IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

AND

TRANSMISSION SYSTEM CAPITAL PLAN F2009 TO F2018

DECISION

July 10, 2008

Before:

Robert H. Hobbs, Chair
Liisa A. O'Hara, Commissioner

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1.0 INTRODUCTION

1.1 Application

On December 21, 2007 the British Columbia Transmission Corporation ("BCTC") filed its Transmission System Capital Plan F2009 to F2018 ("F2009 TSCP", "Application", Exhibit B-1) with the British Columbia Utilities Commission ("Commission" or "BCUC"). Regulatory approval of the F2009 TSCP was requested under sections 45(6), 45(6.1) and 45(6.2) of the Utilities Commission Act ("Act" or "UCA"). This Application is the fifth application associated with BCTC's management of the transmission system capital portfolios, having been preceded by applications or filings approved by Order No. G-103-04 for the first Transmission System Capital Plan, Order No. G-91-05 for the Transmission System Capital Plan F2006 to F2015 Application ("F2006 TSCP Application"), Order No. G-76-06 for the Transmission System Capital Plan F2006 to F2015 Update Filing ("F2006 TSCP Update Application"), and Order No. G-69-07 for the Transmission System Capital Plan F2008 to F2017 Application ("F2008 TSCP Application"). Each Order was accompanied with a Decision or Reasons for Decision, identified respectively as the G-103-04 Decision, the F2006 TSCP Decision, the F2006 TSCP Update Decision, and the F2008 TSCP Decision.

Although the F2009 TSCP describes projects within the period F2009 to F2018, BCTC only requests approval for capital expenditures in F2009 and F2010. BCTC intends to file its F2010 capital plan sometime in 2008, which is anticipated to request approval for any additional projects identified for F2010 and to seek approval for projects and programs beginning in F2011. Previous capital plan filings were rolling two-year plans. BCTC submits that starting with the F2010 capital plan, it plans to publish bi-annual plans. The filing of these plans will alternate with the filing of BCTC's revenue requirements applications, which will also be two-year applications (Exhibit B-1, p. 10). This change in the timing of capital plan filings will be addressed further in Section 2.1.

1.2 Regulatory Requirements

BCTC is required by Section 45 of the UCA to file annual capital plans. Under the Master Agreement between BCTC and British Columbia Hydro and Power Authority ("BC Hydro"), BCTC is responsible for planning, constructing and obtaining regulatory approvals for enhancements, reinforcements, and sustaining and growth investments in BC Hydro's transmission system. BCTC has therefore filed for approval of capital investments for BC Hydro's transmission system which will be funded by BC Hydro, as well as for capital investments directly funded and owned by BCTC.

1.3 Orders Sought

In the Application BCTC is seeking an order which states that the F2009 TSCP meets the requirements of sections 45(6) and 45(6.1) of the Act, approves the F2009 TSCP under section 45(6.2)(a) and, pursuant to section 45(6.2)(b), determines that all projects and programs listed in Section 1.6.2 of the Application are in the public interest.

The orders sought under section 45(6.2)(b) of the Act pertain to certain specified projects in the (1) Growth Capital Portfolio (2) Sustaining Capital Portfolio and (3) the BCTC Capital Portfolio.

1.4 Regulatory Review Process

By letter dated December 21, 2007, BCTC filed its F2009 TSCP Application. Commission Order No. G-173-07 dated December 24, 2007 subsequently established a written hearing process and Regulatory Timetable.

Interventions were subsequently received from the Joint Industry Electricity Steering Committee ("JIESC") (Exhibit C1-1), BC Hydro (Exhibit C2-1), Elk Valley Coal Corporation (Exhibit C3-1), the Independent Power Producers Association of BC ("IPPBC") (Exhibit C4-1), FortisBC Inc. (Exhibit C5-1), the British Columbia Old Age Pensioners Organization et. al. ("BCOAPO") (Exhibit C6-1), the Matsqui First Nation Lands Department (Exhibit C7-1), and the Pipeline Power Group and Associates ("PPGA") (Exhibit C8-1).

By letter dated January 7, 2008 BCTC proposed to hold a workshop to provide an overview of the F2009 TSCP to Commission staff and Registered Intervenors (Exhibit B-2). The workshop was held on January 22, 2008, and BCTC subsequently submitted the workshop presentation materials and attendance list (Exhibit B-3).

BCTC filed the responses to Commission and Intervenor Information Requests on February 27, 2008 (Exhibit B-5-1), along with a request for confidential treatment of certain Information Request responses (Exhibit B-5-2).

BCTC's Argument was filed on March 6, 2008, and the Submissions of three Intervenors, BC Hydro, BCOAPO and IPPBC, were filed by March 14, 2008, with BCTC's Reply filed on April 1, 2008.

In Order No. G-107-08 dated June 26, 2008, the Commission approved, *inter alia*, the F2009 TSCP with these reasons to follow.

1.5 Commission Approval of Expenditures

Article 19 of the Master Agreement ("MA") between BCTC and BC Hydro addresses the subject of transmission system capital expenditures. Under Article 19.5, BCTC is required to obtain the Commission's approval, or BC Hydro's consent, before BC Hydro is required to fund these expenditures.

Article 19.6 of the MA provides that if the Commission subsequently determines that any of these expenditures were imprudent and not recoverable in rates, BCTC is required to bear these costs.

BCTC states that given the concurrent requirements of section 45 of the Act and Article 19 of the MA, BCTC will generally seek the Commission's approval prior to proceeding with transmission system capital investments as this approach adds certainty to the capital spending interaction between BCTC and BC Hydro (Exhibit B-1, p. 13).

BCTC further reaffirms that for those projects identified in Section 1.6.2 of the Application, BCTC is seeking the Commission's approval that capital expenditures on these projects are in the public interest, rather than for a precise expenditure. BCTC also states that it will provide explanations for any projects with significant cost variances and that it recognizes that in some cases a prudency review may follow such projects (Exhibit B-1, p. 14).

In the F2008 TSCP Decision, the Commission Panel stated that in cases where project expenditures vary significantly from the estimate provided, there may be further consideration of the recovery of costs in rates, as determined, in most cases, during a revenue requirement proceeding (F2008 TSCP Decision, p. 4).

BC Hydro's Owners' Revenue Requirement ("BCH ORR") reflects the costs related to BC Hydro's ownership of the transmission system and management of transmission property rights as stated in Article 4.7 of the MA. In its F2009 and F2010 Transmission Revenue Requirement Application ("RRA") BCTC stated that BCTC and BC Hydro propose that the BCH ORR be reviewed in the BC Hydro F2009-2010 Revenue Requirement Application, with the exception of non-tariff revenues. By Order No. G-105-08 the Commission approved a Negotiated Settlement Agreement for the BCTC RRA which accepts this proposal.

Commission Determination

The Commission Panel accepts the process outlined by BCTC for approval of capital expenditures and the eventual cost recovery in rates but notes that the increasing use of negotiated settlements in the case of revenue requirement applications may risk the transparency of cost recovery and disallowance of capital expenditures in rates.

1.6 The 2007 Energy Plan

The Provincial Government released "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan") on February 27, 2007. BCTC identifies three Policy Actions of particular significance to it, namely Policy Actions 12, 13 and 14. Policy Action 12 relates to technological capability and efficient and reliable delivery of power, Policy Action 13 relates to maintaining adequate transmission capacity and implementation of a transmission congestion relief policy, and Policy Action 14 relates to reliability standards consistent with North American Standards.

BCTC described projects and activities that fall under the umbrella of Policy Actions 12 and 13 (Exhibit B-5-1, BCUC 1.84.1, Attachment). However, BCTC states that the F2009 Capital Plan does not reflect any incremental expenditures arising from implementation of the 2007 Energy Plan (Exhibit B-1, p. 30).

1.7 Special Directions

In response to Special Direction No. 9 ("SD9") issued by the Government to the Commission in November 2003, BCTC put forward the Transmission Expansion Policy ("TEP") Paper that identified three types of projects that BCTC could advance under SD9, generally, projects supporting development of generation in B.C., projects that restore or enhance existing capacity, and projects that expand import/export capacity. More specifically, the projects are expected to fall into the following categories:

- A planned system upgrade for a Network Customer that can be beneficially advanced in time;
- A system upgrade required for either a Network, Point-to –Point, or Interconnection customer that can beneficially be made larger than the immediate requirement;
- A project that BCTC identifies as having future benefits, but which has not been triggered by a customer request (Exhibit B-1, Appendix B, pp. 70-71).

BCTC's first project under SD9 was the 5L51/52 Thermal Upgrade Project, approved by Order No. G-58-08. BCTC is considering options for the Golden 69 kV System Reinforcement Project and the Westbank 139 kV Reconfiguration Project in the context of potential SD9 opportunities (Exhibit B-1, p. 142; Exhibit B-5-1, BCUC 1.46.1). This topic will be further addressed in Section 3.1.

1.8 FERC Order No. 890

BCTC describes a number of activities associated with the U.S. Federal Energy Regulatory Commission's ("FERC") Order No. 890, including actively participating in North American Electric Reliability Corporation ("NERC") workshops addressing the standardization of methodologies to determine Available Transmission Capacity ("ATC"), consulting customers and stakeholders on transmission planning processes, and assessing the requirement for any necessary tariff changes driven by FERC Order No. 890 (Exhibit B-1, p. 405).

BCTC identifies the Market Operations Business System Project as starting in F2009 and being completed in F2010, but a definitive scope and estimate were not available because BCTC states the full ramifications and extent of work required to implement the changes associated with FERC Order No. 890 are not known at this time. BCTC plans to make a separate submission once it has determined whether a capital or other solution is preferred (Exhibit B-1, p. 363).

1.9 Subsequent Events

The Act was amended by the Utilities Commission Amendment Act, 2008 ("Amending Act"), which received Royal Assent on May 1, 2008. The Amending Act repealed sections 45(6.1) and 45(6.2) of the Act, under which BCTC is seeking approval of this Application. By virtue of the *Interpretation Act* and the timing of this Application, it remains governed by the repealed sections 45(6.1) and 45(6.2) of the Act.

Section 5 of the Act has been amended to require the Commission to conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or a different period if specified by the minister. This inquiry must begin by March 31, 2009, and at least once every 6 years after the conclusion of the previous inquiry.

Commission Determination

The Commission Panel considers the Application a filing pursuant to the repealed sections 45(6.1) and 45(6.2) of the Act.

2.0 BCTC CAPITAL PLANNING PROCESS

2.1 Timing of Capital Plan Filings

BCTC has filed Capital Plans annually since 2005. BCTC states that it plans to publish its Capital Plan and to file it with the Commission bi-annually beginning with the F2010 Capital Plan. Previous filings were rolling two-year plans, but after consulting stakeholders BCTC has decided that bi-annual plans will be more efficient administratively. The next BCTC revenue requirement application will also be a two-year application, and it is scheduled to alternate with the timing of the next two-year BCTC Capital Plan. Later in 2008, BCTC intends to file its F2010 Capital Plan, which will request approval for any additional projects identified for F2010 and to seek approval for projects and programs beginning in F2011. In this Application BCTC seeks approval of projects and programs for F2009 and F2010 (Exhibit B-1, pp. 10-11).

BCTC stated that Commission Order No. G-139-06 approved a settlement agreement for the BCTC F2007 Transmission Revenue requirement. The settlement provided that, among other things:

> "6. As part of its next revenue requirement application ("RRA"), BCTC will examine and address the desirability of harmonizing its future RRA filings with BC Hydro's RRA filings and will include a recommendation based on this analysis" (Exhibit B-5-1, BCOAPO 1.1.1, Attachment p. 1).

BCTC informed the Commission and stakeholders that such a harmonization would not be desirable and the Commission recognized this recommendation in Letter No. L-92-07. Instead, BCTC decided to focus on the objective of improving the efficiency of regulatory processes and improving transparency of consistent treatment of costs between BCTC and BC Hydro applications where appropriate, regardless of how that is achieved (Exhibit B-5-1, BCOAPO 1.1.1, Attachment, p. 1) The outcome of this process was the new filing timetable for the RRA and capital plan filings.

BCTC confirmed that under the new filing plan there will be occasions where approval for some capital expenditures in the "second year" of the Revenue Requirement Application ("RRA") will have to be sought as a part of the RRA as opposed to the capital plan filing. BCTC does not see this as a hindrance to the new bi-annual process.

BCTC is not required to seek Commission approval for capital expenditures under section 45(6.2)(b) of the Act but seeks these approvals because of the risk imposed by its limited capitalization. Furthermore, BCTC requires approval for recovery in rates of costs of all capital projects with an in-service date during a test period (Exhibit B-5-1, BCOAPO 1.1.1).

Commission Determination

The Commission Panel recognizes BCTC's efforts to streamline the regulatory process and improve the quality of its applications and their communication to customers in both the capital plan and RRA filings. The Commission Panel notes, however, that the F2007 RRA was approved by way of a Negotiated Settlement Process ("NSP"), and that F2008 BCTC RRA required no rate increase due to a change in an accounting policy approved by the Commission, and that the F2009 and F2010 RRA was recently approved by way of another negotiated settlement. Against this backdrop, and while recognizing that the ultimate impact on customer rates is not examined, in the case of the sustaining and growth portfolios, until a BCTC RRA is reviewed, the Commission Panel believes that BCTC could consider further efficiencies by combining RRA and Capital Plan filings, perhaps to be disposed of jointly by way of a negotiated settlement. However, the Commission Panel also believes that a more important consideration may very well be the internal capital planning cycle of BCTC. Ideally, the capital plan filed with the Commission will be the same capital plan that is being used for management purposes. For that reason, the timing of capital plan filings with the Commission should, in most instances, be determined by management preferences.

2.2 BCTC Planning Standards

BCTC is a member of the Western Electricity Coordinating Council ("WECC"), which is a regional member of NERC. BCTC states it plans and operates the transmission system in accordance with NERC planning and operating standards, augmented by WECC. NERC has undertaken to update and augment its Planning Standards and Operating Policies into new NERC Reliability Standards, which became mandatory in the United States in June 2007. BCTC states that WECC may suggest NERC add more mandatory standards to address WECC concerns. BCTC further states that it is currently reviewing the NERC Reliability Standards, and plans to file a BCTC Reliability Standards document with the Commission in the spring of 2008 (Exhibit B-1, Appendix C, p. 1).

Policy Action 14 of the 2007 Energy Plan stated the provincial government's objective to "Ensure that the province remains consistent with North American transmission reliability standards" (2007 Energy Plan, pp. 9-10). BCTC stated that to achieve this goal, it has been leading a process to obtain stakeholder feedback as to how industry consistent reliability standards could be adopted in B.C. (Exhibit B-5-1, PPGA 1.1.3). BCTC does not interpret Policy Action 14 as requiring full compliance with all NERC standards, but stated that adherence to a set of common standards is beneficial to B.C. (Exhibit B-5-1, BCUC 1.9.1).

BCTC notes that the WECC Planning Standards state:

> "To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards … for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance" (Exhibit B-1, Appendix C, p. 2).

BCTC stated that is does not have any standards that differ from NERC/WECC specified standards, but provided additional clarifications regarding the BCTC's interpretation and application of certain standards concerning underfrequency limits, generation shedding for single contingency events, and over-voltage line tripping (Exhibit B-5-1, BCUC 1.90.1). With respect to underfrequency limits, BCTC has adopted, for internal impacts only, a less stringent standard than the WECC standard. With respect to generation shedding for single contingency events, BCTC's policy is to avoid the use of generation shedding for first contingency events. BCTC claimed support for this policy in the NERC standards which disallow curtailment of firm transfers for single contingency events, and in the WECC's Minimum Operating Reliability Criteria, which require generation reserves to be carried for loss of generation capacity due to forced outages of generation or transmission. BCTC allows exceptions to this general policy if the amount of shedding is less than the largest unit on the transmission system, and the required investment to avoid the shedding cannot be justified (Exhibit B-1, Appendix C, p. 7). With respect to over-voltage line tripping, BCTC's policy is that the line over-voltage protection scheme shall not be triggered when the system responds to a single or double contingency.

BCTC states that it uses coincident regional peak demand forecasts for assessing the system's compliance to NERC/WECC Planning Standards on a regional area or system-wide basis, and uses non-coincident station peak demand forecasts when assessments are being performed for local area or individual substation performance. If the assessments show the need for reinforcements, BCTC complements these assessments with probabilistic analysis to validate the need (Exhibit B-1, p. 77).

BC Hydro believes, particularly in cases involving the risk of voltage collapse and cascading outages, that the normal planning criteria of not allowing generation shedding for single contingencies should be followed (BC Hydro Argument, p. 2).

Commission Determination

In the F2008 TSCP Decision, the Commission Panel noted that the NERC/WECC Planning Standards allow generation shedding for single contingencies, and that BCTC has adopted a policy to avoid the use of generation shedding for single contingency events, with certain exceptions (F2008 TSCP Decision, p. 14). The Commission Panel acknowledges the references BCTC has made to the NERC/WECC Planning Standards in support of this policy but still notes that these planning standards do allow generation shedding for single contingencies. The Commission Panel is concerned that a policy to avoid the use of generation shedding for all single contingency events may result in non-economic capital expenditure decisions, and a careful evaluation of projects initiated under this policy is necessary to justify the economic and reliability benefits associated with the capital expenditure. That this policy is specific to BCTC and not mandated by the NERC/WECC Planning Standards indicates to the Commission Panel that it is not a "normal planning criteria" as suggested by BC Hydro, but rather is an attribute unique to the system managed by BCTC. **The Commission Panel directs BCTC to continue identifying in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for single contingency events.**

2.3 Definition and Implementation Expenditures Pending Commission Approval

BCTC describes the capital planning process in Section 4 of the Application. BCTC states that after managers have reviewed study work results, which are expensed, they may authorize capital funds to proceed with Definition Phase work, and that Commission approval may be sought for larger non-routine projects or projects likely to require a Certificate of Public Convenience and Necessity ("CPCN") application. Smaller projects in the Definition Phase, or near the Definition Phase, are included in the Capital Plan to seek public interest approval for the entire project (Exhibit B-1, p. 50).

In the F2008 TSCP Decision the Commission specifically denied Definition Phase funding for two projects citing concerns regarding existing transmission expansion policies for the identification of alternatives during the Planning Phase evaluation. One of these projects was Definition Phase funding for the Golden 69 kV System Reinforcement Project ("Golden Project") (F2008 TSCP Decision, p. 147).

BCTC has again requested Definition Phase funding for the Golden Project in the amount of $3.0 million. BCTC states that it has not identified the preferred option for system reinforcement but identified ten options being considered and that project risk included long lead times should a transmission solution be the preferred option (Exhibit B-1, pp. 142-147).

The F2008 TSCP Decision also stated that:

> "BCTC is directed to provide with its next capital plan its position as to the disposition of costs for Definition Phase project costs, in circumstances where the need for the project is either established in the Planning Phase or assumed for the purposes of completion of the Planning Phase, but the project is no longer needed by the time of completion of the Definition Phase, either due to changed circumstances within the control of BCTC or due to further analysis completed after the Planning Phase" (F2008 TSCP Decision, p. 16).

BCTC states that Definition Phase costs for a cancelled project are expensed in the year the project is cancelled and that a "project/asset write-off account, to which cancelled Definition Phase project costs are charged, is currently included in the depreciation forecast for BC Hydro Transmission. In the event that the write-off amounts are significant, BCTC would likely apply to the Commission for recovery of these costs in rates" (Exhibit B-1, p. 382).

Commission Determination

The Commission Panel accepts the BCTC suggestion that the appropriate time for a review of the treatment of Definition Phase costs if when BCTC applies to have those costs recovered in rates during a revenue requirements proceeding. However, BCTC should provide a schedule of cancelled projects with Definition Phase costs exceeding $200,000 with each transmission capital plan.

The Commission Panel is satisfied that BCTC has appropriately considered existing transmission expansion policies for the identification of project alternatives in the case of the Golden project, and approves, under Section 45(6.2)(b) of the Act the expenditures related to the project as being in the public interest.

2.4 Emergency Capital Expenditures

In the F2008 TSCP Decision the Commission agreed that emergency expenditures should not be forecast in capital portfolios and should continue to be the subject of requests for approval of expenditures subsequent to the completion of repairs. The Commission further directed that BCTC should track and report past years' approved Emergency Capital Expenditures as a separate line item when tracking Sustaining Capital Expenditures (F2008 TSCP Decision, p. 19).

BCTC states that it provided information on historical and current Emergency Capital Expenditures in Table 6-2 of Exhibit B-1 and that BCTC will continue to report the information in the future (Exhibit B-1, p. 383). Table 6-2 contains a breakdown of historical Emergency Expenditures for F2006 and F2007 and references the Commission Letter approving the expenditures (Exhibit B-1, p. 191). Table 6-2 also shows three different expenditures forecast for F2008 and F2009 which have not been approved by the Commission, specifically the BUT 2CB1 Failed Circuit Breaker Replacement, the PLC 984 Replacement at Williston, Ingledow, and Meridian, and the Drop-in Substation Control Building for Fraser Flood. The Drop-in Substation Control Building for Fraser

Flood has since been redeployed to the Colwood Substation in support of major infrastructure upgrades (Exhibit B-1, p. 250). The PLC 984 Replacement at Williston, Ingledow, and Meridian expenditures were initiated in response to a failure at Williston Substation. Expenditures for this initiative are forecast $1.0 million for each of F2008 and F2009 and $0.3 million for F2010 (Exhibit B-1, p. 258). Future replacements at fourteen other substations will be undertaken under existing programs according to criticality.

Commission Determination

The Commission Panel's view is that the existing process on a project by project application by BCTC when emergency repairs are completed has worked well. The Commission Panel notes that the Drop-in Substation Control Building for Fraser Flood has been redeployed to Colwood Substation, hence the expenditures should be assigned to those projects rather than being classified as an Emergency Capital Expenditure. Regarding the PLC 984 Replacement initiative, it is the Commission Panel's view that the costs associated with the repair and replacement of the initial Williston station failure were properly categorized as an Emergency Capital Expenditure. Absent evidence indicating imminent failure, it is not apparent that the non-failure driven replacements at Ingledow and Meridian fall into the same category, having been replaced in a planned, albeit expedited, fashion in advance of any failure of the equipment. The Commission Panel does not approve the forecast amounts of Emergency Capital Expenditures at this time and will reduce the forecast Sustaining Capital Portfolio accordingly. **The Commission Panel directs BCTC to continue to track past years' Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures.**

2.5 UMS Group Report on BCTC

In August 2007, BCTC commissioned a study and report by the consulting firm UMS Group Inc. ("UMS"). The final report dated December 17, 2007 was provided at Appendix I of Exhibit B-1.

