IN THE MATTER OF

BRITISH COLUMBIA TRANSMISSION CORPORATION

AND

AN APPLICATION FOR A
CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
FOR THE INTERIOR TO LOWER MAINLAND TRANSMISSION PROJECT

DECISION

August 5, 2008

Before:

Robert H. Hobbs, Panel Chair and Commissioner
Nadine F. Nicholls, Commissioner
Anthony J. Pullman, Commissioner

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS

TABLE OF CONTENTS

1.0 BACKGROUND AND REGULATORY PROCESS

On November 5, 2007 British Columbia Transmission Corporation ("BCTC") filed an application ("Application") with the British Columbia Utilities Commission ("Commission", or "BCUC") for an order issuing a Certificate of Public Convenience and Necessity ("CPCN") for its proposed project to increase the transfer capability of the Interior to Lower Mainland ("ILM") grid ("ILM Project").

1.1 The Applicant

BCTC is a provincial Crown Corporation that began operations August 1, 2003. Under the *Transmission Corporation Act*, and a number of designated agreements between BCTC and BC Hydro and Power Authority ("BC Hydro"), BCTC has the responsibility to operate and manage the BC Hydro-owned transmission system. BCTC is also responsible for planning, constructing and obtaining all regulatory approvals for enhancements, reinforcement, and sustaining and growth investments to the transmission system, and for entering into commitments and incurring expenditures for capital investments on the transmission system. BC Hydro continues to own the core transmission assets and is required to make capital expenditures to support these investments if such expenditures are approved by the Commission. Certain other capital assets, such as control centres, are funded and owned by BCTC.

1.2 Order Sought

BCTC seeks an Order granting a CPCN for the ILM Project pursuant to sections 45 and 46 of the *Utilities Commission Act*, ("*UCA*" or the "Act") as follows:

"1. A Certificate of Public Convenience and Necessity is granted to BCTC for the ILM Project as described in the ILM Application and modified by the Decision issued concurrently with this Order.

2. BCTC will comply with the directions of the Commission in the Decision issued concurrently with this Order.

3. Prior to awarding major contracts or proceeding with construction of the ILM Project, BCTC is to report the final route alignment, an updated ILM Project cost, and any proposed P3 [Public Private Partnership] arrangement to the Commission. BCTC will also provide its recommendations to the Commission on whether the latest BC Hydro Load Forecast, NITS [Network Integration Transmission Service] application or Long Term Acquisition Plan warrant adjustment to the ILM Project timing and will apply for any further approvals or amendments as necessary.

4. BCTC will file with the Commission quarterly progress reports on the ILM Project schedule and costs, followed by a final report on project completion."

(BCTC Argument, Appendix A)

BCTC submits that it will obtain and rely on the then most recent information available prior to proceeding with the implementation of the ILM Project. In turn, the Commission will have an opportunity to consider this information and BCTC's assessment to ensure that these are not materially different from the Commission's present assessment of the ILM Project.
(BCTC Argument, para. 4-5)

1.3 ILM Project Description

The ILM Project consists of a new 500 kV ac transmission line ("5L83") from the Nicola substation ("NIC") near Merritt to the Meridian substation ("MDN") in Coquitlam, a series capacitor station near the mid-point of the line, and 500 kV single circuit terminations at NIC and MDN. The new line would parallel an existing 500 kV ac transmission line for most of its 246 km length. The ILM Project is estimated to cost $602 million ($2014) and is scheduled to enter service in October 2014 (Exhibit B-1, pp. 6-7). A more complete description of the ILM Project is provided in Section 2.2 of this Decision.

1.4 Regulatory Background

The need to reinforce the ILM grid and increase its transfer capability has been discussed by BC Hydro and BCTC for a number of years.

In its November 19, 2004 Reasons for Decision on the 2004 Transmission System Capital Plan, the Commission noted at p. 30 that BC Hydro's Resource Expenditure and Action Plan ("REAP") of March 31, 2004 contemplated a F2014 in-service date ("ISD") for 5L83 and since no evidence had been presented that an earlier ISD is required, the Commission approved the definition phase expenditures for 5L83 as set out in BCTC's Capital Plan.

In Order G-69-07 dated June 15, 2007 and the Reasons for Decision on the F2008-F2017 Transmission System Capital Plan ("F2008 TSCP Decision"), the Commission noted that the preferred solution for the ILM grid was expected to be identified in May 2007 with the earliest ISD of October 2014.

The issue of the ILM grid reinforcement was also discussed at length during BC Hydro's 2006 Integrated Electricity Plan ("IEP") / Long-Term Acquisition Plan ("LTAP") proceeding. In Order G-29-07 dated May 11, 2007 the Commission accepted that the ILM grid reinforcement was required sometime in the 7 to 15 year timeframe regardless of decisions on the re-powering of Burrard Thermal Generating Station ("Burrard"), and stated that, in light of the loss savings, potential trade benefits, and possibility for implementation delays associated with the ILM Project, it expected that BCTC would be proceeding with its current schedule to bring forward a CPCN application for the ILM Project, and that the ILM Project CPCN application will contain a comprehensive comparison of route alternatives and a comprehensive evaluation of trade benefits (Reasons for Decision accompanying Order G-29-07, p. 173).

1.5 The Regulatory Process

On November 5, 2007 BCTC filed its Application. By Order G-137-07 dated November 8, 2007 the Commission established the first steps in the regulatory process, including a Procedural Conference scheduled for December 20, 2007 (Exhibit A-1).

BCTC stated that it had taken a number of steps with private property owners who may be affected by the ILM Project and had:

> "… mailed property owners:
>
> (a) A letter in January 2007 (Appendix S-1);
>
> (b) Copies of a newspaper advertisement in March 2007 (Appendix S-3);
>
> (c) Three Project Updates in April, June and August, 2007 (Appendix S-4);
>
> (d) Copy of a newspaper advertisement in November 2007 (attached) regarding the filing of the CPCN Application and the BCUC Procedural Order; and
>
> (e) Project Update in February 2008 providing details of the three Community Input Sessions (attached). BCTC also placed Notices in local newspapers regarding the upcoming Community Input Sessions."
>
> (Exhibit B-10, Harris/Casselman 2.7.A)

By letter dated December 19, 2007 the Commission requested that BCTC make opening comments at the Procedural Conference that would address issues raised in certain Information Requests ("IRs") issued by the Commission and Intervenors concerning BCTC's decision to seek a CPCN prior to applying for an Environmental Assessment Certificate ("EAC") and resolving the Public Private Partnership ("P3") issue, and that in its opening comments, BCTC should also comment on the appropriate scope of the proceeding or, in the alternative, suggest a process for determining the scope of the proceeding (Exhibit A-4).

At the first Procedural Conference held on December 20, 2007, two major issues were discussed: the issue of proceeding with the CPCN in advance of the EAC, and the issue of First Nations consultation and accommodation.[1]

---

[1] The terms "First Nations" and "aboriginal" are not used in a consistent fashion by BCTC, BC Hydro or certain Intervenors. For the purposes of this Decision, the Commission Panel uses these terms interchangeably.

Counsel for BCTC stated that proceeding with the CPCN in advance of the EAC was the choice of BCTC for a number of reasons, the first and most significant being that the Environmental Assessment ("EA") process and the parallel process of addressing the First Nations consultation and accommodation issues are expensive. BCTC submitted that to wait for the EAC before applying for the CPCN would cause it to incur significant costs and would put it in a position where, if the Commission did not accept that the result of the EA process was in the public interest, or determined that there should be some material change to what the EA process had approved, it would need to incur additional expense by having to go back and redo major portions of the EAC application.

BCTC also submitted that if it did not proceed with the application for a CPCN in advance of the application for an EAC, it would be difficult to meet a 2014 ISD as it would result in a CPCN application not being made until after the EAC had been issued.

BCTC submitted that it considered an option whereby the two processes move forward in parallel, and where the CPCN process is pushed back further into the timing of the EA process when there might be more information, and effectively the two would end at the same point in time. BCTC submitted that there are significant resource constraints in that scenario since both the CPCN and the EA processes are very labour intensive and tend to rely on the same resources, both internal and external (T1:11-14).

In support of BCTC's position, BC Hydro submits that until there is certainty, or greater certainty at least, that the ILM Project is not required at its earliest ISD, any deferral or delay in the process greatly and unnecessarily increases the risk of not meeting that ISD (T1:27).

Intervenors at the Procedural Conference made the following submissions on the matter. The British Columbia Old Age Pensioners *et al.* ("BCOAPO") submitted that it was concerned that a CPCN could be issued but subsequent developments could have significant cost-effectiveness implications, and that there were too many uncertainties to proceed. BCOAPO proposed a conditional CPCN which would require BCTC to file an updated report before the Commission either confirms or refuses a final CPCN or, in the alternative, if the proceeding continued, then it should be adjourned until the EA process had concluded (T1:30-32).

The Independent Power Producers of B.C. ("IPPBC") submitted it could support either of the BCOAPO's options (T1:35).

The Joint Industry Electricity Steering Committee ("JIESC") submitted that it was very concerned that the ILM Project will not meet its earliest ISD. JIESC commented on the BCOAPO options and urged the Commission "strongly to do the conditional process" (T1:38).

Kwikwetlem First Nation ("Kwikwetlem") submitted that the CPCN Application is premature, stating: "The only way this Commission could proceed with a CPCN ahead of the determination of aboriginal accommodation is if you presupposed that those costs would be negligible. And that would be completely wrong. Aboriginal accommodation costs are likely to be very significant for this project, or the project won't proceed" (T1:44).

As to the timeliness of the application, Kwikwetlem submits that the Commission should defer the Application "…for probably at least one year, to harmonize it both with the EA process and the consultation and accommodation process…. if two processes are one, it should be well developed before this matter proceeds further, and in my submission that's approximately a year and it's certainly six months" (T1:47-48).

No determinations were made regarding the timing of the granting of the CPCN, or regarding the conditions for the CPCN. By issuing Order G-172-07 and establishing a revised Regulatory Timetable, the Commission Panel implicitly rejected Kwikwetlem's request for a deferral of the process of as much as one year. It also rejected the BCOAPO's second option of an interim determination followed by an adjournment. The decision to issue or deny a CPCN and the terms and conditions upon which a CPCN would be issued will be made by the Commission Panel on the basis of the evidence and submissions before it in this proceeding.

At the Procedural Conference, the Commission Panel also established a process to determine whether the adequacy of consultation and accommodation with First Nations potentially affected by the ILM Project should be within the scope of issues the Commission Panel would examine during the proceeding.

As stated in a notice dated January 9, 2008 and prepared by BCTC (Exhibit B-4), the Commission Panel ordered that the process comprise the following steps:

1. Participants in the ILM Project proceeding were asked to provide BCTC, by January 3, 2008, the names of First Nations, other than those that are already identified in the Application, that they believed should be notified of the process to determine whether the adequacy of consultation and accommodation with First Nations should be within the scope of the issues the Commission Panel examines;

2. BCTC would send notice of the Commission Panel's intention to address the scoping question on consultation and accommodation to First Nations on or before January 11, 2008;

3. First Nations were asked to express their interest, if any, in making submissions on the scoping question by January 18, 2008;

4. BCTC and BC Hydro would file and circulate their submissions on the scoping question by January 21, 2008;

5. Intervenors in the ILM Project proceeding, as well as First Nations that had expressed an interest in the scoping question, were to file their submissions by February 4, 2008;

6. BCTC and BC Hydro would provide reply submissions by February 13, 2008; and

7. An oral phase of argument on the scoping question would take place on February 25, 2008.

The notice was distributed to 67 aboriginal groups. Expressions of interest were received from:

- Kwikwetlem;
- Vision Financial Services;
- Sto-Lo First Nation;
- Nlaka'pamx Nation ("Nlaka'pamx");
- Okanagan Nation Alliance ("ONA"); and
- Nlaka'pamux Nation Tribal Council ("NNTC")

BCTC and BC Hydro filed their submissions with the Commission on January 21, 2008. Intervenor submissions were received from BCOAPO, Terasen Utilities, Kwikwetlem, NNTC, ONA, and Upper Nicola Indian Band ("UNIB") (the last three Intervenors are referred to collectively as the "Joint First Nations") on or before February 4, 2008. Reply submissions were received by February 13, 2008.

By letter dated February 21, 2008 (Exhibit A-8), the Commission Panel concluded that it should not consider the adequacy of consultation and accommodation efforts on the ILM Project as part of its determinations in deciding whether to grant a CPCN for the ILM Project and issued its reasons in Letter L-6-08 (Exhibit A-8A).

Following the Procedural Conference, the Commission issued Order G-172-07 dated December 21, 2007, which revised the Regulatory Timetable and established an Oral Public Hearing to commence in Vancouver on April 14, 2008 and Community Input Sessions to be held in Merritt, Harrison Hot Springs and Coquitlam on March 14, 15 and 29, 2008, respectively (Exhibit A-5).

By letter dated March 4, 2008 the Commission advised that the Community Input Sessions in Harrison Hot Springs and Coquitlam were cancelled pursuant to the terms of Commission Order G-172-07 since less than four presentations had been scheduled for those Sessions, and that the individuals who had advised Commission Counsel of their intention to appear at those Sessions could make their presentations during the Oral Public Hearing (Exhibit A-9). By letter dated March 12, 2008 the Commission advised that the Community Input Session scheduled for

March 14, 2008 in Merritt had also been cancelled since the number of scheduled presentations was less than the minimum number of four presentations specified in Commission Order G-172-07.

By letter dated March 19, 2008 (Exhibit A-14), the Commission Panel stated that it was considering whether or not Procedural Conference No. 2 scheduled for Tuesday, March 25, 2008 by Order G-172-07 was necessary, and requested Intervenors to identify agenda items, if any, by March 20, 2008.

Following responses from Intervenors, the Commission issued Exhibit A-15, confirming the Procedural Conference No. 2 to address certain procedural matters, including whether an oral hearing was required or if the ILM proceeding could be completed as a written process.

The first issue considered in the Procedural Conference No. 2 was whether or not the oral hearing was necessary. The only Intervenors that identified issues for cross-examination during an oral hearing were IPPBC, BCOAPO, and Messrs. Casselman and Harris ("Harris/Casselman"). The description of issues identified by BCOAPO was limited to "unresolved First Nations issues that present a potential ratepayer risk" (T2:126). BCOAPO committed to providing a more detailed description of issues for the oral hearing, probably within 48 hours of a decision confirming the oral hearing (T2:162). IPPBC identified specific issues with reference to the evidence (T2:118-25). Mr. Harris, representing Harris/Casselman, also identified specific issues, and was of the view that a written process would provide a satisfactory opportunity to pursue those issues (T2:131).

BCTC accepted that the issues identified by Harris/Casselman were within the power of the Commission to consider (T2:133-35). BCTC submitted that the issues identified by IPPBC were more appropriate for a further IR process than cross-examination (T2:145), noting that IPPBC had not filed any IRs with the first round of IRs, and that the issues identified by IPPBC were a substitute for IPPBC leading evidence (T1:143), and noted that neither IPPBC led evidence, nor did any other Intervenor.

The Commission concluded that a written hearing process was adequate for review of the Application and issued Order G-61-08 being a revised Regulatory Timetable that converted the oral hearing process to a written hearing process, and cancelled the Oral Hearing scheduled for April 14, 2008. Individuals or groups who previously expressed an interest in making Community Input presentations were advised that the Commission Panel would endeavour to hear those presentations the week of April 14, 2008 (Exhibit A-17). No individuals or groups came forward with oral presentations, but some did submit letters of comment (Exhibit E-4; Exhibit E-5).

BCTC filed its Argument on May 12, 2009. As per directions provided to BC Hydro by the Commission in Exhibit A-17, BC Hydro also filed Argument on May 12, 2008 with respect to two inputs to the cost-effectiveness analysis, being the discount rate based on BC Hydro’s cost of capital and the value to be ascribed to energy losses.

By letter dated May 19, 2008, BCOAPO made an application for an adjournment of the proceeding pending the outcome of the Appeal, noting that the B.C. Court of Appeal had issued its decision granting Kwikwetlem Leave to Appeal from the Commission's ruling regarding the scope of its jurisdiction concerning the Crown's duty to consult and accommodate First Nations. By letter dated May 21, 2008 the Commission denied BCOAPO’s request (Exhibit A-21).

The following Intervenors filed their Argument on May 26, 2008: BC Hydro, BCOAPO, JIESC, IPPBC, City of Abbotsford, Harris/Casselman and Nlaka’pamx.

BCTC filed its Reply on June 3, 2008.

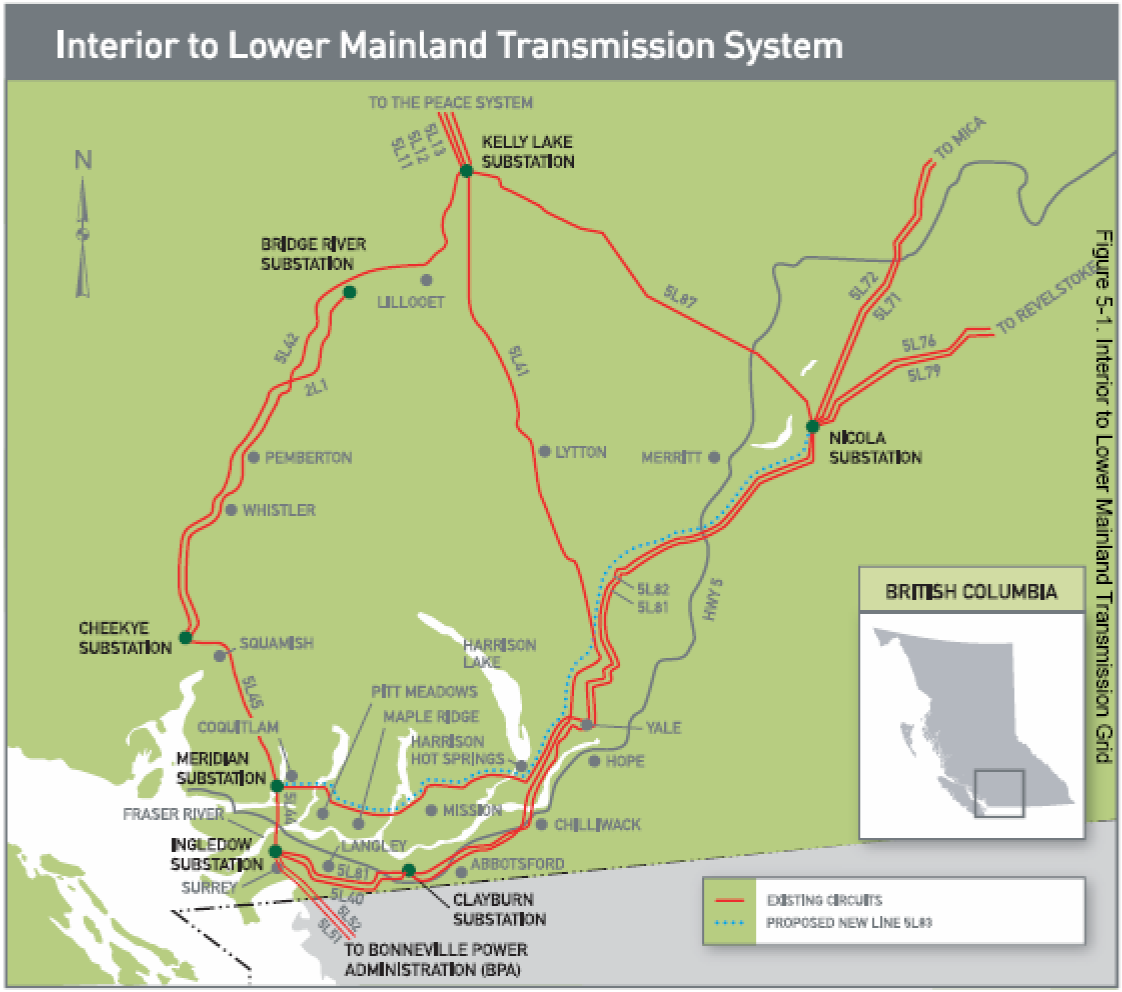
The Oral Phase of Argument, scheduled for Wednesday July 3, 2008, was cancelled by letter dated June 16, 2008 (Exhibit A-22).

2.0 PROJECT DESCRIPTION AND SCHEDULE

This Section describes the ILM Project, its schedule, the other approvals BCTC requires prior to implementation, and the team BCTC has assigned to its design and implementation. The possibility of the ILM Project being implemented by means of a P3 is also discussed.

2.1 The Existing ILM Grid

BCTC describes the ILM grid, shown in the diagram below, as the most critical transmission path in B.C. The ILM grid transmits electricity from the Interior region, where the bulk of BC Hydro's generation is located, to the Lower Mainland ("LM") and Vancouver Island ("VI") ("LM-VI") regions (also referred to collectively as the "Coastal region"), which together comprise approximately 70 percent of provincial demand. The ILM grid is also a key transmission path for both firm and non-firm trading activity. The ILM grid comprises eight 500 kV transmission lines. The power transfer from the Interior to the LM and VI regions takes place over four of these lines: 5L81 and 5L82 which connect NIC in the South Interior region to Ingledow ("ING") and MDN substations in the LM region; 5L42 which connects Kelly Lake substation ("KLY") in the Interior to Cheekye substation ("CKY"), and 5L41 which connects KLY to Clayburn substation ("CBN") in the LM region. Four additional lines allow for power sharing between the substations: 5L45 connects CKY and MDN in the LM region; 5L44 connects MDN and ING in the LM region; 5L40 connects CBN and ING in the LM region; and 5L87 connects NIC and KLY in the Interior. Five of the ILM lines (5L41, 5L42, 5L87, 5L81, and 5L82) are series compensated to increase transfer capability (Exhibit B-1 and Exhibit B-1-1, Appendix H, pp. 5-6). A map of this system is replicated below.



(Exhibit B-1, p. 43)

2.2 Physical Aspects of the ILM Project

The ILM Project as proposed by BCTC consists of the following physical components:

- a new 246 km long, 500 kV ac transmission line, 5L83, between NIC and MDN;
- a new 500 kV series capacitor station which would be located approximately at the mid-point of the new 500 kV circuit;
- modifications at NIC and MDN to accommodate the circuit terminations; and
- associated telecommunications, protection and control equipment. (Exhibit B-1, p. 6)

2.2.1 Transmission Line

BCTC proposes that 5L83 is a new single circuit steel tower transmission line between NIC and MDN, running parallel to the existing 5L82 for most of the 246 km length. When 5L82 was planned, an additional right-of-way ("ROW") width was acquired for portions of the NIC to MDN route, anticipating one or two future additional lines. BCTC states that approximately 156 km of the existing ROW is sufficient to accommodate 5L83, however new ROW and additional ROW width will need to be acquired for the remaining portions. (Exhibit B-1, p. 44)

BCTC states that it has identified 25 nodes on the 5L83 route, and 32 segments between these nodes. Several segments have more than one alignment alternative. A reference alignment comprised of 18 of the identified segments was selected based on use of existing ROW, not passing through First Nations reserve land, and preliminary environmental assessment information, and was used for estimating purposes (Exhibit B-1, p. 44; Exhibit B-5, BCUC 1.3.1). The remaining segments represent alternate alignments and routes. The segments in the reference alignment are identified in the table below (Exhibit B-1, pp. 47-53).

