IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

TRANSMISSION SYSTEM CAPITAL PLAN F2008 TO F2017

DECISION

June 15, 2007

Before:

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

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1.0 INTRODUCTION

1.1 Application

On December 21, 2006 the British Columbia Transmission Corporation ("BCTC") filed its F2008 to F2017 Transmission System Capital Plan ("F2008 TSCP") with the British Columbia Utilities Commission ("Commission" or "BCUC"). Regulatory approval of the F2008 TSCP ("Application") was requested under Sections 45(6), 45(6.1) and 45(6.2) of the Utilities Commission Act ("Act" or "UCA"). The first application related to a transmission system capital plan was filed in May 2004 and requested approval for capital expenditures beginning in F2005. It was subsequently approved by Order No. G-103-04. The F2006 to F2015 Transmission System Capital Plan Application ("F2006 Application") was the subject of Order No. G-91-05 and the accompanying Reasons for Decision (collectively the "F2006 TSCP Decision"). On January 27, 2006 BCTC filed an Update Application ("F2006 Update Application") to the F2006 Application requesting that certain projects be removed and others added, and requesting reconsideration of one aspect of Order No. G-91-05. Order No G-76-06 approved the Update Application, subject to certain conditions and comments in the Order and accompanying Reasons for Decision (collectively the "F2006 TSCP Update Decision").

The F2008 TSCP describes projects within the period F2008 to F2017; however, BCTC only requests approval for capital expenditures in F2008 and F2009. In late 2007 BCTC intends to file its F2009 capital plan in which BCTC is expected to seek approval for additional projects identified for F2009 and to seek approval for projects and programs beginning in F2010.

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 to 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

BCTC is seeking an order which states that the F2008 TSCP meets the requirements of Sections 45(6) and 45(6.1) of the Act, approves the F2008 TSCP 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.

The orders sought under Section 45(6.2)(b) of the Act pertain to specific 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, 2006, BCTC filed its F2008 TSCP Application. BCUC Order No. G-5-07 dated January 19, 2007 subsequently established a written hearing process and Regulatory Timetable.

On January 9, 2007 the District of Mission requested that the Commission vary the F2006 TSCP Decision, and direct BCTC to apply for a Certificate of Public Convenience and Necessity ("CPCN") for a proposed new 69 kV transmission line in Mission. The District of Mission filed a second letter on March 2, 2007 to provide additional information. By letter dated March 5, 2007, the Commission denied the request to vary Order No. G-91-05, but noted that the District of Mission might wish to seek approval as a late intervenor in the F2008 TSCP proceeding, and make submissions regarding its specific concerns (Exhibit A-3). The District of Mission requested late intervenor status the same day (Exhibit C10-1).

In addition to the District of Mission, interventions were subsequently received from: BC Hydro, the British Columbia Old Age Pensioners Organization *et. al.* ("BCOAPO"), West Fraser Timber Co. Ltd., the Independent Power Producers Association of BC ("IPPBC"), Energy Solutions for Vancouver Island Society ("ESVI"), Elk Valley Coal Corporation, Columbia Power Corporation ("CPC"), the Joint Industry Electricity Steering Committee ("JIESC") and FortisBC Inc.

BCTC filed most of the responses to Commission and Intervenor Information Requests on March 14, 2007 (Exhibit B-6), with certain responses, updated responses, and corrections filed over the next week.

On March 30, 2007 BCTC filed a report on the progress of discussions with the District of Mission regarding the routing of transmission circuits (Exhibit B-11).

BCTC's Argument was filed on March 23, 2007; the Submissions of seven intervenors were filed on April 2, 2007, and BCTC's Reply was filed on April 13, 2007. In ESVI's Submission it requested further information on the Jordan River facilities on Vancouver Island. BCTC provided this information to ESVI and other intervenors by its Submission to ESVI Information Request dated May 1, 2007.

1.5 The Nature of Commission Approvals

BCTC states:

> "It should also be noted that, as with BCTC's previous Capital Plans, BCTC is not seeking Commission approval for the precise amount associated with each project or group of projects identified in this Application. The amounts identified in association with each project are estimated costs and actual expenditures will vary from these estimates in some cases. If BCTC were limited to expenditures in the precise amounts set out in this Capital Plan it would need to re-apply to the Commission in those cases where actual project spending exceeds estimates. BCTC does not believe this is a practical approach. Accordingly, for those projects that are identified in Section 1.6.2, BCTC is seeking the Commission's approval that capital expenditures on these projects are in the public interest rather than for a precise expenditure. As outlined by the Commission in its Decision on BCTC's F2006 Capital Plan (page 2, as amended by Commission Letter L-12-06), BCTC will provide explanations for any projects whose actual costs vary significantly from the estimate provided to the Commission and recognizes that in some cases a prudency review may follow for such projects. As further indicated by the Commission in its Decision, it is more likely that actual expenditures will be considered when the amount to be recovered in rates will be determined, in most cases during a revenue requirements proceeding" (Exhibit B-1, p. 13).

Commission Determination

The Commission Panel agrees with BCTC's interpretation of the F2006 TSCP Decision, and Letter No. L-12-06, that the nature of the approvals granted is that the projects are in the public interest, but that precise expenditure levels are not approved, and in cases where 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 requirements proceeding.

The Commission Panel believes that in the context of transmission expenditures, the most likely venue to consider cost recovery is a BCTC revenue requirements proceeding. In such a proceeding BC Hydro must defend the BCH Owner's Revenue Requirement, a component of which could be a reduction to revenue requirement resulting from a decision denying recovery of capital expenditures for prudency reasons. In this same venue, if it was determined that a capital expenditure related to assets owned by BCTC was not prudent, then such a decision would directly reduce BCTC's revenue requirement and rates.

The Commission Panel notes that, while BCTC is the entity responsible for the construction of BC Hydro-owned transmission assets, any disallowance reduces BC Hydro's revenue requirement. Clause 19.6 of the Master Agreement keeps BC Hydro whole, while penalizing BCTC in the event of a disallowance.

The Commission Panel further notes that when it approves a transmission project, it is also approving the corridor and route of a new line and the site of a substation. One of the criteria proposed by BCTC and previously accepted by the Commission as triggering a CPCN application is that the impact on a particular community or constituency likely cannot be mitigated to the community's satisfaction. When approving projects without the requirement for a CPCN, the Commission Panel is relying upon BCTC's submissions that community impacts, often associated with a project's corridor, route, or site, are likely to be mitigated to the community's satisfaction. In the event that the circumstances of the project are materially different than the planning assumptions, including assumptions related to cost, or impacts on communities that likely cannot be satisfactorily mitigated, the Commission Panel expects BCTC to seek further regulatory review of the project.

1.6 The New Provincial Energy Plan

The Provincial Government released "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan") on February 27, 2007. On February 28, 2007, ESVI requested that the 2007 Energy Plan be allowed as evidence in the proceeding and that Intervenors be permitted to file supplemental Information Requests relating to the 2007 Energy Plan (Exhibit C5-3).

BCTC did not agree that the 2007 Energy Plan should be introduced as evidence at this proceeding and stated:

> "In short, BCTC believes that any attempt to insert an assessment of the 2007 Energy Plan into the F2008 Capital Plan proceeding will be rushed and BCTC's responses will not be fully considered. While the F2008 Capital Plan contains a ten-year view of BCTC's capital investments, the approvals sought are limited to projects beginning in F2008 and F2009, and F2008 and F2009 Sustaining Capital Program expenditures. BCTC considers that the projects and programs proposed for approval in this F2008 Capital Plan are necessary based on current needs. BCTC submits that the better approach is to deal with the current Capital Plan based on the Commission's existing procedural order. In this way, the matter can be dealt with in a timely manner and BCTC can continue with its assessment of the 2007 Energy Plan and reflect its direction in BCTC's next capital plan" (Exhibit B-4, p. 2).

The Commission Panel agreed with BCTC's submission and denied ESVI's request (Exhibit A-4).

The 2007 Energy Plan contains nineteen Policy Actions related to electricity. Of these, five mention BCTC or the transmission system directly. They are; (1) Policy Action 12 related to technological capability and efficient and reliable delivery of power (2) Policy Action 13 relating to maintaining adequate transmission capacity (3) Policy Action 14 related to reliability standards consistent with

North American Standards (4) Policy Action 15 related to continued public ownership of BCTC and (5) Policy Action 16 related to upgrading and maintaining transmission lines.

CPC stated that it supported early action by BCTC to implement the 2007 Energy Plan with specific reference to three policy actions (CPC Submission, p. 4).

BCOAPO states that the lack of definition of “self-sufficiency” in the 2007 Energy Plan is problematic and that the Commission will need to establish or designate the most appropriate forum to begin an evaluation of the meaning and usefulness of the phrase in relation to the public interest. BCOAPO submits that the best place to address this question will be BC Hydro’s next Long-Term Acquisition Plan (“LTAP”) (BCOAPO Submission, pp. 2-3).

2.0 BCTC CAPITAL PLANNING PROCESS

2.1 Timing of Capital Plan Filings

Section 45(6) of the UCA provides that a utility must file, at least once a year a statement in a form prescribed by the Commission of the extensions to its facilities it plans to construct.
Section 45 (6.1)(a) further provides that a public utility must file with the Commission in a form and at a time required by the Commission, a plan of the capital expenditures the public utility anticipates making over the period specified by the Commission.

To satisfy these requirements BCTC states it will continue to plan to publish its capital plan annually and file it with the Commission annually. With each filing, BCTC requests approval for expenditures beginning in the first two years of the capital plan. BCTC states that the annual filing of a two-year rolling plan assists in obtaining earlier approval for many of the projects in the second year of the Application and assists with resource planning for the implementation of these projects (Exhibit B-1, p. 9).

2.2 BCTC Planning Standards

BCTC states that planning standards are not objectives in themselves but are used by planners in the development of projects to meet objectives related to: (a) serving firm load, (b) enabling economic generation dispatch, (c) enabling point-to-point power transfers, (d) affordability, (e) system performance, (f) community impact and (g) environmental compliance (Exhibit B-1, pp. 51-52).

BCTC is a member of the Western Electricity Coordinating Council ("WECC"), which is a regional member of the North American Electric Reliability Council ("NERC"). The NERC/WECC Planning Standards establish the criteria within which members are required to plan and operate their electrical systems. BCTC states it plans and operates its transmission system in accordance with these standards (Exhibit B-1, p. 52).

Section 5.6(b) of the Master Agreement states:

> "BCTC will operate the Transmission System in a manner that complies with any reliability criteria established by the Commission and any reliability criteria established by NERC, WECC, and the Northwest Power Pool, subject to any requirements of the Commission" (Exhibit B-6, BCOAPO 1.27.2).

Section 26(a) of the Act provides the Commission with jurisdiction to "determine and set just and reasonable standards, classifications, rules, practices or service to be used by a public utility".

The 2007 Energy Plan established policy actions, some of which related directly to BCTC. In particular, Policy Action 14 states: "Ensure that the province remains consistent with North American transmission reliability standards." The 2007 Energy Plan notes that the transmission system is part of a much larger interconnected grid and that the province needs to work with other jurisdictions to maximize the benefits of interconnection (2007 Energy Plan, pp. 9-10).

BCTC stated it has expended funds in F2007 to implement certain NERC reliability standards related to the Transmission Scheduling System (Exhibit B-6, BCUC 1.16.2).

NERC has recently undertaken a review and update of its standards and these will become mandatory in June 2007. BCTC stated that it monitors the NERC activities and is assessing their potential future impact on the planning and operation of the transmission system. BCTC also stated that it considers the standards to be appropriate and that a BCTC nominee was a member of the team that drafted the new standards (Exhibit B-6, BCOAPO 1.27.1).

BCTC noted that its preliminary assessment of these new standards is that over 95 percent of BCTC's compliance costs will be related to approximately 15 standards included in three categories: critical infrastructure protection ("CIP"), personnel performance, training and qualifications ("PER") and facilities design connections and maintenance ("FAC") (Exhibit B-6, BCUC 1.69.1).

The CIP-related standards pertain to enhancement of existing standards requiring more security controls to be established and broadens the number of critical cyber-assets within the scope of the standards. BCTC stated there will be initial and on-going costs to enhance and document additional safety management processes and controls as well as an applied-for investment of $1.085 million in F2008 to implement systems to effectively implement network management systems, and monitor security (Exhibit B-6, BCUC 1.69.1). BCTC also stated that NERC has imposed a staggered compliance schedule with defined levels of compliance by the end of the second quarter of each calendar year from 2007 to 2010 (Exhibit B-6, BCUC 1.111.1).

In that regard, BCTC noted that it will be required to certify additional operators and dispatchers to meet NERC PER standards, and that while there will be initial and on-going costs it is not anticipated that capital expenditures will be required. BCTC expected that the same would be true for FAC compliance requirements, and that there would be no or limited impacts for compliance with other standards (Exhibit B-6, BCUC 1.69.1).

BCTC confirms that there are no projects in the Application that are driven by the need to conform to NERC/WECC Planning Standards during maintenance (Exhibit B-1, p. 266).

WECC members must comply with NERC/WECC Planning Standards regarding impacts allowed on other systems, but may, as permitted by the NERC/WECC Planning Standards, apply different standards for impacts on their own systems (Exhibit B-1, p. 53).

In reference to those standards, BCTC states that it has adopted a less stringent limit on the dip in frequency (from 60 Hz) for various contingencies solely for the loss of the B.C. to U.S. interties when importing from the U.S. BCTC states that adhering to the NERC/WECC standard would significantly reduce the 2,000 MW import limit. The event cited is a double circuit outage on the interconnections between Vancouver and Blaine, Washington. BCTC states the probability of such an event is very low and the consequences acceptable. While the adopted limit is less stringent than the NERC/WECC standard within the B.C. system, BCTC continues to conform with the NERC/WECC standard for impacts on systems outside the B.C. system (Exhibit B-1, p. 56).

BCTC also states that a power system interconnected with other systems may experience unexpected combinations of operating conditions. As a result BCTC has put in place various safety nets both in response to WECC requirements and at its own initiative (Exhibit B-1, p. 57). These safety nets address issues such as generation shedding and over-voltage protection schemes.

With regard to policy matters, BCTC states that it has adopted a policy to avoid the use of generation shedding for first contingency events when all facilities are in-service. There are exceptions to the policy when the cost of the investment required to avoid the shedding cannot be justified. BCTC will accept generation shedding for less common and more severe events (Exhibit B-1, p. 58).

BCTC further states its planning policy is that line over-voltage protection schemes shall not be triggered in response to single or double contingency events (outage of one and two elements respectively). To achieve this, BCTC requires that sufficient voltage control equipment be installed so that the 500 kV lines do not trip on over-voltage for operating contingencies with all elements in-service or in response to single or double contingency events (Exhibit B-1, p. 59).

The F2006 TSCP Decision contained several directives with respect to planning standards. At pages 15 and 16 the Decision states:

> "The Commission Panel therefore encourages BCTC to define areas of the system where relaxed system performance criteria could be employed to delay the need for capital investment requirements, and to carefully consider cost/reliability tradeoffs in its project proposals" (F2006 TSCP Decision, p. 15).
>
> and,
>
> "The Commission Panel commends BCTC for augmenting its deterministic planning with probabilistic and economic assessments and suggests that it look for additional opportunities to do so in the future."
>
> and,

> "In relaxing strict adherence to deterministic system performance criteria, probabilistic methods (for instance, calculating EENS) should be used to help define risks and consequences. In particular, for capital projects to relieve congestion on non-WECC-rated transmission paths (non-Transfer Paths), future project evaluation and justification should include an analysis that identifies the duration and amount of congestion that would be incurred absent the project. The analysis should compare the cost of that congestion against the cost of relieving it" (F2006 TSCP Decision, p. 16).

BCTC states that it has relaxed generation shedding related criteria by allowing shedding of generation for some single contingencies, and is considering generation shedding of intermittent resources as an alternative to building transmission. BCTC further states it is increasingly using probabilistic and economic assessments to examine capital expenditures and that it is intending to undertake probabilistic studies on a more routine basis in future years as it develops its planning resources. BCTC states its investment prioritization methodology, as discussed in Section 4 of this Decision, helps to identify projects which add little value and present low risk of deferral. However, regarding the costing of congestion BCTC states:

> "The evaluation of the economics of a reduction in generation dispatch resulting from a reduction in congestion can only be performed by BC Hydro given the complexities of planning and operating hydro resources" (Exhibit B-1, pp. 264-265).

Directive 8 of the F2006 TSCP Decision states:

> "… the Commission Panel directs BCTC to consider economics in its assessment of whether transmission upgrades should proceed. The Commission Panel does not consider that the simple existence of a NERC/WECC Planning Standards violation is sufficient justification for transmission upgrades in every case" (Exhibit B-1, p. 265).

In response BCTC states it has broadened the scope of factors considered in its Growth Capital planning to include a path utilization forecast methodology, probabilistic reliability studies to augment deterministic studies, and the use of the prioritization methodology that helps identify projects which, although less cost effective than others, may have additional value through alignment with corporate values and risk tolerances (Exhibit B-1, pp. 265-266).

BCTC was also directed to review Attachment J of the Open Access Transmission Tariff ("OATT") to determine whether any changes were required given the Commission's directives in the F2006 TSCP Decision on system planning and the interpretation of reliability standards. BCTC has completed the review of the revised Attachment J as submitted to the Commission in February 2006, and does not believe that any further changes are required at this time (Exhibit B-1, p. 266).

BCTC does identify that an issue exists with respect to whether or not generation reserves should be deducted from the coastal resources available for dispatch, as this would advance the need for the Interior to Lower Mainland Transmission Reinforcement ("ILMTR") project. BCTC states that BC Hydro has agreed to do a joint reliability study to resolve this issue before BC Hydro's next Network Integration Transmission Service ("NITS") application (Exhibit B-1, Appendix B, p. 19). BCTC claimed that provisions in the NITS Agreement allow it to re-dispatch BC Hydro generation to relieve transmission constraints to ensure reliable operation of the transmission system (Exhibit B-6, BC Hydro 1.3.5).

BC Hydro believes that it has the right under the OATT and the NITS Agreement to specify how it wishes to dispatch and regulate its current and planned generation resources to serve load, and BCTC is required to plan the system to provide that level of service. BC Hydro submits that the next transmission capital plan should be based on the most recently approved LTAP base resource plan and Contingency Resource Plans ("CRPs") (BC Hydro Submission, p. 2).

Although BC Hydro supports BCTC's continuing consideration and evaluation of probabilistic tools and believes that probabilistic tools are useful as aids to quantitatively compare various options that meet the deterministic planning criteria, BC Hydro states that probabilistic tools should not replace traditional deterministic criteria. In BC Hydro's view deterministic criteria are necessary for the safe and reliable delivery of electricity to customers (BC Hydro Submission, p. 2).

With respect to BCTC's path utilization methodology, BC Hydro notes that analysis of historical utilization is not necessarily indicative of future performance and should not be used to determine the appropriate cut-plane capacity required to meet future system reliability needs (BC Hydro Submission, pp. 2-3).

BC Hydro supports BCTC's development of a transmission congestion relief policy and encourages BCTC to quickly begin engaging with stakeholders in open planning forums about this matter. BC Hydro notes that the development of a definition for congestion should be part of the engagement process (BC Hydro Submission, p. 3).

BCTC clarifies that it does not intend to abandon deterministic planning criteria as it refines and enhances its probabilistic analyses, and agrees with BC Hydro that deterministic planning criteria are the backbone of a reliable system and are at the heart of the NERC/WECC Planning Standards. BCTC states, however, that economic considerations are also important and it intends to continue its efforts to complement deterministic criteria with probabilistic tools that can both help choose between options and provide additional information in determining whether or when an expansion is justified (BCTC Reply, para. 28).

With respect to the development of a congestion relief policy, BCTC does not believe it would be productive at this time to engage in a debate to attempt to precisely define whether and when the system should be expanded (BCTC Reply, para. 29).

BCTC is in agreement with BC Hydro's submissions on the terms and conditions of its service to BC Hydro under the OATT and NITS Agreement, and believes that the Commission does not need to address these differences in this proceeding (BCTC Reply, para. 30).

Commission Determination

The Commission Panel notes 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 first contingency events, with certain exceptions. **The Commission Panel directs 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.**

The Commission Panel considers the issue of generation reserves as discussed in the context of BCTC's analysis of BC Hydro's NITS application to be a planning assumption issue, and notes that there was some discontinuity with respect the BCTC's and BC Hydro's positions on generation re-dispatch, which perhaps could extend to BCTC's stated intent to consider generation shedding of intermittent resources instead of building transmission. The Commission Panel is concerned about the resolution of this issue between BCTC and BC Hydro, and is likewise concerned about other planning assumptions applied to the analysis of the Integrate Electricity Plan ("IEP") portfolios, LTAP base resource plan and CRPs, and the NITS application. The Commission Panel encourages BCTC to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis and the NITS application review. **The Commission Panel directs BCTC to submit with its next capital plan a comprehensive description of the planning assumptions used in the IEP portfolio evaluations, LTAP analysis, and analysis of BC Hydro's NITS application. Future capital plan filings should either re-affirm the previous planning assumptions or describe any changes made to the previously described planning assumptions.**

The Commission Panel notes that BCTC's strictly deterministic interpretation of both the NERC/WECC and its own planning standards has been rejected in the past (F2006 TSCP Decision, p. 7). The Commission Panel continues to encourage BCTC's use of probabilistic methods to supplement deterministic planning criteria, and considers them a valuable tool to help determine the most economic time to implement an investment decision that may otherwise be invoked earlier through the strict application of deterministic criteria. The Commission Panel also encourages BCTC to continue analyzing the re-dispatch of generation resources nominated in NITS applications to help relieve transmission constraints. **The Commission Panel directs BCTC to submit as part of future capital plan filings an assessment of which transmission reinforcements could be delayed or deferred through the reasonable re-dispatch of generation resources nominated in NITS applications. BCTC should also identify in this assessment the mechanisms under OATT that allow the re-dispatch of generation around transmission constraints, and comment on whether these mechanisms are available for operating purposes, planning purposes, or both.**

2.3 Definition and Implementation Expenditures Pending Commission Approval

Concern was expressed in Directive 1 of the F2006 TSCP Decision that there was some uncertainty about what approval BCTC is seeking for Definition Phase-only projects, and directed BCTC to provide a clear statement of where in the overall identification, design, and construction process it expects the Commission's approval of the need for a Growth Capital project (F2006 TSCP Decision, p. 6).