BCTC states that UMS is a well established leader in benchmarking and the identification of best practices for utilities and uses proprietary techniques for normalizing data to allow valid comparisons among companies operating in different regions with varied market drivers and regulatory requirements. BCTC states that UMS' terms of reference primarily required the assessment of BCTC's levels of spending in comparison to other transmission utilities and those known to be good and superior performers (Exhibit B-1, p. 26). BCTC further states that while the primary purpose of the study was to obtain input on BCTC's spending levels, UMS was also asked to address BCTC's Asset Management processes, capabilities and effectiveness (BCTC Argument, p. 5).

The findings of UMS' analysis are summarized as follows:

> "BCTC's costs for transmission system investments (Growth, Sustain and OMA), including those projected out to 2009, are below the range of what should be expected for a system like BCTC's.
>
> We can expect to see BCTC's costs of replacements grow steadily over the next ten years as it begins to address an asset replacement wave and balances the timing of the spending for replacements against workforce availability. It may need to advance replacements to ensure a manageable workload.
>
> BCTC's system performance is good and is reflective of solid work being done by BCTC in managing the assets and in making sound investment decisions.
>
> BCTC is a solid Asset Manager. Its analytical capabilities are logical, credible and can reasonably be relied upon.
>
> BCTC has continuously improved upon its Asset Management capabilities with results clearly evident in the system cost and operations performance, and is actively working on continuous improvement efforts.
>
> BCTC will be facing a number of challenges in the next several years as its asset base ages and the effects of several externalities become clearer.
>
> We did identify gaps in BCTC's performance that are consistent with other Asset Management organizations at BCTC's stage of implementation. BCTC is aware of the gaps and is committed to working to close them" (Exhibit B-1, Appendix I, p. 1-1).

BCTC affirms that it is aware of the gaps identified by UMS and is taking action and that further actions required need to be thoughtful in order to avoid being over-committed. BCTC states the most important UMS recommendations for closing the gaps are:

> “ (a) Continue the evolution toward a “One Asset” view. In the short-term, this would consist of finding cross group working strategies that ensure better cross portfolio collaboration;
>
> (b) Ensure there is a clear, uniform and well understood vision of the transmission system 20 years out;
>
> (c) Develop a Asset Management IT strategy, and system architecture;
>
> (d) Review the externalities identified in the UMS report (e.g., NERC/WECC mandatory standards) and evaluate which should be addressed in the near term and medium term;
>
> (e) Develop a strategy and comprehensive plan to address the end of life replacement wave that appears to be on the horizon; and
>
> (f) Improve Performance Management systems and reporting by going beyond asset performance to include, for example, Contractor performance” (Exhibit B-1, p. 37).

BCTC stated it retained UMS to provide advice in response to issues raised by the Commission and stakeholders at various time and cited four examples from previous decisions or settlements. BCTC further stated that UMS was retained to review Sustaining Capital Expenditures and compare them to the levels found worldwide in good and superior performing utilities which it stated would also address a Commission directive regarding benchmarking which accompanied Commission Order No. G-96-04 (Exhibit B-5-1, BCUC 1.4.1).

The directive referenced was:

> “The results of the benchmarking studies, as provided by the PA Consulting Group report and the Haddon Jackson Report, are a useful means of assessing the appropriateness of reliability programs. The Commission Panel suggests that if BC Hydro and BCTC are not presently obtaining those reports annually they should do so on an annual basis. In addition, the Commission Panel directs BC Hydro to update the benchmark studies for its next revenue requirements application” (Decision accompanying Order No. G-96-04, p. 91).

BCTC also stated that during the course of the review UMS was further retained to go beyond the comparative evaluation of Sustaining Capital Expenditures and to evaluate and recommend changes regarding asset management processes and practices. When requested to provide BCTC’s terms of reference for the UMS report, BCTC provided a document entitled “Proposal for Support For F2009 – F2018 Transmission System Capital Plan Application” (the “Proposal”) (Exhibit B-5-1, BCUC 1.4.1).

The undated Proposal was prepared for, and accepted by, Fasken Martineau DuMoulin LLP (“Fasken”), counsel for BCTC, in a response to a request by Fasken to provide support services in developing and filing evidence. UMS stated that as the study developed they would work with Fasken closely to ensure that UMS’ focus remains on the areas where UMS can add the greatest value in the development of the case. UMS suggested a recommended approach to: (1) review the relationship between sustaining expenditures and reliability; (2) investigate optimal spending levels contrasting BCTC with industry best practices; and, (3) investigate industry practices for prioritization or optimization. In addition UMS proposed to review and provide an opinion on BCTC’s System Asset Management tool suite. The Proposal cited that a detailed work plan was attached as Exhibit A to the Proposal, but no such attachment was provided. (Exhibit B-5-1, BCUC 1.4.1, Attachment 1, pp. 4-6)

BCTC stated that it paid UMS US$459,000 for the completed study and anticipated additional costs of approximately $25,000 related to responding to Information Requests. As of February 27, 2008 BCTC stated that the costs had not been recovered in rates and that it expected the costs would be recovered in test year revenue requirements, or through the Regulatory Expense Deferral Account, should it receive Commission approval to clear variance balances (the difference between actual and forecast regulatory expenses) (Exhibit B-5-1, BCUC 1.4.2). These amounts were not separately identified in the BCTC F2009-F2010 RRA, and in describing Regulatory expenses, BCTC states that “Variances in Regulatory Affairs expenditures from year to year are driven primarily by the number and magnitude of regulatory proceedings that BCTC initiates or participates in” (BCTC F2009-F2010 Revenue Requirements Application Proceeding, Exhibit B-1, pp. 152,154).

Commission Determination

The Commission Panel is concerned that BCTC did not provide terms of reference, as opposed to a consultant’s proposal, for the UMS report. While the evidence is not clear, there is considerable support for the thesis that the document was prepared primarily as regulatory support, rather than to improve BCTC's capital planning process and capital program execution. This thesis is supported in part by the nature of the analysis UMS undertook to provide, the retention of UMS through legal counsel rather than by an operating department, and the intent to recover the costs of the report as a regulatory expense. The Commission Panel believes that the UMS report does provide useful information on spending levels in other utilities, and recognizes that the use of consultants to provide regulatory input can be helpful. However, the Commission Panel further questions the value of the UMS report to support the level of Sustaining Capital Expenditures because the spending levels provided for benchmark companies included all capital (Growth and Sustaining) and OMA expended on the assets. Considerable judgement was used by UMS to remove extraordinary spending to ensure comparability between BCTC, the proxies, and the peer group averages. The Commission Panel is also concerned about the lack of visibility of this significant expense in BCTC's F2009-F2010 RRA and the overall transparency of consulting expenses. **The Commission Panel expects that in the future such expenditures will be provided with greater transparency in both the capital planning and revenue requirement processes.**

2.6 Goto Sargent Report

BCTC states it retained the firm of Goto Sargent Inc. ("Goto") in June 2007 in order to provide, among other things, an opinion on the level of confidence BCTC should have in the life and annual forecast numbers in the project portfolio. BCTC states that Goto's recommendations were made from the perspective of managing projects for cost and schedule performance. Goto's recommendations indicated a need for better estimates, tools and disciplined project execution by BCTC and its service provider in order to improve the level of confidence in forecast costs and the efficient execution of projects. Goto's report is dated July 10, 2007, and when UMS was subsequently retained in August 2007, UMS' assessment of these issues confirmed Goto's findings (Exhibit B-1, pp. 40-41).

BCTC described a seven point action plan to address issues raised by Goto, many parts of which focus on the coordination with, and enhancement to, the skill sets of BCTC's service provider, BC Hydro Engineering (Exhibit B-5-1, BCUC 1.11.1). BCTC states it is working closely with BC Hydro Engineering on their initiatives and are confident that better estimates, better tools, and enhanced efficiency in the execution of projects will be realized (Exhibit B-1, p. 41).

2.7 Post Implementation Reviews and Reports

In the F2008 TSCP Decision the Commission provided directions to BCTC regarding two aspects of Post-Implementation reporting. The first directive was as follows:

> "Therefore, the Commission Panel directs BCTC to annually review projects with a budget in excess of $10 million, where the budgeted costs differs from actual by 20 percent or more, or where the project in-service date changed by in excess of six months, and prepare an internal report of the lessons, if any, that were learned from the project implementation and that may be applicable to future projects. The report should make reference to the Project Implementation Risk Matrices, and how this tool influenced the outcome. The report could also address issues such as project management, contracting and external matters that were contributing factors to the outcome. The Commission Panel directs BCTC to provide a list of those projects for which a report was prepared in its next capital plan" (2008 TSCP Decision, p. 20).

In response, BCTC provided a table showing projects over $10 million completed between September 2005 and November 2007. The table showed that only one project had a cost variance in excess of twenty percent and that no project had an in-service date delay of more than six months. BCTC further states that it has revised its Project Management standards to expand the content of its Project Completion Reports to include the identification of lessons learned. The Project Completion Reports will also address the other issues identified by the Commission, and the use of the Project Implementation Risk Matrix will be included in BCTC's Project Management standards when its development is completed (Exhibit B-1, pp. 384-385).

In the F2008 TSCP Decision the Commission also directed BCTC to include in its next capital plan filing information regarding variances exceeding both ten percent and $100,000 of budgeted amounts submitted in the F2008-F2017 TSCP Application and to continue to report such amounts in future filings. BCTC provided a list of projects in progress which matched these criteria and committed to continue providing this information in the future (Exhibit B-1, p. 385).

Commission Determination

The Commission Panel is satisfied that BCTC has complied with the intent of its directions regarding lessons learned and finds that BCTC has appropriately modified its Project Completion Report such that it is not necessary for BCTC to provide a list of projects for which a report was prepared in future filings. The Commission Panel believes the variance reporting continues to be useful.

2.8 Prioritization Methodology

2.8.1 Introduction

In F2007 BCTC introduced a formal methodology for the prioritization of projects in each portfolio as a means to assist senior management in making project selection and deferral decisions. BCTC states the Prioritization Model ("PM") is an aid which ultimately does not relieve BCTC of decision making responsibility. BCTC states it has made adjustments to the model based on experience, Commission directives and the changing business environment. BCTC expects the PM to continue to evolve and change over time (Exhibit B-1, p. 55).

The PM was described in some length in the F2008 TSCP Decision, pages 40-44, and therefore that description will not be repeated here.

2.8.2 Treatment of Line Losses

BCTC stated that line loss reductions and trade benefits are not included in the financial criteria but are only included in the market efficiency criteria because the concept behind the prioritization is that the financial category only includes revenues and benefits that flow directly to BCTC. BCTC further stated that "By separating BCTC benefits from third party benefits, the prioritization process is able to put different weights on BCTC and third party benefits" (Exhibit B-5-1, BCUC 1.17.1).

BCTC describes the market efficiency criteria as:

> “ (a) Real Line Losses Reduction: the estimated reduction in transmission line energy losses due to the investment;
>
> (b) Congestion Reduction: the estimated reduction in annual congestion due to the project;
>
> (c) Trade Benefits: the investment’s expected impact on trade; and
>
> (d) Transmission Expansion Opportunity: **the benefits to ratepayers** of the investment related to BCTC's Transmission Expansion Policy” (emphasis added) (Exhibit B-1, p. 58).

Commission Determination

The Commission Panel notes that when calculating the financial impact of non-BCTC portfolio projects the impact is on BC Hydro rates and hence ultimately BC Hydro’s customers. Considering for instance loss reduction savings, which will ultimately serve to reduce rates for BC Hydro customers, the Commission Panel is not convinced there is a substantial distinction, but for timing, between the impact on BC Hydro’s rates caused by capital expenditures or line losses. The foregoing notwithstanding, the Commission Panel recognizes that in some instances it may be reasonable to give a factor which can be monetized at the ratepayer level, a weight or importance beyond financial terms. The Commission Panel recognizes that savings, such as loss reductions, that accrue to third parties that do not impact BC Hydro’s rates, or BCTC rates, should not be included in the financial category, but may receive weight in another category. The Commission Panel encourages BCTC to comment on this issue in its next capital plan.

2.8.3 Application of Expert Judgment and Subjectivity

BCTC states that once needs and alternatives have been identified, the PM is then employed. In order to finalize results expert judgment is applied. Expert judgment addresses factors not addressed by the optimization tool such as “ … limited resources by the service providers and equipment suppliers, minimum levels of activity to sustain engineering expertise without additional cost, volume and duration of investments to ensure stable expenditures and long duration programs that still addresses risk but minimize rate impact" (Exhibit B-1, p. 94).

BCTC pointed to 19 projects where the application of expert judgment either reduced a project in scope or deferred it to future years, and 13 projects where expert judgment was applied and projects, which would have otherwise been excluded from the plan, were included. BCTC stated that the application of this judgment resulted in reductions of costs of $14.2 million and $4.3 million in F2009 and F2010 respectively (Exhibit B-5-1, BCUC 1.28.3).

BCTC states that Study Work which takes place in the planning phase examines needs in detail, and then establishes criteria for identifying and assessing alternatives. Once criteria are established, alternative solutions to address the need or opportunity are identified and examined. The risk of deferral is also considered. Alternatives are assessed and those that do not meet the established criteria may be removed from consideration at this point. Remaining alternatives are also assessed for their impact on factors which may be unrelated to the need or opportunity. These factors include safety, environment, reliability, market efficiency, relationships, and financial considerations. Study Work results in the identification of a preferred alternative, with sometimes a subset of options which need to be further addressed (Exhibit B-1, p. 49).

BCTC stated that its planning process ensures that all prioritized investments have some value or address some risk, and repeats that lower value, lower deferral risk investments will be deferred in response to constraints on resources and funding availability. BCTC stated it will defer lower value, lower deferral risk investments if they are not cost-effective in order to " … limit the impact on rates in recognition of resource constraints" (Exhibit B-5-1, BCUC 1.109.1).

BCTC states that it has renamed the F2008 dollar savings criteria as the Efficiency Savings criteria in F2009, and that it defines Efficiency Savings as time, efficiency and effectiveness improvements that result in cost reductions that do not impact the bottom line. BCTC provided an example where an improvement leads to labour savings and where that labour is redeployed. BCTC states that since total labour expense does not change, there is no impact on the bottom line. BCTC notes that it avoids the cost of having to add a resource it would otherwise have needed to add (Exhibit B-5-1, BCUC 1.111.1).

BCOAPO submits that in the most recent iteration of BCTC's capital plan, it supported BCTC's use of project prioritization in its planning process and that it continues to support the utility's ongoing efforts to improve the process. BCOAPO further submits that one of the most valuable roles a capital plan can play is to provide a system-wide analysis in which the question with respect to each initiative is not '"*Can this project justify itself from a cost-benefit standpoint?*" but rather, "*Which projects constitute the most effective use of the finite capacity of ratepayers to bear system cost?*"' (BCOAPO Argument, pp. 3-5).

Commission Determination

The Commission has previously recognized and commended BCTC's efforts in deploying and refining its Prioritization Model. The Commission Panel agrees that the Prioritization Model is a tool and that it will always be necessary to apply judgment, and that a certain amount of subjectivity will always exist. However, the Commission Panel notes that almost any project may be construed to have some value or avoid some risk. Since BCTC has not identified any funding constraints, or identified a limit on rate increases that would constitute a funding constraint, it appears to be only resource constraints and the lack of "cost-effectiveness" that will limit the number of projects proffered. Furthermore, it is not clear how "cost-effectiveness" in this instance is related to the Financial category in the Prioritization Model.

The Commission Panel notes the addition or deletion of 32 projects due the application of expert judgment, and observes that in this case that judgement has resulted in cost savings. While the Commission Panel does not consider this number high in a relative sense, it notes that that the frequency experienced does raise the possibility that the Prioritization Model could be refined to limit the amount of intervention required by expert judgement.

The Commission Panel believes that where possible, if a project results in identifiable dollar cost savings, the savings should be included in the Financial category rather than in the more subjective Efficiency Savings category. The example provided in this regard by BCTC is unconvincing and BCTC itself notes that a cost is avoided that was otherwise required. The Commission Panel will further address the issue of "soft savings" in Section 7.

BCTC is directed to comment on the following concerns in its next filing: applicable and appropriate constraints or thresholds within the Prioritization Methodology for project selection, continued optimization of the Prioritization Methodology to better reflect the results achieved by expert judgement intervention, and the allocation of dollar cost savings within the Prioritization Methodology.

2.9 Long-Term Transmission Outlook Report

BCTC initiated a new component of its planning process, the Long-Term Transmission Outlook Report in May 2007. BCTC states this report will incorporate needs identified through the proposed Congestion Relief Policy being developed by the Province, BCTC's own TEP, and the BCTC's new loss reduction strategy which is under development (Exhibit B-1, p. 38).

BCTC stated the report will provide a 30-year transmission vision for B.C., however work has just begun to scope the document and develop a project plan, and once formally initiated, the development of the Long-Term Transmission Outlook Report will take approximately 12 to 18 months (Exhibit B-5-1, IPPBC 1.6.1).

IPPBC supports the development of the Long-Term Transmission Outlook Report and encourages BCTC to complete its publication within 12 months (IPPBC Argument, p. 10).

Commission Determination

The Commission Panel endorses BCTC's work on a report assessing and addressing the long-term requirements of the transmission system, and notes that this work should integrate with other long-term transmission initiatives as discussed Section 8.1 of this Decision.

3.0 PREVIOUS DIRECTIVES

The Application contains reports on the 39 directives contained in the F2008 TSCP Decision (F2008 TSCP Decision, pp. 100-106), one directive from Commission Order No. G-91-05, and a further four directives from the Commission Letter dated December 4, 2007 regarding the Fox Creek Project Report. BCTC states it has complied with 43 of the 44 directives (Exhibit B-1, p. 378), but later advised that it believed it had complied with only 41 (Exhibit B-5-1, p. 1). BCTC requested further clarification from the Commission on Directive 16 from Order No. G-69-07 (Exhibit B-5-1, BCUC 1.79.4).

In the G-103-04 Decision, BCTC was directed to file a State of the Transmission System Report ("STSR") with its future capital plan filings (G-103-04 Decision, pp. 8-9). BCTC has complied with this directive and provides the updated STSR ("2007 STSR") in Appendix B of the Application.

Commission Determination

The Commission Panel notes that previous Decisions contained directives that BCTC has complied with in this Application, but has not separately identified in either Section 9 or Appendix A of the Application. Specifically, the Commission Panel notes the directives described in Sections 9.4, 9.6, 9.9, 9.13, 9.20, 9.29, 9.30, 9.34, 9.39, and 9.40 of the F2008 TSCP Application appear to have been complied with in the current Application, but not identified as such in either Section 9 or Appendix A of the Application. **The Commission Panel directs BCTC to specifically report compliance with the directives described in Sections 9.4, 9.6, 9.9, 9.13, 9.20, 9.29, 9.30, 9.34, 9.39, and 9.40 of the F2008 TSCP Application in future filings. This should be reported along with the reporting on the concordance with all other directives pursuant to the directive described in Section 9.9 of the F2008 TSCP Application.**

3.1 State of the Transmission System Report

The 2007 STSR follows the same structure and outline as the 2006 STSR, which was included as Appendix B in the F2008 TSCP Application. The 2007 STSR contains "big picture" descriptions of the issues facing the bulk system, the regional systems, local systems, problems with specific equipment and strategic issues that are addressed by the projects proposed in the Application. An overview of and general context for the STSR is provided in Section 1 of the 2007 STSR. BCTC states that the 2007 STSR was prepared using BC Hydro's updated Long-Term Acquisition Plan ("LTAP") in the form of Base Resource Plans ("BRPs") as a basis (Exhibit B-1, p. 42).

A description of the physical facilities of the existing transmission system, including the bulk system and its interconnections to other systems, the regional systems and the communication, protection and control systems is provided in Section 2 of the 2007 STSR. The impacts of Independent Power Producers ("IPPs") and projects external to B.C. on the transmission system are addressed in Sections 3 and 4, respectively, of the 2007 STSR. The TEP, as it relates to SD9, is addressed in Section 5 of the 2007 STSR along with details of the TEP Implementation Plan. The condition of the transmission system assets, the Sustainment Investment Model, and the long-term forecast for Sustaining Capital investments are provided in Section 6 of the 2007 STSR. Risks to the transmission system, such as operational and maintenance risks, security risks, oil spills, and natural events (fires, earthquakes, ice storms, etc.), and their impact on system reliability, maintenance programs, and resulting Sustaining Capital investments are discussed in Section 7 of the 2007 STSR. Finally, Section 8 the 2007 STSR contains a discussion and analysis of system performance measures such as System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI") and Delivery Point Unreliability Index ("DPUI"), along with the contribution of certain classes of transmission equipment to the outage indices (Exhibit B-1, pp. 42-46).

BCTC states that for convenience and context the 2007 STSR repeats material from the 2006 STSR which describes general issues and conditions (Exhibit B-1, Appendix B, p. 6). Where these general issues have been identified in the F2008 TSCP Decision, they will not be repeated in this Decision.

3.1.1 System Issues

BCTC subdivides the transmission system into four regional systems: the North Interior, the South Interior, the Lower Mainland, and Vancouver Island. The transmission system is currently managed from BCTC's System Control Center ("SCC") in the Lower Mainland, with support from four Regional Control Centers ("RCCs"). By late F2008, BCTC plans to have replaced the current SCC and RCCs with a new centralized control centre, replacing obsolete technology and addressing seismic risk and other issues in the process (Exhibit B-1, Appendix B, p. 8).