Reference Alignment	Distance	New ROW requirements (length, area, ownership)
Segment A-B	50.0 km	6.1 km widening, 7.1 ha area; 1 Crown, 3 private parcels
Segment B-C	19.4	4.4 km widening, 19.7 ha area; 1 Crown parcel 6.5 km new, 42.9 ha area; 1 Crown parcel
Segment C-D	19.0	19.0 km new, 125.0 ha area; 1 Crown parcel
Segment D-E	5.2	1.0 km widening, 3.2 ha area; 1 Crown parcel 3.9 km new, 19.5 ha area; 1 Crown parcel
Segment E-G1	13.0	13.0 km new, 65.0 ha area; 1 Crown parcel
Segment G1-H	5.2	5.2 km new, 26.0 ha area; 1 Crown parcel
Segment H-J1	5.5	5.5 km new, 27.5 ha area; 1 Crown parcel
Segment J1-L	13.0	13.0 km new, 65.0 ha area; 1 Crown parcel
Segment L-N	5.3	1.1 km widening, 4.3 ha area; 1 Crown parcel 4.2 km new, 21.0 ha area; 1 Crown parcel
Segment N-O	7.3	7.3 km widening, 30.8 ha area; 1 Crown parcel
Segment O-O1	9.8	9.8 km widening, 61.4 ha area; 1 Crown parcel
Segment O1-P	5.0	6.1 km widening, 7.1 ha area; 1 Crown parcel
Segment P-Q	29.5	0.8 km widening, 1.5 ha area; 1 Crown, 7 private parcels
Segment Q-R	8.7	8.7 km new, 57.4 ha area; 1 Crown, 4 private parcels
Segment R-S	10.7	All existing ROW
Segment S-T	22.6	All existing ROW
Segment T-U	8.7	0.9 km widening, 2.4 ha area; 1 Crown, 1 private parcel
Segment U-V	8.2	All existing ROW
Total	246.1 km	116.4 km, 586.8 ha area; 18 Crown, 15 private parcels

The reference alignment impacts approximately 148 residential properties, and will require new agreements over 5 residential and 10 non-residential privately held parcels, with 4 of these land parcels requiring new ROW and the remainder a widening of the existing ROW (Exhibit B-5, BCUC 1.90.1; Exhibit B-10, IPPBC 2.12.1, IPPBC 2.12.2). The total new ROW area required over privately held parcels is estimated at approximately 24.44 ha (Exhibit B-5, BCUC 1.90.2). There are no new ROW requirements over private land parcel crossings for the reference alignment between nodes B and P.

In response to concerns expressed by individual landowners regarding BCTC's ROW management practices (Harris/Casselman Argument, pp. 1-2; Exhibit E-4), BCTC states that it employs industry-accepted best management practices (Exhibit B-10, Harris/Casselman 2.4.B.i) and that on private lands it will take special measures, such as only utilizing herbicides if the owner consents to their use (Exhibit B-1, p. 122) and replacing aesthetic screen trees with fences (Exhibit B-14, Harris/Casselman 3.5.B.ii).

BCTC identified an alternate segment running directly between node C and node E, parallel to the existing 5L81 and 5L82. This alternate segment bypasses node D and is shorter than the reference alignment, however, the alternate segment passes through Spotted Owl Wildlife Habitat Area, and hence was not chosen as the reference alignment (Exhibit B-1, p. 47; Exhibit B-5, BCUC 1.3.5).

There are 10 nodes and 18 segments between node E and node N. The reference alignment is the shortest available route between nodes E and N, with a distance of 42 km. There are 16 possible alternate routes and alignments between nodes E and N, not including the two possible alignment alternatives for segment J-K (Exhibit B-1, pp. 47-53).

The shortest route possible using the nodes and segments identified by BCTC is 241.3 km and the longest route is 254.8 km.

BCTC stated that although the final route alignment will depend on results of technical and environmental studies and consultation with First Nations groups and other stakeholders, it anticipates that any changes would result in less than a 10 percent change in the length of the line (Exhibit B-5, BCUC 1.11.1).

BCTC states that all existing 500 kV circuits in B.C. use a flat conductor configuration, but both flat and delta configuration towers will be used for 5L83. Although delta towers are slightly taller and more expensive than flat configuration towers, a narrower profile can be achieved, reducing the amount of clearing and additional ROW width required. BCTC is proposing to use flat structures between nodes A and D, and between nodes O and R. (Exhibit B-1, pp. 48-49)

The delta tower configuration offers certain other advantages over the flat configuration. These advantages include a slightly higher power transfer capability, lower surge impedance, and lower electromagnetic field ("EMF") signature levels at the edge of the ROW (Exhibit B-7, BCOAPO 1.8.a). The delta tower configuration results in 56 percent lower magnetic field levels and 51 percent lower electric field levels at the edge of the ROW as compared to the flat configuration (Exhibit B-5, BCUC 1.8.6).

BCTC proposes to use a 4 bundle – SP926.7 45/7 aluminum conductor steel reinforced for 5L83 (Exhibit B-1, p. 54). BCTC stated that a cost-benefit analysis demonstrated that the additional cost of installing a larger conductor size in order to reduce losses could not be justified (Exhibit B-14, BCUC 3.200.3).

2.2.2 Series Capacitor Station

BCTC states that a series capacitor station is required near the mid-point of 5L83 to provide voltage support, increases the available capacity of the circuit and permits use of the full thermal rating. Five potential sites are identified for the series capacitor station:

"i. Ruby Creek ("RYC") – Greenfield site, near Node O, on land currently owned by BC Hydro;

ii. American Creek ("AMC") – Existing Series Capacitor station, near Node M, that would be expanded within the existing property line;

iii. Chapmans ("CHP") – Existing Series Capacitor station, near Node G, that would be expanded within the existing property line;

iv. Sawmill Creek ("SAW") – Greenfield site near Node H; and

v. North Skeemis ("NSK") – Greenfield site near Node G."

(Exhibit B-1, pp. 53-54)

BCTC uses the RYC site for the reference alignment and cost estimate because it best matches the reference alignment. The series capacitor bank has a rating for 2,727 amperes and 892 MVAr, and is insulated to 1,800 kV basic impulse level ("BIL") platform-to-ground (Exhibit B-1, p. 55).

BCTC stated that the series capacitor station will help to balance power flows on 5L83 with the rest of the power flows in the ILM grid and provided an analysis that showed this flow balancing resulted in overall loss savings of 21.4 MW in the ILM grid even though losses on 5L83 increased by some 15.4 MW (Exhibit B-5, BCUC 1.17.7).

2.2.3 Substation Modifications

BCTC states that at both MDN and NIC, 5L83 would be terminated at the existing 5L82 termination positions, and 5L82 would be relocated to new termination positions.

At NIC, a new circuit breaker, shunt reactor and associated equipment are required to create the new line position. In the course of re-terminating 5L82, certain modifications will be implemented to avoid limiting operating flexibility. These modifications include equipping the new breaker with staggered-pole-closing capability and new line termination surge arresters.

At MDN, the substation configuration is currently a double bus, double breaker configuration, but will ultimately become a breaker-and-a-third configuration. Consequently, the new termination bay will also include a second position, possibly for a future MDN to ING circuit. New breakers will be required for both the 5L82 and 5L83 line positions. (Exhibit B-1, pp. 55-57)

BCTC stated that later stages of operation may have loads in excess of 3,000 amperes, which exceeds the rating of certain components used in the MDN main bus. Replacing and upgrading certain components and connections in the main bus would be required to accommodate loads of up to 4,000 amperes (Exhibit B-5, BCUC 1.76.1 and BCUC 1.76.2).

2.2.4 Telecommunications, Protection and Control Equipment

The NIC and MDN facilities are already equipped with all necessary telecommunications, but a new telecommunications link would be required for the series capacitor station if it is not part of an existing facility. New protection equipment is included for each of the line terminations, as is integration to the new System Control Centres.

BCTC states that the series capacitor station will require a communication tower and antenna, a Class 1 MW digital microwave radio, a Synchronous Optical Network, plus other associated equipment. Depending on the final site chosen for the series capacitor station, a separate repeater station may be required to obtain line-of-sight communications.

The 5L81 and 5L82 protection systems may be affected by the new parallel line and will need to be modeled and if required, re-calibrated. The 5L83 protection relays employ a scheme that requires real-time communications between the protection relays at the series capacitor bank and the protection relays at both NIC and MDN. (Exhibit B-1, p. 58)

2.3 Public Private Partnership

BCTC states that it has submitted the Application under the assumption of a conventional implementation of the ILM Project, but points out that under a direction from the Province of British Columbia (“Province” or “government”) dated July 3, 2007 Crown Corporations must assess all capital projects greater than $20 million for suitability as a P3, and that the assessment required to comply with the Province’s requirements could not be completed in time for consideration in the review of the CPCN Application. BCTC is therefore seeking approval of the ILM Project, assuming BCTC will implement the ILM Project with BC Hydro as the asset owner. However, BCTC states that if its P3 assessment, which is anticipated to be prepared after the completion of the proceeding to review the Application, indicates that a P3 arrangement is appropriate for the ILM Project, it will “return to the Commission if any further approvals are required” (Exhibit B-1, p. 62).

BCTC stated that the Commission has jurisdiction under section 45(1) and (6.1) of the Act to examine whether a proposed project, and the expenditures associated with it, are in the public interest. As P3 arrangements can be used to trade off project costs against protection from risks, the selection of a particular P3 arrangement can affect the overall project costs and associated ratepayer impacts. In that context, it is open to the Commission to review the risk and cost associated with potential or proposed P3 arrangements.

BCTC noted that the Commission also has the jurisdiction to undertake a prudence review of actual project costs, usually as part of a subsequent revenue requirements proceeding and that the appropriateness of its selection of a P3 arrangement in this particular instance could be part of an ex-post facto prudence assessment.

BCTC stated that, while it has not considered this issue in detail given the current status of the P3 issue, it did not believe a separate “approval” for a P3 arrangement was necessary unless the P3 partner was providing utility service under the Act (Exhibit B-10, BCUC 2.125.4).

BCTC stated that the P3 assessment for the ILM Project was scheduled to be completed by October 2008 (Exhibit B-5, BCUC 1.4.1), and that, in the event that a P3 arrangement is proposed, it would report the P3 arrangement to the Commission and would seek approval for any terms or conditions of the P3 arrangement that were not consistent with the CPCN granted by the Commission (Exhibit B-10, BCUC 2.125.5).

2.4 Other Approvals

BCTC lists the Canadian federal and provincial approvals it requires for the ILM Project in Tables 10-1 and 10-2 respectively of its Application (Exhibit B-1).

BCTC states that the ILM Project is subject to a detailed EA process under the *British Columbia Environmental Assessment Act* (“*BCEAA*”), and that, while it anticipates filing its EAC application with the British Columbia Environmental Assessment Office (“EAO”) after receipt of a CPCN, it had carried out a preliminary environmental overview assessment of the potential biological, physical, socioeconomic and heritage effects of the ILM Project. BCTC reports that the only potential material issues which have been identified as part of this review are potential effects on the Spotted Owl (*Strix occidentalis*) and its habitat, on the Oregon Spotted Frog (*Rana pretiosa*) and on a Garry Oak (*Quercus garryana*) ecosystem near Yale, but that none of these are expected to result in significant impacts or effects that would have a material impact on the timing, scope or cost of the ILM Project (ExhibitB-1, pp. 100-101).

By letter dated June 5, 2008, BCTC filed the final Terms of Reference (“TOR”) for the EAC application with the EAO.

2.5 Project Team

The composition of the ILM Project Team is summarized in the Application. BCTC has retained BC Hydro Engineering Services to provide significant engineering support for the ILM Project.

Golder Associates Ltd. is the ILM Project’s environmental consultant and is working with a number of sub-consultants who bring specialized expertise required for the full complement of discipline-specific technical studies required for the EAC application.

Under the Key Agreements between BCTC and BC Hydro, BC Hydro retains primary responsibility for properties and property rights and for aboriginal relations with respect to transmission system assets, operations, and new capital projects. All other aspects of the ILM Project are BCTC's responsibility (Exhibit B1, pp. 32-41).

2.6 ILM Project Schedule

BCTC states that its "project plan is based on the following milestones:

- CPCN issued: summer 2008;
- Environmental Assessment Certificate issued: summer 2009;
- Right of Way Acquisition: summer 2009 to spring 2012;
- Material Procurement: 2010 to 2014;
- Right of Way Preparation: 2010 to 2011;
- Tower Construction and Conductor Stringing: 2011 to fall 2014; and
- In-service Date: fall 2014."

(Exhibit B-1, p. 7)

The Application includes a Definition Phase schedule and an Implementation Phase schedule (Exhibit B-1, pp. 64-68). BCTC later submitted an updated and expanded Definition Phase schedule (Exhibit B-5, BCUC 1.5.1).

BCTC stated that the Definition Phase of the ILM Project started with public consultation on January 3, 2005. Critical upcoming milestones prior to the Implementation Phase include the Commission decision on the Application by September 19, 2008, the EAC application October 1, 2008, and the Ministers' decision by September 11, 2009 (Exhibit B-5, BCUC 1.5.1).

Following receipt of a CPCN, BCTC stated that it intends to complete the EAC application review process, complete a P3 business case, and receive tenders for the major components of the ILM Project. After these steps have been completed but prior to accepting tenders for the major components of the ILM Project, BCTC stated that it will report the final route alignment, an updated project cost, and any proposed P3 arrangement, if adopted, to the Commission, and will also provide its recommendations as to whether the latest BC Hydro load forecast, Network Integrated Transmission Service ("NITS") application or BC Hydro LTAP warrant adjustment to the ILM Project timing (Exhibit B-5, BCUC 1.84.1).

The Implementation Phase of the ILM Project is shown as beginning on December 1, 2008, with an ISD of October 31, 2014 and concluding on December 31, 2015, with the only activity taking place between the ISD and the end of the ILM Project being restoration (Exhibit B-1, pp. 65-68).

3.0 JURISDICTION AND OTHER LEGAL ISSUES

This Section considers the legal and policy framework that may affect the ILM Project. In particular, in February, 2007 the Province released the BC Energy Plan – A Vision for Clean Energy Leadership ("2007 Energy Plan"). On May 1, 2008 the *Utilities Commission Amendment Act 2008* ("*UCAA 2008*") received Royal Assent and was brought into force.

3.1 2007 Energy Plan

The 2007 Energy Plan contains a number of policy actions relating to BCTC and the provincial transmission system, three of which are germane to these proceedings:

> "12. The BC Transmission Corporation 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;
>
> 13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy; and
>
> 14. Ensure that the province remains consistent with North American transmission reliability standards."
>
> (2007 Energy Plan, p. 39)

IPPBC observes that BCTC stated that one of the priority initiatives in response to the 2007 Energy Plan is to report to the government on the analysis of transmission system losses and provide an action plan on loss reduction initiatives (Exhibit C10-3, attachment from BCTC F2009-F2018 Transmission System Capital Plan proceeding, Exhibit B-5-1, BCUC 1.8.1).

In addition, the 2007 Energy Plan addresses Burrard and states that:

> "By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014.
>
> However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise" (2007 Energy Plan, p. 11).

The relevance of Burrard is considered by the Commission Panel in its analysis of the alternatives available to BCTC and BC Hydro to reinforce the ILM grid, one of which fell into the category of "non-wires" solutions and revolved around demand side management ("DSM") and the development of dependable generating capacity in BC Hydro's Coastal region.

3.2 Special Direction 10

On June 25, 2007 the Province issued Special Direction 10 ("SD 10") to the Commission, which requires the Commission when considering an application for a CPCN under section 45 of the *UCA* to consider the self-sufficiency and insurance criteria, as follows:

> "The Commission must use the criterion, that the authority is to achieve energy and capacity self-sufficiency by becoming capable of meeting, by 2016 and each year thereafter, the electricity supply obligations, and exceeding as soon as practicable but no later than 2026 the electricity supply obligations by at least 3,000 gigawatt hours per year and by the capacity required to integrate that energy in the most cost-effective manner solely from energy generating facilities within the Province, assuming no more in each year than the firm energy capability from the assets that are hydroelectric facilities."

The self-sufficiency objective of BC Hydro was established in section 64.01 of the *UCA*.
The relevance of section 64.01 of the *UCA* and SD 10 is considered by the Commission Panel in Section 7 of this Decision dealing with line losses.

3.3 Utilities Commission Act

Section 46 of the *UCA* as amended by the *UCAA 2008* requires the Commission to consider the Province's energy objectives before granting a CPCN. Section 46(3.1) of the *UCA* states:

> 46 (3.1) In deciding whether to issue a certificate under subsection (3), the commission must consider
>
> (a) the government's energy objectives,
>
> (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and
>
> (c) whether the application for the certificate is consistent with the requirements imposed on the public utility under sections 64.01 and 64.02, if applicable.

Section 1 of the *UCA* as amended by the *UCAA 2008* defines the "government's energy objectives" as:

> "(a) to encourage public utilities to reduce greenhouse gas emissions;
>
> (b) to encourage public utilities to take demand-side measures;
>
> (c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;
>
> (d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;
>
> (e) to encourage public utilities to use innovative energy technologies (i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or (ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;
>
> (f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation."

Section 5 of the *UCA* as amended by the *UCAA 2008* requires the Commission to conduct an inquiry to make determinations with respect to British Columbia's infrastructure and capacity needs for electricity transmission for the period ending 20 years after the day the inquiry begins.

3.4 Public Interest

Sections 45 and 46 of the *UCA* authorize the Commission to issue, refuse to issue, or issue with conditions, a CPCN for a project such as the ILM Project. In deciding whether to issue a CPCN, the Commission must determine whether a project meets the test of public convenience and necessity, and properly conserves the public interest. The *UCA* does not define public convenience and necessity, or public interest.

The Commission has considered the issue of what constitutes the public interest and public convenience and necessity in several recent decisions. In the Vancouver Island Generation Project ("VIGP") Decision, the Commission concluded that "the test of what constitutes public convenience and necessity is a flexible test" (VIGP Decision, p. 76). In the Vancouver Island Transmission Reinforcement Project ("VITR") Decision, the Commission found "that there is a broad range of interests that should be considered in determining whether an applied-for project is in the public convenience and necessity" and "that it is both impractical and undesirable to attempt a precise definition of general application" (VITR Decision, p. 15). In the Amended and Restated Long-Term Energy Purchase Agreement ("LTEPA+") Reasons for Decision, the Commission reiterated the foregoing conclusions and added that it "should not exclude from consideration in determining the public interest any class or category of interests which form part of the totality of the general public interest" (LTEPA+ Decision, p. 29).

In this proceeding, there were no comments or debate concerning the scope of the public interest.

Commission Determination

Consistent with previous decisions, the Commission Panel accepts that there is a broad range of interests that should be considered in determining whether the ILM Project is in the public interest, and that the test of what constitutes the public interest is a flexible test. Socioeconomic, environmental and other non-financial considerations may be relevant to a determination of the public interest and are considered in Section 9 of this Decision.

3.5 EAC and Duty to Consult and Accommodate

BCTC requires an EAC for the ILM Project before it can proceed (Exhibit B-1, Appendix O). The EAO has issued a section 11 procedural order for the ILM Project, and an appendix to that order lists First Nations and other groups that must be consulted in the EA process (Exhibit B-1, Appendix P).

The TOR approved by the EAO on May 23, 2008 and filed June 5, 2008 (Exhibit B-7-2) require BCTC to describe its First Nations consultation activities and its efforts to address First Nations issues (pp. 4-5). The TOR also require BCTC to identify First Nations interests and potential impacts, to develop strategies to avoid, minimize or otherwise mitigate potential effects of construction and operation activities (pp. 32-33), and to summarize commitments developed through consultation with First Nations to mitigate impacts (p. 45).

In both the VITR Decision and Revelstoke Unit 5 Decision, the Commission relied on the EA process, and concluded in the VITR Decision:

> "The government has legislated regulatory approvals that must be obtained before VITR proceeds. Pursuant to Section 8 of the EAA, BCTC requires an EAC for VITR. Given the Section 11 Procedural Order and the Terms of Reference for VITR, the Commission Panel is satisfied that a process is in place for consultation and, if necessary, accommodation. In the circumstances of VITR, the EAO approval, if granted, will follow some time after this decision. Through this legislation, the government has ensured that the project will not proceed until consultation and, if necessary, accommodation has also concluded. The Commission Panel concludes

> that it should not look beyond, and can rely on, this regulatory scheme established by the government" (p. 48).

In the Revelstoke Unit 5 Decision, the Commission said:

> "The Provincial and Federal Governments have created legislation, the Environmental Assessment Act and the Canadian Environmental Assessment Act, which ensure that regulatory approvals must be obtained before Revelstoke Unit 5 can proceed and that the project will not proceed until consultation and, if necessary, accommodation has been completed" (p. 34).

In the ILM Application, BCTC relies on the Commission's finding in the VITR Decision that the Commission can rely on the EA process to satisfy the First Nations consultation and possible accommodation requirements applicable to the Project (Exhibit B-1, pp. 15-16).

BCTC describes its First Nations consultations in section 8 of the Application and provides a list of the 30 First Nations that have accepted initial capacity funding. BCTC submits that Comprehensive Capacity Funding Agreements (Exhibit B-5, BCUC 1.103.1) have been distributed to many First Nations and that funds are being made available for their participation and costs in activities related to the EA process (Exhibit B-1, p. 141).

During the Procedural Conference held on December 20, 2007, BC Hydro supported BCTC's position to rely on the EA process, and submitted that consideration of the adequacy of consultation and accommodation is not within the scope of the CPCN proceeding (T1:27). Kwikwetlem, UNIB, and the Nlaka'pamx disagreed with BCTC's and BC Hydro's position.

During the Procedural Conference, a process for consideration of the scope of the proceeding regarding First Nations issues was established (T1:86-88). The question for consideration was stated as follows:

> "Should the Commission Panel consider the adequacy of consultation and accommodation efforts on the ILM Project as part of its determinations in deciding whether to grant a CPCN for the ILM Project?"

The Commission reviewed submissions from BCTC, BC Hydro, Terasen, BCOAPO, Kwikwetlem and the Joint First Nations, and decided that it should not consider the adequacy of consultation and accommodation efforts as part of its determinations in deciding whether to grant a CPCN (Exhibit A-8). In its reasons, the Commission followed the reasons provided in both the VITR Decision and the Revelstoke Unit 5 Decision and provided further comments. In doing so, the Commission rejected the submissions of Kwikwetlem and the Joint First Nations that the VITR Decision and the Revelstoke Unit 5 Decision should not be followed (Exhibit A-8A).

The issue of First Nations participation in the CPCN proceeding also arose during the Procedural Conference. Kwikwetlem submitted that if the adequacy of consultation and accommodation is outside the scope of the proceeding then it is "...effectively...shut out of the proceeding and probably wouldn't participate" (T1:48). BCTC submitted that the CPCN proceeding provided First Nations and other parties to apply for Intervenor funding, express their concerns, participate in the IR process and test evidence, and that a ruling with respect to the adequacy of consultation does not impact a party's ability to put its case forward to the Commission (T1:61).

While rejecting the submissions of the First Nations Intervenors regarding the scope of the proceeding, the Commission emphasized that the First Nations could still participate in the hearing, stating:

> "The relevance to this proceeding of the potential impacts of the cost of accommodation, including project scope or design changes to accommodate First Nations interests, does not appear to be disputed by anyone (BCTC Reply, p. 6). In fact, that evidence may helpfully explain recommendations made by BCTC regarding the scope and design of the ILM Project. First Nations are entitled to full and fair participation in this proceeding." (Exhibit A-8A, p. 5)

Several First Nations Intervenors informed the Commission that they did not intend to submit evidence, because of the Commission's decision regarding the adequacy of consultation and accommodation (Exhibits C5-5, C7-7, C12-6, and C13-6).

By letter dated March 6, 2008 (Exhibit C5-4), counsel on behalf of Kwikwetlem notified the Commission that it had filed Notice of Application for leave to appeal the Commission's decision on the First Nations scoping issue (Exhibit A-8), and requested a stay of proceedings until the B.C. Court of Appeal has rendered its decision. The Commission concluded that it did not have jurisdiction to stay the proceedings and denied the request (Exhibit A-13).