Within the Growth Capital Portfolio BCTC is seeking approval of Definition Phase funding for the projects described below as provided in Section 1.6 of the Application:

- Ashton Creek Substation Shunt Capacitor Banks ($253,000) – relates to the addition of two 500 kV, 250 MVAr switched capacitor banks in the Ashton Creek substation (Exhibit B-1, p. 91);

- Central Vancouver Island Reinforcement ($2,500,000) – Includes studies of several alternative solutions including a 230 kV transmission line from a tap at 2L123/2L128 to the Jinglepot substation, an additional 138 kV transmission line from Dunsmuir substation to Jinglepot, or upgrading the existing lines (Exhibit B-1, p. 106);

- 5L91/5L98 Series Compensation ($1,600,000) – involves the installation of two series capacitors for 5L91 and 5L98 transmission circuits in the South Interior (Exhibit B-1, p. 93).

For the following projects, no approval is sought, but the F2008 TSCP provides for expenditures in F2009 and F2010:

- Golden 69 kV System Reinforcement ($2,500,000) – Re-examination of the forecast basis for needed capacity increases (Exhibit B-1, p. 78 and p. 111).

- North Thompson 138 kV System ($2,500,000) – Purpose not specified (Exhibit B-1 p. 78 and p. 113), however BCTC states the transformer is overloaded by 32 percent.

BCTC states that capital projects pass through three phases: Planning, Definition, and Implementation. BCTC establishes the need for each project at the conclusion of the Planning Phase; the costs of the Planning Phase are not capitalized. BCTC states that for smaller, generally routine, non-CPCN projects, approval will be sought in the capital plan for the entire project including both Definition and Implementation Phases. BCTC further states that in certain circumstances BCTC needs to do Definition Phase work before need has been firmly established, in order to meet in-service dates (Exhibit B-1, pp. 257-258).

Commission Determination

The Commission Panel is satisfied that BCTC has met the requirement of Directive 1 from the F2006 TSCP Decision, but has specific concerns in three areas.

The Ashton Creek Substation Shunt Capacitor Banks and 5L91/5L98 Series Compensation projects are examples of projects where BCTC is seeking approval to proceed with Definition Phase work in advance of establishing need. **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.**

BCTC does not request public interest funding for the total expenditures of $4,000,000 on the Golden 69 kV System Reinforcement and North Thompson 138 kV System projects listed for F2009. As described in Section 1 of this Decision, BCTC states it is seeking approval for projects and programs for F2008 and F2009. This would include these two projects. These two projects are discussed in more detail in Section 5.10 of this Decision. The Commission Panel is concerned that not all transmission expansion policies were adequately considered during the Planning Phase evaluation, and therefore the requested funding may be applied against Definition Phase development of sub-optimal project selections. **The Commission Panel specifically denies Definition Phase funding in F2009 for the Golden 69 kV System Reinforcement and North Thompson 138 KV System projects. If BCTC applies for Definition Phase funding for these projects before or as part of the next capital plan, it should be prepared to show how it has considered existing transmission expansion policies for the identification of project alternatives during the Planning Phase evaluation.**

2.4 Assessment of Community Impacts of Projects

Commission Order No. G-103-04 accepted BCTC's proposed five criteria for filing a CPCN, one of which was that the impact on a particular community or constituency likely cannot be mitigated to the community's satisfaction. BCTC stated that it does not believe that there are any projects in its Sustaining or BCTC Capital Portfolios that would have a material impact on the public and for which approval is sought in this Application (Exhibit B-6, BCUC 1.7.3).

BCTC stated that its decision to seek approval in a capital plan application rather than a CPCN application rested on its belief that the project characteristics did not meet the CPCN criteria, including the criteria of whether community impacts could be adequately mitigated (Exhibit B-6, BCUC 1.7.2). BCTC further states that many growth-related projects take place at existing facilities or are of a routine nature and unlikely to cause community concerns, and that Sustaining and BCTC projects are even less likely to trigger such concerns. BCTC notes it could collect more information and proceed further into detailed project planning before making such an assessment, but does not believe this is generally necessary. Finally, BCTC states it would appreciate the Intervenors' and Commission's views on this subject (BCTC Argument, p. 9). No intervenor responded to BCTC's request.

Commission Determination

The Commission Panel agrees that BCTC need not proceed further into detailed project planning before making the assessment of whether a CPCN application is required. However, the Commission Panel notes that it has also commented in Section 1.5 on the consequences of significant changes to the underlying project-related assumptions.

2.5 Emergency Capital Expenditures

BCTC states that Emergency Capital Expenditures are not addressed in the capital portfolios since they are unplanned events which result in a loss or reduction of service or present an unsafe condition. BCTC corrects the condition expeditiously and informs the Commission of the emergency and the intended response. At the conclusion of the repair BCTC requests the approval of the expenditure in a subsequent capital plan application, which satisfies the requirements of Article 19.9 of the Master Agreement under which BCTC operates BC Hydro's transmission assets. BCTC states this process appears to have worked well on a number of occasions. BCTC did not identify any prior period Emergency Capital Expenditures for which it was seeking approval (Exhibit B-1, pp. 13-14).

To put this topic in context, BCTC noted that only one emergency unplanned expenditure has been added to the amount recovered in rates since January 1, 2006 (Exhibit B-6, BCUC 1.58.1).

Commission Determination

The Commission Panel agrees that Emergency Capital 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 Panel directs BCTC to track past years' approved Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures, as was done in Table 9-1 of the Application.**

2.6 Implementation and Post-Implementation Reviews and Reports

Section 3.1 discusses the State of the Transmission System Report ("STSR") and associated on-going reporting requirements. Section 3.2 sets out reporting requirements for variances from one plan to the next.

BCTC describes the Implementation Phase as follows:

> "This phase covers the implementation of the work to build the asset. The work includes all of the required project management, engineering, procurement, and construction work described in the Project Plan. Projects are continuously monitored against their Project Plans, including cost, progress (schedule), and quality of the work. Risk factors are also continuously monitored, and mitigation plans are implemented as needed. Whenever cost is forecast to exceed the authorized amount by 10%, or a significant schedule slippage occurs, a variance review is conducted and internal approval sought. The project concludes upon completion of the Project Plan and acceptance of the new asset for use" (Exhibit B-1, p. 38).

BCTC stated that it uses a Project Implementation Risk Matrix to manage project specific risks during the Implementation Phase (Exhibit B-6, BCUC 1.4.2). During the Implementation Phase BCTC performs variance reviews in the form of a document titled "Change Notice". This brief document provides a general project description, describes the change, the reasons for the change, and records the client's assessment/agreement with the change (Exhibit B-6, BCUC 1.63.1).

BCOAPO submits that the Commission should direct BCTC to provide information in its next capital plan filing regarding any material change in costs of 10 percent or more for previously approved projects with continued spending in the forecast period (BCOAPO Submission, p. 4).

BCTC states it is willing to provide such variance reporting with a material variance defined as both exceeding 10 percent and $100,000 for previously approved projects, regardless of whether the schedule associated with the project has changed (BCTC Reply, p. 15).

Commission Determination

The Commission Panel believes that for some projects there may be an additional phase in the capital process. When projects are completed in significantly more or less time than forecast, and/or experience costs which are significantly more or less than forecast, the Commission Panel believes that lessons may be learned that may be applied to future projects. The Commission Panel finds no evidence of an attempt to systematically learn from both successes and failures**. 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.**

The Commission Panel agrees with BCOAPO's submission on variance reporting, and accepts BCTC's proposal to provide information in its next capital plan filing regarding variances exceeding both 10 percent and $100,000 of budgeted amounts submitted in this Application for approved projects, and to continue such reporting in future capital plan filings until directed otherwise.

3.0 PREVIOUS DIRECTIVES

The F2006 TSCP Decision contained 46 directives to BCTC (F2006 TSCP Decision, pp. 64-70). Directive 7 directed BCTC to provide a status update for each directive in each capital plan until such time as BCTC had complied with the directive. In this Application, BCTC has complied with this directive in Section 9 and Appendix A of Exhibit B-1. BCTC states it has complied with 43 of the directives and provided a status update of the other three (Exhibit B-1, p. 257).

In the Reasons for Decision accompanying Order No. G-103-04, BCTC was directed to file a STSR with its future capital plan filings (Reasons for Decision, Order No. G-103-04, pp. 8-9). BCTC has complied with this directive and provides the updated STSR ("2006 STSR") in Appendix B of the Application. A large number of directives from the F2006 TSCP Decision are addressed in the 2006 STSR.

In this Application, BCTC also addresses specific directives from the F2006 TSCP Decision regarding the identification of changes from one capital plan to the next, evaluation of customer and non-wires solutions to transmission constraints, and IPP interconnections.

3.1 State of the Transmission System Report

The 2006 STSR is a comprehensive document that provides an overview of the existing transmission system, and identifies both the current issues facing the system and where the system needs to be expanded or reinforced, particularly in response to rapid and significant load growth. Resource additions from IPPs, impacts of projects external to the B.C. transmission system, potential Special Direction No. 9 ("SD9") projects, and projects resulting from exposure to natural, operational, maintenance, security and other risks are addressed in the 2006 STSR. Finally, the 2006 STSR contains an assessment of existing equipment condition and performance, and 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") (Exhibit B-1, pp. 30-33).

3.1.1 System Issues

BCTC states that the 2006 STSR was prepared on the basis of BC Hydro's LTAP, and that the analysis of the transmission system's performance and needs is linked to the load forecasts and locational, generation forecasts in the LTAP. BCTC describes the issues that arise in the four regional transmission systems in the province: the North Interior, the South Interior, the Lower Mainland, and Vancouver Island. At the bulk system level, the current most significant transmission needs relate to the South Interior System and the Interior to Lower Mainland ("ILM") portions of the system. The South Interior System is experiencing congestion. BCTC has prepared a South Interior Bulk System Development Plan Report ("South Interior SDP") to identify and evaluate options for new transmission system infrastructure and transmission reinforcements that address this congestion and future constraints (Exhibit B-1, Appendix C). Also discussed in the 2006 STSR are near-term options to address imminent ILM constraints. These options include the addition of series and shunt capacitor banks to increase the Total Transfer Capability ("TTC") of the ILM transmission path. The most immediate needs of the Lower Mainland to Vancouver Island portion of the bulk system are being addressed by the Vancouver Island Transmission Reinforcement ("VITR") project. The Northern portion of the bulk system has adequate capacity to meet present needs, although BCTC has begun to study future transmission upgrades required to serve proposed wind and coal generation (Exhibit B-1, Appendix B, pp. 6-22).

The 2006 STSR contains a review of both the internal interties to the systems owned by Alcan Inc. ("Alcan"), and FortisBC Inc. ("FortisBC"), and the external interties to the systems in Alberta and Washington State. The Alcan intertie rating is under review and will likely decrease because of recent testing. The FortisBC interties are sufficient for existing use, but congestion may increase on the South Interior System if FortisBC increases wheeling volumes under the General Wheeling Agreement. This is discussed in the South Interior SDP (Exhibit B-1, Appendix B, pp. 22-23).

The Alberta intertie has a WECC-approved rating of 1,200 MW for the B.C. to Alberta path and 1,000 MW for the Alberta to B.C. path, but it is normally limited to 780 MW and 800 MW respectively because of constraints in the Alberta system. A B.C.-Alberta Electricity Transmission Subcommittee is studying the feasibility and potential benefits of reinforcing this transmission intertie and BCTC recently initiated a joint study with the Alberta Electric System Operator ("AESO") to examine the potential for economic benefits from a second Alberta intertie (Exhibit B-1, Appendix B, pp. 24-25).

The U.S. intertie is comprised of a 500 kV intertie in the west side of the province, and a 230 kV intertie in the east side of the province. There can be little or no available transfer capacity on the east side intertie because of historic scheduling rights and the return of a portion of the Canadian Entitlement ("CE"). The combined U.S. intertie has a WECC-approved rating of 3,150 MW for the B.C. to U.S. path and 2,000 MW for the U.S. to B.C. path. The firm capacity in both directions is 1,750 MW based on the expected available transfer capacity after the loss of the cross-border 5L51 500 kV transmission line. This intertie has other constraints during periods of low load or certain combinations of low generation and high imports (Exhibit B-1, Appendix B, pp. 25-26).

The regional transmission systems are generally comprised of a large portion of the 230 kV system and all of the 138 kV and 60 kV systems. BCTC states that within the regions, most of the proposed reinforcements are required due to load growth, customer requests for service, or system reliability issues in radial parts of the system. BCTC identifies a number of issues in the Metro Vancouver area concerning load growth, significant seismic risks, or age-associated deterioration. In the Northern Interior, two significant projects identified in the 2006 STSR are the reinforcements associated with the interconnection of a 112 MW hydroelectric IPP located on the Iskut River, and a new 287 kV line, referred to as the Northwest Transmission Line ("NTL") project, from Skeena substation to Bob Quinn Lake intended to interconnect proposed IPPs and supply a number of potential mining loads. In the South Interior, BCTC identifies two primary issues as the need to meet area loads where the forecast has changed significantly, and reliability for communities that are fed by long radial systems. Significant projects driven by both issues are being investigated for supply to the Golden and North Thompson areas. A number of significant issues are identified in the

Vancouver Island region. The west coast of Vancouver Island is supplied by a radial 60 kV line with the worst record of performance in the province. The peak demand of Vancouver Island's central coastal communities is forecasted to exceed the rating of the supplying transmission lines by F2009. Certain contingencies can already overload these transmission lines, triggering the need for sectionalizing transmission lines, shifting supply points and curtailing load. BCTC states that the 138 kV system in Vancouver Island South is already congested and load curtailments could be required for a number of contingencies. BCTC has proposed or is considering options for projects, some of which may be the subject of separate CPCN applications, to address these and other issues on Vancouver Island (Exhibit B-1, Appendix B, pp. 27-45).

A new primary system control centre ("SCC") in the Fraser Valley and a back-up control center ("BCC") in the Okanagan are being constructed as part of the System Control Modernization Project ("SCMP"). The SCMP is described in the 2006 STSR as being on schedule to be in-service in F2009 (Exhibit B-1, Appendix B, p. 46).

3.1.2 Impact of IPPs

BC Hydro's F2006 Call resulted in a large number of possible IPP generation additions distributed throughout B.C., and BC Hydro is planning more calls in the future. BCTC states that under the OATT Standard Generator Interconnection Procedures, it must undertake Interconnection Feasibility Studies, System Impact Studies, and Interconnection Facilities Studies to understand the impact of an IPP on the transmission system before an interconnection can take place (Exhibit B-1, Appendix B, p. 49).

In advance of individual studies, BCTC performs and posts studies that attempt to identify the amount of Available Transmission Capacity ("ATC") available for generation on the transmission cut-planes between various regions. These studies also attempt to quantify the cost and timing of specific projects to increase the ATC of the cut-planes. BCTC states that these studies indicate that transmission reinforcement will be required in a number of areas if proposed IPP projects proceed.

Regional cut-plane limits are summarized in Appendix 6 of the 2006 STSR (Exhibit B-1, Appendix B, p. 51).

3.1.3 External Projects

BCTC undertakes studies on proposed projects in neighbouring systems that may have an impact on the existing transmission system or proposed projects in B.C. In the past year, BCTC has focussed on two proposed transmission initiatives: Sea Breeze Victoria Converter Corporation's ("Seabreeze VCC") Juan de Fuca project and the Montana-Alberta Tie project. The Juan de Fuca project has received approval from the National Energy Board, and the WECC path rating process is underway. BCTC provided a draft Transmission Interconnection Impact Study and Facility Study Agreement for the Juan de Fuca project in January 2006, but SeaBreeze VCC has not yet requested these to be finalized. BCTC's participation in the Montana-Alberta Tie project studies is focussed on ensuring the project can be integrated into the WECC system while protecting the existing ratings and operating requirements of the B.C. transmission system and interties (Exhibit B-1, Appendix B, p. 53-54). BCTC describes a number of other external projects that it continues to monitor for possible impacts on the B.C. system (Exhibit B-1, Appendix B, pp. 54-57).

3.1.4 Transmission Expansion Policy and SD9

In 2005, BCTC issued an Expansion Policy Paper that addressed the identification and evaluation of projects submitted under SD9, which allowed for the advancement of projects that are not driven by existing customer growth or contracts. BCTC expects these projects to fall into three main categories: projects supporting development of generation in B.C., projects that restore or enhance existing capacity; and projects that expand import/export capacity. BCTC identifies projects in each category (Exhibit B-1, Appendix B, p. 58).

Projects supporting development of generation in B.C. include transmission reinforcements on northern Vancouver Island and in the Lillooet-Harrison Lake corridor, and integrating green energy projects on the Sunshine Coast. Projects that restore or enhance existing capacity include the addition of a shunt capacitor at Meridian substation and the installation of a new phase-shifting transformer at Nelway substation. Projects that expand import/export capacity include an interconnection with Alaska, an intertie from Alberta to the Peace Canyon Generating Station, reinforcements to the existing Alberta intertie and reinforcements between the U.S. and Southeast B.C. (Exhibit B-1, Appendix B, p. 59). Although BCTC goes on to identify a number of factors that would affect the economic value of proposed transmission expansion projects, there are no evaluations provided for any of the identified projects (Exhibit B-1, Appendix B, p. 60).

BCTC provides references and locations for draft standards it has developed that address the future interconnection of wind generation projects. BCTC proposes that wind generation penetration should not exceed 10 percent of total installed generation in order not to impact the integrity of the integrated system (Exhibit B-1, Appendix B, pp. 60-61).

3.1.5 Equipment Condition and Performance

An Asset Baseline Study was conducted in 2004 that established a condition baseline for thirty-three classes of assets in the transmission system, which addressed the entire installed base (Exhibit B-1, Appendix B, p. 62). In the F2006 TSCP Decision, the Commission issued several directions regarding the frequency of the asset condition audits and certain issues pertaining to the collection and analysis of asset condition data. Specifically, the Commission found the three-year interval between asset condition audits to be appropriate (F2006 TSCP Decision, p. 26), recommended against the application of the "fatal flaw" factor to sub-set populations within an asset class for which valid data may not exist (F2006 TSCP Decision, p. 26), and recommended that BCTC establish correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI (F2006 TSCP Decision, p. 27).

BCTC is implementing a number of initiatives to provide a system that automatically updates the asset condition database whenever routine inspections are done, enabling continuous updating of the Asset Health Index on a routine basis. These initiatives are in the implementation stage and are expected to become routine procedure in F2008, however a complete data set may not be available until F2014 (Exhibit B-1, Appendix B, pp. 62-63).

The 2006 STSR contains summary descriptions for the condition of twelve specific asset classes. Of these twelve asset classes, the Vegetation/Rights-of-Way asset group appears to be in the worst condition, with 49 percent of the asset class reported in fair, poor, or very poor condition. BCTC states this is expected and part of the planned vegetation control program (Exhibit B-1, Appendix B, pp. 63-67).

BCTC describes a Sustainment Investment Model ("Model") that is intended to forecast long-term Sustaining Capital Expenditures based on an estimated number of assets reaching their useful life combined with an estimated replacement cost (Exhibit B-1, Appendix B, pp. 68-70). The Model is considered further in Section 6.4 of this Decision.

3.1.6 Risk Items

The transmission system is exposed to a number if risks that could impair its intended operation. These risks are categorized in the 2006 STSR as natural risks, such as seismic events, river erosion, avalanches, snow creep, mud slides, ice storms, lightning, forest fires, and geomagnetically induced currents, and a category of other risks, which includes operational and maintenance risks, security risks, oil spills, and station fires. BCTC describes how it plans for these risks by having emergency response plans prepared and spare equipment available. The transmission system does have inherent capability to absorb some risk because it is designed to be able to withstand failures of any single element (Exhibit B-1, Appendix B, pp. 72-83).

If the expenditures on the Vegetation/Rights-of-Way program are not considered as mitigation towards decreasing the effects of forest fires, the largest amount of expenditures directed towards natural risks is for mitigating the effects of seismic risks. BCTC describes F2008 and F2009 expenditures for reinforcing 2L3/2L49 Second Narrows Crossing tower 688, design and implementation projects for reinforcing substation control buildings at Williston, Meridian and Atchelitz substations, and the construction of a seismically secure building for the SCMP (Exhibit B-1, Appendix B, pp. 73-74).

3.1.7 System Performance Measures

BCTC reports system performance in terms of SAIDI, SAIFI, DPUI, Intertie Congestion, and Equipment Reliability (Exhibit B-1, Appendix B, pp. 83-92).

SAIDI is reported in the 2006 STSR as 2.07 in F2006, compared with a BCTC F2006 target of 2.12, and has been on a declining trend since F2004, although it is above the Canadian Electrical Association ("CEA") composite for all years where a comparison is provided. BCTC notes that it includes the effect of planned outages in its measure of SAIDI, and the CEA does not (Exhibit B-1, Appendix B, p. 84).

A breakdown of SAIDI by cause is also provided. In F2006, the largest contributor to SAIDI was environment and weather. Outages due to defective equipment were at their lowest level in F2006 for all the years reported (Exhibit B-1, Appendix B, p. 85).

SAIFI outages are further categorized into momentary interruptions less than one minute ("SAIFI-MI"), and sustained interruptions greater than one minute ("SAIFI-SI"). BCTC reports the F2006 SAIFI-MI as 0.76, the F2006 SAIFI-SI as 1.07, and the composite SAIFI as 1.82. These values compare favourably with CEA statistics, which do not include the effect of planned outages that BCTC does include. There is no clear trend in either SAIFI measure over the period since F2002 (Exhibit B-1, Appendix B, p. 88).

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 25.31 minutes in F2006, and is reported for the past three year with no obvious trend. The BCTC DPUI is comparable to the CEA average (Exhibit B-1, Appendix B, pp. 89-90).

BCTC has defined a measure for intertie congestion and reported the amount of congestion on the transmission interties to Alberta and the U.S. using this measure. Congestion on a transmission path is defined to exist in those hours in which both 90 percent or more of the transmission path's posted TTC is used and less than 90 percent of the maximum theoretical capacity of the transmission path with all elements in-service is available. For the period between October 2004 and March 2006, the Alberta to B.C. transmission path was the most congested intertie, being congested for 66 percent of the time mostly caused by constraints in Alberta. In the same period, the transmission intertie with the greatest amount of congestion that was attributed to constraints in B.C. was on the U.S. to B.C. transmission path, accounting for 88 percent of the congested hours on that path (Exhibit B-1, Appendix B, pp. 90-91).