With respect to the North Interior regional system, BCTC states that it has been studying potential future transmission upgrades required to integrate new generation resources in the Peace region, and how the addition of proposed major industrial loads or large generating facilities in the North Coast area could trigger investments to reinforce the bulk system. BCTC states the existing capacity will adequately cover the forecast dependable generation capacity additions up to 2010 including the dependable generation capacity from BC Hydro's F2006 CFT and firm transfer service to Alcan. A number of reinforcement options have been identified, but will remain in the planning phase until resource additions are more certain (Exhibit B-1, Appendix B, pp. 12-14).

A significant change to the plan for the North Interior regional system from the 2006 STSR is the status of the Northwest Transmission Line project associated with the interconnection of a number of proposed IPPs and supply to a number of potential mining loads, which was put "on hold" due to the deferral of the Galore Creek mine project (Exhibit B-1, Appendix B, p. 43; Exhibit B-1, p. 24).

On a local level in the North Interior regional system, BCTC reports the following:

- as a result of load growth at the Fort St. James substation ("FM2"), the Chetwynd substation ("CWD"), and the Tumbler Ridge substation ("TLR"), it is undertaking a number of reinforcement projects, ranging from the study of reinforcement options at FM3 to the replacement of transformers at CWD and TLR, and

- it is planning to bisect, and then upgrade, transmission line 1L362 by adding the new Bear Mountain substation to interconnect the 120 MW Bear Mountain IPP project consisting of 57 wind turbines, and

- it is studying the impact of additional industrial loads, and transmission service supply requests in the Fort Nelson area.

  (Exhibit B-1, Appendix B, pp. 43-45)

With respect to the South Interior regional system, BCTC states it has performed a conceptual study for integrating three more large generating units (Revelstoke 6, Mica 5 and Mica 6) into the transmission system. As a result of the addition of Revelstoke 5 and further increases in South Interior area generation, more South Interior West reinforcements are required. BCTC has completed Definition Phase activities on the addition of shunt capacitor banks at Ashton Creek substation (“ACK”) and series capacitors on 5L91/5L98. In this Application, BCTC is requesting approval for the implementation phase of the ACK shunt capacitor banks (Exhibit B-1, Appendix B, pp. 15-20).

On a local level in the South Interior regional system, BCTC reports the following:

- it is studying major reinforcements for the Upper Columbia 69 kV system north of Invermere, for the North Okanagan 69 kV system south of Vernon, and for the North Thompson 138 kV system north of Kamloops because the existing systems are reaching their respective maximum capacities, and
- it is studying a second supply source for the community of Westbank because of reliability concerns about the existing single 80 km long 138 kV transmission circuit supplying the community.

  (Exhibit B-1, Appendix B, pp. 45-47)

With respect to the Interior to Lower Mainland regional system, BCTC is continuing to advance a new series compensated 500 kV transmission line (5L83) between Nicola substation (“NIC”) and Meridian substation (“MDN”), and on November 5, 2007, filed an application for a CPCN for this transmission line. BCTC has also studied the Interior to Lower Mainland grid’s voltage stability limits and the options available to overcome them. The voltage stability limit can be effectively increased by adding reactive power support at MDN and NIC. Further increases in grid capability would require thermal and reactive reinforcements, including new transmission lines (Exhibit B-1, Appendix B, pp. 20-23).

BCTC reports significant developments on the Lower Mainland to Vancouver Island ("LM-VI") regional system. The two 500 kV circuits to Vancouver Island (5L29 and 5L31) have been assigned a winter firm capacity of 1400 MW as a result of studies which consider the daily variation in Vancouver Island load, the short term overload capability of the cables, and the cooling of the cables during the lower transfer hours between the two peak load periods each day. The 230 kV Vancouver Island Transmission Reinforcement Project ("VITR"), which replaces and augments the transmission capacity previously provided by two 138 kV circuits (1L17 and 1L18), is currently under construction and has an expected in-service date of October 2008. On June 4, 2007, a permanent failure occurred on one of the two High Voltage Direct Current ("HVDC") Pole 1 cables crossing Georgia Strait. As a result, during off-peak seasons, BCTC states it is not using Pole 1 to preserve its availability for use if another outage occurs in the system supplying Vancouver Island. BCTC states it has decided not to repair the failed HVDC cable because a submarine cable repair would take a long time, would have a very high cost, and the capacity addition from VITR will be in service in 2008. Until VITR is in service, the firm load carrying capacity of the LM-VI system will be approximately 300 MW below the peak Vancouver Island demand given in BC Hydro's December 2006 load forecast, a situation for which BCTC states it has developed contingency plans (Exhibit B-1, Appendix B, pp. 23-26).

On a local level in the Lower Mainland regional system, BCTC reports the following:

- subsequent to the successful repair of a failure on transformer T2 at Cathedral Square substation which supplies downtown Vancouver, BCTC has developed contingency plans for future transformer failures, and

- it is reassessing the scope of the seismic upgrading project at Murrin substation because the previously approved project for the installation of a curtain wall has been determined not to be practical because of underlying soil conditions, and

- it is jointly reviewing with BC Hydro the need for a new 230 kV/12 kV substation in the Mount Pleasant area, and

- it is installing additional transformer capacity and other upgrades at Kidd#1 substation and Horne Payne substation to serve increased Vancouver and Burnaby loads, and

- it is studying options to reinforce the supply to the City of New Westminster, and

- it is studying additional transmission supply into the Como Lake substation to resolve post-contingency loading on other transmission circuits supplying that substation, and

- it is studying options, some of which are new substations, to serve the growing loads in Langley, Mission and Richmond, and

- it is studying options to address the 360 kV to 60 kV transmission path connection through the Wahleach Generating Station 13 kV bus, which then involves other aging equipment on the 360 kV portion of the system, and

- it is planning to upgrade the North Vancouver substation and Deep Cove substation because of local load growth, and

- it is studying the conversion of transmission line 1L48 from 138 kV to 230 kV to interconnect the East Toba and Montrose Hydroelectric Projects.

  (Exhibit B-1, Appendix B, pp. 42-45)

On a local level in the Vancouver Island regional system, BCTC reports the following:

- it is studying the transmission supply to the north end of Vancouver Island, and

- it is studying supply options for the Courtenay district, and

- it is planning a transformer upgrade at Great Central substation which supplies Long Beach, and is studying future reinforcement options for the Long Beach area, and

- it is advancing a CPCN Application for the Central Vancouver Island Transmission Project to address overloading of the 138 kV system serving the central area of Vancouver Island, and

- it is implementing a thermal upgrade project on transmission lines 1L10 and 1L11 and moving the Sidney load from the Goward substation to the Keating substation to alleviate constraints on the 138 kV system serving the south area of Vancouver Island, and

- thermal upgrades are required on transmission lone 1L121 and 1L134 to enable the interconnection of multiple IPPs.

  (Exhibit B-1, Appendix B, pp. 48-52)

With respect to the interties with other systems, BCTC states that it has assessed the system impact associated with Alcan's proposed plans to modernize its Kitimat works, completed a conceptual planning study to provide voltage support which would facilitate a 1200 MW transfer capacity from

B.C. to Alberta, completed a joint study with the Alberta Electric System Operator ("AESO") to examine the potential economic benefits from a second B.C.-Alberta intertie, and reports that in 2007, the firm transfer capacity from the U.S. to B.C. was raised to 1930 MW on the B.C.-U.S. intertie. BCTC identifies two possible reinforcement options which would facilitate 1200 MW of transfer capacity from B.C. to Alberta, but states that improvements in the transfer capacity in the Alberta to B.C. direction are dependent on projects and reinforcements in Alberta, the scope and schedule of which are uncertain. Regarding a second intertie with Alberta, the recommendation from the joint study is that BCTC and AESO work with the Alberta and B.C. governments to develop possible business models that would result in an equitable sharing of costs and benefits from additional intertie capacity (Exhibit B-1, Appendix B, pp. 26-30).

3.1.2 Impact of IPPs

As in the F2006 STSR, BCTC continues to report on the process associated with interconnecting the many IPPs that were successful in BC Hydro's F2006 Call for Tender. To assist IPP proponents in assessing their impact on the transmission system and potential interconnection costs, BCTC has produced planning level estimates of the firm ATC in each area of the provincial grid. These studies have been posted on BCTC's website, and include the preliminary estimated cost, implementation period, and solution strategy to enhance the ATC where necessary (Exhibit B-1, Appendix B, pp. 56-59).

BCTC reports on the various impacts that IPPs have on its transmission planning processes. BCTC states that integration of wind resources poses a special challenge because of its intra-hour, hourly and daily fluctuation. To better understand these effects, BCTC is conducting a detailed Wind Integration Study (Exhibit B-1, Appendix B, pp. 60-61).

3.1.3 WECC Initiatives

BCTC describes a number of projects involving the Alberta system and potential impacts on the BCTC transmission system. One of these projects is another intertie with Alberta, as discussed earlier. BCTC explains that there is the potential for increased wind generation development in Alberta following the lifting of the 900 MW wind generation limit previously imposed in that jurisdiction, resulting in a greater need for generation reserves and dynamic scheduling. The new intertie would enhance the ability of BC Hydro and others to supply that need. BCTC also describes opportunities for increasing supply to the Fort Nelson area through the Alberta system, and the potential effects associated with the introduction of the Montana-Alberta Transmission Line project (Exhibit B-1, Appendix B, pp. 64-65).

BCTC reports that Pacific Gas and Electric ("PG&E") has concluded a WECC Regional Planning Review process to consider the transmission of between 1500 MW and 3000 MW of renewable resource generation from B.C. and the Pacific Northwest to Northern California. The preferred alternative that emerged from this process is a hybrid transmission project consisting of a 1500 MW 500 kV AC line extending from Selkirk substation, south to Oregon, where it would interconnect with an HVDC line continuing on to California. The next phase is the WECC Project Rating Review process in which BCTC is a participant through the Steering Committee. BCTC is placing particular focus on the required upgrades to its internal bulk transmission system. Several other WECC-based initiatives have the opportunity to tie into or provide bypasses to the PG&E-sponsored project, but these other initiatives do not appear to have a direct interconnection to the BCTC system (Exhibit B-1, Appendix B, pp. 65-69).

Regarding Sea Breeze Power's proposed Juan de Fuca cable project, BCTC reports that it has achieved Phase 2 status in the WECC Project Rating Review process with a planned rating of 550 MW, and the BCTC will commence work on an interconnection study as soon as Sea Breeze Power signs the study agreement (Exhibit B-1, Appendix C, pp. 67-68).

3.1.4 Transmission Expansion Policy

The purpose and genesis of the TEP was provided in the F2008 TSCP Decision. Through its efforts in 2006 and 2007, BCTC has developed a TEP Implementation Plan that sets outs the process that BCTC will follow to pursue TEP opportunities, and outlines expectations with respect to stakeholder engagement in this process. At the same time, BCTC recognizes that there will be some interaction with the anticipated Congestion Relief Policy as intended in the 2007 Energy Plan (Exhibit B-1, Appendix B, pp. 70-71).

BCTC reports that it received "considerable response" to a Request for TEP Expressions of Interest, and will analyze the TEP submissions in conjunction with the Technical Advisory Committee and, where appropriate, will make recommendations to further pursue TEP project concepts (Exhibit B-1, Appendix B, p. 70).

BCTC submitted its first application for a CPCN for a TEP project on December 12, 2007 for a project to upgrade the 500 kV 5L51 and 5L52 circuits of the Ingledow-Custer transmission line, resulting in an increase in the Total Transfer Capability ("TTC") of the B.C.-U.S. intertie. This project was prioritized with other non-TEP Growth capital projects during the process which culminated in the F2009 TSCP, but not with other potential TEP projects. The project was subsequently approved by Commission Order No. G-58-08, dated April 22, 2008.

IPPBC submits that the delay in planning and prioritizing of other TEP projects may be at least partly attributable to the complexity of the prioritization methodology. IPPBC submits that the model may lend itself much more readily to evaluating Intertie Enhancement Projects, than it does to evaluating cluster type projects which will be required to facilitate new energy supply to BC Hydro through new IPP interconnections. This is substantially, submits IPPBC, because the Intertie Enhancement type of project has more easily quantifiable economic benefits. Accordingly, IPPBC recommends that a simpler pre-screening methodology needs to be developed to advance the cluster projects in a more realistic time frame (IPPBC Argument, pp. 6-7).

In Reply, BCTC states that it disagrees with IPPBC's submission that the prioritization process is too complex and unwieldy to be applied to Cluster projects. BCTC expects that future potential TEP projects will provide additional insights into how the nature and assessment of benefits associated with TEP projects are best captured, and BCTC will revisit the PM to attempt to reflect these (BCTC Reply, p. 5).

3.1.5 Equipment Condition and Performance

BCTC reports that the condition of the transmission assets is generally good, but is deteriorating at an increasing rate and that an increasing number of original components are approaching end-of-life. An Asset Baseline Study ("ABS") was conducted in 2004 that established a condition baseline for thirty-three classes of assets in the transmission system. Although BCTC is required under Article 7 of the Asset Management and Maintenance Agreement with BC Hydro to provide an update to the ABS every three years, BCTC and BC Hydro agreed to defer the study scheduled for 2007 because there was not enough new data to provide meaningful comparisons to the 2004 study, and the cost of obtaining enough new data was thought to be too high (Exhibit B-1, Appendix B, pp. 73-74).

BCTC is continuing with the implementation of the IMAX and AMP systems approved in the F2008 TCSP Decision in order to enhance data collection and decision support, and for most equipment, expects to have good data on 2010. A complete data set is expected by F2014. In the mean time, BCTC provided to BC Hydro a report on the actions taken on assets rated as poor or very poor in the 2004 ABS and agreed to expedite assessments on access roads and civil and wood pole structures (Exhibit B-1, Appendix B, pp. 74-75; Exhibit B-5-1, BCUC 2.117.1).

The 2004 ABS identified 14.8 percent of circuit breakers as being in poor condition, and the circuit breaker program is the largest component of the Sustaining Capital portfolio. BCTC reports that all 104 air blast circuit breakers in its asset base are approaching 40 years in service and are due for major upgrades by 2014. BCTC suggests that life extension and/or refurbishment is no longer economically and technically feasible and replacement is the only option. The Application contains projects for the replacement of 500 kV air blast circuit breakers at Ingledow, Dunsmuir, and Nicola substations (Exhibit B-1, Appendix B, pp. 76-77).

BCTC states that programs are in place to address the relatively high proportion of assets identified as being in poor condition in the 2004 ABS for the following asset classes: protection and control systems, gap-type surge arrestors, and tone and test equipment (Exhibit B-1, Appendix B, pp. 76-89). BCTC claims the fibre optic cable to the Chapman's Capacitor Station is at end-of-life and requires replacement (Exhibit B-1, Appendix B, p. 83). This project was denied approval in the F2008 TSCP Decision (F2008 TSCP Decision, p. 77).

As in the F2006 STSR, BCTC again describes the Sustainment Investment Model ("Model"), reports the Phase 1 results, and advises that Phase 2 of the Model development is still underway (Exhibit B-1, Appendix B, pp. 90-94). The Model is considered further in Section 6.2 of this Decision.

This topic is addressed further in Section 3.5 of this Decision.

3.1.6 Risk Items

A new element is introduced in BCTC's review of risks to the system in the 2007 STSR, and that is the Critical Infrastructure Protection ("CIP") program, in which processes and systems are implemented to protect the critical cyber assets within BCTC to comply with NERC standards (Exhibit B-1, Appendix B, p. 96).

In addition to numerous risk studies, investigations and assessments, BCTC identifies F2009 expenditures on seismic upgrading of 2L3/49 Second Narrows Crossing, seismic upgrades to the Williston, Meridian and Atchelitz substation control buildings, seismic upgrades to microwave sites at Jarvis and Thynne, improvements to physical security at substations, replacement of above ground fuel and oil storage tanks, and replacing halon-based fire suppression systems (Exhibit B-1, Appendix B, pp. 96-104).

BCTC states that it is assessing risks in the various substations and transmission systems that will supply the 2010 Olympic venues and that programs will be prioritized to ensure reliability of the transmission system is sustained for the Olympics (Exhibit B-1, Appendix B, p. 104).

3.1.7 System Performance Measures

BCTC continues to report system performance in terms of SAIDI, SAIFI, DPUI, Equipment and Transmission Reliability, and Intertie Congestion (Exhibit B-1, Appendix B, pp. 105-117).

SAIDI is reported in the 2007 STSR as 4.23 in F2007, a significant increase over the F2006 level of 2.07 (Exhibit B-1, Appendix B, p. 105). In compliance with the F2008 TSCP Decision, BCTC separately identifies forced (3.82) and planned (0.41) components of the SAIDI performance (F2008 TSCP Decision, p. 30). BCTC further categorizes contributions to SAIDI by cause. Not counting the November and December 2006 wind and snow storms, the biggest contributors to SAIDI in F2007 were outages caused by defective equipment and outages caused by trees and animals, which coincidentally also showed the largest increase over F2006 performance (Exhibit B-1, Appendix B,

p. 106). Further analyzing the defective equipment outages, substation equipment and line equipment caused outages show large increases in F2007 as compared to F2006, while outages due to fire from pole top equipment are down significantly. BCTC notes that in F2006 it undertook a bonding program to reduce the number of pole top fires (Exhibit B-1, Appendix B, p. 108).

SAIFI outages are categorized into momentary interruptions less than one minute (“SAIFI-MI”), and sustained interruptions greater than one minute (“SAIFI-SI”). BCTC reports the F2007 SAIFI-MI as 1.28 and the F2007 SAIFI-SI as 1.26, both of which are higher than F2006 levels. Again, in compliance with the F2008 TSCP Decision, BCTC separately identifies forced (1.10) and planned (0.16) components of the SAIFI-SI performance. There is a rising trend in both SAIFI measures over the period since F2004 (Exhibit B-1, Appendix B, p. 110).

DPUI is a measure that equates the annual duration of accumulated planned and unplanned outages to the length of a single outage affecting the entire system load during the system peak demand. DPUI was 52.66 minutes in F2007, up significantly from the F2006 performance of 25.31 minutes (Exhibit B-1, Appendix B, p. 111). After removal of the effects of the November and December 2006 wind and snow storms, the F2007 DPUI is 31.51 minutes (Exhibit B-5-1, BCUC 1.89.1).

BCTC reports on equipment reliability for transmission line, cable, transformer, and circuit breaker asset classes, and compares the forced, sustained outage rate for equipment at each transmission voltage class against CEA statistics, where available (Exhibit B-1, Appendix B, pp. 113-114).

In the F2006 STSR, BCTC defined a measure for congestion and reported the amount of congestion on the transmission interties to Alberta and the U.S. using this measure. In the F2007 STSR, BCTC reports the monthly performance of the measure to May 2007, and demonstrates by way of a moving average, reduced intertie congestion as compared to the previous year (Exhibit B-1, Appendix B, pp. 116-117).

Commission Determination

The Commission Panel commends BCTC for its preparation of the 2007 STSR, and views it as a necessary component in support of capital plan applications because the detailed technical information to support the capital plan does not appear elsewhere.

The Commission Panel commends BCTC for bringing forward a CPCN Application for the 5L51/52 Thermal Upgrade project and encourages BCTC to pursue its assessment of other potential TEP projects. The Commission Panel notes that BCTC is aware of the issues IPPBC has raised with respect to cluster projects, and is satisfied that the Prioritization Methodology is flexible enough to accommodate the concerns raised by IPPBC.

The Commission Panel notes that forced sustained transmission line outages due to defective equipment were up significantly for the 60 kV voltage class, but down significantly for the 230 kV and 138 kV classes (Exhibit B-1, Appendix B, p. 113), and that forced sustained outages attributable to transformers and circuit breakers are higher for almost every voltage class, except for 500 kV circuit breakers (Exhibit B-1, Appendix B, p. 114). The Commission Panel is concerned that the trend line of SAIDI, SAIFI, and DPUI indices indicates deteriorating performance.

3.2 Changes from One Capital Plan to the Next

Directive 15 of the F2006 TSCP Decision directed BCTC to file, in each future capital plan a table, in a form to be determined by BCTC noting any projects that have been accelerated, deferred, or cancelled, and showing any change in expenditure patterns (F2006 TSCP Decision, p. 30). Directive 11 of the F2008 TSCP Decision directed BCTC to provide a table showing for all projects in their Implementation Phase, the approved total annual expenditures, the revised total annual expenditures, and the difference between the approved and revised annual expenditures, as well as the approved and revised in-service dates (F2008 TSCP Decision, p. 32). In response to these directives BCTC has provided a section of the Application for each of the Growth, Sustaining, and BCTC portfolios, containing the required tables.

Table 5-3 of the Application, as revised to show percentage variances, shows changes to 16 non-IPP and 5 IPP Growth Capital projects from the F2008 Capital Plan to the F2009 Capital Plan for projects where the current forecast exceeds both 10 percent and $100,000 of the project estimate included in the F2008 Capital Plan or where the project has significant delays (Exhibit B-1, p. 107; Exhibit B-5-1, BCUC 1.29.1). Table 5-4 of the Application provides, for all Growth Capital projects In Progress, revised total and annual expenditures as well as in-service dates, compared to the total and annual expenditures and in-service date provided to the Commission at the time the project was approved (Exhibit B-1, pp. 111-113).

In terms of greatest relative change, the largest plan over plan change has occurred to the Retermination of Sidney 60 kV Supply to Keating project with a cost increase of 122 percent and the Kidd 1 – Substation Redevelopment project with a cost increase of 113 percent. BCTC provided detailed explanations for these cost increases (Exhibit B-5-1, BCUC 1.32.1; Exhibit B-5-1, BCUC 1.33.1, 1.33.2 and 1.33.3).

BCOAPO observes that while there is a reasonable rationale for the variance associated with each project identified in Table 5-3, the number of projects impacted by such adjustments, and the size of some of the changes, are troublesome. BCOAPO urges the Commission to be particularly vigilant regarding cost escalation within BCTC's capital portfolio (BCOAPO Argument, p. 2).