By letter dated March 7, 2008 (Exhibit A-11), the Commission sought comments on the matters raised in the Kwikwetlem letter from all participants by March 11, 2008 with reply comments from Kwikwetlem by March 12, 2008. The Commission also sought comments on whether or not the pre-hearing regulatory process, including the Community Input Session scheduled for March 14, 2008 in Merritt, should also be suspended in the event the hearing is suspended (Exhibit A-11). On March 25, 2008, at the second Procedural Conference, the Commission Panel considered a request by the Joint First Nations that the oral public hearing be adjourned (Exhibit C7-8). The request of the Joint First Nations was a request for an adjournment of the written process pending an application that was to be filed on March 25, 2008 for leave to the B.C. Court of Appeal of the scope ruling in Exhibit A-8, with reasons found in Exhibit A-8A (T2:107). The Joint First Nations submitted there is no urgency to proceed as scheduled, and that some or all of the work done may need to be redone depending on the court's directions to the Commission (T2:109; T2:161).

Whereas the reasons for denying the Kwikwetlem request for a stay of proceedings had turned on the question of jurisdiction, that was not the case for the Joint First Nations' request. The Commission accepted, for the purposes of the adjournment decision, submissions of BCTC and BC Hydro regarding the urgency associated with the project. The Commission further accepted that if the CPCN is not granted at the conclusion of the proceeding the work will not need to be redone, and if the CPCN is granted at the conclusion of the proceeding, the evidence regarding the adequacy of consultation and accommodation will need to be filed, but was not related to many issues in the proceeding, such as need. The Commission concluded that the issues regarding the adequacy of consultation and accommodation are sufficiently discrete to not prejudice the First Nations later if they chose not to participate in this proceeding prior to the B.C. Court of Appeal decision. In any case, First Nations had an opportunity to participate in the proceeding, as the

Commission had stated in Exhibits A-8A and A-16. The Commission denied the request for an adjournment (Exhibit A-17).

On May 15, 2008 the B.C. Court of Appeal granted Kwikwetlem and the Joint First Nations leave to appeal the ruling (Exhibits A-8, A-8A) regarding whether or not the Commission Panel should consider the adequacy of consultation and accommodation efforts in the ILM Project.

By letter dated May 16, 2008, BCOAPO applied for an adjournment of this proceeding pending the outcome of the B.C. Court of Appeal decision granting Kwikwetlem and the Joint First Nations leave to appeal the ruling (Exhibits A-8, A-8A) regarding whether or not the Commission Panel should consider the adequacy of consultation and accommodation efforts on the ILM Project. BCOAPO submitted that the granting of leave raises a very real risk that any time, effort and money expended in the interim in this matter will be wasted and all or part of the process may need to be redone.

Referring to its previous decision (Exhibit A-17) to deny the Joint First Nations' request, the Commission Panel found that the granting of leave was not a sufficient change in circumstances to depart from the previous decision denying an adjournment, and denied BCOAPO's request (Exhibit A-21).

On May 26, 2008, counsel for the Nlaka'pamx submitted that the regulatory proceedings should be adjourned pending the outcome of the appeal (Nlaka'pamx Submission, p. 1). Nlaka'pamx further submitted that they "have applied for and not received any capacity funding to assist them with their participation in these proceedings" (Nlaka'pamx Submission, p. 1).

BCTC submits that if the Nlaka'pamx had issues within the scope of the proceeding that they wished to raise, they had an opportunity to participate and to obtain participant funding. BCTC further submits that all of the bands identified in the Nlaka'pamx Submission were offered capacity funding, and five of the six bands were also tendered comprehensive capacity funding agreements for the ILM Project's EA process (BCTC Reply, para. 57).

Commission Determination

Consistent with previous decisions, the Commission concluded in Exhibit A8-A that it should not look beyond, and can rely on, the regulatory scheme established by the government to ensure that First Nations have been consulted and, if necessary, accommodated. BCTC requires an EAC for the ILM Project and therefore a process is in place for First Nations consultation and, if necessary, accommodation. Although the EAC, if granted, will be given sometime after a CPCN is granted, the ILM Project will not proceed until the EA process has concluded.

Given the section 11 Order and the TOR for the ILM Project, the Commission Panel is satisfied that the EA process will include consideration of the potential effects on First Nations interests. Therefore, as with VITR and Revelstoke Unit 5, the Commission Panel can rely on the EA process to ensure that the duty to consult and accommodate has been satisfied. The EA requirement ensures that if the duty to consult has not been met and adequate accommodation, where necessary, has not been provided then the project will not proceed, and there will be no impacts on First Nations rights and title.

The Commission must ensure procedural fairness for participants, including First Nations, in Commission processes. The Commission Panel notes that, although the issue of whether BCTC had met its duty to consult and accommodate First Nations was ruled out of scope, the impacts on First Nations and risks to project costs were still well within scope. The First Nations Intervenors were encouraged to be active participants in the ILM proceeding, but chose not to lead or elicit evidence.

4.0 NEED AND PROJECT JUSTIFICATION

This Section examines the need for ILM grid reinforcement in the context of BCTC's planning standards, the existing capacity of the ILM grid, BC Hydro load forecasts, and expected resources for serving loads.

4.1 System Planning Standards

BCTC states that it is a member of the Western Electricity Coordinating Council ("WECC"), which is a regional member of the North American Electric Reliability Corporation ("NERC"). BCTC plans and operates the transmission system in accordance with NERC planning and operating standards, augmented by WECC (Exhibit B-1, Appendix G, p. 52).

BCTC includes a document entitled NERC/WECC Planning Standards, Revised April 10, 2003, as Appendix F of its Application. BCTC states that it applies NERC/WECC Planning Standards to ensure reliability in the planning of the transmission system. NERC defines reliability as comprising both adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements (Exhibit B-1, Appendix G, p. 52).

The specified system response to most single contingencies is identified in Table 4-1 – "Summary of NERC and WECC Planning Standards" as "No loss of firm loads except on radial systems and local networks served by the affected facility. System adjustments and curtailment of firm transfers permitted to prepare for the next contingency" (Exhibit B-1, Appendix G, p. 54).

4.2 Existing ILM Grid Capability

BCTC states that the transfer limits of transmission systems are generally constrained by the lowest of their thermal, voltage stability, or transient stability limits. These limits are calculated using the single contingency ("N-1") planning criteria whereby the system is required to remain stable and within its transfer limits following a single outage (Exhibit B-1, p. 70).

BCTC states that the existing ILM grid is constrained by four N-1 limits:

1. Continuous Thermal Limits

   The continuous thermal limit of the ILM grid is defined by the rating of the series capacitors banks, and is approximately 5,000 MW.

2. One-Hour Thermal Overload Limits

   A one-hour thermal overload rating gives the operator time to redispatch available Coastal region generation or increase imports to reduce the ILM grid's transfer to within the continuous thermal limit. The one-hour thermal overload limit for the existing ILM grid is approximately 6,300 MW.

3. Voltage Stability Limits

   Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after a contingency. The voltage stability limit of the existing ILM grid is approximately 5,800 MW.

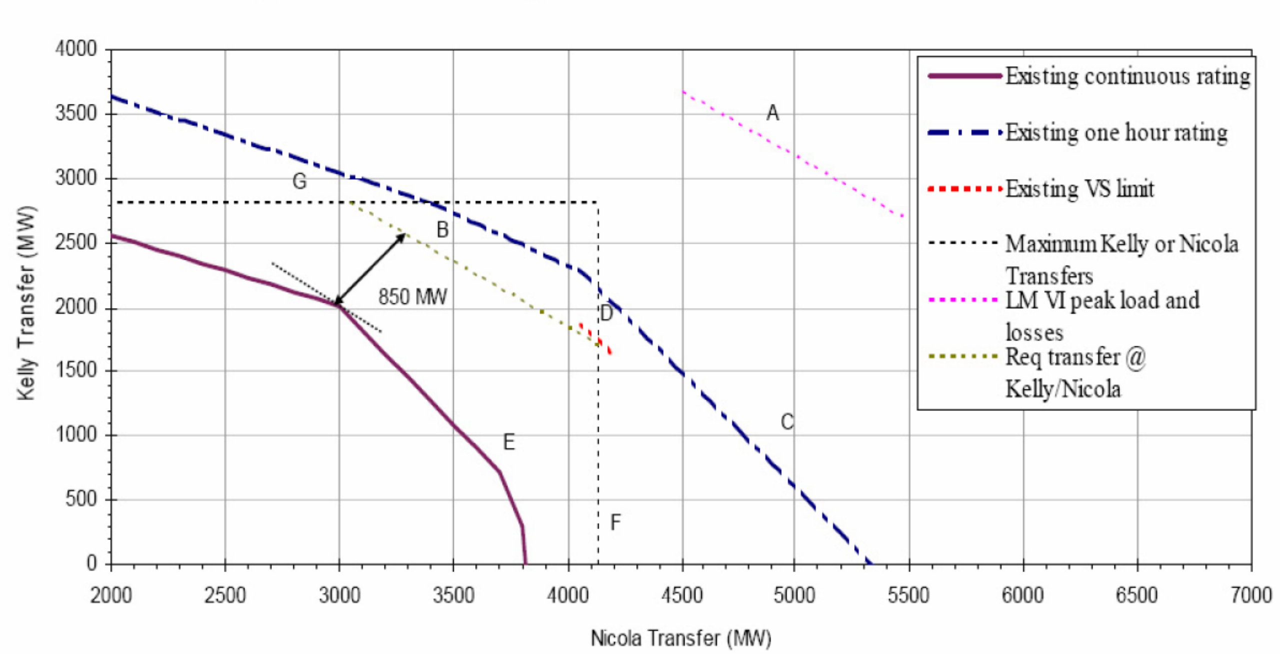
4. Transient Stability Limits

   Transient stability is the ability of a group of generators to return to their normal operating states following a system disturbance.

Transient stability simulations have confirmed that the power system remains transiently stable at transfer limits at or below the voltage stability limits of the ILM grid. Hence, voltage stability is the dominant constraint on the ILM grid relative to transient stability. (Exhibit B-1, Appendix H, pp. 8-9)

BCTC states that the N-1 thermal and voltage stability limits are represented as single numbers for simplicity but are actually a range of values which are determined by the amount of power transferred to the LM and VI regions from KLY and NIC, which can be represented by a graphical plot called a nomogram. The nomogram shows that the continuous thermal limit of 5,000 MW corresponds to a transfer of approximately 2,000 MW from KLY and 3,000 MW from NIC (Exhibits B-1 and B-1-1, Appendix H, pp. 8-11), which is shown as the “knee-point” on the nomogram. A nomogram depicting the existing ILM grid and current loads for the winter of F2015 is reproduced below.

Figure 6-5. ILM Nomogram for Amended LTAP Portfolio F2015



(Exhibit B-1, Figure 6-5)

BC Hydro submits that transmission planning criteria require that the net load of the Coastal region must be capable of being supplied under reasonable worst case scenarios of Interior region generation dispatch. BC Hydro observes that a certain optimal generation dispatch configuration is required to realize the 5,000 MW continuous thermal limit of the ILM grid. To account for the possibility of having some generation out-of-service over the winter peak, BC Hydro states that it plans for a 14 percent generation reserve margin assuming no transmission limitations. As a result, if an N-1 incident occurred during the system peak it may not be possible to optimally dispatch

Interior region generation to realize the full thermal limit of the ILM grid, and BC Hydro would have to rely on the market to supply loads which will likely require changes to import/export schedules. BC Hydro states that BCTC's design of the system is based on a single operating dispatch, which is unduly restrictive and not consistent with the intent of WECC planning criteria. BC Hydro claims that the capability for full North and South Interior region generation dispatch flexibility is part of reliability criteria and not an optional added capability. BC Hydro states the 5,000 MW knee-point represents an optimal dispatch of the system and cannot be considered as the most stressed condition (BC Hydro Argument, pp. 2-4).

BCTC stated that the 5,000 MW limit was the maximum limit and allows the best utilization of the grid and otherwise the continuous limit is below 5,000 MW and that with a flow from NIC of 3,800 MW the continuous limit of the ILM grid would be 3,800 MW (Exhibit B-10, BC Hydro 2.5.1 and 2.5.3). BC Hydro therefore submits that the current capability of the ILM grid is more appropriately characterized as only 3,800 MW or less (BC Hydro Argument, p. 3).

BCTC takes issue with BC Hydro's submission and submits that it does not believe it is obligated to ensure full dispatch flexibility under N-1 conditions by either its OATT or NERC/WECC standards, the latter of which it states are primarily concerned with serving loads not generation dispatch patterns (BCTC Reply, p. 5). BCTC acknowledges that under some emergencies or freshet conditions where the power must be generated or water is spilled, a maximum dispatch pattern leads to a higher committed use on the ILM grid and therefore tends to require an earlier reinforcement (Exhibit B-1, Appendix H, p. 7).

BCTC submits it has been and continues to be its practice to provide full dispatch flexibility from either the North or South Interior region under pre-contingency ("N-0") conditions and that under N-1 conditions most contingencies are restored in one or two hours resulting in full dispatch flexibility being provided 99 percent of the time. BCTC states that transfer capability is a range of values on a nomogram and that 5,000 MW is the upper limit and is the appropriate limit, rather than 3,800 MW which corresponds to zero dispatch from the North Interior region, which is not a reasonable scenario (BCTC Reply, para. 10-13).

Commission Determination

The Commission Panel endorses BCTC's interpretation of NERC/WECC standards as being primarily concerned with serving loads, and not generation dispatch patterns. The Commission Panel agrees with BCTC that the continuous firm capability of the existing ILM grid of 5,000 MW based on the continuous thermal limit is an appropriate rating. The Commission Panel rejects BC Hydro's suggestion that the continuous firm capability of the ILM gird should be 3,800 MW, which is required to ensure full dispatch flexibility under N-1 conditions. The Commission has specifically addressed the use of generation shedding for first contingencies in the F2008 TSCP Decision (F2008 TSCP Decision, p. 14). The Commission Panel also commented on this in the F2009-F2018 Transmission System Capital Plan Decision ("F2009 TSCP Decision") associated with Order G-107-08 dated June 26, 2008:

> "In the F2008 TSCP Decision, the Commission Panel noted that the NERC/WECC Planning Standards allow generation shedding for single contingencies, and that BCTC has adopted a policy to avoid the use of generation shedding for single contingency events, with certain exceptions (F2008 TSCP Decision, p. 14). The Commission Panel acknowledges the references BCTC has made to the NERC/WECC Planning Standards in support of this policy but still notes that these planning standards do allow generation shedding for single contingencies. The Commission Panel is concerned that a policy to avoid the use of generation shedding for all single contingency events may result in non-economic capital expenditure decisions, and a careful evaluation of projects initiated under this policy is necessary to justify the economic and reliability benefits associated with the capital expenditure. That this policy is specific to BCTC and not mandated by the NERC/WECC Planning Standards indicates to the Commission Panel that it is not a "normal planning criteria" as suggested by BC Hydro, but rather is an attribute unique to the system managed by BCTC. The Commission Panel directs BCTC to continue identifying in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for single contingency events." (F2009 TSCP Decision, p. 11)

4.3 Need for Reinforcement of the ILM Grid

In examining the requirements for reinforcement of the ILM grid, BCTC used a 20-year planning horizon, which aligns with the 20-year horizon that was used in the development of resource portfolios that provide an input into BCTC's transmission plans. BCTC stated that because of uncertainties with respect to magnitude, location, and timing of future resources in the latter half of the planning horizon timeframe, the amount of total capacity that should be added to the ILM grid could not be determined with any accuracy; however, there was enough certainty with respect to loads and resources in the first half of the planning horizon to confirm the need to increase the capacity of the ILM grid. (Exhibit B-10, IPPBC 2.1.1)

BCTC stated that the need for reinforcement of the ILM grid is triggered by BC Hydro's request for network service, as a Network Customer, under section 29 of BCTC's OATT (Exhibit B-5, BCUC 1.40.5.2). Furthermore, BCTC states that under Attachment J of the OATT, it is required to plan the transmission system for the base load/resource plan and the contingency resource plans ("CRPs") (BCTC Argument, para. 13). Under Attachment J of the OATT, BCTC is required to reserve Available Transmission Capacity ("ATC"), to the extent it is available on the existing system, to satisfy the requirements of BC Hydro's CRPs. If not enough ATC is available to satisfy the CRPs, BCTC must identify the scope and cost of upgrades to the system ("Network Upgrades"), and inform BC Hydro that use of the forecast generation resources identified in the CRPs would not be possible until specific Network Upgrades have been completed.

BCTC states that the need for the ILM grid reinforcement is based on the increasing imbalance in the LM and VI region between BC Hydro's December 2006 reference peak load forecast and the resources contained in BC Hydro's 2006 Amended LTAP ("2006 Amended LTAP"). BCTC states there will be a sharp drop in Coastal region generation between F2014 and F2015 when BC Hydro plans to cease relying upon Burrard for planning purposes. This is slightly offset by increases in other Coastal region generation (Exhibit B-1, p. 73). BCTC states that the increasing imbalance will create a gap between the load and the resources available to the LM/VI region of approximately 850 MW by the winter of F2015 and that unless increased continuous transfer capability is provided on the ILM grid, load shedding and/or curtailment of firm exports will be necessary (Exhibit B-1, p. 76).

BCTC states that should future events occur that suggest that the in-service date of the ILM Project could be deferred, it may be prudent to defer the construction of the ILM Project. Prior to construction of the ILM Project in late 2009, BCTC identifies several events that might occur which would better inform it as to the necessary timing of the ILM Project, such as

a) new load forecasts from BC Hydro, including updates on DSM uptake;
b) new firm Point to Point contracts on the ILM grid;
c) a new BC Hydro LTAP;
d) the results of upcoming BC Hydro calls for power; and
e) a decision on the future of Burrard.

(Exhibit B-1, p. 84)

At the first Procedural Conference counsel for BCTC added that a new NITS application from BC Hydro where BC Hydro can identify and nominate resources might influence the timing of the ILM Project (T1:9).

BCTC stated that it understands from BC Hydro that there is no indication in the 2006 Amended LTAP that higher levels of DSM savings could be achieved through higher levels of expenditures and BCTC indicated that an additional 849 MW of Coastal region DSM would be necessary in F2015 to defer the ILM grid reinforcement and 2,054 MW would be required in F2027. To meet the requirements of CRP1 an additional 1,262 MW of Coastal region DSM would be necessary in F2015. To meet the requirements of CRP2 an additional 1,500 MW of Coastal region DSM would be necessary in F2015. BCTC also said that the added DSM required to defer reinforcement does not provide the flexibility to fully dispatch either the South or North Interior region generation, which would be provided by the reinforcement of the ILM grid (Exhibit B-5, BCUC 1.49.2). The DSM programs included in the 2006 Amended LTAP were EE3, EE4, and EE5 plus LD2.

BCTC was asked if the results of the latest Conservation Potential Review ("2007 CPR") could defer the ILM grid reinforcement. BCTC responded with the following table:

		Lower Mainland + Vancouver Island Potential DSM Capacity (MW) in F2016		
		Economic Potential	Upper Achievable	Lower Achievable
1	2007 CPR	2,169	1,343	867
2	2002 CPR	1,305	803	547
		Lower Mainland + Vancouver Island Potential DSM Energy (GWh) in F2016		
		Economic Potential	Upper Achievable	Lower Achievable
3	2007CPR	10,979	5,187	2,505
4	2002CPR	7,700	5,380	3,727

(Exhibit B-10, BCUC 2.158.2)

The table shows a substantial increase in DSM resources compared to the 2002 Conservation Potential Review ("2002 CPR"), which was an input to the 2006 Amended LTAP. BCTC described the Achievable Potential as an estimate of the proportion of savings identified in the Economic Potential forecast that could be achieved within the study period under different scenarios. Achievable Potential recognizes that it is difficult to induce customers to purchase and install all the electrical efficiency technologies that meet the criteria defined by the Economic Potential forecast. The results are, therefore, presented as a range, defined as upper and lower (Exhibit B-10, BCUC 2.158.2). The Lower Achievable Potential assumes a scenario where market conditions, program efforts, and incentive levels remain at a similar level when compared to existing levels. The Upper Achievable Potential assumes a scenario where market conditions and government policy are supportive and energy savings are aggressively pursued (Exhibit B-10, BCUC 2.158.2).

BCTC stated that the incremental DSM from F2006 to F2016 is 500 MW. Therefore, in the Lower Achievable case the increase is 367 MW, leaving a gap of 483 MW. For the Upper Achievable case the increase in the DSM available is 843 MW by F2016, which is enough to meet the requirements of the 2006 Amended LTAP, but not the requirements of either approved CRP1 or CRP2.

Without commenting on CRP1 and CRP2 requirements, BCTC stated:

> "However, a decision on deferring the line would need to be made before construction starts. It is likely that this would be long before there was a high enough level of confidence in the ability to achieve the Upper Achievable scenario to make decisions on the assumption that this would be achieved. The results of the 2007 CPR indicate that DSM levels higher than the Upper Achievable levels would be required to defer ILM." (Exhibit B-10, BCUC 2.158.2)

BCTC stated that BC Hydro's 2007 Load Forecast shows a reduction of 189 MW in F2017 and 376 MW in F2027 compared to the previous forecast used in the Application. Since about 70 percent of the load is in the LM-VI regions this would still leave a gap in F2016 of about 350 MW under the 2006 Amended LTAP resource assumptions (Exhibit B-14, BCUC 3.191.1).

Based on the 2006 Load Forecast, the Upper Achievable DSM scenario from the 2007 CPR, and assuming that only three units of Burrard are retired in 2014, the ILM grid reinforcement could be deferred beyond the 20-year planning horizon. Based on the 2006 Load Forecast, the Lower Achievable DSM, and assuming that only three units of Burrard are retired in 2014, the ILM grid reinforcement could be deferred to F2027 (Exhibit B-14, BCUC 3.207.2). Both conclusions regarding a deferral of the ILM grid reinforcement are without consideration of CRP1 and CRP2. Moreover, BCTC stated that it does not have resource portfolios that correspond to the Upper and Lower Achievable levels of DSM identified in BCTC's response to BCUC IR 2.158.2.

No party addressed the 2007 CPR in argument nor was the document entered into evidence.

In addressing the effects of repowering or continuing to operate Burrard on the timing of the ILM grid reinforcement, BCTC observed that:

> "Based on a 5000 MW limit, with judicious use of the CE [Canadian Entitlement] during Burrard repowering construction, the repowering of Burrard in the amended LTAP base case would defer an ILM reinforcement to 2017. This assumes certainty that repowering would take place when a decision needed to be taken to start or defer construction of ILM." (Exhibit B-5, BCUC 1.39.5.1)

BCTC later qualified the effect of Burrard on the timing of the ILM grid reinforcement:

> "Running Burrard beyond 2014 does not result in a deferral of the ILM Project. As shown in Figure 5-7 of Appendix H, an additional 150 MW of imports has to be scheduled in 2013, in addition to running Burrard, to meet the continuous N-1 thermal limits of the grid. Deferral of the ILM would only be achieved through continued running of Burrard and additional imports such as the Canadian Entitlement." (Exhibit B-10, BCUC 2.155.2)

BC Hydro agrees with BCTC's conclusions that the ILM grid needs to be upgraded, but disagrees with BCTC's suggestion that there is still a question of timing (BC Hydro Argument, p. 1).

JIESC agrees that a project is clearly required as much of the new capacity and energy required to service the LM-VI regions must come from the Interior region and will require increased transmission capacity in order to be able to do so. JIESC is of the view that this project is too important to take a chance on it not being ready when required and accordingly approval should be given at this time, even if the Commission were to be of the view that a short delay of a few years might occur. The remote possibility that a delay might be in customer's interests simply does not warrant risking exposure to the virtually certain substantial negative impacts on customers of the ILM grid reinforcement not being available in a timely manner (JIESC Argument, p. 1)

BCOAPO agrees with the general proposition that it would be a very good idea to reinforce the ILM grid (BCOAPO Argument, p. 1).

IPPBC agrees with BCTC's conclusion that there is need for increased transfer capability on the ILM grid (IPPBC Argument, p. 1).

