim orders only" (BC Hydro Reply, pp. 50-51).

Commission Determination

Having considered the evidence, the Commission Panel finds that customers will not be adversely affected because of the interim rates and approves BC Hydro's proposal to continue interim rates, as amended by this Decision, until the review of the 2008 LTAP is concluded. Further, the Commission Panel directs BC Hydro to submit its second compliance filing as soon as practicable after receipt of the 2008 LTAP Decision to finalize the permanentF2009 and F2010.

The Commission Panel does not, as a matter of principle, condone interim rates for long periods of time. Given that subsection 44.2(2) of the *UCA* is an impediment to finalizing rates, the Commission Panel recommends that in the future BC Hydro should consider having all DSM related issues dealt with in future revenue requirement applications.

4.10.2 Disposition of Interim Rate Refund

Commission Order G-40-08 prescribed an interim across-the-board rate increase of 6.56 percent for BC Hydro ratepayers effective April 1, 2008. The disposition of the difference between the forecast revenue to be collected in F2009 under that 6.56 percent interim rate increase and the forecast revenue to be collected in F2009 under the post-review revised interim rate increase must be addressed regardless of the timing of the decision to finalize rates for the test period.

Positions of the Parties

As described in Section 4.9 above, in its Argument BC Hydro submits that, upon further reflection, the difference between the forecast F2009 revenue on interim rates and the forecast F2009 revenue on final rates be applied against the Deferral Account balances. Specifically, BC Hydro proposes that "in the F09/F10 RRA compliance filing, BC Hydro will include a transfer to the NHDA in F2009 that will result in a final F2009 rate increase of exactly 6.56 percent" for the following reasons:

(1) Applying the difference to the Deferral Account balances in F2009 would reduce the forecast amount of debt required in both F2009 and F2010, which would also reduce the forecast amount of deemed equity in both years;

(2) The resulting reduction in the Deferral Account balances would result in the Deferral Account Rate rider being lower than it otherwise would be for the next four to six years;

(3) Applying the difference to the Deferral Account balances reduces the percentage rate increase required in F2010 from 10.17 percent to 7.50 percent, avoids the administrative costs of processing a rate refund, and would directionally offset the expected impact of the difference between the forecast and actual F2010 non-current pension costs;

"In light of BC Hydro's view that final F2009 rates can not be established until the resolution of the 2008 LTAP proceeding, a refund in regard to F2009 interim rates would not be issued until *after* any interim F2010 rate increase, which is bound to be confusing to customers." (BC Hydro Argument, pp. 130-131)

BCOAPO submits that it would prefer a refund and rejects BC Hydro's justification to artificially flatten the test period's rate increases (BCOAPO Argument, p. 13).

The BCSEA submits that it supports BC Hydro's proposal to include an additional transfer to the NHDA in F2009 that would result in a final interim F2009 rate increase of exactly 6.56 percent. By way of justification, the BCSEA submits that it emphasizes "prevention of customer confusion" and "sending the right price signal" as important issues in favour of BC Hydro's approach (BCSEA Argument, pp. 1-4).

The CEC submits that the refund for F2009 over-collection should be made to customers and that the administrative costs of the refund "[are] justified by virtue of benefit to customers of receiving the refund versus the opportunity cost of leaving the funds with BC Hydro" (CEC Argument, p. 104).

The JIESC submits that it strongly supports the refund to customers based on their F2009 bills, that "this is the only method that is consistent with Commission Order G-40-08, which granted a 'refundable' interim [rate increase]," and that it "is the only fair option because it returns the money to the customers who overpaid in proportion to their share of the overpayment". The JIESC also submits that the interim rates were not obtained or approved on the basis that the Deferral Accounts be paid down, and that in that case the benefit would not necessarily be going to the customers who paid the rate in the first place. Lastly, the JIESC submits that BC Hydro's proposal results in a higher compounded rate increase for F2009 and F2010 (JIESC Argument, pp. 47-50).

With respect to the JIESC submissions, in reply, BC Hydro first notes that the JIESC failed to incorporate the impact of the lower Deferral Account Rate Rider resulting under its proposal and submits that after incorporation of the impact of a 0.5 percent reduction in the rate rider, BC Hydro's proposal would result in a lower compounded rate increase for the test period than would a refund to customers.

Regarding the potential inconsistency with Order G-40-08, BC Hydro submits that "this would only be the case if the Commission's approval of interim rates unlawfully fettered its discretion to establish, in this proceeding, the appropriate level of recovery of the Deferral Account balances for F2009" and that because it was not the case "it is open to the Commission to decide, in this proceeding, the appropriate level of recovery of the Deferral Account balances for F2009." Finally, concerning the alleged unfairness to customers who have "overpaid", BC Hydro submits that if the Commission approves BC Hydro's proposal to include an additional transfer to the NHDA in F2009 that would result in a final interim F2009 rate increase of 6.56 percent, "there will be no difference between the interim and revised interim rates for F2009 and consequently no customer will have 'overpaid'."

BC Hydro further notes that the actual net balance in the Deferral Accounts at the end of F2008 was $91.7 million owed by customers and, therefore "there is no unfairness to current customers on the basis of 'overpayment' in F2009 when there is a large outstanding net balance in the Deferral Accounts that was incurred in past periods and is to be recovered from the current or future customers" (BC Hydro Reply, pp. 54-55).

Commission Determination

The matter raised by BC Hydro as to the "lawfulness" of the Commission determining a revised interim rate increase for F2009 arising from its review of the Application that differed from the interim rate increase approved by order G-40-08 was canvassed at length in the Oral Argument Phase pursuant to item 1 of Exhibit A-26. There was agreement amongst the parties that the setting of a revised interim rate increase as described was within the Commission's jurisdiction.

The Commission Panel notes the consensus among the ratepayer related Intervenors that any refund for F2009 over-payment be paid directly to those who participated. The Commission Panel finds that BC Hydro's proposal lacks transparency and raises concerns with respect to fairness.

The Commission Panel finds BCSEA’s concern regarding “price signals” to be unfounded as any refund will likely not be payable until after the close of F2009, so ratepayers would not see any rate reduction *per se*. Any increase in revised interim rates for F2010 will simply be seen as the difference from the interim rates for 2009 albeit it will be less than if the revised interim rate increases had been in place for both years; the refund will be seen as a one-time event.

Accordingly, BC Hydro is directed to issue refunds for any over-collection of revenues including interest at BC Hydro’s most recent annual weighted average cost of debt for its most recent fiscal year in F2009 as soon as practicable after its compliance filing regarding the revised interim rates for F2009 and new interim rates for F2010 resulting from this Decision.

5.0 REGULATORY ACCOUNTS AND RATE RIDER

5.1 Overview

The purpose of a regulatory account is to defer for potential future recovery or refund costs or revenues that under GAAP would otherwise be recorded in the current accounting period. BC Hydro notes three different situations in which a regulatory account could be appropriate:

1. To better match costs and benefits for different generations of customers;
2. To smooth out the rate impact of a large non-recurring cost; and
3. To defer to a future period differences between forecast and actual costs or revenues.

With respect to the deferral of differences between forecast and actual costs, BC Hydro remains of the view that it should assume financial responsibility for controllable risks and create regulatory accounts for non-controllable risks, with the understanding that "controllable " and "non-controllable" are relative terms. BC Hydro submits that "in this way the establishment of regulatory accounts for the purpose of deferring and amortizing the differences between forecast and actual costs essentially puts the financial responsibility for those costs, and thus the risk of cost variances, on ratepayers". BC Hydro reiterates the criteria it proposed in the F05/F06 RRA to be used to assess whether a risk was controllable or non-controllable:

1. BC Hydro's ability to directly or indirectly influence the cost category;
2. The volatility of the cost category;
3. The predictability of the cost category;
4. The materiality of the cost category to the revenue requirement; and
5. The frequency of major exceptions within the cost category (Exhibit B-1, pp. 6-1 to 6-3; BC Hydro Argument, p. 137).

In its F05/F06 RRA Decision, the Commission Panel accepted the above criteria but concluded that risk/reward considerations were also relevant and noted that even if some costs are non-controllable, the risk of forecast variances may be appropriately borne by the shareholder, such as the forecast risk related to interest rates and foreign exchange rates (BCUC October 29, 2004 Decision, pp. 29-30).

BC Hydro further submits that the establishment of a regulatory account does not, of its own, pre-determine whether and over what period any balances in that regulatory account may be recovered and that it bears the risk that deferred costs may ultimately not be recoverable from customers. Consequently, BC Hydro also submits that there is no reason to establish a limit on the total amount that can be deferred since the risk of recovery resides with the shareholder until recovery of the costs is approved by the Commission. Finally, BC Hydro submits that the existence and use of deferral accounts has no impact on cost control within BC Hydro (BC Hydro Argument, pp. 138-141).

In this Application, BC Hydro is not proposing any changes to the above criteria but is proposing some changes to existing Deferral Accounts and creation of a few new regulatory accounts. These proposals will be discussed in further detail below.

BCOAPO submits that the three situations identified by BC Hydro are “indeed sufficient to justify regulatory accounts” and that “controllability” is “a relative term that requires consideration of factors like volatility and predictability” (BCOAPO Argument, p. 14).

The JIESC submits that numerous deferral accounts, the various threshold levels and the manner of recording and recovery have evolved “in the absence of a consistent philosophy beyond BC Hydro’s interest in full cost recovery protecting its shareholder”. Therefore, the JIESC submits that the Commission should require BC Hydro to conduct a comprehensive review of deferral accounts prior to filing its next RRA and that otherwise “there is a real danger of BC Hydro becoming a cost plus utility with little responsibility or incentive left to manage or control costs” (JIESC Argument, p. 26).

The IPPBC submits that it remains opposed to the creation and proliferation of deferral accounts other than those specifically required by HC2 and that a reasonable period for clearing balances should be one to three years (IPPBC Argument, pp. 7-9).

The CEC made extensive requests in respect of the use of deferral accounts to mitigate rate impacts which are addressed in Section 5.7 and elsewhere in this Decision.

In reply, BC Hydro submits that in failing to address its evidence on these matters the JIESC has failed to make a case for the review it requests, and that given the prominence of the issue of regulatory accounts in this proceeding "it is fair to say that the JIESC has just had the review they now seek" (BC Hydro Reply, pp. 55-56).

5.2 Proposed Changes to Deferral Accounts

BC Hydro currently refers to the following four regulatory accounts as "Deferral Accounts": HDA, NHDA, TIDA and BCTCDA. The HDA and the NHDA are collectively referred to as the cost of energy Deferral Accounts. The proposed changes to previously approved deferrals are as follows.

5.2.1 Load Curtailment

Load Curtailment was addressed in more detail in Section 4.3.3.

Commission Determination

As the Commission Panel approved the inclusion of expanded load curtailment costs in the HPO earlier in this Decision, it follows that any variances between forecast and actual costs will flow into the HDA.

5.2.2 Load Variance

In the F05/F06 RRA, BC Hydro proposed to exclude from deferral treatment the impact of load variance because variances from forecast were expected to be symmetrical and "fall within a range of $20 million on an annual basis." In the F07/F08 RRA, however, BC Hydro proposed that the cost of load variance net of incremental domestic revenues be transferred to the cost of energy Deferral Accounts. This proposal was not approved by the parties to the NSP agreement, as approved by Order G-143-06, which stated that "differences between the forecast and actual cost of energy arising from differences between forecast and actual customer load would continue to be excluded from the HDA and NHDA."

Based on the asymmetry and volatility in load actually experienced in the period F2005 to F2008 and the expectation that volatility may increase in future years, BC Hydro proposes that the net cost of load variance be included in the two cost of energy Deferral Accounts effective April 1, 2008. In practice, since BC Hydro's domestic energy sales exceed the 49,000 GWh Heritage energy obligation, the net impact of load variance only affects the NHDA. Accordingly, BC Hydro proposes that the variance arising be included in the NHDA (Exhibit B-1, pp. 6-4 to 6-7).

BCOAPO submits that "the past practice of not deferring the cost of load forecast variances remains valid in most circumstances because load forecasting is properly part of a utility's risk, but that as a result of current exceptional circumstances it now is prepared to accede to BC Hydro's request, provided the deferral is "expressly limited to costs incurred during the F2009-F2010 test period". BCOAPO further submits that it firmly opposes a permanent load variance account "despite BC Hydro's apparent concerns about the impact of new rate structures like the RIB" (BCOAPO Argument, p. 16).

The CEC supports BC Hydro's proposal to include the net cost of load variance in HDA and NHDA and submits that customer response to new rate structures is an important additional source of uncertainty CEC Argument, p. 110).

The JIESC, while philosophically opposed to the proposal because the utility should bear the forecasting risk, supports the proposal “at this time” due to economic factors, unproven DSM measures and new rate structures. The JIESC further submits that this deferral account should be eliminated “as more normal conditions return” (JIESC Argument, p. 32).

In reply, BC Hydro submits that, even in the absence of new rate structures, the actual net impact of load variances for the period F2005 to F2008 exceeds any load forecast risk that “reasonably resides with the utility” and that therefore the Commission should approve inclusion of the net cost of load variance in the NHDA on a permanent basis (BC Hydro Reply, p. 58).

Commission Determination

In light of the recent volatility of BC Hydro’s load forecasts, the uncertain economic outlook, the recent introduction of the RIB, and the uncertain impacts of future DSM programs, BC Hydro’s proposed deferral treatment for load variance is approved for the test period.

5.2.3 Annual ROE Adjustment

As of the date of the Hearing, BC Hydro’s allowed ROE was deemed to be equal to the pre-income tax annual return allowed to the most comparable investor-owned utility regulated under the *UCA*, which has been determined to be Terasen Gas Inc. (“TGI”) (HC2, section 4(d)).

BC Hydro uses TGI’s allowed pre-income tax 2008 ROE of 11.78 percent for each of the test years F2009 and F2010 as a placeholder and plans to adjust its F2010 revenue requirement to reflect any revisions to TGI’s ROE and income tax rates for 2010. Consistent with past practice and “in the interest of regulatory efficiency” BC Hydro requests approval to include any changes in F2010 arising from changes to TGI’s ROE and income tax rates for 2010 in the NHDA (Exhibit B-1, p. 6-7).

BC Hydro stated it will revise its F2009 ROE for the new lower effective tax rate if the BCUC directs TGI to change its income tax expense used in setting its 2008 rates before BC Hydro's F2009 rates are finalized (Exhibit B-8, BCUC 2.167.2).

BC Hydro testified that TGI's actual allowed ROE and effective income tax rate for 2009 should be available by January 2009 (T6: 996). BC Hydro submits that if that information is available prior to its compliance filing with respect to the F09/F10 RRA the actual information could be incorporated in that filing thereby eliminating the need for a deferral mechanism in the current test period (BC Hydro Argument, p. 145).

BCOAPO agrees with BC Hydro's proposal and submits that it is consistent with past practice (BCOAPO Argument, p. 16). CEC supports BC Hydro's proposal in principle, but submits that a separate regulatory account should be used, rather than the NHDA, in the event that the ROE adjustment is not incorporated in BC Hydro's compliance filing (CEC Argument, pp. 55, 99, 111).

JIESC submits that in 2008, the blended federal/provincial income tax rate was reduced from 31.5 percent to 31.0 percent which should have resulted in a decrease in the effective tax rate used to calculate BC Hydro's allowed ROE of 0.5 percent but has not been. JIESC further submits that BC Hydro's position misconstrues the Commission's intent in Order G-88-08 when it accepted TGI's proposal to record the 2008 income tax reduction in a deferral account with a three year amortization. The JIESC submits that the effective rate changed when the tax rate changed and that unlike TGI, BC Hydro is not operating under a PBR, and accordingly should be utilizing a tax rate based on taxes payable by TGI and not on an amortization schedule under its negotiated settlement agreement (JIESC Argument, pp. 35-36).

In reply, BC Hydro submits that since the use of the NHDA is consistent with past practice and since it would not be in the interest of regulatory efficiency to establish a separate regulatory account, the Commission should approve BC Hydro's proposal (BC Hydro Reply, pp. 59-60).

Commission Determination

The Commission Panel notes that TGI's after-tax ROE was finalized in November 2008 at 8.47 percent as per Commission Letter L-55-08, and that its 2009 Revenue Requirements were finalized by Order G-191-08 and presumes that TGI would have filed its regulatory schedules to support the rates. Therefore, the Commission Panel finds that BC Hydro now has the required information to calculate its pre-tax ROE for F2010 in its compliance filing, which should eliminate the need of a deferral account.

With regard to the JIESC Argument, the Commission Panel notes the JIESC's concern but finds that the issue is restricted to F2009. The Commission Panel notes that historically BC Hydro has calculated its pre-tax ROE based on TGI's forecast taxes payable, not based on the effective marginal statutory tax rate and is not prepared to change the methodology at this time. **Accordingly, the Commission Panel approves BC Hydro's approach to dealing with its F2009 pre-income tax ROE.**

5.3 Deferral Account Rate Rider Adjustment Mechanism ("DARR")

From February 1, 2007 to March 31, 2008, pursuant to the F2007/F2008 RRA NSP agreement, a 2.0 percent rate rider was charged on all BC Hydro customer bills, with all revenues received being applied against the balances in the HDA, NHDA, TIDA and BCTCDA. Effective April 1, 2008 the rate rider has been set at 0.5 percent on an interim basis. This new rate rider reflects BC Hydro's proposal to adopt a formulaic approach, which is an outcome of BC Hydro's commitment in the F2007/F2008 RRA NSP to address amortization of the Deferral Account balances in a more structured way.

BC Hydro states that it recognizes the permanent nature of the Deferral Accounts, and that there may be significant volatility in the net balance from year to year, and proposes that it would be appropriate to adjust the level of the DARR each year in a manner that would meet the following objectives:

- minimize intergenerational inequity by being responsive to the changing net balance in the Deferral Accounts;
- maintain rate stability for customers to the extent practicable; and
- be administratively simple and transparent (Exhibit B-1, p. 6-8).

To achieve these objectives, BC Hydro proposes that the level of the DARR to be effective on April 1st of a given fiscal year for that year be based on the net balance in the Deferral Accounts as of September 30th of the previous year, in accordance with the following table:

Table 5.1
Deferral Account Rate Rider

Net Balance as of September 30th		% Rate Rider Effective Following April 1st
> $ million	<= $ million	
-	(500)	(5.0)
(500)	(450)	(4.5)
(450)	(400)	(4.0)
(400)	(350)	(3.5)
(350)	(300)	(3.0)
(300)	(250)	(2.5)
(250)	(200)	(2.0)
(200)	(150)	(1.5)
(150)	(100)	(1.0)
(100)	(50)	(0.5)
(50)	0	0.0
0	50	0.0
50	100	0.5
100	150	1.0
150	200	1.5
200	250	2.0
250	300	2.5
300	350	3.0
350	400	3.5
400	450	4.0
450	500	4.5
500	-	5.0

Source: Exhibit B-1, p. 6-9

BC Hydro proposes that, in conjunction with the filing of each September 30th Quarterly Deferral Account Report, it will seek an order from the Commission approving a change to the DARR, effective the following April 1st. Should BC Hydro at any time consider that a deviation from the table is warranted due to special circumstances, it would file an application for approval of such deviation (Exhibit B-1, p. 6-9). BC Hydro confirmed that there would be an opportunity for Intervenors to review and comment on any such applications (T5:731-732).

BC Hydro submits that this proposed approach would satisfy the stated objectives as follows:

- intergenerational inequity would be minimized because the level of the rate rider would, all else equal, recover the net balance in the deferral Accounts in a period of approximately four to six years;
- rate stability would be maintained because the level of the rate rider would only change in increments of 0.5 percent and would be set at zero if the net balance was between -$50 and + $50 million; and
- the process of updating the level of the rate rider each year would be simple and transparent (Exhibit B-1, pp. 6-9 to 6-10).

In particular, BC Hydro submits that there is no reason to expect the positive and negative additions to the Deferral Accounts to be symmetrical over time, and therefore no reason to expect their self-liquidation without the use of a rate rider (BC Hydro Argument, p. 148; Exhibit B-5, BCUC 1.78.5).

With respect to the DARR to be effective on April 1, 2009, BC Hydro notes that the Commission has not yet approved the proposed mechanism and proposes to seek approval of the level of the rate rider to be effective on April 1, 2009 as part of the F09/F10 compliance filing (BC Hydro Argument, p. 149).

BCOAPO submits that it appreciates BC Hydro's confirmation that there will be an opportunity for Intervenors to comment on its applications to the Commission seeking a change in the level of the DARR (BCOAPO Argument, p. 17). BCSEA submits that it "strongly supports the concept of a predictable, objective mechanism for clearing the Deferral account net balance" and also supports clearing the balance over four to six years (BCSEA Argument, pp. 7-8). The CEC submits that the DARR should only apply to the HDA and NHDA, and that an appropriate amortization period for these accounts would be ten years (CEC Argument, pp. 111-112).

In reply, BC Hydro submits that since the CEC is the only Intervenor opposing the DARR mechanism as proposed by BC Hydro, and since there is no evidentiary basis on which to approve a different mechanism, the Commission should approve its proposal (BC Hydro Reply, p. 61).

Commission Determination

The Commission Panel finds that the proposed DARR mechanism presents a more structured approach to clearing the net balances, meets the stated objectives, and that the estimated amortization period of 4–6 years is reasonable, and accordingly accepts the DARR mechanism as proposed by BC Hydro.

Furthermore, the Commission Panel approves the Deferral Account Rate Rider of 0.5 percent for the period from April 1, 2008 to March 31, 2009.

5.4 Proposed Changes to Existing Regulatory Accounts

BC Hydro's existing regulatory accounts include accounts for expenditures made on DSM activities, actual First Nations negotiation and settlement costs, and for recording loss provisions required under GAAP related to all First Nations claims. They also include accounts for amortization of a net book value adjustment resulting from the F2007/2008 RRA Depreciation Study, foreign exchange gains and losses on the translation of foreign currency denominated long-term monetary instruments, and amortization of the Pre-1996 Contribution In Aid of Construction ("CIAC") asset. As well, there are regulatory liability accounts for Site C expenditures incurred in F2007 and F2008; for Future Removal and Site Restoration costs ("FRSR"); for capturing F2007 and F2008 costs associated with major storm restoration; for unplanned maintenance, and unplanned capital expenditures; and for the purpose of deferring up to $8.2 million incurred in F2008 for the PEI.

BC Hydro states that it is not proposing any changes to these existing regulatory accounts except as specified below. BC Hydro seeks final orders from the Commission regarding:

(i) the continuation of the provision of Order G-143-06 that allowed it to defer all costs related to the development of the Site C project in F2009 and future years, until such a time as a decision is made on whether to proceed with the project;

(ii) a transfer of the F2007 Storm Restoration regulatory account balance into the NHDA "since the NHDA provides for significant unplanned major distribution capital costs related to single event equipment or infrastructure failure, and BC Hydro considers these major storms to similarly be extraordinary, unforeseeable and unplanned major events";

(iii) the continuation of the provision of Order G-17-08 that allowed BC Hydro to defer the F2008 costs incurred in relation to the PEI, to allow for the deferral of expenditures expected to be incurred in F2009 to F2011 (Exhibit B-1, pp. 6-10 to 6-15).

These proposed changes are addressed in more detail below.

5.4.1 Site C

BC Hydro states that its actual Site C expenditures for F2007-F2008 totaled $8.2 million and its forecast for F2009 and F2010 Site C expenditures is $17.5 and $14.6 million, respectively. BC Hydro further notes that it would not be opposed to limiting the extension of the Site C regulatory account to the end of F2010 and that it would apply for a further extension, if necessary, at a future date. Finally, BC Hydro states that "given the uncertainty of costs related to Stage 3 of the project, which is expected to start during F2010 and is dependent on the results of Stage 2, BC Hydro is of the view that it would not be appropriate to limit the approval of Site C regulatory account expenditures by total dollar amount (Exhibit B-10, Appendix 1, Schedule 5.0, p. 19; Exhibit B-5, BCUC 1.65.1).