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. BCTC observes that for the transmission line asset class, the frequency of forced outages is higher and the duration of the outage tends to be longer than the CEA average, however, for the cable, transformer, and circuit breaker asset classes, BCTC exhibits better equipment reliability than the CEA average (Exhibit B-1, Appendix B, pp. 91-92).

BCTC states that the STSR is evolving, and submits that the 2006 STSR is a significant improvement over the previous STSR, and that it will continue to introduce further improvements in future STSRs. BCTC observes that the STSR is very time-consuming to prepare, and seeks both more uses for the document, and feedback on the usefulness of the STSR and ways it can be manageably enhanced, particularly in its role of supporting the transmission capital planning process (BCTC Argument, pp. 24-25).

BC Hydro believes the STSR is an important contextual document for BCTC's capital plans and encourages BCTC to periodically update and publish state of the transmission system reports (BC Hydro Submission, p. 4).

Commission Determination

The Commission Panel agrees with BCTC that the 2006 STSR is a significant improvement over the previous STSR. The 2006 STSR addresses both the issues facing the regional systems and the proposed solutions. This provides the necessary information to assess the need for the projects in the capital plan, and as such the 2006 STSR is a fundamental component of the overall capital plan. The Commission Panel acknowledges that the preparation of the STSR is very time-consuming, but also that the detailed technical information to support the capital plan does not appear elsewhere in the Application. **The Commission Panel encourages BCTC to suggest changes to the frequency of the STSR if BCTC determines the existing frequency does not serve a useful purpose, but directs BCTC to submit an updated STSR with future capital plan applications until directed otherwise.** Certain portions of the 2006 STSR are very descriptive of the existing system, and instead of repeating these with each STSR, it may be more useful to describe changes in the system from the previous STSR.

The Commission Panel notes that BCTC may not have a complete data set for the Asset Health Index until F2014. The Commission Panel affirms the Directive from page 26 of the F2006 TSCP Decision, and considers that a three-year interval between asset condition audits remains appropriate.

The Commission Panel directs BCTC to continue reporting performance measures in future capital plans, largely as they are provided in the 2006 STSR. BCTC should report its performance measure with and without planned outages in order to make the comparison against CEA statistics more relevant. The Commission Panel also considers the trend graph supplied in response to BCUC 1.131.1 (Exhibit B-6) to be a useful long-term indicator, and directs BCTC to file this trend information in future capital plans.

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). In response to this directive BCTC has provided a section of the Application for each of the Growth, Sustaining, and BCTC Portfolios, containing the required tables.

BCTC states that the changes to approved projects in the Growth Capital Portfolio that have been accelerated, deferred or cancelled are reflected in Table 5-3 of the Application. BCTC further states that for on-going projects, revised expenditure patterns and in-service dates can be found in Table 5-1 of the Application under the heading "Projects in Progress" (Exhibit B-1, p. 84).

Table 5-1 includes in-service dates and expenditure patterns for previously approved projects, but shows neither the change in the in-service date nor the change in the expenditure pattern. Table 5-3 shows 14 projects and provides a reason for each schedule change. Of the 14 projects, all are either cancelled or delayed (Exhibit B-1, pp. 77-80; p. 85).

Changes to projects in the Sustaining Capital Portfolio are tabulated and discussed in Section 6.3 of the Application. Table 6.3-1 provides a reconciliation of the prior plan (adjusted for the impact of the F2006 TSCP Decision) to the current plan in total, but not at the individual project level (Exhibit B-1, pp. 135-137).

BCTC claims it has taken into account reductions in the Sustaining Capital Portfolio expenditures as directed by the Commission, but identified two changes to these levels to account for: (1) an increase to the station security project of $2 million starting in F2008 and an increase to the seismic upgrade project of $3.5 million in F2008 and F2009; and, (2) a reduction to the cable sustainment project of $2 million in F2008 and $1 million in each of F2009 and F2010 (Exhibit B-1, p. 136).

BCTC further describes three specific changes at the project level that have occurred from the F2006 Application related to: (1) line terminations at Cathedral Square substation; (2) polychlorinated biphenyl ("PCB") equipment at the Vancouver Island Terminal ("VIT") substation; and, (3) a seismic project at Murrin substation (Exhibit B-1, p. 137).

Commission Determination

The Commission Panel finds that BCTC's compliance with Directive 7 from the F2006 TSCP Decision is lacking in some respects, and that the responses provided give cause for concern. As also discussed in Section 5.10 of this Decision, the number of Growth Capital projects which have been delayed, as identified in Table 5-3 of the Application, gives rise to the concern that BCTC will not be able to complete the work it has identified in this capital plan, which in turn could result in negative impacts on reliability or unmet needs of load growth. Delayed projects will be monitored in future applications because they may be indicative of a failure between the planning process and the ability to execute projects. Their delay causes an over-estimation of the funding that BCTC (and ultimately BC Hydro) requires for such projects in at least the short-term. Furthermore, BCTC has not provided information on the changes to in-service dates and expenditure patterns for Growth Capital. **In all future capital plan applications, BCTC is to provide a modified table in the format of the "Projects in Progress" portion of Table 5-1 in this Application. For each year during the Implementation Phase of a project BCTC is to include 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. The Commission Panel further directs BCTC to provide a modified table in the format of Table 5-3 in this Application, modified to include the total dollar value for each project, as well as the priority ranking of the project when the project was approved.**

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). BCTC states that by Letter No. L-16-06 the Commission accepted a proposal from BCTC that it would continue to evaluate the development of re-dispatch service within the context of the Commission's instructions in the F2006 TSCP Decision, and was prepared to continue its re-evaluation and include those results in its Rate Review Report to be filed by December 31, 2006 (Exhibit B-1, p. 267).

BCTC filed the "Open Access Transmission Tariff (OATT) Compliance Filing – Rate Design Report" on December 20, 2006 ("Rate Design Report"). The responses to the Commission directives were provided in Appendix B of the Rate Design Report. By letter dated January 24, 2007, the Commission accepted the filing of the Rate Design Report.

In this Application no viable non-wires alternatives were identified. BCTC states that it will continue to pursue the identification and potential application of non-wires solutions in its future studies and capital plan applications (Exhibit B-1, p. 267).

Commission Determination

The Commission Panel recognizes the challenges that BCTC faces in offering non-wires solutions and is encouraged by its efforts to investigate these options with BC Hydro and other stakeholders. This issue is addressed further in Section 8.3.2 of this Decision.

3.4 Expenditures on IPP Interconnections

BCTC provides a proposed approach for Commission approval to deal with the uncertainty surrounding IPP interconnections in response to the following Commission Directive:

> "So far as concerns the IPP interconnections it is clear to the Commission Panel that the established regulatory parameters are not serving their intended purpose. The Commission Panel notes BCTC's observation that it is still analyzing different approaches to IPPs, and expects to provide a recommended approach on how to treat the uncertain nature of IPP interconnections in its next Capital Plan Application. The Commission Panel directs BCTC to address this issue in its proposed November 2006 application" (F2006 TSCP Update Decision, p. 13).

BCTC proposes to treat IPP interconnections in the following manner in future and current transmission capital plans subject to Commission approval and with the exception of the specific projects described in the F2006 TSCP Update Decision (Exhibit B-6, BCUC 1.51.1):

> "BCTC will identify an amount for the interconnection of IPP projects based on a forecast of capital needed for the upcoming year, although not necessarily assigned to specific IPP projects. However, BCTC will not seek approval from the Commission for these expenditures but will rely instead on the requirements of the OATT as the authority for proceeding with IPP interconnections. For those projects which were originally approved by the Commission and subsequently deferred, and for which the Commission has indicated in Order G-67-06 that further approval is now required prior to resurrecting such projects, BCTC will proceed to sign facilities agreements executed and returned by IPP customers, will proceed with the study work and interconnection process, and will seek the new approval through the Capital Plan submission when the timing coincides, or will file a letter with the Commission, as directed" (Exhibit B-1, p. 279).

BCTC requests specific confirmation that the Commission accepts this IPP proposal so this approach can be factored into the F2009 capital planning process (BCTC Argument, p. 13).

BCTC further described the OATT requirements stating that Network costs for transmission requirements are recovered through NITS charges, and that Interconnection costs are comprised of Direct Assignment and Network Upgrade costs. Direct Assignment costs are paid by the proponent and the Network Upgrade costs are recovered through NITS charges. A letter of credit is obtained to cover the Network Upgrade costs in case the IPP project does not reach commercial operation (Exhibit B-6, BCUC 1.24.1).

BCTC's view is that approval of the F2008 TSCP under Sections 45(6) and (6.1) of the Act does not require public interest approval of all projects within the F2008 TSCP, and only establishes the requirement of filing the F2008 TSCP. BCTC stated further that Section 45 (6.2)(b) allows the Commission to determine whether specific projects are in the public interest but does not require approval of all individual expenditures. BCTC submitted that the requirements of OATT, which have been approved as being in the public interest, and the letter of credit requirements avoid uncertainty and ensure that ratepayers are adequately protected. Considering all of the above BCTC stated that it believes its requested approach is consistent with the Act (Exhibit B-6, BCUC 1.51.2).

Commission Determination

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.

3.5 Three Outstanding Directives from the Previous Decision

BCTC prepared a Concordance Table of 46 Directives and states that it has complied with 43 Directives and provides status updates for the remaining three (Exhibit B-1, p. 257).

The first outstanding Directive related to data monitoring, collation and analysis and required that the level of activity should be sufficient to ensure that an adequate data-based condition assessment is available for at least 90 percent of the assets within each class meeting the 70 Percent Rule by the third audit (F2006 TSCP Decision, p. 26). BCTC states that it is revising its maintenance standards and is working towards this goal, and that the requirement of the Directive will be met for 63 of the 76 classes. The benefits and costs of meeting the goal for the remaining thirteen classes will be evaluated after the revision of the maintenance standards is completed (Exhibit B-1, p. 268).

The second outstanding Directive relates to a Commission recommendation regarding data collection and analysis processes necessary to establish correlations among asset classes' health-related metrics and the impacts on reliability indicators (F2006 TSCP Decision, p. 27). In response BCTC states it has put in place a Reliability Data Management System which provides reliable historical asset performance data. BCTC also proposed in this Application to improve data collection and analysis with Mobile Application Enhancements (Exhibit B-1, p. 269).

The final outstanding Directive states:

> "The Commission Panel expects BCTC to collect sufficient data to allow the identification of the worst performing asset classes by quantification of the effect of equipment failures on the reliability indices, and to present this data in support of future sustaining capital plans and programs. The Commission Panel reaffirms the following direction from Order G-103-04:
>
> > The Commission therefore directs BCTC to provide, in future Capital Plans, a classification of transmission failures by equipment type and age, as well as an indication of the impact of transmission failures on reliability indices. Statistics should be included for as many years in the past as are reasonably available in order that trends may be observed. Should the requested statistics not exist, BCTC is to file a plan for collecting the necessary data in the future" (F2006 TSCP Decision, p. 51).

In responding to the Directive BCTC states:

> "Information on the impact of equipment failures on SAIDI is provided in Section 8 of the STSR in Appendix B. The information includes a breakdown by the major asset classes.
>
> Equipment reliability data for Lines, Cables, Transformers and Circuit Breakers by voltage level and with comparison to CEA averages are also provided in Section 8 of the STSR.
>
> BCTC is in the process of developing and improving its analysis tools and Asset Management Information System. These tools and system will allow more detailed quantification of the impact of equipment failures on reliability indices by asset class in the future" (Exhibit B-1, p. 273).

Commission Determination

The Commission Panel notes that BCTC has made substantial progress on the first outstanding Directive and expects BCTC to continue reporting its progress with each capital plan application in the future.

The Commission Panel considers that BCTC is complying with the second outstanding Directive and expects BCTC to report on the progress of establishing correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI.

Regarding the third outstanding Directive, the Commission Panel is of the view that the equipment reliability data and the comparison to CEA averages does provide helpful information for making Sustaining Capital investment decisions. **The Commission Panel directs BCTC to provide in future capital plans equipment reliability data as selected by BCTC and provide the CEA averages, and in the case of Line-related Forced Sustained Outages (as defined in the 2006 STSR, Section 8.3), to separate equipment failure outages from those outages caused primarily by weather or vegetation.**

4.0 PRIORITIZATION OF CAPITAL PROJECTS

4.1 Introduction

In the F2006 TSCP Decision, the Commission expressed concerns with BCTC's Growth Capital project ratings system which consisted only of the ratings "mandatory" and "discretionary" and described these ratings as inadequate.

As a result the F2006 TSCP Decision stated that:

> "The Commission Panel therefore directs BCTC to refine the Growth Capital ranking system to better discriminate between growth capital projects. The ranking system should consider the factors that BCTC has set out in Section 2 of the F2006 TSCP, but should also consider factors such as lead-time, forecast uncertainty and probabilistic measures such as Expected Energy Not Served ("EENS") (see Section 3.2)" (F2006 TSCP Decision, p. 7).

4.2 The Prioritization Methodology

BCTC states that a significant development in the F2008 TSCP is the implementation of a formal prioritization methodology for all capital portfolios which is provided in response to Directive 2 quoted above, and in response to a Directive found at page 62 (BCTC Argument, p. 10).

The description of the prioritization methodology is provided in less than the four pages which comprised Section 4.4 of the Application (Exhibit B-1, p. 39).

BCTC states that:

> "BCUC Information Request No. 1 included over sixty questions regarding the prioritization process. The majority of these questions sought clarification about how the Prioritization Tool works including inputs, weightings, general methodology of the tool, and the theory behind the methodology. Further clarification was sought through detailed reviews of applications of the tool to specific projects. Questions were also asked regarding the application of prioritization results to the formation of the Capital portfolios and the consistency of the model with other forms of analysis used by BCTC" (BCTC Argument, p. 10).

BCTC further states that the prioritization tool is not a substitute for management decision-making but provides a significant tool to aid in the creation of the capital portfolios. BCTC anticipates a process of fine-tuning and further improvement (BCTC Argument, p. 11).

BCOAPO submits that BCTC's prioritization methodology is a positive factor in its capital planning process and that BCTC should be encouraged to refine this methodology and use it in future applications (BCOAPO Submission, p. 3).

BCTC engaged UMS Group Inc. ("UMS"), a consultancy, stated to be experienced in creating similar methodologies within other utilities, to assist it in developing a formal prioritization methodology (Exhibit B-1, p. 39). UMS has over 30 similar clients on three continents (Exhibit B-6, BCUC 1.27.3).

The Request For Proposal Detailed Specifications ("RFP") to which UMS responded required respondents to provide a fixed price quote and specified that all work performed during the course of the project becomes the sole property of BCTC (Exhibit B-6, Attachment to BCUC 1.27.1, p. 3). Among other things, the successful bidder was to provide a beta test showing a successful demonstration of the process. In addition the Optimization Module for 50 key projects was stated to be a deliverable (Exhibit B-6, Attachment to BCUC 1.27.1, p. 14).

BCTC states that a significant development in BCTC's Capital Planning process is the implementation of a formal methodology for project prioritization in each portfolio, but while the planning process used for the three portfolios is common, the objectives of each portfolio are quite different, as are the inputs to the process (Exhibit B-1, p. 39). However, in the case of Sustaining Capital BCTC also states that it optimizes the portfolio (Exhibit B-1, p. 35).

BCTC states that it has developed three matrices to manage its risk exposure (Exhibit B-1, p. 39). The Corporate Risk Matrix manages BCTC's corporate risks, the Project Deferral Risk Matrix is used for prioritizing capital projects and is discussed below (this matrix was provided in the form of an information request response in Exhibit B-6, BCUC 1.4.2), and the Project Implementation Risk

Matrix which is used to manage risks during the Implementation Phase. BCTC stated that only the Project Deferral Risk Matrix is applicable at the stage at which capital projects are brought forward to the Commission for approval (Exhibit B-6, BCUC 1.4.2).

The prioritization tool considers two attributes of each project (1) deferral risk and (2) value. To calculate a numeric figure for each of deferral risk and value, eighteen criteria or metrics in six categories, which are derived from BCTC's Corporate Goals, are analyzed. The criteria within the categories are summarized as follows (Exhibit B-1, pp. 41-43):

Financial

1. Net present value
2. Benefit to cost ratio
3. Rate Impact
4. Dollar Savings

Reliability

1. Transmission System Average Interruption Duration Index
2. Distribution Customer Hours
3. Transmission Reliability Index
4. Expected Energy Not Served

Market Efficiency

1. Real Line Loss Reduction
2. Congestion Reduction
3. Trade benefits

Asset Condition

1. Equipment Spares Support
2. Asset Health
3. Failure rate

Relationships

1. Community/Public Relations
2. First Nations

Environment and Safety

1. Environment
2. Safety

Within each of the goal-related categories the individual criteria must be weighted to arrive at an overall score for each category. BCTC explained the weighting and methodology for the Asset Condition category in detail, and stated that the "…proportions for the impact and logic of each metric have been chosen through consensus judgment by BCTC managers and BCTC transmission experts" (Exhibit B-6, BCUC 1.33.1).

The deferral risk is the risk associated with the project being deferred one year (Exhibit B-6, BCUC 1.38.1). For each goal, the consequence and probability components of the most likely risk scenario (the consequence with the highest probability) are computed on a scale of 0 to 5 using the Deferral Risk Matrix. Once these components have been determined, the risk score for each goal is calculated by multiplying the consequence and the probability. This results in a risk score between 0 and 25 for each goal. The highest risk score of the six goals becomes the deferral risk of the project (Exhibit B-6, BCUC 1.28.2).

The value attribute is computed as a weighted average of the scores across the goals, again with consequences ranking from 0 to 5 (Exhibit B-1, p. 40). The weighting for the individual goals and an explanation of how the weights were determined were provided in response to an information request. BCTC stated that the assignment of weightings was facilitated by UMS staff during several discussions with senior BCTC staff using a methodology described as the "forced pair" methodology which BCTC stated was an established technique to develop group consensus on relative weighting across various goals. The weightings applied to the goals to compute the value score are:

	Goal-Related Category	**Weighting**
1	Financial	30.6%
2	Reliability	21.5%
3	Asset Condition	20.0%
4	Relationship	5.3%
5	Environment & Safety	8.8%
6	Market Efficiency	13.7%

BCTC stated that even though a low weighting was determined for Environment and Safety it did not mean that they were not a high priority. BCTC stated that its rigorous environmental and safety standards ensure that safety and environmentally driven projects score highly in terms of deferral risk and are selected on this basis. Projects initiated to meet Federal, Provincial or Municipal requirements are considered to be mandatory but are still scored (Exhibit B-6, BCUC 1.29.1).

For Growth Capital projects, based on the application of the prioritization process described above, projects were ranked from 1 to 9, with 1 being the highest priority. Projects in the highest priority groups 1 to 3 are said to contribute significantly to reliability or market efficiency goals and have moderate to significant risks if deferred. Projects in the mid range of groups 4 to 7 are said to contribute to Financial Goals and have a lower risk of deferral. Funding requests for projects in groups 8 and 9 were deferred due to low incremental revenues and the low risks associated with deferral (Exhibit B-1, pp. 86-87).

For Growth Capital projects the results of the prioritization are shown Table 5-4 at page 87 of Exhibit B-1.

BCTC stated that in calculating the rate impact for Growth Capital projects that it is unable to estimate the incremental revenue associated with such expenditures, but agreed that the rate impacts will be partially offset by such incremental revenues (Exhibit B-6, BCUC 1.46.1 and 1.46.2).

BCTC stated that regarding the financial category used in computing value, that rate impact had been assigned a weight of 17.7 percent while net present value had a weight of 54 percent (Exhibit B-6, BCUC 1.38.1).

For projects in the Sustaining Portfolio a further process described as “optimization” occurred. The risk of deferral and value scores resulting from the prioritization process were calculated and then normalized on a scale of 0 to 5. These values were plotted together with investment (Exhibit B-1, pp. 138-139). Consideration was also given to the project duration as more fully described in an information response:

> "The prioritization process assessed incremental levels of investment for on-going projects. This was done by disaggregating on-going projects into component projects and then combining the component projects into groups with similar levels of estimated value and deferral risk. Each group of component projects was then scored for value and risk of deferral at the group level. Discrete projects were also scored. Through plotting the groups and discrete projects on a Value versus Risk of Deferral chart, lower priority (i.e., lower value combined with lower risk of deferral) groups and discrete projects were identified (lower left quadrant of Figure 6.4-1 on page 138 of the Application) and reviewed for potential deferral. Selected groups and discrete projects were then recombined into programs, resulting in program sizes that optimize value and risk tradeoffs. Total portfolio costs were also considered for acceptability with respect to rate impact before finalizing the portfolio" (Exhibit B-6, BCUC 1.4.7).

Each of the projects was segregated into four quadrants across value and deferral risk by grouping the projects according to fourth quartile scores where 25 percent of projects had a risk of deferral or overall value score lower than other projects. Thus projects in the fourth quarter represented both low risk and low value relative to the other projects and were generally deferred (Exhibit B-1, pp. 138-139).

However, there were 11 fourth quadrant projects that were not deferred. The reasons given for not deferring these projects were varied and are listed below:

	Project	**Reason for Not deferring**
1	Surge Arrestors	Risk to high value equipment
2	Seismic Upgrades Substations	Safety and system reliability
3	Seismic Upgrades Buildings	System reliability
4	Telecommunications	Favourable benefit cost
5	PLC Replacement	Reliability
6	Cathedral Square termination	Safety
7	Transmission Arcing Horn	Reduced OM&A
8	Disconnect Switches	Reliability
9	Rights Acquisition	Maintenance and Operation
10	Establish Circuit ratings	Reliability and safety
11	Second Narrows Seismic Upgrade	Reliability

Most BCTC projects were ranked by the prioritization methodology numerically from 3 to 20. Rankings 1 and 2 were reserved for two projects described as mandatory because of legislative and NERC reliability standards. Separate justifications were then given for individual projects (Exhibit B-1, pp. 213-253).

When asked to compare its prioritization approach to the approach BC Hydro used in its 2006 IEP/LTAP, BCTC stated it was unable to do so because it did not have sufficient information to understand BC Hydro's prioritization process (Exhibit B-6, BCUC 1.29.3).

BCTC was also asked to provide the detailed analysis behind the Walters Substation prioritization process, including all working papers, studies and analyses and spreadsheets employed in electronic format, and in particular the same information for each of the alternatives to Walters that it had considered which BCTC states were: (1) do nothing, (2) install a second transformer at Cypress substation, (3) a distribution alternative and (4) load curtailment. BCTC stated that it was unable to provide a working spreadsheet for this analysis as it was based on the Prioritization Model which is proprietary. BCTC provided a detailed explanation of the calculation of both the value and risk scores for Walters, but did not provide the same analyses for the alternatives considered, nor was any other information provided (Exhibit B-6, BCUC 1.38.1).