BCTC provides in Table 6-3 of the Application a reconciliation of the level of Sustaining Capital expenditures as approved by the F2006 TSCP Decision and reaffirmed by the F2008 TSCP Decision against the increases sought in this Application for F2009 and F2010 (Exhibit B-1, p. 194). BCTC explains that the requested $21.4 million increase in F2009 Sustaining Capital over the forecast F2008 amount is attributable to a $5.4 million addition for inflation calculated at 5 percent, a $0.1 million increase for additional third-party requested projects, a $2.1 million increase for forecast carry-forwards associated with the Protection and Control Replacement project, the Lower Mainland Robustness project, and the Emergency Drop-in Control Building project, and a $13.8 million increase to address changes in Other Work to address system reliability issues and other unacceptable risks (Exhibit B-1, pp. 194-195). No reconciliation is provided for the proposed $25.2 million increase in F2009 Sustaining Capital over the approved F2008 amount. BCTC further explains that the requested $10.5 million increase in Sustaining Capital expenditures for F2010 over the requested F2009 amount is attributable to a $5.9 million addition for inflation calculated at 5 percent and a $4.6 million increase to address changes in Other Work to address system reliability issues and other unacceptable risks (Exhibit B-1, p. 196). The requested F2009 Sustaining Capital amount of $112.9 million is reflected back into F2007 dollars in Table 6-2 of the Application by backing out BCTC's proposed inflation adjustments (Exhibit B-1, p. 191). The requested F2009 Sustaining Capital amount is $101.4 million expressed in F2007 dollars, including allowances for emergency capital and third party requested projects.

In BC Hydro's view, BCTC has demonstrated the need for its planned increase in Sustaining Capital expenditures to maintain asset health and system performance (BC Hydro Argument, p. 3).

BCOAPO accepts BCTC's contention that it is difficult to predict or define a relationship between Sustaining Capital expenditures and reliability indices, and notes that the Sustaining Capital expenditures are in line with or slightly below the spending suggested by BCTC's Sustainment Investment Model (BCOAPO Argument, pp. 3-4).

BCTC reports that no projects submitted in the F2008 Capital Plan have been cancelled, and provides in Table 7-4 of the Application a list of BCTC Capital projects that have been deferred or changed in the current Application. Two projects with a total cost of $445,000 have been deferred to F2009, and the System Control Modernization project will be in-service in March 2008, ahead of its previously reported in-service date of September 2008 (Exhibit B-1, p. 321).

Commission Determination

The Commission Panel finds the variance reporting from one capital plan to the next useful for tracking project performance against expectations. The Commission Panel notes that in the cases where project costs changed by more than 100 percent from one capital plan to the next, BCTC defended the continued selection of the preferred solution against the other options. These explanations were useful and warranted given the size of the change in the preferred solution, but were not comprehensive enough in the analysis of other options. **In future capital plans, and until directed otherwise, the Commission Panel directs BCTC to provide a thorough evaluation of**

options in situations where the cost of the preferred solution for an approved project changes by more than 100 percent.

The Commission Panel is extremely concerned about the rapid and sustained increase in the requested Sustaining Capital expenditures. The increase is supported by BC Hydro and BCOAPO, and the Commission Panel notes that the deteriorating performance as suggested by the reliability indices discussed in Section 3.1 of this Decision would also support the need for increased expenditures. However, the Commission Panel notes that the increase claimed for inflation is not supported by the evidence as discussed in Section 4 of this Decision. Also, it has been noted that the costs of the Emergency Drop-in Control Building project are better assigned to the capital project addressing the issues at Colwood substation. **The Commission Panel approves an amount of $105.0 million for the F2009 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the $101.4 million forecast F2009 Sustaining Capital expenditures expressed in F2007 dollars, escalated at 2 percent inflation for two years, less an amount of $0.5 million to account for the re-allocation of costs associated with the Emergency Drop-in Control Building project. The Commission Panel approves an amount of $107.0 million for the F2010 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the approved F2009 Sustaining Capital expenditures plus a 2 percent increase for inflation, less a $0.1 million adjustment for a reduced amount of third-party requested projects.**

3.3 Customer and Non-wires Solutions to Transmission Constraints

Directives 10a and 10b from the F2006 TSCP Decision directed BCTC to initiate discussions with customers on potential customer provided solutions to transmission constraints including but not limited to demand reduction and deferral credits or rates and non-wires solutions in general (F2006 TSCP Decision, pp. 19-20).

There appears to be only one project in this Application for which non-wires options have been considered, with no practical solutions identified (Exhibit B-1, p. 177).

Commission Determination

The Commission Panel is concerned that BCTC's efforts towards investigating non-wires options may be waning, and encourages BCTC to ensure that this is not the case. **The Commission Panel directs BCTC to report in future capital plans the specific instances where non-wires options have been considered in project option evaluations.**

3.4 Expenditures on IPP Interconnections

Directive 12 of the F2008 TSCP Decision stated:

> "The Commission Panel concurs with BCTC that the provisions in the OATT adequately address future IPP interconnections, and accepts BCTC's proposal to forecast capital for the interconnection of IPP projects for the upcoming year; however, where possible, BCTC should assign such amounts to specific IPP projects. For projects identified in the F2006 TSCP Update Decision as requiring further approval, the Commission Panel accepts BCTC's proposal that it will sign facilities agreements with IPP customers, will proceed with study work and the interconnection process, and will seek Commission approval or file a letter with the Commission" (F2008 TSCP Decision, p. 35).

BCTC states it is no longer seeking approval from the Commission for generation interconnections through the Capital Plan submission because the provisions in the Open Access Transmission Tariff ("OATT") provide adequate authority to proceed with generation interconnections except for those projects originally approved by the Commission and subsequently deferred, and for which the Commission has indicated in Order No. G-67-06 that further approval is now required prior to resurrecting such projects. In the case of these exceptions, BCTC reports there are no projects in this category for approval in this Application, and since the F2008 TSCP Application, BCTC filed letters with the Commission for the Zeballos Lake IPP Interconnection, the Ashlu Creek IPP Interconnection, and the South Cranberry Creek IPP Interconnection projects (Exhibit B-1, p. 387).

3.5 Asset Health Index Report

As discussed in Section 3.1 of the Decision, BCTC and BC Hydro agreed to defer the Asset Health Study scheduled for 2007. The Commission acknowledged and accepted this deferral in Letter No. L-92-07.

BCTC stated that it intends to conduct an Asset Health Study in F2011 (Exhibit B-5-1, BCUC 1.86.1). This study is expected to be completed with improved and updated asset health information accumulated since the baseline Asset Health Study.

As part of the agreement to defer the Asset Health Study, BCTC also agreed to:

> “ (a) Continue collecting asset condition data;
>
> (b) Automate the AHI calculation;
>
> (c) Complete a baseline health study on access roads in F2008;
>
> (d) Produce an inventory and condition data for all civil and wood pole structures before the next full study in F2011; and
>
> (e) Report by June 2007 on the actions taken and the present status of assets rated as poor or very poor in the 2004 ABS” (Exhibit B-1, p. 74).

BCTC prepared a report “The Condition Assessment (Baseline Study) Update” (the “Update Report”) dated July 5, 2007 and provided this report to BC Hydro on August 2, 2007 (Exhibit B-5-1, BCUC 2.117.1). The Update Report identifies actual F2005 to F2007 and planned F2008 and F2009 expenditures on assets that were identified as being in “poor” or “very poor” condition in the ABS. The Update Report did not address disconnect switches, transformers, instrument transformers, shunt reactors, station cables, synchronous condensers, static VAr compensators, high pressure air systems, standby generators, microwave equipment, power line carriers, series capacitors, HVDC pole 2, and manholes & duct systems. The F2007 through F2009 expenditures are identified as $72.4 million, $72.1 million and $81.0 million, respectively. The largest increases in F2009 planned expenditures over F2007 actual expenditures are for the asset classes of gas-insulated switchgear

($1.7 million), facilities general ($6.7 million), and vegetation and right-of-way management ($1.8 million) (Exhibit B-5-1, Attachment to BCUC 2.117.1, pp. 3-4).

BCTC stated that it participates in two benchmarking studies that relate to Asset Health. First, the Canadian Electricity Association's ("CEA") ERIS (Equipment Reliability Information System) – Forced Outage Performance of Transmission Equipment study, which collects forced outage data for transmission equipment with an operating voltage of 60 kV and above for utilities across Canada. The second study that BCTC participates in is the International Transmission Operations and Maintenance Study ("ITOMS"). ITOMS compares asset performance and practices within the transmission industry worldwide (Exhibit B-5-1, BCUC 1.55.4).

Commission Determination

The Update Report contains a valuable mid-term assessment of the actions taken on the assets deemed to be in the worst condition. The Commission Panel notes the protective relay replacements accounted for $9.9 million of the total F2007 expenditures of $72.4 million and are forecast to be $9.3 million in F2009. The Commission Panel observed in the F2006 TSCP Decision that Station Protection and Control Program was driven by equipment operability and obsolescence, but that there was insufficient evidence to support operability claims. The Commission Panel notes from the Update Report that the ABS did not specifically list protection equipment that was "poor", but rather that it pointed to all electromechanical type of relays to be in poor condition (Exhibit B-5-1, Attachment to BCUC 2.117.1, p. 15). The Commission Panel is concerned that the blanket "poor" assessment of all electromechanical relays masks applications where existing electromechanical relays are adequate for the application, and thus there may be an opportunity for reduced spending in this asset class.

The Commission Panel notes the two benchmarking studies in which BCTC participates and approves of BCTC's participation in these studies as well as in past broad and detailed comparative benchmark studies, such as the PA Consulting Group report and the Haddon Jackson Report referred to in the Decision accompanying Order No. G-96-04 that had addressed the system's assets. However, upon review of the CEA ERIS report, the Commission Panel notes that the report does not contain any data specific to the performance of BCTC's assets, and that BCTC did not provide the individual utility report prepared by the CEA containing the comparisons to the contributors own data. **The Commission Panel directs BCTC to identify in the next capital plan application the industry benchmarking surveys to which it provides data, and to identify those in which it participates more fully, and to report the results of those surveys, including the utility-specific reports from CEA. BCTC is also directed to provide, in the next capital plan application, a summary report that identifies a representative cross-section of surveys being performed in the electric utility sector.**

3.6 Outstanding Directives from Previous Decisions

BCTC first states that it has complied with 43 of 44 directives listed in the concordance table provided as Appendix A in the Application, but later BCTC advised that it believed it had complied with 41 and provided status updates for the remaining three, those being Directives 25, 26 and 38 from the F2008 TSCP Decision (Exhibit B-1, p. 378).

BCTC also requested further clarification regarding Directive 16 from the F2008 TSCP Decision (Exhibit B-5-1, Cover Letter), which, in part, directed BCTC to provide information from the PM for project alternatives. BCTC states that it is not appropriate to use the PM to evaluate alternative solutions to a problem and that alternative solutions to a need only need to be compared against each other (Exhibit B-1, p, 390). BCTC stated that it recognized that many of the criteria used by the PM may be the same as those established for a specific need, that there were differences and that such an approach could lead to an incomplete evaluation of the alternatives. While BCTC recognized that a more structured approach similar to the PM could be used to examine alternatives, it stated that considering the complexity of the PM, a modified and simplified model would have to be designed to assess alternatives (Exhibit B-5-1, BCUC 1.79.3). BCTC stated that it had deduced that the Commission is interested in the use of the PM for the selection of the preferred alternative as a stand-alone and separate activity from portfolio building (Exhibit B-5-1, BCUC 1.79.4).

Directive 25 from the F2008 TSCP Decision addressed the Mission and Matsqui Area Supply project, and directed BCTC to apply to the Commission to find the revised project to be in the public interest once an agreement with the District of Mission had been reached regarding the potential rerouting of a portion of the 69 kV transmission facilities associated with that project (F2008 TSCP Decision, p. 58).

In the Application, BCTC states that it proposes to proceed with the original overhead crossing of the Fraser River to Mission using the previously agreed upon railway alignment, and that a report would be provided to the Commission requesting approval for the additional costs to complete the project (Exhibit B-1, p. 398). Subsequently, BCTC provided a project review report in which it attempted to determine why and where variances occurred, determine if there was any opportunity to mitigate the variances, determine the revised forecast, and understand the lessons learned from the project review (Exhibit B-5-1, Attachment to BCUC 1.82.1).

Directive 26 from the F2008 TSCP Decision addressed the 5L91/5L98 Series Compensation project, and directed BCTC to submit a study concerning certain aspects of Canadian Entitlement utilization if and when a CPCN application was submitted for the project (F2008 TSCP Decision, p. 66). BCTC states that a CPCN application for the SI Series Compensation project is expected to be submitted in 2008 (Exhibit B-1, p. 398).

Directive 38 from the F2008 TSCP Decision addressed the FERC Order No. 890, and directed BCTC to bring its assessment of FERC Order No. 890 forward to the Commission once its consultations and assessments were concluded (F2008 TSCP Decision, p. 93). As is also discussed in Section 1.8 of this Decision, BCTC's assessment of the implications of FERC Order No. 890 is ongoing, and it plans to bring its assessment on the planning process and other tariff provisions forward to the Commission in the second quarter of 2008 (Exhibit B-1, pp. 405-406).

Commission Determination

The Mission and Matsqui Area Supply project was approved by the Commission in the F2006 TSCP Decision at an estimated total capital cost of $43.2 million (F2006 TSCP Decision, p. 43). The updated capital cost estimate for this project is $56.9 million. The Commission Panel notes that BCTC has not sought approval for this incremental expenditure in this Application.

The Commission Panel accepts the explanations provided with respect to Directives 26 and 38 from the F2008 TSCP Decision. However the Commission Panel is concerned that BCTC has not complied with all other Directives to the same extent. Specifically, in the F2006 TSCP Decision, BCTC was directed to "identify whether any capital projects are driven by the need to conform to Section I.A.M2 during maintenance outages." (F2006 TSCP Decision, p. 17) In the F2008 TSCP Application, BCTC stated "[s]ubject to further direction from the Commission, BCTC will continue to report on this matter in future Capital Plans." (F2008 TSCP Application, p. 266) The Commission Panel can find no mention of this commitment in this Application. **The Commission Panel directs BCTC to comment on all Directives contained in past Decisions, even if such reporting confirms that that no update is required, or the requested information is not applicable.**

The Commission Panel accepts that the PM is not an appropriate tool to evaluate alternatives to a specific need. Accordingly the Commission Panel exempts BCTC from the requirement of the second part of Directive 16 which was:

> "For projects with alternatives that are considered feasible or for which there is evidence that a more detailed and costly assessment should be undertaken prior to eliminating the alternative completely, those alternatives should be listed, along with their total (only) risk and value scores, and priority numbers and quadrants, where applicable" (Exhibit B-1, p. 389).

4.0 INFLATION AND COST TRENDS

BCTC forecasts its capital expenditures in real term and then escalates them to nominal dollars for forecast years which facilitates comparison with the actual expenditures when made. This section examines the inflation forecast as it relates to capital expenditures on the transmission system.

4.1 Projected Inflation

In the F2008 TSCP Decision, the Commission acknowledged that inflation in the non-residential industry sector was running at higher levels than the British Columbia Consumer Price Index ("BCCPI"). However, the Commission concluded that BCTC had provided insufficient evidence to justify an inflation forecast specific to its projects which would be higher than general inflation. The Commission directed BCTC to use a 2.0 percent inflation factor, and invited BCTC to provide comprehensive justification of any other inflation adjustment it may propose as part of its next application (F2008 TSCP Decision, p. 83).

BCTC addresses the issue of inflation at Sections 2.2.10 and 9.31 of the Application, and provided the "BC Hydro Construction Cost Trends and Outlook September 17, 2007" ("MMK Report") prepared by MMK Consulting Inc. ("MMK") at Appendix E of the Application. Section 9.31 also provided links to two publications which BCTC states are of interest. BCTC proposes inflation rates of 6.0 percent for F2008 and of 5.0 percent for each of F2009 and F2010 (Exhibit B-1, p. 33).

BCTC summarizes the MMK Report as recommending cost inflation for transmission, stations and distribution, based on the recent strength of U.S. equipment price indices and confirmed by the recent experience of BC Hydro staff, as being from 4 to 6 percent for 2007 through 2010 (Exhibit B-1, p. 33).

BCTC states:

> "BCTC selected the high end of the recommended range for F2008 and the mid-range for F2009 and F2010 to reflect significant increases in the cost of equipment. BCTC has been mostly protected from the significant increases in the cost of certain

> equipment through the use of long term procurement contracts. The majority of these contracts did not include escalation clauses for metal pricing and currency exchange that are now the norm in new contracts. The contracts are now coming due for renewal and BCTC is experiencing the cost increases seen in the industry" (Exhibit B-1, p. 402).

BCTC provides two examples of inflation it stated it had experienced. The first was the escalation in what BCTC states was the BC Hydro Electrician Actual Hourly Rate which BCTC states has been increasing at approximately 5 percent annually since 2005. The second example provided showed a one year increase in the cost of two identical pieces of equipment, ordered one year apart, of 55 percent (Exhibit B-1, p. 34).

Regarding the electrician's wages, BCTC stated that the description provided in the Application was incorrect and that the information portrayed was the fully loaded BC Hydro rate for electricians (Exhibit B-5-1, BCUC 1.7.2), and that the actual hourly rate had increased by 6.6 percent from 2005 to 2008 (Exhibit B-5-1, BCUC 1.7.1). This is an annual average increase of 2.0 percent for that period. BCTC showed a further increase of 4.0 percent from April 2008 to April 2009, based on the collective agreement.

BCTC was asked to explain why it was appropriate to assume that the differences between the loaded and unloaded values would continue to escalate in the future and replied:

> "The basis for the rate that BC Hydro charges for its services is the collective agreement wage rate and this rate will continue to rise until at least F2010 as referenced in BCTC's response to BCUC IR 1.7.1. Therefore, BCTC believes that the rates shown in Figure 2-3 will continue to rise until at least F2010. Beyond F2010, BCTC has no specific information on collective agreement wage rates or on BC Hydro's loadings on these rates." (Exhibit B-5-1, BCUC 1.7.2)

BCTC stated labour billings constituted 23 percent of sustaining capital costs and that about one third of this would be associated with electricians. BCTC further stated the escalation in electrician's wages is typical of other trades (Exhibit B-5-1, BCUC 1.7.3).

BCTC provided the following further information in document form regarding inflation:

(1) BC Hydro recommended project inflation rates which BCTC adopted and which were said to be based on the September 17, 2007 MMK Report and discussions with Manitoba Hydro, Hydro Quebec, Vancouver Airport, and the B.C. Ministry of Transportation.

(2) Hanscomb Newsletter Third Quarter 2007 which is stated to use the Non-Residential Building Construction price Index for various Canadian cities with data to mid August 2007.

(3) Market Intelligence Newsletter dated Q4 2006 which provides “construction cost” forecast for the Lower Mainland of 5.0, 3.0 and 3.0 for 2008, 2009 and 2010 respectively.

(4) Information from ENR.com related to large transmission projects in the United States.

(5) Construction Looking Forward which shows Labour Requirements from 2007 to 2015 for British Columbia.

(6) Summary Cost Report dated December 2006 prepared by ENR, which begins by stating “Construction’s inflationary cycle turned the corner during 2006 and will continue heading downhill through 2007 and 2008, according to industry forecasts.” The report forecasts a 4.2 percent price increase for a category labelled “const, machinery and equip.”, and negative inflation for many other categories (Exhibit B-5-1, BCUC 1.83.1, Attachments 1 and 2).

4.2 The MMK Report

The MMK Report states that the cost inflation outlook for BC Hydro for transmission, stations and distribution is based on the recent strength of U.S. equipment prices confirmed by the recent experience of BC Hydro staff, and that as a result they expect Canadian cost inflation for this equipment to be much stronger than in recent years and they note that Statistics Canada industry specific electric utility distribution construction price indices were in the range of 2 to 4 percent annually (Exhibit B-1, Appendix E, p. 3).

The MMK report further states that BC Hydro staff confirm that experience in mid 2007 confirms significant price increases, in the area of 25-30 percent for purchases relating to BC Hydro’s transmission, stations and distribution projects (Exhibit B-1, Appendix E, p. 20). BC Hydro stated that it did not supply written evidence to MMK, only general cost increase examples, and that confidentiality with suppliers was a concern. BC Hydro states that “[w]hen given this information the thinking was specifically for items like transformers and conductors" (Exhibit B-5-1, BCUC 1.92.1).

MMK provided a graph of U.S. Cost Indices for Electric Utility Equipment Manufacturing Quarterly Average 2000 to 2007 (Exhibit B-1, Appendix E, p. 20). BCTC was asked to adjust this information for the change in value of the Canadian Dollar relative to the American Dollar. The information provided by MMK through BC Hydro shows that the "U.S. Basic Index for Electric Power and specialty transformer manufacturing" had increased from 143.9 in Q2 2004 to 206.2 in Q2 2007, the most recent period provided. This is an annual average change of 12 percent. MMK adjusted the U.S. Basic Index by the exchange rate for the same period and the index was shown as rising from 134.7 to 155.8, or an average annual increase of 5 percent. For the category of "Turbine and power transmission equipment manufacturing" the average annual changes in the price index was 3 percent on an unadjusted basis and negative 4 percent when adjusted for the exchange rate. In both cases MMK cautioned that "[i]n providing this calculation, we caution that the index in question is for equipment sold in the United States, and thus not necessarily an indicator of prices available to BC Hydro." (Exhibit B-5-1, BCUC 1.91.1)

The two price index series were described as:

> "BCTC forwarded this IR to BC Hydro, who forwarded it to MMK for response. MMK's response is as follows.
>
> As per the US Department of Labor Statistics definitions:
>
> PCU335311 – Electric power and specialty transformer manufacturing includes the following US products for use in the US:
> (a) Primary products:
> - i Power regulators, boosters, and other transformers and parts for all transformers
> - ii Power and distribution transformers, except parts
> - iii Fluorescent lamp ballast
> - iv Commercial, institutional and industrial general purpose transformers, all voltages
> - v Specialty transformers, except fluorescent lamp ballasts
>
> (b) Secondary products and miscellaneous receipts.
>
> PCU33361 – Turbine and power transmission equipment manufacturing includes the following US products for use in the US:

(a) Turbine and turbine generator set units manufacturing

- i Primary products:
  1. Turbine generator sets
  2. Steam, gas, and other turbines and turbine generators
  3. Parts & accessories for turbines, turbine generators, and turbine generator sets
- ii Secondary products and miscellaneous receipts

(b) Speed changers, drive, and gear manufacturing

- i Primary products:
  1. Loose gearing, including gears, pinions, racks, and worms, sold separately
  2. Speed changers, and Ind. High speed drives, and parts other than loose gearing
- ii Secondary products and miscellaneous receipts

(c) Mechanical power transmission equipment manufacturing:

- i Primary products:
  1. Pain bearings and bushings
  2. Mechanical power transmission equipment, except speed changers, drives and gears
- ii Secondary products and miscellaneous receipts

(d) Other engine equipment manufacturing

- i Primary products:
  1. Parts and accessories (except aircraft and gasoline automotive engines)
  2. Gasoline engines (except aircraft, automobile, highway truck, buts and tank)
  3. Diesel, semi diesel and dual fuel engines (except automotive)
  4. Diesel, semi diesel, and dual-fuel engines for automobiles, trucks, and buses
  5. Piston-type natural gas engines, including LPG engines (excluding gas turbines)
- ii Secondary products and miscellaneous receipts."