BC Hydro submits that the timeline of Stage 2 has been extended, pushing out any start date for Stage 3. On further reflection, BC Hydro submits that the Site C regulatory account should be extended to include all costs incurred related to the Site C project, until such a time as a decision is made on whether to proceed to construction because such a determination would “improve regulatory efficiency” and “would not have any impact on the ability of Intervenors or the Commission to examine the costs of the Site C project (BC Hydro Argument, p. 150).

BCOAPO does not object to extending the related regulatory account until such time as a decision is made whether to proceed to construction (BCOAPO Argument, p. 17). CEC supports BC Hydro’s proposal to extend the Site C regulatory account until such time a decision is made on whether to proceed to construction (CEC Argument, p. 112).

BCSEA supports the continuation of the Site C regulatory account for Site C costs incurred prior to the end of F2010 or the date of a government decision to proceed from Stage 2 to Stage 3, whichever comes first. BCSEA submits that the efficacy of the Commission’s review of the Site C regulatory account will be diminished by a *fait accompli* effect if the review is postponed indefinitely and that the end of Stage 2 and the decision whether to proceed to Stage 3 is a critical project milestone (BCSEA Argument, pp. 8-9). JIESC opposes BC Hydro’s proposal as “an open-ended extension” and submits that the Commission should limit the expenditures to those incurred in the test period (JIESC Argument, p. 33).

In reply, BC Hydro submits that it has requested a determination that the expenditures planned for Stage 2 are in the public interest in the 2008 LTAP proceeding and that therefore there is no need for the Commission again to review the Site C regulatory account at the end of Stage 2 and that, consequently, the Commission should approve the extension of the Site C regulatory account until at least the end of F2010 (BC Hydro reply, p. 62).

Commission Determination

The Commission Panel notes a general consensus among the parties for the proposition of extending the Site C regulatory account at least to the end of the test period. **Accordingly, the Commission Panel approves the extension of the Site C regulatory account until the end of F2010.**

5.4.2 F2007 Storm Restoration

The F2007 Storm Restoration costs are subject to review in this RRA by Orders G-76-07 and G-77-07, respectively. The Commission approved the creation of a regulatory account to capture the costs associated with the F2007 unplanned major storm restoration and the incremental F2008 operating expenditures incurred to improve BC Hydro's response to future storms, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year (Exhibit B-1, Appendix F, pp. 129-132).

BC Hydro included its Winter Storm Report (October 2006 - January 2007) as Appendix F to the Application (Exhibit B-1, pp. 20-127).

BC Hydro submits that the full balance in the F2007 Storm Restoration regulatory account as at March 31, 2008 of $43.2 million, including interest, ought to be recovered in rates. BC Hydro further submits that inclusion of this balance in the NHDA, for the reasons previously stated, also allows for recovery through the proposed DARR and thereby eliminates the need for the Commission to determine an amortization period for a separate account (BC Hydro Argument, pp. 151-152).

BCOAPO supports BC Hydro's application for the transfer of this regulatory account to the NHDA for recovery in rates through the DARR mechanism (BCOAPO Argument, pp. 17-18).

The CEC submits that the amount and prudence of the F2007 storm expenditures are uncontested and that they should be recovered from customers. However, the CEC submits that it is inappropriate to avoid having the Commission consider the appropriateness of the amortization period and requests that the amount be recovered over a period specific to the account (CEC Argument, pp. 112-113).

In reply, BC Hydro submits that there are costs to all parties of introducing additional regulatory accounts because, in addition to accounting and reporting requirements, the Commission needs to approve both an amortization period and a recovery mechanism for each regulatory account. BC Hydro further submits that for items that are small or non-recurring, such as the F2007 Storm, the additional costs associated with separate regulatory accounts are not warranted and that such items should continue to be included in the NHDA and recovered through the DARR (BC Hydro Reply, p. 76).

Commission Determination

The Commission Panel notes that no party takes issue regarding the expenditures outlined in the Winter Storm Report. With regard to the recovery of these expenditures in rates, in light of balancing the administrative efficiency against the appropriate amortization period, the Commission Panel finds that the 4-6 year recovery period projected through the DARR mechanism is a reasonable amortization period. **Accordingly, the Commission Panel approves BC Hydro's proposal to include the F2007 Winter Storm account balance in the NHDA for recovery through the DARR mechanism.**

5.4.3 Procurement Enhancement Initiative

BC Hydro submits that the only relief it is seeking in the F09/F10 RRA regarding the PEI is to continue to defer its implementation costs until its expected "in-service" date in F2012. Specifically, BC Hydro submits that it seeks an order allowing it "to amend the existing regulatory account to defer to and amortize in a future period F2009, F2010 and F2011 implementation costs (expected to be about $23 million) in addition to the $7.3 million that BC Hydro incurred in F2008…". However, BC Hydro notes that it does not seek the deferral of $1 million per annum in operating costs relating to the establishment of the Office of the Chief Procurement Officer ("CPO"), which it plans to include in the base operating costs (BC Hydro Argument, p. 153).

BC Hydro further submits that, as it is only seeking an accounting order on the PEI, the Commission need not rule on the prudency and reasonableness of the PEI. BC Hydro nonetheless made submissions on this matter, as described below, in the event the Commission concluded that this issue is to be resolved in this proceeding. Lastly, BC Hydro submits that should the Commission disallow the deferral of the F2009-F2011 planned expenditures, the amortization of the actual F2008 expense of $7.3 million would still require resolution (BC Hydro Argument, p. 154).

BC Hydro submits that the anticipated benefits of the SS and P2P components of this initiative were addressed in the context of Accenture costs (see Section 4.4.3.3 of this Decision) and Fixed-Term Productivity Initiatives (see Section 4.4.4.3 of this Decision). The PEI was also extensively canvassed in IRs and at the Oral Hearing. With regard to the magnitude of costs approaching $36.4 million, comprised of $8 million for the SS component and the balance for the P2P component. BC Hydro submits that:

> "The issue is understandable, since the bulk of the costs are not in regard to tangible assets, but in regard to far more intangible changes in the way things are being done. It is not too difficult to paint a picture of a physical asset, and describe why it costs what it does. It is much harder to describe and get a sense of what is involved in changing the way employees do things, and why, from an outside perspective, it should cost anything to have them do things differently."
> (BC Hydro Argument, p. 155)

A business case supporting BC Hydro's application for a regulatory asset in January, 2008 was provided as Appendix H to the Application. Included in that Appendix is Commission Order G-17-08 authorizing BC Hydro to establish the "PEI Regulatory Asset" for the purpose of deferring up to $8.2 million of PEI related expenditures incurred in F2008, plus interest. At Recital G of that order, the Commission stated, among other things, that "[a]s with capitalized costs, the PEI costs would be subject to a prudency review before being included in BC Hydro's rates."

In addressing the absence of a comprehensive business case to support the entirety of its expenditure, BC Hydro testified that the development of the project proceeded in a staged manner, "so that as BC Hydro developed its understanding of the potential benefits and costs of the project it had "off-ramps" it could avail itself of to minimize exposure to costs" (T9: 1422-1423). BC Hydro also provided a graphical description of the resulting change in its business processes in Undertaking No. 69 and a potential rate impact analysis of the PEI in Undertaking No. 71 (Exhibit B-78).

Based on the evidence it provided, BC Hydro submits that there is no basis to conclude that the PEI is imprudent (BC Hydro Argument, p. 159).

BC Hydro further submits that the fundamental reason for the proposal to defer and amortize PEI costs is to match its costs with the period in which its benefits will be realized, and that recovery of those costs should therefore commence with its start-up in F2012. BC Hydro also proposes to address the amortization period in its next RRA. BC Hydro also submits that if the PEI is not found to be imprudent, and if the accounting order is not granted, the planned expenditures of $19.6 and $3.7 million for F2009 and F2010 respectively would then be required to be recovered in the test period rates. Regarding its already deferred F2008 costs of $7.3 million, BC Hydro proposes, for administrative simplicity, that they be absorbed into the NHDA and amortized in accordance with the rate rider mechanism (BC Hydro Argument, pp. 159-160).

Intervenor Submissions

BCOAPO expects that the PEI costs will continue to accrue in the regulatory account until the PEI comes into service in F2012 when it will be subject to "a kind of prudency review when BC Hydro applies to have those monies recovered in rates,", and therefore it is premature for the

Commission to make a ruling on the prudency of these expenses. Accordingly, BCOAPO supports BC Hydro's application (BCOAPO Argument, p. 18).

The CEC also agrees with having the PEI expenses placed in a regulatory account and "accepts BC Hydro's proposal to consider the recovery of the costs at the time of completion of the project in 2012." It submits that the Commission should not rule on the prudence at this time as "all of the expenditures to be made have yet to be made" (CEC Argument, p. 113).

The JIESC submits that the business case presented by BC Hydro "has a number of flaws, principal among them its lack of alternatives" and that expected benefits may be difficult to achieve as they are based on "hopes for improved processes and redirection of some limited personnel time spread throughout the corporation." In its cross-examination of BC Hydro's witness, JIESC established that "net of the costs of hardware, software, and interest during construction, the PEI implementation costs were some $25 million" (JIESC Argument p. 44; T9: 1404-1407). Further, BC Hydro's witness confirmed that its basis for this cost was largely that of consolidation of its present procurement processes and training and education of its personnel, and that while the cost included the trainers, it did not include the cost for the time spent by the large number of personnel to be trained, and that no benefits could be expected from this broad cultural change program during the test period (T9: 1407-1409).

In response to a supplementary inquiry from the Commission Panel, BC Hydro provided a detailed breakdown of the $25 million in implementation costs, which contained some information as to the nature and extent of its non-project personnel's involvement in the implementation phase but did not include the requested person-days of time required to be spent by non-project personnel. The response made reference to some "1200 end-users being impacted" for which a training framework was provided, and as well to a "comprehensive change management program" being underway across all levels of the organization to build awareness and support for the initiative (Exhibit B-78, pp. 234-237).

The JIESC also points to BC Hydro's testimony that its business case did not demonstrate consideration of alternative incremental approaches to improving its purchasing processes, which could have been more cost effective. Further, JIESC submits that the metrics in the business case are ill-defined and not measurable, none of those in the business case are reduced to financial terms, and as well, the key benefits are "raised as objectives" and not reduced to financial terms (JIESC Argument, p. 44). In this regard, JIESC points to BC Hydro's witness' confirmation that its plan is to revisit the metrics described in the business case to determine success within 24 months of deployment, and that, in fact, part of the on-going PEI project is to develop the means to track the benefits (T9: 1428).

The JIESC further points to the productivity savings of $2.5 million per year in BC Hydro's business case and submits that this level of benefit on a 10 year project does not justify the cost, and further that any benefits are in any event based on "hopes for improved processes and redirection of some limited personnel time spread throughout the corporation but no quantifiable and measurable savings". In this regard it references BC Hydro's witness' acknowledgment of the dispersed nature of the benefits, and their effect as being to free up its personnel's time for other activities (JIESC Argument, pp. 44-45).

The JIESC submits that the PEI business case does not justify the expenditure and seeks an order, in this proceeding, disallowing the costs (JIESC Argument, p. 7).

As a matter of principle, JIESC submits that the Commission should direct BC Hydro to include a credible cost-benefit analysis with "defined and financially quantified metrics for goals and performance measurement following implementation in all future business cases" (JIESC Argument, p. 45).

In reply, BC Hydro submits that "the rebuttable presumption having been raised by BC Hydro evidence that the PEI is meant to allow BC Hydro to reduce the costs of the supplies it acquired to provide service, the evidentiary burden shifts to those who would say the project is imprudent".

BC Hydro further submits that "the evidence cited by the JIESC fails to meet that test" (BC Hydro Reply, pp. 63-65).

In view of its importance and materiality, certain aspects of this matter were canvassed in the Oral Argument Phase pursuant to item 5 of Exhibit A-26.

BC Hydro stated that the lateness, and extent, of the supplementary evidence it filed was, in its view, sufficient to temper its initial request to have the prudency of its decisions in respect of the PEI determined in this proceeding (T15: 2852).

BCOAPO and the CEC argued that the matter was best to be examined when BC Hydro applied for recovery of its deferred costs when the benefits were to start to be realized. The JIESC took the position that, while its preference was to settle the matter in this proceeding, it had no fundamental opposition to the position of the other Intervenors. No party expressed any concern with regard to any intergenerational equity considerations arising from delaying a determination as to the recoverability of costs by BC Hydro to as late as F2012 (T15: 2848-2854).

BC Hydro made no submissions in reply.

Commission Determination

At the outset, the Commission Panel notes that BC Hydro has established no linkage between its PEI initiative and the key matter of reliability.

In respect of BC Hydro's claim to having a rebuttable presumption of prudency in respect of its decisions to proceed with the PEI initiative, if in fact such a claim were upheld, the Commission Panel finds that the evidentiary record is more than sufficient for its rebuttal.

The Commission Panel gives particular weight to the fact that the business case for this major initiative does not identify quantifiable savings to justify its cost, and as well, that the evidentiary record is not clear as to the full cost of its implementation - which BC Hydro acknowledges as requiring investment of significant, but un-quantified amounts of its non-project personnel's time to accomplish the necessary "cultural change" across the organization. **Accordingly, the Commission Panel directs BC Hydro to segregate all of the incurred-to-date and forecast direct and indirect costs related to the PEI, including those proposed to be recovered in rates in the test period (such as the cost of the office of the CPO), and inclusive of the capital component, in the existing approved regulatory account until such time as BC Hydro applies for recovery of those costs. Further, BC Hydro is directed to segregate to that existing regulatory account its planned expenditures for the test period including not only the costs of the office of the CPO, but also its best estimate of the cost of its non-project personnel's time involved in implementation of the PEI, and to highlight the quantum of that latter cost in that application.**

The Commission Panel notes BC Hydro's submissions to the effect that neither will the benefits of the initiative be quantifiable, nor the metrics to assess them be available until the PEI is operational after the test period. **In order that any future determination as to the reasonableness of BC Hydro's decisions in this matter can be made and the costs thereof allocated by the Commission, the Commission Panel further directs BC Hydro to include in any application to recover its costs as then accumulated in the existing regulatory account, the financial and any other quantifiable benefits related to the PEI, including the performance metrics for future monitoring of the project benefits.**

5.5 New Regulatory Accounts

5.5.1 Capital Project Investigation Costs

BC Hydro requests approval to establish a new regulatory account for capital project investigation costs to formalize its past practice of capitalizing investigation costs. Historically, BC Hydro has accounted for capital project investigation costs as part of property, plant and equipment, and depreciated these costs in accordance with the depreciation rates approved by the Commission. BC Hydro proposes that the balances in the Capital Project Investigation ("CPI") Cost regulatory account be amortized over 40 years, which represents the weighted average life of generation projects excluding dams (Exhibit B-1, p. 6-16; Exhibit B-5, BCUC 1.86.5).

BC Hydro states that based on its analysis of forecast spending, the estimated CPI costs for F2009 and F2010 are $14.6 million and $8.6 million, respectively, which compares to a forecast of $14.8 million for F2008 (Exhibit B-1, Appendix A, Schedule 2.2, p. 6).

BC Hydro confirmed its understanding that both FortisBC and Terasen Gas account for Preliminary and Investigative capital project charges as deferred charges in accordance with the BCUC Uniform System of Accounts Prescribed for Electric Utilities - Account No. 183. It further confirmed that if, as a result of the investigative work, a plant is acquired or constructed, this account is credited and the appropriate utility plant account is charged and that the practice of these two utilities would appear to conform to GAAP for Rate Regulated Entities (Exhibit B-5, BCUC 1.86.2).

BC Hydro testified that with its growing number of capital projects, CPI costs are becoming more significant and that from a GAAP perspective these costs are more in the nature of an operating cost (T4: 638-639). BC Hydro further testified that CPI costs are preliminary investigation costs, which could lead into a decision about a capital project "of which there are multiple decisions, multiple types of projects to which you would relate it to." BC Hydro also testified that each CPI cost will be tracked separately and that therefore BC Hydro will have the ability to make appropriate adjustments to the balance in the regulatory account should a capital asset be sold or retired (T7: 1111).

BC Hydro further stated that both its current and proposed forms of presentations are acceptable under Canadian GAAP. BC Hydro stated that to ensure consistency, it is now presenting capital project investigation costs as regulatory assets as opposed to including the balance within capital, similar to how DSM costs are presented (Exhibit B-5, BCUC 1.86.1).

BC Hydro submits that should the Commission not approve the establishment of this new regulatory account, the forecast CPI costs for the test period should be included in the forecast of current operating costs for F2009 and F2010 (BC Hydro Argument, p. 161).

BCOAPO supports BC Hydro's proposal to include CPI costs in a regulatory account, and to amortize the balances in the account over 40 years (BCOAPO Argument, p. 18).

The CEC submits that these expenditures are made to produce benefits over many years and that therefore they should not be treated as operating costs. CEC further submits that it accepts BC Hydro's interpretation of GAAP and supports a regulatory account, but that each capital project investigation cost should be amortized over the same time period as the associated capital project (CEC Argument, pp. 113-114).

In reply, BC Hydro submits that, given the relatively small amounts of CPI costs vis-à-vis its total capital expenditures, it is appropriate to apply a composite 40-year amortization period to all CPI costs rather than amortizing them individually (BC Hydro Reply, p. 66).

Commission Determination

The Commission Panel accepts BC Hydro's interpretation of the GAAP treatment of CPI costs as operating expenses and notes the difficulty BC Hydro appears to be having in assigning these costs to specific future capital projects. The Commission Panel also notes while that the proposed change in presentation will not have a material impact on BC Hydro's revenue requirements, it nonetheless raises concerns with treating what are essentially operating costs in a capital- like manner. **Accordingly, the Commission Panel allows BC Hydro to include CPI costs in a regulatory account only for the test period, and directs BC Hydro to provide a detailed analysis of actual F2009 and actual/projected F2010 CPI costs in its next RRA. To amortize the account balance, BC Hydro is to indicate which amounts can be assigned to a capital project while the remaining amounts will require justification for the necessary write-offs as operating expenses. BC Hydro's proposal for the amortization of the CPI account balance over 40 years is denied.**

5.5.2 Finance Costs

BC Hydro formally amended its application to propose deferral treatment in relation to finance charges and non-current PEB costs (Exhibit B-64, pp. 5-6).

This section deals with the finance charges aspect of the OEU, and should be read with reference to Sections 4.6.2 and 4.6.3 of this Decision.

BC Hydro requests approval for a new deferral mechanism that would defer the difference between the forecast and actual weighted average cost of debt ("WACD") for F2009 and F2010 applied to the forecast mid year net debt for each fiscal year (Exhibit B-77, BCUC 4.208). BC Hydro submits that the financial crisis continues to unfold and that governments are expected to take further extraordinary measures to mitigate the impact of the crisis but that "it is not clear, whether such measures will translate into reductions to short-term interest rates for commercial borrowers that will be sustained through the test period." However, BC Hydro submits that it should continue to bear the risk associated with foreign exchange rate variances related to the interest on the US$ debt as well as the volume of debt, and that therefore these risks are not covered by the proposed deferral treatment (BC Hydro Argument, pp. 162-163).

Specifically, BC Hydro proposes the establishment of the WACD Regulatory Account, to defer differences between forecast and actual WACD applied to forecast mid-year net debt in F2009 and F2010, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year. BC Hydro further proposes that the disposition of any balances in this new regulatory account and the issue of whether it should continue beyond the current test period be addressed in the next RRA (BC Hydro Argument, p. 165).

<u>Intervenor Submissions</u>

BCOAPO supports BC Hydro's proposal only for F2009 and F2010 in recognition of current, unique circumstances and because it is somewhat unclear whether BC Hydro is seeking temporary or permanent deferral treatment in relation to WACD (BCOAPO Argument, p. 19).

The CEC supports BC Hydro's deferral proposal (CEC Argument, p. 64).

JIESC submits that "there can no longer be any doubt that an interest deferral account is absolutely required to ensure fair and reasonable rates". JIESC further submits that the interest rate deferral account should include variations in finance charges arising from variations in both interest rates and debt levels. By way of explanation, the JIESC submits that timing of the substantial capital projects forecast by BC Hydro is subject to many forces that are beyond BC Hydro's control and that Special Directions only require it to "recover the interest costs on its debt", no less and no more (JIESC Argument, pp. 26-28).

In reply, BC Hydro expresses its intention to bring forward a proposal in its F2011 RRA for continuation or termination of the deferral treatment "as circumstances warrant."

BC Hydro also submits that it has greater ability to forecast and control debt levels compared to interest rates and that it should bear the risk associated with debt levels (BC Hydro Reply, p. 69).

Commission Determination

The Commission Panel finds that, given the volatility and uncertainty of the current economic circumstances it is appropriate to establish a regulatory account in relation to the WACD for F2009 and F2010. Having reached this determination, the Commission Panel is further persuaded by submissions of the JIESC and Alan Wait that BC Hydro's proposal provides only a partial solution to the volatility in interest rates and that the impact of changes in financing requirements and swap arrangements should also be included in the deferral treatment in order to ensure complete coverage of the variability. **The Commission Panel approves BC Hydro's proposal, in principle, and further directs that it also encompass deferral of the difference between the forecast and actual incurred interest expense, including the difference between the forecast and actual swap income as reported in "Other Income" for F2009 and F2010.**

5.5.3 School Taxes and Grants-In-Lieu

BC Hydro requests that a regulatory account be established to collect differences between actual and forecast school taxes and grants-in-lieu during F2009 and F2010, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year. BC Hydro further proposes that the disposition of any balance in this regulatory account be addressed in a future RRA, since amortization is not proposed to commence in the current test period.

As noted in Section 4.5, the forecast taxes are $167 million and $177 million for F2009 and F2010 respectively. BC Hydro explains that these forecasts include amounts related to a pending review of the valuation of the distribution system by the B.C. Assessment Authority, which has not taken place since the mid-'80s, and submits that because the valuation is not complete, there could be a material difference between forecast and actual taxes during the RRA test period (Exhibit B-1, p. 6-16; T10: 1668).

BC Hydro submits that disposition of any balance in this regulatory account be addressed in a future RRA, since amortization is not proposed to commence in the current test period (BC Hydro Argument, p. 167).

Both BCOAPO and the CEC submit that they support BC Hydro's proposal (BCOAPO Argument, p. 19; CEC Argument, pp. 63, 97, 116). The JIESC supports BC Hydro's proposal but notes that this is a regulatory account that could be phased out in future (JIESC Argument, p. 29). BC Hydro agrees with the JIESC that this regulatory account could be phased out after the completion of the review of the valuation of the distribution system (BC Hydro Reply, p. 70).

Commission Determination

The Commission Panel approves BC Hydro's proposed regulatory account to collect differences between actual and forecast taxes during F2009 and F2010, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year. This account is to be phased out after the completion of the review of the valuation of BC Hydro's distribution system.

5.5.4 Future Storm Damage

BC Hydro requests approval to defer the incremental costs incurred to restore service to customers when major storms occur in the future, and to transfer approved deferred costs plus interest to the NHDA.

BC Hydro states that for budgeting and regulatory account purposes, it considers a single weather-related event to be a major storm if the operating costs associated with restoring power to customers exceed $2 million and the storm meets one or more of the following criteria:

- more than 100,000 customers are simultaneously without power;
- the event is province-wide or encompasses a large geographic region; or
- the restoration period is greater than two days, or additional resources from outside the affected region are required.

By way of justification, BC Hydro notes that major storms are non-controllable, extraordinary events and that emergency restoration costs related to major storms are significantly less controllable than they are for service disruptions caused by minor storms or other events. BC Hydro further states that the $2 million threshold "stems from BC Hydro's conviction that it should assume financial accountability for all normal, controllable business risks and recover through regulatory accounts expenditures made in respect of infrequent, uncontrollable risks" (Exhibit B-1, pp. 6-16 to 6-19).