Commission Determination

The Commission Panel accepts the gap in F2015 between the load and dependable resources available to serve the LM-VI regions is 850 MW for the 2006 Amended LTAP. Therefore, the Commission Panel concludes that, based on the evidence in this proceeding, reinforcement of

the ILM grid is required by the earliest ISD of the ILM Project. The Commission Panel notes that reinforcement of the ILM grid by F2015 will also meet the requirements of CRP1 and CRP2, and will provide additional flexibility for dispatch of Interior region generation.

The Commission Panel concurs with BCTC that a number of events related to the timing and size of the load-resource gap, including new load forecasts from BC Hydro, updates on DSM uptake and a decision on the future of Burrard, may occur in the period before BCTC submits its Update Report, which will better inform BCTC as to the necessary timing of the ILM Project prior to commencing construction.

The Commission Panel notes that certain alternatives for reinforcement of the ILM grid may also have economic benefits such as reduced losses. In the event circumstances change that allow deferral of the ILM Project past its earliest ISD from the perspective of planning standards, the Commission Panel notes that an earlier ISD could still be justified on economic grounds. The economic rationale for advancing reinforcement of the ILM grid before it is required for planning standards is discussed in Section 7 of this Decision.

5.0 IDENTIFICATION AND ASSESSMENT OF ALTERNATIVES

This Section reviews BCTC's process to identify, evaluate and screen alternatives to increase the ILM grid transfer capability.

5.1 Identification of Alternatives

BCTC describes its four-step process as follows:

> "Alternatives that appear to meet the objectives and are consistent with reliability and other functional requirements are identified in the first step. The design concepts for the identified alternatives are further developed in the second step to allow clearly preferable alternatives to emerge. In the third step, the remaining solutions are screened to identify the preferred option. Primary considerations at the third step include technical performance, reliability, project costs, environmental effects, community effects, First Nations interests, implementation risks, regulatory risks, and other factors identified by the project team or through stakeholder consultation. In the fourth step, the preferred option is subjected to further detailed analysis to verify that it meets all the objectives." (BCTC Argument, para. 21)

BCTC stated that its approach to alternative identification and assessment had been reviewed and accepted by the Commission in the hearing of the VITR project CPCN application, and that this same general approach was used for the ILM Project (Exhibit B-10, BCUC 2.147.1.1).

BCTC states that the forecast constraints of the ILM grid could be fully or partially removed by one or a combination of the following categories of solutions: building a new transmission line from the Interior region to the Lower Mainland region, by upgrading the existing ILM circuits; and/or by adding more Coastal region generation/DSM (Exhibit B-1, p. 78), and that it identified the following specific alternatives for the ILM Project:

"(a) Do-Nothing;

(b) Coastal Generation and Demand Side Management;

(c) Upgrades of Existing Circuits (UEC);

(d) A new 500 kV Alternating Current transmission line (5L83) between Nicola substation and Meridian substation;

(e) A new 500 kV Alternating Current transmission line between Nicola substation and Ingledow substation;

(f) A new 500 kV Alternating Current transmission line (5L46) between Kelly Lake substation and Meridian substation; and

(g) A new 500 kV High Voltage Direct Current line between Nicola substation and Meridian substation."

(Exhibit B-1, p. 8)

5.2 Eliminated Alternatives

BCTC states that it had eliminated a "Do Nothing" alternative at the first step of the project selection process because it would not be able to meet planning or operating criteria and would require load shedding once the transfer capability of the ILM grid was exhausted (Exhibit B-1, p. 81). BCTC estimates that the expected energy not served ("EENS") in F2017 would increase by 2,396 MW.h compared to a case where the ILM grid was reinforced (Exhibit B-5, BCUC 1.62.1) and that the value of each MW.h not served is $5,000 (Exhibit B-1, Appendix I, p. 36). BCTC provided further comment on the "Do Nothing" alternative by considering the ability to supply the Lower Mainland and Vancouver Island regions by wheeling power through the U.S. transmission grid and identified numerous obstacles in this wheeling path (Exhibit B-5, BCUC 1.95.1).

For the second step of the project selection process, BCTC prepared a report ("Alternatives Report") that described the evaluation of alternatives and provided recommendations regarding those alternatives that were not the preferred alternatives for the ILM Project (Exhibit B-1,

Appendix I, p. 8). The alternatives that failed at this step of the project selection process were 5L46, NIC to ING, the Coastal region generation and/or additional DSM, and the high voltage direct current ("HVDC") alternatives. The alternatives were screened for their characteristics with respect to total transfer capability ("TTC") as limited by continuous thermal limits and voltage stability limits, reliability as indicated by EENS, cost, losses, and double outage requirements (Exhibit B-1, Appendix I, p. 15).

5.2.1 Coastal Region Generation and/or Additional DSM

This alternative assumes that some combination of future Coastal region generation, continued availability of the Canadian Entitlement ("CE") for use as a transmission planning resource, designation of firm energy imports on existing facilities or future facilities such as the proposed Juan de Fuca project, or additional DSM measures in the LM-VI regions over and above those levels identified in existing resource plans, would be adequate to limit the peak power flows on the ILM grid to its existing thermal and voltage stability limits (Exhibit B-1, Appendix I, p. 12). Coastal region generation could include new generation projects or continued generation from Burrard beyond 2014.

Neither BC Hydro nor BCTC have undertaken any specific studies to estimate the DSM resources required to defer the need for the ILM grid reinforcement (Exhibit B-5, BCUC 1.49.2). BCTC relies upon the forecasts of Coastal region generation, including BCTC's own variations of availability of Burrard generation and the CE for re-dispatch as a planning resource, and DSM measures that BC Hydro provided in its 2004 NITS Application, 2006 IEP, and 2006 LTAP resource portfolios (Exhibit B-1, Appendix I, pp. 15-16).

BCTC observes that, in its analysis of BC Hydro's 2006 Amended LTAP, CRP1, and CRP2 portfolios during BC Hydro's 2006 IEP/LTAP proceeding, the need for reinforcing the ILM grid was confirmed in all eighteen of the examined scenarios, with the timing varying between 2014 and 2023 (Exhibit B-1 Appendix I, p. 16). BCTC relied upon this analysis in its screening of the Coastal region generation and/or DSM alternative (Exhibit B-5, BCUC 1.66.1), and stated that even the realization of the Upper Achievable DSM scenario from BC Hydro's 2007 CPR would be unlikely to defer the timing of the ILM Project (Exhibit B-10, BCUC 1.158.2). BCTC submits that the forecast ranges of Coastal region generation and DSM do not indicate adequate amounts of new resources to defer the need for increased transfer capability on the ILM grid beyond its earliest ISD, and hence this option is eliminated (BCTC Argument, para. 24).

5.2.2 5L46

The 5L46 option comprises the construction of a new 500 kV series compensated transmission line (5L46) between KLY and CKY through the Pemberton Valley and Whistler corridor. This line would be approximately 203 km long and, for most of the route, it would be parallel to the existing 5L42, but would require the acquisition of new ROW. The circuit would have line terminations at KLY and CKY, one 122.5 MVAr line reactor at KLY, one 122.5 MVAr switchable line reactor at CKY, and a series capacitor station, either at Creekside ("CRK") or near the mid-point of the circuit.

BCTC describes the technical characteristics as follows:

> "At flow patterns that correspond to 2000 MW transfer from KLY, the 5L46 alternative would increase the continuous thermal capacity of the ILM grid from the existing 5000 MW to approximately 5200 MW. The 5L46 alternative would increase voltage stability limit of the ILM grid from 5800 MW to approximately 6384 MW. Addition of 470 MVAr of reactive power support would further increase the voltage stability limit of the 5L46-reinforced network from 6384 MW to 6748 MW. Therefore, the TTC of the 5L46-reinforced ILM grid would be limited by its thermal capacity of 5200 MW. The expected continuous rating of the transmission circuit would be 3.0 kAmp." (Exhibit B-1, Appendix I, p. 13)

BCTC submits that the nomograms utilized to evaluate the performance of the alternatives illustrate that the 5L83 and UEC alternatives provide higher incremental ILM grid thermal transfer capabilities from the NIC side, whereas the 5L46 alternative enhances thermal transfer capabilities from the KLY side but has limited impact on the NIC side (Exhibit B-1, Appendix I, p. 19). BCTC claims the following disadvantages of the 5L46 alternative as compared to the 5L83 and UEC alternatives:

- the higher transfer capability from the NIC side of the 5L83 and UEC alternatives is a better match than the KLY side for the future resources identified in BC Hydro's [2006] Amended LTAP, CRP1, and CRP2, most of which are in the South Interior region;
- 5L46 would not reduce system losses to the same extent as 5L83;
- 5L46 would likely require new ROW for most of its 203 km; and
- 5L46 was also found to require more double outage generation shedding and load shedding than 5L83 (Exhibit B-1, Appendix I, p. 19, Exhibit B-1-1, (Errata)).

BCTC states that an analysis performed in 2005 had showed the 5L46 alternative to be about 8 percent more expensive than the 5L83 alternative (Exhibit B-1, pp. 80-82), and claimed that if the analysis was redone using 2007 estimates, the relative difference would be similar as the same cost escalation factors would affect both estimates (Exhibit B-5, BCUC 1.82.1).

BCTC submits that it eliminated the 5L46 alternative because it had higher losses and a lower transfer capability, and was approximately 8 percent more expensive than 5L83, and would require the acquisition of new ROW for most of its route (BCTC Argument, para. 24).

5.2.3 NIC to ING

This alternative comprises the construction of a new 500 kV series compensated line between NIC and ING. BCTC states that it considered two corridor alternatives for termination of a new line at ING:

1) a new 500 kV line that followed a corridor directly between NIC and ING, and
2) building 5L83 between NIC and MDN and a new line between MDN and ING.

A number of route alignments were examined under the two corridor alternatives. The least expensive alignment between NIC and ING would consist of 5L83 plus a new 500 kV line double-circuited with 5L44 from MDN to the Port Mann Bridge and another 500 kV line double-circuited with 2L22 and 2L27 to ING along the existing ROW. These alternatives would have similar thermal and voltage stability ratings as the 5L83 alternative (Exhibit B-1, Appendix I, p. 14).

BCTC states that one of the benefits of this alternative was an increase in the firm transfer capability to ING relative to the 5L83 alternative, which in turn could facilitate additional electricity trade opportunities on the western B.C.-U.S. intertie; however both alternatives adequately address domestic load requirements and confirmed export requirements (Exhibit B-1, Appendix I, p. 19). However, BCTC noted that although the ROW needs for both the 5L83 alternative and the NIC to ING alternative were common from NIC to node P near Agassiz, it was not practical to acquire new ROW from Agassiz to ING for the NIC to ING alternative because of residential and commercial development along the potential route (Exhibit B-10, Harris/Casselman 2.5.I.i). BCTC stated that the least expensive route for a direct line from Agassiz to ING would be double-circuiting on existing ROW, however even this routing was more expensive than running the transmission line via MDN along the 5L83 route (Exhibit B-10, IPPBC 2.4.1).

BCTC submits that it eliminated the NIC to ING alternative from further consideration because 5L83 could meet the load requirements of the Coastal region, and any extension from MDN to ING could be undertaken if and when needed, and the least expensive route for a NIC to ING transmission line was through MDN via the 5L83 route (BCTC Argument, para. 24).

5.2.4 HVDC

This alternative would use HVDC technology to transfer power from NIC to MDN either by a new 500 kV HVDC bi-pole or by converting the existing 5L81 and/or 5L82 circuits from ac to HVDC. BCTC engaged an external consulting firm, DC Interconnect Inc. (“DCI”), to assess the HVDC alternative; DCI prepared a report (“DCI Report”) that BCTC submits as Appendix L in this Application (Exhibit B-1, pp. 80-82).

An HVDC alternative would be designed to have similar incremental one hour thermal overload and continuous thermal capabilities as 5L83. Conversion of the existing ac circuits to DC would include both bi-pole and tri-pole technologies. To minimize the cost of tri-pole conversion, converting 5L82 to tri-pole HVDC would be done in 2014 followed by conversion of 5L81 around 2020 (Exhibit B-1, Appendix I, p. 14).

BCTC states that DCI concluded that the cost of HVDC converter stations, not including overhead and interest during construction, would be as high as $378 million ($2007) (Exhibit B-1, Appendix I, p. 20; Exhibit B-1, Appendix L, p. 30). The cost for the transmission line portion of an HVDC bi-pole circuit would add an additional $177 million to $203 million before contingency, inflation, overhead, or interest during construction charges for a combined total of between $555 million and $581 million, compared to the cost of the 5L83 alternative of $406.5 million (Exhibit B-1, Appendix I, p. 26). BCTC submits that in general, for the same level of power transfer, HVDC circuits can offer significant savings over ac circuits over distances greater than 500 to 600 km (Exhibit B-1, p. 82).

From a loss perspective, for the HVDC configurations that were analyzed, the ILM grid losses were almost identical for both the HVDC and the 5L83 alternatives (Exhibit B-1, Appendix L, p. 29).

BCTC submits that it eliminated the HVDC alternative from further consideration because an HVDC line and the required converter stations would have much higher capital and operating costs than 5L83 (BCTC Argument, para. 24).

IPPBC submits that BCTC did not properly evaluate two other alternatives, namely a new 5L83 built as an ac line but insulated for HVDC, and a much longer HVDC (relative to 5L83) line that runs directly from a point near new generation in the Peace River or Columbia River regions to MDN or ING (IPPBC Argument, p. 5).

With respect to the first option, BCTC replies that “IPPBC is incorrect in asserting that BCTC is not considering building 5L83 as an ac circuit with insulation sufficient for future conversion to HVDC”, and states that it intends to further examine and develop this variation of 5L83 as the ILM Project proceeds to design and procurement, and that a more definitive commitment will require the cost of such insulation to be verified through the tenders received during the procurement process (BCTC Reply, para. 45).

With respect to the second option, BCTC states that it has addressed the immediate needs of the system and that there is simply no evidence in BC Hydro’s 2006 Amended LTAP or CRPs that would currently justify the very significant expenditures to build a larger HVDC system in lieu of 5L83 to reach the Peace region and observes that presently forecast generation additions are expected in the South Interior region, and not the North Interior region, so additional transmission capacity from the North Interior region does not make sense at this time (BCTC Reply, para. 47).

5.3 Remaining Alternatives

Upon completion of the second step of the screening process, BCTC was left with two alternatives for reinforcement of the ILM grid: 5L83, which is described in Section 2 of this Decision, and UEC, which is described below.

5.3.1 UEC

BCTC describes UEC as a collection of individual projects to upgrade series capacitor banks, replace circuit breakers, and upgrade transmission lines to increase conductor ratings, all designed to increase the thermal rating of the existing ILM grid:

“(a) Upgrade of Chapmans (CHP) series capacitor banks to 2.73 kA (at 1.0 PU Voltage)

(b) Upgrade of CRK series capacitor banks to 2.73 kA (at 1.0 PU Voltage)

(c) Upgrade of American Creek (AMC) series capacitor banks on 5L81 and 5L82 to 3.0 kA (at 1.0 PU Voltage)

(d) Upgrade of Guichon (GUI) series capacitor banks to 2.73 kA (at 1.0 PU Voltage)

(e) Upgrade summer rating of 5L41 to 3.0 kA

(f) Upgrade summer rating of 5L42 to 3.0 kA

(g) Upgrade summer rating of 5L44 to 3.0 kA

(h) Upgrade summer rating of 2L1/2L5 to 0.98 kA

(i) Replace ING circuit breakers 5CB7, 5CB8, and 5CB11 with 3.0 kA circuit breakers

(j) Replace ING circuit breakers 5CB9 and 5CB10 with 4.0 kA circuit breakers

(k) Replace NIC circuit breakers 5CB12, 5CB18, 5CB22, and 5CB28 with 4.0 kA circuit breakers

(l) Replace MDN circuit breakers 5CB7 and 5CB8 with 4.0 kA circuit breakers"

(Exhibit B-1, Appendix I, pp. 12-13)

Commission Determination

The Commission Panel notes that BCTC used the same four-step screening process for the identification and assessment of alternatives for the ILM Project as it used for the VITR project. The Commission Panel continues to endorse the application of the screening process described by BCTC.

With respect to IPPBC's claim that a longer HVDC transmission line from either the Peace or South Interior regions to the Lower Mainland may be a better long-term solution than the proposed ILM Project, the Commission Panel agrees with BCTC's assessment that the HVDC line from the Peace region is not supported by resource projections in BC Hydro's 2006 Amended LTAP and CRPs. The Commission Panel notes that BCTC did not comment on the HVDC line to the South Interior region suggested by IPPBC; however, the Commission Panel observes that an HVDC transmission line between the Lower Mainland and South Interior regions would likely be shorter in length than the 500 to 600 km distance which BCTC suggests is required for HVDC transmission to be cost-effective compared to ac transmission.

In general, the Commission Panel accepts BCTC's elimination of the identified alternatives and supports the result that the 5L83 and the UEC alternatives proceed to detailed analysis and comparison procedures for selection of the preferred project.

6.0 PROJECT COSTS

This Section reviews cost estimates of the ILM Project, including calculation of the amount of contingency, inflation, corporate overheads, and interest during construction. A comparison with the 2004 estimate is also considered.

6.1 Overview of Project Costs

BCTC states its September 2007 ILM Project capital cost estimate of approximately $602 million ($2014) is based on a report prepared by BCTC's consultants working on the Project Team, with the majority of the costs being estimated by BC Hydro's Engineering Services Department (Exhibit B-1, p. 59).

BCTC states that, given recent cost escalation experienced in the industry, it retained SNC Lavalin, an independent firm of consulting engineers, to perform a review of BC Hydro's cost estimate in order to assess the reasonableness of the estimate in consideration of current industry and market trends (Exhibit B-1, p. 59).

BCTC stated that a final cost estimate cannot be determined until conclusion of several major activities including the EA process, First Nations consultation, detailed design, and competitive tendering; and that the cost estimate included in the Application was the best that could be provided with the information available (Exhibit B-5, BCUC 1.11.1).

6.2 Estimate Accuracy Range

BCTC states that its estimate of the ILM Project capital cost of $602 million has a range of accuracy of -10 percent to +30 percent , which is a subjective estimate based on the amount of engineering design completed to date (Exhibit B-1, p. 59).

BCTC stated that the accuracy of the cost estimate was derived based on the American Association of Cost Engineers (“AACE”) Recommended Practice and that, with less than 15 percent of the engineering complete, and with no material or construction contracts or regulatory approvals in place, the -10 percent to +30 percent accuracy was considered appropriate and that, at this stage of the project, the accuracy has been considered independently from the contingency identified in the probabilistic estimates included in the Application (Exhibit B-5, BCUC 1.42.1).

6.3 Capital Cost of the Project

BC Hydro’s cost and schedule estimates for the ILM Project are included in the Application as Appendix C, “Nicola to Meridian 500 kV Transmission Line Alternative Cost and Schedule Report” (“Cost and Schedule Report”), which is dated November 1, 2007. The capital cost of the ILM Project is as follows:

Cost Item	**$million**
Definition Phase	$29.4
Implementation Phase	
BCTC-Managed Costs	$8.9
5L83 Transmission Line	$269.1
Substations	$11.9
Capacitor Station	$26.4
Total Implementation Phase	$316.3
Total Direct Costs	$345.7
Contingency	$82.3
Inflation	$80.5
Corporate Overheads	$17.1
Interest during Construction	$76.5
Total	$602.1

(Source: Exhibit B-1, Table 5-5, p. 61)

The Application is not entirely consistent in its presentation of dollar estimates but the Direct Costs and Contingency all appear to be estimated in $2007. The Inflation line item in the above table brings the final total cost estimate into $2014. Interest during Construction ("IDC") is included in the total cost estimate to reflect the carrying costs that would be capitalized when the project is brought into service in 2014. The Contingency in the above table is a P50 contingency.

6.4 Definition Phase

BCTC stated that the Definition Phase costs total $29.4 million and comprise BCTC-managed costs totalling $12.9 million, such as regulatory, communications, Project Management Office ("PMO") and environmental; BC Hydro-managed costs for engineering and properties totalling $ 7.9 million (Exhibit B-5, BCUC 1.110.1); and BCTC-managed costs for aboriginal relations and negotiation work (which remains the responsibility of BC Hydro) totalling $8.6 million, details of which were provided by BC Hydro in a confidential filing (Exhibit C1-4, BCUC 1.42.6).

6.5 Implementation Phase

6.5.1 BCTC-Managed Costs

BCTC states that the BCTC-managed costs in the Implementation Phase costs are estimated to total $8.9 million and comprise costs such as regulatory, communications, PMO, environmental, and aboriginal relations and negotiations work carried out by BC Hydro (Exhibit B-1, p. 61).

BCTC stated that the following costs were excluded from this cost estimate:

- aboriginal accommodation costs;
- environmental mitigation and compensation costs; and
- costs for any legal challenges of the Commission or EAO decisions.

(Exhibit B-1, p. 60, and Exhibit B-5, BCUC 1.23.3)

BCTC stated that the outcome of the EA process will result in a Table of Commitments and Assurances which will form part of the EAC and will include performance-based requirements for environmental construction monitoring, post-construction monitoring, mitigation, and compensation requirements that will form the basis for environmental costs during the Implementation Phase. BCTC anticipated the maximum impact on project costs arising from the outcome of the EA process would be less than 5 percent of the overall capital costs of the ILM Project (Exhibit B-5, BCUC 1.119.1).

BC Hydro filed its May 2007 estimate of aboriginal accommodation costs in confidence with the Commission and stated that it comprised a range of values based on the ILM Project's reference route, known potential impacts and consultation to that date, and that there remained significant variability in the estimate and that further studies and consultation would be required to produce a more definitive forecast of the ILM Project's aboriginal accommodation costs (Exhibit C1-4, BCUC 1.115.1).

BCTC stated that the level of risk and magnitude of aboriginal accommodation costs are influenced by various factors including:

- "the number of Aboriginal groups with whom consultation is required;
- the level of impact the project has on aboriginal rights; and
- the ability to avoid or mitigate these impacts on aboriginal rights."

(Exhibit B-5, BCUC 1.116.1)

6.5.2 5L83 Transmission Line

The Cost and Schedule Report provides the following detailed estimate for the direct costs of the 5L83 transmission line:

Cost Item	($000s)
Engineering and Project Management	9,272
Survey and Forest Engineering	5,673
Properties	8,895
Material	
Foundations	10,887
Steel Structures and Guys	35,497
Conductor	23,506
Insulators and Hardware	11,424
Quality Assurance and Contract Management	5,009
Construction	
ROW, Access Roads and Restoration	26,453
Foundations	41,325
Tower Erections	62,499
Conductor and Hardware Installation	21,085
Construction Management and Other	7,616
Total	269,141

(Source: Exhibit B-1, Appendix C, Table 2, p.6)

These costs will be managed by BC Hydro. BCTC stated that its cost estimate included in this application applies to a reference route based on the information currently available, and that the EA process will look at potential adjustments to the alignment at various locations along the reference route. BCTC has identified several potential alignment adjustments and additional alignment adjustments may be suggested by BCTC or others in the course of the EA process. BCTC stated that, while it could not anticipate the potential effects on final alignment that may result from the EA process, it expected that the final alignment would fall within or near to the proposed corridor and that any changes would result in less than a 10 percent change in the length of the line (Exhibit B-5, BCUC 1.11.1).

6.5.3 Substations

The Cost and Schedule Report states that the substation costs include 500 kV single circuit transmission line terminations at NIC and MDN, which include the station termination structures, circuit breakers, line shunt reactors and associated equipment within the existing substation property boundaries. The costs for NIC also include an upgrade to its 500 kV buswork, as the addition of 5L83 would increase the rating of the buswork to 3,000 amps from its current rating of 2,000 amps (Exhibit B-1, Appendix C, p. 2). Detailed cost estimates are summarized below. These costs will be managed by BC Hydro.