Commission Determination

The Commission Panel is concerned that the Prioritization Model used by BCTC is proprietary, despite the requirements of its RFP that all work performed become the property of BCTC. Not being able to provide the model seriously impairs the transparency of the prioritization process and further impedes understanding of the methodology employed. BCTC should be aware, based on past Commission decisions, of the Commission's concerns that models brought forward to the Commission not be viewed as "black boxes". The Commission Panel does recognize that, in some circumstances, proprietary interests are paramount to the public interest in full disclosure. In this Decision, the Commission Panel has not made a decision regarding whether or not the Prioritization Model should be disclosed in future proceedings. For the purposes of this Decision, the information provided in the information request process is adequate. The Commission Panel notes that, while BCTC states that its new prioritization methodology is a significant development, it failed in the Application to provide the information necessary to understand the model, and that some of the required basic information was only revealed by the information request process.

The above comments not withstanding, the Commission Panel believes that BCTC has made significant progress and agrees with BCTC that this is a process which will improve and be fine-tuned over time. However, the Commission Panel believes more information on the methodology and assumptions are required.

Therefore, the Commission Panel directs BCTC to file a report that could be described as the "operator's manual" for the Prioritization Model. This report should contain all weightings and probabilities for each category and criteria and any sub criteria, as well as a full description of the methodology employed in determining the weights and probabilities. The report should describe key assumptions, particularly those used to derive values as a result of a judgment process, as opposed to quantitatively. The report should contain a detailed example, including all numeric calculations for at least one project in each of the Growth, Sustaining, or BCTC Capital Portfolios. If BCTC cannot provide the information for proprietary reasons, it is encouraged to select examples from the beta testing of the model. The report should be filed with the next capital plan.

The Commission Panel believes a key part of the capital planning process is the consideration of alternatives to a project, as well as, once the preferred alternative has been selected, the prioritization of the project relative to other projects. The Commission Panel is concerned that BCTC did not provide an example of the consideration of alternatives by the prioritization methodology. **Therefore, the Commission Panel directs BCTC to include in its next capital plan filing, tables for each of the Portfolios listing the projects brought for approval, their risk and value scores by category, and the priority numbers and quadrant values, where applicable. 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.**

The Commission Panel notes that many of the quadrant four sustaining projects that were not deferred appear to be justified not on the model results but for safety or reliability considerations. This suggests to the Commission Panel that there may be threshold values for the safety and reliability metrics beyond which projects become mandatory much as they currently become mandatory for legislative or NERC reliability reasons. **The Commission Panel directs BCTC to comment on this issue in the next capital plan.**

The Commission Panel does not agree with BCTC's assertion that its Corporate Risk Matrix is not applicable at the stage at which capital projects are brought forward to the Commission. **Since corporate risks may ultimately be reflected in costs which will impact rates, BCTC is directed to include its Corporate Risk Matrix in its next capital plan filing.**

The Commission Panel notes that the prioritization methodology may change, but believes comment on the specific area of rate impacts is useful. BCTC acknowledges that its rate impact calculation does not consider revenues and thus will not be accurate. Since a growth project by definition results from an anticipation of growth, the Commission Panel is concerned that BCTC cannot estimate the likely revenues, and hence includes in the heavily weighted financial category, a value for rate impact which it knows to be inaccurate. **The Commission Panel encourages BCTC to comment on this issue in its next capital plan.**

5.0 GROWTH CAPITAL PORTFOLIO

5.1 Key Drivers

The Growth Capital Portfolio is predominantly customer and volume driven, resulting in the need for significant capital investment to meet current and future transmission requirements as the robust economy continues to drive domestic load growth (Exhibit B-1, p. 25). These capital investments are directed towards bulk transmission system facilities used to transfer bulk amounts of capacity and energy between large generating stations, the major load centres and interconnections to other utilities, regional transmission system facilities, and substations or points of connection for loads or generators (Exhibit B-1, p. 59).

BCTC states that the key drivers include the need to integrate new generation resources, including IPPs, involving both interconnection and network upgrade costs. Most of the existing transmission system capacity has been consumed by past growth, resulting in significant growth in bulk system investments such as the VITR project, the ILMTR project and reinforcements in the South Interior transmission system. A higher level of area reinforcements, required largely by existing demand and forecast load growth as well as planned and forecast IPPs, is driving most of the increase over the F2006 Application, and is expected to continue over the next five years with major reinforcements to Central Vancouver Island, Golden, North Thompson and Metro Vancouver areas. This will also be affected by an increase in the IPP work level in response to BC Hydro’s current and planned calls (Exhibit B-1, p. 83).

5.2 Load Forecasts used for Planning Studies

BCTC used BC Hydro’s 2005 Load Forecast as contained in the LTAP as the basis for its Application. BCTC states that in the event the LTAP changes, BCTC will accelerate or defer projects to accommodate revision to the forecast (Exhibit B-1, p. 29).

Commission Determination

The Commission Panel agrees that it is reasonable to base the F2008 TSCP on the Load Forecast contained in BC Hydro's LTAP. The Commission Panel notes that this forecast, and updates, were reviewed in detail during the 2006 IEP/LTAP hearing process.

However, for many of the individual projects, it would be useful to understand the recent load growth rates, as well as forecast future growth, relative to growth in the planning region. **Therefore, the Commission Panel directs BCTC to include in future capital plans a summary table by project, showing the average load growth for the most recent five historical years, preferably weather normalized if possible, and the growth rates projected for future years. The table should also show the planning region in which the project resides and the regional load growth rates for the same periods. If there is significant divergence between the load growth rate upon which the project need is determined, and that of the planning region, BCTC is to provide an explanation of the divergence.** The Commission Panel expects that, where required, explanations should be available to BCTC from BC Hydro, and that no analysis by BCTC will be required.

5.3 Criteria for when Transmission should be Expanded

In the past, BCTC relied primarily on deterministic planning criteria to determine when upgrades or expansions of the transmission system were required, but as discussed in Section 2.2 of this Decision, BCTC has begun to rely on probabilistic analysis to a greater extent. Furthermore, in the F2006 TSCP Decision, BCTC was directed to include path utilization forecasts in its capital plans whenever transmission capacity upgrades are proposed. BCTC has developed and implemented a Path Utilization Forecast methodology to use where transmission capacity upgrades are proposed for major paths (BCTC Argument, pp. 15-16).

5.3.1 Transmission Congestion Relief Policy

In the 2007 Energy Plan announced on February 27, 2007, BCTC has been directed by the Government to ensure there is adequate transmission system capacity by developing and implementing a transmission Congestion Relief Policy (2007 Energy Plan, Appendix A, Policy Action 13). In addition, the Federal Energy Regulatory Commission ("FERC") recently issued Order 890 to address, among other concerns, the role of transmission providers in system planning, which includes assessing congestion impacts (Docket Nos.RM05-17-000 and RM05-25-000). These events, which may influence future capital plans filed by BCTC, occurred too late to be considered as evidence in this proceeding, but are significant nevertheless and will be addressed further in Section 8 of this Decision.

In response to the above initiatives, BCTC intends to develop the requested policy and bring the matter before the Commission once the consultations and assessment are concluded (BCTC Argument, p. 17; BCTC Reply, pp. 7-8).

BC Hydro supports development of a transmission Congestion Relief Policy and encourages BCTC to begin engaging with stakeholders in open planning forums as quickly as possible. Further, BC Hydro observes that the term congestion is used in the F2008 TSCP sometimes in reference to system availability, as a measure of system utilization, as a measure of BCTC's operational performance, or as a proxy for reliability. Accordingly, BC Hydro recommends that development of a definition for congestion should be part of the engagement process (BC Hydro Submission, p. 3).

The Commission Panel supports this initiative which is discussed further in Section 8 of this Decision.

5.3.2 Special Direction No. 9, Section 4 and Transmission Expansion Policy Paper

After issuance of the 2002 Energy Plan, the Government also expanded the mandate of the BCUC by issuing SD9 to the Commission in November 2003. Section 4 of SD9 addresses the topic of new transmission system capital investment without committed contracts and empowers BCUC to determine whether those expenditures are justified on the basis of the future benefits to be derived from the proposed expenditures and may be recovered in current rates.

Pursuant to Order No. G-58-05, concerning the OATT and to the F2006 TSCP Decision, Directive 4, in December 2005, BCTC submitted to the Commission a discussion paper called "Evaluation Methodology for Considering Transmission System Expansion Without Committed Contract". This document is also referred to as the "Transmission Expansion Policy Paper". BCTC further states that following the release of the Transmission Expansion Policy Paper and the Commission's response, BCTC continued to work closely with stakeholders throughout 2006 and will continue to consult the IPP community on Transmission Expansion Policy ("TEP") implementation and convey the feedback to the Transmission Planning Advisory Council ("TPAC"). All these activities are expected to lead to the 2007 BCTC Public Planning Forum (Exhibit B-1, pp. 260-261).

BCTC outlines its TEP in more detail in the 2006 STSR. Specifically, BCTC asserts that through this initiative it is attempting to proactively address the challenges associated with managing different timeframes to develop transmission resources to support planned and potential generation, and BCTC's role in making the transmission system available to capture electricity market opportunities (Exhibit B-1, Appendix B, p. 58).

BCTC expects that under SD9 it could advance projects in the following three areas:

- Projects supporting development of generation in B.C.;
- Projects that restore or enhance existing capacity; and
- Projects that expand import/export capacity (Exhibit B-1, Appendix B, p. 58).

BCTC stated that it will review all significant Growth Capital projects that can be advanced in time, increased in size or reconfigured to determine if beneficial capacity could be created by undertaking such advancement, size increase or reconfiguration. Where such changes are determined to be beneficial, BCTC will include the altered project in its capital plan and will clearly identify the project as being altered under SD9, will identify the incremental cost of the alteration, and will identify the benefit-cost analysis underlying the proposed alteration. In such cases, BCTC will proceed with such changes to the base project only where it has received all necessary regulatory approvals to do so (Exhibit B-6, BCUC 1.36.1, Attachment 1, pp. 7-8).

BCTC also proposed a process whereby it could use its unique perspective on the market to suggest, review and develop "BCTC-led" transmission investments that could produce electricity market benefits, but for which there was little or no opportunity for customer funding. Where such projects are submitted for regulatory approval, BCTC will clearly identify the project as being proposed under SD9, will identify the portion of the project, if any, that is being funded by a requesting customer or cluster of customers, and will identify the benefit-cost analysis underlying the proposed project (Exhibit B-6, BCUC 1.36.1, Attachment 1, p. 9).

Projects that BCTC states it is considering under SD9 include reinforcing transmission on northern Vancouver Island, in the Lillooet-Harrison Lake corridor, and on the Sunshine Coast, installing additional equipment at the Meridian and Nelway substations, and creating new or stronger interties to neighbouring systems in Alaska, northern and southern Alberta, and the U.S. (Exhibit B-1, Appendix B, p. 58; BCTC Reply, para. 32). At the present time, BCTC is not proposing any facilities pursuant to SD9 (Exhibit B-1, p. 63).

IPPBC states that facilities to provide transmission service to IPP's in "cluster areas" could be developed in accordance with BCTC's OATT and/or through the capital plan process and notes the considerable overlap between the two avenues (IPPBC Submission, p. 2). IPPBC believes BCTC is not taking advantage of any such opportunity and has reservations about the effectiveness of OATT clustering and open season procedures. In fact, argues IPPBC, more progress should have been made in the period following the development and review of the TEP (IPPBC Submission, p. 3).

After highlighting the difficulties experienced by IPPs in proposing development of generating projects in areas where there are no transmission facilities and responding to BC Hydro calls for supply of electricity, IPPBC states that BCTC should move immediately to implement its TEP and report back to the BCUC within two months. Otherwise, observes IPPBC, it will be impossible to meet the intent of SD9 prior to the 2007 Call and possibly even the 2009 Call (IPPBC Submission, p. 6).

BCTC states it does not believe that IPPBC's submission accurately portrays the steps that BCTC has taken pursuant to SD9 and the introduction of its TEP (BCTC Reply, para. 31). BCTC acknowledges the challenges associated with managing different timeframes to develop transmission resources to support planned and potential generation. BCTC argues it is aware of its role in dealing with these challenges as well as of its role in attempting to ensure that the transmission system is available to capture market opportunities (BCTC Reply, para. 32). BCTC confirms that it has identified market access, including the consideration of transmission system investments under the TEP, as one of its five Key Strategic Issues (Exhibit B-1, p. 22).

BCTC opposes IPPBC's submission that BCTC move forward immediately to implement its TEP and report back to the Commission within two months because that is too short a time to integrate considerations resulting from the 2007 Energy Plan and other changes in the transmission planning environment, and would not offer an opportunity for consultation with stakeholders (BCTC Reply, para. 36).

Commission Determination

The Commission Panel acknowledges the significant effort BCTC has expended in stakeholder consultation in conjunction with the TPAC and in development of the TEP as a vehicle for strategic investment. The Commission Panel also observes that market access, including the consideration of transmission system investments under the TEP has been escalated to a level of strategic importance by the Senior Executive and the Board of BCTC. At the same time it notes that the F2008 TSCP, which was filed over three years after the issuance of SD9, does not include a proposal and justification for even a single facility pursuant to SD9. The Commission Panel, while being mindful of the long-term interests of ratepayers, supports the goal of an open transmission grid with transparent access and available transmission capacity. The Commission Panel notes that BCTC continues consultation regarding issues raised in the TEP, including how to identify and evaluate potential TEP projects. **The Commission Panel directs BCTC to prioritize potential TEP projects with other projects using the Prioritization Model.** The Commission Panel acknowledges that the Prioritization Model may need to be modified to accommodate the benefits contemplated in the TEP. **The Commission Panel directs BCTC to report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. In the event that BCTC identifies a potential TEP project and then decides that the project should be implemented, BCTC should seek approval of the project prior to the next capital plan.**

5.4 Interconnection Expansion with Alberta and the U.S.

The BCTC transmission system is interconnected to the transmission systems in Alberta and Washington State. The TTC for each intertie is determined in two ways. A WECC path rating process establishes the maximum permitted transfer capability based on certain WECC criteria, and BCTC also continually calculates the TTC based on similar NERC/WECC criteria and uses this to set the hourly operational limit (which cannot exceed the WECC path rating) (Exhibit B-1, Appendix B, pp. 23-24).

The B.C.-Alberta intertie consists of one 500 kV line and two 138 kV lines. Transient stability limitations require that on a contingency of the 500 kV line, that the two 138 kV ties be tripped, except during low transfer conditions. As a result, the intertie is effectively limited to the capacity of only the 500 kV line at most transfer levels (Exhibit B-1, Appendix B, p. 24).

The B.C.-U.S. intertie consists of a Westside Intertie with two 500 kV lines in parallel, and an Eastside Intertie with two 230 kV lines, one of which can be switched between the U.S system and the BCTC system, and is normally connected to the BCTC system. There is often little or no ATC on the Eastside Intertie because of grandfathered scheduling rights across this path, and nominated returns of CE. The B.C. to U.S. path rating is transient stability limited under low load conditions, but can also be reduced during heavier load and outage periods. The U.S. to B.C. path rating is based on the outage of one of the parallel 500 kV lines, and may be reduced during low BC Hydro generation conditions to prevent unacceptable frequency dips for loss of the import path (Exhibit B-1, Appendix B, pp. 25-26).

The maximum theoretical ratings of the interties for inflows into the BCTC system are lower than the outflow ratings for the same paths (Exhibit B-6, BCUC 1.136.1), and data provided by BCTC shows that the interties are considerably more congested for inflows (into the BCTC system) as compared to outflows (out of the BCTC system) (Exhibit B-1, Appendix B, p. 91, Table 8.1).

BCTC states that it monitors and performs studies on projects involving or in neighbouring systems that could affect the BCTC transmission system. Such projects include the Juan de Fuca project, the Montana-Alberta Tie project, and other projects in neighbouring WECC member systems (Exhibit B-1, Appendix B, pp. 53-57).

IPPBC states that the TSCP does not adequately cover the issue of expansion of the transmission interties with Alberta and the U.S. and claims that as more generation is developed in B.C., there is going to be a need to increase the capacity of the interties. IPPBC submits the planning for this should commence immediately (IPPBC Submission, p. 6).

BCTC states that it has identified market access, including the consideration of transmission system investments under the TEP, as one of its five Key Strategic Issues. BCTC lists several intertie expansion projects among the projects being considered under the TEP, including the installation of a new phase-shifting transformer at Nelway to increase capacity on the Eastside Intertie with the U.S., an interconnection with Alaska, a B.C.-Alberta Northeast intertie, enhancing the B.C.-Alberta Southern intertie capacity, and a new Southeast B.C.-U.S. intertie (BCTC Reply, para. 32).

Commission Determination

The Commission Panel acknowledges that assessing investments to increase intertie transfer capability is complex and requires significant consultation with a variety of stakeholders, including those in the neighbouring systems. The Commission Panel acknowledges BCTC's activities in pursuing such opportunities within the framework proposed by the TEP, and in Section 5.3 of this Decision has directed BCTC to prioritize potential TEP projects with other projects using the Prioritization Model. **The Commission Panel directs BCTC to provide a detailed description of the highest ranked intertie expansion project in the next capital plan. The description should include, if possible, the identification and quantification of potential benefits accruing to ratepayers.**

The Commission Panel endorses BCTC's continued diligence in monitoring and studying projects involving or in neighbouring systems that could affect the BCTC transmission system.

5.5 South Interior Bulk System Development Plan

In the F2006 TSCP Decision, BCTC was directed to submit a comprehensive system development plan for the South Interior Bulk System. The South Interior SDP is Appendix C of the Application.

A number of upgrades and reinforcements are identified in the South Interior SDP, including a fourth transformer at Selkirk substation, two 500 kV, 250 MVAr mechanically-switched shunt capacitors at the Ashton Creek substation, series compensation of the 500 kV lines between Selkirk substation and Ashton Creek substation (5L91) and between Vaseux Lake substation and Nicola substation (5L98), and a 500 kV, 250 MVAr mechanically-switched shunt capacitor at Nicola substation (Exhibit B-1, Appendix C, p. iii).

The addition of Revelstoke Unit 5 without additional system reinforcement will result in the transfer capability at the West of Selkirk cut-plane being at least 250 MW short by the summer of 2011. The shunt capacitors at the Ashton Creek substation are proposed to alleviate the shortfall in transfer capability caused by the addition of Revelstoke Unit 5 (Exhibit B-1, Appendix C, p. 19; Exhibit B-6, BCUC 1.115.3).

BCTC stated that although the fourth transformer at Selkirk substation would accommodate new generation in the area, the new generation did not drive the need for the project and the fourth transformer is needed to meet existing NITS usage and to eliminate existing generation shedding in the event of a transformer contingency at Selkirk substation. The cost of this project will be recovered through NITS, and new generation planned for the area will not be required to make any contributions towards the cost of the fourth transformer (Exhibit B-6, BCUC 1.54.1 and 1.54.2). Other reinforcement options that could be implemented to defer the need for the fourth transformer at Selkirk substation were shown to have a higher Net Present Value ("NPV") than that of the proposed option (Exhibit B-6, BCUC 1.55.1).

CPC agrees with the analysis and findings of the F2008 TSCP in relation to the current congestion on the South Interior Bulk System and the need for significant new transmission. CPC supports BCTC taking early action to implement its plan for the South Interior Bulk System in order to relieve congestion and enhance domestic and export market access (CPC Submission, pp. 2-4).

Commission Determination

The Commission Panel commends BCTC on the preparation of the South Interior Bulk System Development Plan report, and the supporting appendices, particularly the South Interior Transmission Path Utilization Forecast.

The Commission Panel notes that the Revelstoke Unit 5 project is driving at least part of the need for the Ashton Creek substation shunt capacitors. **For future capital plans, the Commission Panel directs BCTC to identify separately those projects and corresponding expenditures that are directly attributable to specific generation additions.**

The Commission Panel approves BCTC's request for a determination under Section 45(6.2)(b) of the Act that capital expenditures on the Selkirk 500/230 kV Transformer T4 Addition, the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors – Definition Phase, and the 5L91/5L98 Series Compensation – Definition Phase projects are in the public interest.

5.6 Mission and Matsqui Area Supply Project

BCTC received approval for the Mission and Matsqui Area Supply project under the F2006 TSCP Decision. The Commission received a letter from the District of Mission dated January 9, 2007, requesting that the Commission vary the F2006 TSCP Decision and direct BCTC to apply for a CPCN. The District of Mission filed a second letter dated March 1, 2007 to provide additional information. By letter dated March 5, 2007, the Commission denied the request of the District of Mission to vary the F2006 TSCP Decision, which would have resulted in a direction to BCTC to apply for a CPCN for all or part of the Mission and Matsqui Area Supply project. Instead, the District of Mission was encouraged to apply to the Commission for registration as a late Intervenor in this proceeding and make submissions on issues regarding the execution of the Mission and Matsqui Area Supply project (Exhibit A-3).

By letter dated March 5, 2007, the District of Mission applied for Intervenor status, and supplied the previous letters in support of its application. The substance of the District of Mission's concern with the Mission and Matsqui Area Supply project was that BCTC's current and proposed alignments for the transmission lines associated with the project were unacceptable from both economic and aesthetic perspectives (Exhibit C10-1).

BCTC stated that it had not changed the scope and routing for the transmission line portion of the project, and had responded to the District of Mission that the request to locate the transmission line on the bridge had been rejected by BCTC for cost increase and schedule risk considerations (Exhibit B-6, BCUC 1.10.2).

By letters dated March 30, 2007, both BCTC and the District of Mission reported that ongoing discussions were progressing well and moving in a positive direction. BCTC stated that should BCTC and the District of Mission reach an agreement on the routing of the transmission line, BCTC would apply to the Commission to find the revised project to be in the public interest. The District of Mission requested that the Commission provide a reasonable delay in the process, in order to finalize the details of agreement (Exhibit B-11; Exhibit C10-2).

By letter dated April 12, 2007, the Commission informed the District of Mission that it had concluded that the Regulatory Timetable for this proceeding should not be extended, and denied the request of the District of Mission for a delay.

The District of Mission states that it wants the transmission line portion of this project that it is concerned with installed on the Mission Bridge, and only on the Mission Bridge (District of Mission Submission, p. 2).