BC Hydro submits that if deferral treatment were not available for restoration costs for major storms, BC Hydro would have to include a provision or contingency in its operating budgets knowing that in most years the provision would not be fully required but that in some years, such as F2007, it would be inadequate. BC Hydro further submits that to be given a reasonable opportunity to earn its allowed return, budget provisions would need to be equal to the average actual restoration costs for major storms over a reasonable period of time (BC Hydro Argument, p. 168).

BC Hydro further submits that it is appropriate to account for this deferral as part of the NHDA since the NHDA provides for significant unplanned major distribution capital costs related to single event equipment or infrastructure failure. In addition, BC Hydro submits that this deferral allows for recovery though the proposed rate rider mechanism (BC Hydro Argument, p. 169).

Both BCOAPO and the CEC submit that they support BC Hydro's proposal to establish a regulatory account. However, the CEC submits that such costs should be captured in a separate regulatory account rather than in the NHDA (BCOAPO Argument, p. 19, CEC Argument, pp. 116-117). BC Hydro's reply in respect to disaggregation of accounts from the NHDA was already addressed in Section 5.4.2.

Commission Determination

The Commission Panel finds that the evidentiary record supports, in principle, BC Hydro's approach to dealing with storm related restoration costs through a regulatory account. That notwithstanding, the Commission Panel finds that BC Hydro's approach to budgeting and deferral of these costs is not satisfactory, as it could lead to circumstances where, in a year with only one "major storm", as defined, an otherwise un-utilized portion of its base budget could be recovered unjustifiably through rates**. The Commission Panel therefore directs BC Hydro to include in its base OMA for the test period average storm-related restoration costs in 2009 dollars for F2009, and 2010 dollars for F2010, respectively, to be calculated as the average of actual costs for the five most**

recent "normal weather" years: e.g. F2003, F2004, F2005, F2006, and F2008 would be used for F2009; and to record any variance from the average amount for each test year in a separate regulatory account ("the Storm Damage Regulatory Account") to be dealt with in its next RRA.

5.5.5 F2010 Non-Current Post Employment Benefit Costs

As described in Section 4.4.3.2 of this Decision, BC Hydro is applying for a new deferral mechanism that would defer differences between forecast and actual F2010 non-current pension costs.

Specifically, BC Hydro proposes the establishment of the Non-Current Pension Regulatory Account, to defer differences between GAAP compliant forecast and actual non-current pension costs in F2010 and that the disposition of any balances and a possible continuation of the deferral treatment be addressed in its next RRA.

Intervenor Submissions

BCOAPO submits that it supports deferral of the difference between forecast and actual GAAP non-current pension costs for F2010 but that it "would strongly oppose any suggestion that this cost be permanently treated as deferrable" (BCOAPO Argument, p. 19).

The CEC also supports a deferral treatment for non-current pension costs but seeks further variances form the treatment required by GAAP as described in Section 4.4.3.3 (CEC Argument, pp. 64-65, 115-116).

The JIESC submits that if a regulatory account is approved for non-current pension costs for the test period, it should have an opening credit balance of $25.3 million to ensure that the F2008 change in costs is treated in a manner consistent with the treatment being sought for F2009 and F2010 (JIESC Argument, p. 32).

In reply, BC Hydro characterizes the JIESC proposal as being "clearly retroactive ratemaking and confiscatory," noting that "except where the Commission has approved deferral treatment, differences between forecast and actual costs accrue to the shareholder until such time as rates become subject to an interim order." Accordingly, BC Hydro submits that "there is no basis in law to make the requested initial balance anything other than zero" (BC Hydro Reply, p. 67).

BC Hydro further submits that no Intervenor opposes BC Hydro's request for approval to defer the F2010 forecast variance for non-current pension costs (BC Hydro Reply, p. 68).

Commission Determination

The Commission Panel accepts BC Hydro's position and approves the Non-Current Pension regulatory account to defer differences between forecast and actual non-current pension costs in F2010.

5.5.6 DSM Reconciliation Account

In Section 4.10.1, the Commission Panel has accepted BC Hydro's proposal to establish a deferral account for the DSM reconciliation after receipt of the 2008 LTAP Decision.

5.5.7 Amortization

As described at Section 4.6.1.2 of this Decision, the Commission Panel determined that the most effective solution to ensuring that amortization charges collected in revenue requirements for the test period appropriately reflect the capital assets that are actually utilized for the benefit of ratepayers during the same test period is to establish a new regulatory account. **Therefore, the Commission Panel allows a deferral of the difference between the forecast and actual amortization expenses resulting from any variances between forecast and actual capital additions and directs that a regulatory account be established for this purpose.**

5.5.8 GMS 3 Regulatory Account

As described in Section 4.3.1 of this Decision, BC Hydro is directed to segregate all of the incurred-to-date and future direct and indirect costs related to the failure of G.M. Shrum Unit 3. **Accordingly, BC Hydro is directed to establish a new regulatory account called the 'GMS3 RA' for this purpose.**

5.5.9 Employment Cost Regulatory Account

As described in Section 4.4.5 of this Decision, BC Hydro is directed to segregate to a regulatory account any variance from its planned total net employment costs in OMA for the test years. **Accordingly, BC Hydro is directed to establish an Employment Cost Regulatory Account.**

5.6 Other Regulatory Accounts – CEC Submissions

The CEC comments extensively in regard to the structure and operation of BC Hydro's existing regulatory accounts, and BC Hydro's proposals for new such accounts, and makes requests in both of those respects as well as proposals for new regulatory accounts (CEC Argument, pp. 46-72 and 100-118).

The CEC agrees with BC Hydro that there are three situations in which regulatory accounts are desirable and supports the establishing of regulatory accounts for those reasons. The CEC also agrees with the criteria BC Hydro proposes to assess whether a risk of a cost variance is controllable or non-controllable for the purposes of transferring the risk to ratepayers. Further, the CEC agrees that there should be no limit on the use of deferral accounts so long as the deferral is for the appropriate reasons (CEC Argument, pp. 108-109).

The CEC supports some of the BC Hydro proposals for regulatory accounts, either wholly or in part (e.g. Site C and Major Storm Damage), and rejects others (excess revenue to be included in NHDA). It suggests amendments to certain of the proposed accounts (e.g. Capital Investigation Costs) and in other cases requests that new regulatory accounts be established (e.g. variances with respect to the use of overtime) (CEC Argument, pp. 112-114, 45-55,47).

In this Section, the Commission Panel comments on some of the CEC submissions on regulatory accounts. Where it does not comment on others, it is because the CEC has accepted the BC Hydro proposal, or the Commission Panel has addressed the submission elsewhere in this Decision or has concluded that there is insufficient evidence to justify the Commission Panel accepting the proposal or request made by the CEC.

(i) Water Inflow Variability

In the CEC's submission, "the most significant issue affecting the HDA and NHDA deferral accounts is water inflow variability and the prices for energy purchases or sales." It submits that variability in water inflows will smooth over a time period materially longer than the four-year time frame of BC Hydro's amortization proposal for the Deferral Accounts, requests that the Commission Panel set the amortization period at ten years (CEC Argument pp. 56-60,111-112).

The Commission Panel has addressed the matter of water level variability at section 4.3.4 of this Decision. Concerning the CEC's specific request for relief in terms of amending the amortization period of the HDA and NHDA, BC Hydro refers to the 10 year amortization proposal at pages 60-61 of its Reply Argument and appears to reject the 10 year amortization period based on the absence of evidence. **Despite the absence of any reply on this issue, the Commission Panel agrees that the evidence before it is insufficient to justify the request for a ten year amortization period.**

(ii) BC Hydro Initiatives not Proposed for Regulatory Account Treatment

The CEC listed BC Hydro's Initiatives for which it has not identified regulatory accounts in the following table.

CEC Table 1

Initiatives		
$ in millions	F2009	F2010
Labour Strategies	$4.8	$7.1
Buildings Properties	$6.0	$9.0
Asset Security	$1.1	$6.0
First Nations	$5.7	$7.2
NERC Compliance	$1.2	$0.9
Burrard	$3.2	$3.9
Civil Maintenance	$3.5	$5.5
General Asset Maintenance	$3.4	$4.1
Asset Security	$1.1	$6.0
Capital Process	$1.8	$0.3
Outage Communication	$2.0	$1.6
RCE	$0.5	$1.5
System Hardening	$4.8	$5.8
Auto-splice Replacement	$1.5	$8.0
Total	$40.5	$61.9

Source: CEC Argument, p. 66;
Exhibit B-64, Understanding 76 spreadsheet, Schedule 5

In the CEC's view "these initiatives represent significant efforts to generate benefits for customers in the future" and should be included in regulatory accounts to enable allocation of their costs to the future when customers will realize the benefits. In addition, the CEC proposes that the initiatives should not attract interest in the test period and should not be amortized for the test period, but that BC Hydro should be ordered to determine appropriate amortization periods for the initiatives and seek approval for them in its next RRA (CEC Argument, pp. 65-66, 70).

In reply, BC Hydro specifically references the Labour Strategies and the First Nations initiatives. On the Labour Strategies Initiative, it comments that the initiative addresses current period training, development, and recruitment costs, and is an on-going initiative. Further, BC Hydro submits that its First Nations Initiative does not include recovery of the costs of any negotiations or settlements with First Nations, that it has only to do with current matters, and is also an on-going initiative.

In its reply to First Nations cost matters as raised by the JIESC, BC Hydro had confirmed that future First Nations settlement costs will be the subject of case by case applications.

BC Hydro also submits that none of the other Initiatives warrant deferral on the basis of better matching of costs and benefits to ratepayers, and that it would be particularly unfair to future ratepayers if none of the costs were recovered in the test period as proposed by the CEC (BC Hydro Reply, pp.71-74).

The Commission Panel finds that the evidence before it is insufficient to justify the relief requested by the CEC.

(iii) Overhead Capitalization

The CEC proposes that the Commission Panel order BC Hydro to capitalize overheads to the specific regulatory accounts with capital project-like traits, that the overhead for "unknown event" types of regulatory accounts be determined at the time of the making of the expenditure, that BC Hydro be required to complete the table [which follows] for SMI costs and any others, as applicable, as part of its compliance filing and further, that BC Hydro be required to make a compliance filing with a more appropriate overhead rate if it has one, or use the same rate as is used for capital projects (CEC Argument, p.72).

The CEC provided the following table:

CEC Table 2

$ in millions	Additions	
Regulatory Account	F2009	F2010
Site C	17.5	14.6
SMI		
PEI	18.5	2.0
FOBI		
Storm Restoration		
Unplanned Maint.		
Capital Project Invst	14.6	8.6
Initiatives	40.5	61.9
Total	90.6	87.1

Source: CEC Argument, p. 71
Exhibit B64, Understanding 76 spreadsheet, Schedule 2.2

In reply, BC Hydro submits that it does defer overheads associated with regulatory accounts where "it is appropriate to do so," and cites DSM, Site C, and CPI as examples. Further, BC Hydro submits that with respect to the PEI, no similar overheads are incurred "because of the nature of that initiative." In summary, BC Hydro submits "that there are no overheads associated with any regulatory accounts that are not already being appropriately deferred" (BC Hydro Reply, p. 74).

The Commission Panel finds that the evidence before it is insufficient to justify the relief requested by the CEC.

5.7 Baseline Forecasts for Deferral and Other Regulatory Accounts

BC Hydro submits that for deferral and other regulatory account purposes it requires, and seeks, the Commission determinations of the following specific baseline forecasts:

Table 5.2
Baseline Forecasts for Deferral and Other Regulatory Accounts

($ million)	F2009 Oct 17 Update No Refund	F2010 Oct 17 Update No Refund
Heritage Payment Obligation (variances captured in HDA)	409.7	445.1
Non-Heritage COE Subject to Deferral (variances captured in NHDA)	628.0	688.5
Trade Income (variances captured in TIDA)	190.0	154.8
BCTC Costs (variances captured in BCTCDA)		
Transmission Asset Maintenance Fee	90.9	92.4
GRTA Asset Management Fee	8.3	8.2
SDA Asset Management Fee	15.0	14.7
Net NITS and PTP Charges	43.3	37.6
External PTP Revenues	(8.4)	(8.3)
Revenues (variances captured in NHDA)	2,933.4	3,143.7
Interest Rates		
Weighted Average Cost of Debt	6.22%	6.06%
Mid-Year Net Debt	8,070.0	9,142.5
Non-Current Pension Cost (Income)	N/A	(51.4)

Source: BC Hydro Argument, p. 185

BC Hydro further submits that it has addressed certain inconsistencies noted by Intervenors between the above table and the OEU in its Reply Argument and that "BC Hydro always intended to update the baseline forecasts for the deferral and other regulatory accounts as part of its compliance filing with respect to the F009/F2010 RRA" (BC Hydro Reply, p. 71).

Commission Determination

The Commission Panel directs BC Hydro to update Table 5.2 in its compliance filing.

6.0 OTHER ISSUES

6.1 Gas Hedging

BC Hydro seeks Commission approval to re-commence hedging in natural gas in order to provide ratepayers with additional protection from rate volatility. It currently engages in hedging of electricity alone and sees little value in hedging one commodity only (Exhibit B-1, p. 3-20).

The JIESC "accepts that hedging can decrease volatility depending on the term of amortization of cost of energy variances but submits that hedging also comes at a cost to customers. Accordingly, JIESC asks the Commission to order BC Hydro to discontinue future hedging of both natural gas and electricity" (JIESC Argument, p. 24).

The CEC reviewed the evidence as to BC Hydro's hedging experience over the past 5 years and noted "a distinct bias toward incurring a cost to obtain the hedge positions" (CEC Argument, p. 25). "The CEC submits that the use of deferral accounts with a ten year amortization period is as effective with less cost and risk to ratepayers than the BC Hydro hedging proposal" (CEC Argument, p. 28).

The BCOAPO also "sees little to no value" in the Commission allowing BC Hydro to re-commence natural gas hedging activities in the current market (BCOAPO Argument, p. 20).

BC Hydro argues in reply "that the appropriate course of action would be for the Commission to either (i) relieve BC Hydro from its commitment to not engage in natural gas hedging, or (ii) confirm that it is not in the interests of BC Hydro ratepayers to engage in electricity hedging but not engage in natural gas hedging" (BC Hydro Reply, p. 79).

Commission Determination

The Commission Panel notes the comments of the JIESC, CEC and BCOAPO, as well as the comments of BC Hydro that it sees little value in hedging one commodity only. **Based on the evidence before it, the Commission Panel is not prepared to grant BC Hydro the relief it requests from its commitment to abstain from hedging in natural gas at this time. The Commission Panel finds that there is insufficient evidence to make a determination on part (ii) of BC Hydro's request for relief.**

6.2 Capital Plan

The Commission Panel invited argument on, amongst other things, how the capital projects included in BC Hydro's Application should be dealt with, particularly in light of the amendment to the *UCA* effective May 1, 2008 which repealed subsection 45(6.1). That section required public utilities to file capital expenditure plans with the Commission.

BC Hydro submits that the repeal of subsection 45(6.1) is basically irrelevant as it included the list of capital projects in its Application as a compliance filing only, in order to satisfy its obligations pursuant to the F2007/F2008 RRA NSA. It submits that it otherwise sought no relief in this proceeding with respect to its capital plan (BC Hydro Argument, p. 173).

BC Hydro had similarly agreed, as part of the F2007/F2008 RRA NSA, to file "Major Threshold Project" applications for capital projects with gross costs exceeding $50.0 million, pursuant to subsection 45(6.2)(b) of the *UCA* (Exhibit B-1, p. 5-3). Subsection 45(6.2)(b) was also repealed effective May 1, 2008. BC Hydro submits that, as the Application indicates, there are no plans to proceed with any new, unapproved capital projects with a cost exceeding $50.0 million, such that the issue concerning future capital plan reviews can be addressed in the LTAP proceeding.

BCOAPO argues that "[a] review of a Revenue Requirement Application cannot take place in a vacuum: it must include some consideration of future capital spending because a revenue requirement includes depreciation and financing costs for assets projected to come into service in the bridge and test years. If BC Hydro is to justify those [as yet unapproved] costs it is absolutely necessary for the Commission Panel to have information before it that can be used to measure the reasonableness of the capital additions associated with those costs" (BCOAPO Argument, p. 20).

BCOAPO states that it "is not suggesting that the RRA process is needed to "approve" a capital plan, but rather that it must logically be part of the record…" BCOAPO notes the significant potential for overlap as among various types of applications such as CPCNs, LTAPs and RRAs. BCOAPO is of the view that it would be unrealistic and potentially unwieldy to defer all capital projects to LTAP applications. BCOAPO takes the position that "if there is a need to review capital projects not traditionally viewed as relevant to long-term planning and acquisitions, then they should be included in the RRA whenever possible. At a minimum, the RRA is an opportunity to look at the cost and consequences – both good and bad – for each project to determine if they are reasonable" (BCOAPO Argument, pp. 20-21). BCOAPO does note, however, the importance of CPCN applications which involve "specific consideration of and approval for the proposed spending" (BCOAPO Argument, p. 20).

The JIESC expresses concern over the number of different processes used for review of capital expenditures. The JIESC is of the view that there is "a very real connection between decisions on capital expenditures and other activities and expenditures" and submits that, in BC Hydro's case, this connection has been broken. The JIESC suggests changes to the current process to consolidate approval of revenue requirements, current capital expenditures and the LTAP into one application. The JIESC further submits that major projects which do not involve long life physical plant and fall below the $50.0 million review threshold should be reviewed in advance of any significant expenditures, using a cost threshold of $10.0 million (JIESC Argument, p. 46-47).

Terasen supports BC Hydro's suggestion that it address the issue of future capital plan reviews in the 2008 LTAP proceeding, as do the IPPBC (Terasen Argument, p. 7; IPPBC Argument, p. 23).

The CEC submits that the *UCA*, as amended, allows the Commission to make determinations about projects which might require a CPCN in an LTAP hearing. It is also of the view that the scope of an RRA hearing is broad enough to encompass any expenditure, capital or otherwise, that might affect the rates being set. It agrees with BC Hydro that, as there is no capital approval requested in the instant RRA hearing, there is nothing to defer to the LTAP.

The CEC also submits that, apart from annual compliance filings relating to planned construction and extensions to facilities, there is no obligation on a utility to file capital plans. It therefore states that it is "not certain that the Commission can require information on other capital plans…other than in regard to rates in an RRA hearing." The CEC states that it "does not believe there [is] much choice other than to deal with the implications of these capital plans in the RRA hearings, but also observes that while "[t]he Commission can, in an RRA hearing, require information on just about anything it considers relevant to setting the rates for the period in question", if there is no revenue requirements impact on the period in question, the review could be quite limited.

The CEC agrees with BC Hydro's suggestion that the capital review process can be addressed in the LTAP proceeding (CEC Argument, pp. 133-136).

In reply, BC Hydro reiterates its position that "Intervenor and Commission questions and concerns are more properly dealt with in the LTAP (BC Hydro Reply, p. 79).

Commission Determination

The Commission Panel finds that the capital plan included in the Application is relevant to BC Hydro's Revenue Requirements as there are implications for rates arising from the related financing charges and depreciation expense. The Commission Panel notes that the capital review process pursuant to the *Act* contemplates that those matters will be addressed in the context of an LTAP proceeding. **Accordingly, the Commission Panel recommends BC Hydro to include in its next RRA the revenue requirement implications arising from planned capital expenditures during the test period, and also asks that those implications be clearly set out for each such capital item.**

6.3 Service Level Agreements with BCTC

BC Hydro provides various services, including engineering and field services to BCTC, for a fee, pursuant to contracts. BC Hydro seeks approval in the RRA of the cost of providing the services.

No Intervenor took issue with the approvals sought.

Commission Determination

The Commission approves the estimated costs for BC Hydro's provision of services as filed.

6.4 Risk Sharing between BC Hydro and Its Ratepayers and Insurance

<u>6.4.1 Risk Sharing</u>

The matter of risk sharing between BC Hydro and its ratepayers arose in several contexts in the course of the proceeding, in many cases related to uncertainty in BC Hydro's forecasts arising from recent increases in economic uncertainty and volatility. In order to better understand the parties' positions, the Panel Chair invited submissions in argument pursuant to items 1(a) and 1(b) of Exhibit A-24 as to the appropriate approach between BC Hydro and its ratepayers for material events, including controllable and uncontrollable events.

BC Hydro notes that there was some overlap between these matters and the principles regarding the establishment of regulatory accounts to capture the differences between forecast and actual costs, making reference to the G.M. Shrum failure, and major storm events. BC Hydro submits that the approach taken by the Commission ought to consider the prospective and after-the-fact bases, the role of prudency, and its controllability of the cost category (BC Hydro Argument, pp. 175-176).

BC Hydro submits that on a prospective basis, customers should either bear the risks through a regulatory account or they should pay amounts in rates that on average, over time, allow the utility to earn its allowed ROE, noting by way of example that ratepayer risk could be mitigated by insurance premiums being included in a utility's revenue requirements. On an after-the-fact basis, BC Hydro argues that the consideration is primarily factual, i.e., whether rates that were in place at the time of the event included an allowance to transfer risk from ratepayers to the shareholder, either through contingencies or a "risk premium," and that to the extent that the risks were not so transferred, they belong to the ratepayers. BC Hydro notes an exception, in that "[it] does not believe its ratepayers should bear the risk of utility imprudence, regardless of risk considerations" (BC Hydro Argument, pp. 176-177).

With respect to the controllability of events, BC Hydro submits that "an event should be considered non-controllable if, despite prudent (objectively reasonable) decisions it cannot be prevented,", and cites storms, market price and currency fluctuations, and failures resulting from unknown (and unknowable) equipment design flaws – such as the G.M. Shrum failure – as examples. BC Hydro takes the position that "the extent to which the cost consequences of non-controllable events should be deferred and recovered later from ratepayers should turn on the extent to which the cost consequences were similarly uncontrollable" (BC Hydro Argument, p. 177).

The JIESC submits that the responsibility for controllable events such as major breakdowns (e.g. the G.M. Shrum failure) must rest with BC Hydro and its shareholder where the cause of the major breakdown or the extent of the damage was preventable with due-diligence and prudent management. In other circumstances, the JIESC believes that ratepayers should be at risk for uncontrollable costs resulting from uncontrollable events where those events are material and the related expenditures are truly incremental, and cites storm outages, interest rates and currency and load volatility as examples. The JIESC submits that deferral thresholds should not be viewed on an account by account, or event by event, basis but should, to the extent possible, be grouped together in logical arrangements and assigned significance thresholds before any transfer of costs is made to a deferral account, and that, once a threshold has been exceeded for a particular group, only the costs in excess of the threshold in that account or grouping should be permitted for recovery from, or credit to ratepayers (JIESC Argument, pp. 8-9).

BCOAPO submits that "[It] does not accept that the question whether events are controllable or non-controllable should be the major determinant as to whether costs are recoverable from customers on either a forecast (rate setting) or prospective (regulatory account) basis." BCOAPO notes that if BC Hydro fails to avoid a controllable event it "would likely be a relevant circumstance for the prudency equation,", and further that "on the other hand, it may be imprudent to avoid the cost of avoiding all (or most) controllable events" (BCOAPO Argument, p. 21).

The CEC takes a similar position to that of BCOAPO, submitting that "it does not believe that just because there is an element of control that BC Hydro exercises with respect to given events that it should be held liable for the costs …", and that "the test has been, and should continue to be one of prudency." Further, the CEC submits that "if there is a stringent and post event responsibility for potentially controllable events BC Hydro will adopt such a costly and inappropriate level of caution, with such a cost as to outweigh the benefits in avoided costs" (CEC Argument, p. 121).

IPPBC states that "[it] is very concerned about determining which aspects of BC Hydro's business are "controllable" and which are "uncontrollable", but submits that "as a publicly owned utility the ratepayers and taxpayers are one and the same so no particular purpose is achieved by devising a risk sharing arrangement between BC Hydro and its ratepayers, including IPPs who, through the indexation of water rentals, have a substantial interest in the outcome" (IPPBC Argument, p. 21).