Cost Item	**MDN**	**NIC**	**Total ($000s)**
Engineering and Project Management	692.0	719.0	1,411.0
Material	1,440.0	2,159.0	3,599.0
Construction	2,570.5	4,339.7	6,910.2
Total	4,702.5	7,217.7	11,920.2

(Source: Exhibit B-1, Appendix C, pp. 12-14, Tables 3 and 4)

6.5.4 Capacitor Station

The Cost and Schedule Report states that a 500 kV series capacitor station will be constructed to provide series compensation on the new transmission line. Depending on the final route alternative selected, the series capacitor bank would be constructed at one of five or six locations. The estimate for the series capacitor station is based on a new 2,727 amp, 892 MVAr mid-line series capacitor bank at RYC. RYC was chosen for the cost estimate as it is the site that best matches the reference alignment (Exhibit B-1, Appendix C, pp. 2-3).

The reference alignment series capacitor station cost estimate at RYC is broken down below. These costs will be managed by BC Hydro.

Cost Item	($000s)
Engineering and Project Management	1,746.0
Material	5,497.9
Construction	19,112.0
Total	26,355.9

(Source: Exhibit B-1, Appendix C, Table 5, p. 15)

The Cost and Schedule Report states that the capacitor station cost estimate does not include any property acquisition, as BC Hydro owns the property at RYC, but that it includes all costs required to construct the station at this site, including the need to loop the 500 kV line in under the existing line, a new 20 km distribution line and a new telecommunications site (Exhibit B-1, Appendix C, p. 61).

BCTC stated that RYC has been used for the cost estimate as a conservative assumption because it has been estimated to be the highest cost of the five potential locations for a series capacitor station and was also neutral to the route alignment. BCTC indicated that it will select a preferred location for the series capacitor station once the final route alignment has been selected.

BCTC stated that the estimated direct costs of the five capacitor station alternatives ranged from $20.8 million at AMC and CHP, $25.4 million at SAW and NSK, and $26.4 at RYC (Exhibit B-5, BCUC 1.15.1-3).

No Intervenor challenges BCTC's base estimates of the Definition and Implementation Phase costs.

6.6 Contingency

The Cost and Schedule Report states that contingency amounts can typically vary anywhere from 5 to 35 percent of total direct construction costs, but can be even higher depending on the risk and level of design. Determining the contingency amount involves some form of risk analysis where possible cost variations are identified and probabilities of occurrence assessed. Contingency is to provide for costs which cannot be specifically identified at the time of estimate preparation but which can be foreseen with varying degrees of probability throughout the life of the project. Contingency has not been included for items subject to external influences not under the control of the Project Manager such as changes in project scope or operating criteria, changes in government policies and regulations, changes in working conditions, changes in escalation/inflation, corporate overhead, taxation and duties, claim settlements, accidents or catastrophes, abnormal weather, or strikes and work stoppages (Exhibit B-1, Appendix C, pp. 18-19).

BCTC calculates its contingency as follows:

	$ million
Definition Phase	5.9
Implementation Phase	
BCTC Managed Costs	1.8
5L83, Substations and Capacitor Station	59.6
Inflation	15.0
	82.3

The Cost and Schedule Report estimates P50 and P90 values for the direct construction costs (i.e., costs of the transmission line, substation modifications, and capacitor station) using a Monte Carlo analysis. The table below summarizes the results of this analysis.

($million)	**Estimated**	**P50**	**P90**	**Contingency (Estimated – P50)**
5L83	269.2	322.0	346.8	52.8
Substations	11.9	13.7	15.2	1.8
Capacitor Station	26.5	31.5	34.6	5.0
Total	307.6	367.2	396.7	59.6

(Source: Exhibit B-1, Appendix C, Table 6, p. 21)

The Monte Carlo analysis resulted in a P50 contingency estimate of $59.6 million or about 19.3 percent on these costs. The comparable P90 contingency is $89 million. The Monte Carlo analysis is discussed further below.

BCTC did not calculate contingencies for the Definition Phase Costs or for the BCTC-managed costs in the Implementation Phase using a Monte Carlo analysis.

BCTC stated that for the Definition Phase a variety of contingencies were allowed totalling $5.9 million. These included:

- BC Hydro Engineering: 1.9 percent contingency;
- BCTC-managed costs: 8.3 percent contingency; and
- Aboriginal relations and negotiation: 19.3 percent contingency.

BCTC stated that it used a straight 20 percent contingency for BCTC-managed costs during the Implementation Phase, resulting in a contingency of $1.8 million.

The Cost and Schedule Report states that an additional contingency of $15 million was allowed on the estimate of inflation that was also not included in the Monte Carlo analysis (Exhibit B-1, Appendix C, p. 22).

BCTC calculated the total P10, P50 and P90 costs for the ILM Project as follows.

($million)	**P10**	**P50**	**P90**
Total Direct Costs	$345.7	$345.7	$345.7
Inflation	$80.5	$80.5	$80.5
Contingency	$48.4	$82.3	$123.6
Corporate Overhead	$16.0	$17.1	$18.5
IDC	$71.4	$76.5	$82.7
Total	$562.0	$602.1	$651.0

(Source: Exhibit B-5, BCUC 1.113.2, Attachment)

As noted elsewhere, these are incomplete estimates of the total ILM Project cost as they exclude certain items such as accommodation costs.

6.6.1 Monte Carlo Analysis

The Cost and Schedule Report states that a Monte Carlo analysis was conducted using the "@Risk" program. The @Risk program uses a Latin Hypercube algorithm (much like a Monte Carlo simulation) of all the tasks in a project. The cost of each task is given a probability distribution with high and low estimated values. A simulation consists of thousands of recalculations or iterations. During each iteration, a random cost is assigned to each task based on the underlying probability distribution for each uncertain variable. The model produces a probability distribution around the total cost of all tasks input for a project.

BC Hydro's Monte Carlo analysis breaks down the specific projects into distinct tasks (e.g., Project Management, Civil Design, etc.), with each task being assumed to be independent of each other as much as possible. In the analysis of the ILM Project, the project was broken down into four sub-projects, each with at least 20 tasks. Each of these tasks is given a "best estimate value" (estimated cost without contingency, inflation, or IDC), and then range estimates are developed by assigning high and low estimated values to each task. The range is the absolute difference between maximum and minimum values for the task and represents the uncertainty or variability in the outcome of the task. The Cost and Schedule Report states that for the ILM Project, where detailed engineering has not commenced, no material has been purchased, and no major contracts signed, a considerable range in costs exists in most of the tasks.

BC Hydro uses a triangular probability distribution for each task. In this distribution, the minimum value has a 1 in 40 chance of being lower and the maximum value has a 1 in 40 chance of being higher. The expected value is the best estimate. The simulation then produces a probability distribution for the combined cost of all tasks and this distribution is analyzed for minimum, maximum, skewedness, standard deviation, and P50 and P90 values. P50 is the value or estimated cost where probability not to exceed is 50 percent and P90 is the value or estimated cost where the probability not to exceed is 90 percent. (Exhibit B-1, Appendix C, pp. 20-21)

BCTC explained in detail how the Monte Carlo analysis is used to estimate a contingency. The P50 estimate represents an estimated cost where the probability not to exceed is 50 percent, and the contingency is then the difference between the P50 value from the Monte Carlo simulation and the "best estimated value" (Exhibit B-5, BCUC 1.60.1).

BCTC addressed the validity of using approximately 80 tasks to analyze a project of $300 million, whose sub-projects have estimated values of $269.2 million, $26.5million, $6.0 million and $9.2 million, respectively. BCTC stated that the tasks used in the Monte Carlo analysis are based on discrete activities that are reasonably independent and is not directly related to the dollar value of individual tasks. For example, a $150 million that has been secured by contract with a guarantee would be input as one task and given a tight range. There would be no further advantage to breaking this task into fifteen separate items. Using approximately 20 independent items in @Risk was adopted by BC Hydro as a good manageable number, reflecting reasonably discrete and independent activities. (Exhibit B-5, BCUC 1.32.1)

BCTC explained why a triangular probability distribution was chosen to represent the cost uncertainty for individual tasks in the ILM Project and how it affected the outcome of the Monte Carlo analysis, and that this particular methodology has been the standard for all BC Hydro estimates (Exhibit B-5, BCUC1.23.7 and BCUC 1.32.2).

BCTC stated that BC Hydro did not assume any correlation among the project tasks in performing the Monte Carlo analysis. BCTC observed that Monte Carlo analysis gives better results when a project is more defined and when the correlations are fully understood, and that the best practices in Monte Carlo analysis of large projects attempt to combine those tasks that have significant correlation as a single task and keep the number of independent tasks to about 20. BCTC also noted the analysis is only a supplement to good engineering judgment for calculating contingency and looking at project risk. (Exhibit B-5-1, BCUC 1.112.1-3)

BCTC discussed the impact of 10 percent, 20 percent and 30 percent correlation and noted that the increasingly positive correlations result in increasingly higher P90 levels, lower P10 values, and similar P50 values. In a typical @Risk simulation there are 10,000 iterations and with each iteration a random value is selected for each task based on the probability distribution for the cost of each task. With the addition of correlation factors, the values within the task ranges are no longer randomly selected. A positive correlation of 10 percent between two tasks increases slightly the statistical likelihood that a high or low cost for one will mean a high or low cost for the other. The addition of correlations among individual tasks flattens the combined probability distribution by pushing out the P90 and P10 values farther with each 10 percent increase in the correlation, but keeping the P50 about the same (Exhibit B-10, BCUC 2.180.2).

No Intervenor challenges BCTC's use of a Monte Carlo analysis to establish a contingency for the ILM Project.

6.7 Inflation, Corporate Overheads and Interest during Construction

The table below sets out the Inflation, Corporate Overheads and IDC rates used by BCTC in the Application.

Year (1)	Inflation	Corporate Overheads	IDC
2007	6%		
2008	5%	3.42%	6.88%
2009	5%	2.44%	6.88%
2010	4%	3.32%	6.88%
2011	3%	3.39%	6.88%
2012	3%	3.39%	6.88%
2013	3%	3.39%	6.88%
2014	3%	3.39%	6.88%
2015	3%	3.39%	6.88%

(Sources: Exhibit B-1, Appendix C, pp. 19-20; Exhibit B-5, BCUC 1.31.1)

Note 1: For inflation the years are calendar years and for Corporate Overheads and IDC the years are fiscal years ending March 31.

6.7.1 Inflation

The Cost and Schedule Report includes an adjustment for inflation on the ILM Project of $80.5 million, before an additional contingency of $15 million referred to above.

The Report states that MMK Consulting Inc. ("MMK") was contracted by BC Hydro to review the cost trends in the B.C. Non-Residential Construction Industry and determine appropriate inflation rates to be used in its project estimates.

In its March 15, 2007 report filed as Appendix G to the Cost and Schedule Report, which was filed as Appendix C in Exhibit B-1, MMK proposed that BC Hydro should use a 2 percent to 4 percent escalation rate for all years through 2015 for transmission lines and substations. However, in March 2007 a briefing note was issued by BC Hydro's Chief Engineer's Team that recommended BC Hydro revise its escalation rates , based on discussions with other utilities, other owners' recommended rates and recent tenders received by BC Hydro (Exhibit B-5, BCUC 1.59.1 (Attachment)). Subsequently, MMK issued a new report dated September 17, 2007, which also supported the final inflation rates used in the cost estimates and summarized at the beginning of this Section. BCTC stated that a detailed escalation analysis, employing direct labour, statutory labour costs, construction equipment (rental or owned), construction material, and engineered equipment (purchased) to calculate the weighting per item and its escalation over the project, cannot be provided, as the escalation included in the CPCN estimate was applied as a single percentage across the project, and was not calculated differently for specific items. This single percentage accounts for the "basket" of cost elements such as labour, materials, equipment, fuel, etc., as well as market conditions and has been applied to the total estimate (Exhibit B-5, BCUC 1.38.2.1).

6.7.2 Corporate Overheads

The Cost and Schedule Report calculates Corporate Overheads to be $17.1 million.

BCTC stated that the Corporate Overhead rates were calculated based on the forecasted Corporate Overheads cost divided by the total forecasted direct capital expenditures (capital excluding interest during construction and Corporate Overheads) for transmission projects and were based on the June 2007 capital forecast (Exhibit B-5, BCUC 1.31.1-3).

6.7.3 Interest During Construction

The Cost and Schedule Report shows IDC to be $76.5 million.

BCTC stated that BC Hydro advised that the IDC rate was based on BC Hydro's forecasted actual cost of debt as approved in the BC Hydro F2007/F2008 Revenue Requirement Application Negotiated Settlement Agreement. BCTC stated that part of the reason to adopt the methodology used to derive BC Hydro's IDC rate was so that the IDC rate was more stable and transparent, and that it was simpler to use a constant rate for the project financial estimates rather than a different rate for each year of the study based on each year's forecast interest rates (Exhibit B-5, BCUC 1.56.3).

No Intervenor challenges BCTC's calculation of Inflation, Corporate Overheads or IDC.

6.8 BCTC's Efforts to Validate the ILM Project's Costs

BCTC took a number of steps to validate its estimate of the ILM Project costs. Specifically, it retained SNC Lavalin to critique its estimates, reconciled its estimate with its 2004 estimate, and looked at the unit costs of other major transmission projects in North America.

6.8.1 SNC Lavalin

BCTC retained SNC Lavalin to review BC Hydro's cost estimate to assess the reasonableness of the estimate in consideration of current industry and market trends (Exhibit B-1, p. 59). BCTC stated that since BC Hydro had no role in the process of selecting SNC Lavalin and since SNC Lavalin had not participated in preparing the ILM Project cost estimate provided by BC Hydro Engineering Services, BCTC believed that SNC Lavalin could be used to perform an independent review BC Hydro's estimate (Exhibit B-5, BCUC 1.35.2).

BCTC includes a report by SNC Lavalin dated November 1, 2007 and entitled “Interior to Lower Mainland (ILM) Transmission Project Cost Estimate Review” as Appendix E to its Application (“the Review”). The Review encompassed the aspects of the BC Hydro estimate that had the greatest potential for market and other influences. These included engineering, material, construction, and escalation.

The Review was performed for the following portions of the project scope: 5L83, the substations, and the series capacitor station.

The Review analyzed the costs for each portion of the project scope at current prices, and discussed project escalation consolidated separately in the escalation section. The Review considered only the Implementation Phase portions of the estimate and did not evaluate services provided by BCTC or BC Hydro, such as Land and Property Services, Forest Engineering, Legal Services, and Community and Aboriginal Relations. The Review included 15 cost estimate categories, overheads and IDC (Exhibit B-1, Appendix E, p. 2). SNC Lavalin’s forecast of escalation was higher than that prepared for BCTC by MMK. (Exhibit B-1, Appendix E, p. 13)

BCTC states the Review resulted in a difference of approximately $35 million. SNC Lavalin participated in a workshop with BC Hydro estimating staff and engineers to discuss the Review, including its estimating methods, and industry and market conditions. BCTC considers the BC Hydro estimate to be reasonable given the stage to which the ILM Project has progressed. BCTC states that it has used the cost estimates developed by the Project Team for the purpose of calculating revenue requirement and other economic impacts in the Application. However, at this stage in the ILM Project development, both cost estimates are within a valid range of estimates for the ILM Project cost (Exhibit B-1, p. 59).

6.8.2 Comparison with 2004 estimate

BCTC compared the estimate shown in its May 2004 Transmission System Capital Plan ("2004 TSCP") of $301.4 million with the $602 million cost provided in the Application and stated that the estimate increased by $300.7 million for the following reasons:

- "The engineering estimates provided in the 2004 estimate did not include the ILM Feasibility Study, the Upgrade Existing Circuits (UEC) options analysis and additional support activities for BCTC's regulatory requirements. The 2007 estimate reflects these additions ($5.0 million);
- The material estimates provided in the 2004 estimate have been adjusted to reflect current material prices as recently experienced on the Fort St John Area Reinforcement and VITR projects ($16.0 million);
- The construction estimates provided in the 2004 estimate were based on the market conditions at that time and have been adjusted to reflect external contractor costs as recently experienced on the Fort St John Area Reinforcement and VITR projects. All construction estimates have been adjusted to allow for labour and terrain premiums to undertake the work given that a significant amount of line construction activities would be required to be completed within restricted timeframes (i.e. environmental restrictions, weather limitations, etc.) ($96.9 million);
- The route has been modified and lengthened to meet geotechnical and environmental requirements (included in the $96.9 million above);
- The estimate provided in 2004 included a contingency of 15 percent, while the current $602 million estimate includes a contingency of almost 19.4 percent ($55.6 million);
- The estimate provided in the 2004 was based on regulatory, environmental and First Nations engagement / accommodation processes in place at that time. These processes have substantially changed and the estimates updated to reflect these changes in processes($20.5 million);
- The estimate has been updated to include anticipated regulatory, environmental, public consultation and First Nations engagement activities (included in the $20.5 million above);

- The 2004 estimates included inflation rates of only 2.1 percent, and these inflation rates have been increased to account for current demand in the transmission industry ($50.9 million); and

- Given the increased inflation and construction labour costs, and the deferral of the project in-service date from 2013 to 2014, the corporate overheads and interest during construction have increased ($55.8 million)."

(Exhibit B-10, BCUC 2.144.1)

6.8.3 Costs of Comparable Projects

BCTC stated that it compared the unit costs of the ILM Project with other 500 kV projects. However, BCTC noted that while large utilities have major projects in the planning stages, few other than the 500 kV Path 15 project in central California and the 345 kV Bethel to Norwalk line in southern Connecticut have been built. The cost to build transmission lines is heavily dependent on the location and the economic conditions that exist at the time of implementation. BCTC noted that a 500 kV transmission line built in the mountains of B.C. over the next five years will likely have very different costs from the 500 kV line built in California or the 345 kV line in Connecticut (Exhibit B-5, BCUC 1.23.15.1).

No Intervenor challenges BCTC's attempts to verify the cost of the ILM Project.

Commission Determination

The Commission Panel accepts BCTC's estimation of ILM Project costs, including inflation, Corporate Overhead and IDC. The Commission Panel notes that BCTC excluded certain costs listed under Section 6.5.1 of this Decision, and provides further directions to BCTC regarding these same costs in Section 10 of this Decision.

The Commission Panel accepts BCTC's use of a reference alignment for the purpose of establishing a base estimate, and does not require further review of the alignment as long as the final alignment is substantially consistent with either the reference alignment or the segment alternatives as presented in the Application.

The Commission Panel accepts the approach BCTC used to determine a P50 and P90 contingency for the ILM Project, but notes that the base number and contingency do not yet include costs such as environmental mitigation or aboriginal accommodation costs.

The Commission Panel notes that BCTC did not use BC CPI as the basis for forecasting inflation and that the Commission, in Order G-107-08, F2009 TSCP Decision, directed BCTC to continue to use an inflation adjustment equal to BC CPI. Solely for the purposes of economic analysis of the ILM Project and the conditions to this Decision, the Commission Panel will accept BCTC's calculation of inflation based on forecasts other than BC CPI.

7.0 BCTC PROJECT SELECTION – UEC VS. 5L83

This Section reviews BCTC's comparison of UEC and 5L83, first against certain technical characteristics, and then from an economic perspective. BCTC's comparison was also supported by sequencing analysis and by a separate horizon year analysis, which are considered in this Section. The potential cost of deferring the ILM Project is also discussed. Finally, BCTC's rationale for the selection of 5L83 as its preferred alternative is considered.

7.1 Comparison of UEC with 5L83

Following the elimination of the "Do nothing" alternative, and the "Coastal Generation and/or DSM", 5L46, NIC to ING, and HVDC alternatives, BCTC was left with two remaining alternatives to evaluate and compare, namely 5L83 and UEC.

Rather than using the prioritization model methodology, BCTC states that it subjected the remaining alternatives to a more detailed review using the following seven planning indicators as the comparison criteria:

"(a) Thermal Overload Capacity

(b) Continuous Thermal Capacity

(c) Voltage Stability

(d) Network Losses

(e) PV [Present Value] of Costs

(f) Double Outage Limitations

(g) EENS Reliability Performance"

(Exhibit B-1, Appendix I, pp. 21-22)

BCTC stated that its prioritization model was not developed, and had limited value, for the purposes of comparing planning alternatives or planning sequences (Exhibit B-5, BCUC 1.67.1). The prioritization model was developed for portfolio-level investment comparisons, and BCTC has other need-specific processes to compare alternatives to select the preferred solution (Exhibit B-10, Attachment to BCUC 2.166.1, BCTC F2009-F2018 TSCP proceeding; Exhibit B-5-1, BCUC 1.79.3).

BCTC provides a detailed comparison of UEC with 5L83 in its Alternatives Report. BCTC compares the two alternatives on the basis of seven factors: thermal overload capacity, continuous thermal capacity, voltage stability limits, network losses, present value ("PV") of costs, double outage limitations, and EENS reliability performance and sets out the initial comparison of the technical characteristics of UEC and 5L83 in the following table.

	Technical Indices	**5L83**	**UEC**	**Comments**
1	Thermal Capacity (Overload)	Approx. 8400 MW	Approx. 8400 MW	Defined by the N-1 thermal overload nomograms
2	Thermal Capacity (Continuous)	6220 MW to 6750 MW	6000 MW to 6570 MW	Defined by the N-1 thermal continuous nomograms
3	Voltage Stability Limit	Approx. 7120 MW	Approx. 6355 MW	With 470 MVAr additional reactive power support
4	Transmission Loss Savings	Approx. 307 GW.h/yr	None	Average ILM transmission loss savings in 2014/15
5	PV of Costs	$-121.9M	$251.5 M	For energy valued at $74.0/MW.h
6	Double Outage Generation Shedding	393 MW to 681 MW	1080 MW to 1659 MW	Based on the N-2 shedding requirements
7	Double Outage Load Shedding	380 MW to 640 MW	938 MW to 1470 MW	Based on the N-2 shedding requirements
8	Reliability – Expected Energy Not Served	121 MW.h/yr to 172 MW.h/yr	127 MW.h/yr to 180 MW.h/yr	Based on 500kV outages

(Source: Exhibit B-1, pp. 82-83)

7.2 Technical Characteristics

BCTC concludes that 5L83 and UEC could increase the continuous thermal capability of the existing ILM grid from 5,000 MW to 6,750 MW and 6,570 MW respectively, but that the ILM grid would then be limited by voltage stability to 6,550 MW for 5L83 and to 5,800 MW for UEC. Additional reactive power would be required to support heavy flows on the ILM grid. With 470 MVAr reactive power additions, the voltage stability limit of the ILM grid would increase from 6,550 MW to 7,120 MW for 5L83 and from 5,800 MW to 6,355 MW for UEC (Exhibit B-1, Appendix I, p. 13).

BCTC describes voltage stability as the "ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after a contingency. A system enters a state of voltage instability when a disturbance, increase in load demand, or change in system condition causes a progressive and uncontrollable drop in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power. Exceeding this limit could result in cascading system outages" (Exhibit B-1, p. 71). BCTC states that "voltage stability is the dominant constraint on the ILM grid relative to transient stability" (Exhibit B-1, Appendix H, p. 9).

BCTC stated that the incremental transfer capability to the ILM grid of 5L83 is 1,750MW. BCTC also notes that 5L83 results in less double outage generation shedding and load shedding than UEC, while the reliability improvement of 5L83 over UEC is not considered significant (Exhibit B-1, Appendix I, pp. 8-9). The usage of the incremental 5L83 reinforced ILM grid capacity reaches 50 percent by 2017, 80 percent by 2022, and will be exhausted by 2025 (Exhibit B-10, BCUC 2.154.1). The ILM grid with 5L83 must be further reinforced in 2020 to allow flexibility of dispatch (Exhibit B-14, IPPBC 3.2.1).

BCTC stated that the incremental transfer capability to the ILM grid of UEC is 1,355 MW. The higher incremental transfer capability of 5L83 would be used for the dispatch of Interior region resources, and is a more significant factor than the increased capital cost of 5L83 over UEC (Exhibit B-10, BCUC 2.147.2).