BCTC states that it is engaged in discussions with the District of Mission regarding the potential realignment of a portion of the 69 kV transmission facilities associated with this project in the vicinity of Mission, and that if BCTC and Mission are able to reach an agreement, BCTC will seek the Commission's approval of the revised project. BCTC is not seeking any order from the Commission in relation to the Mission and Matsqui Area Supply project as part of the F2008 TSCP proceeding (BCTC Reply, pp. 1-2).

Commission Determination

The Commission Panel accepts BCTC's proposal in its letter of March 30, 2007, that upon reaching an agreement with the District of Mission regarding the potential rerouting of a portion of the 69 kV transmission facilities associated with the Mission and Matsqui Area Supply project in the vicinity of Mission, BCTC will apply to the Commission to find the revised project to be in the public interest.

5.7 Response Regarding Kinder Morgan's TMPSE Project

In Order No. G-67-06, the Commission directed BCTC to address the JIESC's concerns with the existing regulatory process under which BCTC is asked to undertake a transmission system project in response to a Third-Party customer request directed to BC Hydro.

The JIESC was concerned that with the split of BC Hydro and BCTC into two separately regulated entities, the regulatory process that was in place to address substantial projects being built to serve an identifiable customer did not provide the Commission with the information it needed in order to an appropriate decision. Specifically, the JIESC commented that in cases where BCTC was applying for Third-Party customer-driven projects embedded in NITS applications, the Commission would be unable to examine the revenues, costs and necessary investments to fund the project and determine whether the utility's customer contribution policy had been appropriately applied. The JIESC proposed that this also put the Commission in the untenable position that it could approve the project on the basis of BC Hydro's NITS application to BCTC and then be faced with having to approve the project in the BC Hydro rate base, on the basis that the project was requested by BCTC and approved by the Commission. The JIESC submitted that the Commission must direct better integration of the regulatory process to ensure that the Commission and stakeholders have all the information they require with respect to a project, at the time approval is sought, so this situation is avoided (F2006 TSCP Update Decision, p. 12).

BCTC states that it has reviewed and considered the JIESC's concerns regarding the existing regulatory process under which BCTC is asked to undertake a transmission system project in response to a Third-Party customer request and believes that the existing tariffs and regulatory practices do not provide any significantly different way to address such a request than was undertaken in response to the TransMountain Pumping Stations Expansion ("TMPSE") project. BCTC acknowledges that while this response may not address the concerns expressed by the JIESC, it is prepared to respond to suggestions that attempt to arrive at a common resolution to this issue. BCTC notes that there are no projects in the F2008 TSCP that raise the same issue as the TMPSE project (Exhibit B-1, pp. 280-281).

BCTC suggested that instead of changing the existing process, it should be assumed that utilities comply with their approved tariffs and policies, and if information is brought to the attention of the Commission that calls into question whether a utility has complied with its approved tariff and policies, then a review by the Commission may be warranted. If a utility is found to have violated its tariff, the Commission can determine what, if any, sanctions against the utility may be appropriate (Exhibit B-6, BCUC 1.52.1).

BC Hydro submits that the better process is to allow the utilities to apply their approved tariffs to interconnection requests, whether the request is by an IPP or load customer and that a requirement for BCTC and BC Hydro to demonstrate tariff compliance for every load interconnection would create an unnecessary regulatory process, and could result in unnecessary delay for the load customer's interconnection (BC Hydro Submission, p. 3).

Commission Determination

The Commission Panel notes that there were two distinct concerns originally expressed by the JIESC. One concern was the Commission's inability to determine whether the utility's customer contribution policy had been appropriately applied for a Third-Party customer-driven transmission project embedded in a NITS application. A second concern was that on approving a specific project in BCTC's capital plan application, the Commission would be forced to approve the project for BC Hydro's rate base without having had the opportunity to fully examine the revenues, costs and necessary investments surrounding a Third-Party customer driven transmission project.

The Commission Panel is satisfied that both concerns are addressed by BCTC's submission that if information is brought to the attention of the Commission that calls into question whether a utility has complied with its approved tariff and policies, then a review by the Commission may be necessary. The Commission Panel notes that any expenditure can be the subject of a prudency review, whether on a complaints basis, the Commission's own volition, or as part of a revenue requirements process.

5.8 Projects for Which a CPCN Application 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. At this time, BCTC does not believe there is any reason to adjust the CPCN criteria (Exhibit B-1, p. 15).

BCOAPO agrees that no changes are required to BCTC's criteria for determining the need for a CPCN application (BCOAPO Submission, p. 2).

BCTC has proposed that it will likely file CPCN applications for the following projects described in the F2008 TSCP: (a) the Interior to Lower Mainland Transmission Reinforcement project; (b) the 5L91/5L98 Series Compensation project; (c) the Central Vancouver Island Reinforcement project (d) the Golden 69 kV System Reinforcement project; (e) the Metro Vancouver Supply Reinforcement project; and (f) the North Thompson 138 kV System Reinforcement project. Although it is yet to be determined, the NTL project may also be the subject of a CPCN application if it proceeds (Exhibit B-6, BCUC 1.7.1).

5.8.1 Interior to Lower Mainland Transmission Reinforcement Project

The ILMTR project is currently in the Definition Phase as previously approved by Order No. G-103-04. Although Definition Phase work is currently scheduled to be completed in F2010, a preferred solution is expected to be identified in May 2007 (Exhibit B-1, p. 47). Following the completion of the Definition Phase, Implementation Phase approval will be sought, with the timing dependent on the resolution of BC Hydro's resource plans (Exhibit B-1, p. 99).

The earliest in-service date for this project is October 2014, and BCTC stated that this could not be delayed by uprating other components in the ILM transmission path because the in-service date was determined by assuming all practical upgrades had been implemented (Exhibit B-6, BCUC 1.117.1).

The options for the ILMTR project were compared in the System Impact Study For BC Hydro Distribution NITS 2004 – Stage 3 (Final) Report. In that report, the Nicola substation to Meridian substation transmission line (5L83) is identified as the preferred option (Exhibit B-6, BC Hydro 1.3.5, Attachment 1).

5.8.2 5L91/5L98 Series Compensation Project

The need for and characteristics of the 5L91/5L98 Series Compensation project is described in the South Interior Cut-Plane Reinforcement Justification Report (Exhibit B-1, Appendix C, Appendix 1). The Southern Interior Bulk System is congested, and the congestion will increase with higher CE amounts delivered to the Nicola substation and/or the addition of new generation in the South Interior area. The increased congestion can be relieved by adding relatively expensive series capacitor stations to the 500 kV lines between Selkirk substation and Ashton Creek substation (5L91) and between Vaseux Lake substation and Nicola substation (5L98) (Exhibit B-1, Appendix C, Appendix 1, p. 2).

Series capacitors are relatively expensive compared to other types of system compensation equipment, and have some small environmental and social impacts as the stations are usually installed near the middle of the line and require a modest amount of land. Due to the higher cost, more complex equipment and land requirement, the lead time for this type of project is longer than for other types of system compensation equipment, but this lead time can be reduced by doing Definition Phase work early (Exhibit B-1, Appendix C, Appendix 1, p. 14).

5.8.3 Central Vancouver Island Reinforcement Project

Two 138 kV lines from Dunsmuir substation to Jinglepot substation (1L115 and 1L116) supply Vancouver Island’s central coastal communities with an existing firm capacity of 195 MVA. BCTC states that peak demand is forecasted to exceed firm capacity by 6 MVA per circuit in F2009, and that over the next twenty years, the capacity shortfall is forecasted to grow to 300 MW to 400 MW. The combination of some Remedial Action Scheme (“RAS”) based line tripping and retermination of the 138 kV load of Sidney substation is forecast to address this issue until F2009, but a long-term solution to address forecast requirements on Central Vancouver Island needs to be put into place.

Several alternative solutions are being considered including a 230 kV transmission line from nearby 230 kV lines to the Jinglepot substation where it would be transformed to 138 kV, an additional 138 kV transmission line from Dunsmuir substation to Jinglepot substation, or upgrading the existing lines (Exhibit B-1, pp. 106-107).

The studies for the Central Vancouver Island Reinforcement project are ongoing and a preferred option has not yet been selected. The location and the route of the new transmission line for the option based on the new 230 kV transmission line to Jinglepot substation are still being assessed (Exhibit B-6, BCUC 1.8.3). Depending upon the nature, cost and stakeholder concerns associated with the proposed solution, a CPCN application may be required (Exhibit B-1, Appendix B, p. 43).

5.8.4 Golden 69 kV System Reinforcement Project

The supply to Golden may require reinforcement to meet forecast growth in demand, however BCTC is re-examining the forecast basis (Exhibit B-1, p. 111). BCTC has identified several options and alternatives if reinforcement is found to be necessary. These options and alternatives are: (a) construct a 230 kV transmission line from Invermere substation to a new substation in the vicinity of Golden; (b) develop 230/138 kV transformation at Invermere substation and construct a 138 kV transmission line from Invermere substation to a new substation in the vicinity of Golden; (c) develop 230/138 kV transformation at Invermere substation, construct a 138 kV transmission line from Invermere substation to Spillamacheen substation, cut and tie the new construction to the 138 kV-rated section of the existing 69 kV transmission line from Spillamacheen substation to Golden substation, and convert Golden substation to 138 kV or develop a new substation in the vicinity of Golden; (d) construct a second 69 kV transmission line from Invermere substation to Golden substation; (e) install static compensators and capacitor banks at Golden to maximize the supply capability of the existing system; (f) install peaking diesel generators or an energy storage system; or, (g) rely on IPP development in the Golden area (Exhibit B-6, BCUC 1.123.1).

5.8.5 Metro Vancouver Supply Reinforcement Project

BCTC was previously directed to file CPCN applications for projects involving Metro Vancouver 230 kV supply projects, and was specifically directed to include the Sperling Feeder Section Addition project in this Application (Reason for Decision accompanying Order No. G-103-04, p. 31; F2006 TSCP Update Decision, p. 13). BCTC determined that the Sperling Feeder Section Addition project was entirely a Substation Distribution Asset, and claims that it is the responsibility of BC

Hydro to seek approval from the Commission, and thus the project has been omitted from the F2008 TSCP (Exhibit B-1, p. 280).

BCTC has identified a number of potential projects for the Metro Vancouver area, but has not identified any specific initiatives to be the subject of a CPCN application. Projects in the Metro Vancouver area for which approval has been requested in this Application include a clearance upgrade to two 60 kV transmission circuits serving New Westminster (60L60 and 60L67), a capacity upgrade at Kidd No. 1 substation and a transformer addition a Walters substation (Exhibit B-1, Appendix B, pp. 31-32).

5.8.6 North Thompson 138 kV System Reinforcement Project

The portion of the South Interior regional system supplying load in the North Thompson area is already constrained and needs reinforcement to accommodate significant increases in industrial load. By early F2009, total load is forecast to increase by 47 percent over present levels. In order to supply this growth, substantial reactive power support is presently being installed (Exhibit B-1, p. 113).

BCTC anticipates applying for Definition Phase funding to address North Thompson reinforcement options in its F2009 capital plan (Exhibit B-1, Appendix B, pp. 39-40). Based on long-range planning studies undertaken several years ago, the most practical project at this time was identified as the construction of a 102 kilometre 230 kV transmission line from Hundred Mile House substation in the Central Interior area to Clearwater substation in the North Thompson Valley and the development of 230/138 kV transformation at Clearwater substation (Exhibit B-6, BCUC 1.84.1).

5.8.7 Northwest Transmission Line Project

The NTL project is currently not part of Growth Capital Portfolio. The NTL is a potential 287 kV transmission line from Terrace to Bob Quinn (335 kilometres), to meet future load growth requirements from mining projects, and allow interconnection of potential IPP projects. BCTC has conducted an aerial survey of the area, completed an environmental overview study and updated the potential customer load requirements. BCTC stated that the Provincial Government is currently considering if it has a role in facilitating the development of a transmission extension, and if so, what that role might be. To that end, the Provincial Government is working with BCTC and BC Hydro to investigate the potential for a transmission line extension, various cost-sharing arrangements with industry, ways to reduce regulatory risk, how best to pursue environmental and land-use approvals, and how to ensure the transmission line is available to meet industry's needs. BCTC observed that this does not change its normal obligations to consider transmission needs of regions and specific customers as required under its mandates and tariff and planning obligations (Exhibit B-6, BCUC 1.25.1).

Commission Determination

The Commission Panel is concerned with the timing of CPCN applications for projects identified in this Application. BCTC has previously been directed to provide a clear statement of where, in the overall identification, design, and construction process, it expects the Commission's approval of the need for a Growth Capital project (F2006 TSCP Decision, p. 6). The Commission Panel brings to BCTC's attention Appendix A accompanying Order No. G-70-06 which states utilities have an obligation to contribute to an efficient and effective regulatory process by the timely filing of applications, and reminds BCTC that any project expenditures, including contractual commitments made with third parties, in advance of regulatory approval are at risk of recovery through rates.

The Commission Panel notes that there are several projects in the Metro Vancouver area for which approval has been requested in this Application, however none of these projects appear to be directly related to the Metro Vancouver 230 kV Supply project for which BCUC has been directed to submit a CPCN application (Reasons for Decision accompanying Order No. G-103-04, p. 31).

The Commission Panel also notes that the need for and timing of the 5L91/5L98 Series Compensation project is at least partly dependent on BC Hydro's nomination and use of CE. The Commission Panel is concerned that the reliance on CE may not be possible given transmission constraints outside the BCTC system and that CE flows may be contributing to path congestion when they are not required for reliability purposes. **If and when BCTC submits a CPCN application for the 5L91/5L98 Series Compensation project, the Commission Panel directs BCTC to submit a study that analyzes and describes the anticipated amount of seasonal and hourly reliability-driven Canadian Entitlement utilization. In order to assist in the determination of whether or not the anticipated seasonal and hourly Canadian Entitlement utilization from the requested study is consistent or inconsistent with past utilization of the Canadian Entitlement, the Commission Panel also directs BCTC to provide historical data of the reliability-driven utilization of the Canadian Entitlement in a format that allows for a reasonable comparison to the anticipated seasonal and hourly Canadian Entitlement utilization.**

Several costly transmission projects, such as the Golden 69 kV System Reinforcement project and the North Thompson 138 kV System Reinforcement project have been proposed for areas currently served by single radial transmission lines. The Commission Panel encourages BCTC to consider the application of SD9 in such situations, and examine the feasibility of alternate routes to the remote ends of the radial lines, rather than paralleling existing transmission lines.

5.9 BC Hydro Request Regarding ILMTR and Ingledow SVC

BCTC states that it is not re-filing its request for approval of Definition Phase funding for the Ingledow Static VAr Compensator (“SVC”) project (Exhibit B-1, p. 269). In the F2006 TSCP Decision, BCTC had been directed that in re-filing for approval of Definition Phase funding for this project, it was to provide either a justification for the project that addressed various issues identified by the Commission Panel in that proceeding, or a plan to develop the justification and a statement as to why the associated costs should be capitalized (F2006 TSCP Decision, p. 37).

BCTC stated that the potential addition of shunt capacitors in the Lower Mainland area and modification of line drop compensation settings on Burrard Thermal Generating Station units are among the future BCTC options that would provide sufficient reactive power at a capital cost that is much less than an SVC in the Lower Mainland. However, BCTC stated its intent to undertake a comprehensive review of the Lower Mainland reactive power requirements following the approval of BC Hydro’s LTAP base resource plan and CRPs (Exhibit B-6, BC Hydro 1.5.1).

BC Hydro is concerned that BCTC may not complete its comprehensive review of the Lower Mainland reactive power requirements in time for the Ingledow SVC project to be included in BCTC's next capital plan application. BC Hydro requests that BCTC address the need for an Ingledow SVC in its next capital plan application, specifically taking into account certain benefits identified by BC Hydro (BC Hydro Submission, p. 5).

BCTC states that it will attempt to have the Lower Mainland reactive power analysis completed by its next capital plan, and that the analysis will take into account the benefits identified by BC Hydro (BCTC Reply, para. 21).

Commission Determination

The Commission Panel directs BCTC to submit as part of its next capital plan a report that provides an analysis of, and a proposal for, the Lower Mainland's reactive power requirements. This report should describe and attempt to quantify the various benefits associated with the options for the Lower Mainland's reactive power requirements, and also contain a comprehensive description of the planning assumptions used in the analysis. If BCTC recommends that the Ingledow SVC is the preferred option and requests approval of Definition Phase funding, the Directives from the F2006 TSCP Decision remain applicable.

5.10 Balance of the Growth Capital Portfolio

The projects in the Growth Capital Portfolio are separated into the following categories as defined by the key drivers: Bulk System Reinforcements, Area Reinforcements, Station Expansion and Modification Projects, Customer Requested Projects, and Independent Power Producer Interconnections.

5.10.1 Bulk System Reinforcements

BCTC identifies F2008 expenditures for the following Bulk System Reinforcement projects, and requests approval for the projects designated as such (Exhibit B-3, p. 77):

Bulk System Reinforcements (Thousands of Dollars)	**Prior Years**	**F2008 Cost**	**Total Project**	**Approval**	**Original Approval**
ILM - Interior to Lower Mainland Reinforcement - Definition Phase	5,811	8,439	21,976	G-103-04	15,700
Nicola 500 kV Station Reconfiguration - Definition Phase		100	249	G-91-05	214
Selkirk - 1x123 MVAr, 500 kV Shunt Reactor	19	211	4,961	G-103-04	6,103
Vancouver Island Transmission Reinforcement	31,160	60,312	248,800	C-4-06	238,500
Selkirk 500/230 kV Transformer T4 Addition	27	1,396	17,756	Section 5.5	
Ashton Creek 2x250 MVAr, 500kV Shunt Capacitors - Definition Phase		253	253	Section 5.5	
5L91/5L98 Series Compensation - Definition Phase		1,400	1,600	Section 5.5	
Vancouver Island – RAS	50	1,200	1,850	Sought	
Provision for Unidentified Remedial Action Schemes		500	1,000	Sought	
Subtotal Bulk System Reinforcements		73,811			

BCTC identifies both the Nicola 500 kV Station Reconfiguration – Definition Phase project and the Selkirk – 1x123 MVAr, 500 kV Shunt Reactor project as being delayed. The Nicola 500 kV Station Reconfiguration – Definition Phase project is delayed 24 months due to engineering resource constraints (Exhibit B-1, p. 85, Table 5-3).

5.10.2 Area Reinforcements

BCTC identifies F2008 expenditures for the following Area Reinforcement projects, and requests approval for the projects designated as such below (Exhibit B-3, p. 78):

Area Reinforcements (Thousands of Dollars)	**Prior Years**	**F2008 Cost**	**Total Project**	**Approval**	**Original Approval**
Fox Creek Substation - Fort St. John Area Reinforcement	28,696	163	28,859	G-91-05	17,986
Golden 69 kV Capacitor Bank Additions	6	1,492	1,498	G-67-06	1,810
Highland Valley 138-69 kV Transformer (T1) Replacement	46	380	3,908	G-103-04	4,380
Mission and Matsqui Area Supply	9,549	31,893	41,442	G-91-05	43,205
1L10 and 1L11 Thermal Upgrade	15	500	515	Sought	
60L60 and 60L67 Clearance Upgrade	20	580	600	Sought	
Retermination of 60 kV Supply to Keating	26	60	13,607	Sought	
Central Vancouver Island Reinforcement Project - Definition Phase		1,500	2,500	Sought	
Salmon Arm Substation 230-138 kV T4 RAS	6	133	139	Sought	
Vernon Substation Transformer T11 Protection Upgrade	5	216	221	Sought	
Subtotal Area Reinforcements		36,918			

BCTC identifies both the Golden 69 kV Capacitor Bank Additions project and the Highland Valley 138-69 kV Transformer (T1) Replacement project as being delayed from their original forecast in-service dates (Exhibit B-1, p. 85, Table 5-3).

BCTC provided an explanation for the cost overrun of the Fox Creek Substation – Fort St. John Area Reinforcement project ("Fox Creek Project"). Specifically, substation costs increased by $3.927 million due to the installation of a second power transformer for reliability and increased cost estimates developed through detailed engineering. Transmission Line costs increased by $4.497 million due to development of engineering estimates during the Implementation Phase of the project, together with route location assumption changes and First Nations accommodation that was not anticipated at the time planning level estimates were developed. Further cost escalation of $2.509 million was attributable to general construction and material cost increases (Exhibit B-6, BCUC 1.76.1).

BCTC submits the cost increase reflects the ongoing progress in the planning of individual projects, and in this case reflects a situation where project approval was sought before all project characteristics were defined. BCTC acknowledges that parties may or may not feel that this is an adequate explanation for the variance between the original estimate for the Fox Creek Project and the final cost of the project, but that if they do not, BCTC is not attempting to have the Commission pre-judge this issue, which can be further pursued through a prudency review (BCTC Argument, p. 7).

5.10.3 Station Expansion and Modification

BCTC identifies F2008 expenditures for the following Station Expansion and Modification projects, and requests approval for the projects designated as such below (Exhibit B-1, p. 79):

Station Expansion and Modification (Thousands of Dollars)	**Prior Years**	**F2008 Cost**	**Total Project**	**Approval**	**Original Approval**
Cathedral Square third 230-12 kV Transformer	141	446	12,262	G-91-05	7,275
Murrin Fault Level Reduction – 230-12 kV Murrin Transformer Replacement	984	6,982	7,966	G-67-06	8,076
Oyster River 132-25 kV Transformer Addition	34	704	3,439	G-67-06	3,000
Seventy Mile House 69-25 kV Transformer Addition	3	31	2,544	G-91-05	1,205
Chetwynd Transformer Replacement of T1 and T2	528	3,122	3,650	Sought	
Colwood 138-25 kV Transformer Addition	69	1,978	7,513	Sought	
Grief Point Station Upgrade	241	300	3,272	Sought	
Gavin Lake 66-25 kV Transformer and Feeder Network Upgrade		1,415	1,992	Sought	
Hope - 25 kV Conversion	162	2,539	2,701	Sought	
Kidd#1: Add Capacity	409	1,000	10,409	Sought	
Sechelt Transformer Replacement	51	548	4,993	Sought	
Shawnigan Lake Transformer Replacement	47	4,004	5,472	Sought	
Walters Transformer Addition	39	3,879	5,056	Sought	
Westbank Substation 138-25 kV Transformer Replacement	17	1,950	2,680	Sought	
Subtotal Station Expansion and Modification		30,735			

Several of the projects for which approval is sought have already incurred substantial costs prior to F2008. In the case of the Chetwynd Transformer Replacement of T1 and T2, $528,000, or fourteen percent of the total costs have already occurred.