Terasen expresses its agreement with BC Hydro's submissions, that uncontrollable events of a material nature and variations from forecast in important parameters should in general be the risk of ratepayers. Terasen refers, in particular, to Section 61(4) of *the Act* as supporting the view that uncontrollable costs are a ratepayer risk as it "permits "flow-through" applications for changes in energy supply costs, expenses or taxes "over which the utility has no effective control." Terasen notes that an alternative approach to flowing through such costs is to defer and amortize the costs, but in either approach the costs of the uncontrollable item or event accrues to the ratepayers (Terasen Argument, p. 1-2).

No other Intervenor made submissions in this matter.

In reply, BC Hydro states that "[It] did not believe that its submissions are materially at odds with Intervenors' …," noting only one exception which "arises from the comment of the IPPBC … that because BC Hydro is a crown corporation, that "ratepayers and taxpayers are one and the same." In that regard, BC Hydro submits that "[IPPBC's] view of the matter serves to undermine and is inconsistent with the purpose of the Commission, which fundamentally is to balance the interests of ratepayers and (monopoly public service providers such as BC Hydro" (BC Hydro Reply, p. 80).

In light of the submissions received, the Commission Panel sought further submissions from the parties in Oral Argument Phase pursuant to item 7 of Exhibit A-26, as to whether the ratepayers' views suggested an attitudinal shift from the traditional regulatory paradigm that "a utility is entitled to the opportunity to earn its allowed rate of return on equity" towards a model wherein" BC Hydro is to be given, but not to exceed its allowed rate of return on equity."

BC Hydro submits that should there be such a shift in regulatory paradigm, it would be inappropriate to take that approach in setting BC Hydro's rates and use of deferral accounts. BC Hydro cites section 4 of HC2 as directing the Commission to "set rates for BC Hydro that allow BC Hydro to collect sufficient revenue in each fiscal year to enable BC Hydro to achieve its allowed rate of return" and submits that section 4 of HC2 is "not a guarantee that BC Hydro will be allowed or be able to achieve its allowed rate of return. It said it must be in a position to do so" (T16: 2889-2890).

BCOAPO submits that it does not support the notion of a "paradigm shift" and says that " what utilities including BC Hydro are entitled to, subject to the *Act,* is an opportunity to earn their allowed rate of return, and - - however that should not be read as an opportunity to earn at least the utility's allowed return. That is, it does not entail a right to an opportunity to exceed the allowed return and earn more than a reasonable rate of return. And the appropriate remedy, in most instances, if they were over-earning, would be an adjustment in subsequent years." BCOAPO further submits that "A general approach which eliminates all utility risk, for example, through excessive use of deferral accounts, would eliminate one of the most powerful incentives for any utility to manage its affairs efficiently and prudently" (T16: 2893-2894).

The JIESC also does not support the notion of a "paradigm shift". Subject to a "solid review" any time that a deferral account is put in place, JIESC supports the deferral account practice for significant items beyond the control of the utility which are subject to significant fluctuation, and states that it strongly opposes deferral accounts for controllable items, in most cases, noting that its support in this proceeding for certain deferral account items which have traditionally been controllable is based on "a belief that in the current environment they're neither controllable or foreseeable" (T16: 2910-2911).

The CEC, with reference to its Argument, clarifies that its submissions in support of a more extensive use of deferral accounts in this proceeding "was not intended to be a fundamental shift in terms of how we, as ratepayers, look at the regulation of BC Hydro or its entitlement to pursue an approved rate of return.", but rather "[we] are just trying to give the Commission the benefit of a perspective which we hope may assist in mitigating rate impact" (T16: 2920-2922).

IPPBC distinguishes BC Hydro from other utilities regulated by the Commission by reference to the decision of the BC Court of Appeal in *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996), 36 Admin L.R. (2d) 249; 20 BCLR (3d) 106 (C.A.) (BC Hydro Book of Authorities, Tab 3), where, at page three [para. 6] that Court said:

> "A further distinction between BC Hydro and investor-owned utilities is that BC Hydro's sole 'shareholder' and not its directors determines when and in what amounts 'dividends' will be paid."

IPPBC submits that "[BC Hydro's] shareholder wants its return, it's said so, and BC Hydro should be given an opportunity to earn its return. And certainly that's the position of IPPBC, is that all has to be taken into account in terms of the balancing [act that the Commission has to do under the legislation]" (T16: 2925-2926).

With reference to its Argument, IPPBC states its position in respect of deferral accounts as " but for the two that are required by law, you shouldn't be using deferral accounts, because they're removing management from reality", and further, that if "this Commission is going to go beyond the two required by law, then IPPBC's view is --- "[m]ake sure you clear those balances in a hurry, because you never know what's coming, --" and , ultimately, "you may end up in a situation where you've got a large deferred liability on your books that the next generation is going to have to take care of" (T16: 2926-2927).

Terasen noted that PBR or other regulatory models that make use of formulas or other non-traditional means of setting rates were now a statutorily authorized departure from the "traditional paradigm" pursuant to subsection 60(1)(b). Terasen took issue with the BCOAPO's submission, as phrased by Terasen, that "… if rates were set on a forecast basis, to have the utility earn something more than its allowed return [then] those rates would not be just and reasonable," and submits that subsection 59(5) of the *Act* says that rates are unjust or unreasonable if the rate is (a) more than a fair and reasonable charge for the service and (b) if the rate is insufficient to yield a fair and reasonable return", and that in Terasen's view, subsection 59(5) "establishes a band within which rates can be just and reasonable." Terasen further submitted that "nothing in the legislation or in common law … prescribes such a model for BC Hydro or for other utilities [where the utility is to be given but not to exceed its return on equity]", and that in any event, it would be opposed to such a model (T16: 2928-2932).

In reply, BC Hydro submits that deferral accounts are an appropriate means to deal with volatility, and should be considered on their own merits. Further, in the case of cost items where there is no symmetry of risk, i.e. where the forecast cost is zero, the deferral account just captures reality. For issues where there is a larger degree of expected symmetry BC Hydro's position is that there can be some variance, "but one would expect it and hope it would average out over a period of time." With respect to the opportunity to earn a rate of return on equity and no more, with reference to its Argument (pp. 19-20), BC Hydro reaffirmed "the desire of [its] shareholder to recover only that return on equity that BC Hydro is given a reasonable opportunity to earn" and further, that "[i]ts shareholder does not have a particular interest in receiving the potential benefits of PBR , meaning higher than allowed return, potentially" (T16: 2934-2936).

Commission Determination

The Commission Panel makes no specific determinations in respect of the matter of risk sharing between BC Hydro and its ratepayers. The Commission Panel appreciates the extent and relevance of the submissions made by the parties, and finds the review of these matters to be of assistance in informing its determinations in this Decision.

6.4.2 Insurance

As described at section 4.3.1 of this Decision, BC Hydro's approach to insurance coverage as a vehicle to mitigate risks arose during a discussion with the Commission Panel in the G.M. Shrum failure matter, in the course of which BC Hydro disclosed that it carried coverage, with a $5.0 million deductible against boiler and machinery failure, but carried no coverage in respect ancillary losses such as Business Interruption ("BI"). Given BC Hydro's description of the health and condition of its generating assets as canvassed by IPPBC, and, in particular, its acknowledgment of the risks associated certain of those aging assets "being held together with tape and twine, essentially, until we get the thing replaced", the Commission Panel invited further submissions in argument as to whether, and if so what, if any, changes should be contemplated in BC Hydro's approach to insurance coverage (T13: 2223-2335; Exhibit A-24, items 1.1.1, 1.1.2).

By way of further context, pursuant to an inquiry from the Commission Panel, BC Hydro summarized its current insurance coverages in Exhibit B-83. BC Hydro stated that "[it] had concluded that BI coverage was not economical or appropriate as a risk management product, and noted that neither Quebec Hydro nor Manitoba Hydro carried such coverage." As well, BC Hydro clarified that "[it"] did not have property insurance to cover overhead transmission and distribution poles and wires as capacity for this insurance is very limited and it is very expensive. As a result no major electric transmission utility in Canada has [such] coverage."

In Argument BC Hydro refers to Exhibit B-83, and submits that if such BI and property insurance were available, and assuming the risk of loss is a ratepayer loss, the premiums for such coverage would be included in its revenue requirements. BC Hydro submits that its current approach results in lower rates overall because of the high premium costs that would have to be built into rates, and, as well, the uncertainty of BI coverage (BC Hydro Argument, p. 178).

BC Hydro noted that it could carry such insurance if and where available, and include the premiums in revenue requirements. Ratepayers would then, to the extent of the insurance coverage, be protected from the unplanned costs, at the expense of paying the premiums. BC Hydro states that, "if ratepayers and the Commission are interested in further consideration of a different approach to these particular coverages, or more generally, BC Hydro could report on the matter in its next [RRA]" (BC Hydro Argument, p. 179).

The JIESC submits that one of the benefits of external insurance coverage is that insurers often require plant inspections and risk assessments when covering heavy machinery/outage repair costs. JIESC notes its concern with the possible cost of insurance as described in Exhibit B-83 and accordingly recommends the Commission direct BC Hydro to review its existing insurance coverage and the appropriateness of broadening that coverage (JIESC Argument, pp. 9-10).

BCOAPO submits that "... the Commission has no jurisdiction to order BC Hydro to change its insurance arrangements in any way. [Its] only purchase-point on this question is in determining whether, in its view, the utility has imprudently under-insured (or alternatively over-insured) against a risk or set of risks", and that "[in] the absence of adequate evidence [to make the foregoing determination(s)] the commission really has nothing to say about the issue" (BCOAPO Argument, p. 222).

The CEC submits that "BC Hydro's customer base represents a very large pool for risks of outage and that BC Hydro in effect provides the insurance function by spreading out the costs to all customers", and further, that "adding a further layer of commercial insurance on top of this process would not be cost effective …" (CEC Argument, p. 126).

IPPBC submits that "before making any decisions on whether it would be appropriate for BC Hydro to broaden its [insurance] coverage, BCH would have to file a complete insurance coverage report as part of its next rate application" (IPPBC Argument, p. 21).

Terasen notes BC Hydro's "testimony" to the effect that such types of insurance are not cost effective and submits that there is no evidence to suggest that that conclusion is incorrect in this case. Terasen also submits that the decision to insure or not to insure should be based on cost effectiveness; that both the costs of acquired insurance and self-insurance are normal operating costs; and that a similar standard of prudency should be applied to the nature and breadth of insurance coverage, as well as to the decision to self insure, as is applied to other utility expenditures (Terasen Argument, p. 3).

Commission Determination

The Commission Panel notes that the submissions from the parties in respect of its inquiry as to the risk sharing aspects of self insurance costs and deductibles are generally consistent with those given by the commenting parties in response to risk sharing matters as described at Section 6.4.1 above.

The Commission Panel is concerned as to the lack of transparency and disclosure regarding BC Hydro's insurance coverages and the degree to which ratepayers may be unreasonably exposed to otherwise insurable risks. The Commission Panel expressly rejects the notion advanced by the CEC that "BC Hydro's customer base represents a large pool for risks …" as, taken to the extreme, that would result in BC Hydro carrying no insurance coverage."

To enable BC Hydro's insurance coverage to be better understood by its customers and the Commission, the Commission Panel directs BC Hydro to file as part of its next RRA a comprehensive cost/benefit analysis of its insurance coverages over the five years précising the first fiscal year of that RRA. The analysis is to include non-forecast losses in areas for which BC Hydro "self insures" incurred in those five years by event and functional circumstance, and to include its best estimate of what the cost benefit circumstances in respect of those losses would have been had coverage been in place. As well, the analysis is to provide BC Hydro's proposal for the test period covered in its next RRA, including any changes it proposes in its insurance coverages and the justification for them.

6.5 Reporting

6.5.1 International Financial Reporting Standards

In April 2008, the Canadian Accounting Standards Board published its omnibus Exposure Draft, *Adopting IFRS in Canada*, confirming the mandatory transition date to IFRS for publicly accountable enterprises for fiscal years beginning on or after January 1, 2011.

With regards to its conversion to IFRS BC Hydro states, in part:

> "The conversion to IFRS will result in significant changes to BC Hydro's accounting policies; internal, external, and regulatory reporting; and IT systems. IFRS will ultimately result in pervasive changes to financial processes and procedures, and influence the interpretation of information produced for financial decision making and performance assessment.
>
> BC Hydro has commenced work on developing a project charter and detailed project plan. The project plan will provide a detailed conversion timeline, highlighting significant milestones to enable tracking project deliverables. IFRS will be effective commencing in BC Hydro's F2012 reporting period. However, as comparative figures on both a quarterly and annual basis will be required for F2011, it is planned that a substantial amount of the conversion work effort will be completed by the end of F2010 to allow for the capture of financial results in F2011 on both a Canadian GAAP and IFRS basis.
>
> BC Hydro has already completed a comparison of significant differences between IFRS and Canadian GAAP. These differences have been applied to identify specific areas of significant impact for BC Hydro. Detailed work continues to refine the analysis to identify impacted areas and the corresponding changes that will be required to policies, procedures and systems. BC Hydro anticipates that opportunities to incorporate operational efficiencies within existing processes may be identified as part of the planning process.
>
> Work will also be required to ensure that IFRS changes are properly reflected in financial metrics, business policies, and the Special Directions and accounting orders that comprise BC Hydro's regulatory framework. The potential need for alternate reporting mechanisms for regulatory purposes is also being explored.
>
> Consultation with stakeholders will be a critical piece of the IFRS implementation activities. BC Hydro anticipates discussions with key external stakeholders such as the BCUC and the Province will be required to ensure impacts are communicated and strategies are developed and implemented to ensure a smooth transition."
>
> (Exhibit B-5-1, BCUC 1.119.1)

Additionally, during the hearing BC Hydro testified that it was working with other utilities in Canada, the CEA, and its external accountants on how to move forward with international standards (T4: 625-626; T7: 1119).

No Intervenors commented on this matter.

Commission Determination

The Commission Panel recognizes that the conversion to IFRS may impact financial metrics, accounting policies, business policies, Special Directions and accounting orders which impact the Commission's regulation of BC Hydro. Of particular concern are changes to accounting or business policies that impact the rate making process by way of changes to recovery in rates, differences between the regulated financial schedules and the financial statements, or the creation of regulatory deferral accounts that alter the revenue stream.

The Commission Panel directs BC Hydro to provide within four months of the date of this Decision a report on the IFRS project and its progress to date. The report should include the project charter, a detailed project plan, a consultation plan with stakeholders, any potential changes to business or accounting policies, any unresolved issues, a summary of the present accounting policies under Canadian GAAP that conform to IFRS, a listing and rationale for all anticipated accounting policy changes, and a listing and explanation of accounting policy positions related to IFRS that are the same and/or divergent from other utilities under the Commission's jurisdiction or elsewhere in Canada. In particular, BC Hydro is also to include details of its plan to coordinate its approach with that of other BC resident utilities regulated by the Commission and its shareholder's requirements.

6.5.2 BCUC Uniform System of Accounts for Electric Utilities

The NSP agreement for BC Hydro's F07/ F08 revenue requirements contained Commitment 40, which states that:

> "BC Hydro will work with Commission staff to develop an Annual Report to the Commission that:

i. follows the BCUC Electric Utilities Annual Report form adapted for BC Hydro's unique circumstances;

ii. addresses reporting for plant and deferral accounts and how BC Hydro can report its OM&A in an informative and comparative format;

iii. will allow year-to-year comparisons of BC Hydro's actual and forecast financial information regardless of how BC Hydro is internally organized."

Commitment 41 of that agreement states that:

> "BC Hydro will issue a public report regarding the proposed new Annual Report, together with recommendations on implementation, to the Commission by December 31, 2007."

On December 21, 2007 BC Hydro filed a letter providing a status update on the development of the proposed Annual Report (Exhibit B-5-1, BCUC 1.98.1). The letter indicated that further work was required. On August 8, 2008 BC Hydro filed with the Commission its F2007 Annual Report to the Commission pursuant to Letter L-36-94 and L-14-95, and subsection 45(6) of the Utilities Commission Act (Exhibit A2-13). BC Hydro testified that it has made progress on Commitment 40 such as providing further information on plant assets and deferral accounts, but recognizes that operating costs is one area that needs further work (T7: 1092-1093).

BC Hydro's witness testified in an exchange with Commission Counsel:

> Mr. Wong: A: "In light of the fact that B.C. Hydro is moving towards international financial reporting standards, and obviously needs to develop codes or accounts to manage to do that, we are in the process of developing a system to allow us to match our activities to the code of accounts represented by the BCUC uniform system of accounts. We see this as being, as I said, a multi-year project that we are working towards, trying to do it in an integrated fashion so that we can ultimately report out as the needs required but by doing it in a productive and efficient manner.

> MR. FULTON: Q: So then, taking it from that, Mr. Wong, do you then see that 2012 then, when the IFRS reporting standards come into play, as being the appropriate time for B.C. Hydro to complete its modification of its financial information system and reporting requirements so that it would then be able to implement the BCUC system of -- uniform system of accounts?
>
> MR. WONG: A: That is correct. We are hoping to be able to do it earlier, but it all is dependent upon us achieving the changes that we require. So, as you know, we have a project underway right now looking at those international accounting standards. Obviously the earlier we get it done the earlier we can be able to report out on that. But fiscal 2012 is the date that we absolutely need to make sure this happens."
>
> (T7: 1088-1089)

The JIESC submits that the Commission must order BC Hydro to comply with the Commission's Uniform System of Accounts for Electric Utilities ("USoA") for BCUC reporting and applications. The JIESC prefers an earlier deadline than the 2012 implementation date indicated by BC Hydro (JIESC Argument, p. 45).

BC Hydro, in its Reply, submits that the work that is already underway should be allowed to continue and that the Commission should not establish an arbitrary deadline by which it should be completed (BC Hydro Reply, p. 82).

The Act, at section 49 (Accounts and Reports) states:

> "The commission may, by order, require every public utility to do one or more of the following:
>
> (a) keep the records and accounts of the conduct of the utility's business that the commission may specify, and for public utilities of the same class, adopt a uniform system of accounting specified by the commission;
>
> (b) provide, at the times and in the form and manner the commission specifies, a detailed report of finances and operations, verified as specified;"

Commission Determination

The Commission Panel notes that BC Hydro is moving to implement the BCUC USoA. The Commission Panel believes that a consistent and standard reporting methodology that does not change from year to year is highly desirable for all stakeholders. The ability to have reported information in a particular year that is comparable without modification to any other year assists in establishing a historical financial record that is transparent, comparable, and consistent. The Commission Panel notes that back-casting information based on a future year format and thus requiring changing prior reported information to make it consistent is both time-consuming and costly.

The Commission Panel further notes that the reporting structure of the BCUC USoA is applicable to both the utility's Annual Report to the Commission and the financial information in revenue requirements applications. The actual financial results in the Annual Reports should provide consistent historical information that is directly relevant and comparable to the financial information presented in revenue requirement applications. An informative Annual Report should provide information that includes explanatory variance analysis, significant changes or events, supporting regulatory schedules, cross-referencing, and reconciliation from the financial statements to the regulatory schedules.

The Commission Panel accepts that BC Hydro is working with Commission staff on developing an informative Annual Report, but is concerned as to the rate of progress.

The Commission Panel directs BC Hydro to adopt the BCUC USoA by no later than the F2012 reporting year. If certain plant accounts already in place cannot be coded to the proper BCUC account, BC Hydro is to make an application for an exemption for these historical amounts. All plant additions commencing as of the date of this Decision should have the ability to be recorded and reported to the appropriate BCUC account codes. BC Hydro may be able to adopt the USoA **earlier** and it is encouraged to do so. **The Commission Panel further directs that if BC Hydro is to**

re-platform to a replacement financial system this replacement financial system is to fully incorporate the BCUC USoA.

The Commission Panel further directs BC Hydro to submit an Action Plan within three months of the date of this Decision. The Action Plan should provide the timeline and milestones on how BC Hydro plans to implement the USoA and to develop the new Annual Report for the F2012 reporting year. BC Hydro is required to provide annual progress reports until the plan is fully implemented, which include updates on incorporation of any new financial information system BC Hydro may be considering.

For clarity, the Commission Panel directs that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the USoA. The first filed revenue RRA that follows the USoA should also include parallel financial information that transitions from the previous reporting style used in the prior filed RRA.

6.6 Deemed Equity – OIC No. 028

OIC No. 028 amends HC2 to include the concept of "deemed equity". This concept basically requires a calculation of equity which results in an average equity component of 30 percent. OIC No. 028 also changed the definition of "equity" to accord with GAAP, which was not the case in the past. The GAAP definition of equity resulted in the removal of certain items, such as CIAC, which were previously specifically included in the definition of equity.

Certain Intervenors raised concerns regarding the calculation of deemed equity at 30 percent when historic actual equity levels have been less than 20 percent.

Alan Wait argues that "[t]he 30% deemed equity provision in HC2, which allows for double costing on about 10% of the capital structure, is totally inconsistent with the Cost Based Regulation the BCUC applies to privately owned utilities. This amounts to an over charge $70 million plus per year [sic], and growing each year" (Wait Argument, pp. 7-8).

BCOAPO also notes that “these regulations (particularly OIC 028) result in Hydro’s customers being charged an equity cost on any deemed equity in excess of BC Hydro’s actual equity and therefore they are paying for it twice.” The BCOAPO asks the Commission to identify this anomaly in its decision.

BC Hydro notes that the government did not seek the advice of the Commission on this particular issue, or on a number of other issues relating to the statutory regime under which the Commission and BC Hydro operate and suggests that the Commission should decline to comment (BC Hydro Reply, p. 13).

Commission Determination

The Commission finds that HC2 as amended by OIC No. 028 dated January 17, 2008 is clear in its direction as to the calculation of BC Hydro’s “deemed equity” and accordingly makes no determinations in this matter.

7.0 SUMMARY CONSIDERATION OF BC HYDRO'S REVENUE REQUIREMENTS

Determining the appropriate amount for BC Hydro's overall revenue requirements, particularly the Operating Cost elements, has presented a highly challenging task for the Commission Panel in setting "just and reasonable" rates for BC Hydro within the requirements of the statutory framework, and specifically in the balancing of the matters set forth in subsection 60(1)(b) of the *Act.*

In Section 2.1.1, the Commission Panel discussed the statutory framework of the Application and referred to the parties' submissions on *Hemlock Valley* and *BC Electric Railway* and their application to the Commission Panel's exercise of its rate setting jurisdiction in the context of the Application. In Section 2.1.2, the Commission Panel determined that its rate setting powers were not limited in the manner suggested by BC Hydro, relying on certain passages cited by the BCOAPO and Terasen from those two cases.

Accordingly, the Commission Panel is of the view that it has considerable discretion in its review of the Revenue Requirements costs forecast in the Application, but remains mindful that in setting rates for BC Hydro, it must do so in a manner that meets the requirements of the *Act* and HC2.

The Commission Panel notes that, in the aggregate, the determinations that have resulted from its review of the Application to this point have had little impact on the quantum of BC Hydro's revenue requirements as applied for. The preponderance of those determinations have had the effect of mitigating uncertainties and instability in the environment BC Hydro faces in the test period, or of deferring to future periods the costs of certain of BC Hydro's management decisions that remain in contention.

In accordance with its determinations at Section 2 of this Decision, the Commission Panel has considered its obligations under sections 59 and 60 of the *Act*, and in particular the need to balance the matters described in subsection 60(1)(b). The Commission Panel finds that the rates that would result from its approval of BC Hydro's Application, as amended by its other Determinations, would not comply with subsection 60(1)(b)(i) inasmuch as the requirements of subsection 60(1)(b)(iii) would not have been met.