(Exhibit B-5-1, BCUC 1.91.2)

MMK presented information on the price trends in construction labour in three different categories, (Exhibit B-1, Appendix E, p. 22) and provided more detailed information on the category of percentage increase in the weekly earnings in heavy and civil engineering construction. The increases were 1.2, 1.0 and -1.0 percent for 2004/05, 2005/06 and 2006/07 respectively. MMK explained that the statistics presented are not consistent with information provided by industry sources who report significant labour cost increases in recent years (Exhibit B-5-1, BCUC 1.93.1).

BCTC stated that the “Heavy and civil engineering construction category” is the most appropriate for the BCTC portfolio of projects because IBEW wages rates seem to correspond with the weekly earnings presented and because the majority of transmission line work in the province is carried out by either the Line Contractors Association of B.C. or BC Hydro, whose members have higher basic hourly wages than those of a BC Hydro electrician (Exhibit B-5-1, BCUC 1.93.3). MMK states that the hourly percentage settlements for trade unions shown in the report is 2.8 percent for 2007 to 2008 and that the IBEW Electric Workers is the highest change at 3.5 percent in the same period (Exhibit B-5-1, BCUC 1.93.4).

MMK presents information on annual trends in the price of steel, copper and aluminum, while noting that caution should be used in assessing the implications of metal price trends for electric utility construction costs, since among other things, trends might be out-weighed by industry specific supply and demand trends. MMK states that (1) copper prices in the first half of 2007 averaged near 2006 average levels and remain at or near all time highs following a dramatic rise in 2007, (2) steel prices flattened in 2006 but continue to be strong during the first half of 2007 at or close to record 2006 levels, and (3) aluminum prices increased sharply in 2006 and flattened in the first half of 2007 but were at record highs (Exhibit B-1, Appendix E, pp. 25-28). BCTC stated that metal prices had a significant impact on material costs and that overall material costs constitute 20 and 29 percent of Sustaining and Growth portfolio costs respectively (Exhibit B-5-1, BCUC 1.94.1).

MMK provided annual cost indices for the three metals for both the United States and Canada. In the United States the five year average price changes range from 6 percent for aluminum to 23 percent for copper, while the 2007 over 2006 change ranged from 5 to 6 percent. For the Canadian index the 5 year average increase ranged from 4 percent for both steel and aluminum to 28 percent for copper. The 2007 percent increases ranged from negative 1 to negative 8 percent. MMK noted that while commodity pressures did ease in much of 2007 between August 2007 and February 2008 future prices rose sharply for copper and aluminum (Exhibit B-5-1, BCUC 1.94.2).

MMK provided further information on futures prices for the three metals which showed annual increases for different periods from 2007 to 2009 ranging from 1 percent to minus 9 percent. MMK cautioned that a flat futures market is not equivalent to a forecast that commodity prices will be stable in the future, but indicates investors are divided equally between expecting a price increase or decrease (Exhibit B-5-1, BCUC 1.95.1).

BCTC submits that based on the evidence and analysis filed and actual inflation experienced that the proposed inflation adjustments are reasonable and justified (BCTC Argument, para. 18-20).

No Intervenor commented directly on BCTC's proposals regarding inflation adjustments, however BCOAPO submits that the Commission should be particularly vigilant regarding cost escalation and that BCTC should continue to work hard to avoid runaway costs (BCOAPO Argument, p. 2).

Commission Determination

The Commission Panel notes that in the F2008 TSCP Decision BCTC was invited to provide a comprehensive justification of any inflation adjustment other than BCCPI. The Commission Panel views BCTC's justification to have four main components: the MMK Report, anecdotal evidence of recent BC Hydro experience, labour cost increases, and the expiration of fixed price contracts. The MMK report appears to have been given the most weight by BCTC in assessing cost escalation.

MMK's reasons for their recommendation on cost escalation bears repeating: "For transmission, stations and distribution, <u>based on the recent strength of US equipment price indices, confirmed by the recent experiences of BC Hydro staff</u>, we expect future Canadian cost inflation pressures for transmission, stations and distribution to be much stronger than in the past few years" (underlining added) (Exhibit B-1, Appendix E, p. 3). The Commission Panel is not persuaded that the information presented by MMK regarding the recent strength of U.S. equipment prices forms a basis for predicting cost increases above CPI in British Columbia. The Commission Panel further notes that the U.S. equipment price index when adjusted for exchange rates provides little or no justification for MMK's conclusion, and gives little weight to their caution regarding the use of the adjusted data. Even these concerns aside, the descriptions of the price indices used by MMK do not give the Commission Panel confidence that they are applicable in the circumstances of BCTC.

MMK confirms its conclusion based on the recent experiences of BC Hydro staff. The Commission Panel notes that the only such evidence provided was related to one instance covering two identical transformers. The Commission Panel gives this evidence little weight. The Commission Panel further notes that MMK also provides information on labour cost and commodity cost increases. The Commission Panel does not view the commodity price information as supporting MMK's recommended escalation rates for future periods. However, the labour cost escalation does appear to support increases in this category of 3 to 4 percent per annum, as does the information provided regarding electrician's wages. Other information on labour costs was not supportive, but the Commission Panel acknowledges MMK's cautionary note in this regard, and BCTC's estimate that labour costs comprise 23 percent of Sustaining Capital costs.

Finally, the Commission Panel agrees that there have been significant commodity price increases, and that if BCTC had been procuring its equipment on long-term fixed price, or non-indexed contracts, that the expiration of these contracts could now see BCTC facing embedded price pressure. No evidence as to the scope, magnitude or duration of any such contracts was presented.

The Commission Panel directs BCTC to continue to use an inflation adjustment equal to the BCCPI.

5.0 GROWTH CAPITAL PORTFOLIO

The projects contained in the Growth Capital portfolio are required to reinforce the transmission system to meet the capacity and energy transfer demands for firm domestic load, and enable economic generation dispatch and firm point-to-point deliveries. The selected projects are tested against measures of affordability, system performance, community and First Nations impact, and environmental compliance (Exhibit B-1, pp. 75-76).

5.1 Key Drivers

BCTC states that, in general, Growth projects are customer and volume driven. The current Network Integration Transmission Service ("NITS") demand and resource forecasts are combined with other point-to-point transmission and generation interconnection requests, and the capability of the system is then tested against BCTC and NERC/WECC Planning Standards and performance requirements. BCTC then identifies system reinforcements to address any non-compliant performance (Exhibit B-1, pp. 76-79).

5.1.1 Load Forecasts Used for Planning Studies

BCTC states that the load forecast used for the bulk system was BC Hydro's December 2006 Load Forecast while the July 2007 Distribution Substation Load Forecast was used for the regional system (Exhibit B-1, p. 80). PPGA requested that BCTC file the Fort Nelson area forecast which BCTC declined to provide citing BC Hydro's claim that some information was confidential and customer sensitive (Exhibit B-5-1, PPGA 1.2.1).

5.1.2 Resource Forecasts and Dispatch Assumptions

BCTC states it uses the following inputs for its resource forecast:

(a) BC Hydro's current Long-Term Acquisition Plan, which was the 2006 Amended Long-Term Acquisition Plan, and

(b) Generation resources as identified in information updates provided by BC Hydro as part of its NITS service, which includes the Canal Plant Agreement resources and IPPs with whom BC Hydro has contracted to purchase the output, and designated by BC Hydro as network resources (Exhibit B-1, p. 79).

BCTC subsequently stated that the latest resource information also included an update supplied by BC Hydro in August 2007 which appears to contain a Base Resource Plan with and without Burrard, and Contingency 1 and Contingency 2 generation resource plans (Exhibit B-5-1, BCUC 1.22.1, Attachment7.xls, Attachment8.xls, and Attachment9.xls).

An important aspect associated with the identification of resources and the utilization of the transmission assets is the method of dispatch between regions. BCTC states that refinement of the assumptions regarding resource dispatch for planning purposes for the next NITS application is under development jointly by BCTC and BC Hydro (Exhibit B-1, p. 80). The resource dispatch determines the Committed Use ("CU") across transmission cut-planes. For this Application, BCTC used the following assumptions in determining CU:

- For generation in the South Interior region, Maximum Continuous Rating ("MCR") in the spring freshet and Dependable Generation Capacity ("DGC") in the winter less the region's light load in each respective season.

- For generation in the North Interior region, the DGC for heritage resources and the Equivalent Load Carrying Capacity ("ELCC") for the intermittent resources in the winter less the region's light load in that season. BCTC states that BC Hydro suggested nominating MCR for the North Interior resources including intermittent resources until a study is done jointly with BCTC to see if MCR should be dispatched instead of DGC. This study has not reached a conclusion and BCTC has used the resource dispatch that most closely matches the usage of the system.

- For CU on the Interior to Lower Mainland ("ILM") cut-plane, winter peak load was used with DGC from either the South Interior or North Interior region, minus the DGC of the Coastal region. BCTC also states that BC Hydro suggested nominating MCR for the South Interior and North Interior resources including intermittent resources until a study is done with BCTC to see if MCR should be dispatched instead of DGC. This study has not reached a conclusion and BCTC has used the resource dispatch that most closely matches the usage of the system.

- Full Burrard plant capacity or Canadian Entitlement is available for dispatch until 2013 to the extent necessary until the ILM grid is reinforced. BCTC submits that the self-sufficiency criteria set in Special Direction 10 could imply that the CE cannot be relied upon by BC Hydro for planning its generation resources, and that it expects the issue will likely be addressed in BC Hydro's next Long-Term Acquisition Plan proceeding (Exhibit B-1, pp. 81-82)

BCTC stated that the assumptions described above are not significantly different than historic dispatch assumptions (Exhibit B-5-1, BC Hydro 1.1.1).

BCTC notes that under the OATT, there is no obligation on BC Hydro or any other generator to re-dispatch generation, and that re-dispatch arrangements are entirely voluntary. BCTC states that it believes that its role in facilitating a re-dispatch market may be in the provision of information on re-dispatch opportunities that would relieve transmission constraints (Exhibit B-1, p. 381).

BCTC further stated that it is not considering interim transmission reinforcement options for the ILM upgrade to address BC Hydro's Contingency Resource Plans ("CRPs"). Instead, in addition to reserving any existing ATC needed for the CRPs according to Attachment J of the OATT, it will consider seeking approval of Definition Phase funding for transmission reinforcements required for the CRPs based partly on the likelihood of the CRPs materializing (Exhibit B-5-1, BC Hydro 1.2.1).

BC Hydro submits that it encourages BCTC to undertake and complete the study work for the CRPs at its earliest convenience (BC Hydro Argument, p. 1).

IPPBC submits that BCTC should provide a report to the Commission as promptly as possible describing the circumstances and rationale for using DGC or MCR in assessing the capacity associated with various resource types such as heritage hydro generation or intermittent IPP generation, and also describing the assessment of ELCC for the various forms of intermittent generation on a system-wide basis (IPPBC Argument, p. 6).

In Reply, BCTC submits that it and BC Hydro continue to discuss the appropriate dispatch assumptions to be used for planning the transmission system, and that the issue is more complicated than suggested by IPPBC (BCTC Reply, p. 4).

Commission Determination

It is not apparent to the Commission Panel that BC Hydro's August 2007 Base Resource Plan and Contingency generation resource plans were used in the development of this Application. Although BCTC identified having access to this information, it does not describe it in the data set of the information it used for the forecast of resources (Exhibit B-1, BCUC 1.114.1).

The Commission Panel acknowledges that assessing the impact on the transmission system of the dispatch of resources by BC Hydro under the NITS application is complicated. **The Commission Panel also acknowledges the effort being made by both BCTC and BC Hydro towards developing a common understanding regarding the dispatch assumptions of resources identified in the NITS application, and encourages BCTC to continue assessing how the existing transmission system can be best utilized through re-dispatch of NITS-nominated resources. The Commission Panel directs BCTC to file a report describing these assumptions with the earlier of the next capital plan application or following BC Hydro's next NITS application.**

5.1.3 Committed Use, Integration of New Generation, and Third Party Requests

BCTC states that the transmission requirements associated with following the service requests are also used in the transmission planning process:

- BC Hydro's NITS application which contains service requirements for the City of New Westminster, Point Roberts, and FortisBC, and certain transmission service provisions related to the Canal Plant Agreement between BC Hydro, FortisBC, TeckCominco Metals Ltd., and Columbia Power Corporation.
- Transmission capacity specified by FortisBC's to allow resources in the Kootenays to serve loads in the Okanagan. This transmission service is provided under the General Wheeling Agreement with FortisBC, a grandfathered transmission services agreement which existed prior to the establishment of the OATT.
- Long-term Firm Point-to-Point Transmission Service contracts with OATT customers.

- Requests by generator owners to interconnect new generators, or to accommodate changes to existing generators.

BCTC submits that the Commission previously confirmed that the provisions in BCTC's OATT adequately address future generation interconnections, and accepted BCTC's proposal to forecast generation interconnections for the upcoming year, where possible, assigning such amounts to specific generation projects. BCTC proposes to continue with this treatment (BCTC Argument, para. 33).

BC Hydro submits that it continues to support BCTC relying on its OATT, including the interconnection procedures and agreements attached to the OATT, as the authority for proceeding with IPP interconnections, and that it supports BCTC continuing with its existing treatment of future generation interconnections (BC Hydro Argument, p. 2).

IPPBC submits that in the identification of interconnection costs for the integration of new IPP generation, BCTC should definitely not include costs that are solely for the account of IPPs (i.e. direct assignment costs), and that these costs do not belong in any BCTC capital estimates (IPPBC Argument, p. 3).

In Reply, BCTC submits that it does not believe that the assertion put forward by IPPBC is consistent with Directive 12 or section 45(6) of the Act. BCTC proposes that it is open to including in future Capital Plans only those interconnection costs of projects which are net of third party funding, subject to the Commission’s approval (BCTC Reply, p. 4).

Commission Determination

The Commission Panel observes that there are no complaints regarding the provisions of the OATT that address generation interconnections, and that these provisions continue to serve their intended purpose.

The Commission Panel finds the information provided in the Application regarding generation interconnection costs to be informative, but it may be over-reaching its intended purpose. **The Commission Panel directs BCTC to provide in future capital plans an estimate of all generation interconnection costs, except those which are 100 percent third party funded and will remain owned by and the responsibility of the third party.**

5.1.4 Response to New Standards

As discussed in Section 2.2 of this Decision, BCTC states that it is currently reviewing the NERC Reliability Standards, and plans to file a BCTC Reliability Standards document with the Commission in the spring of 2008. BCTC stated that although the regulatory impact of non-compliance with NERC standards is limited at this time as NERC standards are not mandated in the province of B.C., there may be significant operational and economic impacts. For example, BCTC submitted that when there is non-compliance with the NERC CIP standards, unauthorized individuals may gain physical or logical access to critical infrastructures, possibly resulting in significant safety, economic and financial impacts to BCTC and stakeholders (Exhibit B-5-1, BCUC 1.74.4).

BCTC has proposed the Laptop, Desktop and Removable Media Encryption BCTC Capital project which is primarily driven by compliance requirement with the NERC CIP standard (Exhibit B-1, pp. 344-345).

Commission Determination

The Commission Panel notes that although BCTC claimed that there may be significant operational and economic impacts associated with non-compliance with NERC standards, details of these impacts were not provided. BCTC stated that non-compliance with the NERC CIP standard could result in unauthorized access to critical infrastructures. However, BCTC did not provide an assessment of the measures it is currently taking to prevent unauthorized access, and whether these measures are adequate, even though the measures may not be in full compliance with NERC standards. The Commission Panel encourages BCTC to evaluate in future capital plans the effects of temporary non-compliance with specific NERC/WECC standards in cases where long-term compliance could be attained through planned projects and programs, and especially in circumstances where the projects or programs are not being proposed solely for the purpose of attaining compliance by a specified deadline.

5.2 Other Drivers

There are other potential drivers arising from the 2007 Energy Plan and past Capital Plan Decisions that influence the Growth Capital planning process. These drivers include the application of the TEP, and standards employed by BCTC that go beyond NERC/WECC requirements.

5.2.1 Response to Policy Actions 12 and 13

Directive 37 of the 2008 TSCP Decision required BCTC to file a report related to Policy Action 12 and Policy Action 13 on or before December 1, 2007. BCTC submitted a letter dated December 3, 2007 to the Commission in response to the Directive (Exhibit B-5-1, Attachment to BCUC 1.84.1).

With respect to Policy Action 12, BCTC advised that its progress on consultation activities and other progress related to the TEP would be outlined in the CPCN application for the 5L51/52 Thermal Upgrade project (Exhibit B-5-1, Attachment to BCUC 1.84.1, p. 2).

With respect to Policy Action 13, BCTC stated that the Congestion Relief Policy directed under Policy Action 13 is a Government Policy, and advised that it is supporting Government in development of this policy by providing advice and identifying options for Government's consideration (Exhibit B-5-1, Attachment to BCUC 1.84.1, p. 4).

IPPBC seeks clarification from the Commission with respect to whether BCTC is playing an active or passive role in the development of Congestion Relief Policy (IPPBC Argument, p. 10).

In Reply, BCTC submits that although it is supporting Government on its initiative regarding Congestion Relief, it is a Government initiative (BCTC Reply, p. 5).

5.2.2 Transmission Expansion Policy

Directive 21 of the 2008 TSCP Decision required BCTC to, among other things, report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. Directive 22 required BCTC to provide a detailed description of the highest ranked intertie expansion project in the next capital plan (F2008 TSCP Decision, pp. 53, 55).

BCTC states that in the coming months it will analyze suggestions for TEP projects received in response to an invitation for Expressions of Interest for project ideas and, where appropriate, will make recommendations to further pursue TEP project concepts (Exhibit B-1, p. 67). BCTC provided a list of potential TEP projects it was assessing (Exhibit B-5-1, BCUC 1.20.1).

5.2.3 Projects to Avoid Generation Shedding

Directive 1 of the 2008 TSCP Decision required BCTC to identify in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and to identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for first contingency events (F2008 TSCP Decision, p. 14).

The only project BCTC identifies as being planned to avoid generation shedding is the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors project ("Ashton Creek project") (Exhibit B-1, p. 181).

BC Hydro supports this application of BCTC's policy to avoid generation shedding for first contingencies, particularly on the 500 kV system, and it proposes that generation shedding be reserved for situations of maintaining transmission capacity after permanent outages in anticipation of the next contingency, for sudden double contingencies, for additional economy transfers and for temporary transfer capability for uncertainties related to resources, load growth and reinforcement project delays (BC Hydro Argument, p. 2).

Commission Determination

The Commission Panel finds BC Hydro’s argument persuasive and accepts the application, in these circumstances, of BCTC’s policy of avoiding generation shedding for first contingencies. Notwithstanding other concerns regarding the Ashton Creek project discussed later in this Decision, the Commission Panel acknowledges the importance of preserving the integrity of 500 kV bulk transmission system, particularly when the impact is the shedding of considerable generation in response to the identified first contingencies (Exhibit B-1, Appendix F, p. 4). BCTC is cautioned that this does not constitute an endorsement of this particular policy for use in other parts of the system, and each instance of the application of this policy will continue to be evaluated on its individual merits.

5.3 Projects for Which a CPCN Application Has Been or Will Be Filed

BCTC states that it will make a CPCN application when one or more of the following five criteria are met: (1) total project cost is expected to exceed $50 million; (2) the impact on a particular community or constituency likely cannot be mitigated to its satisfaction; (3) the risk associated with a project, as established through BCTC’s corporate risk management framework, is identified as High or Extreme; (4) the project establishes a precedent for significant future investment, where “significant” means $50 million or more over either a ten-year period or the life of the asset; and (5) the Commission exercises its discretion to require a CPCN application. BCTC states that at this time, it does not believe there is any reason to adjust the CPCN criteria (Exhibit B-1, p. 16).

There are two projects in progress for which CPCNs have been approved, specifically the System Control Modernization project and the Vancouver Island Transmission Reinforcement project, which were approved by Commission Order No. C-1-05 and Order No. C-4-06, respectively. BCTC has identified the following projects for which CPCN applications have been, or may be, filed:

- The Interior to Lower Mainland Transmission project for which BCTC submitted a CPCN application on November 5, 2007 (Exhibit B-1, p. 25).
- The Central Vancouver Island (“CVI”) project (Exhibit B-1, p. 28).

- The South Interior Series Compensation ("SISC") project (Exhibit B-1, p. 28).
- The Golden 69 kV System Reinforcement project (Exhibit B-1, p. 35).
- The Mount Pleasant Area Reinforcement project (Exhibit B-5-1, BCUC 1.3.1).
- The Metro Supply Reinforcement project (Exhibit B-5-1, BCUC 1.3.1).
- The North Thomson Reinforcement project (Exhibit B-5-1, BCUC 1.3.1).
- The Long Beach System Reinforcement project (Exhibit B-5-1, BCOAPO 1.7.1).