BCTC identifies the Cathedral Square third 230-12 kV Transformer project, the Seventy Mile House 69-25 kV Transformer Addition project, and the Murrin Fault Level Reduction – 230-12 kV Murrin Transformer Replacement project as being delayed from their original forecast in-service dates (Exhibit B-1, p. 85, Table 5-3).

The Cathedral Square third 230-12 kV Transformer project is both delayed and increased in cost because of a fundamental change in scope regarding the unsuitability of equipment originally identified for the project (Exhibit B-6, BCUC 1.78.2).

Approval was sought for the Seventy Mile House 69-25 kV Transformer Addition project based on a planning level estimate. BCTC stated that the current estimate has an accuracy of +/- 10 percent. The delay in the project in-service date is attributable to a changed load forecast and longer equipment delivery lead-times (Exhibit B-6, BCUC 1.5.1 and BCUC 1.79.1).

5.10.4 Customer Requests

BCTC identifies F2008 expenditures for the following Customer Requested project (Exhibit B-3, p. 80):

Customer Requested Projects (Thousands of Dollars)	**Prior Years**	**F2008 Cost**	**Total Project**	**Approval**	**Original Approval**
Kinder Morgan Canada TMPSE Project	35,304	16	35,320	G-67-06	34,584
Subtotal Customer-Requested Projects		16			

5.10.5 Independent Power Producer Interconnections

BCTC identifies F2008 expenditures for the following IPP Interconnection projects, and requests approval for the project designated as such below (Exhibit B-3, p. 80):

Independent Power Producer Interconnections (Thousands of Dollars)	**Prior Years**	**F2008 Cost**	**Total Project**	**Approval**	**Original Approval**
Forest Kerr IPP		500	34,710	G-103-04	27,541
Ashlu Creek Water IPP - Supply Construction Load	586		586	Sought	
Ashlu Creek Water IPP - Interconnection		3,808	3,908	Future	
Future IPP's - Direct Assignment		2,750	99,250	Future	
Future IPP's - Network Upgrades		5,000	196,800	Future	
Subtotal Independent Power Producer Interconnections		11,558			

BCTC identifies the Forest Kerr IPP project as being delayed from the original forecast in-service date because of delays with the IPP (Exhibit B-1, p. 85, Table 5-3). BCTC noted that the Facilities Agreement is outstanding (Exhibit B-6, BCUC 1.5.1).

Commission Determination

The Commission Panel is concerned about delays in projects which have been approved, particularly where those delays are due to resource constraints, be they internal or external, because such delays may negatively impact reliability or result in an inability to meet the particular need intended to be met by the project. Delays caused by decreased load forecasts or similar deferments in need are appropriate and will lower customer rate impacts. Therefore, the Commission Panel encourages BCTC to delay projects when appropriate to do so. However, a large number of deferred projects may be considered indicative of shortcomings in the planning process, as discussed in Section 3.2 of this Decision. The Commission Panel notes that the instances of significant expenditures on Station Expansion and Modification projects prior to approval may lead to similar concerns about the planning process, albeit for seemingly accelerated expenditures outside of the structured capital planning process rather than for the seemingly unplanned deferral of expenditures.

The Commission Panel notes the costs of several projects have exceeded their originally approved amounts. In the cases of the Fox Creek Project, the Cathedral Square third 230-12 kV Transformer project, and the Seventy Mile House 69-25 kV Transformer Addition project, the approved amounts were based on scopes that were inadequately defined at the time that approval was requested. Subsequent scope refinement caused the costs to increase.

However, the explanation provided for the Fox Creek Project brings into question whether or not the project scope and cost were adequately defined at the time approval was requested, and whether the subsequent changes to scope were appropriate. The Commission Panel concludes that a report on this project will be helpful both from an ongoing capital planning perspective, and to assess whether or not a prudency review is necessary. **The Commission Panel directs BCTC to submit by September 30, 2007, a report for the Fox Creek Project detailing changes to project scope, schedule and cost between the request for approval and the completed project. The report should explain and justify changes to the project scope and schedule, provide explanations for all material cost variances, and include a discussion of changes to its capital planning process that BCTC has implemented or recommends based on experience with this project.**

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 F2008 TSCP are in the public interest.

6.0 SUSTAINING CAPITAL PORTFOLIO

6.1 Key Drivers

The Sustaining Capital Portfolio is driven by the need to invest capital in the maintenance and replacement of existing transmission assets, to ensure that reliability, safety and environmental standards are maintained. To address the needs of an ageing infrastructure, BCTC forecasts that the trend in Sustaining Capital expenditures will increase over the ten-year period relative to the F2006 Application. This change reflects the addition of inflation and a higher level of planned work as BCTC continues to refine its planning approach to manage asset demographics (Exhibit B-1, p. 25).

The overall objectives of the Sustaining Capital Portfolio are maintaining reliability at current levels or slightly better, achieving low lifecycle costs for the assets, addressing known safety and environmental issues, and managing low probability, high impact risks. The key parameters of these objectives are the performance, condition, maintainability, exposure to external risks (earthquake, fire, severe weather) and lifecycle costs of the transmission assets and the overall safety and environmental consequences of operating, maintaining and managing the transmission system.

The format for describing the Sustaining Capital Portfolio has changed from the format used in BCTC's F2006 Application. The F2006 Application consisted of six major programs: Protection and Control, Stations, Telecommunications, Underground and Submarine Cables and Oil Systems, Overhead Lines and Rights of Way. The Sustaining Capital Portfolio in this Application is categorized as eleven programs within two categories, Stations and Lines.

6.2 Stations Sustaining Capital Programs

The six programs within the Stations category for which approval is being sought for F2008 and F2009 expenditures are Auxiliary Equipment, Circuit Breakers, Other Power Equipment, Risk Mitigation, Protection and Control and Telecommunications. Approval is also being separately sought for a significant new project within the Circuit Breaker Program, which is the Horsey Gas-Insulated-Switchgear ("GIS") Replacement (Exhibit B-1, pp. 18-19; p. 135; p. 140).

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. 131; Exhibit B-6, BCUC 1.40.1).

Station Programs Expenditures (Millions of Dollars)	**F2008** (Nominal $)	**F2008 Real** (Inflation adjusted) F2007 $	**F2009** (Nominal $)	**F2009 Real** (Inflation adjusted) F2007 $
Auxiliary Equipment	4.9	4.7	7.0	6.4
Circuit Breakers	18.2	17.5	20.0	18.5
Other Power Equipment	3.2	3.0	6.5	6.0
Risk Mitigation	8.4	8.1	11.8	10.9
Protection and Control	9.3	8.9	9.3	8.6
Telecommunications	10.6	10.2	5.3	4.9
Station Programs Total	54.6	52.4	59.8	55.3

The inflation adjusted or real F2007 dollar expenditures for each year are calculated based on the results of an excerpt from an MMK Consulting Inc. ("MMK") report titled "Cost Trends in British Columbia Non-Residential Industry", dated September 22, 2006 (Exhibit B-6, BCUC 1.40.1), to facilitate the comparison of currently forecast expenditure levels to those approved in the F2006 TSCP Update Decision. The inflation forecast provided from the excerpt was 4 percent per year in each of F2008 to F2010, and 3 percent thereafter.

The 2006 MMK report was not provided or examined during this proceeding and the inflation forecast referred to is found in a footnote to a table in the information request response. The excerpt from the 2006 MMK report was not provided, nor was the methodology employed in calculating the forecast made available for examination (Exhibit B-6, BCUC 1.40.1). However, a previous report of the same title dated December 19, 2005 was provided in the BC Hydro 2006 IEP/LTAP proceeding as Exhibit B10-1, BCUC 2.372.1, Attachment 1. This latter document presented trends in Canada-wide electric utility construction price indices with respect to distribution systems, transmission lines, and substations. In each case the price indices appear to escalate by less than two percent per year (F2006 IEP/LTAP Exhibit B10-1, BCUC 2.372.1, Attachment 1, p. 9).

The total expenditure identified in BCTC's F2006 Update Application for the Protection and Control, Stations, and Telecommunications programs, which are considered to be equivalent to the Station programs in this Application was $45.1 million (Exhibit B-1, p. 276, Table 9-1).

Most of the projects within the programs have been previously approved or are ongoing annual activities. The new projects identified in the Application are: the Grounding Upgrades project in the Auxiliary Equipment program; the 12/25/60/138 kV Reactor Circuit Breaker project and the Horsey GIS Replacement project in the Circuit Breakers program; the Mechanical Transformer Electronic Temperature Monitor ("ETM") Upgrades project in the Other Power Equipment program; the Security Project in the Risk Mitigation program; and the Chapman Fibre Optic Cable Replacement project and the Tone and Test Panel Replacement project in the Telecommunications program (Exhibit B-1, pp. 140-175).

BCTC was requested to provide a comparison of the NPVs of the proposed Chapman Fibre Optic Cable Replacement project as compared to keeping the existing system. BCTC provided spreadsheets showing the financial impact of "Do Nothing" and the "Recommended Solution". The "Do Nothing" option identified by BCTC contains a large unexplained capital expenditure in F2012, without which, the "Do Nothing" option would have a lower NPV than the preferred option (Exhibit B-6, BCUC 1.99.1).

Commission Determination

The Commission Panel has several specific comments related to individual projects in the Stations Sustaining Capital Program. Overall expenditure levels will be addressed in Section 6.4 of this Decision.

BCTC states that the VIT Synchronous Condenser Circuit Breaker Replacements project is required because of lack of support from the manufacturer, no spare part availability on the market, and no other circuit breakers of this type are in use which could be used as spare parts to delay replacing the breakers (Exhibit B-1, p. 151). However, BCTC later stated that even if spare parts were available, the breaker replacements could not be delayed because the fault duty exceeds the fault interrupting capability of the circuit breakers (Exhibit B-6, BCUC 1.93.1). The Commission Panel notes that this particular project is not being driven by the inability to maintain the equipment, but rather by the rating of the equipment, which may have to do more with recent Growth Capital projects such as the VITR project. The Commission Panel is concerned that Growth Capital projects are not capturing the entire scope required for their implementation, and hence, this may be inappropriately biasing the comparison of alternatives.

The Commission Panel notes that the Mechanical Transformer ETM Upgrades project appears to be discretionary and consists of replacing equipment that is being used by the bulk of the industry with newer ETMs that are just gaining popularity in the industry (Exhibit B-6, BCUC 1.96.1). The Commission Panel is concerned that “early adopters” of this new technology may be faced with premature failures or replacement because the equipment does not yet have a sufficient track record of reliable operation. While it may be justifiable to install this new technology on new transformers, it may be too soon to embark on a comprehensive replacement program within the installed base.

The Commission Panel does not approve the Chapman Fibre Optic Cable Replacement project as proposed because absent an explanation of the large expenditure in F2012, it is higher cost than a potential alternative and does not appear to be justified by safety, environmental, or compliance considerations.

6.3 Overhead Lines and Cables Sustaining Capital Programs

As discussed in Section 6.1, the format for describing the Sustaining Capital Portfolio has changed from the format used in BCTC’s F2006 Application. The five programs within the Lines category for which approval is being sought for F2008 and F2009 expenditures are Cable Sustainment, Overhead Lines Life Extension, Overhead Lines Performance Improvements, Overhead Lines Risk Mitigation and Right-of-Way (“ROW”) Sustainment. Approval is also being sought separately for Third-Party Funded Projects that form part of the ROW Sustainment Program (Exhibit B-1, pp. 18-19; p. 135; p. 140).

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. 132; Exhibit B-6, BCUC 1.40.1).

Line Programs Expenditures (Millions of Dollars)	**F2008** (Nominal $)	**F2008 Real** (Inflation adjusted) F2007 $	**F2009** (Nominal $)	**F2009 Real** (Inflation adjusted) F2007 $
Cable Sustainment	2.0	1.9	3.1	2.9
Overhead Lines Life Extension	11.9	11.4	12.2	11.3
Overhead Lines Performance Improvements	3.8	3.6	4.3	4.0
Overhead Lines Risk Mitigation	7.4	7.1	6.7	6.2
Right-of-Way Sustainment	5.7	8.4	8.7	8.0
Line Programs Subtotal	30.8	29.6	32.9	30.5
Third-Party Funded Projects	3.0	2.9	2.1	1.9
Line Programs Total	33.8	32.5	35.0	32.4

As in the previous Section, the inflation adjustment adjusts the F2008 and F2009 expenditures to an F2007 base to assist in the comparison of expenditure levels to those identified in the F2006 Update Application. The total expenditure identified in the F2006 Update Application for the Underground and Submarine Cables and Overhead Lines/ROW and Asset Management Support Systems programs, which are considered to be equivalent to the Line programs in this Application, was $38.1 million (Exhibit B-1, p. 276, Table 9-1).

As with the Stations category, most of the projects within the Line programs have been previously approved or are ongoing annual activities. Only one new project is identified in the Application for the Line category, and that is the Spacer-Damper Replacements project in the Overhead Lines Extension program (Exhibit B-1, pp. 175-200).

Commission Determination

The Commission Panel notes a significant reduction in the inflation-adjusted F2008 and F2009 expenditures within the Line programs as compared to the F2007 planned expenditure level, and that the F2008 and F2009 expenditures include Third-Party Funded Projects whereas the F2007 expenditures did not.

6.4 Sustainment Investment Model and Level of Expenditures

The overall level of nominal and real (inflation-adjusted) sustaining capital expenditures is shown below:

Sustaining Capital Expenditures (Millions of Dollars)	**F2008** (Nominal $)	**F2008 Real** (Inflation adjusted) F2007 $	**F2009** (Nominal $)	**F2009 Real** (Inflation adjusted) F2007 $
Station Programs	54.6	52.4	59.8	55.3
Line Programs	30.8	29.6	32.9	30.5
Sustaining Capital Subtotal	85.4	82.0	92.7	85.8
Third-Party Funded Projects	3.0	2.9	2.1	1.9
Sustaining Capital Total	88.3	84.9	94.7	87.6

In comparison, the total F2007 Sustaining Capital Expenditure identified in the F2006 Application was $83.1 million expressed in F2007 dollars (Exhibit B-1, p. 276, Table 9-1).

BCTC has developed an analytical tool called the Sustainment Investment Model (“Model”) in response to Directive 35 from the F2006 TSCP Decision, which stated:

> “The Commission Panel suggests that BCTC re-evaluate the key driver criteria in order to yield an ongoing lower level of sustaining capital expenditures. The Commission Panel anticipates that the reductions of approximately 10 percent in the F2006 and 15 percent in the F2007 Sustaining Capital Portfolios directed above are sustainable through re-evaluation, re-prioritization and re-distribution of programs. Therefore, the 15 percent reduction should apply to future years’ forecasts until changes in the trends of the reliability indices or asset health assessments suggest the need for changes from the status quo in the size of the Sustaining Capital Portfolio” (F2006 TSCP Decision, p. 59).

BCTC states that the Model was developed to assist in the planning of Sustaining Capital investments in order to maintain current levels of reliability by estimating the number of transmission assets reaching the end of their useful lives in each decade (Exhibit B-1, Appendix B, p. 68).

In Phase 1 of the Model development, expert opinion was used to determine an end-of-life estimate for each of the 33 asset classes in the 2004 Asset Baseline Study, which in turn was used to determine forecast asset retirements and resulting re-investment requirements over the next ten decades. The results of Phase 1 forecast that $87 million of annual Sustaining Capital expenditures are required to keep up with forecasted retirements. The sensitivity to a +/-5 percent error in the forecasted asset retirements was a Sustaining Capital expenditure range of $72 million to $102 million. BCTC then compared the forecast percentage of asset retirements and the actual percentage of asset retirements over the last decade and found acceptable agreement with 5.85 percent and 6.1 percent respectively (Exhibit B-1, Appendix B, p. 69).

In Phase 2 of Model development, which is currently underway, historical data will be used to calculate the end-of-life estimate, and replacement cost will be based on recent actual values rather than inflation-adjusted historical values. Preliminary results indicate annual Sustaining Capital expenditures of $85 million dollars are required, with a range of $67 million to $103 million for a +/-5 percent error in the forecasted asset retirements (Exhibit B-1, Appendix B, p. 69-70).

Future development includes validating and calibrating the Model as more recent data become available, and determining the relationship between Sustaining Investment and reliability.

BCTC recommends a Sustaining Capital level of $87 million per year on average for the years 2005-2014 to help manage predicted retirements and potential reliability impacts, with periodic spikes in the expenditures in response to events unrelated to normal wear and tear or when a known threat or problem arises (Exhibit B-1, Appendix B, p. 70; BCTC Argument, p. 21).

BCTC states it undertook further work to assist in identifying the appropriate level of Sustaining Capital expenditures by participating in industry benchmarking surveys, but the results were inconclusive (BCTC Argument, p. 21; Exhibit B-6, BCUC 1.20.1; Exhibit B-6, BCUC 1.130.1). BCTC supplied a graph that showed both the historic SAIDI and Sustaining Capital expenditures over the period of 1994 to 2007. The F2007 SAIDI is projected at almost double the F2006 SAIDI, but there is no indication as to whether this is attributable to age and condition-related equipment failure, or to the Lower Mainland region's windstorms. The level of Sustaining Capital expenditures in the last four years appears to have increased substantially and consistently as compared to pre-F2000 expenditures (Exhibit B-6, BCUC 1.131.1).

BCTC further states it appreciates that the proposed level of Sustaining Capital expenditures is greater than the amount set out in the F2006 TSCP Decision. BCTC believes that the requested levels are justified; however, if the Commission does not accept BCTC's current justification for these levels, BCTC requests that the Commission identify a global reduction to be applied to the Sustaining Capital portfolio (BCTC Argument, p. 22).

In Table 6.3-1 of the Application, BCTC provides a table reconciling the approved levels of expenditures in F2007 dollars, which was $83.1 million, to the nominal dollar expenditures in the F2008 TSCP. F2008 Third-Party Funded Projects are shown as $2.9 million. Also in F2008, Other Changes in Work is shown as a reduction of $1.1 million. Finally, inflationary costs of $3.4 million, consistent with the four percent inflation rate cited above, is included to bring the total in F2008 to $88.3 million expressed in nominal dollars (Exhibit B-1, p. 136).

The text below Table 6.3-1 describes "the main changes" in work in F2008 as an increase of $2 million related to station security and a further increase of $3.5 million in F2008 and F2009 related to seismic upgrades, offset by a reduction of $2 million in F2008 in the cable sustainment project. Third-Party Funded Projects are stated to represent $1 million in F2008 (Exhibit B-1, pp. 136-137).

BC Hydro submits that it costs more over the long-term to allow a system to degrade and then spend to restore it, compared to adhering to a Sustaining Capital program based on least long-term cost, particularly after factoring in customer impacts. BC Hydro believes that BCTC's Sustaining Capital Portfolio is justified, and there is no basis in the evidence for the Commission to apply a global reduction to the Sustaining Capital Portfolio (BC Hydro Submission, p. 4).

No other Intervenors commented on the level of Sustaining Capital expenditures.

Commission Determination

The Commission Panel commends BCTC for the ongoing development of the Sustainment Investment Model, but notes that the Model is still in development, and that the strongest results are based on expert opinion input rather than actual costs, conditions and other measures. With future development of the Model, it appears that it will capture trends in reliability indices and the relationship between Sustaining Capital expenditures and changes in the asset health assessments. The Commission Panel acknowledges that a statistically significant correlation between reliability indices and Sustaining Capital expenditures may not be established, and that statistical analysis may be more likely to establish a correlation between changes to Sustaining Capital expenditures and asset health assessments.

The Commission Panel notes that Sustaining Capital expenditures have increased dramatically over the last five years as compared to prior years. In this Application BCTC has provided insufficient evidence, which could have been provided in either in reliability indices trends or in asset health assessments, to justify an increase to Sustaining Capital expenditure directed by the F2006 TSCP Decision. The Commission Panel notes that Directive 35 from the F2006 TSCP Decision directs that the reduction to Sustaining Capital expenditures should apply to future years' forecasts until changes in the trends of reliability indices or asset health assessment suggest otherwise. The changes shown in Table 6.3-1 and described in the text below the table are not consistent with the directions for suggesting a change to the amount of Sustaining Capital expenditures. **Therefore, the Commission Panel directs BCTC to conform to the directives made in the F2006 TSCP Decision and the F2006 TSCP Update Decision with respect to Sustaining Capital expenditures.**

The Commission Panel acknowledges that inflation in the British Columbia non-residential industry sector is running at higher levels than the British Columbia Consumer Price Index ("BCCPI"), however, the Commission Panel concludes that BCTC has provided insufficient evidence to justify the use of an inflation forecast higher than general inflation as represented by the BCCPI. The evidence provided regarding the MMK Consulting report is contained in a footnote to an information request response. **The Commission Panel directs BCTC to use an inflation factor of 2.0 percent for each of F2008 and F2009 to budget for Sustaining Capital based on the forecast of BCCPI. The Commission Panel invites BCTC to provide comprehensive justification of any other inflation adjustment it may propose for F2009 and beyond, as part of its next capital plan filing.**

For clarity, the Commission Panel approves as being in the public interest Sustaining Capital expenditures of $83.1 million in each of F2008 and F2009 when expressed in F2007 dollars, and further Third-Party Funded expenditures of $2.9 million and $1.9 million expressed on the same basis. The same amounts expressed in nominal dollars are Sustaining Capital expenditures of $84.8 million and $86.5 million in F2008 and F2009 respectively, and Third-Party Funded expenditures of $3.0 million and $2.0 million in F2008 and F2009, respectively.

7.0 BCTC CAPITAL PORTFOLIO

The BCTC Capital Portfolio addresses all capital assets owned by BCTC, as compared to the assets in the Growth and Sustaining Capital Portfolios, which are owned by BC Hydro. The BCTC Capital Portfolio comprises three major asset groups: (1) Information Technology ("IT"); (2) Control Centre Technologies; and (3) Facilities (office space, furniture, fixtures and equipment) (Exhibit B-1, p. 72).

7.1 Key Drivers

BCTC submits that the BCTC Capital Portfolio is driven by its need to complete the transition to a stand-alone corporate environment (Exhibit B-1, p. 25). The main risks addressed by the BCTC Capital Portfolio are the security and reliability of BCTC's IT network and backup systems and the technical health of applications. The portfolio does not carry significant residual risks (Exhibit B-1, p. 29).