In reaching this conclusion, the Commission Panel has considered BC Hydro's witnesses' testimony to the effect that there is an active culture of "cost consciousness" at BC Hydro, and that its owner has an active interest in seeing that electricity rates in BC remain "competitive". The Commission Panel does not find that evidence persuasive, as it is generally unsupported by tangible evidence from BC Hydro of measures to achieve, or metrics to establish dollar denominated, or otherwise quantifiable, improvements in BC Hydro's efficiency, costs of service, or performance. The only substantive program specifically tabled by BC Hydro that it represented as meeting these criteria was the PEI initiative, and that program has been found, at section 5.4.3 of this Decision, to be demonstrably lacking in respect of both tangible cost reductions and efficiency metrics, and accordingly directed its costs to be deferred to a future proceeding for a determination as to their reasonableness and recovery, if any, by BC Hydro. In the main, BC Hydro's responses to inquiries framed in the context of quantitative evidence of adverse trends in its cost performance were qualitative in nature, making reference to the need for parties to consider its reasons for the increasing costs, yet providing few specifics in support of those reasons.

Pursuant to subsection 60(1)(b.1), the Commission Panel finds that, in all of the circumstances, in order to also give effect to subsection 60(1)(b)(iii), it is appropriate that BC Hydro find within its Proposed Operating Costs, improvements and efficiencies equivalent to 3.0% of the annual value applied-for. At Table 4-1 of its Application, BC Hydro documents its Proposed Operating Costs, which, inclusive of fixed-term initiatives, total some $610 million for F2009, and $649 million for F2010. The Commission Panel recognizes that these costs will be amended by its prior determinations in this Decision, and that the final interim rates resulting will be established in BC Hydro's compliance filing.

The Commission Panel further recognizes that the bulk of F2009 is past, and BC Hydro has little if any opportunity to further influence its expenditures for that fiscal year, but notes that BC Hydro has ample opportunity to constructively influence its programs and spending for F2010.

Accordingly, in order to achieve balance amongst the matters in subsection (60)(1)(b) the Commission Panel directs BC Hydro to establish rates for F2010 in its compliance filing that reflect its Operating Costs for that year, as described above by reference above to Table 4-1, at 97 percent of those applied-for, after taking into account the impact of the Commission Panel's prior determinations in this Decision on that value of $649 million.

The Commission Panel finds that the rates that will result are not in conflict with the requirements of subsection 60(1)(b)(i), in that the quantum of the resulting revenue requirement disallowance for F2010 will be less than some $20 million out of the total Operating Costs, inclusive of initiatives, of some $649 million for that year, and that BC Hydro has ample discretion within which to find improvements in its costs and efficiencies in its execution of its programs and operating activities, and accordingly is fairly compensated for the service it provides and is not denied the opportunity to earn a reasonable return on its equity. In this regard, the Commission Panel gives particular weight to the testimony of BC Hydro's CEO in the course of an exchange with CEC concerning the impact on ratepayers of BC Hydro's steeply increasing costs – a concern raised by all ratepayer groups:

> " … my hope would be that the Commission would make judgments as appropriate, and would leave BC Hydro to manage the results of those judgments. In other words, the Commission would be making statements about the amount of revenue requirement that would be allowed, and that would - - it would be left to BC Hydro to decide what was the best way to carry out that instruction" (T3: 382).

8.0 ROE ADJUSTMENT REGULATORY ACCOUNT – OIC NO. 074

On February 17, 2009 the B.C. Government issued OIC No. 074 amending sections 4 and 7 of HC2, effective February 17, 2009. OIC No. 074 is attached as Appendix 3 to this Decision.

The relevant sections now read as follows:

Basis for establishing authority revenue requirements

4 Subject to section 7, in regulating and setting rates for the authority, the commission must ensure that those rates allow the authority to collect sufficient revenue in each fiscal year to enable the authority to

(a) provide reliable electricity service,

(b) meet all of its debt service, tax and other financial obligations, despite the inclusion of debt in deemed equity,

(c) comply with government policy directives, including, without limitation, government policy directives requiring the authority to construct, operate or extend a plant or system, and

(d) achieve an annual rate of return on deemed equity

(i) for the authority's fiscal years 2009-2010, 2010-2011 and 2011-2012, that is equal to the sum of the following two percentages:

(A) pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act;*

(B) 1.63%, and

(ii) for any other fiscal year of the authority, that is equal to the preincome tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the Utilities Commission Act.

Deferral accounts

7 When regulating and setting rates for the authority, the commission:

(a) must allow the authority to establish one or more accounts to reflect and record variances between

(i) the heritage payment obligation and the authority's forecast of the heritage payment obligation, and

(ii) the trade income and the authority's forecast of trade income,

(b) may allow the authority to establish one or more other deferral accounts for other purposes, and

(c) must set or regulate the authority's rates in such a way as to allow the deferral accounts to be cleared from time to time and within a reasonable period of time, and

(d) for the authority's 2009-2010 fiscal year, must allow the authority to establish an account to defer for recovery in a later fiscal year or years the difference between the revenue required under section 4 as it read before it was amended effective February 17, 2009, and the revenue required under that section as it reads after that date.

The effect of OIC No. 074 is twofold. Firstly, it requires the Commission to increase BC Hydro's revenue requirements for F2010, F2011, and F2012 in order to afford BC Hydro to the opportunity to earn its previously determined pre-income tax annual return on equity plus an additional 1.63 percent.

Secondly, the Commission is required to allow the BC Hydro to establish a deferral account for F2010 to defer for recovery in a later fiscal year or years the difference between the revenue required under section 4 pre-February 17, 2009, and the revenue now required under that section.

Positions of the Parties

In its letter dated February 20, 2009, BC Hydro notes that the evidentiary phase of the F09/F10 has been closed for over two months and that it presumes, in light of the impending end to F2009, that a Commission decision is imminent and that it would be unfortunate if the Commission unnecessarily paused at this juncture to consider these amendments. BC Hydro points out that "the calculation of the rate of return on deemed equity under the amendments is straightforward and in any event could be reviewed when BC Hydro seeks to recover the balance in the required regulatory account." Further, BC Hydro submits that it "will include a proposal to recover the balance in the new regulatory account in its next revenue requirements application".

Specifically, BC Hydro seeks approval to establish a new ROE Adjustment regulatory Account to defer the impact on BC Hydro's F2010 revenue requirement of the incremental rate of return on deemed equity prescribed in OIC No. 074, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year.

In its letter dated February 24, 2009, the JIESC submits that it is inappropriate to set up a deferral account to accumulate the additional revenue from its customers during F2010 that BC Hydro will be seeking to later recover from them without also recording, in a deferral account, the cost savings that BC Hydro has publicly stated it intends to implement in order to offset the impacts of the increase in its return on equity. The JIESC further submits that if it's suggested regulatory treatment is not considered appropriate, then "the Commission must reopen the F2010 revenue requirement hearing to obtain evidence on what cost reduction and mitigation measures BC Hydro should be taking in response to OIC 074 and should then adjust the F2010 revenue requirement accordingly."

In its letter of the same date, BCOAPO registers its "strong concurrence" with the position of the JIESC.

On February 26, 2009, the Commission provided any other Intervenor wishing to comment an opportunity to do so by noon on March 2, 2009. BC Hydro was asked to reply by noon March 3, 2009.

On March 2, 2009, the CEC responded by letter, outlining a number of scenarios in relation to the pending F2009/F2010 RRA Decision to explain its position. First, if the Commission leaves the rates as interim and allows for a process for adjusting them the Commission can set its own rules. Second, "if the Commission fixes the rates then there may be different scenarios based on the nature of the decision…". Should the Commission endorse BC Hydro's position, the CEC submits, then the Commission should establish a complementary deferral account as recommended by the JIESC.

However, if the Commission endorses parts of the customers' positions in terms of cost reductions (as opposed to a requirement for deferral of costs that have future benefits), the CEC expresses some concern about "impacts on supply, reliability, safety, security, conservation and environmental impacts" if BC Hydro were to be looking for further cost reductions in response to the HC2 amendments. Finally, the CEC submits that unless the Commission in its Decision directs BC Hydro to defer costs that have future benefits, then "it will be left to BC Hydro to apply to the Commission for such an account or for the Commission to accept the JIESC letter as grounds for conducting a process leading to establishing such an account."

By letter dated March 3, 2009, the JIESC supplemented its earlier submissions with references to statements by BC Hydro's CEO in a letter to the Times Colonist newspaper in Victoria to reinforce its position in respect of BC Hydro's public commitment to offset the impact of OIC No. 074 by way of cost savings and efficiencies.

By letter dated March 3, 2009, BCOAPO referenced the above letter filed by the JIESC and states:

> "While this development could potentially call for a re-opening of the Revenue Requirement proceeding, we agree with JIESC that a far more efficient alternative, which could adequately address our clients' concerns, would be the modification of the proposed deferral account to capture BC Hydro's cost savings and efficiencies. We also ask that BC Hydro clarify the extent to which its resolve to absorb the impact of the Amendments will continue throughout the three-year duration of the government's increased return on equity."

By email dated March 3, 2009, Mr. Alan Wait expressed complete agreement with the JIESC submission of the same date.

In reply, by letter dated March 3, 2009, BC Hydro first refers to the CEC comments and confirms that its letter of February 20, 2009 asks for a Commission approval of the ROE Adjustment Account. BC Hydro then states that "the JIESC submissions are founded on a misunderstanding of statements made by BC Hydro regarding its plans to review operating costs with a specific view to offsetting the increased return on equity." By way of explanation, BC Hydro confirms that its F2010 operating budgets continue to be the subject of the F2009/F2010 RRA and that it has no plans, at this time, to reduce its F2010 OMA in response to the increased ROE because it will have to respond first to any Commission determinations regarding BC Hydro's cost structures in its F2009/F2010 RRA decision. With regard to planning for F2011, BC Hydro notes that it "will develop its detailed budgets in order to mitigate the effect on rates of the increased return on equity consistent with reliable, safe service over the long-term, and in light of the F09/F10 decision." BC Hydro attaches to this letter its recent 2009/10-2011/12 Service Plan as referred to by the JIESC, which includes financial forecasts at page 27 supporting BC Hydro's explanation.

In summary, BC Hydro submits that "whether or not the BCUC establishes the requested operating cost deferral account, its balance at the end of F2010 will be zero" and "that in these circumstances there is little point in directing its establishment." Therefore, BC Hydro submits that the JIESC request for the regulatory treatment or, in the alternative, for the reopening of the F2010 revenue requirement hearing should be dismissed.

Commission Determination

The Commission Panel has reviewed submissions of BC Hydro and Intervenors on this matter and has reached the following conclusions:

Pursuant to subsection 3(2) of the *UCA* the Commission Panel is required to comply with government directions such as OIC No. 074. OIC No. 074 specifically directs the Commission to allow BC Hydro to establish an account to defer for recovery in a later fiscal year(s) the effect of the HC2 amendment on its revenue requirements for F2010.

The Commission Panel notes that the deferral account aspect of OIC No. 074 only affects F2010 and is persuaded by BC Hydro's reply that the operating cost deferral account requested by the JIESC is not required at this time.

The Commission Panel authorizes BC Hydro to establish the ROE Adjustment Regulatory Account to defer the impact on BC Hydro's F2010 revenue requirement of the incremental rate of return on deemed equity as prescribed by HC2 as amended by OIC No. 074.

As OIC No. 074 is silent regarding the interest bearing aspect of BC Hydro's application dated February 20, 2009 the Commission Panel will not address that issue. That matter, along with any other concerns raised by Intervenors for future years can be canvassed in BC Hydro's next RRA or when BC Hydro applies for recovery of the deferred amount for F2010.

The Commission Panel notes that with this mechanism in place, OIC No. 074 has no bearing on any other determinations in this Decision.

9.0 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.

British Columbia Hydro and Power Authority

	Directive	**Page**
1.	The Commission Panel finds that its rate setting powers are not limited in the manner suggested by BC Hydro.	30
2.	The Commission Panel makes its determinations in this Decision based on the evidence and submissions before it, in a manner consistent with the overall scheme of the *Act* and HC2.	30
3.	The Commission Panel determines that in the case of reviewing the cost consequences of BC Hydro's past management decisions a rebuttable presumption of prudency is relevant, and that the two-part test arising from the *Enbridge Gas* and *ATCO 2005* decisions applies. In its review of BC Hydro's planned and forecast expenditures for the test period the Commission Panel finds that, as suggested by Terasen, BC Hydro's presumption of prudency has little, if any, relevance to the matters reviewed, and accordingly makes its determinations in this Decision based on the evidence before it in a manner consistent with the overall scheme of the *Act* and HC2	38
4.	BC Hydro is requested to report on any progress towards a formalized safety management program in its next RRA.	49
5.	With respect to reliability, BC Hydro is requested to report on its progress regarding implementation of management systems for quality that are compatible with ISO and other quality management standards in its next RRA.	53
6.	BC Hydro is directed to transparently and quantifiably link, in dollar amounts, its planned expenditures to the maintenance of and/or improvement in, its supply and distribution reliability measures and to justify those measures and expenditures in its next RRA.	53
7.	The Commission Panel accepts BC Hydro's proposal to defer the net impact of load forecasts as described and for reasons given at Section 5.2.2 of this Decision, BC Hydro's load forecast of October 17, 2008 is approved, as there should be no material impact on customers due to variance from that forecast.	63

8.	The Commission Panel requests that BC Hydro initiate discussions with the Province with a view to increasing the cap on trade income beyond the current $200 million limit, or, in the alternative, removing both the cap and the floor that currently limit the ratepayers' participation in Powerex's performance, and to report to the Commission as to the progress and outcome of those discussions on a regular basis.	68
9.	The Commission Panel finds that allocating a portion of corporate overhead to Powerex is reasonable, and is consistent with past practice. The Commission Panel therefore directs BC Hydro to continue the corporate allocation charge to Powerex in the amount of $4.3 million per year for the test years, being the average of the allocations for F07 and F08. The Commission Panel also clarifies that the $199 million forecast for Powerex net income is net of that $4.3 million corporate allocation.	70
10.	Subject to modification by the Commission Panel's determinations elsewhere in the areas of challenge identified by BC Hydro, BC Hydro's forecast of domestic energy costs is approved.	74
11.	Given the seriousness and materiality of the GMS Unit 3 failure, BC Hydro is directed to segregate all of the incurred-to-date and future direct and indirect costs of the outage and repair, inclusive of the impact on its cost of energy, in a separate regulatory account ("the GMS3 RA"), and to apply, at its discretion, to the Commission for recovery of those costs at such time as all of the costs are known and can be appropriately allocated by the Commission. At such time BC Hydro is expected to include in its application the studies and reports which recommended the installation of the safeguards, and its reasons for not responding constructively to them, in order that a determination as to the reasonableness of its management's decisions at that time can be made.	79
12.	The Commission Panel accepts that load curtailment costs are an integral part of the cost of energy and the costs should be included in the HPO.	87
13.	The Commission Panel directs BC Hydro to file with its next RRA a comparison of the economic impacts in terms of its annual costs and deferral account balances with and without the CEC proposal in respect of the use of average water levels in place for the eight years preceding and the forecasts for the test years covered by that RRA.	91
14.	For its next RRA, BC Hydro is directed to submit its OMA forecast on a line item basis for each business unit, consistent with the system of accounts it employs to hold its managers accountable for budgetary performance, with a four year history for each expenditure category. Further, it is to quantifiably and transparently link the planned levels of expenditures to its key influences, key cost drivers, and objectives.	98

15.	In consideration of the non-current pension cost, the Commission Panel finds that the evidence is sufficient to warrant a deferral mechanism to remove that source of volatility from BC Hydro's revenue requirements for the remainder of the test period, i.e., for F2010.	109
16.	For its next RRA BC Hydro is directed to provide documentation, covering a five year actual history and the next test period as to what the planned and actual expenditures would be under these combined non-current pension cost funding scenarios, and, assuming a deferral mechanism had been in place for the five year reference period, what the closing balances would be for each of the years.	109
17.	To ensure that the subject of corporate donations will be further reviewed, the Commission Panel directs BC Hydro to provide a specific and more fulsome justification of the linkage between its donation program and its key influences, key cost drivers and objectives in its next RRA if it intends to continue to request that 100 percent of corporate donations be included in its revenue requirement, rather than having the costs shared between its shareholder and ratepayers.	113
18.	The Commission Panel finds that BC Hydro has not explored alternatives to further expanding its call handling capacity, which is not a key area in terms of safety or reliability and accordingly, disallows the OCI-related amounts of $2.0 million in F2009 and $1.9 million in F2010 in BC Hydro's revenue requirements.	118
19.	To find a balance in accommodating BC Hydro's challenges while ensuring that the ratepayers will not be burdened by unnecessary labour costs or exposed to over-collection by BC Hydro should its planned total expenditures on employee compensation not materialize, the Commission Panel directs BC Hydro to segregate to a regulatory account any variance from its planned total net employment costs in OMA for the test years (the Employment Cost Regulatory Account), with the balance in that account at the end of F2010 to be dealt with in its next RRA.	131
20.	For greater clarity, the Commission Panel directs BC Hydro to include overtime paid in its calculation of total net employment costs as directed above.	131
21.	In light of its concerns in respect of BC Hydro's growth in permanent employment, the Commission Panel also directs BC Hydro to submit a comprehensive Resourcing Strategies Plan, addressing FTEs, headcounts, Vacancy Rates, part-time staff & contractors, status of retirement uptake, overtime statistics by business group for all non-executive personnel categories, and to provide four years of actual data supporting projections for the test period in its next RRA. The report should clearly address the linkage of employment growth to and between base operating and capital expenditure related activities, as well as to reliability matters in particular.	131

22.	The Commission Panel directs BC Hydro to prepare a report providing documentation on the existing and new Capitalized Overhead Methodology under IFRS and file it with its next RRA. Similarly, BC Hydro is also directed to provide its employment costs for its OMA forecasts on a net basis, excluding amounts that are either charged directly to capital, transferred to capital overhead or recovered through external recoveries, in its next RRA.	135
23.	The Commission Panel directs BC Hydro to conduct a comprehensive and informative benchmarking study such as the PA Consulting Group study and/or the Haddon Jackson generation indexing study it submitted in the F05/F06 RRA Proceeding and update its other benchmarking studies for its next RRA.	142
24.	The Commission Panel finds BC Hydro's management of taxes acceptable, including the proposal for a regulatory account to capture variances in school taxes and grants-in-lieu, which is further addressed in Section 5.5.3.	143
25.	The Commission Panel finds that an alternate solution is to establish a new regulatory account for any differences between the forecast and actual amortization expense resulting from forecast variances in capital additions, and accordingly directs BC Hydro to establish such an account to be dealt with in its next RRA.	149
26.	The Commission Panel finds that the appropriate manner to resolve the issues concerning the short-term interest rate forecast for the test years is through the deferral mechanism applied for by BC Hydro, as amended, as is described and determined at Section 5.5.2 of this Decision.	151
27.	The BC Hydro proposal to credit the NHDA for $75.3 in order to achieve a final F2009 rate increase of 6.56 percent is denied.	155
28.	The Commission Panel finds that customers will not be adversely affected because of the interim rates and approves BC Hydro's proposal to continue interim rates, as amended by this Decision, until the review of the 2008 LTAP is concluded. Further, the Commission Panel directs BC Hydro to submit its second compliance filing as soon as practicable after receipt of the 2008 LTAP Decision to finalize the permanentF2009 and F2010.	158
29.	BC Hydro is directed to issue refunds for any over-collection of revenues including interest at BC Hydro's most recent annual weighted average cost of debt for its most recent fiscal year in F2009 as soon as practicable after its compliance filing regarding the revised interim rates for F2009 and new interim rates for F2010 resulting from this Decision.	162

30.	As the Commission Panel approved the inclusion of expanded load curtailment costs in the HPO earlier in this Decision, it follows that any variances between forecast and actual costs will flow into the HDA.	165
31.	In light of the recent volatility of BC Hydro's load forecasts, the uncertain economic outlook, the recent introduction of the RIB, and the uncertain impacts of future DSM programs, BC Hydro's proposed deferral treatment for load variance is approved for the test period.	167
32.	The Commission Panel approves BC Hydro's approach to dealing with its F2009 pre-income tax ROE.	169
33.	The Commission Panel finds that the proposed DARR mechanism presents a more structured approach to clearing the net balances, meets the stated objectives, and that the estimated amortization period of 4–6 years is reasonable, and accordingly accepts the DARR mechanism as proposed by BC Hydro.	172
34.	The Commission Panel approves the Deferral Account Rate Rider of 0.5 percent for the period from April 1, 2008 to March 31, 2009.	172
35.	The Commission Panel approves the extension of the Site C regulatory account until the end of F2010.	175
36.	The Commission Panel approves BC Hydro's proposal to include the F2007 Winter Storm account balance in the NHDA for recovery through the DARR mechanism.	176
37.	The Commission Panel directs BC Hydro to segregate all of the incurred-to-date and forecast direct and indirect costs related to the PEI, including those proposed to be recovered in rates in the test period (such as the cost of the office of the CPO), and inclusive of the capital component, in the existing approved regulatory account until such time as BC Hydro applies for recovery of those costs. Further, BC Hydro is directed to segregate to that existing regulatory account its planned expenditures for the test period including not only the costs of the office of the CPO, but also its best estimate of the cost of its non-project personnel's time involved in implementation of the PEI, and to highlight the quantum of that latter cost in that application.	182
38.	In order that any future determination as to the reasonableness of BC Hydro's decisions in this matter can be made and the costs thereof allocated by the Commission, the Commission Panel further directs BC Hydro to include in any application to recover its costs as then accumulated in the existing regulatory account, the financial and any other quantifiable benefits related to the PEI, including the performance metrics for future monitoring of the project benefits.	182

39.	The Commission Panel allows BC Hydro to include CPI costs in a regulatory account only for the test period, and directs BC Hydro to provide a detailed analysis of actual F2009 and actual/projected F2010 CPI costs in its next RRA. To amortize the account balance, BC Hydro is to indicate which amounts can be assigned to a capital project while the remaining amounts will require justification for the necessary write-offs as operating expenses. BC Hydro's proposal for the amortization of the CPI account balance over 40 years is denied.	184
40.	With regard to BC Hydro's request for approval of a new deferral mechanism that would defer the difference between the forecast and actual weighted average cost of debt ("WACD") for F2009 and F2010, the Commission Panel approves its proposal, in principle, and further directs that it also encompass deferral of the difference between the forecast and actual incurred interest expense, including the difference between the forecast and actual swap income as reported in "Other Income" for F2009 and F2010.	187
41.	The Commission Panel approves BC Hydro's proposed regulatory account to collect differences between actual and forecast taxes during F2009 and F2010, plus interest at BC Hydro's weighted average cost of debt for its most recent fiscal year.	188
42.	The Commission Panel directs BC Hydro to include in its base OMA for the test period average storm-related restoration costs in 2009 dollars for F2009, and 2010 dollars for F2010, respectively, to be calculated as the average of actual costs for the five most recent "normal weather" years: e.g. F2003, F2004, F2005, F2006, and F2008 would be used for F2009; and to record any variance from the average amount for each test year in a separate regulatory account ("the Storm Damage Regulatory Account") to be dealt with in its next RRA.	189
43.	The Commission Panel accepts BC Hydro's position and approves the Non-Current Pension regulatory account to defer differences between forecast and actual non-current pension costs in F2010.	191
44.	The Commission Panel allows a deferral of the difference between the forecast and actual amortization expenses resulting from any variances between forecast and actual capital additions and directs that a regulatory account be established for this purpose.	191
45.	BC Hydro is directed to establish a new regulatory account called the 'GMS3 RA' for this purpose.	192
46.	BC Hydro is directed to establish an Employment Cost Regulatory Account.	192
47.	The Commission Panel agrees that the evidence before it is insufficient to justify the request for a ten-year amortization period of the HDA and NHDA.	193