BCTC presented the forecast of the usage of the ILM grid based on resources identified in the approved 2006 Amended LTAP portfolio.

	Year	Required transfer@Kelly and Nicola (MW)	Incremental ILM capacity with 5L83 (MW)	Incremental ILM usage with 5L83 (MW)	Percent of incremental ILM grid capacity used (%) (d)/(c) x 100
	2014\2015	5849	1750	849	48.52%
	2015\2016	5865	1750	865	49.42%
	2016\2017	5873	1750	873	49.90%
	2017\2018	5941	1750	941	53.77%
	2018\2019	6041	1750	1041	59.48%
	2019\2020	6147	1750	1147	65.52%
	2020\2021	6262	1750	1262	72.09%
	2021\2022	6384	1750	1384	79.06%
	2022\2023	6493	1750	1493	85.34%
	2023\2024	6609	1750	1609	91.95%
	2024\2025	6756	1750	1756	100%
	2025\2026	6904	1750	1904	100%
	2026\2027	7054	1750	2054	100%

(Source: Exhibit B-10, BCUC 2.154.1)

7.2.1 Transmission Loss Savings

BCTC states that it calculated the ILM grid's expected energy losses with 5L83 and with UEC and found that the energy losses associated with UEC were greater than energy losses for 5L83. BCTC states that it used the following assumptions to calculate the difference in energy losses for 5L83 and UEC after 2014:

- Load and Load Curve: In this analysis, the December 2006 load forecast was used to simulate the 2014/15 peak hour load. To represent the expected load and loss variations and to estimate the average energy losses in 2014/15, the recorded 2005/2006 load curve was applied; and
- Generation and ILM Flow: To simulate the generation that would supply the peak hour load and transmission losses in 2014/15, it dispatched generation up to the dependable capacity of the [2006] Amended LTAP resources and restricted the peak hour flow on

> the ILM grid by the voltage stability limit of UEC with 470 MVAr of reactive reinforcement at 6,355 MW. (Exhibit B-1, Appendix I, p. 24)

BCTC states that its loss analysis indicated that, when compared to UEC, 5L83 would reduce the average F2015 transmission energy losses by approximately 307 GW.h (Exhibit B-1, Appendix I, p. 24).

BCTC stated that its first analysis of loss differences between 5L83 and UEC was based on the four resource portfolios that originated in the NITS 2004 application and that for each of these four portfolios, separate winter and summer base cases were prepared with varying levels of Coastal region generation and combinations of maximum or dependable Interior generation. The firm export to the U.S. was maintained at 230 MW plus a transmission reliability margin of 50 MW. Each base case was modeled with either 5L83 or UEC as the ILM grid reinforcement. Recognizing that the flow on the ILM grid would not remain at a constant level throughout the year, these base cases were input into BCTC's Power Loss ("PLOSS") program, which uses the load curve to scale the generation on an hourly basis to balance the load and compute losses for each hour of the season, along with a seasonal load duration curve for 2005 to simulate the changing loading of the grid throughout the year. (Exhibit B-5, BCUC 1.2.1)

To validate these results, BCTC stated that it prepared another set of base cases that loaded the ILM grid, with either UEC or 5L83, up to 6,355 MW (the voltage stability limit of UEC). Using the more recent hourly load curve from April 1, 2005 to March 31, 2006, the PLOSS program was used to compute the annual energy losses, which were 1,043 GW.h and 732 GW.h for UEC and 5L83 respectively for a difference between the two average energy losses of 311 GW.h per year. As this result was within 1 percent of the average of results from earlier studies, BCTC used the 307 GW.h/yr loss difference between UEC and 5L83 in the analysis in this Application. (Exhibit B-5, BCUC 1.2.1)

IPPBC submits that BCTC should study the possibilities that might exist for loss reductions that could be achieved as part of the 5L83 analysis. IPPBC claims that BCTC only viewed loss savings as future benefits that could improve the ILM grid's total transfer capacity and is critical of BCTC for not considering loss savings as part of its analysis in Exhibit B-1, Appendix K (IPPBC Argument, pp. 10 – 11).

BCTC replies that it did not consider losses in its analysis in Appendix K because the purpose of that study was to determine whether 5L83 made sense in both the 20-year and 30-year timeframes. BCTC argues that where the losses were material to its decision-making, such as the selection among alternatives, it did assess losses (BCTC Reply, para. 50). BCTC agrees that comparing the losses associated with different alternatives is important and notes that losses were one of the screening criteria for alternatives. BCTC notes that it included the difference in losses between 5L83 and UEC in its economic analysis. In addition, BCTC notes that given the distance involved in the ILM Project, the savings in tower costs, conductors and losses for HVDC were not sufficient to overcome the higher cost of the HVDC converters, as noted in the DCI report and various responses to IRs (BCTC Reply, para. 51).

BCTC also indicates it does not understand IPPBC's criticism that BCTC only viewed the loss savings as future benefits since loss savings can only be evaluated relative to some base line.

The loss savings associated with different reinforcement alternatives occur only in the future when the reinforcement alternative comes into service. BCTC submits that given plans to build the ILM Project at the earliest practical in service date, there are no other loss savings that can be obtained other than the future loss savings which it considered (BCTC Reply, para. 52).

Finally BCTC notes that the Transmission System Loss Study referenced in its response to IPPBC 3.8.1 (Exhibit B-14) is concerned with the capacity and energy losses on the entire transmission system and this broader system-wide study in no way invalidates the more specific loss assessments made of the ILM grid in the preparation of the Application (BCTC Reply, para. 52).

No other Intervenor challenges BCTC's calculation of transmission loss savings.

Commission Determination

The Commission Panel does not understand IPPBC's concern that BCTC should have studied the possibility that might exist for further loss reductions as part of 5L83 or that BCTC only viewed loss savings as future benefits. The Commission Panel agrees that BCTC has considered the difference in losses between project alternatives and these losses are in fact future benefits. The Commission Panel accepts BCTC's calculation of transmission loss savings of 307 GW.h per year. The Commission Panel notes these are loss savings under an average water year. The Commission Panel expects that loss savings would be lower in a critical water year, since there would be fewer exports from the system. The Commission Panel considers this distinction may be important in the valuation of losses as discussed further below.

7.3 Economic Analysis

7.3.1 Methodology

BCTC notes that a simple comparison of capital costs does not take into account other important differences such as transmission loss savings, operating and maintenance ("O&M") expenses, and applicable taxes. BCTC therefore provides a more complete comparison of the total cost of each project taking into account these other costs and savings over the 50-year lives of the alternatives compared. Although individual UEC projects can be delivered sooner than a new transmission circuit, BCTC's analysis assumes that both alternatives are completed in October 2014. BCTC compares the projects in 2014 using $2014. As a result, BCTC adds inflation and IDC prior to 2014 to the total capital costs for each project. BCTC then adds the PV of all recurring costs (and savings) to capital cost estimates in order to determine the overall net cost of each project on a present value basis in 2014. (Exhibit B-1, Appendix I, p. 25)

No Intervenor challenges BCTC's methodology of performing its economic analysis.

7.3.2 Assumptions

BCTC assumes that the transfer on the ILM grid never exceeds the 6,355 MW TTC of the UEC alternative. BCTC also assumes that future load growth in the LM-VI regions would be met by a combination of future increases in Coastal region generation, DSM, and imports on the western intertie.

BCTC states that it used the following assumptions in the PV comparison of 5L83 and UEC:

- all capital costs are in 2007 un-inflated dollars;
- ISD of both 5L83 and UEC: 2014;
- real discount rate: 2.5 percent;
- duration of the PV analysis: 50 years;
- O&M annual rate for steel towers: 0.10 percent;
- O&M annual rate for substations: 1.01 percent;
- annual taxes for 500 kV transmission lines: $4,056/km;
- annual tax rate on physical plant: 1.47 percent; and
- levelized value of transmission loss savings: $74/MW.h.

(Exhibit B-1, Appendix I, p. 26)

BCTC states that the economic comparison does not include any allowance for differences in trade benefits, and that in a report of its analysis of energy shaping benefits BC Hydro had advised it that, absent relief of other constraints, 5L83 would on average provide increased energy shaping benefits in the range of $0.11 million to $1.67 million annually (Exhibit B-1, Appendix T). BC Hydro stated that the additional transfer capability due to 5L83 would enable its system to sell more energy during the high price winter heavy load hour periods by operating the major hydro plants at higher, but less efficient output levels more often (Exhibit C1-3, BCUC 1.107.1).

7.3.3 Capital and O&M Costs

BCTC states that the comparison of alternatives was concluded in May 2007 and was based on April 2007 capital cost estimates of both 5L83 and UEC developed by the Project Team. BCTC states:

> "While the April cost estimate for 5L83 is lower than the current estimate, the cost estimates used in the comparison were all prepared in the same time frame and with a similar level of analysis. The change between the April estimate and the September estimate for 5L83 primarily relates to revisions to the environmental permitting task, stakeholder consultation and a change in the reference alignment to address permitting considerations and environmental issues (e.g. Spotted Owl habitat). Therefore, the comparison of alternatives in May remains valid despite the development of an updated cost estimate for 5L83" (Exhibit B-1, pp. 59-60).

BCTC does not offer a comparison of the capital cost of 5L83 used in the PV Tool with that used in the Application of $602 million, but a review of the PV tool in Exhibit B-5, BCUC 1.70.11 suggests that the difference may be approximately $40 million.

In its analysis, BCTC also adds the capital cost of one 250 MVAr / 500 kV mechanically switched capacitor ("MSC") at NIC and two 110 MVAr / 230 kV MSCs at MDN to both the 5L83 and UEC alternatives, and states that the cost of these projects is included in BCTC's F2008 TSCP (Exhibit B-1, Appendix I, p. 26).

No Intervenor challenges the capital or O&M cost assumptions used by BCTC.

7.3.4 Discount Rate

BCTC states that when its planning analysis was being prepared, the discount rate reflected in the analysis was based on the Commission-directed nominal discount rate of 4.6 percent, or 2.5 percent real after an adjustment for inflation, but that BC Hydro subsequently proposed in its 2007 Energy Purchase Agreement with Alcan that the discount rate should be 5.25 percent nominal or 3.15 percent real after inflation, to reflect current interest rates (Exhibit B-1, Appendix G, p. 91).

The discount rate used for the economic (and ratepayer impact) analyses within the Application is consistent with the 2007 IEP/LTAP Decision in which the Commission accepted BC Hydro's arguments regarding the actual operation of Special Directions HC1 and HC2 ("HC1 and HC2"), and the minimal linkages between capital spending and actual equity levels in BC Hydro. The Commission noted the long-run incremental cost of funds should still be set based on occasional forecasts of capital expenditures and the availability of debt financing, but accepted that based on the forecasts filed in that proceeding, capital projects will effectively be financed with 100 percent debt for the foreseeable future (Exhibit B-14, BCUC 3.216.0).

By Orders in Council ("OIC") 27 and 28 approved on January 17, 2008 (after BCTC filed its Application), the Province amended the definition of BC Hydro's equity included in HC1 and HC2. Under the amended HC1, BC Hydro's equity is now defined using Generally Accepted Accounting Principles ("GAAP") and therefore BC Hydro's equity currently only includes retained earnings and no longer includes deferred revenue, contributions arising from the Columbia River Treaty or contributions in aid of construction. The amended HC2 deems BC Hydro's equity for ratemaking purposes to be 30 per cent of the sum of BC Hydro's average debt and average equity balances for the year. Under HC1, BC Hydro's dividend payment to the Province is reduced if the payment would cause BC Hydro's debt to equity (as redefined) ratio to exceed 80:20.

BC Hydro stated that:

> "The changes to Heritage Special Directions HC1 and HC2 mean that incremental capital expenditures, all of which are debt financed will now have an impact on BC Hydro's level of equity for rate setting purposes. In particular, total debt is included in the calculation of deemed equity. Given this, BC Hydro believes it is appropriate to adopt a discount rate that reflects the allowed return on deemed equity rather than solely based on BC Hydro's long-term debt cost. Following from the 2006 IEP/LTAP Decision on the appropriate discount rate to use to evaluate resource options, a 30 per cent deemed equity capital structure, forecast average long-term debt costs of 6.00 per cent and forecast allowed return on equity of 11.78 per cent, leads to the adoption of a nominal discount rate of 7.73 per cent, which BC Hydro proposes to round to 8 per cent." (Exhibit C1-12, BCUC 3.216.1)

BCTC stated that BC Hydro had advised it that, for planning purposes, its F2009 forecast of debt cost for a term longer than 10 years was 5.04 percent, which included the cost of issuance (Exhibit B-14, BCUC 3.217.3)

No Intervenor challenges the discount rate used by BCTC.

7.3.5 Value of Transmission Loss Savings

BCTC states that, for the purposes of its economic analysis, it valued transmission loss savings at $74/MW.h, which it based on BC Hydro's F2006 Call Weighted Average Levelized Plant Gate Price (Exhibit B-1, Appendix I, p. 26).

BCTC's analysis did not take into account any weighting factors for energy saved in High Load Hours, which it estimated in response to Exhibit B-14, BCUC 3.188.2 and BCUC 3.188.4 to increase the value by only 2 to 3 percent. BCTC submits that these analyses did not result in loss savings materially different than those estimated under the original $74/MW.h (BCTC Argument, para. 29).

BC Hydro submits that the 5L83 loss reduction results in an increased delivery of energy to the LM region to meet load, and points out that the cost of energy delivered to the LM region, as calculated in the F2006 CFT, is $88/MW.h, which is the average levelized adjusted bid price using a nominal eight per cent discount rate but that, if 5L83 does not proceed, the losses being saved by 5L83 would need to be supplied by other resources whose capacity and energy would have to be delivered to the LM region, and that BCTC should have adjusted the $88/MW.h bid price for delivery to the LM region to adequately reflect the value of the residual incremental savings that result from the avoidance of both the cost of producing and of delivering the capacity and energy to the LM region (BC Hydro Argument, para. 3.2).

BC Hydro submits that SD 10 is legally binding on the Commission and is relevant to what value should be assigned to the 5L83 energy loss savings because it affects the availability of alternatives by ruling out purchases from external markets as a resource option that BC Hydro can plan to rely on to replace the capacity and energy losses being avoided by 5L83. Using short-term forecasts of spot market prices as the basis for valuing the 5L83 energy savings is inconsistent with SD 10 and does not reflect the value of the long-term reduction in the requirement for dependable capacity and firm energy to BC Hydro's system (BC Hydro Argument, para 3.5).

No other Intervenor challenges BCTC's evaluation of losses.

7.3.6 Results

BCTC calculated the PVs of the two alternatives to be as follows.

PV ($Million)	Base Year 2007	Corrected Base Year 2014	Original Application Base Year 2014
5L83	(129.4)	(122.2)	(121.9)
UEC	213.4	245.4	251.5
Difference	342.8	367.6	373.4
Source	Exhibit B-5, BCUC 1.70.11	Exhibit B-5, BCUC 1.99.1	Exhibit B-1, p. 83

Based on this comparison, BCTC concludes: "The lower PV of costs makes 5L83 fiscally more attractive than the UEC alternative notwithstanding the UEC's lower capital costs" (Exhibit B-1, Appendix I, p. 27).

BCTC provided the PV Tool in response to BCUC 1.70.11 (Exhibit B-5), which includes an interactive spreadsheet that compares the total costs of UEC and 5L83 alternatives, including differences in losses.

7.3.7 Sensitivity Analyses

BCTC states that the savings in energy losses is a significant factor in making 5L83 less costly than the UEC alternative, and that its PV analysis is also very sensitive to discount rate assumptions. BCTC conducted a variety of sensitivity analyses with respect to losses and discount rates as part of its original Application and in response to various IRs, which are discussed further below. BCTC also conducted sequencing and horizon studies, which are also discussed below.

7.3.7.1 Sensitivity to changes in PV cost

BCTC considered the impact of a 5 percent decrease and 30 percent increase in the project cost estimates used in the PV cost comparison of each project. The analysis values energy losses at $74/MW.h for each of the three estimates shown in the following summary of this analysis.

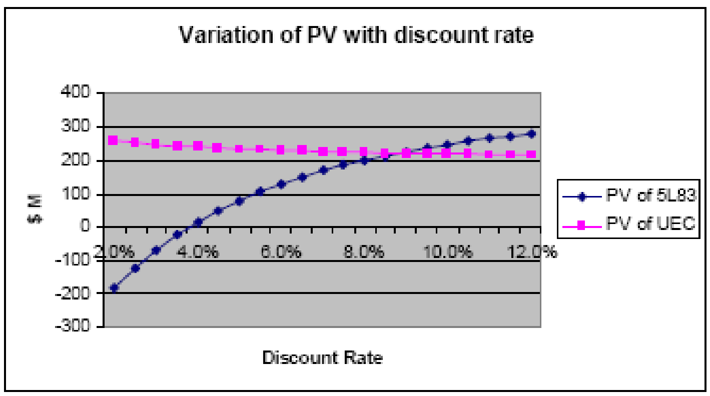
ILM Alternative	**PV of Cost ($M) Low Estimate (95% of the base estimate)**	**PV of Cost ($M) Base Estimate**	**PV of Cost ($M) High Estimate (130% of the base estimate)**
UEC	238.9	251.5	326.9
5L83	(147.4)	(121.9)	30.5
Difference	386.3	373.4	296.4

(Exhibit B-5, BCUC 1.116.5)

BCTC calculated that the PV of 5L83 costs would be less than the PV of UEC costs by 386.3 million with project cost estimates at 95 percent of the base estimate and by $296.4 million with project cost estimates at 130 percent of the base estimate, using a real discount rate of 2.5 percent and valuing transmission loss savings at $74/MW.h.

7.3.7.2 Sensitivity to changes in discount rate

BCTC notes that financial comparisons between 5L83 and UEC are sensitive to changes in discount rates, largely as a result of the benefit of loss savings over time for 5L83, relative to UEC, and conducts a sensitivity analysis to evaluate the impact of changing discount rates on the PV comparison of 5L83 and UEC. BCTC evaluated the difference in the PV of the alternatives using discount rates ranging from 2 percent to 12 percent real. The average price of electrical energy was assumed fixed at $74/MW.h for the purposes of these analyses. Other calculation parameters remained unchanged. The results of these sensitivity analyses are summarized below.



(Exhibit B-1, Appendix I, Figure 3-3)

BCTC observes that as the discount rate increases, the difference between the PV of costs for the 5L83 and UEC alternatives decreases and the two alternatives would have similar PV of costs at a real discount rate of 8.8 percent.

BCTC commented on the wide range of discount rates stating:

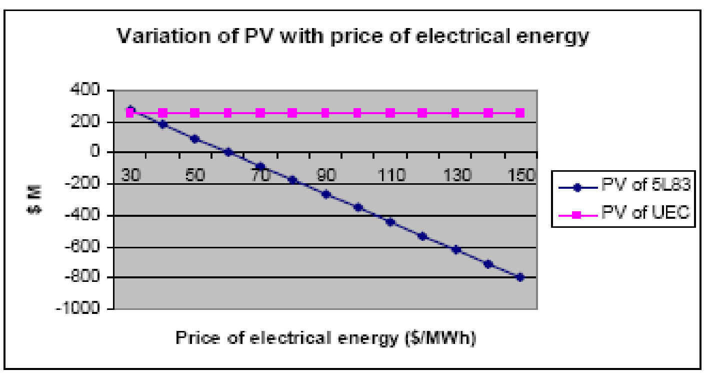
> "BCTC understands that a discount rate should relate to BC Hydro's cost of capital and that, because the discount rates are real rates, they notionally reflect the risk free rate plus some risk premium. BC Hydro has instructed BCTC to use the same discount rate for all transmission projects (currently 6%) indicating that the risk associated with transmission projects is relatively consistent, which is reasonable given the similar nature of projects and the stability of revenue streams in BC Hydro's regulated environment. Consequently, BCTC believes that it is highly

unlikely that real discount rates in the order of 10% or 12% would occur in the foreseeable future. Accordingly, BCTC does not believe that the analysis using 10% or 12% discount rates should be accorded any weight in the assessment of the ILM Project." (Exhibit B-14, BCUC 3.189.2)

BCTC submits that "…comparisons using a 6% real discount rate are the most relevant, and that higher discount rates are unlikely to occur in the foreseeable future." BCTC also notes that "…even at a real discount rate of 8%, 5L83 still retains a significant cost advantage over UEC" (BCTC Argument, para. 28).

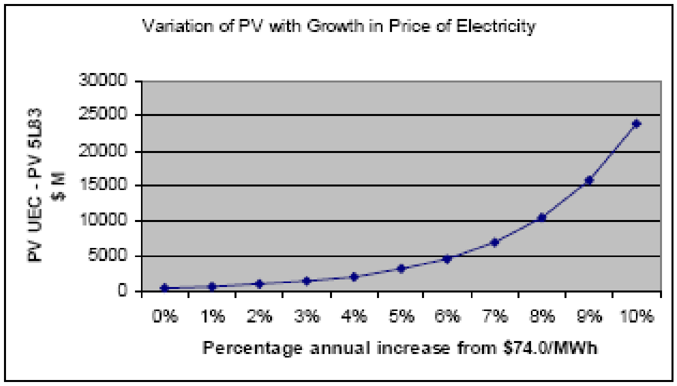
7.3.7.3 Sensitivity to changes in value of transmission loss savings

BCTC notes that the value of energy loss savings is directly proportional to the price of electricity, which is set by market forces and can be different from the forecast value. BCTC provides sensitivity analyses for its economic comparison of 5L83 and UEC based on energy prices ranging from $30/MW.h to $150/MW.h. The results of these analyses are shown in Figure 3-1 of Appendix I, which is replicated below.



(Exhibit B-1, Appendix I, p. 27).

The above analysis assumes that real energy prices remain constant. BCTC also conducts sensitivity analyses reflecting different real rates of escalation for energy prices and includes the table below, which shows the difference in the PV of costs between UEC and 5L83 for annual real growth in the price of energy ranging between 1 and 10 percent. BCTC notes this analysis shows that an annual increase in the price of electricity would improve the attractiveness of 5L83 over UEC from a financial perspective.



(Exhibit B-1, Appendix I, Figure 3.2)

Commission Determination

The Commission Panel accepts BCTC's approach to include capital costs and ongoing costs / savings in the alternatives comparison, and notes in particular the importance of differences in losses in the ranking of the two alternatives. The Commission Panel, however, found BCTC's PV analyses difficult to follow as it was not always clear what base years were being used for dollar estimates or for present valuing purposes. The Commission Panel expects BCTC in future to file materials that are more clear and consistent with respect to the presentation of dollar values and PV estimates.

The Commission Panel notes that BCTC's economic comparison of 5L83 and UEC used capital cost estimates developed in April 2007, which in the case of 5L83 appear to have increased by as much as $40 million by the time of the Application. The Commission Panel notes that the factors to which BCTC ascribed the cost increase for 5L83 may not have been present to the same degree for UEC. The Commission Panel will take this factor into account when determining an amount by which UEC's PV exceeds that of 5L83.

The Commission Panel accepts that BCTC's simple approach to valuing losses on an unweighted basis (e.g., based on an average losses and energy value) was reasonable in this case and that the more detailed analysis conducted in response to IRs (i.e., based on more detailed consideration of timing of losses and weighting factors for value of energy) did not have a material impact on the overall economic analysis in this instance. The Commission Panel believes that as BC Hydro places more emphasis on the time in which energy is delivered, a different approach to the evaluation of transmission line losses may become more appropriate.