BCTC separately applied for approval for the capital expenditures associated with the 5L51/52 Thermal Upgrade project on December 12, 2007. The requested capital expenditures were approved by Commission Order No. G-58-08. Two other projects appear to meet the criteria described above for requiring a CPCN application, but are not specifically identified as such in the Application. These projects are the 5L76/5L79/5L96 Series Compensation project (Exhibit B-1, p. 138), and the Undefined Upgrades for GMS X WSN X KLY System project (Exhibit B-1, p. 141).

Of the projects identified above, BCTC is seeking Definition Phase funding for only the Golden 69 kV System Reinforcement project in this Application (Exhibit B-1, p. 19). Definition Phase expenditures for the ILM, CVI and SISC projects have been approved in previous Capital Plan applications. Approval for Definition Phase expenditures for the Mount Pleasant Area Reinforcement project, the Metro Supply Reinforcement project, the North Thomson Reinforcement project, or the Long Beach System Reinforcement project has not been requested in this Application.

5.3.1 Golden 69 kV System Reinforcement Project

BCTC states it is applying for approval of the Definition Phase expenditures for the Golden 69 kV System Reinforcement project before it has established a preferred alternative in order to meet the in-service date (Exhibit B-1, p. 50).

Directive 5 of the 2008 TSCP Decision required BCTC to provide a description of how it considered the TEP for the identification of project alternatives (F2008 TSCP Decision, p. 17).

BCTC identifies ten potential options for this project, one of which is a TEP alternative (Exhibit B-1, pp. 142-147). BCTC provided estimates of the incremental capacity associated with each of the ten options, except for the TEP option, which had not yet been reviewed from a system perspective (Exhibit B-5-1, BCUC 1.43.2).

Commission Determination

The Commission Panel is concerned that BCTC has advanced the examination of alternatives for this project without a thorough investigation of the TEP alternatives. This concern is compounded by the timing of the request for approval of Definition Phase expenditures before a preferred alternative is identified. **The Commission Panel approves the Definition Phase expenditures for the Golden 69 kV System Reinforcement project, but directs BCTC to provide with any request for approval of Implementation Phase expenditures for this project, a thorough examination and comparison of the TEP alternative, the preferred alternative, and the next highest ranked alternative. In the event that the TEP alternative is either the preferred alternative or the next highest ranked alternative, the comparison shall include the top three ranked alternatives.**

5.4 Ashton Creek Substation Capacitor Bank Project

BCTC is seeking approval for the Implementation Phase of the Ashton Creek Substation Capacitor Bank project, which consists of the work related to the addition of two 500 kV, 250 MVAr switched shunt capacitor banks at the Ashton Creek Substation. BCTC states that the project has a low overall risk because of the extensive planning, engineering and regulatory review that has taken place (Exhibit B-1, pp. 129-130).

BCTC states that without the project, there is a shortage of ATC at the West of Selkirk cut-plane during both the winter and summer seasons. During the winter season, the ATC is between negative 200 MW during the lightest load period and positive 106 MW during the maximum peak load period. During the summer freshet season, the ATC is between negative 583 MW during the lightest load period and negative 364 MW during the maximum peak load period (Exhibit B-1, Appendix F,

p. 4). Even after the project implementation, BCTC supplies data that appears to show a shortage of up to 353 MW of ATC under certain summer light load conditions during a transmission outage (Exhibit B-1, Appendix F, p. 7).

In response to Directive 3 from the F2008 TSCP Decision, BCTC states that this project could be deferred if the generation that impacts the West-of Selkirk Cut-plane is reduced and other generation output not using the path is increased to serve the load. However, BCTC cautions that this action changes the optimal dispatch of the generation resources and may result in water spill at the plants in the Selkirk area, and that the action may not be achievable at all times subject to certain system constraints (Exhibit B-1, p. 379).

BCTC provided a comparison of two cost estimates for this project, one by BC Hydro Engineering Services during the early stages of project definition and a second by SNC-Lavalin after preliminary engineering. The SNC-Lavalin estimate showed a cost increase of 78 percent over the BC Hydro Engineering Services estimate (Exhibit B-5-1, BCUC 1.37.1).

BCTC was asked to provide a probability analysis for the duration of certain dispatch conditions, but it declined, claiming the requested condition was more stressful than had been assumed for the conditions BCTC did study (Exhibit B-5-1, BCUC 1.97.1).

BCTC submits that the need for the Ashton Creek Substation Capacitor Bank project was based on a realistic assessment of generation and load patterns in the South Interior region, and that even after the project, the aggregate total generation in the South Interior East region would need to be reduced by about 250 MW in situations when the forced transmission outage cannot be restored in a short period of time (BCTC Argument, para. 28).

As discussed in Section 5.2.3 of this Decision, BC Hydro expresses support for this project and believes that it is needed by 2010 (BC Hydro Argument, p. 2).

Commission Determination

The Commission Panel is alarmed by the increase in the estimate for the Ashton Creek Substation Capacitor Bank project, especially considering that a recent cost estimate was submitted for review in May 2007 as part of BC Hydro's CPCN application for the Revelstoke Unit 5 project (Revelstoke Unit 5 CPCN application proceeding, Exhibit B-3, BCUC 1.7.1.1). The Commission Panel is also disappointed that BCTC did not apply the probabilistic analysis methodologies it has developed against the dispatch conditions that were considered in the report provided as Appendix F in this Application.

Notwithstanding the above concerns, the Commission Panel approves the expenditures for Ashton Creek Substation Capacitor Bank project, but is concerned about the timing and full scope of the project. The Commission Panel expects BCTC to advise the Commission of changes, if any, to the timing and scope of the project prior to construction of the project and to consider the timing of South Interior resource additions and load forecasts that are contained in BC Hydro's 2008 Long-Term Acquisition Plan Application. If BCTC concludes that changes to the timing or scope of the project are appropriate, then BCTC should justify the changes in a report to the Commission with a probabilistic analysis of the duration of outages for the specific seasonal dispatch conditions considered in the report.

5.5 Woods Lake Area Reinforcement Project

BCTC is seeking approval for Definition Phase expenditures associated with Woods Lake Area Reinforcement project, for which it has identified eight options. Aside from a "do-nothing" option and a generation addition option which are considered by BCTC not to be feasible, four options involve an interconnection with the FortisBC system, one option is an improvement of BCTC's transmission system from Vernon Terminal ("VNT") to Woods Lake Substation ("WDS"), and the final option is demand side management ("DSM"). BCTC does not consider DSM to be a practical solution because it claims that the energy consumers served by the WDS may be reluctant or unable to alter their energy consumption patterns and lifestyle to meet demand side management requirements (Exhibit B-1, pp. 148-153). BCTC provides Study Phase cost estimates to the Commission on a confidential basis (Exhibit B-5-1, BCUC 1.44. 1).

BCTC identifies that there are deficiencies with the right-of-way rights associated with the existing 69 kV circuit supplying WDS (60L205 VNT-WDS), proposes to address this issue as part of the project. BCTC states that it is continuing planning discussions with FortisBC in order to develop the preferred option, and provided an update of the status of those discussions (Exhibit B-5-1, BCUC 1.44.2).

Commission Determination

The Commission Panel encourages BCTC to continuing working with FortisBC to develop a solution that would be beneficial to the ratepayers of both utilities, and approves Definition Phase expenditures associated with Woods Lake Area Reinforcement project. This approach should be extended to other situations where reinforcements are required at the boundaries of the BCTC and FortisBC systems, as may be the case for the Westbank 138 kV System Reconfiguration project.

5.6 Balance of the Growth Capital Portfolio

The projects in the Growth Capital Portfolio are separated into the following categories: Bulk System Reinforcements, Area Reinforcements, Station Expansion and Modification Projects, Customer Requested Projects, and Generation Interconnection Projects.

5.6.1 Bulk System Reinforcements

BCTC identifies F2009 expenditures for the following Bulk System Reinforcement projects, and requests approval for the projects designated as such (Exhibit B-1, pp. 100, 111):

Bulk System Reinforcements (Thousands of Dollars)	Prior Years	F2009 Cost	Total Project	Approval	Original Approval
500/230 kV Selkirk Transformer T4 Addition	200	4,211	23,887	G-69-07	17,756
ILM - Interior to Lower Mainland Reinforcement - Definition Phase	18,554	13,261	31,815	G-103-04	15,700
RAS - Provision for Unidentified Additions - F2008-F2009	35	840	875	G-69-07	1,000
RAS - Vancouver Island	2,745	920	3,665	G-69-07	1,850
Selkirk – 500 kV 123 MVAr Shunt Reactor	560	5,574	6,134	G-103-04	6,103
South Interior Series Compensation (SISC) Project - Definition Phase	1,498	102	1,600	G-69-07	1,600
Vancouver Island Reinforcement Project (VITR)	122,105	164,916	287,261	C-4-06	238,500
Ashton Creek 2x250 MVAr, 500kV Switchable Shunt Capacitor - Implementation Phase		1,552	20,049	Section 5.4	
RAS - Bridge River Generation Shedding Modifications	700	1,600	2,300	Sought	
RAS - GMS Generation Shedding Modifications - Stage 2		220	2,090	Sought	
RAS - Revelstoke G5 Generation Shedding Modifications		112	1,677	Sought	
Subtotal Bulk System Reinforcements		193,308			

BCTC states that the significant increase in the 500/230 kV Selkirk Transformer T4 Addition project is attributable to the approved amount being based on a planning estimate, and the project in-service date is delayed because of constraints in the transformer supply chain (Exhibit B-1, pp. 108, 114).

BCTC identifies task scope refinements for regulatory, environmental and First Nations consultation as the reason for the large increase in costs for ILM - Interior to Lower Mainland Reinforcement - Definition Phase project. For instance, the archaeological impact assessment, required as part of the environmental assessment is one of the largest and most complex ever carried out in the province, the cost of which was not anticipated in 2004 (Exhibit B-1, pp. 108, 114-115).

BCTC states that the cost increases in the VITR project are attributed to inflation, and legal and environmental costs (Exhibit B-1, pp. 108, 117).

BCTC stated that the cost of the RAS - Revelstoke G5 Generation Shedding Modifications project was not included in the Revelstoke Unit 5 CPCN Application because the Remedial Action Scheme ("RAS") is a BCTC requirement (Exhibit B-5-1, BCUC 1.39.1).

5.6.2 Area Reinforcements

BCTC identifies F2009 expenditures for the following Area Reinforcement projects, and requests approval for the projects designated as such below (Exhibit B-1, pp. 101, 111):

Area Reinforcements (Thousands of Dollars)	**Prior Years**	**F2009 Cost**	**Total Project**	**Approval**	**Original Approval**
Mission and Matsqui Area Supply	38,406	17,398	56,900	G-91-05	43,205
Retermination of Sidney 60 kV Supply to Keating	2,186	8,625	30,249	G-69-07	13,607
Golden 69 kV System - 69 kV Reinforcement - Definition Phase		3,000	3,000	Section 5.3.1	
Woods Lake Area Reinforcement - Definition Phase		500	500	Section 5.5	
Subtotal Area Reinforcements		29,514			

As discussed in Section 3.6 of the Decision, BCTC has supplied a comprehensive analysis of the cost increases of Mission and Matsqui Area Supply project (Exhibit B-5-1, Attachment to BCUC 1.82.1). With respect to the large increase in the cost of the Retermination of Sidney 60 kV Supply to Keating project, BCTC maintained that it is still the preferred option to resolve both the local and system constraints because the estimate for the next lowest cost option has a lower bound of $30 million subject to an estimate accuracy of +100 percent/ -50 percent (Exhibit B-5-1, BCUC 1.32.1).

5.6.3 Station Expansion and Modification

BCTC identifies F2009 expenditures for the following Station Expansion and Modification projects, and requests approval for the projects designated as such below (Exhibit B-1, pp. 102, 112-113):

Station Expansion and Modification (Thousands of Dollars)	**Prior Years**	**F2009 Cost**	**Total Project**	**Approval**	**Original Approval**
Cathedral Square - 230/12 kV Transformer	580	11,719	13,649	G-103-04	8,605
Chetwynd - T1 and T2 Transformer Replacements	100	3,122	4,660	G-69-07	3,650
Colwood - 138-25 kV Transformer Addition	178	7,400	7,578	G-69-07	7,513
Gavin Lake 66-25 kV Transformer and Feeder Network Upgrade	2,196	569	2,765	G-69-07	1,992
Golden - 69 kV Capacitor Bank Addition	242	1,300	1,542	G-67-06	1,810
Grief Point 12 kV Circuit Conversion	255	2,850	3,105	G-69-07	3,272
Hope - 25 kV Conversion	2,498	900	3,398	G-69-07	2,701
Kidd 1 - Substation Redevelopment	200	2,000	22,200	G-69-07	10,409
Oyster River - 132-25 kV Transformer Addition	100	3,375	3,475	G-67-06	3,000
Porteau Station Expansion	50	2,450	2,500	G-67-06	3,553
Sechelt Transformers Replacement (T1 and T2)	221	4,980	5,201	G-69-07	4,993
Seventy Mile House- 69/25 kV Transformer Addition	242	1,895	2,692	G-91-05	1,205
Shawnigan Lake Substation - Transformer Replacement	322	5,250	5,572	G-69-07	5,472
Walters Transformer Addition	159	5,018	5,177	G-69-07	5,056
Westbank - T1 Transformer Replacement	100	2,650	2,750	G-69-07	2,680
Port Kells Substation - Shunt Capacitor Addition	339	1,600	1,939	Sought	
Qualicum Substation - Reconfiguration	165	1,472	1,637	Sought	
Sidney Substation Transformer Cooling Upgrades	677	600	1,277	Sought	
Tumbler Ridge - Transformer Replacement	93	2,428	8,219	Sought	
Subtotal Station Expansion and Modification		63,116			

With respect to the large increase in the cost of the Kidd 1 - Substation Redevelopment project, BCTC advises that it is still a planning level estimate with an accuracy of +/- 50 percent. The large increase over the previous project estimate is partially attributed to a planned protective dike, which was intended to seismically secure the station, being found to be ineffective, resulting in a relocation of the transformer and the construction of a secure building for and indoor feeder section (Exhibit B-1, p. 122).

BCTC provided an analysis of options for the Tumbler Ridge - Transformer Replacement project that showed the Present Value (“PV”) of an option consisting of the feasible addition of third 25 MVA transformer was greater than the preferred option because the addition of the third transformer only delayed the preferred option by two years (Exhibit B-5-1, BCUC 1.52.2).

5.6.4 Customer Requests

BCTC identifies F2009 expenditures and requests approval for the following Customer Requested project (Exhibit B-1, p. 103):

Customer Requested Projects (Thousands of Dollars)	**Prior Years**	**F2009 Cost**	**Total Project**	**Approval**	**Original Approval**
Kinder Morgan Canada (“KMC”) TMX-1 Project - Upgrade	8,084	747	8,831	Sought	
Subtotal Customer-Requested Projects		747			

BCTC states that the interconnection of the KMC load falls under the BC Hydro tariff, and as BC Hydro has nominated the KMC load increase in a NITS submission, BCTC is obligated to supply it in accordance with the OATT. BCTC states that the existing system does not have the capacity to serve this load, and claims that there is insufficient time available to implement either a DSM project or to construct generation and meet the in-service date. BCTC identifies a potential overlap of this project with the North Thompson 138 kV Reinforcement Project, but states that there was insufficient time to implement a major system reinforcement project. Therefore, upgrading the existing facilities to meet the requirements necessary for the critical peak load period is the most economic option available (Exhibit B-1, pp. 174-178).

BCTC estimated $648,000 in direct assignment costs and $8,188,000 in network upgrade costs (Exhibit B-5-1, BCUC 1.53.1).

5.6.5 Generation Interconnection Projects

BCTC identifies F2009 expenditures for the following Generation Interconnection projects (Exhibit B-1, pp. 103, 113):

Generation Interconnections (Thousands of Dollars)	**Prior Years**	**F2009 Cost**	**Total Project**	**Approval**	**Original Approval**
Ashlu IPP Construction Load and Interconnection	4,012	14	4,026	G-7-07 / G-69-07	4,494
East Toba and Montrose Creek Hydroelectric Project	2,606	17,578	39,632	Tariff	n/a
Forest Kerr IPP		667	46,298	G-103-04	27,541
Savona ERG IPP	1,627	10	1,636	Tariff	n/a
Zeballos Lake Hydro IPP	3,724	76	3,800	G-157-06	3,760
Future Distribution IPPs	5,000	5,000	70,000	Future	
Future Transmission IPPs	29,663	141,835	863,781	Future	
Subtotal Generation Interconnections		165,179			

BCTC states that the Generation Interconnection work level is expected to increase to accommodate the thirty-eight generators with an Electricity Purchase Agreement ("EPA") from BC Hydro's 2006 Call For Tenders ("2006 CFT") (Exhibit B-1, p. 105). The cost forecast for the F2009 expenditures comes from the interconnection studies performed for the selected projects in the F2006 CFT (Exhibit B-5-1, IPPBC 1.10.1).

The projects identified with F2009 Expenditures are driven by Facilities Agreements, Service Level Agreements and existing tariffs (Exhibit B-1, pp. 124-126). BCTC states that under the current Standard Generator Interconnections Procedures tariff, generators pay for only a few, if any, of the interconnection facilities, but they are required to post security for the remaining majority if not all of the interconnecting facilities (Exhibit B-1, p. 179). BCTC provided a description of the processes involved for generation interconnection requests including the application process by BC Hydro to BCTC, the BC Hydro application to the Commission, the BCTC application to the Commission and the consultation process with interested parties (Exhibit B-5-1, JIESC 1.1.1).

As discussed in Section 3.4 of this Decision, the Commission accepted BCTC's proposal to forecast capital for the interconnection of IPP projects for the upcoming year, and instructed BCTC to, where possible, assign amounts to specific IPP projects. BCTC would not seek approval for these expenditures but would rely instead on the requirements of the OATT as the authority for proceeding with generation interconnections.

BC Hydro submits that it supports the continued use of this approach (BC Hydro Argument, p. 2).

BCTC has forecast potential costs associated with future generation interconnection projects of over $900 million based on past experience with generation interconnections, estimates associated with projects from BC Hydro's 2006 CFT, and an attempt to extrapolate those forecasts into the future based on assumptions regarding future generation requests. The forecast costs are not based on estimates from specific project plans (BCTC Argument, para. 32).

The requirements for BCTC to report Generation Interconnection costs in the future is addressed in Section 5.1.3 of this Decision.

Commission Determination

The Commission Panel notes that BC Hydro supports BCTC's F2009 Growth Capital portfolio (BC Hydro Argument, p. 1), and that BCOAPO does not take issue with the Capital Plan (BCOAPO Argument, p. 5).

The Commission Panel is concerned about the number of projects with significant delays and cost increases and encourages BCTC to continue to improve its estimating and planning processes. The Commission Panel is also concerned about the comparison of alternatives for projects where there are multiple phases in some alternatives, but not in others. The concern arises from phased alternatives and the advancement of phases based on load growth projections that differ greatly from the actual historic load growth trend for the load center being studied. The Commission Panel acknowledges that BCTC responds to the load forecasts it receives from BC Hydro, and an optimal solution to this issue is not apparent at this time. Of specific concern is the Tumbler Ridge -

Transformer Replacement project. **The Commission Panel directs BCTC to confirm with BC Hydro the probability of the projected spot load increases that are driving the need for the replacement of two transformers in 2011 for the option consisting of the feasible addition of a third 25 MVA transformer for the Tumbler Ridge - Transformer Replacement project, and to provide a letter to the Commission confirming the selection of the preferred alternative after a careful examination of the forecast load increases and other factors that may reduce the load on the Tumbler Ridge Substation.**

The Commission Panel finds that the Growth Capital Portfolio expenditures relating to the projects for which approval is being sought as set out in the F2009 TSCP are in the public interest.

6.0 SUSTAINING CAPITAL PORTFOLIO

BCTC states that the Sustaining Capital Portfolio addresses transmission infrastructure capital equipment replacements, refurbishment, and enhancements and is focussed on the efficient and cost-effective management of existing transmission infrastructure assets. Corporately, the Portfolio supports the objectives of safety, system reliability, financial and environment (Exhibit B-1, pp. 87-88).

6.1 Key Drivers

In addition to helping achieve the corporate objectives, BCTC identifies that one of the specific fundamental business considerations driving the planned capital expenditures in the F2009 Capital Plan is ensuring transmission system safety and reliability (Exhibit B-1, p. 27). This fundamental business consideration is by the following Sustaining Capital Portfolio key drivers:

> “ (a) Maintain System Reliability (Asset Health, Asset Performance);
> (b) Manage Risks (Safety, Seismic, Environment, Fire/Explosions, Weather, Security, Relationships); and
> (c) Address Third-Party Requested Projects.”
>
> (Exhibit B-1, p. 88)

Another fundamental business consideration is the need to address ageing infrastructure, which requires a long range development plan. BCTC states that it is analyzing the age profile of its asset categories and developing long range plans to address asset ageing (Exhibit B-1, pp. 27, 40). Consequently, BCTC is proposing to increase Sustaining Capital Expenditures throughout the ten-year Capital Plan period (Exhibit B-1, p. 31).

6.1.1 Ageing Infrastructure

BCTC states that the health of transmission system assets is determined through a study of maintenance records, inspection data, test results, and awareness of industry practices. In F2006, BCTC used these methods to develop the Sustainment Investment Model. The key findings of the study are:

(a) The transmission infrastructure investment bubble from the 1960s and 1970s will have a lasting impact on lifecycle investments.

(b) In F2006 dollars, the average annual capital expenditure required to replace assets that are at end-of life is estimated to be $87 million, the midpoint of the range of between $72 million and $102 million. In F2009 dollars the mean value would increase to approximately $103 million, based on a range of between $85 million and $123 million (Exhibit B-1, pp. 89-90).

As discussed in Section 3.1.5 of this Decision, in 2004 BCTC conducted the ABS that measured asset health and established a condition baseline for thirty-three classes of assets in the transmission system. The ABS concluded that there are numerous assets within the transmission system that are in poor or very poor condition. In lieu of conducting another baseline audit which would rely on very similar data to the initial ABS, BCTC and BC Hydro have foregone the ABS update that was supposed to take place this year and have instead, focused more resources on converting data to electronic format, automating data capture, and collecting missing asset health data (Exhibit B-1, p. 183).