48.	The Commission Panel directs BC Hydro to update Table 5.2 in respect of Baseline Forecasts for Deferral and Other Regulatory Accounts in its compliance filing.	197
49.	The Commission Panel is not prepared to grant BC Hydro the relief it requests from its commitment to abstain from hedging in natural gas at this time. The Commission Panel finds that there is insufficient evidence to make a determination on part (ii) of BC Hydro's request for relief.	199
50.	The Commission approves the estimated costs for BC Hydro's provision of services to BCTC as filed.	202
51.	The Commission Panel recommends BC Hydro to include in its next RRA the revenue requirement implications arising from planned capital expenditures during the test period, and also asks that those implications be clearly set out for each such capital item.	202
52.	To enable BC Hydro's insurance coverage to be better understood by its customers and the Commission, the Commission Panel directs BC Hydro to file as part of its next RRA a comprehensive cost/benefit analysis of its insurance coverages over the five years précising the first fiscal year of that RRA. The analysis is to include non-forecast losses in areas for which BC Hydro "self insures" incurred in those five years by event and functional circumstance, and to include its best estimate of what the cost benefit circumstances in respect of those losses would have been had coverage been in place. As well, the analysis is to provide BC Hydro's proposal for the test period covered in its next RRA, including any changes it proposes in its insurance coverages and the justification for them.	211
53.	The Commission Panel directs BC Hydro to provide within four months of the date of this Decision a report on the IFRS project and its progress to date. The report should include the project charter, a detailed project plan, a consultation plan with stakeholders, any potential changes to business or accounting policies, any unresolved issues, a summary of the present accounting policies under Canadian GAAP that conform to IFRS, a listing and rationale for all anticipated accounting policy changes, and a listing and explanation of accounting policy positions related to IFRS that are the same and/or divergent from other utilities under the Commission's jurisdiction or elsewhere in Canada. In particular, BC Hydro is also to include details of its plan to coordinate its approach with that of other BC resident utilities regulated by the Commission and its shareholder's requirements.	213
54.	The Commission Panel directs BC Hydro to adopt the BCUC USoA by no later than the F2012 reporting year. If certain plant accounts already in place cannot be coded to the proper BCUC account, BC Hydro is to make an application for an exemption for these historical amounts.	216

55.	The Commission Panel further directs that if BC Hydro is to re-platform to a replacement financial system this replacement financial system is to fully incorporate the BCUC USoA.	216
56.	The Commission Panel further directs BC Hydro to submit an Action Plan in respect of the USoA within three months of the date of this Decision.	217
57.	For clarity, the Commission Panel directs that BC Hydro revenue requirement applications filed after January 1, 2011 contain financial information that follows the USoA.	217
58.	The Commission Panel directs BC Hydro to establish rates for F2010 in its compliance filing that reflect its Operating Costs for that year, as described above by reference above to Table 4-1, at 97 percent of those applied-for, after taking into account the impact of the Commission Panel's prior determinations in this Decision on that value of $649 million.	221
59.	The Commission Panel authorizes BC Hydro to establish the ROE Adjustment Regulatory Account to defer the impact on BC Hydro's F2010 revenue requirement of the incremental rate of return on deemed equity as prescribed by HC2 as amended by OIC No. 074.	226

Disposition of Intervenor Requests for Relief

	Directive	Page
1.	The Commission Panel finds that the regulatory record confirms that BC Hydro acted reasonably in respect of that portion of the EPAs awarded in the F2006 Call that met the requirements of the 2005 REAP NSP Agreement. Inasmuch as the deliveries from IPPs in the test years are within the 2005 REAP NSP agreement volume, the Commission Panel determines that there is no basis on which to make any adjustment to BC Hydro's revenue requirements for the test years as requested by COPE.	85
2.	The Commission Panel declines to grant the CEC the relief it requests in reference to use of average water levels to establish cost of energy.	90
3.	The Commission Panel finds that BC Hydro's formula based approach to establishing its forecast OMA expenditures for the test period to not be determinative of the amounts of those expenditures and accordingly declines to grant JIESC the relief requested.	103
4.	The Commission Panel declines to disallow any costs related to the Accenture contract and to grant COPE the relief it requests.	112
5.	The Commission Panel declines to grant the relief requested by the JIESC in respect of reductions to on-going and fixed-term initiatives.	123
6.	The Commission Panel declines to grant the CEC the relief requested in this proceeding. That notwithstanding, Commission Panel finds that BC Hydro can and should provide its best estimate in terms of a forecast for this potential revenue stream from the Accenture relationship in future revenue requirement applications and is directed to do so for its next RRA.	154
7.	The Commission Panel finds that the evidence before it is insufficient to justify the relief requested by the CEC in respect of a regulatory account treatment for initiatives.	195
8.	The Commission Panel finds that the evidence before it is insufficient to justify the relief requested by the CEC in respect of further overhead transfers to regulatory accounts.	196

10.0 DISSENT OF COMMISSIONER RHODES

I concur with all the Determinations and reasons in this Decision except for the Determination regarding Interest Rates as addressed in Section 4.6.2. I am unable to agree with the Commission Panel Majority on this issue for the following reasons:

BC Hydro submits that the presumption of prudence does not apply to interest rate forecasts and that the task of the Commission is to select a forecast interest rate based on the evidence before it (BC Hydro Argument, p. 113). BC Hydro also submits in argument that the best evidence is the interest rate forecast contained in the October 1st Evidentiary Update (Exhibit B-22), which it received from the Treasury Board as of July 28, 2008. That forecast shows rates of 2.92 percent and 4.49 percent for F2009 and 3.65 percent and 4.92 percent for F2010, for short term and long term interest rates, respectively (BC Hydro Argument, p. 113).

The CEC takes the position that BC Hydro has historically taken a very conservative approach to interest rates and has consistently demonstrated an under forecasting of its short term interest rates. The CEC argues that the forecasts contained in the Evidentiary Updates “are very likely greater than they will turn out to be and …should be reduced further by the Commission” (CEC Argument, pp. 49-50.) The CEC suggests that “it is highly probable that there will be further interest rate reductions as a stimulus response to significant impacts on the global economy which are evident and continuing and requests that the Commission order BC Hydro to determine rates based on an additional rate reduction of 0.25 percent for F2009 and a further 0.5 percent for F2010 (CEC Argument, p. 51).

Alan Wait also notes that the short term interest rate projections provided by the BC Government are conservative and “appear to be too high” (Wait Argument, p. 3).

The BCOAPO expresses dissatisfaction that interest rates were not updated in the October 17th Update but notes that the proposed deferral account for finance costs would mitigate the impact.

BC Hydro submits in reply that “the Commission is obliged to make its decision on the basis of the record before it, and may not simply substitute an arbitrary figure for a forecast, *no matter how tenuous in the current circumstances that forecast is*.” It submits that the “principled solution to the *admitted problem* is the creation of a regulatory account…” (emphasis added) (BCH Reply, p. 41).

I note that the evidentiary record (Exhibit B-5, CEC 1.6.1) confirms the CEC’s position as to the consistent historical under forecasting of short term interest rates by BC Hydro and I also agree with the CEC that there is a strong likelihood of continuing interest rate cuts given the significant global economic downturn being experienced (CEC Argument, pp. 49-51). I do not accept BC Hydro’s suggestion that the Commission Panel must allow it to use a “tenuous forecast” from July of 2008 (per Exhibit B-11-1, BCUC 3.188.4.2) simply because that is the interest rate forecast it put forward when it was requested to update its forecast information, as its most recent forecast. Nor do I accept BC Hydro’s argument that the “principled solution to the *admitted problem* is the creation of a regulatory account” (emphasis added) (BC Hydro Reply, p. 41).

I am of the view that, in all of the circumstances, the July interest rate forecast put forward by BC Hydro is not reasonable and therefore should not be used as a basis for calculating BC Hydro’s revenue requirements in the test period.

I agree with the CEC that deferral accounts are not a sufficient answer in these circumstances because rates are calculated on the basis of the forecasts so there is a significant risk that ratepayers will be overcharged in the test period. (CEC Argument, p. 77) I am of the view that such overcharge will result in rates being charged in the test period which are “unjust or unreasonable” within the meaning of subsection 59(5)(a) of the *UCA.*

I consider that the Bank of Canada Press Release dated October 8, 2008 (Exhibit A2-4), which states, in part,

> "The Bank of Canada today announced that it is lowering its target for the overnight rate by ½ percentage point to 2 1/2 per cent. The operating band for the overnight rate is correspondingly lowered, and the Bank Rate is now 2 ¾ per cent.
>
> The intensification of the global financial crisis is having a marked impact on all countries. In recent weeks conditions in global financial markets have deteriorated sharply, the U.S. economy has weakened further, and commodity prices have fallen abruptly."

provides the basis for an alternative to the rate forecasts used by BC Hydro.

I also note the evidence of BC Hydro that:

> "[a]s was the case with the decrease in the Bank of Canada's overnight lending rate announced on October 8, 2008, it continues to be unclear whether *the further decrease announced on October 21, 2008* will be fully realized in interest rates available to commercial borrowers (and if so, when the reductions would be fully realized), and whether the reductions in the Bank of Canada rates and any reductions in rates available to commercial borrowers will be sustained through the test period….It is clear the financial crisis continues to unfold and governments are expected to take further extraordinary measures to mitigate the impacts of the crisis. It is not clear, however, whether such measures will translate into reductions to short-term interest rates for commercial borrowers that will be sustained through the test period in the Application. Thus, BC Hydro does not agree that the current Bank of Canada overnight rates should be used as the forecast of short-term interest rates BC Hydro will be charged over the test period." (emphasis added) (Exhibit B-77, BCUC 4.209.1)

I also note BC Hydro's further evidence that "[a]lthough less certain, it is also BC Hydro's view that the actual interest rates in F2009 and F2010 are likely to be lower than the forecast included in the October 17 Update" (which I note, did not, in fact, update interest rates) (Exhibit B-77, BCUC 4.211.1), the confirmation in its OEU that: "…since the outset of the oral phase of the hearing a global financial crisis has emerged that has cast considerably more uncertainty over a number of BC Hydro's forecasts than would otherwise be the case" (Exhibit B-64, p. 1) and the testimony of its CFO that "[t]here's no question that what we're seeing now with the federal banks both in Canada and the United States are actively trying to decrease rates to stimulate the economy" (T14: 2523).

I am, therefore, of the view that the best and most recent evidence available supports a lower short term interest rate forecast for the test period and I would therefore direct BC Hydro to recalculate its Revenue Requirements incorporating a .25 percent reduction to its short term interest rate forecast for F2009 and a further 0.75 percent reduction to its short term interest rate forecast for F2010.

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of March 2009.

Original signed by:

LIISA A. O'HARA
PANEL CHAIR

Original signed by:

ROBERT J. MILBOURNE
COMMISSIONER

DISSENT

I have had the opportunity of reading the Determinations and reasons of the Commission Panel Majority in final draft and concur with their findings in all areas except for the Determination in Section 4.6.2, Interest Rates. I respectfully dissent from my colleagues' findings in that area for the reasons stated in Section 10.0 of this Decision.

Original signed by:

ALISON A. RHODES
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-16-09

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

and

An Application by British Columbia Hydro and Power Authority
for Review of the F2009 and F2010 Revenue Requirements Application

BEFORE: L.A. O'Hara, Panel Chair
R.J. Milbourne, Commissioner March 13, 2009
A.A. Rhodes, Commissioner (dissenting in part)

O R D E R

WHEREAS:

A. British Columbia Hydro and Power Authority ("BC Hydro") filed on February 20, 2008, pursuant to sections 58 to 61 of the Utilities Commission Act ("the Act"), its F2009 and F2010 Revenue Requirements Application for, among other things, approval of across-the-board rate increases of 6.56 percent and 8.21 percent, effective April 1, 2008 and April 1, 2009, respectively, and approval of a reduction of the Deferral Account Rate Rider from 2.0 percent to 0.5 percent, effective April 1, 2008 (the "F09/F10 RRA" or "Application"); and

B. The Application also sought refundable interim relief pursuant to sections 58 to 61 and section 90 of the Act to allow BC Hydro to increase its rates by 6.56 percent on an across-the-board basis and to decrease its Deferral Account Rate Rider from 2.0 percent to 0.5 percent, both effective April 1, 2008, pending a full hearing into the F09/F10 RRA and orders subsequent to that hearing, on the basis that on April 1, 2008 BC Hydro's current rates would otherwise no longer be fair, just, sufficient and not unduly discriminatory; and

C. On February 25, 2008 the Commission issued Order G-21-08 establishing the Regulatory Timetable for the F09/F10 RRA. The Regulatory Timetable included a Workshop on March 6, 2008 and a Procedural Conference on April 28, 2008; and

D. On February 28, 2008 the Commission issued Order G-28-08 that included a requirement for the publication of a Notice of Applications; and

E. On March 14, 2008 the Commission issued Order G-40-08 that approved interim refundable rate changes for the 6.56 percent across-the-board rate increase and the decrease in BC Hydro's Deferral Account Rate Rider from 2.0 percent to 0.5 percent, both effective April 1, 2008; and

F. Following the April 28, 2008 Procedural Conference the Commission by Order G-78-08 dated April 30, 2008 established a Regulatory Timetable for review of the F09/F10 RRA through an Oral Public Hearing to commence on Monday, October 6, 2008 at 9:00 a.m., if the Negotiated Settlement Process ("NSP") scheduled to commence on August 18, 2008 did not conclude in an agreement; and

G. On July 2, 2008 BC Hydro filed an Evidentiary Update to the F09/F10 RRA that included F2008 actual results and F2008 closing balances of all regulatory and deferral accounts, an update on the Demand Side Management ("DSM") energy savings and expenditures to be consistent with forecasts in BC Hydro's 2008 Long Term Acquisition Plan Application ("2008 LTAP"), as well as updated forecasts for energy sales, revenues and cost of energy; and

H. On August 13, 2008, the Joint Electricity Steering Committee ("JIESC") filed a letter requesting that the Commission cancel the NSP and proceed to the full public hearing on Monday, October 6, 2008. The British Columbia Old Age Pensioners' Organization *et al.* ("BCOAPO") and Rental Owners and Managers Society of BC supported the JIESC's request. BC Hydro replied to the JIESC's and BCOAPO's letters noting it would not be worthwhile to proceed with the NSP in the circumstances; and

I. By Order G-119-08 the Commission cancelled the NSP and established a Pre-hearing Conference on August 21, 2008 to receive submissions from Intervenors and BC Hydro on further regulatory process; and

J. Following the August 21, 2008 Pre-hearing Conference the Commission issued Order G-122-08 that among other things confirmed the commencement of the Oral Public Hearing date of October 6, 2008; and

K. In its Final Argument, BC Hydro seeks final rate increases of 6.56 percent and 7.50 percent effective April 1, 2008 and 2009, respectively, subject to the resolution of the 2008 LTAP; and

L. The oral evidentiary phase concluded on October 29, 2008. Subsequently, the oral argument phase took place on January 16 & 19, 2009; and

M. On February 17, 2009 the B.C. Government issued Order-In-Council ("OIC") No. 074, which amended sections 4 and 7 of Heritage Special Direction No. HC2 to the Commission, effective February 17, 2009. OIC No. 074 requires the Commission to set rates for BC Hydro to enable it to achieve an annual rate of return on deemed equity equal to the sum of the pre-income tax annual return on equity allowed by the Commission to the most comparable investor-owned energy utility and an additional 1.63 percent; and

N. The Commission has considered the Application and evidence all as set forth in the Decision issued concurrently with this Order.

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

1. The applied-for across-the-board rate increase of 6.56 percent and 7.50 percent, effective April 1, 2008 and 2009, respectively, subject to a revenue requirement compliance filing incorporating any further transfers to the NHDA in F2009 and F2010 necessary to maintain final rate increases of 6.56 percent and 7.50 percent, effective April 1, 2008 and 2009, respectively, after incorporating the impacts of certain determinations regarding DSM in the 2008 LTAP are not approved as filed.

2. The interim decrease in the Deferral Account Rate Rider from 2.0 percent to 0.5 percent, effective April 1, 2008, is approved.

3. BC Hydro is to calculate revised interim F2009 and F2010 rates and to submit in a compliance filing two sets of financial schedules including the spreadsheet model in accordance with the directives in the Commission's Decision, on or before March 27, 2009. The first set is to reflect the Commission's Decision, without regard for the amendments to Heritage Special Direction No. HC2 arising from OIC No. 074 dated February 17, 2009, while the second set is to reflect the Commission's Decision, but show the effect of the amendments on the F2010 revenue requirement.

4. If the F2009 revised interim rates are less than the interim rates of 6.56 percent, BC Hydro is to refund to customers the difference in revenue including interest at BC Hydro's most recent annual weighted average cost of debt for its most recent fiscal year, as soon as practicable. If the F2009 revised interim rates exceed 6.56 percent, the under-collection of revenues from April 1, 2008 to March 31, 2009 are to be placed in a deferral account for recovery at a future time. BC Hydro is to report on the average refund or rate increase by customer class.

5. BC Hydro is directed to submit a second compliance filing within 30 days of the Commission's final Decision and Order regarding the 2008 LTAP to finalize the F2009 and F2010 rates. The second compliance filing is to incorporate the further transfers to the NHDA in F2009 and F2010 necessary to maintain the final and permanent rate increase at the revised interim rate increase level, after incorporating the impacts of certain determinations in the 2008 LTAP regarding DSM. The revised interim rates for F2009 and F2010 are then approved as final and permanent rates for the period from April 1, 2008 to March 31, 2010 inclusive.

.../4

6. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules which conform to the Commission's Decision for both the revised interim rates and the permanent and final rates. BC Hydro is to provide all customers with a notice of the change in rates, by way of an information notice and media publication.

7. BC Hydro will comply with all other directives in the Decision accompanying this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 13th day of March 2009.

BY ORDER

Original signed by:

L.A. O'Hara
Panel Chair

ERICA M. HAMILTON
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Log No. 24130

VIA E-MAIL

November 3, 2008

BC HYDRO F2009/F2010 REVENUE REQUIREMENT	EXHIBIT A-24

TO: British Columbia Hydro and Power Authority
Registered Intervenors (F09/F10 RRA)

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Project No. 3698500/Order No. G-21-08
F2009 and F2010 Revenue Requirements Application

Further to the Panel Chair's comments in Transcript Volume 14, pp. 2653-2654, following is a letter from the Commission Panel listing matters on which it invites submissions from the parties in Argument.

Yours truly,

Original signed by:

Erica M. Hamilton

AR/dg
Enclosure

MATTERS ON WHICH THE COMMISSION PANEL INVITES SUBMISSIONS IN ARGUMENT

The following list is not exhaustive, and is intended only to highlight some areas where the Commission Panel believes its determinations could be helpfully informed if the parties choose to address them. It is not intended to in any way limit the submissions of the Parties in either scope or content.

1. What is an appropriate approach to risk sharing between BC Hydro and its rate payers for material events and/or departures from forecast values of important parameters during the test years including:

    (a) controllable events such as major breakdowns (e.g.) the GM Shrum failure, and
    (b) uncontrollable events (e.g.) storm outages, interest rate and currency exchange rate volatility, load volatility, etc.?

    1.1.1 Would it be appropriate for BC Hydro to broaden its existing insurance coverage for material outage/repair costs to include weather related incidents, and to add business interruption coverage to limit the impact of these risks? If so, how should the deductible and/or non-recoverable costs then be allocated as between BC Hydro and its rate payers?

    1.1.2 If BC Hydro elects to "self insure" against otherwise insurable risks, how should the impacts of any such events be allocated as between it and its ratepayers?

    1.2 How should uncertainty and volatility related to non-current post-employment benefit expense forecasts be addressed:

    (a) Deferral account and the inclusion of the best estimate in the test year cost of service, or
    (b) Differentiation between treatment of non-current post-retirement benefits and other post employment benefits (OPEB), or
    (c) Estimates only revised when triennial actuarial evaluations received, or
    (d) Other?

2. Is there any reason to give consideration to the duration of the Commission Order setting rates following the review of the F2009/F2010 RRA to be other than as set out in the Application?

3. How should the linkage of the RRA Decision to the LTAP Decision be dealt with in view of the expectation that the LTAP decision will not be available until sometime into Fiscal 2010:

    - Interim Rates until the LTAP Decision is issued, or
    - Permanent Rates with a regulatory/deferral account to deal with the LTAP impact. If so, how should the deferred amount be dealt with, or
    - Other?

4. What, if any, should be the general criteria for establishing new deferral accounts?

   4.1 If new deferral accounts are created, how should they be dealt with in terms of amortization?

5. In light of the recent amendments to the UCA, how should the capital projects included in the Application be dealt with?

   - defer all capital projects to LTAP, or
   - include some, such as health and safety, environment, IT, etc. projects in the RRA, but defer projects with a growth component to LTAP, or
   - require a CPCN for some of the projects brought forward in the RRA; if so, at what dollar value limit, or
   - Other?

ERICA M. HAMILTON
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BRITISH COLUMBIA UTILITIES COMMISSION

LETTER NO. L-63-08

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VIA E-MAIL

December 30, 2008

BC HYDRO **F2009/F2010 REVENUE REQUIREMENT**	**EXHIBIT A-26**

TO: British Columbia Hydro and Power Authority
Registered Intervenors (BCH-F09-10RR-RI)

Re: British Columbia Hydro and Power Authority ("BC Hydro")
Project No. 3698500/Order No. G-21-08
F2009 and F2010 Revenue Requirements Application

Further to Exhibit A-25, the Commission Panel ("Panel") has determined the Oral Phase of Argument provisionally scheduled to begin at 9:00 a.m. on January 16, 2009 is required.

The Panel invites Oral Submissions from the parties directed towards it achieving a better understanding of the parties' positions in respect of the matters listed below. The parties are cautioned that the manner in which the matters are framed is not to be taken as any indication of the direction as to the determinations, if any, that the Commission may make in respect of any of these matters.

Submissions are to be confined to the evidentiary record. The parties may refer to authorities from other proceedings of the Commission, or the Courts where they believe those authorities may be of relevance but have not been entered.

Parties are requested to advise the Commission, in writing with reference by item number, by January 12, 2009 if they wish to make submissions on an item. Unless the parties otherwise agree, the Panel presently intends that on all issues, BC Hydro will make any submissions it has first, followed by Intervenors with a right of reply by BC Hydro. If any party intends to rely upon an authority during the oral phase not previously referred to in Argument, a copy of the authority is to be provided with its letter to the Commission along with references by item number(s) to the matter(s) to which it applies. The Panel will allow BC Hydro during reply, or any other party that it may allow to reply to the submissions of another party on an item during the oral phase, to refer to authorities not identified by that party in its letter to the Commission, provided the authorities are in response to authorities referred to in the other party's letter to the Commission.

The matters are as follows:

1. Pursuant to Order G-40-08, an interim refundable general rate increase for F2009 is in place and (i) if the Panel should determine that the rate increase for F2009, inclusive of any change in the Rate Rider, should be different, and if the Panel determines that the rate changes for F2009 and F2010 should not be made final until the 2008 LTAP Decision is rendered, are there any reasons why the Panel could not rescind and/or vary or amend Order G-40-08 to reflect that new value for F2009 in order that, if appropriate, refunds for F2009, if any, could be made to ratepayers in a timely fashion?

   If the Panel was to make a determination of an interim rate for F2009 that is different from that in the Order G-40-08 and which also results in a refund, (ii) in light of BC Hydro's comments in its Reply Argument at page 53, the Panel also invites argument on BC Hydro's position that "it is open to the Commission to decide, in this proceeding, the appropriate level of recovery of the Deferral Account balances for F2009."

2. BC Hydro takes the position that, unless a forecast expenditure can be determined to be demonstrably imprudent, the Commission has no basis on which to disallow it from its Revenue Requirements, and cites *Hemlock Valley* as its authority. Certain other parties have directed the Panel to sections 59 and 60 of the Act, specifically to the language at s. 60(1)(b)(iii) which speaks to other factors the Commission is to consider in setting rates, which factors BC Hydro submits are "subordinate" to the determination in *Hemlock Valley*. The Panel invites further argument on this matter, and refers parties to *ATCO Electric Limited v. Alberta (Energy and Utilities Board) 2004 ABCA 215 (CanLII),* paragraphs 126 – 136.