The Commission Panel accepts BC Hydro's response that the effect of OIC 27 and 28 is to increase the appropriate discount rate relative to the 2006 IEP/LTAP determinations, and notes that this reduces but does not eliminate the cost advantage of 5L83. The Commission Panel is not entirely convinced of the specific discount rate calculated by BC Hydro, which assumes a weighted average cost of capital based on 70 percent debt and 30 percent deemed equity. The Commission Panel considers there is insufficient evidence in this proceeding to make a final determination with respect to the appropriate discount rate and instead relies on the evidence that the ranking of project alternatives remains unchanged within the likely range of 7 to 8 percent (nominal) cost of capital, which assuming a 2.1 percent forecast inflation rate translates into a real discount rate in the 5 to 6 percent range.

The Commission Panel accepts that the F2006 CFT could be used as a benchmark for the cost of firm power in B.C. in order to value the transmission loss savings associated with 5L83. The Commission Panel acknowledges that the value used by BCTC excludes the cost of delivery to the Lower Mainland, which may in fact be a reasonable addition for valuing loss savings on the ILM grid. However, the Commission Panel finds that there may be other ways of valuing the entire loss savings estimated by BCTC for 5L83 than at the cost of new firm power in B.C. The Commission Panel notes that SD 10 applies to critical water conditions and there is no evidence in this proceeding that losses would equal 307 GW.h/year under critical water conditions. In fact, they would likely be lower because of reduced exports under critical water conditions. BCTC did not provide an estimate of loss savings under critical water conditions. In average water years, the Commission Panel considers that it may be reasonable to replace losses with market purchases. This suggests a value closer to Mid-C prices (a common market index used by BC Hydro), at least for a portion of average losses. Further, if the province achieves self-sufficiency and is in an export situation in most average water years, it may be reasonable to value losses using prices at Mid-C

LESS the cost of wheeling and losses to Mid-C, since losses in average water years will result in foregone export sales rather than additional purchases. Given uncertainty over the value of losses, the Commission Panel has relied on a range of values between $60/MW.h and $90/MW.h, reflecting the F2006 CFT price as an upper limit and the value of exported surplus power at Mid-C as the lower limit.

The Commission Panel concludes that 5L83 continues to have the lower PV under virtually all scenarios for losses and discount rates and in particular those scenarios the Commission Panel considers to have the most weight, namely real discount rates between 5 and 6 percent and values of losses between $60/MW.h and $90/MW.h and that, under the mid-point of these parameters, the PV of 5L83 is approximately $100 million less than that of UEC.

7.4 Sequencing Analysis

BCTC also considers the sequencing of the 5L83 and UEC alternatives in its Alternatives Report (Exhibit B-1, Appendix I, Section 3.5.3, p. 30). BCTC considers two sequences as follows:

1) 470 MVAr reactive power installation prior to 2014, followed by commissioning of 5L83 in 2014, followed by implementing a partial UEC in 2020.

2) 470 MVAr reactive power installation prior to 2014, followed by completing all UEC upgrades in 2014, followed by commissioning of 5L83 in 2019.

The PV Tool was modified to include the PV analysis for the two long-term planning sequences: 5L83 followed by the partial UEC sequence and the UEC followed by the 5L83 sequence (Exhibit B-5, BCUC 1.70.11; and Exhibit B-10, BCUC 2.168.1). BCTC's sequencing study shows that Sequence 1 has a PV approximately $150 million lower than Sequence 2. The difference between the PV of the two sequences is mainly attributable to the 5L83 energy loss savings between 2014 and 2019.

This sequencing analysis was later updated to reflect the amendments to SD HC1 and HC2. Using the higher 6 percent real discount rate and maintaining the energy value of losses at $74/MW.h, Sequence 1 has a PV approximately $76 million lower than Sequence 2 (Exhibit B-10, BCUC 2.168.1).

The following table provides the additional PV of the UEC followed by 5L83 sequence at real discount rates ranging from 2 percent to 8 percent and for energy loss savings at values ranging from $55 to $95 per MW.h. The table is based on the P50 estimates of the UEC and 5L83 cost estimates as of April 2007. The comparisons are in $2007.

Value	Discount Rate						
of Losses	2%	3%	4%	5%	6%	7%	8%
$55/MWh	116,656	99,222	84,129	71,071	59,780	50,026	41,609
$60/MWh	122,946	104,930	89,315	75,788	64,074	53,940	45,180
$65/MWh	129,237	110,639	94,502	80,504	68,369	57,855	48,752
$70/MWh	135,527	116,347	99,688	85,221	72,664	61,769	52,323
$75/MWh	141,818	122,056	104,874	89,938	76,958	65,683	55,895
$80/MWh	148,108	127,764	110,060	94,655	81,253	69,598	59,466
$85/MWh	154,399	133,473	115,247	99,372	85,548	73,512	63,038
$90/MWh	160,689	139,181	120,433	104,089	89,842	77,426	66,609
$95/MWh	166,980	144,890	125,619	108,806	94,137	81,341	70,181

(Source: Exhibit B-14, BCUC 3.211.1)

The analysis confirms that of the two long-term planning sequences the least cost alternative is the 5L83 followed by the UEC sequence under all discount rates and energy loss values included in the table.

As stated earlier in this Section of the Decision, BCTC's prioritization model was not developed for the purpose of comparing planning sequences. However, the prioritization model does rank 5L83 as one of the highest priority projects (Exhibit B-5, BCUC 1.67.2).

No Intervenor challenges BCTC's sequencing analysis.

Commission Determination

The Commission Panel agrees with BCTC that its sequencing analysis confirms that of the two long-term planning sequences the lesser cost alternative is the 5L83 followed by UEC sequence under the range of discount rates and energy loss values it found to be appropriate above.

7.5 Horizon Year Analysis

BCTC performs a horizon year study to demonstrate that the mid-term reinforcement with 5L83 is compatible with a long-term vision of the transmission system (Exhibit B-1, Appendix K, p. 6). The study concludes that 5L83 is an effective and adequate solution for improving thermal and voltage stability limits of the ILM grid and is appropriate with respect to the long-term development sequence (Exhibit B-1, Appendix K, p. 27).

Although the sequencing analysis considers two alternatives that include UEC, BCTC has not concluded that 5L83 should be followed by UEC. There is still uncertainty over the size, timing and location of future resources in the latter half of the 30-year horizon. The study presents a portfolio of reinforcements to assess whether 5L83 continues to be the preferred upgrade when viewed from a longer-term perspective (Exhibit B-10, IPPBC 2.1.1). In fact, BCTC stated that it is unlikely that UEC would be the next upgrade to the ILM grid after 5L83 (Exhibit B-14, BCUC 3.203.1). Once 5L83 is built, it will allow the transfer capability of the ILM grid to be extended to 7500 MW, an additional 950 MW, by the relatively inexpensive addition of shunt compensation and static VAr compensators (“SVCs”), and modest upgrades of the series capacitors (Exhibit B-14, BCUC 3.203.1). After this development the next likely reinforcement will be 5L46, which can further extend the ILM grid transfer capability to 9,100 MW. (Exhibit B-14, BCUC 3.203.1)

BCTC acknowledges that there are initiatives underway that will also look at long-term transmission needs with BC, including the inquiry by the Commission now required under section 5 of the Act, as amended by Bill 15. BCTC does not believe that these initiatives should defer consideration of the

ILM Project for fear that they may result in a determination that some other alternative may be a better solution than 5L83 (Exhibit B-14, BCUC 3. 203.1; BCTC Reply, para. 48).

No Intervenor challenges BCTC's horizon year analysis.

Commission Determination

The Commission Panel agrees with BCTC that its horizon year study shows that 5L83 continues to be the preferred upgrade when viewed from a longer-term perspective. The Commission Panel notes that BCTC has not concluded that 5L83 should be followed by UEC. The Commission Panel makes no determination in this Decision regarding the next project for increasing the ILM grid transfer capacity and alternatives to expand capacity beyond 5L83 will need to be evaluated on their own merits, when that capacity is required.

7.6 Deferral Analysis

BCTC was asked to estimate the effect of deferral of 5L83 in net present value terms (Exhibit B-5, BCUC 1.61.1). BCTC stated that assuming no other capacity reinforcements during the deferral period, using a discount rate of 6 percent and valuing transmission loss savings at $74/MW.h, there would be the following benefits from deferring the ILM Project from October 2014 until October of the indicated year:

			$ millions			
	2015	2016	2018	2020	2022	2024
PV ($2007)	7.1	13.7	26.0	36.8	45.5	55.1

and that these benefits would be reduced using a higher loss valuation and vice versa (Exhibit B-10, BCUC 2.161.3 and 2.161.4).

BCTC qualified its response made above by stating that “the costs of running Burrard and additional imports coastal resources to achieve that deferral [of the ILM Project] would have to be added to the deferral costs shown in BCUC 2.161.1”, and suggested that the total capacity cost would be in the $25 to $30 million ($2004) range.

BCTC concluded that if the cost of capacity reinforcements is considered, then total costs are higher than implementing the ILM Project at its earliest ISD (Exhibit B-10, BCUC 2.155.2).

No Intervenor challenges BCTC’s deferral analysis.

Commission Determination

Given the timing of the ILM Project is currently driven by system planning standards rather than economic criteria, the Commission Panel does not find the deferral analysis relevant to its determination of need or economic benefit. However, in the event new information becomes available suggesting the project may not be required by its earliest ISD based on system planning standards, the Commission Panel expects BCTC to consider also the economic costs of a deferral. The Commission Panel also notes that BCTC’s analysis of the costs of deferral is very sensitive to the valuation of losses and expects BCTC to consider its comments elsewhere in this Decision on the quantification and valuation of losses if economic criteria become relevant in the decision of when to proceed with the ILM Project. The Commission Panel also notes that BCTC’s approach to the deferral analysis is entirely deterministic (i.e., assumes perfect foresight) and as such includes no provision for the “option value” associated with deferral of large capital projects in the face of uncertainty. The Commission Panel encourages BCTC to consider methods for incorporating considerations of option value in future deferral analyses.

7.7 Final Project Selection

Based on its technical and economic comparisons, BCTC concludes that the 5L83 Alternative is the preferred alternative for increasing the transfer capability of the ILM grid. BCTC states: "Circuit 5L83 meets the Planning Standards, provides adequate transfer capability, and has the lowest overall costs when the value of losses and the UEC Alternative's lower transfer capability are considered" (Exhibit B-1, p. 82).

BCTC acknowledges that its cost comparisons do not include the potential aboriginal accommodation costs, the potential costs of environmental mitigation and compensation, and the potential additional cost of the final route alignment for 5L83 in its comparisons of 5L83 and UEC (BCTC Argument, para. 30). BCTC indicates it is not in a position to provide a quantitative comparison of these respective costs at this point in time. However, BCTC argues it is highly unlikely that differences in aboriginal accommodation costs or environmental mitigation and compensation costs between UEC and 5L83 would make up the difference in the PV cost comparison (BCTC Argument, para. 31).

BCTC also submits:

> "While the change in discount rate has reduced 5L83's cost advantage over UEC, 5L83 still provides 220 to 250 MW more in continuous thermal capacity limit than UEC, significantly higher voltage stability limits, lower double outage generation shedding, and lower double outage load shedding. Accordingly, the technical performance advantages of 5L83 over UEC are significant even if the two alternatives were equal from a cost perspective. In addition, while this is speculation, BCTC expects that it is unlikely it will get easier to construct new transmission lines in the future" (BCTC Argument, para. 31).

BCTC acknowledges its comparison is based on current cost estimates and that this assessment could change as the final estimated cost for 5L83 becomes more certain. However, BCTC notes it will know the tender values for the major project components before it makes a decision to proceed with implementation. BCTC also notes it will know the final alignment of the ILM Project and any additional costs associated with this alignment prior to implementation. Finally, BCTC submits that "…even if it does not know with absolute certainty what the final aboriginal accommodation and environmental mitigation costs are, it will be in a much better position to assess these costs" (BCTC Argument, para. 32). BCTC states it can address these costs when they become known and if it believes they would have a material impact on the alternatives assessment.

BCOAPO submits that the ILM Project "is clouded by an exceptional degree of uncertainty" (BCOAPO Argument, p. 1). Specifically, BCOAPO notes the ultimate route of the proposed transmission line has not yet been settled; the nature, extent, and ultimate cost of First Nations accommodations are unknown; the cost of construction is unclear; and the optimum date for the line to come into service is uncertain (BCOAPO Argument, p. 1).

BCTC does not accept BCOAPO's characterization that the ILM Project is clouded by an exceptional degree of uncertainty. BCTC submits that in its Application and in responses to IRs, it has thoroughly explored the uncertainties identified by BCOAPO (BCTC Reply, para. 21).

Commission Determination

The Commission Panel concludes that building a new transmission line, specifically 5L83, is the preferred alternative for reinforcement of the ILM grid from the NIC side, and concludes that UEC is uneconomic when compared to building a fifth line, 5L83, that provides higher transfer capability and lower losses. The Commission Panel finds that 5L83 meets the system planning standards, provides adequate transfer capability, and has the lowest overall costs when the value of losses and UEC's lower transfer capability are considered. The Commission also concludes that building 5L83 is the preferred first step in the long-term plan for the ILM grid.

The Commission Panel concludes in Section 4 of this Decision that there is persuasive evidence that incremental transfer capability of the ILM Project will be required at the earliest practical ISD based on the 2006 Amended LTAP portfolio, as well as for the approved CRP1 and CRP2. The Commission

Panel accepts the submissions of BCTC that it would be imprudent to choose a path at this time that would preclude the earliest practical ISD.

The Commission Panel notes that 5L83 still provides 220 to 250 MW more in continuous thermal capacity limit than UEC, significantly higher voltage stability limits, lower double outage generation shedding, and lower double outage load shedding and it would still be preferred even if 5L83 over UEC were equal in PV, which they are not in virtually any scenario.

The Commission Panel agrees with BCOAPO that there is considerable uncertainty surrounding the project costs but that this has been addressed through extensive sensitivity analysis and notes that BCOAPO has failed to suggest any scenarios where 5L83 would not likely be a better choice than UEC.

The Commission Panel does have some concerns regarding the treatment of losses in BCTC's economic analysis. The Commission Panel accepts BCTC's estimate for annual average loss savings but notes this is based on an average water year. However, for the purposes of valuation, the Commission Panel believes the losses during a critical water year would be more indicative of the amount of firm energy acquisitions that may be avoided as a result of the loss savings. The Commission Panel also notes that the projection of savings over the entire 50 years was not clearly justified by BCTC and some further rationale for the period of time that such benefits are attributed to projects should be provided in future applications. That said, the Commission Panel is satisfied that reducing the period over which savings would be realized does not significantly alter the ranking of UEC and 5L83. The Commission Panel also notes that time-weighted values should have been considered in a full evaluation of losses; however, BCTC did demonstrate through its responses to IRs that the differences in valuation would not be significant in this case. Although none of these issues alter the Commission Panel's findings regarding the justification of 5L83 in this particular case, the Commission Panel notes that such issues should be addressed more explicitly by BCTC in future economic analyses for projects of this magnitude.

The Commission Panel expects BCTC to include an updated sequencing analysis as part of the Update Report, discussed further below.

8.0 PROJECT RISKS

This Section reviews BCTC's approach to risk identification and mitigation. Finally it considers regulatory parameters for quarterly reporting and cost incentive/penalty mechanisms.

8.1 Project Risks and Risk Management

The Cost and Schedule Report identifies a number of risks from a design perspective, such as the impact on the project cost of increasing the conductor size; outage constraints during construction; route changes; changes to the tower designs; the configuration of both substations; the site for the capacitor station; transmission construction work force availability; and material delays and cost increases for both overhead line material and substation equipment (Exhibit B-1, Appendix C, pp. 16-18).

BCTC states that its Project Team has identified and assessed project risks through the Definition Phase, and developed mitigation plans for managing them. BCTC states that risk identification and mitigation is an ongoing process and the Project Team will continue to identify risks and mitigation measures throughout the Definition and Implementation phases and expects that the risks and mitigation strategies will change as the ILM Project moves through its phases.

BCTC states that its Project Team identified risks affecting a number of project disciplines and activities including engineering, design, procurement, stakeholder consultation, and the environmental assessment. In addition to the 10 risks identified in the Report at pp. 16-18, BCTC's Project Team held a workshop on July 7, 2007 the results of which are set out in Exhibit B-5-1, BCUC 1.41.1. The Project Team further evaluated the likelihood and impact of each risk. The results of these assessments provided a relative ranking of the identified risks. Following the risk assessment, mitigation plans were developed for each risk. BCTC proposes to monitor mitigation plans and update them at least quarterly to reflect the current risk and mitigation activities for the ILM Project (Exhibit B-1, p. 86).

BCTC states that the risks identified to date for the ILM Project mainly relate to developing accurate cost estimates, being in a position to meet the fall 2009 construction start date, and meeting the scheduled ISD, and that as the ILM Project develops, more risks and mitigation plans will be identified and added to the risk inventory (Exhibit B-1, p. 86).

BCTC states that monitoring of risks and mitigation activities will continue throughout the Definition and Implementation Phases of the ILM Project. The Project Team, Steering Committee and Risk Management Committee are involved in the review process (Exhibit B-1, pp. 86-89).

BCTC stated that it uses an Enterprise Risk Management ("ERM") framework to identify, assess, mitigate and monitor its risks. The Risk Identification phase involves the identification of potential risks, including examples and potential impacts related to the achievement of the project objectives. In the Risk Assessment phase, the likelihood and impact of the identified risks are assessed in workshops using BCTC's Project Risk Matrix, which assigns one of five levels of likelihood (<1 percent, 1 percent to 10 percent, 11 percent to 50 percent, 51 percent to 90 percent, and >90 percent) for each risk. There are also five levels of impact (numbered 1 to 5, depending on a set of pre-determined criteria and tolerances based on BCTC's corporate goals). The impact of a risk may affect the following categories:

- Schedule Delays;
- Safety;
- Financial;
- Reliability;
- Market Efficiency;
- Relationships;
- Organization & People; and
- Environment.

Consideration of the probability and impact together results in a severity classification.

BCTC stated that the risk severity is indicated by the intersection of the likelihood score and the impact score, and that there are five levels of risk severity: Low, Guarded, Moderate, High, and Extreme with the severity classification providing an indication of the level of response required for the risk (e.g., risk can be managed using routine procedures, or senior management attention may be required).

During risk assessment workshops, Project Team members discuss the likelihood of each risk and each member assigns a value to each risk using an automated voting system which provides an average score, while a similar process yields an impact score for each risk, reflecting the average impact assessment of the Project Team members. The likelihood and impact scores are multiplied together to produce the total score for each risk, which is an indication of the severity classification. Total scores are also used to rank the risks for a project.

BCTC stated that at its July 12, 2007 ILM Project risk assessment workshop, 27 risks were identified and ranked. The top four ranked risks were as follows:

1) the risk that the cost estimate changes due to further environmental and engineering studies after the CPCN has been filed;
2) the risk that construction does not start in the fall of 2009;
3) the risk that market constraints prevent BCTC from receiving competitive proposals; and
4) the risk that the EAC is suspended because the EAO is not satisfied that First Nations consultation is sufficient.

(Source: Exhibit B-5-1, BCUC 1.41.1, Attachment 2).

BCTC stated that the risk analysis for Implementation Phase risks is still underway. The assessment of the risks is expected to take place in late January and mitigation planning will be done subsequently (Exhibit B-5-1, BCUC 1.41.1). BCTC provided a copy of its quarterly report on VITR which addresses Risk Management issues.

BCTC considers its response to the occurrence of what it terms "Risk Events" and states that in the course of identifying potential risks and developing mitigation strategies, it has considered the impacts of risk events, both before and after mitigation, as well as potential high level responses, which for the three primary risks could include:

- communication of material changes to the cost estimate to the Commission, including an explanation of the change in conditions or scope that leads to the change in the estimate, and possibly a request for additional approvals;
- an accelerated construction schedule or a delay in the ISD could address delays in achieving the construction start date; and
- a detailed procurement plan will be completed prior to 2009.

(Exhibit B-1, pp. 88-89)

BCTC addressed the proposed mitigation of risks to the ILM Project posed by a shortfall in internal and external engineering resources identified by BC Hydro and stated that it has sufficient resources available at this time to carry the ILM Project through the Definition Phase up to early 2009, and that implementation strategies will be developed well in advance to obtain the necessary engineering and construction resources to complete the ILM Project if a CPCN is granted. Strategies will include a proactive outreach to engineering and construction firms throughout Canada and the US and perhaps overseas if the market conditions warrant it. BCTC already has long-term engineering services agreements with both BC Hydro Engineering and SNC Lavalin. Engineer-Procure-Construct or Design-Build contracting strategies can also mitigate any shortage of resources.

BCTC stated that it cannot avoid resource constraints imposed by very strong markets in the electricity transmission industry, but that effective advance planning, industry outreach and cultivation of productive business relationships with suppliers and service providers can provide adequate mitigation (Exhibit B-5, BCUC 1.42.9).

No Intervenor challenges BCTC's identified ILM Project risks or its risk management processes.

8.2 Quarterly Reporting

BCTC addresses the quarterly progress reports it will be required to provide to the Commission on the ILM Project status, cost, schedule and risks and notes that it responded to a number of IRs about the use of Earned Value reporting as the basis for managing the ILM Project. BCTC submits that the evidence shows that Earned Value reporting is a costly and data intensive method of reporting on projects which is typically useful in scientific research projects where project milestones are difficult to define whereas the ILM Project uses well understood and defined technology, components and milestones against which project progress can be measured. On this basis, BCTC submits that Earned Value reporting would not be beneficial in the management and control of the ILM Project and would add unnecessary cost to both BCTC and BCTC's suppliers.

BCTC submits that the format of project reporting it currently follows with respect to the VITR Project provides adequate information on project status, cost, schedule and risks and is produced through BCTC's current reporting systems and capital project management processes. Given this, BCTC does not believe that the costs of implementing Earned Value reporting should be visited upon BCTC, its contractors or ratepayers (BCTC Argument, para. 66-67).

BC Hydro considers the reporting format and submits that the decision of which project execution tools or methods to use on a specific project should be the choice of the project proponent, in this case BCTC, since "it is the project proponent who understands their project reporting systems and their ability to track and report on project status, costs, schedule and risks" (BC Hydro Argument, p. 17).

No other Intervenor comments on the content of the quarterly reports that BCTC will provide to the Commission.

Commission Determination

The Commission Panel finds that the content of the quarterly report proposed by BCTC to be adequate and sees no reason to require it to implement Earned Value reporting.

8.3 Cost Incentive/Penalty Mechanisms

The Commission asked BCTC whether it would be willing to commit to a cost cap in light of the ILM Project timing and uncertainty. BCTC replied that it is not willing to commit to a cost cap on the ILM Project, and stated that it believes that incentive/penalty mechanisms are best applied to incent good management behaviour that is within management's control and that such mechanisms should align the interests of utility management with the interests of the regulator and of customers (Exhibit B-5, BCUC 1.7.5).

BCTC expressed concern, given the size of its equity capitalization, with its ability to manage the consequences of cost caps similar to the cost cap established by the VITR Decision when applied to multiple CPCN projects. BCTC submitted that concerns about possible imprudence would be more suitably addressed by a post-project review, where it will be able to establish with the Commission those factors within its control which it acted upon to manage project costs prudently, and the impact of those factors beyond its control. In this way BCTC submitted that it will be held accountable for what it could control and not be penalized for factors for which it could not take action to mitigate.

BCTC addressed the cost increases on the VITR Project and stated that they were caused by a number of factors, primarily the result of prevalent market conditions in B.C. and in the utility industry for competitively tendered materials and construction services. BCTC stated that the market uncertainty that gave rise to the cost escalation experienced with VITR is an uncertainty beyond BCTC's control that BCTC likely will also be exposed to on the ILM Project. The tight market for labour and equipment is again expected to be a factor in the ILM Project cost. The uncertainty is present because of the long lead times for planning and constructing large transmission projects.