BCTC provided an updated trend graph of corrective work expenditures that showed that the trend line for expenditures in the six-year period between F2003 and F2008 was relatively flat, or just slightly increasing, although the F2008 data only contained nine months of data (Exhibit B-5-1, BCUC 1.103.1).

The failure rates of transformers and circuit breakers were examined in the UMS report. UMS stated that these are two of the most costly groups of assets within the transmission system and are also those for which a level of sophistication and diligence is required in assuring sound lifecycle cost performance. BCTC’s failure rates for breakers and transformers were found to be well below industry norms and therefore indicative of a sound maintenance program. UMS also verified that failure rates for other system components were comparable to breaker and transformer performance and concluded that BCTC exhibits similar performance across its entire asset base (Exhibit B-1, Appendix I, p. 1-3).

Information regarding the age distribution of BCTC's circuit breaker and transformer assets was provided in the UMS report (Exhibit B-1, Appendix I, pp. 5-17, 5-18). BCTC stated UMS examined the possibility that BCTC was prematurely retiring assets. UMS found that the overall number and level (percentage of assets retired each year) of BCTC's capital replacements in the period 2004 - 2006 were unremarkable compared to other transmission companies, but since 2006, the rate of replacements had risen due to negative performance experienced within several classes of breakers. This recent increase in replacements has affected approximately 16 percent of the circuit breaker asset base, and would have the effect of reducing the average age by approximately 2.1 years, which is not enough to explain the unusual age distribution. Therefore, UMS concluded that early replacement of assets was not responsible for the current age profile difference between BCTC and other transmission businesses (Exhibit B-5-1, BCUC 1.108.2).

BCTC submits that asset health is an assessment of the physical condition of the equipment, and that asset health is a leading indicator of asset performance and reliability. Poor asset health leads to lower asset reliability and to lower system reliability if the asset impacts the system (BCTC Argument, para. 46).

BCOAPO submits that BCTC should continue to improve its information on asset condition and performance and improve processes for determining sustainment spending requirements based on the results. BCOAPO observes that age is a poor and overly simplistic predictor of sustainment requirements (BCOAPO Argument, p. 3).

Commission Determination

In the absence of Asset Health Index data through a current ABS, the Commission Panel encourages BCTC to consider corrective action expenditures when assessing the condition of assets. Since there is no identifiable increasing trend in the amount of corrective action expenditures over the last six years, it may be reasonable to assume the overall health of assets is more or less constant over that time, and that asset age alone is not sufficient reason to accelerate asset replacement.

6.1.2 Ensuring Transmission Safety and Reliability

BCTC states that asset performance is the ability of any asset, whether it is in a healthy or a degrading condition, to function as designed when required to ensure system reliability (Exhibit B-1, p. 90). BCTC further states that asset performance is witnessed through observations by BCTC Real-time Operations, System Planning and Performance Assessment, and Asset Management, which enables it to target specific problem areas within the system (Exhibit B-1, p. 92).

BCTC states that in addition to system reliability, there are a number of other risks related to safety, environmental, seismic, weather and flood, security and fire that need to be managed. BCTC submits that the risk environment is continually evolving, and with it, acceptable risk tolerance levels within the broader public community (Exhibit B-1, p. 91). BCTC claims that many risks that have been identified in the past have not been addressed because of financial constraints, which results in a continued backlog of unresolved risk issues that require attention and are being addressed, in part, by this plan (Exhibit B-1, p. 92).

The UMS report states that BCTC has been experiencing significantly lower failure rates than many of its peers in the industry for several years, and UMS suggests that indicates either a highly effective maintenance strategy/program and a well targeted replacement program, or a much younger system than in the other companies used in the comparison database (Exhibit B-1, Appendix I, p. 5-16).

BCTC states that it is not presently able to directly link overall Sustaining Capital Expenditures to system reliability or customer impacts, and that is not aware of any other transmission-related companies who have been able to predict or define the impact of incremental or decremental spending on reliability (BCTC Argument, para. 41). BCTC goes on to say that while it is currently unable to quantitatively link global Sustaining Capital Expenditures to its reliability indices, it does believe that trends in transmission asset health justify an increase in Sustaining Capital Expenditures (BCTC Argument, para. 41).

BCOAPO accepts BCTC's contention that it is difficult to predict or define a relationship between Sustainment Spending and Reliability Indices, and submits it is preferable to relate spending requirements to asset condition and performance (BCOAPO Argument, p. 3).

Commission Determination

The Commission Panel observes that there is contradictory evidence regarding whether the present state of equipment is unacceptably and adversely affecting transmission system safety and reliability, and concludes there is not enough information upon which to make a decision to increase or decrease Sustaining Capital Expenditures based on this measure.

6.2 Sustainment Investment Model and Level of Expenditures

As discussed in the previous Section, the Sustainment Investment Model forecast an average annual capital expenditure for the overall Sustaining Capital Portfolio of $87 million in F2006 dollars to replace assets that are at end of life, the midpoint of a range of $72 and $102 million. BCTC submits that in F2009 dollars, based on actual and forecast inflation, the midpoint value would increase to $103 million (BCTC Argument, para 47). The expenditure investment range is based on a moving ten-year average. The model predicts that Sustaining Capital investments need to increase to keep up with obsolescence and end-of-life asset condition over time (Exhibit B-1, p. 90).

BCTC stated that the Sustainment Investment Model is useful in predicting long-term replacement and refurbishment capital expenditures for a consistent level of transmission system reliability. The model forecasts that 8.1 percent of transmission infrastructure assets are required to be retired over the period F2006 to F2015. BCTC claimed that if Sustaining Capital as directed by Directive 32 of the 2008 TSCP decision was used consistently, only 7.3 percent of forecasted retired assets would be addressed, suggesting that approximately 0.8 percent of forecasted asset retirements would have to be deferred to future years. BCTC stated that based on the Sustainment Investment Model, this deferral will have negative impacts on reliability, future Sustaining Capital Expenditures, and Emergency Capital Expenditures (Exhibit B-5-1, BCUC 1.87.1). BCTC also noted that the expenditures forecast by the Sustainment Investment Model do not include capital expenditures for risk mitigation, third party projects or enhanced performance (Exhibit B-5-1, BCUC 1.87.2).

BCTC states that the individual program needs within the Sustaining Capital portfolio are identified through assessing asset condition, performance, operational effectiveness, risks, and third-party requests. A strategic assessment is then conducted to identify opportunities for individual asset replacements, asset-class replacements, integrated asset replacements, or regional or system replacements (Exhibit B-1, p. 92). Alternative solutions are developed that run across a full range of asset options: run-to-failure, status quo routine maintenance, enhanced or modified routine maintenance, repair, refurbish/rebuild, replace and redesign (Exhibit B-1, p. 93). Each solution alternative is evaluated by a cost/benefit analysis using a variety of quantitative and qualitative methods (Exhibit B-1, p. 94). Expert judgment is then applied to the results to finalize the Sustaining Capital Portfolio plan. Not all investments that are prioritized are included in a specific year's Capital Plan, and some are deferred to future years.

BCTC prepared a report in response to Item 10 of Appendix A of Commission Order No. G-139-06, requiring BCTC to report on relationships of infrastructure spending, reliability metrics and customer impacts, and to consider a number of other issues. This report is also in response to Directive 13 from Commission Order No. G-69-07. Directive 13 requests the status of BCTC's progress in establishing correlations among asset class health index values, failure rates, suspected remaining lifetimes, and impacts on reliability (Exhibit B-1, Appendix H, p. 1).

The report addresses each topic according to the order in which they appear in Item 10 of Appendix A of Commission Order No. G-139-06:

- Link changes in reliability Indices to impacts on end use customers to establish the costs and benefits of establishing specific reliability targets.
- Examine the normal year-to-year variations in the reliability indices to establish the period(s) over which targets should be established and the periods over which "real" trends can be detected (statistical process control theory may be of some use here).
- Determine whether system-wide metrics or more localized (e.g., substation by substation) metrics are appropriate as investment triggers and/or inputs to project prioritization tools.
- Propose a clear priority-setting mechanism for expenditures on existing infrastructure and provide examples of how those mechanisms are to be employed.

- Seek feedback from customers on the impact of outages and the cost/reliability trade off.
- Ensure that the metrics used in assessing the performance of BCTC, its contractors, and its employees measure, to the greatest extent possible, controllable factors.
- Propose one or more mechanisms, by which BCTC can, over time, establish a statistical relationship between the amount and timing of infrastructure expenditures and changes in the various measures of system reliability.

The report also expands on certain topics with a broader context to attempt to provide an insight into the reliability management activities that BCTC is pursuing (Exhibit B-1, Appendix H).

UMS examined BCTC's spending levels relative to its peers, consisting of other Canadian and U.S. transmission companies. Overall, UMS found BCTC's recent spending levels to be below the range that they expected for a company with its system characteristics (Exhibit B-1, Appendix I, p. 1-2). Both BCTC and UMS state that they are unaware of any industry-specific methodology to predict or define the impact of incremental or decremental spending on transmission reliability (Exhibit B-1, Appendix I, p. 3-7; BCTC Argument, para. 41).

BCTC stated that it continues to refine the Sustainment Investment Model to reflect the most current information regarding asset demographics and end-of-life and expected replacement costs. The initial model forecasted average annual expenditures of $87 million when expressed in F2006 dollars. BCTC stated that it does not foresee any significant change from this base amount for the period F2005-F2014.

The overall level of nominal and real (inflation-adjusted) sustaining capital expenditures proposed by BCTC in the Application is shown below:

Sustaining Capital Expenditures Including Third Party and Emergency (Millions of Dollars)	**F2009** (Nominal $)	**F2009 Real** (Inflation adjusted) F2007 $	**F2010** (Nominal $)	**F2010 Real** (Inflation adjusted) F2007 $
Station Programs	71.7	64.4	75.7	64.8
Line Programs	41.2	37.0	47.7	40.8
Sustaining Capital Total	112.9	101.4	123.4	105.6

(Exhibit B-1, p. 191)

The inflation adjusted or real F2007 dollar expenditures for each year are calculated based on values of 6 percent for F2008, and 5 percent for each of F2009 and F2010, as shown in Table 6-2 of the Application.

In comparison, the total amount approved in the F2008 TSCP Decision for F2008 Sustaining Capital was $87.7 million and for F2009 Sustaining Capital was $88.5 million, both expressed in nominal dollars (Exhibit B-1, p. 195).

BCTC requests that if the Commission does not accept BCTC's justification for the overall level of Sustaining Capital Expenditures, that the Commission then identify a global reduction to the Sustaining Capital portfolio (BCTC Argument, para. 37).

BC Hydro submits that BCTC has demonstrated the need for its planned increase in Sustaining Capital Expenditures to maintain asset health and system performance (BC Hydro Argument, p. 3).

BCOAPO submits that it recognizes that necessary and prudent capital investment to sustain the transmission system is essential in order to adequately serve the interests of ratepayers (BCOAPO Argument, p. 4).

Commission Determination

The Commission Panel observes that the UMS report focuses on expenditure levels and not asset performance. The Commission Panel does not believe the metric for judging utility performance is expenditure level. In the limited cases where UMS has compared BCTC’s actual asset performance rather than expenditures, BCTC has been shown to be a superior performer. The UMS report takes much of its data from the report in Appendix H of the Application. At least half of the UMS report is generic in nature and could have prefaced the report for any utility. In this instance, the Commission Panel considers the UMS report to represent poor value for money.

The Commission Panel notes that the expenditures forecast by the Sustainment Investment Model do not include capital expenditures for risk mitigation, third party projects or enhanced performance. The Commission Panel suggests the projects that substantially enhance performance be considered Growth Capital projects.

The Commission Panel continues to be supportive of BCTC's efforts to enhance the Sustainment Investment Model and views this as a strategic tool to be used along with the future Asset Health Index report to be forward-looking indicators that may be useful to determine levels of Sustaining Capital Expenditures. The Commission Panel notes BCTC's assertion that no transmission-related companies have been able to predict or define the impact of incremental or decremental spending on reliability. The Commission Panel accepts this assertion, but affirms its instructions to BCTC to continue monitoring the relationship between Sustaining Capital Expenditures and transmission reliability to determine whether increasing or decreasing spending levels have any discernible effect on reliability, or whether spending should generally increase or decrease in response to reliability trends.

The Commission Panel has applied a global reduction to the amount of requested F2009 and F2010 Sustaining Capital Expenditures. The approved amount of F2009 and F2010 Sustaining Capital Expenditures is addressed in Section 3.2 of this Decision.

6.3 Stations Sustaining Capital Programs

The six annual programs within the Stations category for which approval is being sought for F2009 and F2010 expenditures are Auxiliary Equipment, Circuit Breakers including the Horsey GIS Replacement and Mica GIS Replacement projects, Other Power Equipment, Risk Mitigation including the Murrin Substation Reconfiguration and Seismic Upgrade Project, Protection and Control including Third Party Requested projects, and Telecommunications (Exhibit B-1, pp. 19-20).

The proposed expenditures for the Station Sustaining Capital Programs for both projects in progress and those for which approval is being sought are shown in the table below (Exhibit B-1, p. 191).

Station Programs Expenditures Including Third Party and Emergency Expenditures (Millions of Dollars)	**F2009** (Nominal $)	**F2009 Real** (Inflation adjusted) F2007 $	**F2010** (Nominal $)	**F2010 Real** (Inflation adjusted) F2007 $
Auxiliary Equipment	6.7	6.0	7.6	6.5
Circuit Breakers	25.3	22.7	26.4	22.6
Other Power Equipment	11.0	9.9	15.5	13.3
Protection and Control	13.0	11.7	11.9	10.2
Risk Mitigation	8.3	7.5	8.8	7.5
Telecommunications	7.5	6.7	5.6	4.8
Station Programs Total	71.8	64.5	75.8	64.9

The inflation adjusted or real F2007 dollar expenditures for each year are calculated based on values of 6 percent for F2008, and 5 percent for each of F2009 and F2010, as shown in Table 6-2 of the Application.

The largest requested increases in F2009 expenditures over F2008 forecast expenditures are in the Circuit Breakers and Other Power Equipment annual programs with increases of $6.4 million and $7.8 million respectively, expressed in nominal dollars (Exhibit B-1, p. 191).

BCTC is forecasting an increased level of expenditures for the 500 kV & 230 kV Air Blast Circuit Breakers Replacement program based partly on a Mean Time Between Failures (“MTBF”) of 516 days. The minimum reliability criterion is 1095 days which BCTC explained is based on the NERC/WECC N-1 criteria, which calls for functional performance on the bulk electric system greater than or equal to 0.33 per year, or equivalently, 1 event in 3 years (Exhibit B-5-1, BCUC 1.59.1). BCTC acknowledged that this standard does not apply to component pieces (e.g. circuit breakers), and that although the loss of a single breaker may or may not cause a transmission line outage, the loss of two has a high probability of causing an outage. BCTC claimed that it was logical to use an MTBF of 1095 for component pieces to provide an indication of when the system may be at risk for NERC/WECC violations of the N-1 standards.

BCTC forecasts the VIT PCB Equipment Replacement project at $3.4 million for F2010, based on the need for the continued operation of the capacitors at Vancouver Island Terminal (“VIT”) even after the VITR project is in-service (Exhibit B-1, p. 240; Exhibit B-5-1, BCUC 1.62.1).

Contradictory evidence has been submitted that the VIT capacitors may not be needed after the VITR project (Exhibit B-5-1, Attachment to BCUC 2.117.1, pp. 3, 13).

Commission Determination

The Commission Panel is concerned that BCTC has misapplied the NERC/WECC probability of failure criterion. The Commission Panel agrees with BCTC that the standard does not apply to component pieces. The Commission Panel considers it logical that the larger the asset fleet, the shorter the MTBF for the fleet as a whole if the probability of failure for a single component piece is held constant. For instance, if a fleet of 100 circuit breakers has an MTBF of 500 days that does not mean that a single breaker within that fleet can be expected to fail once every 500 days, which it appears is what BCTC is implying in applying this value to the NERC/WECC criterion. **The Commission Panel rejects the use of the MTBF criterion in its current form as BCTC's minimum reliability criterion, and directs BCTC to revise this criterion and submit it in the next capital plan filing.**

The Commission Panel notes the contradictory evidence regarding the need for the VIT capacitors and directs BCTC to submit a clarification in the next capital plan filing.

The Commission Panel approves all F2009 and F2010 Stations Sustaining Capital Programs and the projects therein subject to overall expenditure levels described elsewhere in this Decision.

6.4 Overhead Lines and Cables Sustaining Capital Programs

The five annual programs within the Lines category for which approval is being sought for F2009 and F2010 expenditures are Cable Sustainment, Overhead Lines Life Extension, Overhead Lines Performance Improvements, Overhead Lines Risk Mitigation and Right-of-Way ("ROW") Sustainment including Third Party Requested Projects (Exhibit B-1, p. 20).

The proposed expenditures for the Line Sustaining Capital Programs for both projects in progress and those for which approval is being sought are shown in the table below (Exhibit B-1, p. 191).

Line Programs Expenditures Including Third Party and Emergency Expenditures (Millions of Dollars)	F2009 (Nominal $)	F2009 Real (Inflation adjusted) F2007 $	F2010 (Nominal $)	F2010 Real (Inflation adjusted) F2007 $
Cable Sustainment	5.0	4.5	5.8	5.0
Overhead Lines Life Extension	12.7	11.4	16.0	13.7
Overhead Lines Performance Improvements	4.5	4.0	5.4	4.6
Overhead Lines Risk Mitigation	9.9	8.9	10.0	8.6
Right-of-Way Sustainment	9.1	8.2	10.5	9.0
Line Programs Total	41.2	37.0	47.7	40.8

The inflation adjusted or real F2007 dollar expenditures for each year are calculated based on values of 6 percent for F2008, and 5 percent for each of F2009 and F2010, as shown in Table 6-2 of the Application.

The largest requested increase in F2009 expenditures over F2008 forecast expenditures is in the Overhead Lines and Risk Mitigation annual program with an increase of $1.3 million, expressed in nominal dollars (Exhibit B-1, p. 191).

BCTC states that it will begin deploying a new alternative to traditional marker balls on certain aerial crossings. The new alternative is the Obstacle Collision Avoidance System ("OCAS"), and BCTC's analysis showed it has a 1.23 PV advantage in life cycle costs over marker ball installations (Exhibit B-1, pp, 281-282; Exhibit B-5-1, BCUC 1.69.1).

Commission Determination

The Commission Panel directs BCTC to report in future capital plan filings, and until directed otherwise, the total costs-to-date for each of the six OCAS installations anticipated in F2009 along with a comparison to the original life cycle cost analysis.

The Commission Panel approves all F2009 and F2010 Overhead Lines and Cables Sustaining Capital Programs and the projects therein subject to overall expenditure levels described elsewhere in this Decision.

6.5 Chapman Fibre Optic Cable Replacement Project

In the F2008 TSCP Decision the Commission did not approve this project as proposed because absent an explanation for a large unspecified expenditure in F2012, the proposal was higher cost than a potential alternative and did not appear to be justified by safety, environmental or compliance considerations (F2008 TSCP Decision, p. 77).

BCTC has re-applied for the project. The project is required to enable a major 500 kV circuit to continue to operate at its designed transmission capability with Chapman's series capacitor bank in service. BCTC states that there is currently a high probability that the fibre optic cable will fail at any time. BCTC states the cable has had many incidents and is costly to maintain, and in any event the cable is not expected to last past 2012 (Exhibit B-1, pp. 261-262).

BCTC has assessed three options and presented the results of a PV calculation which shows the preferred option is to replace the fibre optic cable with microwave radio in F2009. Another option of performing the replacement in F2012 is some $450,000 more expensive while the "replace like for like" option is many times more expensive. BCTC states it has updated the previous PV calculation using the current PV model which includes a 2.5 percent discount rate rather than the 6 percent used in the previous calculation and submission (Exhibit B-1, pp. 263-264).

BCTC stated that microwave radio has certain operational advantages over fibre optic cable including reliability and lower operating costs, and that in the proposed application the lower bandwidth available with microwave does not pose a disadvantage (Exhibit B-5-1, BCUC 1.65.2).

Commission Determination

The Commission Panel notes that Option 3 will be economic at higher discounts rates and has operational advantages relative to the next best option, and therefore approves the project as applied-for.

7.0 BCTC CAPITAL PORTFOLIO

The BCTC capital Portfolio consists of those assets both owned and operated by BCTC, as opposed to assets in the Growth and Sustaining Portfolios which are owned by BC Hydro but planned and operated by BCTC.