3. Further to 2. above, BC Hydro takes the position that, absent a determination of imprudency on its part, the burden of establishing which falls to the party seeking such a determination, all of its forecast expenditures, along with any past expenditures on which those forecasts may be based, are "immunized" against amendment or variation by the Commission. The Panel notes the general agreement among the parties that the appropriate standard for assessment of prudency is to be found in *Enbridge*. However, BCAOPO takes exception to BC Hydro's position in respect of the burden of making the case for imprudence, by differentiating between cases involving "retrospective" assessment of the consequences of a utility's past decisions, and cases where the circumstances involve the utility's recovery of its "prospective" expenditures through rates – in which case the burden of establishing the prudency of the proposed expenditure is said to accrue to the utility.

   In its Reply Argument, BC Hydro notes that no authority was provided for BCOAPO's view in the case of such prospective expenditures, and further that none of the authorities BC Hydro cited in its Final Argument "support such a position" and accordingly that BCOAPO's position is " simply incorrect." The Panel invites further argument on this matter, and specifically requests that BCOAPO provide it with authority for its submission on this point.

4. Certain parties have argued for an Order from the Commission to disallow any recovery by BC Hydro of the direct and indirect costs associated with the failure of GM Shrum Unit 3 failure on the basis that its decisions in respect of that unit were imprudent. The Panel notes, among other things, that the final costs are not available, there may be a material insurance recovery of a portion of the direct costs, and, while not expressly described in the record of the proceeding, there is a possibility

that a portion of the direct repair costs may qualify as a capital expense if in fact the repaired unit's life expectancy is extended as a result of the repair.

If the Panel were to direct BC Hydro to segregate all of the incurred-to-date and future direct and indirect costs of the repair in a separate Deferral Account ("the GMS3 DA") and to apply to the Commission for recovery of costs when the facts were better established, and at which time the matter of imprudence could be assessed, would that give rise to any material inter-generational equity or other issues of concern?

5. Certain parties have argued for an Order from the Commission to disallow any recovery by BC Hydro of the incurred-to-date and future costs of the PEI initiative on the basis that the business case for the initiative is inadequate to justify the forecast quantum of the costs of the initiative and accordingly that the decision to proceed with it is imprudent. The Panel notes that BC Hydro has authority pursuant to Order G-17-08 to defer a portion of the portion of the incurred-to-date costs, and that it is seeking to defer a portion of the forecast expenses to be incurred up to the operationality of the program in 2012 while not deferring certain other of the costs of the initiative, which it seeks to recover as OMA expenses in the test period or through a capital account.

   If the Panel were to direct BC Hydro to segregate all of the incurred-to-date and future costs of the PEI initiative, inclusive of the capital component, in a Deferral Account (the "PEI DA") until such time as BC Hydro was more knowledgeable of, and able to, if possible, quantify the benefits of the initiative and then applied for recovery of those costs, at which time the matter of prudency could be assessed, would that give rise to any material inter-generational equity or other issues of concern?

6. A party has argued for an Order from the Commission to disallow any recovery by BC Hydro of the forecast "excess cost" of electricity supplied during the test period by IPP's over market prices for that electricity on the basis that BC Hydro's decisions in respect of the amount and timing of IPP supply it awarded in the F 2006 Call were imprudent. The Panel notes that both the party requesting the order and BC Hydro rely on the same Decisions of the Commission in support of their positions, albeit with different interpretations of the Commission's language.

   The Panel invites further argument on this matter and refers parties to *Nova Scotia Power Inc., Re, 2006 NSUARB 23 (Can LII),* paragraphs 56 to 96, and *Nova Scotia Power Inc., Re 2005 NSUARB 27 (Can LII)*, paragraphs 47 to 97.

7. The Panel acknowledges and appreciates the submissions made by parties in response to its invitation for Argument on the matter of "risk sharing" between BC Hydro and its ratepayers. The Panel notes a general consensus among the parties that the issue of "controllability" of any risk is secondary to the matter of BC Hydro's prudency in response to the realization or mitigation of that risk. The Panel also notes the direction of the requests of certain parties towards a more widespread utilization of Deferral Accounts to ensure that variation from forecast parameters is captured to the potential benefit of ratepayers, particularly where the potential for variance is asymmetric about the forecast value.

In the aggregate, the Panel believes this suggests a shift in ratepayers' attitudes from the traditional regulatory paradigm that "a utility is entitled to the <u>opportunity</u> to earn its allowed rate of return on equity" towards a model wherein "BC Hydro is <u>to be given, but not to exceed,</u> its allowed rate of return on equity." The Panel (i) invites further argument from the parties as to whether the Panel's interpretation of the positions of the parties is accurate.

Further, (ii) if the Panel were to accommodate or otherwise recognize such a perceived directional shift in making its determinations on some or all of the numerous requests from BC Hydro and the other parties for Deferral Account treatment of the manifold matters in the Application and the parties' arguments, many of which, in the context of an unregulated entity would accrue solely to the corporation save and effect for any force majeure impacts on its customers, would that give rise to any material intergenerational equity or other issues?

Yours truly,

Original signed by:

Erica M. Hamilton

LO'H/dlf

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 074 *, Approved and Ordered* FEB 17 2009

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that, effective February 17, 2009, the Heritage Special Direction No. HC2 to the British Columbia Utilities Commission, B.C. Reg. 158/2005, is amended

(a) by repealing section 4 (d) and substituting the following:

(d) achieve an annual rate of return on deemed equity

(i) for the authority's fiscal years 2009-2010, 2010-2011 and 2011-2012, that is equal to the sum of the following two percentages:

(A) pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*;

(B) 1.63%, and

(ii) for any other fiscal year of the authority, that is equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act*.

(b) in section 7 by striking out "and" *at the end of paragraph (b), striking out* "of time." *at the end of paragraph (c) and substituting* "of time, and" *and by adding the following paragraph:*

(d) for the authority's 2009-2010 fiscal year, must allow the authority to establish an account to defer for recovery in a later fiscal year or years the difference between the revenue required under section 4 as it read before it was amended effective February 17, 2009, and the revenue required under that section as it reads after that date.

DEPOSITED
FEB 17 2009
B.C. REG. 27/2009

Minister of Energy, Mines and Petroleum Resources

Presiding Member of the Executive Council

(This part is for administrative purposes only and is not part of the Order.)

Authority under which Order is made:

Act and section:- *BC Hydro Public Power Legacy and Heritage Contract Act*, S.B.C. 2003, c. 86, s. 4

Other (specify):- OIC 1123/2003

January 29, 2009 R/109/2009/27

LIST OF ACRONYMS

ABSBC, Accenture	Accenture Business Services British Columbia Limited Partnership
ABSU	Accenture Business Services for Utilities Limited
Act, UCA	Utilities Commission Act
ATCO 2005	*ATCO Gas and Pipelines Ltd. v. Alberta Energy and Utilities Board* 2005 CarswellAlta 582, 2005 ABCA122
ATCO 2008	2008-2009 General Rate Application of ATCO Gas
AUB	Alberta Utilities Board
BC Electric Railway	*British Columbia Electric Railway Co. v. British Columbia Public Utilities Commission*, [1960] S.C.R. 837
BC Hydro	British Columbia Hydro and Power Authority
BCOPAO	The BC Old Age Pensioners Organization *et al*.
BCSEA	British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter
BCTC	British Columbia Transmission Corporation
BCTCDA	BCTC Deferral Account
BI	Business Interruption
CA	Collective Agreement
CAIDI	Customer Average Interruption Duration Index
CC&C	BC Hydro's Customer Care and Conservation department
CCSC	Customer Care and Conservation
CEA	Canadian Electricity Association
CEC	Commercial Energy Consumers of British Columbia
CEMI-4	Customers Experiencing Multiple Interruptions

CIAC	contributions-in-aid-of-construction
CIP	Capital Project Investigation
CIS	Customer information system
Commission, BCUC	British Columbia Utilities Commission
COPE	Local 378 of the Canadian Office and Professional Employees Union
CPI	Consumer Price Index
CPI	Capital Project Investigation
CPO	Chief Procurement Officer
DARR	Deferral Account Rate Rider
DSM	Demand-side Management
EARG	Engineering Aboriginal Relations and Generation
Enbridge Gas	*Enbridge Gas Distribution Inc. v. Ontario(Energy Board)* [2006] O.J. No. 1355, 41 Admin L.R. (4^{th})69(C.A.)
EPA	Electricity Purchase Agreement
ERO	Electric Reliability Organization
ET	Executive Team
EU	Evidentiary Update
F05/F06 RRA	BC Hydro's 2004/05 to 2005/F06 Revenue Requirements Application
F09/F10 RRA, Application	BC Hydro's F2009/F2010 Revenue Requirements Application
FRSR	Future Removal and Site Restoration
FTE	Full-time Equivalents
GAAP	Generally Accepted Accounting Principles
GMS	G.M. Shrum Generating Station
GMS3 RA	G.M. Shrum Unit 3 Regulatory Account

GWh	Gigawatt hours
HAD	Heritage Payment Obligation Deferral Account
HC2	Heritage Special Direction No. HC2 to the British Columbia Utilities Commission
HDA	Heritage Deferral Account
Hemlock Valley	*Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1992), 66 B.C.L.R (2d) 1 (C.A.)
Heritage Contract Act	BC Hydro Public Power Legacy and Heritage Contract Act
HPO	Heritage Payment Obligation
HPO	Heritage Payment Obligation
Hydro Act	Hydro and Power Authority Act
IEP	Integrated Electricity (Energy) Planning
IFRS	International Financial Reporting Standards
IPPBC	Independent Power Producers Association of British Columbia
IPPs	Independent Power Producers
IR	Information Request(s)
IRA	Index Reserve Account
IT	Information Technology
JIESC	Joint Industry Electricity Steering Committee
LTAP	BC Hydro's Long Term Acquisition Plan
MCM	Marginal Cost Model
MPB	Mountain Pine Beetle
MSA	Master Services Agreement
MW	megawatt

MWh	megawatt hour
NERC	North American Electric Reliability Corporation
NHDA	Non-Heritage Deferral Account
NIA	Non-Integrated Area
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
NSPI	Nova Scotia Power Inc.
NSUB	Nova Scotia Utility Board
OCI	Outage Communication Initiative
OEU	Omnibus Economic Update
OMA	Operating, Maintenance and Administration Cost
OPEB	Other Post-employment Benefits
P2P	Procure-to-Pay
Participants Guide	Understanding Utility Regulation: A Participants Guide to the BC Utilities Commission
PBR	Performance Based Rate-making
PEB	Post-employment Benefits
PEI	Purchasing Enhancement Initiative
PLT	Power Line Technician
Powerex	Powerex Corp.
Powertech	Powertech Sales Inc.
PSEC	Public Sector Employees' Council
RA	Regulatory Account
Rate Rider	Deferral Account Rate Rider

RCE	Remove Community Electrification
RDA	Rate Design Application
RIB	Residential Inclining Block Rate Application
ROE	Return on Equity
RRA	Revenue Requirement Application
SAIFI	System Average Interruption Frequency Index
SMI	Smart Metering Infrastructure
SOW	Statement of Work
SS	Strategic Sourcing
Terasen	Terasen Utilities (Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc.)
TFP	Total Factor Productivity
TGI	Terasen Gas Inc.
TIDA	Trade Income Deferral Account
TPA	Transfer Pricing Agreement
TSRA	Transmission Service Re-pricing Application
USoA	BCUC Uniform System of Accounts for Electric Utilities
WACD	Weighted Average Cost of Debt

LIST OF APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
J. CHRISTIAN N. ELLEGOOD I. WEBB J. SOFIELD	British Columbia Hydro and Power Authority
D. CURTIS S. HILL	British Columbia Transmission Corporation
M. GHIKAS D. PERTTULA	Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gs (Whistler) Inc. (collectively “Terasen Utilities”)
D. AUSTIN	Independent Power Producers Association of British Columbia
P. COCHRANE R. CARLE	City of New Westminster
R. B. WALLACE	Joint Industry Electricity Steering Committee
D. NEWLANDS	Elk Valley Coal Corporation
C. DAL MONTE	Catalyst Paper Corporation
C. WEAFER	Commercial Energy Consumers of British Columbia
L. WORTH J. QUAIL	B.C. Old Age Pensioners' Organization Council Of Senior Citizens' Organizations Federated Anti-Poverty Groups of B.C. West End Seniors' Network (collectively “BCOAPO”)
W. J. ANDREWS	B.C. Sustainable Energy Association Sierra Club of Canada, British Columbia Chapter (collectively “BCSEA”)
J. HUNTER M. OULTON	Canadian Office and Professional Employees Union, Local 378
A. WAIT	On His Own Behalf

S. MEADE	On His Own Behalf

D. Chong W.J. Grant P.W. Nakoneshny N. Rajan S. Sue S. Mah	Commission Staff
G. Isherwood E. Switlishoff	Contract Staff
Allwest Reporting Ltd.	Court Reporters

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

and

British Columbia Hydro and Power Authority
F2009/F2010 Revenue Requirements Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated February 22, 2008 and Order No. L-5-08 establishing a regulatory process and timetable to review the F2009/F2010 Revenue Requirements Application
A-2	Letter dated February 25, 2008 issuing Order No. G-21-08 to establish a Workshop, Procedural Conference and Regulatory Timetable for the F2009/F2010 Revenue Requirements Application
A-3	Letter dated February 28, 2008 and Order No. G-28-08 establishing a Procedural Conference
A-4	Letter dated March 12, 2008 issuing Commission Information Request No. 1
A-5	Letter dated March 14, 2008 and Order No. G-40-08 with Reasons for Decision setting an interim refundable rate increase
A-6	Letter dated April 22, 2008 providing a draft agenda for the Procedural Conference scheduled for April 28, 2008
A-7	Letter dated April 25, 2008 providing a proposed regulatory timetable for review of the application
A-8	Letter dated April 30, 2008 and Order No. G-78-08 establishing a Negotiated Settlement Process and Regulatory Timetable
A-9	Letter dated May 16, 2008 issuing Commission Information Request No. 2 to British Columbia Hydro and Power Authority

Exhibit No.	Description
A-10	Letter dated June 30, 2008 issuing Order No. L-32-08 revising the regulatory timetable for review of the application
A-11	Letter dated July 9, 2008 issuing Information Request No. 3 to BC Hydro
A-12	Letter dated August 1, 2008 notifying BC Hydro regarding Stuart Meade's late Information Request
A-13	Letter dated August 6, 2008 filing Information Request No. 1 to JIESC on Intervenor Evidence
A-14	Letter dated August 14, 2008 issuing Notice of Commission Panel Chair change
A-15	Letter dated August 15, 2008 issuing Commission Order G-119-08 establishing a Pre-Hearing Conference
A-16	Letter dated August 15, 2008 issuing an extension to the JIESC to file its responses to the Information Requests
A-17	Letter dated August 25, 2008 issuing Commission Order G-122-08 with Reasons for Decision as Appendix A regarding Oral Public Hearing
A-18	Letter dated September 12, 2008 requesting comments on whether a Hearing Issues List would contribute to the effectiveness of the Oral Hearing
A-19	Letter dated September 15, 2008 issuing information on what to expect at a Procedural Hearing
A-20	Letter dated September 18, 2008 issuing Commission Order G-134-08 with Reasons for Decision as Appendix A
A-21	Letter dated September 30, 2008 issuing Commission Panel Information Request No. 1 to BC Hydro
A-22	Letter L-47-08 dated October 1, 2008, Commission Panel will not be issuing a Hearing Issues List
A-23	Letter dated October 23, 2008 issuing Commission Information Request No. #4 to BC Hydro
A-24	Letter dated November 3, 2008 issuing instructions on submissions for Arguments

Exhibit No.	Description
A-25	Letter dated December 22, 2008 confirming that the hearing of Oral Submissions, if any, will take place on January 16, 2009
A-26	Letter dated December 30, 2008 advising that the Oral Phase of Argument provisionally scheduled to begin at 9:00 a.m. on January 16, 2009 will take place and inviting Oral Submissions from the parties

COMMISSION COUNSEL DOCUMENTS

A2-1	**SUBMITTED AT HEARING** – Copy of letter dated September 16, 2006 filing BC Hydro's restated budget and overview of the organizational changes
A2-2	**SUBMITTED AT HEARING** – Excerpt from BC Hydro 2004 – 2006 Revenue Requirements Application and BC Transmission Corporation Application for Deferral Accounts, page 138
A2-3	**SUBMITTED AT HEARING** – Letter dated September 16, 2008 filing comments regarding an amendment to BC Hydro's Rate Schedule 3808 Power Purchase Agreement
A2-4	**SUBMITTED AT HEARING** – Copy of Press Release entitled "Central Banks Announce Coordinated Interest Rate Reductions"
A2-5	**SUBMITTED AT HEARING** – Copy of Table 3.3.2 – 2008 Gross O&M Expense from FortisBC's Preliminary 2008 Revenue Requirements dated October 1, 2007
A2-6	**SUBMITTED AT HEARING** – Copy of Exhibit A-5, Page 1 of the Terasen Gas 2007 Annual Review of the 2008-2009 Extension of the 2004 – 2007 Multi-year Performance Based Rate Plan
A2-7	**SUBMITTED AT HEARING** – BC Hydro Witness Aid – Net Operations, Maintenance, Admin & General costs
A2-8	**SUBMITTED AT HEARING** – BC Hydro Witness Aid – Net Operations, Maintenance, Admin & General costs without pension
A2-9	**SUBMITTED AT HEARING** – BC Hydro Witness Aid – Labour Increase
A2-10	**SUBMITTED AT HEARING** – Copy of Decision between the Ontario Energy Board Act 1998 and Union Gas Limited
A2-11	**SUBMITTED AT HEARING** – BC Hydro Witness Aid – Formula Based Operating Costs (Net OMA&G) Base Adjustment

Exhibit No.	Description
A2-12	**SUBMITTED AT HEARING** – Copy of letter dated April 17, 2003 filing BC Gas Application for Multi-Year Performance Based Rate Plan for 2004-2008
A2-13	**SUBMITTED AT HEARING** – Copy of letter dated August 8, 2008 filing BC Hydro's Annual Financial Report
A2-14	**SUBMITTED AT HEARING** – Excerpt from Knotia – CICA Handbook - Section 3061 – Property plant and equipment
A2-15	**SUBMITTED AT HEARING** – Excerpt from COPE 378 blog comments on Accenture vote on general wage increase
A2-16	**SUBMITTED AT HEARING** – Copy of News Release – Compensation plan for Non-Union Public Sector Employees
A2-17	**SUBMITTED AT HEARING** – BC Hydro Witness Aid – Full Time Equivalent Growth
A2-18	**SUBMITTED AT HEARING** – Excerpt – Introduction from Pacific Northern Gas Revenue Requirements Decision, April 24, 1992
A2-19	**SUBMITTED AT HEARING** – Excerpt from Page 5-16 of the BC Hydro F97/F08 Revenue Requirements Application
A2-20	**SUBMITTED AT HEARING** – Copy of Table 5-7 – ABSU Draft Amended Master Service Agreement (AMSA)
A2-21	**SUBMITTED AT HEARING** – Witness Aid – Appendix J of the BC Hydro F97/F08 Revenue Requirements Application
A2-22	**SUBMITTED AT HEARING** – Excerpt from the BCTC Revenue Requirement F2009 and F2010, dated 20 February 2008 – Chapter 9 - Operations, Maintenance and Administration Expenses
A2-23	**SUBMITTED AT HEARING** – Copy of BC Hydro's Press Release dated February 7, 2007, titled "Cross-Jurisdictional Team to Take an Aggressive Approach to Metal Theft
A2-24	**SUBMITTED AT HEARING** – Copy of Order G-58-06, for the Application by FortisBC Inc. for Approval of its F2006 Revenue Requirement Application and Establishment of a Multi-Year Performance Based Regulation Mechanism
A2-25	**SUBMITTED AT HEARING** – Copy of O & M Savings Report, Appendix 4
A2-26	**SUBMITTED AT HEARING** – Copy of the Information Request No. 1.4.7 response from the BC Hydro Residential Inclining Block Rate Application

Exhibit No.	Description
A2-27	**SUBMITTED AT HEARING** – Witness Aid - BC Hydro's Residential Interim Rate as at October 1, 2008

APPLICANT DOCUMENTS

B-1	Letter dated February 20, 2008, filing BC Hydro's F2009/F2010 Revenue Requirements Application
B-2	Letter dated March 4, 2008 filing the Agenda for the Workshop scheduled for March 6, 2008
B-3	Presentation at March 6, 2008 Workshop
B-4	Letter dated March 11, 2008, filing comments on the request for interim rate increase, pursuant to Order L-5-08 (Exhibit A-1)
B-5	Letter dated April 23, 2008, filing response to Intervenors' Information Request No. 1
B-5-1	Letter dated April 23, 2008, filing response to the Commission's Information Request No. 1
B-5-1-A	Letter dated July 28, 2008, filing the updated response to the Commission's Information Request No. 1.8.1 to include four additional audit reports
B-5-2	**CONFIDENTIAL** - Letter dated April 23, 2008, filing response to the Commission's Information Request No. 1
B-5-3	Letter dated April 25, 2008 filing response to the Commission's Information Request 1.115.2
B-5-4	Letter dated May 13, 2008 filing revised responses to Information Request No's 1.4.2, 1.26.2, 1.30.1, 1.31.1, 1.32.1, 1.39.1, 1.39.2, 1.47.2, 1.47.4, 1.47.5, 1.47.6, 1.50.3, 1.52.1, 1.52.2, 1.55.1, 1.56.1, 1.58.1, and 1.114.5
B-5-5	Letter dated October 28, 2008 filing a revised response to Commission Information Request 1.28(a)
B-6	**SUBMITTED AT PROCEDURAL CONFERENCE** – BC Hydro Strawman Proposed Regulatory Timetable

Exhibit No.	Description
B-7	Letter dated April 28, 2008 filing Appendix A, confirmation of publication as directed by Order G-28-08
B-8	Letter dated June 26, 2008 filing response to Intervenors' Information Request No. 2
B-8-1	Letter dated June 26, 2008 filing response to the Commissions' Information Request No. 2
B-8-2	**CONFIDENTIAL** - Letter dated June 26, 2008 filing response to the Commissions' Information Request No. 2
B-9	Letter dated June 30, 2008, filing request for extension to the Regulatory Timetable filing dates
B-10	Letter dated July 2, 2008 filing Evidentiary Update
B-11	Letter dated July 22, 2008 filing responses to Information Requests from the Commission and Intervenors
B-11-1	Letter dated August 8, 2008 filing an updated response to Information Request No. 1, Question 3.188.4.2
B-11-2	Letter dated September 29, 2008 issuing Revised response to JIESC Information Request No. 3.31.1
B-12	Letter dated August 1, 2008 filing response to Information Request of Stuart Meade (Exhibit C23-2)
B-13	Letter dated August 6, 2008 filing Information Request No. 1 to JIESC on Intervenor Evidence.
B-14	Letter dated August 6, 2008 filing response to Stuart Meade regarding his 82 new Information Requests (Exhibit C23-2)
B-15	Letter dated August 14, 2008 filing comments on the letters filed by JIESC and BCOAPO regarding the Negotiated Settlement Process
B-16	Letter dated August 13, 2008 filing response to COPE 378 requesting leave to submit evidence