The key drivers for the BCTC Capital Portfolio are: (a) sustaining asset health; (b) opportunities for increasing personnel efficiency; (c) improving decision support; and (d) compliance with legislative, regulatory, internal security and business continuity requirements (Exhibit B-1, p. 73).

7.2 Information Technology

The format of the BCTC Capital Portfolio has been changed for this Application such that the Business Support Systems and Information Technologies asset groups referred to in previous capital plans, have now been combined to form the IT asset group, which is now subdivided into Business Support Systems and General IT Assets. The Business Support Systems include the Financial Systems Program, the Reliability Data Management System, the Asset Management Programs, the Financial Modelling Programs, the Transmission Scheduling System, the Dispatch Compliance Management System, and the Control Room Operating Window System. Examples of General IT Assets include the Microsoft Exchange/Outlook e-mail system, the Microsoft SharePoint collaboration system, personal computers (desktops and laptops), the corporate network, and shared storage and backup systems (Exhibit B-1, pp. 204-205).

The following table identifies the expenditures, in order of priority, on the IT projects submitted for approval in this Application (Exhibit B-1, p. 202, Table 7-1; Exhibit B-1, p. 212):

BCTC Information Technology Expenditures (Thousands of Dollars)	**F2008 Cost**	**F2009 Cost**
Transmission Emergency Centres	77	
NERC Security Standards Implementation	1,085	
Application Health Automation	72	
Market Operations Workflow System (Standard Generator Interconnection Procedures) - Phase II	106	
Human Resources - Payroll Enhancements	100	
Open Access Same-time Information System (“OASIS”) Upgrades	110	
Mobile Application Enhancements	209	
Bus Load Allocation Factor Generator	170	
Financial Systems Program (Oracle) Supplier Performance Management	205	
Financial Systems Program (Oracle) F08 Minor Enhancements	225	
Financial Modelling Project Phase II (Budgeting)	240	
Transmission Scheduling System Enhancements	307	
Planning Model on Demand Base case	367	
Control Room Operating Window System Upgrade	477	
Dispatch Compliance Management Software Upgrade	698	
Corporate Network Segmentation	685	
Asset Management Program Project Execution	714	
Backup Environment Separation - Edmonds	902	
Enterprise Server, Personal Computer and Peripheral Replacement	357	561
BCTC Information Technology Expenditures Total	7,106	561

Although the five lowest priority projects identified above are also among the most costly discretionary IT projects, BCTC stated that other projects have already been eliminated from the portfolio as a result of the prioritization policy. BCTC states that it has maintained the proposed F2008 BCTC Capital expenditures near the same levels as approved by the Commission for F2006 and F2007, excluding SCMP. Before the projects were prioritized, BCTC reviewed each project and dropped those projects that it considered were not justified. The prioritization tool was then used to rank the remaining projects (BCTC Argument, p. 23).

BCTC provided business cases for the five lowest priority projects and summarized the main factors driving the need for these projects. The Dispatch Compliance Management Software Upgrade project and Enterprise Server, Personal Computer and Peripheral Replacement project are driven by the need to keep business operations in step with technology supported by vendors and suppliers. The Corporate Network Segmentation project and Backup Environment Separation project are driven by the need for manageable security and business recovery. The Asset Management Program - Project Execution system enables timely and accurate data to help manage the Growth and Sustaining Capital projects for Engineering and Field Services (Exhibit B-6, BCUC 1.109.1; Exhibit B-6, BCUC 1.110.1)

With respect to the Backup Environment Separation project, BCTC determined that to continue to invest in the existing BC Hydro shared infrastructure would be too costly and BCTC's business recovery objectives would be at the discretion of BC Hydro (Exhibit B-6, BCUC 1.110.1).

Changes to the BCTC Capital Portfolio are provided in Table 7-4 of the Application, titled "BCTC Capital Projects Cancelled". The table lists sixteen cancelled projects. BCTC states that going forward it expects that the improved and more rigorous review process it has instituted will significantly reduce the number of portfolio changes compared with the recent past (Exhibit B-1, p. 210).

Commission Determination

The Commission Panel notes that the Corporate Network Segmentation project and Backup Environment Separation project are linked, as stated in the Corporate Network Segmentation project business case, "[t]o fully realise the benefits of the Corporate Network Segmentation project, Backup Environment Separation project must be implemented" (Exhibit B-6, BCUC 1.109.1, Attachment 2, p. 2). A financial comparison with remaining integrated with BC Hydro is not provided in the business case, and the monetisation of project costs identified in Appendix F of the business case is only marginally less than the monetised project benefits identified in Appendix E, although over half the monetised benefits are "soft savings". The major factor supporting the need for this project appears to be improved network security benefits. Although the potential network security benefits are documented in Appendices B and C of the business case, there is no assessment of BC Hydro's ability to provide comparable levels of security to the integrated network.

The Commission Panel also notes the Backup Environment Separation is also dependent on "soft savings" in order for the monetised benefits to be greater than the monetised project costs (Exhibit B-6, BCUC 1.110.1, Attachment 1, pp. 5-6).

The Commission Panel believes the business cases for the Corporate Network Segmentation project and Backup Environment Separation project do not reflect a reasonable effort to achieve a secure solution integrated in the BC Hydro environment. The Commission Panel expects that building two independent systems is more costly than integrated solutions, and that there is sufficient flexibility in the agreements between BCTC and BC Hydro to allow BCTC to negotiate the security it thinks is required. **The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro's IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro's IT systems, provided that it is not necessary to disclose confidential negotiations or commercial interests to do so.**

The Commission Panel is concerned about the number of BCTC Capital projects which have been cancelled because this gives rise to the concern that BCTC will not proceed with the work it has identified in the F2008 TSCP. Cancelled projects will be monitored in future applications because they may be indicative of a failure between the planning process and the ability to execute projects and their cancellation causes an over-estimation of the funding that BCTC requires for such projects in at least the short-term. **In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 TSCP, modified to show the total dollar amount of each project and the relative priority at the time of approval.**

7.3 Control Centre Technologies

BCTC describes the current Control Centre Technologies assets as five leased control centres, one leased telecommunications network operations centre, and an Energy Management System ("EMS"), comprising software and hardware that control the transmission system.

The SCMP, previously approved by the Commission by Order No. C-1-05, will replace the five leased control centres with two new owned control centres, a primary control centre at the Fraser Valley Office and a backup control centre at the South Interior Office and replace the existing EMS with a modern Areva EMS and a backup EMS at the South Interior Office (Exhibit B-1, pp. 205-206).

The only Control Centre Technologies project for which approval is requested in this Application is the Control Centre Sustainment project with a cost of $225,000 in F2008. In expectation of the new EMS associated with the SCMP, no replacement of existing control centre equipment is planned prior to its retirement (Exhibit B-1, pp. 249-250).

Commission Determination

The Commission Panel finds the requested F2008 capital expenditures for the BCTC Capital Control Centre Sustainment project are in the public interest.

7.4 Facilities

Facilities assets are primarily office furniture and equipment, leasehold improvements, telephone and facsimile systems, and related facilities infrastructure that support BCTC's business operations (Exhibit B-1, pp. 205-206).

The only Facilities projects for which approval is requested in this Application are associated with the headquarters facilities at the Bentall IV office tower in downtown Vancouver. These projects are the Bentall Minor Capital Replacements and Upgrades project, with F2008 expenditures of

$200,000, and the Bentall Leasehold Improvements project, with F2008 expenditures of $920,000 for renovation of the newly acquired fifteenth floor at the Bentall IV office tower. (Exhibit B-1, pp. 241-252).

Commission Determination

The Commission Panel finds the requested F2008 expenditures for the BCTC Capital Facilities assets projects are in the public interest.

8.0 SUBSEQUENT EVENTS

8.1 The 2007 Energy Plan

The BC Energy Plan: A Vision for Clean Energy Leadership, which has been designed to ensure a secure, reliable supply of affordable energy in an environmentally responsible way, was announced on February 27, 2007. The 2007 Energy Plan reaffirms and advances the message and direction given to BCTC by the Government in its 2002 Energy Plan with the introduction of the following three Policy Actions (2007 Energy Plan, Appendix A):

- BCTC is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand (Policy Action 12).

- Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy (Policy Action 13).

- Ensure that the province remains consistent with North American transmission reliability standards (Policy Action 14).

BCTC acknowledges Policy Action 13 and undertakes to bring its response before the Commission once its consultations and assessment are concluded (BCTC Argument, p. 17). Policy Action 14 was referred to in Section 2.2 of this Decision. Although BCTC remained silent on Policy Action 12 in its Argument and provides only a brief reference to a requirement for "a broader and more progressive approach to transmission planning" (BCTC Reply, p. 9), the Commission Panel, to ensure continuity, expands on that topic in this Decision, especially because it relates to the "Criteria for when Transmission System should be Expanded" and SD9, Section 4 which were addressed in Section 5.3.

8.1.1 Policy Action 12

The Government has further clarified its message with more detailed policy action write-ups that were prepared for the Energy Plan (www.energyplan.gov.bc.ca). To emphasize views expressed in Section 5.3 and to set the stage for the next transmission capital plan, the Commission Panel notes the following excerpt:

> "BCTC investments in advanced control and monitoring technologies increase the capacity of existing assets by enabling more precise operation of the transmission system. By taking a broader and more progressive approach to transmission planning, BCTC will also be able to ensure that new transmission infrastructure will be in place to reliably meet the province's future electricity needs.
>
> Since its inception, BCTC has planned system upgrades and new transmission projects in response to a customer's request. Transmission projects, however, require longer lead and construction time than generation or load build. The experience of other jurisdictions with this type of planning approach is that transmission capacity is often not in place when it is needed.
>
> To prevent this situation from occurring in British Columbia, BCTC will move beyond this contract driven approach to an approach that builds infrastructure in advance of need. BCTC will study and propose, where appropriate, system upgrades or expansions based, in part, on its own assessment of future market needs. Three types of transmission projects will benefit from this approach:
>
> - a planned system upgrade for a Network Customer already identified in the BCTC Capital Plan that can be beneficially advanced in time;
> - a system upgrade required for a customer that can beneficially be made larger than the immediate requirement; and
> - a project that BCTC identifies as having future benefits, but which has not been triggered by a customer request.
>
> BCTC will identify this third type of project through an annual project review designed to identify possible projects that would be viable as a BCTC led investment. BCTC will only proceed with an upgrade or expansion project after completion of a strong business case that identifies the costs and benefits of the proposed project, completion of thorough stakeholder and First Nations consultations, and receiving all regulatory approvals" (2007 Energy Plan, Electricity Policies, Policy Action 12, p. 2).

IPPBC was seeking a Commission Order that BCTC move immediately to implement its TEP and report back to the BCUC within two months, rather than waiting until the filing of its next capital plan (IPPBC Submission, p. 6).

BCTC opposes IPPBC's submission stating that BCTC's consideration of the 2007 Energy Plan will not be completed in such a short-time nor can these requirements be integrated with the TEP in two months, including consultation with stakeholders (BCTC Reply, p. 10).

Commission Determination

The Commission Panel notes that the 2007 Energy Plan has not been included as evidence in this proceeding (Exhibit A-4). However, in recognition of its significance and the prominence it received in the Arguments as well as due to concern over potential regulatory gaps and/or timing issues between various BCTC and BC Hydro applications, the Commission Panel has decided to comment on the 2007 Energy Plan for the benefit of future processes.

The Commission Panel accepts, while appreciating the sense of urgency expressed by IPPBC, that BCTC's review of the 2007 Energy Plan should occur with considered thought and adequate stakeholder input. **Accordingly, the Commission Panel directs BCTC to file a report related to Policy Action 12 and Policy Action 13 on or before December 1, 2007. The report should comment on the progress of consultation initiatives and further steps that BCTC considers to be appropriate to implement Policy Action 12 and Policy Action 13. In the filing, BCTC may also seek regulatory comments or direction that may be useful for the creation of the Congestion Relief Policy and the evolution of the TEP. If BCTC does seek such regulatory comments or direction, it may be helpful for BCTC to include a policy discussion paper that could be circulated to stakeholders for comment prior to Commission comments or directions.**

8.2 FERC Order No. 890

On February 16, 2007 the FERC issued its Order No. 890, amending the regulations and the pro forma OATT adopted in Order Nos. 888 and 889, to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential (Docket Nos. RM05-17-000, RM05-25-000). Concerns such as congestion and inadequate infrastructure development, among other issues, were the drivers leading to the reforms of OATT identified in Order No. 890. Accordingly, the transmission providers' role in system planning, including assessment of congestion impacts, is addressed in some detail in the new Order.

After careful consideration BCTC expects to bring this matter before the Commission once its consultations and assessment are concluded (BCTC Argument, p. 17, BCTC Reply, pp. 9-10).

Commission Determination

To continue to satisfy the reciprocity requirements under the pro-forma OATT, BCTC must carefully assess the implications of FERC Order No. 890, and therefore the Commission Panel directs BCTC to bring its assessment of FERC Order No. 890 forward to the Commission once its consultations and assessments are concluded.

8.3 OATT Rate Design Initiatives

On December 20, 2006 BCTC filed its Rate Design Report with the Commission. This report was filed primarily to comply with Order No. G-58-05 and accompanying Reasons for Decision and other reporting requirements.

In the F2008 TSCP, in response to the F2006 TSCP Decision, page 19, Directive 10a, BCTC also referred to the compliance filing indicating that the Rate Design Report will include, among other things, the following:

- Results of the evaluation of development of a re-dispatch service and
- A discussion of non-wires alternatives besides re-dispatch service including the results of consultation on this topic with customers and TPAC (Exhibit B-1, p. 267).

Again, to ensure continuity and linkages to other regulatory proceedings, this section summarizes two issues addressed in the Rate Design Report that focus on potential customer-provided solutions to transmission constraints and will require further action.

8.3.1 Expansion of the Investment Deferral Credit

The first avenue to implement non-wires alternatives is to expand the deferral credit that the Commission approved in the last OATT proceeding (Order No. G-58-05). This deferral credit grants eligible generators 75 percent of the value of any transmission capital investment deferral made possible by their agreeing, and living up to specified performance commitments. The proposed expansion aims to improve the credit in the following two ways:

- to adjust the payment mechanism from a transmission credit to cash, so that it can be available to customers that are connected to the transmission system but do not directly purchase transmission service from BCTC (e.g. loads or generators selling to BC Hydro); and
- to expand customer eligibility from new generators only to existing generators and loads.

With regard to the process and timelines, BCTC indicated that it planned to conduct customer consultations during the February-March, 2007 time period and to subsequently file an application with BCUC, if necessary, after April 2007. The Commission, in its letter dated January 24, 2007, accepted the compliance filing stating it expects to be informed of the outcome either in the form of an application for amendments to the OATT or in the form of a follow-up report.

8.3.2 Re-Dispatch Service and Non-wires Alternatives

BCTC prefaced its response to the regulatory directives regarding non-wires alternatives by noting that BCTC is responsible for operating and maintaining BC Hydro's system pursuant to certain agreements and that BCTC does not own generation or service retail loads. BCTC stated it cannot compel any party, including BC Hydro to provide generation re-dispatch for economic as distinct from reliability considerations (Rate Design Report, p. 2.25). BCTC stated that it had focussed on identifying solutions that had the opportunity for success through practical economic potential. BCTC stated that non-wires potential in B.C. resides largely within BC Hydro and its customers, and any viable solution will involve cooperation between BC Hydro and BCTC (Rate Design Report, p. B-3).

BCTC considers re-dispatch service as another one of the customer-supplied solutions for transmission services, used to either defer investment or resolve congestion by creating new ATC without building transmission infrastructure. In the first case, BCTC states that alternatives are only viable where there are clear advantages related to cost, timing, market opportunity or community acceptance that do not compromise reliability. In the second case, the re-dispatch agreements, which can be supplied by either generators or loads, can be used to create ATC for Long-Term Point-to-Point ("LT-PTP") contracts or to create additional Short-Term Point-to-Point ("ST-PTP") opportunities. In reporting the results of the evaluation of development of re-dispatch service BCTC highlights the following issues:

- BCTC does not own or control generation facilities nor does BCTC serve any retail end-users, which means that BCTC cannot compel loads or resources in B.C. to provide non-wires solutions for the benefit of third parties. Therefore, all opportunities considered must rely on the voluntary supply of generation or load services (Rate Design Report, pp. B-2, B-3).

- Given the above constraints, BCTC believes that its proper role in re-dispatch might be to create mechanisms that inform potential re-dispatch suppliers about the prevailing value of additional ATC that is useful to other transmission customers and act as a facilitator. In terms of a range of possibilities, BCTC believes that at the lower end, its proper role could be that of hosting a bulletin board style foundation for bilateral transactions. At the upper end, BCTC could create a re-dispatch market in an attempt to bring liquidity and flexibility to transmission re-sale and load- or generation-based re-dispatch offers (Rate Design Report, pp. B-7, B-8).

- To make re-dispatch work in B.C., BCTC believes that BC Hydro would need to support the initiative as the owner or controller of the overwhelming majority of generators that could participate in such a regime (Rate Design Report, p. B-12).

BCTC does not believe there is much opportunity for long-term customer supplied solutions in bulk transmission because there are few such projects in its capital plan and because of the nature and timing of those projects. However, to ensure such potential is not ruled out BCTC suggests a high level screening approach. Although BCTC is not optimistic about long-term solutions for bulk transmission, it states that temporary customer-supplied solutions may be available and that it has had discussions with customers to address supply concerns on Vancouver Island (Rate Design Report, p. B-5). BCTC sees more potential for non-wires solutions on radial parts of the system but states they should be evaluated on a case-by-case non-prescriptive basis (Rate Design Report, p. B-6).

BCTC stated it has consulted with stakeholders, and that both BCTC and stakeholders perceive little prospect of success of a bulletin board approach, nor do they feel the time and effort to reconfigure the market would be fruitful given the lack of liquidity in the energy market in B.C. BCTC's current tariff provides that BCTC will investigate re-dispatch for LT-PTP service requests, but BC Hydro has not offered to provide such service. BCTC does not believe that BC Hydro would change this practice in response to a better price signal and does not believe that BC Hydro is currently underutilizing its own system. BCTC will continue exploring with BC Hydro to determine if it is viable to create an active and transparent re-dispatch market or service in the future (Rate Design Report, pp. B-12, B-13).

Regarding demand side management ("DSM"), BCTC does not see value in duplicating BC Hydro's efforts in DSM, but that its role should be to identify DSM-related opportunities for BC Hydro and that this communication should be formalized to maximize potential opportunities. BCTC stated that it and BC Hydro have been working on bridging (short-term) solutions in some cases and that in these cases it may have a role in contracting directly for load management services (Rate Design Report, p. B-9).

BCTC stated that:

> "Moreover, if BCTC identifies through its regular planning activities that particular locations and performance-contract combinations are of particularly high value, it will either seek to have BC Hydro tailor generator-dispatch or load management calls in those locations (either permanently or on a bridging basis) or undertake such call itself. BCTC expects to further explore these opportunities with BC Hydro and other potential suppliers in the coming months" (Rate Design Report, p. B-11).

In the case of load management BCTC will continue to work with BC Hydro and ensure that benefits of such solutions are communicated appropriately and quickly. BCTC will develop a process for posting such information on BCTC's website after consulting customers on the format and content of such postings (Rate Design Report, p. B-14).

Commission Determination

The Commission Panel concludes that, as directed, BCTC has initiated discussions with customers on potential customer-provided solutions to transmission constraints and duly reported to the Commission on the outcome of those discussions. The Commission Panel recognizes the challenges that BCTC faces in offering non-wires solutions and is encouraged by BCTC's efforts to work to investigate these options with BC Hydro and other stakeholders. However, the Commission Panel believes that BCTC should, with the benefit of input from BC Hydro and stakeholders, identify transmission congestion that might be resolved by re-dispatching generation. **The Commission Panel directs BCTC to file a report on or before December 1, 2007 that first identifies congested paths, if any, that might be economically resolved by generation re-dispatch, and then assesses opportunities for resolving congestion by re-dispatching generation. This report may form part of the report related to Policy Action 12 and Policy Action 13.**

The Commission Panel agrees that awaiting the outcome of the stakeholder consultation on expansion of the Investment Deferral Credit is desirable.

8.4 2006 IEP/LTAP Decision

It is essential for the efficient development of the power system in B.C. that generation and transmission planning are coordinated. With the creation of BCTC in 2003, the coordination of generation and transmission planning presents new challenges and issues not only for BC Hydro and BCTC but also for stakeholders, and the BCUC. These issues have now been the subject of several regulatory decisions, including the OATT Decision dated June 20, 2005, previous transmission capital plan decisions, and more recently BC Hydro's 2006 IEP/LTAP Decision dated May 11, 2007. Planning issues also are the subject of the recent 2007 Energy Plan, particularly related to the creation and implementation of the Congestion Relief Policy.

In the 2006 IEP/LTAP Decision, the Commission approved, for use in BC Hydro's next NITS update/application, the LTAP base resource plan and CRPs filed by BC Hydro (2006 IEP/LTAP Decision, Directive 24). Also, Directive 24 invited BC Hydro to seek approval for an updated LTAP and CRPs that better reflect BC Hydro's expectations of future resource additions. In addition, the Commission accepted a joint proposal by BC Hydro and BCTC to study certain effects of transmission planning assumptions that may modify the LTAP base resource plan and CRPs for the next NITS update/application (2006 IEP/LTAP Decision, Directive 13). Therefore, the next transmission capital plan should consider the effects of changes to generation planning arising from the 2006 IEP/LTAP Decision, and perhaps changed expectations about future resource additions.

In the 2006 IEP/LTAP Decision, the Commission stated that it expects BC Hydro to file its next LTAP early in 2008. Further, the Commission expects the next LTAP to examine the effects of both the Throne Speech and the 2007 Energy Plan and provide updates on resource options and on the load/resource balance (2006 IEP/LTAP Decision, p. 42). Therefore, subject to the filing time of the next transmission capital plan relative to the next NITS update/application, the next transmission capital plan may not consider the effects of changes to generation planning arising from the 2007 Energy Plan.

In the 2006 IEP/LTAP Decision, BC Hydro submitted that there is a significant level of coordination between BCTC and BC Hydro, and that this coordination is in compliance with the BCTC Standards of Conduct, and that the existing Standards of Conduct may be too restrictive. The Commission then encouraged BC Hydro to work with BCTC to determine what changes to the Standards of Conduct might be beneficial (2006 IEP/LTAP Decision, pp. 41-42).