7.1 Projects for Approval

BCTC provided a summary of all projects for approval and their costs separated, as in previous applications, into three categories: (1) Information Technology (2) Control Centre Technologies and (3) Facilities. This summary is repeated below:

	BCTC Capital Portfolio - Projects for Approval	**Page**	**IS Date**	**Project Total ($'000)**	**F2009 ($'000)**	**F2010 ($'000)**
	INFORMATION TECHNOLOGY					
	Projects for Approval					
1	Asset Management Program (AMP) server refresh F2010	325	Mar 10	$ 225	$ -	$ 225
2	B2B Portal	327	May 08	467	467	
3	Data Centre Redundancy F2009 and F2010	329	Mar 10	3,412	1,738	1,674
4	E-Business Financial Upgrade F2009 (Oracle Upgrade)	332	Mar 09	924	924	
5	Enterprise Server, PCs, Printers and Peripherals Refresh F2010	334	Mar 10	469	0	469
6	Financial System Sustainment F2009 and F2010 Project	336	Mar 10	1,226	632	594
7	HR/Payroll Sustainment F2009 and F2010	338	Mar 10	329	223	106
8	Identity and Access Management F2009 and F2010	341	Mar 10	1,201	622	579
9	Laptop, Desktop and Removable Media Encryption F2009	343	Mar 09	265	265	
10	Market Operations Workflow -SGIP Sustainment F2009	345	Mar 09	106	106	
11	Mobile Station Inspection Enhancement F2009 and F2010	346	Mar 10	286	143	143
12	Network Segmentation [Re-issued] F2009	348	Mar 09	651	651	
13	Reliability & Loss Program Integration F2009 and F2010	351	Mar 10	420	238	182
14	Security Information Management F2009	353	Mar 09	200	200	
15	SharePoint 2007 Upgrade F2009	355	Mar 09	44	44	
16	Transmission Scheduling System (TSS) Enhancements F2009	356	Mar 09	106	106	
17	wesTTrans Open Access Same Time Info System (OASIS) Upgrades F2009 and F2010	358	Mar 10	151	54	97
18	**Subtotal**			$ 10,482	$ 6,413	$ 4,069
	CONTROL CENTRE TECHNOLOGIES					
	Projects for Approval					
19	Control Centres Sustainment F2009 and F2010	363	Mar 10	$ 234	$ 117	$ 117
20	Control Centre Business Application Enhancement F2009 and F2010	364	Mar 10	902	265	637
21	Real Time Operations (RTO) Servers and Infrastructure Refresh F2009	367	Mar 09	854	854	
22	Site Information System (SIS) Filenet Upgrade F2009	368	Mar 09	471	471	
23	**Subtotal**			$ 2,461	$ 1,707	$ 754
	FACILITIES					
	Project for Approval					
24	BCTC Facilities Enhancements F2009 and F2010	371	Mar 10	$ 424	$ 212	$ 212

(Exhibit B-5-1, BCUC 1.73.1)

There are 24 projects for which approval is requested for expenditure in F2009 and F2010 of which three have a total project cost in excess of $1.0 million. All three of these projects are in the Information Technology Group. The total cost of all projects requested for approval is $13.367 million.

7.2 Future Projects

BCTC has provided information on future projects for which approval is not being sought in this Application. The most significant such project is the Market Operations Business Systems upgrade with a forecasted cost of approximately $8.5 million in F2009 and F2010. BCTC stated that it is not seeking approval for this project since the project scope and timing are dependent upon the implementation of FERC Order No. 890, and that BCTC will prepare a separate submission for this project (Exhibit B-5-1, JIESC 1.2.1).

BCTC provides historical and future costs of its portfolios by component in both tabular (Exhibit B-1, pp. 315-317) and graphical format (Exhibit B-3, p.73).

Commission Determination

The Commission Panel observes that the forecast of future expenditures, and historical expenditures, appear to be relatively stable except for those large and exceptional projects such as the System Control Modernization Program and the Market Operations Business Systems. Therefore the Commission Panel suggests that BCTC consider, for future applications a formulaic approach to requesting approval for its capital portfolio, with significant projects being applied for on an exception basis, as is planned for the Market Operations Business Systems project. BCTC might consider linking such a formula to cut off values for deferral risk and value.

The Commission Panel finds the requested F2008 and F2009 capital expenditures for the BCTC Capital Portfolio are in the public interest.

8.0 SUBSEQUENT EVENTS

There have been several significant events since this Application was filed that will affect some of the actions described in this Application as well as the content and format of future applications. These include the Royal Assent given to the Utilities Commission Amendment Act, 2008, (the Amending Act), the process associated with BCTC's application for a CPCN for the ILM project, and BC Hydro's filing of its 2008 LTAP.

8.1 Amendments to the Utilities Commission Act

As discussed in Section 1.9 of this Decision, the Amending Act made many changes to the Act, some with very broad scope and effect, which will affect the relationship between and actions of the Commission and BCTC. One of the most significant changes that will influence BCTC is the following addition to section 5:

> " (4) The commission, in accordance with subsection (5), must conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins or, if the terms of reference given under subsection (6) specify a different period, for that period.
>
> (5) An inquiry under subsection (4) must begin
>
> (a) by March 31, 2009, and
> (b) at least once every 6 years after the conclusion of the previous inquiry,
>
> unless otherwise ordered by the Lieutenant Governor in Council."

Commission Determination

As discussed in Section 2.9, BCTC is working on a report looking at the long-term transmission needs in B.C. The Commission Panel encourages this work and expects it to integrate with the Section 5 inquiry described above.

Other significant changes include the repealing of sections 45(6.1) and 45(6.2) under which sections approval of this Application is sought, and the addition of sections 44.1 and 44.2. The Commission Panel expects BCTC will carry through with its commitment to file another Capital Plan sometime in 2008, but it remains to be seen how the filing will be interpreted under the new legislation.

8.2 ILM Project CPCN Application Proceeding

The ILM project is the largest project BCTC has proposed and the most expensive transmission project in B.C. in the last twenty years. It is likely to have "spin-off" effects on BCTC's Capital Plans for some time to come.

Several issues that arose in this Capital Plan proceeding also arose in the ILM Project CPCN Application Proceeding. These include the long-term transmission report and the Transmission System Loss Study ("TSLS"). The long-term transmission report is addressed in the previous section and elsewhere in this Decision.

In response to a direct request from the Commission dated January 31, 2008 to provide the terms of reference for BCTC's new loss reduction strategy, BCTC stated that it was in the process of engaging a consultant to undertake a TSLS, but did not provide the terms of reference (Exhibit B-5-1, BCUC 1.8.1).

IPPBC supports the TSLS and expects that it will include a detailed analysis of whether energy and capacity losses can be reduced on a cost-effective basis through the utilization of high voltage overhead direct current transmission (IPPBC Argument, p. 10).

BCTC confirms that it intends to make the TSLS public after its completion in the next few months, and the issue identified by IPPBC will be addressed (BCTC Reply, pp. 5-6).

BCTC filed the terms of reference for the TSLS in the ILM Project CPCN Application Proceeding (ILM Project CPCN Application Proceeding, Exhibit B-14, IPPBC 3.8.0).

Commission Determination

The Commission Panel notes the date on the terms of reference for the TSLS supplied in the ILM Project CPCN Application proceeding is dated December 3, 2007. The Commission Panel notes that this document was not provided in this proceeding in BCTC's response dated February 27, 2008 to the Commission Information Request 1.8.1.

8.3 BC Hydro Long-Term Acquisition Plan Filing

BC Hydro filed the 2008 LTAP on June 12, 2008. The consequences of that plan are likely to have profound consequences on the long-term transmission planning initiative, but unlikely to have any impact on any of the project approved in this Decision, except for Definition Phase projects where TEP alternatives are being considered.

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.

	Directive	**Page**
1.	The Commission Panel directs BCTC to continue identifying in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for single contingency events.	11
2.	The Commission Panel directs BCTC to continue to track past years' Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures.	14
3.	The Commission Panel expects that in the future such expenditures [UMS report] will be provided with greater transparency in both the capital planning and revenue requirement processes.	18
4.	BCTC is directed to comment on the following concerns in its next filing: applicable and appropriate constraints or thresholds within the Prioritization Methodology for project selection, continued optimization of the Prioritization Methodology to better reflect the results achieved by expert judgement intervention, and the allocation of dollar cost savings within the Prioritization Methodology.	24
5.	The Commission Panel directs BCTC to specifically report compliance with the directives described in Sections 9.4, 9.6, 9.9, 9.13, 9.20, 9.29, 9.30, 9.34, 9.39, and 9.40 of the F2008 TSCP Application in future filings. This should be reported along with the reporting on the concordance with all other directives pursuant to the directive described in Section 9.9 of the F2008 TSCP Application.	25
6.	In future capital plans, and until directed otherwise, the Commission Panel directs BCTC to provide a thorough evaluation of options in situations where the cost of the preferred solution for an approved project changes by more than 100 percent.	39

7.	The Commission Panel approves an amount of $105.0 million for the F2009 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the $101.4 million forecast F2009 Sustaining Capital expenditures expressed in F2007 dollars, escalated at 2 percent inflation for two years, less an amount of $0.5 million to account for the re-allocation of costs associated with the Emergency Drop-in Control Building project. The Commission Panel approves an amount of $107.0 million for the F2010 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the approved F2009 Sustaining Capital expenditures plus a 2 percent increase for inflation, less a $0.1 million adjustment for a reduced amount of third-party requested projects.	40
8.	The Commission Panel directs BCTC to report in future capital plans the specific instances where non-wires options have been considered in project option evaluations.	41
9.	The Commission Panel directs BCTC to identify in the next capital plan application the industry benchmarking surveys to which it provides data, and to identify those in which it participates more fully, and to report the results of those surveys, including the utility-specific reports from CEA. BCTC is also directed to provide, in the next capital plan application, a summary report that identifies a representative cross-section of surveys being performed in the electric utility sector.	44
10.	The Commission Panel directs BCTC to comment on all Directives contained in past Decisions, even if such reporting confirms that that no update is required, or the requested information is not applicable.	46
11.	The Commission Panel directs BCTC to continue to use an inflation adjustment equal to the BCCPI.	54
12.	The Commission Panel also acknowledges the effort being made by both BCTC and BC Hydro towards developing a common understanding regarding the dispatch assumptions of resources identified in the NITS application, and encourages BCTC to continue assessing how the existing transmission system can be best utilized through re-dispatch of NITS-nominated resources. The Commission Panel directs BCTC to file a report describing these assumptions with the earlier of the next capital plan application or following BC Hydro's next NITS application.	58
13.	The Commission Panel directs BCTC to provide in future capital plans an estimate of all generation interconnection costs, except those which are 100 percent third party funded and will remain owned by and the responsibility of the third party.	60
14.	The Commission Panel approves the Definition Phase expenditures for the Golden 69 kV System Reinforcement project, but directs BCTC to provide with any request for approval of Implementation Phase expenditures for this project, a thorough examination and comparison of the TEP alternative, the preferred alternative, and the next highest ranked alternative. In the event that the TEP alternative is either the preferred alternative or the next highest ranked alternative, the comparison shall include the top three ranked alternatives.	65

15.	Notwithstanding the above concerns, the Commission Panel approves the expenditures for Ashton Creek Substation Capacitor Bank project, but is concerned about the timing and full scope of the project. The Commission Panel expects BCTC to advise the Commission of changes, if any, to the timing and scope of the project prior to construction of the project and to consider the timing of South Interior resource additions and load forecasts that are contained in BC Hydro's 2008 Long-Term Acquisition Plan Application. If BCTC concludes that changes to the timing or scope of the project are appropriate, then BCTC should justify the changes in a report to the Commission with a probabilistic analysis of the duration of outages for the specific seasonal dispatch conditions considered in the report.	67
16.	The Commission Panel encourages BCTC to continuing working with FortisBC to develop a solution that would be beneficial to the ratepayers of both utilities, and approves Definition Phase expenditures associated with Woods Lake Area Reinforcement project.	68
17.	The Commission Panel directs BCTC to confirm with BC Hydro the probability of the projected spot load increases that are driving the need for the replacement of two transformers in 2011 for the option consisting of the feasible addition of a third 25 MVA transformer for the Tumbler Ridge - Transformer Replacement project, and to provide a letter to the Commission confirming the selection of the preferred alternative after a careful examination of the forecast load increases and other factors that may reduce the load on the Tumbler Ridge Substation.	75
18.	The Commission Panel rejects the use of the MTBF criterion in its current form as BCTC's minimum reliability criterion, and directs BCTC to revise this criterion and submit it in the next capital plan filing.	86
19.	The Commission Panel notes the contradictory evidence regarding the need for the VIT capacitors and directs BCTC to submit a clarification in the next capital plan filing.	86
20.	The Commission Panel directs BCTC to report in future capital plan filings, and until directed otherwise, the total costs-to-date for each of the six OCAS installations anticipated in F2009 along with a comparison to the original life cycle cost analysis.	87
21.	The Commission Panel finds the requested F2008 and F2009 capital expenditures for the BCTC Capital Portfolio are in the public interest.	90

DATED at the City of Vancouver, in the Province of British Columbia, this 10th day of July 2008.

Original signed by:

ROBERT H. HOBBS
CHAIR

Original signed by:

LIISA A. O'HARA
COMMISSIONER

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-107-08

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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 Transmission Corporation
for Approval of a
Transmission System Capital Plan F2009 to F2018

BEFORE: R.H. Hobbs, Chair
L.A. O'Hara, Commissioner June 26, 2008

O R D E R

WHEREAS:

A. Commission Order No. G-69-07 dated June 15, 2007 responded to the British Columbia Transmission Corporation ("BCTC") Capital Plan F2008 to F2017; and

B. BCTC filed its Transmission System Capital Plan F2009 to F2018 dated December 21, 2007 (the "F2009 Capital Plan", the "Application") pursuant to Sections 45(6), 45(6.1) and 45(6.2) of the Utilities Commission Act ("the Act"); and

C. BCTC in the filing applies for an order which states that the F2009 Capital Plan meets the requirements of Sections 45(6) and 45(6.1) of the Act, approves the F2009 Capital Plan under subsection 45(6.2)(a) and, pursuant to Section 45(6.2)(b), determines that all projects and programs listed in Section 1.6.2 of the Application are in the public interest; and

D. The Commission, by Order No. G-173-07, established a written public hearing process and Regulatory Timetable for the review of the Application; and

E. BCTC held a Workshop for Commission staff and Registered Intervenors on January 22, 2008; and

F. The Written Argument phase of the proceeding was completed when BCTC filed its Reply Submission on April 1, 2008; and

G. The Commission Panel has considered the Application, evidence, and submissions of Intervenors and the Applicant.

…/2

NOW THEREFORE pursuant to Section 45 of the Act the Commission orders as follows:

1. The Application meets the requirements of Sections 45(6) and 45(6.1) of the Act.

2. The F2009 Capital Plan is approved pursuant to Section 45(6.2)(a) of the Act.

3. Pursuant to Section 45(6.2)(b) of the Act, the projects and programs listed in Section 1.6.2 of the Application for the financial years ending March 31, 2009 and March 31, 2010 ("F2008" and "F2009", respectively) are determined to be in the public interest.

4. The Sustaining Capital Portfolio budget is reduced to $105.0 million for the F2009 Sustaining Capital expenditures and to $107.0 million for the F2010 Sustaining Capital expenditures, expressed in nominal dollars and including Third-Party requested and funded expenditures.

5. BCTC is directed to comply with all determinations and directives set out in the Reasons for Decision that are to follow.

DATED at the City of Vancouver, in the Province of British Columbia, this 27th day of June 2008.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

LIST OF ABBREVIATIONS & ACRONYMS

2006 CFT	BC Hydro's 2006 Call For Tenders
2007 Energy Plan	The BC Energy Plan: A Vision for Clean Energy Leadership
2007 STSR	2007 State of the Transmission System Report
ABS	Asset Baseline Study
ACK	Ashton Creek substation
Act, UCA	Utilities Commission Act
AESO	Alberta Electric System Operator
Amending Act	Utilities Commission Amendment Act, 2008
Ashton Creek project	Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors project
ATC	Available Transmission Capacity
BC Hydro	British Columbia Hydro and Power Authority
BCCPI	British Columbia Consumer Price Index
BCH ORR	BC Hydro's Owners' Revenue Requirement
BCOAPO	British Columbia Old Age Pensioners Organization et. al.
BCTC	British Columbia Transmission Corporation
BRP	Base Resource Plan
CEA	Canadian Electricity Association
CIP	Critical Infrastructure Protection
Commission, BCUC	British Columbia Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CRP	Contingency Resource Plan
CU	Committed Use
CVI	Central Vancouver Island

CWD	Chetwynd substation
DGC	Dependable Generation Capacity
DPUI	Delivery Point Unreliability Index
DSM	Demand Side Management
ELCC	Equivalent Load Carrying Capacity
EPA	Electricity Purchase Agreement
F2006 TSCP Application	Transmission System Capital Plan F2006 to F2015 Application
F2006 TSCP Update Application	Transmission System Capital Plan F2006 to F2015 Update Filing
F2008 TSCP Application	Transmission System Capital Plan F2008 to F2017 Application
F2008 TSCP Decision	Decision accompanying Order No. G-97-07
F2009 TSCP, Application	Transmission System Capital Plan F2009 to F2018
Fasken	Fasken Martineau DuMoulin LLP
FERC	U.S. Federal Energy Regulatory Commission
FM2	Fort St. James substation
Golden Project	Golden 69 kV System Reinforcement Project
Goto	Goto Sargent Inc.
HVDC	High Voltage Direct Current
ILM	Interior to Lower Mainland
IPPBC	Independent Power Producers Association of BC
IPPs	Independent Power Producers
ITOMS	International Transmission Operations and Maintenance Study
JIESC	Joint Industry Electricity Steering Committee
KMC	Kinder Morgan Canada
LM-VI	Lower Mainland to Vancouver Island

LTAP	Long-Term Acquisition Plan
MA	Master Agreement
MCR	Maximum Continuous Rating
MDN	Meridian substation
MMK	MMK Consulting Inc.
MMK Report	BC Hydro Construction Cost Trends and Outlook, September 17, 2007
Model	Sustainment Investment Model
MTBF	Mean Time Between Failures
NERC	North American Electric Reliability Corporation
NIC	Nicola substation
NITS	Network Integration Transmission Service
NSP	Negotiated Settlement Process
OATT	Open Access Transmission Tariff
OCAS	Obstacle Collision Avoidance System
PG&E	Pacific Gas and Electric
PM	Prioritization Model
PPGA	Pipeline Power Group and Associates
PV	Present Value
RAS	Remedial Action Scheme
RCCs	Regional Control Centers
ROW	Right-of-Way
RRA	Revenue Requirement Application
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

SAIFI-MI	System Average Interruption Frequency Index - Momentary Interruptions
SAIFI-SI	System Average Interruption Frequency Index - Sustained Interruptions
SCC	System Control Center
SD9	Special Direction No. 9
SISC	South Interior Series Compensation
STSR	State of the Transmission System Report
TLR	Tumbler Ridge substation
TSLS	Transmission System Loss Study
TTC	Total Transfer Capability
UMS	UMS Group Inc.
Update Report	Condition Assessment (Baseline Study) Update
VIT	Vancouver Island Terminal
VITR	Vancouver Island Transmission Reinforcement Project
VNT	Vernon Terminal
WDS	Woods Lake Substation
WECC	Western Electricity Coordinating Council

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

and

British Columbia Transmission Corporation
Application for Approval of a Transmission System
Capital Plan F2008 to F2018

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated January 2, 2008, issuing Order No. G-173-07 establishing the Regulatory Timetable and Notice of Written Public Hearing
A-2	Letter dated January 31, 2008 issuing Information Request No. 1 to BCTC
A-3	Letter dated February 7, 2008 issuing Information Request No. 2 to BCTC
A-4	Letter dated February 27, 2008 granting BCTC's request for an extension to the filing date for responses to Information Requests (Exhibit B-4)
A-5	Letter dated March 18, 2008 granting filing extensions for the Intervenor Final Submissions and BCTC's Reply Submission
APPLICANT DOCUMENTS	
B-1	Letter dated December 21, 2007 filing the Application for approval of a Transmission System Capital Plan F2009 to F2019
B-2	Letter dated January 7, 2008 filing proposed Notice of Workshop
B-3	Letter dated January 23, 2008 filing copy of the Workshop presentation slides and attendance list
B-4	Letter dated February 22, 2008 filing request for extension for filing responses to Information Requests to Intervenors
B-5-1	Letter dated February 27, 2008 filing response to the Commission's Information Request No. 2 and Intervenors' Information Request No. 1
B-5-2	**CONFIDENTIAL** - Letter dated February 27, 2008 filing response to the Commission's Information Request No. 1

Exhibit No.	Description
B-6	Letter dated March 17, 2008, filing comments in support of extending the deadline for Intervenor and BCTC's final submissions

INTERVENOR DOCUMENTS

C1-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated January 7, 2008, from R. Brian Wallace, filing request for Registered Intervenor status
C1-2	Letter dated February 8, 2008, filing Information Request No. 1 to BCTC
C2-1	**BC HYDRO & POWER AUTHORITY –** Online web registration received January 8, 2008, filing request for Registered Intervenor status
C2-2	Letter dated February 7, 2008, filing Information Request No. 1 to BCTC
C3-1	**ELK VALLEY COAL CORPORATION (EVCC) –** Email dated January 9, 2008, filing request for Registered Intervenor status and Notice of Attendance for the Workshop on January 22, 2008
C4-1	**INDEPENDENT POWER PRODUCERS OF BC (IPPBC) –** Letter dated January 10, 2008, from David Austin, Tupper Jonsson & Yeadon, legal counsel, and for Steve Davis, President, filing request for Registered Intervenor status
C4-2	Letter dated February 7, 2008, filing Information Request No. 1 to BCTC
C5-1	**FORTISBC INC. –** Online web registration received January 16, 2008, filing request for Registered Intervenor status
C6-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO)** - Letter dated January 17, 2008 from Jim Quail requesting Registered Intervenor status for Leigha Worth, Counsel, and Bill Harper, of Econalysis
C6-2	Letter dated February 7, 2008, filing Information Request No. 1 to BCTC
C6-3	Letter dated March 12, 2008 filing comments on regulatory timetables and request extension to March 14, 2008 to file submissions

Exhibit No.	Description
C7-1	**MATSQUI FIRST NATIONS LANDS DEPARTMENT** – Letter dated January 22, 2008, from Stanley Morgan filing request for Registered Intervenor status
C8-1	**PIPELINE POWER GROUP & ASSOCIATES (PPGA)** – Letter dated January 23, 2008, from Jamie Shand filing request for Registered Intervenor status
C8-2	Letter dated February 7, 2008 filing Information Request No. 1 to BCTC

INTERESTED PARTY DOCUMENTS

D-1	**KERR WOOD LEIDAL ASSOCIATES LTD. -** Online web registration received January 9, 2008 from Ron Monk, requesting Interested Party status
D-2	**NORTH CENTRAL MUNICIPAL ASSOCIATION (NCMA)** - Online web registration received January 23, 2008 from Eileen Benedict, requesting Interested Party status
D-3	**CAMPBELL, JIM –** Letter dated January 24, 2008 request for Interested Party status
D-4	**GERRY GARNETT CONSULTING -** Online web registration received January 24, 2008 from Gerry Garnett, requesting Interested Party status