Exhibit No.	Description
B-17	Letter dated September 10, 2008 from Jeff Christian, Lawson Lundell, legal counsel, filing response to COPE 378's motion
B-18	Letter dated September 12, 2008 from Jeff Christian, Lawson Lundell, legal counsel, filing response to COPE 378 - Exhibit C3-10
B-19	Letter dated September 24, 2008 from Jeff Christian, Lawson Lundell, legal counsel, filing comments on the draft Hearing Issues List
B-20	Letter dated September 29, 2008 submitting evidence relating to BC Hydro Contract with Accenture Business Services of British Columbia
B-21	Letter dated September 29, 2008 stating case to be presented at Oral Hearing
B-22	Letter dated October 1, 2008 issuing Evidentiary update
B-23	Letter dated October 2, 2008 from Jeff Christian, Lawson Lundell, legal counsel, filing Mr. Elton's Opening Statement
B-24	**SUBMITTED AT HEARING** – Filing responses to Information Request No. 1.1.1, 1.1.2 and 1.1.3
B-25	**SUBMITTED AT HEARING** – Filing additional report to Information Request No. 3.186.1.2 on the GMS Unit 3 failure
B-26	**SUBMITTED AT HEARING** – Filing revised responses to the Commission's Information Requests #1.23.5.14 and 2.126.1.2, and to Intervenors' Information Requests No. 2.91 and 1.12.4
B-27	**SUBMITTED AT HEARING** – Filing response to IPPBC Undertaking #2, Volume 4, Page 457, Lines 8-19
B-28	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes Undertaking #4, Volume 4, Page 517, Lines 18-26
B-29	**SUBMITTED AT HEARING** – Filing response to COPE Undertaking #1, Volume 3, Page 423, Lines 18-22 and Page 425, Lines 10-14
B-30	**SUBMITTED AT HEARING** – Filing response to JIESC Undertaking #9, Volume 4, Page 616, Lines 2-16 and Page 617, Lines 1-15
B-30A	**SUBMITTED AT HEARING** – Filing revised response to JIESC's Undertaking #9, Volume 4, Page 916, Lines 2-26 and Page 617, Lines 1-14; Volume 6, Page 910, Lines 10-25

Exhibit No.	Description
B-31	**SUBMITTED AT HEARING** – Filing response to IPPBC Undertaking #3, Volume 4, Page 466, Lines 19-24
B-32	**SUBMITTED AT HEARING** – Filing response to CEC Undertaking #15, Volume 5, Page 833, Lines 25-26 and Page 834, Lines 1 -16
B-33	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne Undertaking #10, Volume 5, Page 673, Lines 4-26 and Page 674, Lines 1-9
B-33A	Letter dated October 27, 2008 filing REVISED response to Undertaking 10 (Exhibit B-33)
B-34	**SUBMITTED AT HEARING** – Filing response to JIESC Undertaking #8, Volume 4, Page 613, Lines 16-26 and Page 614, Lines 1-20
B-35	**SUBMITTED AT HEARING** – Filing response to CEC's Undertaking #16, Volume 5, Page 837, Lines 8-15
B-36	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #24, Volume 6, Page 972, Lines 8-17
B-37	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #5, Volume 4, Page 518, Lines 6 – 26 and Page 519, Lines 1-12
B-38	**SUBMITTED AT HEARING** – Filing response to JIESC's Undertaking #13, Volume 5, Page 767, Lines 15-24, Page 768, Lines 1-26 and Page 769 Lines 1-18
B-39	**SUBMITTED AT HEARING** – Filing response to JIESC's Undertaking #14, Volume 5, Page 772, Line 26 and Page 7730, Lines 1-5
B-39A	**SUBMITTED AT HEARING –** Filing Revised response to JIESC's Undertaking #14, Volume 5, Page 772, Line 26 and Page 7730, Lines 1-5
B-40	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #27, Volume 6, Page 988, Lines 6-26 and Page 989, Line 1
B-41	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #29, Volume 6, Page 969, Lines 17-26 and Page 970, Lines 1-16
B-42	**SUBMITTED AT HEARING** – Filing response to Ms. Worth's Undertaking #12, Volume 5, Page 720, Lines 10-26 and Page 721, Lines 1-12

Exhibit No.	Description
B-43	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #20, Volume 6, Page 913, Lines 20-26 and Page 914, Lines 1-2
B-44	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #25, Volume 6, Page 978, Lines 10-26 and Page 979, Lines 1-10
B-45	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #26, Volume 6, Page 981, Lines 25-26 and Page 982, Lines 1-16
B-46	**SUBMITTED AT HEARING** – Filing response to BCOAPO's Undertaking #11, Volume 5, Page 711, Lines 6-13
B-47	**SUBMITTED AT HEARING** – Filing response to Mr. Wait's Undertaking #18, Volume 6, Page 898, Lines 9-26 and Page 899, Lines 1-2
B-48	**SUBMITTED AT HEARING** – Filing response to Commission Panel's Undertaking #23, Volume 6, Page 947, Lines 19-26 and Page 948, Lines 1-25
B-49	**SUBMITTED AT HEARING** – Filing response to CEC's Undertaking #42, Volume 8, Page 1236, Lines 23-26 and Page 1237, Lines 1-11
B-50	**SUBMITTED AT HEARING** – Letter dated October 15, 2008 filing a report entitled "Contributing Factors and recommended Actions on the GM Shrum Generating Station Generator 3 Runner Failure"
B-51	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #22, Volume 6, Page 937, Lines 11-26 and Page 938, Lines 1-8
B-52	**SUBMITTED AT HEARING** – Filing response to Commissioner O'Hara's Undertaking #40, Volume 7, Page 1209, Lines 23-26 and Page 1210, Lines 1-3
B-53	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #46, Volume 8, Page 1269, Lines 4-24
B-54	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #7, Volume 4, Page 538, Line 26 and Page 539, Lines 1-26
B-55	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #19, Volume 6, Page 912, Lines 14-17
B-56	**SUBMITTED AT HEARING** – Filing response to BCOAPO/Ms. Worth's Undertaking #39, Volume 7, Page 1200, Lines 8-26 and Page 1201, Lines 1-2

Exhibit No.	Description
B-57	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #6, Volume 4, Page 5265, Lines 16-26 and Page 527, Lines 1-2
B-58	**SUBMITTED AT HEARING** – Filing response to JIESC's Undertaking #37, Volume 7, Page 1195, Lines 11-26 and Page 1196, Lines 1-24
B-59	**SUBMITTED AT HEARING** – Filing response to Commissioner O'Hara's Undertaking #17, Volume 6, Page 894, Lines 16-24
B-60	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #21, Volume 6, Page 934, Lines 19-26 and Page 935 Lines 1-22
B-60A	Letter dated October 27, 2008 filing REVISED response to Exhibit B-60
B-61	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #49, Volume 8, Page 1299, Lines 15-26 and Page 1300 Lines 1-12
B-62	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #51, Volume 8, Page 1334, Lines 10-26, Page 1335 Lines 1-26 and Page 1336, Lines 1-3
B-63	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes's Undertaking #56, Volume 9, Page 1391, Lines 1-23
B-64	**SUBMITTED AT HEARING** – Filing response to Commissioner O'Hara's Undertaking #76, Volume 7, Page 1128, Line 2 - Page 1129, Line 21; and Volume 8, Page 1222, Line 8 - Page 1228, Line 12; Page 1231, Lines 18-20
B-65	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes's Undertaking #32, Volume 7, Page 1126 Lines 16-26 and Page 1127 Lines 1-17
B-66	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes's Undertaking #33, Volume 7, Page 1127 Lines 19-26 and Page 1128 Line 1
B-67	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes and Commissioner Milbourne's Undertaking #34, Volume 7, Page 1129 Lines 25-26 and Page 1130 Lines 1-18
B-68	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #35, Volume 7, Page 1160 Lines 1-26 and Page 1162 Lines 1-16
B-69	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #41, Volume 7, Page 1212, Lines 6-16

Exhibit No.	Description
B-70	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #45, Volume 8, Page 1256 Lines 6-22
B-71	**SUBMITTED AT HEARING** – Filing response to Commissioner O'Hara's Undertaking #55, Volume 9, Page 1389 Lines 18-26, Page 1390 Lines 1-12
B-72	**SUBMITTED AT HEARING** – Filing response to Mr. Fulton's Undertaking #64, Volume 9, Page 1540 Lines 1-26, and Page 1541 Lines 1-2
B-73	**SUBMITTED AT HEARING** – Filing response to Commissioner Rhodes' Undertaking #68, Volume 10, Page 1627, Lines 2-12
B-74	**SUBMITTED AT HEARING** – Filing response to Commissioner Milbourne's Undertaking #72, Volume 10, Page 1658, Lines 3-18
B-75	Letter dated October 23, 2008 filing responses to Undertakings 28, 30, 50, 57, 65, 66, 67, 73, 77, 79, 82, 86, 87, 90, and 94
B-76	Letter dated October 27, 2008 filing responses to Undertakings 43, 47, 60, 61, 74, 75, 88, 92, 93, 96 and 99
B-77	Letter dated October 27, 2008 filing responses to Commission and Intervenor Information Requests Round 4
B-78	Letter dated October 28, 2008 filing responses to Undertakings No. 31, 36, 38,44, 53, 58, 59, 62, 69, 70, 71, 78, 81, 84, 85, 89, 91, 95, 98, 100, 101, 102, 103
B-79	**SUBMITTED AT HEARING** – Cope Local 378 Constitution
B-80	**SUBMITTED AT HEARING** – Response to Joint Industry Electricity Steering Committee Information Request No. 1.22(b)
B-81	**SUBMITTED AT HEARING** – NEB Transcript 14 dated February 28, 1995 regarding Order No. GH-S-94 GH-6-94Westcoast Energy Inc. Fort St. John Expansion Project/Grizzly Valley Expansion Project
B-82	**SUBMITTED AT HEARING** – Written Direct Evidence from Lloyd Guenther from the 1993 Revenue Requirements Application on behalf of the Council of Forest Industries of BC, the Mining Association of BC and the Electro-Chemical Producers
B-83	Letter dated November 19, 2008 filing remaining outstanding responses to Undertakings

Exhibit No.	Description
B-83A	**CONFIDENTIAL** - Letter dated November 19, 2008 filing the confidential attachments 1, 2 and 3 for Undertaking 113
B-83B	Letter dated November 21, 2008 filing amended response to Undertaking No. 112
B-83C	**CONFIDENTIAL** - Letter dated December 3, 2008 filing Undertaking No. 113 with confidential attachments 4, 5 and 6

INTERVENOR DOCUMENTS

C1-1	**RENTAL OWNERS AND MANAGERS SOCIETY OF BC –** Letter dated February 22, 2008, from Al Kemp, CEO, filing request for Registered Intervenor status and comments on the application
C1-2	Information Request No. 1 dated March 25, 2008 to BC Hydro and Power Authority
C1-3	Letter dated April 28, 2008 filing comments on the Procedural Conference
C1-4	Letter dated August 14, 2008 filing comments on the Negotiated Settlement Process
C2-1	**WAIT, ALAN –** Online web registration received February 25, 2008 filing request for Registered Intervenor status
C2-2	Letter dated March 6, 2008 filing comments on the interim rate increase
C2-3	Information Request No. 1 dated March 25, 2008 to BC Hydro and Power Authority
C2-4	Information Request No. 2 to BC Hydro received May 21, 2008
C2-5	Letter dated July 9, 2008 filing Information Request No. 3 to BC Hydro
C2-6	Letter dated September 24, 2008 filing comments on the Hearing Issues List
C3-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION LOCAL 378 (COPE 378) –** Email received February 25, 2008 from Lori Winstanley, filing request for Registered Intervenor status
C3-2	Information Request No. 1 dated March 25, 2008 to BC Hydro and Power Authority

Exhibit No.	Description
C3-3	Letter dated May 21, 2008, filing Information Request No. 2 to BC Hydro
C3-4	Letter dated July 9, 2008 filing Information Request No. 3 to BC Hydro
C3-5	Letter dated August 20, 2008 filing Statement of Issues and comments
C3-6	Letter dated August 13, 2008 filing request for Leave to Submit Evidence
C3-7	Letter dated September 5, 2008 from John J.L. Hunter, Hunter Litigation, legal counsel, filing Evidence of Gwenne Farrell
C3-8	Letter dated September 10, 2008 filing notice of new contact information
C3-9	Letter dated September 10, 2008 filing withdrawal of new contact information
C3-10	Letter dated September 11,2008 requesting BC Hydro update evidentiary record and reply to COPE evidence
C3-11	Letter dated September 23, 2008 filing comments on the draft Hearing Issues List
C3-12	**SUBMITTED AT HEARING** – Copy of the Accenture Client Satisfaction Annual Survey Results – February 2008
C3-13	**SUBMITTED AT HEARING** – Excerpt from response to Information Request No. 1.96.0 of the BC Hydro Revenue Requirements Application 2004/05 and 2005/06
C3-14	**SUBMITTED AT HEARING** – Copy of Table 11 - 2006 System Energy Supply – Demand Outlook
C3-15	**SUBMITTED AT HEARING** – Excerpt from BC Hydro's F2006 Call for Tenders – Electricity Purchase Agreements – Reasons for Decision, Appendix B to Order E-7-06, dated September 21, 2006
C3-16	**SUBMITTED AT HEARING** – Excerpt from BC Hydro's 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan - Decision, pages 76 to 81, dated May 11, 2007
C3-17	Letter dated October 27, 2008 from Mark S. Oulton, Hunter Litigation, legal counsel, filing request regarding BC Hydro response to Commission Information Request 1.35.1

Exhibit No.	Description
C4-1	**LEARMONTH, BOB –** Online web registration received February 25, 2008 filing request for Registered Intervenor status and email with comments
C4-2	Letter dated March 3, 2008, filing Information Request No. 1 to BC Hydro
C5-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated March 4, 2008 from R. Brian Wallace at Bull Housser & Tupper, filing request for Registered Intervenor status
C5-2	Letter dated February 7, 2008 filing comments opposing interim rate relief
C5-3	Letter dated March 25, 2008 filing Information Request No. 1 to BC Hydro
C5-4	Information Request No. 2 to BC Hydro dated May 21, 2008
C5-5	Letter dated July 9, 2008 filing Information Request No. 3 to BC Hydro
C5-6	Letter dated July 2008 filing Evidence on behalf of Lloyd G. Guenther, FSI Strategies
C5-7	Letter dated August 13, 2008 filing comments and request to cancel the Negotiated Settlement Process
C5-8	Letter dated August 14, 2008 filing request for an extension to file responses to Information Requests
C5-9	Letter dated August 19, 2008 filing responses to Information Request No. 1
C5-10	Letter dated August 21, 2008 filing revised evidence of L. Guenther submitted as Exhibit C5-6
C5-11	Letter dated September 10, 2008 filing comments on Cope 378 evidence
C5-12	Letter dated September 24, 2008 filing comments on the draft Hearing Issues List
C5-13	**SUBMITTED AT HEARING** – Filing copy of the F2007/F2008 Revenue Requirements, Volume 1 of 3, pages 1-9 to 1-11
C5-14	**SUBMITTED AT HEARING** – Filing copy of the 2004 to 2006 Revenue Requirements & BCTC Deferral Accounts, Executive Summary pages
C5-15	**SUBMITTED AT HEARING** – Filing copy of the Transcript from the BC Hydro Revenue Requirement Hearing, May 18, 2004, Volume 5, pages 476 to 491

Exhibit No.	Description
C5-16	**SUBMITTED AT HEARING** – Copy of email dated September 23, 2008 filing response to queries
C5-17	**SUBMITTED AT HEARING** – Letter dated October 19, 2008 filing request for consideration of the new CICA Handbook Section 3865 and 1530 on accounting process and supporting documentation
C5-18	JIESC issuing Information Request No. 4 dated October 23, 2008 to BC Hydro and Power Authority
C5-19	JIESC Response to Undertaking at Transcript Volume 14, Page 2624, Lines 13-18
C6-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BC (CECBC) -** Letter dated March 5, 2008 from Christopher P. Weafer, Own Bird, legal counsel, filing request for Registered Intervenor status
C6-2	Letter dated March 25, 2008 filing Information Request No. 1 to BC Hydro
C6-3	Letter dated May 21, 2008 filing Information Request No. 2 to BC Hydro
C6-4	Letter dated July 9, 2008 from Christopher Weafer, Owen Bird, legal counsel, filing Information Request No. 3 to BC Hydro
C6-5	Letter dated September 24, 2008 filing comments on the draft Hearing Issues List
C6-6	**SUBMITTED AT HEARING** – Filing excerpt from Information Request No. 1.2.5, dated July 5, 2006 of the BC Hydro F07/08 Revenue Requirements Application
C6-7	**SUBMITTED AT HEARING** – Filing Appendix K, Volume 2 of the BC Hydro Transfer Pricing Agreement, Fiscal year 2004
C6-8	Letter dated October 23, 2008 filing Information Request No. 4 to BC Hydro
C7-1	**CORIX MULTI-UTILITY SERVICES INC. (CORIX) -** Letter dated March 5, 2008 from Ronald Cliff, HighCliff Energy Services Ltd., filing request for Registered Intervenor status
C8-1	**HOWE SOUND PULP & PAPER LIMITED PARNERSHIP (HSLP)** – Letter dated March 5, 2008, from Pierre Lamarche, Manager Energy, filing request for Registered Intervenor status

Exhibit No.	Description
C9-1	**CITY OF NEW WESTMINSTER -** Letter dated March 6, 2008 request for Registered Intervenor status
C10-1	**TERASEN UTILITIES -** Letter dated March 7, 2008 request for Registered Intervenor status
C10-2	Letter dated March 25,2008 issuing Information Request No. 1 to BC Hydro
C11-1	**PEACE RIVER REGIONAL DISTRICT ("PRRD") -** Letter dated March 7, 2008 request for Registered Intervenor status
C11-2	Information Request No. 1 to BC Hydro dated March 17, 2008
C11-3	Letter dated May 21, 2008, filing Information Request No. 2 to BC Hydro
C12-1	**BRITISH COLUMBIA OLD AGE PENSIONER'S ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, END LEGISLATED POVERTY, FEDERATED ANTI-POVERTY GROUPS OF BC, AND TENANTS RESOURCE AND ADVISORY CENTRE ("BCOAPO *ET AL*") -** Letter dated March 7, 2008 request for Registered Intervenor status
C12-2	Letter dated March 25, 2008, filing Information Request No. 1 to BC Hydro
C12-3	Letter dated May 21, 2008, filing Information Request No. 2 to BC Hydro
C12-4	Letter dated July 9, 2008, filing Information Request No. 3 to BC Hydro
C12-5	Letter dated August 14, 2008 filing comments on the Negotiated Settlement Process
C12-6	Letter dated September 10, 2008 filing comments on Cope 378 evidence
C12-7	Letter dated September 12, 2008 filing response to BC Hydro De-contracting services
C12-8	Letter dated September 25, 2008 filing comments on the Hearing Issues List
C12-9	Letter dated October 23, 2008 filing Information Request No. 4 to BC Hydro

Exhibit No.	Description
C13-1	**FORTISBC INC. –** Online web registration received March 7, 2008 filing request for Registered Intervenor status
C14-1	**WEST FRASER MILLS** – Email dated March 7, 2008 from Bill Legrow, VP, Transportation & Energy, filing request for Registered Intervenor status
C15-1	**BC TRANSMISSION CORPORATION (BCTC)** – Letter dated March 7, 2008, from Marcel Reghilini, filing request for Registered Intervenor status
C16-1	**PLUTONIC POWER CORPORATION –** Online web registration received March 7, 2008 from Rupert A. Legge, filing request for Registered Intervenor status
C17-1	**ELK VALLEY COAL CORPORATION (EVCC)** – Email dated March11, 2008, from J. David Newlands, filing request for Registered Intervenor status
C18-1	**CATALYST PAPER CORPORATION –** Online web registration received March 13, 2008 from Dennis Fitzgerald, filing request for Registered Intervenor status
C19-1	**INDEPENDENT POWER PRODUCERS ASSOCIATION OF BC (IPPBC)** - Letter dated March 13, 2008, from David Austin, Tupper Jonsson & Yeadon, and on behalf of Steve Davis, President filing request for Registered Intervenor status
C19-2	Letter dated March 25, 2008 filing Information Request No. 1 to BC Hydro
C19-3	Letter dated July 9, 2008 filing Information Request No. 3 to BC Hydro
C19-4	Letter dated September 24, 2008 filing comments on the draft Hearing Issues List
C19-5	**SUBMITTED AT HEARING** – Filing article entitled "Plug-in hybrid vehicles debut in Seattle" from SperoNews
C19-6	**SUBMITTED AT HEARING** – Excerpt from BC Hydro 2004 – 2006 Revenue Requirements Application and BC Transmission Corporation Application for Deferral Accounts, page 36
C20-1	**BC SUSTAINABLE ENERGY ASSOCIATION, SIERRA CLUB OF CANADA BC CHAPTER (BCSEA ET AL) –** Letter received March 19, 2008 from William J. Andrews, filing request for Registered Intervenor status
C20-2	Letter dated March 25, 2008, filing Information Request No. 1 to BC Hydro

Exhibit No.	Description
C20-3	Letter dated October 23, 2008 filing Information Request No. 3 to BC Hydro
C21-1	**COLUMBIA POWER CORPORATION AND COLUMBIA BASIN TRUST ("CPC/CBT") -** Letter dated March 20, 2008 from Fred Weisberg, Weisberg Law Corporation requesting Intervenor status on behalf of CPC/CBT
C22-1	**ENERGY SOLUTIONS FOR VANCOUVER ISLAND SOCIETY –** Online web registration received March 20, 2008 from Ludo Bertsch, Horizon Technologies Inc. filing request for Registered Intervenor status
C23-1	**MEADE, STUART –** Letters dated February 26 and April 3, 2008, filing request for late Registered Intervenor status
C23-2	Letter dated July 30, 2008 filing Information Request No. 1 to BC Hydro
C24-1	**WESTPAC LNG –** Letters dated April 28, 2008, filing request for late Registered Intervenor status

INTERESTED PARTY DOCUMENTS

D-1	**MANITOBA HYDRO –** Online web registration received from Don Deviaene for Interested Party status
D-2	**GREENWING ENERGY –** Online web registration dated August 27, 2008 from Jake Gray requesting Interested Party status
D-3	**MORRISON, JOHN PAUL –** Online web registration dated September 8, 2008 requesting Interested Party status

LETTERS OF COMMENT

E-1	**MCKEE, MARK** – Letter of Comment emailed February 21, 2008, from Mark McKee of Victoria, BC
E-2	**BOULANGER, MAURICE** - Letter of Comment emailed February 21, 2008, from Maurice Boulanger of Salmon Arm, BC
E-3	**DESAI, FAIZEL** – Letter of Comment emailed February 21, 2008 from Faizel Desai

Exhibit No.	Description
E-4	**LARMON, A.** - Letter of Comment emailed February 22, 2008 from A. Larmon
E-5	**KILLMAN, PATRICIA** - Letter of Comment dated February 21, 2008 from Patricia Killman
E-6	**BROUSSEAU, TIMOTHY -** Letter of Comment dated February 27, 2008 from Timothy Brousseau
E-6-1	**BROUSSEAU, TIMOTHY -** Letter dated May 1, 2008 from Richard Neufeld, Minister of Energy responding to email from Timothy Brousseau
E-7	**SPEARS, FRED AND CHARLENE** – Letter of Comment dated March 2, 2008 from Fred and Charlene Spears
E-8	**PEACE RIVER REGIONAL DISTRICT -** Letter of Comment dated February 28, 2008 from Karen Goodings, Chair
E-9	**NEWLOVE, JOHN & MARGARET -** Letter of Comment dated March 11, 2008 from John & Margaret Newlove
E-10	**MADILL, MYLES -** Letter of Comment dated March 13, 2008 from Myles Madill
E-11	**LEONARD -** Letter of Comment dated May 9, 2008 from Leonard in Vancouver
E-12	**SMITH, HELEN -** Letter of Comment dated May 13, 2008 from Helen J. Smith in Vancouver, BC
E-13	**DAGGITT, MILLIE -** Letter of Comment dated May 13, 2008 from Millie Daggitt
E-14	**STANFORD, ELIZA -** Letter of Comment dated May 15, 2008 from Eliza Standford, Fort St. John, BC
E-15	**FAIRBRASS, MICHAEL -** Letter of Comment dated May 12, 2008 from Michael Fairbrass, Armstrong, BC
E-16	**HAWKINS, RON -** Letter of Comment dated June 11, 2008 from Ron Hawkins of Salt Spring Island, BC
E-17	**CASAULT, MR. & MRS. L. -** Letter of Comment dated June 27, 2008 from Parksville, BC