The Commission Panel notes that in the 2006 IEP/LTAP Decision, the Commission encouraged BCTC to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis and the NITS application review. In this Decision, BCTC has again been encouraged to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis, and the NITS application review (Section 2.2). Further, BC Hydro was directed to provide a description of these planning assumptions in the next LTAP application (2006 IEP/LTAP Decision, Directive 14). In this Decision, the Commission directs BCTC to file with its next capital plan a description of the planning assumptions used in the analysis of BC Hydro's NITS application (Section 2.2).

This Decision directs BCTC to submit as part of its next capital plan a report that addresses the analysis of, and a proposal for, the Lower Mainland's reactive power requirements (Section 5.9). Pursuant to the joint proposal of BC Hydro and BCTC filed in the 2006 IEP/LTAP proceeding, BC Hydro will request BCTC to study the effects of the transmission planning assumptions related to Coastal Regional RMR generation (2006 IEP/LTAP Decision, Directive 13), and BC Hydro may modify these planning assumptions as part of its NITS application. Therefore, the next transmission capital plan will include the requested report, and may also plan based on the conclusions of the report as evidenced in the NITS application.

In the 2006 IEP/LTAP Decision, the Commission provided certain directions regarding project evaluations that are expected to be relevant to BCTC's analysis of transmission projects because such projects are owned and financed by BC Hydro (2006 IEP/LTAP Decision, Directives 25, 26 and 27).

In the 2006 IEP/LTAP Decision, the Commission directed BC Hydro to file a study in the next LTAP that identifies the level of firm transmission capacity available to deliver the CE to British Columbia from the United States (2006 IEP/LTAP Decision, Directive 10).

9.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directives 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 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.	14
2.	The Commission Panel directs BCTC to submit with its next capital plan a comprehensive description of the planning assumptions used in the IEP portfolio evaluations, LTAP analysis, and analysis of BC Hydro's NITS application. Future capital plan filings should either re-affirm the previous planning assumptions or describe any changes made to the previously described planning assumptions.	14
3.	The Commission Panel directs BCTC to submit as part of future capital plan filings an assessment of which transmission reinforcements could be delayed or deferred through the reasonable re-dispatch of generation resources nominated in NITS applications. BCTC should also identify in this assessment the mechanisms under OATT that allow the re-dispatch of generation around transmission constraints, and comment on whether these mechanisms are available for operating purposes, planning purposes, or both.	15
4.	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.	16

5.	The Commission Panel specifically denies Definition Phase funding in F2009 for the Golden 69 kV System Reinforcement and North Thompson 138 KV System projects. If BCTC applies for Definition Phase funding for these projects before or as part of the next capital plan, it should be prepared to show how it has considered existing transmission expansion policies for the identification of project alternatives during the Planning Phase evaluation.	17
6.	The Commission Panel directs BCTC to track past years' approved Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures, as was done in Table 9-1 of the Application.	19
7.	… 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.	20
8.	The Commission Panel agrees with BCOAPO's submission on variance reporting, and accepts BCTC's proposal to provide information in its next capital plan filing regarding variances exceeding both 10 percent and $100,000 of budgeted amounts submitted in this Application for approved projects, and to continue such reporting in future capital plan filings until directed otherwise.	20
9.	The Commission Panel encourages BCTC to suggest changes to the frequency of the STSR if BCTC determines the existing frequency does not serve a useful purpose, but directs BCTC to submit an updated STSR with future capital plan applications until directed otherwise.	30
10.	The Commission Panel directs BCTC to continue reporting performance measures in future capital plans, largely as they are provided in the 2006 STSR. BCTC should report its performance measure with and without planned outages in order to make the comparison against CEA statistics more relevant. The Commission Panel also considers the trend graph supplied in response to BCUC 1.131.1 (Exhibit B-6) to be a useful long-term indicator, and directs BCTC to file this trend information in future capital plans.	30

11.	In all future capital plan applications, BCTC is to provide a modified table in the format of the "Projects in Progress" portion of Table 5-1 in this Application. For each year during the Implementation Phase of a project BCTC is to include 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. The Commission Panel further directs BCTC to provide a modified table in the format of Table 5-3 in this Application, modified to include the total dollar value for each project, as well as the priority ranking of the project when the project was approved.	32
12.	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.	35
13.	The Commission Panel considers that BCTC is complying with the second outstanding Directive and expects BCTC to report on the progress of establishing correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI.	37
14.	The Commission Panel directs BCTC to provide in future capital plans equipment reliability data as selected by BCTC and provide the CEA averages, and in the case of Line-related Forced Sustained Outages (as defined in the 2006 STSR, Section 8.3), to separate equipment failure outages from those outages caused primarily by weather or vegetation.	37
15.	… the Commission Panel directs BCTC to file a report that could be described as the "operator's manual" for the Prioritization Model. This report should contain all weightings and probabilities for each category and criteria and any sub criteria, as well as a full description of the methodology employed in determining the weights and probabilities. The report should describe key assumptions, particularly those used to derive values as a result of a judgment process, as opposed to quantitatively. The report should contain a detailed example, including all numeric calculations for at least one project in each of the Growth, Sustaining, or BCTC Capital Portfolios. If BCTC cannot provide the information for proprietary reasons, it is encouraged to select examples from the beta testing of the model. The report should be filed with the next capital plan.	45

16.	… the Commission Panel directs BCTC to include in its next capital plan filing, tables for each of the Portfolios listing the projects brought for approval, their risk and value scores by category, and the priority numbers and quadrant values, where applicable. 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.	45
17.	The Commission Panel notes that many of the quadrant four sustaining projects that were not deferred appear to be justified not on the model results but for safety or reliability considerations. This suggests to the Commission Panel that there may be threshold values for the safety and reliability metrics beyond which projects become mandatory much as they currently become mandatory for legislative or NERC reliability reasons. The Commission Panel directs BCTC to comment on this issue in the next capital plan.	46
18.	Since corporate risks may ultimately be reflected in costs which will impact rates, BCTC is directed to include its Corporate Risk Matrix in its next capital plan filing.	46
19.	Since a growth project by definition results from an anticipation of growth, the Commission Panel is concerned that BCTC cannot estimate the likely revenues, and hence includes in the heavily weighted financial category, a value for rate impact which it knows to be inaccurate. The Commission Panel encourages BCTC to comment on this issue in its next capital plan.	46
20.	… the Commission Panel directs BCTC to include in future capital plans a summary table by project, showing the average load growth for the most recent five historical years, preferably weather normalized if possible, and the growth rates projected for future years. The table should also show the planning region in which the project resides and the regional load growth rates for the same periods. If there is significant divergence between the load growth rate upon which the project need is determined, and that of the planning region, BCTC is to provide an explanation of the divergence.	48
21.	The Commission Panel directs BCTC to prioritize potential TEP projects with other projects using the Prioritization Model. The Commission Panel directs BCTC to report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. In the event that BCTC identifies a potential TEP project and then decides that the project should be implemented, BCTC should seek approval of the project prior to the next capital plan.	53

22.	The Commission Panel directs BCTC to provide a detailed description of the highest ranked intertie expansion project in the next capital plan. The description should include, if possible, the identification and quantification of potential benefits accruing to ratepayers.	55
23.	For future capital plans, the Commission Panel directs BCTC to identify separately those projects and corresponding expenditures that are directly attributable to specific generation additions.	56
24.	The Commission Panel approves BCTC's request for a determination under Section 45(6.2)(b) of the Act that capital expenditures on the Selkirk 500/230 kV Transformer T4 Addition, the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors – Definition Phase, and the 5L91/5L98 Series Compensation – Definition Phase projects are in the public interest.	56
25.	The Commission Panel accepts BCTC's proposal in its letter of March 30, 2007, that upon reaching an agreement with the District of Mission regarding the potential rerouting of a portion of the 69 kV transmission facilities associated with the Mission and Matsqui Area Supply project in the vicinity of Mission, BCTC will apply to the Commission to find the revised project to be in the public interest.	58
26.	If and when BCTC submits a CPCN application for the 5L91/5L98 Series Compensation project, the Commission Panel directs BCTC to submit a study that analyzes and describes the anticipated amount of seasonal and hourly reliability-driven Canadian Entitlement utilization. In order to assist in the determination of whether or not the anticipated seasonal and hourly Canadian Entitlement utilization from the requested study is consistent or inconsistent with past utilization of the Canadian Entitlement, the Commission Panel also directs BCTC to provide historical data of the reliability-driven utilization of the Canadian Entitlement in a format that allows for a reasonable comparison to the anticipated seasonal and hourly Canadian Entitlement utilization.	66
27.	The Commission Panel directs BCTC to submit as part of its next capital plan a report that provides an analysis of, and a proposal for, the Lower Mainland's reactive power requirements. This report should describe and attempt to quantify the various benefits associated with the options for the Lower Mainland's reactive power requirements, and also contain a comprehensive description of the planning assumptions used in the analysis.	67

28.	The Commission Panel directs BCTC to submit by September 30, 2007, a report for the Fox Creek Project detailing changes to project scope, schedule and cost between the request for approval and the completed project. The report should explain and justify changes to the project scope and schedule, provide explanations for all material cost variances, and include a discussion of changes to its capital planning process that BCTC has implemented or recommends based on experience with this project.	73
29.	The Commission Panel does not approve the Chapman Fibre Optic Cable Replacement project as proposed because absent an explanation of the large expenditure in F2012, it is higher cost than a potential alternative and does not appear to be justified by safety, environmental, or compliance considerations.	77
30.	Therefore, the Commission Panel directs BCTC to conform to the directives made in the F2006 TSCP Decision and the F2006 TSCP Update Decision with respect to Sustaining Capital expenditures.	82
31.	The Commission Panel directs BCTC to use an inflation factor of 2.0 percent for each of F2008 and F2009 to budget for Sustaining Capital based on the forecast of BCCPI. The Commission Panel invites BCTC to provide comprehensive justification of any other inflation adjustment it may propose for F2009 and beyond, as part of its next capital plan filing.	83
32.	For clarity, the Commission Panel approves as being in the public interest Sustaining Capital expenditures of $83.1 million in each of F2008 and F2009 when expressed in F2007 dollars, and further Third-Party Funded expenditures of $2.9 million and $1.9 million expressed on the same basis. The same amounts expressed in nominal dollars are Sustaining Capital expenditures of $84.8 million and $86.5 million in F2008 and F2009 respectively, and Third-Party Funded expenditures of $3.0 million and $2.0 million in F2008 and F2009, respectively.	83
33.	The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro’s IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro’s IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro’s IT systems, provided that it is not necessary to disclose confidential negotiations or commercial interests to do so.	87

34.	In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 TSCP, modified to show the total dollar amount of each project and the relative priority at the time of approval.	87
35.	The Commission Panel finds the requested F2008 capital expenditures for the BCTC Capital Control Centre Sustainment project are in the public interest.	88
36.	The Commission Panel finds the requested F2008 expenditures for the BCTC Capital Facilities assets projects are in the public interest.	89
37.	The Commission Panel directs BCTC to file a report related to Policy Action 12 and Policy Action 13 on or before December 1, 2007. The report should comment on the progress of consultation initiatives and further steps that BCTC considers to be appropriate to implement Policy Action 12 and Policy Action 13. In the filing, BCTC may also seek regulatory comments or direction that may be useful for the creation of the Congestion Relief Policy and the evolution of the TEP. If BCTC does seek such regulatory comments or direction, it may be helpful for BCTC to include a policy discussion paper that could be circulated to stakeholders for comment prior to Commission comments or directions.	92
38.	To continue to satisfy the reciprocity requirements under the pro-forma OATT, BCTC must carefully assess the implications of FERC Order No. 890, and therefore the Commission Panel directs BCTC to bring its assessment of FERC Order No. 890 forward to the Commission once its consultations and assessments are concluded.	93
39.	The Commission Panel directs BCTC to file a report on or before December 1, 2007 that first identifies congested paths, if any, that might be economically resolved by generation re-dispatch, and then assesses opportunities for resolving congestion by re-dispatching generation. This report may form part of the report related to Policy Action 12 and Policy Action 13.	97

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of June 2007.

Original signed by:

ROBERT H. HOBBS
CHAIR

Original signed by:

LIISA A. O'HARA
COMMISSIONER

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-69-07

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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 F2008 to F2017

BEFORE: R.H. Hobbs, Chair
L.A. O'Hara, Commissioner June 15, 2007

O R D E R

WHEREAS:

A. Commission Order No. G-67-06 dated June 14, 2006 responded to the British Columbia Transmission Corporation ("BCTC") Transmission System Capital Plan F2006 to F2015 Update; and

B. BCTC filed its Transmission System Capital Plan F2008 to F2017 dated December 21, 2006 (the "F2008 TSCP", 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 F2008 TSCP meets the requirements of Sections 45(6) and 45(6.1) of the Act, approves the F2008 TSCP 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-5-07, established a written public hearing process and Regulatory Timetable for the review of the Application and, by Order No. G-24-07, established a Revised Regulatory Timetable; and

E. The Commission Panel has considered the Application, evidence, and submissions of intervenors and the Applicant.

NOW THEREFORE the Commission orders as follows:

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

2. The F2008 TSCP is approved pursuant to Section 45(6.2)(a) of the Act.

…/2

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, 2008 and March 31, 2009 ("F2008" and "F2009", respectively) are determined to be in the public interest, except for the following projects:

    - Corporate Network Segmentation
    - Backup Environment Separation – Edmonds
    - Chapman Fibre Optic Cable Replacement component of Telecom Annual Program

4. The Sustaining Capital Portfolio budget is reduced to $84.8 million for F2008 and to $86.5 million for F2009, stated in nominal dollars and net of Third-Party Funded expenditures.

5. BCTC is directed to comply with all determinations and instructions set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of June 2007.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated January 19, 2006 and Order No. G-5-07 establishing a Written Hearing Process and Regulatory Timetable
A-2	Letter dated February 19, 2007 with Information Request No. 1 for BCTC
A-3	Letter dated March 5, 2007 denying request from the District of Mission to vary Order No. G-91-05 and Decision dated September 23, 2005
A-4	Letter dated March 8, 2007 denying request from ESVI to include the 2007 Energy Plan as evidence in the proceeding
A-5	Letter dated March 13, 2007 and Order No. G-24-07 issuing a Revised Timetable
A-6	Letter dated April 12, 2007, responding to request from the District of Mission to extend the Regulatory Timetable
APPLICANT DOCUMENTS	
B-1	Letter dated December 21, 2006 filing BCTC's Transmission System Capital Plan F2008 to 2017 Application
B-2	Email dated January 29, 2007 filing publication schedule for the Notice of Written Public Hearing
B-3	Letter dated February 16, 2007 filing Errata to BCTC's Transmission System Capital Plan F2008 to 2017 Application (Exhibit B-1)
B-4	Letter dated March 7, 2007 filing response from ESVI for the BC Energy Plan to be admitted as evidence in the proceeding (Exhibit C5-3)
B-5	Letter dated March 12, 2007 advising that the responses to Information Requests will be made on March 14, 2007 and requesting an amendment to the Regulatory Timetable to extend the filing dates for Final Submissions
B-6	Letter dated March 14, 2007 filing Information Response to the Commission Information Request No. 1, BCOAPO Information Request No. 1, JIESC Information Request No. 1, BC Hydro Information Request No. 1 and ESVI Information Request No. 1 with attached Excel spreadsheet

EXHIBIT LIST

Exhibit No.	Description
B-7	**CONFIDENTIAL** – Letter dated March 14, 2007 filing response to the Commission Information Request 1.35.2
B-8	Letter dated March 20, 2007 filing response to Elk Valley and updated response to BC Hydro Information Request No. 1.7.4 with attached Excel spreadsheet
B-9	Letter dated March 22, 2007 filing updated response to Elk Valley Coal Corporation IR 1.1.0
B-10	Letter dated March 30, 2007 filing missing attachment to its response to the Commission Information Request 1.12.4
B-11	Letter dated March 30, 2007 filing report on progress of discussions with District of Mission on the routing of transmission circuits
INTERVENOR DOCUMENTS	
C1-1	**BRITISH COLUMBIA HYDRO POWER & AUTHORITY (BC HYDRO)** – Online notification dated January 22, 2007 filing request for Intervenor status
C1-2	Letter dated February 23, 2007 filing Information Request No. 1
C1-3	Letter dated March 12, 2007 filing responses to Commission Information Requests No. 1.34.1 and 1.125.1 to BCTC noting that the questions related to matters within BC Hydro's responsibility
C1-4	**CONFIDENTIAL** – Letter dated March 12, 2007 filing a response to Commission Information Request No. 1.125.1 to BCTC noting that the question related to matters within BC Hydro's responsibility
C1-5	Letter dated March 12, 2007 filing a response to Energy Solutions for Vancouver Island (ESVI) Information Request No. 1 to BCTC as questions related to load forecasts as these matters are within BC Hydro's responsibility
C2-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO)** - Received letter dated January 23, 2007 from Jim Quail requesting Intervenor Status and for Bill Harper, Econalysis Consulting Services
C2-2	Letter dated February 22, 2007 filing Information Request No. 1 to BCTC

EXHIBIT LIST

Exhibit No.	Description
C3-1	**WEST FRASER TIMBER CO. LTD.** - Received fax dated February 9, 2007 from David F. Humber requesting Intervenor Status
C4-1	**INDEPENDENT POWER PRODUCERS ASSOCIATION OF BC (IPPBC)** - Received letter dated February 14, 2007 from David Austin requesting Intervenor Status and for Steve Davis, President
C5-1	**ENERGY SOLUTIONS FOR VANCOUVER ISLAND (ESVI)**- Received online web registration dated February 14, 2007 from Ludo Bertsch, Horizon Technologies Inc., requesting Intervenor Status
C5-2	Letter dated February 23, 2007, filing Information Request No. 1 to BCTC
C5-3	Letter dated February 28, 2007 requesting that the BC Energy Plan be admitted as evidence in the proceeding and requesting a supplemental round of Information Requests
C6-1	**ELK VALLEY COAL CORPORATION (EVCC)** - Received email dated February 14, 2007 from J. David Newlands requesting Intervenor Status
C6-2	E-mail dated February 23, 2007 to BCTC filing Information Request No. 1
C7-1	**COLUMBIA POWER CORPORATION (CPC)** - Received email dated February 14, 2007 from Fred J. Weisberg, Weisberg Law Corporation requesting Intervenor Status and for Bruce Duncan, Vice President Strategic Planning
C8-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** – Letter dated February 15, 2007 requesting Intervenor status from R. Brian Wallace
C8-2	JIESC Information Request No. 1 dated February 23, 2007

EXHIBIT LIST

Exhibit No.	Description
C9-1	**FORTISBC INC.** – Received online web registration dated February 15, 2007 from Joyce Martin requesting Intervenor status
C10-1	**DISTRICT OF MISSION** – Letter dated March 5, 2007 from James Atebe, Mayor requesting late Intervenor status and filing correspondence
C10-2	Letter dated March 30, 2007 filing comments in process finalizing details of the proposed routing of transmission circuits Agreement with BCTC (Exhibit B-10)

INTERESTED PARTY DOCUMENTS

D-1	**CHADWICK**, Rob & Jo-Anne – Fraser River Safari – Registration as Interested Parties dated March 13, 2007
D-2	**BRAICH FAMILY** – Letter dated March 14, 2007 from C. Edward Hanman, Cox, Taylor, Counsel for the Braich Family

GLOSSARY AND ABBREVIATIONS

Acronym	**Term**
2007 Energy Plan	The BC Energy Plan: A Vision for Clean Energy Leadership
ATC	Available transfer capacity or Available transmission capacity
AESO	Alberta Electric System Operator
BC Hydro	British Columbia Hydro and Power Authority
BCCPI	British Columbia Consumer Price Index
BCOAPO	British Columbia Old Age Pensioners' Organization et al.
BCTC	British Columbia Transmission Corporation
BCUC or the Commission	British Columbia Utilities Commission
CE	Canadian Entitlement
CIP	Critical infrastructure protection
CPC	Columbia Power Corporation
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CRP	Contingency Resource Plan
DPUI	Delivery Point Unreliability Index
DSM	Demand Side Management
EENS	Expected Energy Not Served
EMS	Energy Management System
ETM	Electronic Temperature Monitor
ESVI	ESVI Energy Solutions for Vancouver Island Society
F2006 Application	F2006 to F2015 Transmission System Capital Plan Application
F2006 TSCP Decision	Order No. G-91-05 and the accompanying Reasons for Decision
F2006 TSCP Update Decision	Order No. G-76-06 and the accompanying Reasons for Decision
F2006 Update Application	Transmission System Capital Plan F2006 to F2015 Update Filing
F2008 TSCP	F2008 to F2017 Transmission System Capital Plan
FAC	Facilities design connections and maintenance
FERC	Federal Energy Regulatory Commission
GIS	Gas-Insulated-Switchgear
IEP	Integrated Electricity Plan
ILM	Interior to Lower Mainland

Acronym	**Term**
ILMTR	Interior to Lower Mainland Transmission Reinforcement
IPPBC	Independent Power Producers Association of British Columbia
IPP	Independent Power Producer
IT	Information Technology
JIESC	Joint Industry Electrical Steering Committee
kV	kilovolt
LTAP	Long-Term Acquisition Plan
LT-PTP	Long-Term Point-to-Point
Model	Sustainment Investment Model
MMK	MMK Consulting Inc.
NERC	North American Electric Reliability Council
NITS	Network Integration Transmission Service
NPV	Net Present Value
NTL	Northwest Transmission Line
OATT	Open Access Transmission Tariff
OM&A	Operating, Maintenance and Administrative expense
PER	Personnel performance, training and qualifications
TMSPE	TransMountain Pumping Stations Expansion
RAS	Remedial Action Scheme
RFP	Request For Proposal Detailed Specifications
ROW	Right-of-Way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCMP	System Control Modernization Project
SD9	Special Direction No. 9
South Interior SDP	South Interior Bulk System Development Plan Rreport
ST-PTP	Short-Term Point-to-Point
SVC	Static VAr Compensator
TTC	Total Transfer Capability
TEP	Transmission Expansion Policy
TPAC	Transmission Planning Advisory Council

Acronym	**Term**
TSCP	Transmission System Capital Plan
UCA, the Act	Utilities Commission Act
UMS	UMS Group Inc.
VIT	Vancouver Island Terminal
VITR	Vancouver Island Transmission Reinforcement Project
WECC	Western Electricity Coordinating Council