The need to preserve a 2014 ISD necessitates application for a CPCN notwithstanding existing uncertainty regarding future events and market conditions. The presence of the uncertainty is not a justification for the need for a cost cap because BCTC must proceed despite the uncertainty to ensure safe and reliable electricity supply to the Lower Mainland and Vancouver Island. BCTC believes that it should not have to absorb the impacts of market uncertainty for pursuing a public interest transmission project on a timely basis to ensure supply is not put at risk.

BCTC stated that it intends to provide the Commission with an Update Report which will include an updated cost estimate prior to awarding contracts for the major components of the ILM Project and commencing construction, and that this will reduce the level of uncertainty prior to the start of construction of the ILM Project (Exhibit B-5, BCUC 1.7.5).

BCTC submits that the Commission has in the past used cost caps and incentive/penalty mechanisms as conditions attached to CPCNs and included an incentive mechanism as part of the CPCN for the VITR Project, stating in its Decision at page 205: "In view of the confusion, senior management turnover, a significant number of BC Hydro staff working with BCTC on VITR and the project challenges, the Commission Panel believes it is in the interest of ratepayers to introduce an incentive/penalty mechanism to ensure that this major project receives the focus, attention and direction it requires for an on-time, on-budget delivery" (BCTC Argument, para. 57).

BCTC submits that a cost cap or incentive/penalty mechanism is neither necessary nor appropriate in the case of the ILM Project.

BCTC addresses the significant turnover of its executives in 2005, but submits that its Application provides evidence on the extent, breadth and expertise of the Project Team for the ILM Project and demonstrates that it has applied the appropriate resources and secured the necessary expertise to obtain required approvals and to implement a project of the magnitude and complexity of the ILM Project.

BCTC submits that when the Commission approves a project under sections 45 and 46 of the Act, its determination that the project meets the test of public convenience and necessity (i.e., the project is in the public interest) cannot be a determination of a specified final cost for the project since many factors, including factors beyond the control of the utility, may affect the costs incurred between the time of the application and completion of the project while, despite such changed circumstances, the applicant generally does not have the discretion not to proceed with the project.

BCTC submits that there is nothing in Special Direction 9 ("SD 9") or in sections 45 or 46 of the Act that provides the Commission with jurisdiction to establish a spending limit for a project, nor to enforce a spending limit, absent a subsequent finding of imprudence and that disallowance of prudently incurred costs through enforcement of a spending limit would not only violate sections 3.0(b) and 3.0(c) of SD 9, but would also generally be contrary to the regulatory compact established under the Act, because despite BCTC having acted prudently, BCTC would be prevented from recovering a return on, and of, its prudently incurred costs.

However, BCTC recognizes that the Commission does have the authority to review BCTC's project expenditures in the context of a prudence review, where it has reason to believe BCTC's actions may have been imprudent. BCTC considers that a prudence review is the appropriate means to deal with questions about the level of expenditure on a project. If after a prudence review, the Commission finds that, based on the evidence, BCTC has been imprudent, BCTC agrees that imprudent expenditures may be removed from consideration in setting rates, and the requirements of the Master Agreement between BCTC and BC Hydro applied, without violating SD 9 (BCTC Argument, para. 56-65).

BC Hydro agrees with BCTC's submission that a cost cap is neither necessary nor appropriate in the case of the ILM Project (BC Hydro Argument, p.13).

BCOAPO discusses BCTC's rejection of the notion of a "cost collar" to help contain the potential eventual cost of the ILM Project and its proposal to file an Update Review with the Commission, and submits:

> "The problem with this process is that if the updated information (including incidentals like the actual route, the cost of First Nations accommodations, construction cost escalations, and so forth) has a significant adverse impact on the merits of the Project, it does not provide any mechanism to revisit the question whether the project should proceed according to BCTC's evolving scheme. All we are left with is an after-the-fact 'prudency' review in the context of a future revenue requirement proceeding. The horse will have long since left the barn, so the Commission and Intervenors can busy themselves thinking about how much fodder to put in the bin. It is beyond debate that after-the-fact prudency review is an inadequate mechanism to hold utilities accountable for the wisdom of their capital projects. But even more to the point, the opportunity will be long gone to ensure that the course that is selected is in fact the best one for ratepayers and the people of the province as a whole." (BCOAPO Argument, pp. 4-5)

BCOAPO proposes its solution whereby the Commission should approve all aspects of the ILM Project up to the point of commencement of construction. At any time prior to the start of construction BCTC would be at liberty to apply for a CPCN for the full project if it considers that it has sufficiently robust financial information to provide a foundation for the ILM Project or any alternative it wishes to advance at that time (BCOAPO Argument, p 5).

JIESC submits that its principal concern is cost control and points out that BCTC incurred very substantial cost overruns on the VITR Project even though all aspects of that project including public consultation, route selection, engineering and materials and construction commitments were far further advanced than as is the case for the ILM Project. JIESC submits that it "has strong reservations" about the effectiveness of an ex post facto prudence review and accordingly supports a cost collar mechanism with incentives and penalties to encourage cost-effective performance by BCTC, citing the reasons given for such mechanisms in the Commission's VITR Decision at page 205. JIESC submits that if the Commission is reluctant to impose an incentive/penalty mechanism in this case it should ensure that BCTC's Update Report on final alignment, the updated project cost and any proposed P3 arrangement to be made prior to the awarding of major contracts or proceeding with construction not be a simple passive filing, but a meaningful final check point before proceeding, at which time the Commission must be expressly satisfied that the information provided is reasonable and not materially different from the Commission's view at the time of approving the ILM Project (JIESC Argument, p. 2).

IPPBC disagrees with BCTC's aversion to a cost cap on the ILM Project and its belief that a post-project review and some form of interim report filing system to the BCUC would be more appropriate, and submits that its members are subject to the same cost pressures and uncertainty but when they enter into electricity supply contracts with BC Hydro, they bear these risks and in addition, are required to post performance security.

Independent power projects are evaluated by BC Hydro on the basis of transmission requirements. Although BC Hydro's customers ultimately pay for the cost of transmission improvements, independent power projects do not want to be disadvantaged in the project evaluation process because of BCTC's inability to control the cost of new transmission.

IPPBC supports increasing the capacity of the BCTC transmission system, but does not believe in granting BCTC "a blank cheque" and submits that BCTC must build the necessary contingencies into its budgets and "live with the result." IPPBC submits that ex post facto prudency reviews do not create an environment of cost discipline, while interim reports on the project published by BCTC only record problems that are being experienced.

IPPBC submits that not only is it in the interest of ratepayers to establish an incentive/penalty mechanism, it is also in the interest of IPPBC's members, and suggests that, if BCTC distinguishes the ILM Project from VITR on the basis of improvements in project oversight and the increased project management experience gained by developing VITR, these are some of the reasons why BCTC should not be opposed to a project cost cap. IPPBC submits that the VITR project cost cap was reasonable in the context of the ILM Project and that the same approach be used for the ILM Project, and that BCTC should "put a number on the ILM project uncertainties and live with it. The stakeholders would thereby know the limits of their exposure, and any further costs would be an

issue between BCTC and its shareholder – the same risk sharing as IPPs must face."
(IPPBC Argument, p. 13)

In Reply, BCTC addresses the submissions of JIESC, BCOAPO and IPPBC on the issue of cost control and the effectiveness of an after the fact prudence review, and notes that they all supported some form of cost cap or collar mechanism, citing "runaway" costs associated with the VITR Project to support their submissions. BCTC rejects the submission that there were runaway costs on the VITR Project and the suggestion that VITR is an example of a failure of cost control and submits that, to the contrary, the VITR costs were the result of market conditions and effective measures were taken to mitigate cost increases, and that the VITR cost results are better than have been experienced with similar projects in other jurisdictions in the same time frame. BCTC also submits that the circumstances regarding the ILM Project are not similar to those which gave rise to the Commission's concerns, and the imposition of the cost incentive/penalty mechanism, regarding VITR.

With respect to the submissions regarding the effectiveness of "after the fact" prudence reviews, BCTC submits that there is no evidence in this proceeding that prudence reviews are ineffective and, consequently, no evidentiary support for these submissions. BCTC certainly takes the potential for such a review seriously. While BCTC fully appreciates and shares JIESC, BCOAPO and IPPBC's interest in ensuring that the costs of the ILM Project are prudently managed, BCTC's experience is that the impact of a cost cap or collar bears little, if any, relationship to BCTC's ability to manage costs and therefore, even ignoring the requirements of SD 9, imposing such a mechanism would be beyond the Commission's jurisdiction. BCTC submits that it "will not accept a cost cap or incentive as a condition of an ILM CPCN" (BCTC Reply, para.18).

Commission Determination

The Commission Panel is not persuaded that the record in this proceeding supports the introduction of a penalty/incentive mechanism as a condition for granting a CPCN to BCTC for the ILM Project. The steps taken by BCTC demonstrate, on an ex-ante basis, significant concern in addressing the costs of the ILM Project. The Commission Panel is satisfied that the interests of ratepayers and other stakeholder groups will be served by a combination of the following:

- the Update Report, addressed in Section 10 of this Decision, will constitute the first major check point for BCTC;
- the quarterly reports which BCTC will be obliged to prepare and submit will constitute an ongoing review of the ILM Project and how BCTC manages it; and
- an "ex post facto" review process can be instituted by the Commission if it appears that BCTC has not acted prudently in its management of the ILM Project.

9.0 SOCIOECONOMIC, ENVIRONMENTAL AND RATE IMPACTS

This Section first describes BCTC's approach to managing the potential socioeconomic and environmental impacts of the ILM Project, including consultation with stakeholders. EMF levels, environmental impacts, First Nations impacts and private property impacts are then reviewed in turn. Finally, rate impacts are considered.

9.1 Management of Impacts

BCTC's approach to impact management was to undertake a preliminary environmental overview assessment of the potential biological, physical, heritage, cultural, and socioeconomic effects of the ILM Project (Exhibit B-1, p. 100), and to consult with stakeholders in order to gain an understanding of their concerns about the ILM Project. BCTC then attempted to develop a cost-effective proposal, which would avoid, reduce or mitigate impacts and, if necessary, balance stakeholder interests (Exhibit B-1, p. 105).

The ILM Project is subject to a detailed environmental assessment and approval process under the *BCEAA* (Exhibit B-1, p. 93) and the residual impacts will be identified and evaluated in the EAC application, which BCTC intends to file in the fall of 2008 (Exhibit B-1, p. 97). BCTC describes the *BCEAA*, as well as other review and permitting requirements of the ILM Project, in section 7 of the Application. BCTC submits that a detailed examination by the Commission of the socioeconomic and environmental impacts of the ILM Project is unnecessary, because of the comprehensive environmental review and approval process that the ILM Project must satisfy before it proceeds (BCTC Argument, para. 47).

Consultation was an integral part of BCTC's effort to manage the potential socioeconomic and environmental impacts of the ILM Project, and is a component of the EA process (Exhibit B-1, pp. 96-98). Sections 7.1.1.1 and 8 of the Application describe BCTC's consultation activities.

The supporting material included in Appendix S shows that, prior to filing the CPCN Application, BCTC met with a broad range of stakeholders including property owners, the general public and representatives from municipal, regional and provincial governments, Intervenor groups, recreation facilities, and other stakeholders. BCTC provided stakeholders with information about transmission alternatives and about the ILM Project, responded to questions and obtained feedback (Exhibit B-1, Appendices S-1 through S-9).

Under the Master Agreement between BC Hydro and BCTC, BC Hydro retains primary responsibility for First Nations relations with respect to transmission system assets and operations. Accordingly, BC Hydro's Aboriginal Relations and Negotiations department ("ARN") personnel work on the ILM Project team and with the EAO to increase understanding of the interests of impacted First Nations and to attempt to avoid, mitigate or accommodate significant impacts (Exhibit B-1, p. 128).

The EA process includes First Nations consultation requirements, and the EAO identified 60 First Nations and 7 Tribal Councils/Societies that could be impacted by the ILM Project (Exhibit B-1, pp. 130). As described in section 8 of the Application, ARN is conducting a program of consultation with those First Nations (Exhibit B-1, pp. 127-44 and Appendices S-10 through S-18).

BCTC summarizes some of the steps it has taken to minimize the socioeconomic and environmental effects of the ILM Project, including:

"(a) Extensive consultation with stakeholders, identification of issues raised through public consultation, and developing plans to manage those issues;

(b) A detailed First Nations consultation and, if necessary, accommodation process;

(c) The proposed delta towers will significantly reduce right-of-way width, clearing requirements and EMF;

(d) The reference route avoids all First Nations Reserves;

(e) BCTC is performing extensive environmental and archaeology field-studies and data analysis;

(f) BCTC is working closely with Federal and Provincial agencies to choose a final alignment to avoid material effects on Spotted Owl habitat consistent with Government-sponsored development of a long-term recovery plan for the species;

(g) Using existing substation sites, rights-of-way and the paralleling of existing lines, where practical, reduces the footprint on the land, the need for new access roads, and avoids the visual impact of creating new transmission corridors; and

(h) Planning access roads, stream crossings, erosion and sedimentation control and vegetation clearing to avoid negative effects on riparian habitat along the many streams and rivers in the corridor and the fisheries resources which use those watercourses." (BCTC Argument, para. 49)

BCTC submits that, as a result of these efforts, the primary socioeconomic and environmental effects are expected to be limited, and that the EA process "will continue to seek means to avoid negative socioeconomic or environmental effects where practical, to reduce or mitigate unavoidable effects, and to identify reasonable compensation measures for residual, unmitigated effects" (BCTC Argument, para. 50). BCTC further submits that there are no identified socioeconomic or environmental impacts that should result in the Commission finding that the ILM Project is not in the public interest (BCTC Argument, para. 51).

9.2 EMF

EMFs are generated by transmission lines during normal operation. The EMF levels along and in the vicinity of the ILM Project corridor will be affected by the operating current and voltage of the transmission line, and are sensitive to such variables as cable geometry, tower geometry, conductor type, nearby obstacles, and vegetation (Exhibit B-7-1, p.8).

BCTC submitted two EMF reports in this proceeding. The first is a 2007 Exponent report (Exhibit B-1, Appendix R), updating the 2005 EMF report submitted in the VITR proceeding. The second is a DVT Solutions Report (Exhibit B-7-1), which provides estimates of the EMF levels on the reference route.

The 2007 Exponent report includes a review of peer-reviewed research and reviews by scientific panels on the subject of health impacts of power line EMF, and concludes that “the body of research does not suggest that magnetic fields are the cause of cancer or any other adverse health outcome” (Exhibit B-1, pp. 103-104 and Appendix R). The report relied heavily upon the World Health Organization (“WHO”) review of June 2007, which provided the following conclusions:

> “Acute biological effects have been established for exposure to ELF [Extremely Low Frequency] electric and magnetic fields in the frequency range up to 100 kHz that may have adverse consequences on health. Therefore, exposure limits are needed. International guidelines exist that have addressed this issue. Compliance with these guidelines provides adequate protection. Consistent epidemiological evidence suggests that chronic low-intensity ELF magnetic field exposure is associated with an increased risk of childhood leukaemia. However, the evidence for a causal relationship is limited, therefore exposure limits based upon epidemiological evidence are not recommended, but some precautionary measures are warranted.” (Exhibit B-1, Appendix R, p. 21).

The 2007 Exponent report summarized the general recommendation of the WHO as follows:

> “Countries are encouraged to adopt international science-based guidelines. In the case of EMF, the international harmonization of standard setting is a goal that countries should aim for (WHO, 2006). If precautionary measures are considered to complement the standards, they should be applied in such a way that they do not undermine the science-based guidelines.” (Exhibit B-1, Appendix R, p. 29).

DVT Solutions used measurement and modeling to calculate the EMF levels for ten locations on the reference route to determine the predicted levels using annual average line loads of fiscal 2006-07 for existing circuits, the annual average line loads of 2014-15 with the proposed 5L83 circuit, and the annual average line loads of 2026-27 with the proposed 5L83 circuit reaching its maximum load capacity (Exhibit B-7-1, p. 6).

DVT Solutions found that the highest magnetic field levels within the ROW are at the J-K segment for F2007 (145.61mG), F2015 (131.69mG) and F2027 ((144.81mG). The highest magnetic field levels at the edge of the ROW are observed at the R-S segment for F2007 (38.57mG), F2015

(30.06mG) and F2027 (35.96mG) (Exhibit B-7-1, p. 6).

BCTC stated that, in its design of transmission lines, it adopts the electric field IEEE limits as set out in IEEE Standard C95.6-2002, namely: (a) the maximum electric field on the ROW is limited to 10 kV/m, and (b) the maximum electric field at edge of the ROW (and beyond) is limited to 5 kV/m (Exhibit B-10, BCUC 2.130.1). The DVT Solutions report found that the calculated values for electric fields are within the IEEE guidelines, except for two locations where the fields are above the guideline if the new lines are built to the same clearance as the existing lines, but BCTC indicated that the EA process may result in mitigation measures (Exhibit B-10, BCUC 2.185.1).

There is currently no federal or provincial legislation or regulation addressing extremely low frequency (“ELF”) EMF levels or exposures. BCTC stated that a common opinion of the Canadian federal provincial and territorial health authorities is “that adverse health effects from exposure to power-frequency EMF, at levels normally encountered in homes, schools and offices, have not been established” (Exhibit B-5, BCUC 1.8.1).

Two international scientific organizations (ICNIRP and ICES) have published guidelines for limiting public exposure to EMF in order to protect against the direct, acute health effects that can occur from short-term exposure to high levels, but “both organizations judged that evidence for effects from long-term exposure to ELF-EMF was insufficient for setting exposure standards.” ICNIRP recommends a residential magnetic field exposure limit of 833 mG, and ICES recommends a limit of 9,040 mG (Exhibit B-1, Appendix R, p. 23).

BCTC stated that it “supports efforts as previously articulated by the Commission, to reduce EMF levels where mitigation costs are not significant or the benefits clearly exceed the cost of mitigation measures” (Exhibit B-10, BCUC 2.132.1). Precautionary measures applied in the ILM Project include the use of delta towers where technically possible and, where 5L83 would share the ROW with other circuits, adjustment of the phasing to minimize total EMF (Exhibit B-5, BCUC 1.8.7).

Concerns about EMF were raised during BCTC's public consultation (Exhibit B-1, Appendix S), but EMF was not raised as a significant issue by Intervenors in this proceeding.

9.3 Environmental Impacts

BCTC did not submit detailed information on the potential environmental impacts of the ILM Project in its Application but it undertook a preliminary environmental overview assessment to identify potentially material environmental issues. That assessment found potential impacts on the Spotted Owl, a small Garry Oak ecosystem, and the Oregon Spotted Frog (Exhibit B-1, pp. 100-102).

BCTC states it will conduct a detailed environmental assessment for its EAC application, and submits that it will use the results of the assessment to modify the alignment, tower locations and tower designs, where practical, to avoid or minimize any adverse effects (Exhibit B-1, pp. 93, 121). During the EA process, environmental requirements will be determined and BCTC will prepare Commitments and Assurances to mitigate, and where possible, avoid potential adverse environmental effects; the Commitments and Assurances will form part of the legal requirements of the EAC (Exhibit B-10, Harris/Casselman 2.4.A.i). BCTC stated that it will employ industry-accepted Best Management Practices for mitigating potential adverse environmental effects (Exhibit B-5, BCUC 1.116.6; Exhibit B-10, Harris/Casselman 2.4.B.i), and that residual effects will be addressed through site-specific mitigation or compensation measures (Exhibit B-1, pp. 93, 121). BCTC further stated that it will conduct environmental monitoring during construction to ensure that appropriate practices are followed (Exhibit B-14, Harris/Casselman, 3.2.A.i).

9.4 First Nations Impacts

As discussed in Section 3 of this Decision, BCTC is relying on the EA process to obtain an understanding of the potential impacts of the ILM Project on First Nations interests. Because that process is still in its early stages and because, as discussed in Section 9.1 above, BCTC is trying to avoid or mitigate impacts where possible, BCTC did not file evidence of specific impacts on First Nations interests.

BCTC states that ongoing consultation with the affected First Nations has provided “a greater appreciation of the risks and the potential magnitude of impact on 5L83”, and “the current view is that the First Nations risks regarding 5L83 are somewhat greater than the assessment which took place in April of 2007” (Exhibit B-14, BCUC 3.195.1).

As discussed in Section 3 of this Decision, First Nations Intervenors were encouraged to participate in the proceeding, but chose not to file or elicit evidence of potential impacts on their interests.

9.5 Private Property Impacts

The ILM Project affects 148 residential and 99 non-residential parcels of land (Exhibit B-10, IPPBC 2.12.1). New ROW is required on 4 private parcels and widened ROW on 11 private parcels (Exhibit B-5, BCUC 1.90.1). New ROW requirements total 24.44 hectares (Exhibit B-5, BCUC 1.90.2).

No private property owner affected by the new or widened ROW intervened in the proceeding. One Intervenor (Harris/Casselman) owns recreational property that includes the ROW on which the current 5L82 and the proposed 5L83 are located.

BCTC stated that it has consulted property owners impacted by the ILM Project, and responded to their questions and issues, and that consultation will continue during and after the EA process (Exhibit B-1, pp. 120-126, Appendices S-1 and S-8; Exhibit B-10, Harris/Casselman 2.2.A.iii, 2.2.A.iv, 2.2.B.i; Exhibit B-14, Harris/Casselman 3.7.A). BCTC noted that it is required to respond to stakeholder comments made during the EA process (Exhibit B-1, Appendix P; BCTC Reply, para. 61).

BCTC’s management of issues affecting property owners was examined during the proceeding. BCTC explained its procedures for consultation with property owners regarding road standards, clearing practices, and protection of land, forest, wildlife and watercourses (Exhibit B-10, Harris/Casselman 2.2.A.i, 2.2.E, 2.4.B.ii; Exhibit B14, Harris/Casselman 3.TRQ.1, 3.2.B.i, 3.2.B.ii, 3.4.A.iii), and provided detailed information on vegetation management (Exhibit B-14, Harris/Casselman 3.4.B.i). BCTC explained that mitigation measures will be developed and information will be provided in the EAC application (Exhibit B-10, Harris/Casselman 2.4.A.ii; Exhibit B-14, Harris/Casselman 3.4.C.ii, 3.5.A.i, 3.5.C, 3.5.E).

Harris/Casselman allege that problems with the clearing standards and site remediation associated with 5L82 remain, and submit that “the ROW prescriptions and field management practices used by BC Hydro in 1973 do not appear to meet the requirements of small landowners today” (Harris/Casselman Argument, p. 1). Harris/Casselman further submit that “BCTC’s current operational policies and field management practices may not reflect changing land value or uses, nor adequately respond to concerns raised in the application process” (Harris/Casselman Argument, p. 2).

BCTC submits that practices and understandings are changing, and notes that its current field practices represent Best Management Practices and that it has recently updated its Compatible Use Guidelines to help landowners understand what they should expect regarding transmission facilities and operation (BCTC Reply, para. 63).

Procedures for landowner negotiation, compensation and dispute resolution were also examined (Exhibit B-14, Harris/Casselman 3.TRQ.2). Harris/Casselman acknowledge that BCTC has undertaken an extensive public consultation process, but submit that what is lacking is “an accommodation process” to address small landowners’ concerns (Harris/Casselman Argument, p. 2). Harris/Casselman proposes that BCTC be required to negotiate “ROW Prescription Agreements” to accommodate landowners and provide mediation and arbitration mechanisms prior to approval of the Application (Harris/Casselman Submission, pp. 2-3).

BCTC submits that the ROW agreements in place between landowners and BC Hydro remain legally binding agreements which were entered into for perpetuity and that the Commission does not have jurisdiction to interfere with or modify these contracts. BCTC further submits that, in its responses to various IRs, it has addressed the concerns that the proposed “ROW Prescription Agreements” would address (BCTC Reply, para. 65).

9.6 Rate Impacts

BCTC estimates the impact of its preferred alternative, 5L83, on the forecast Transmission Revenue Requirement (TRR) and BC Hydro's total revenue requirements, including year-by-year impacts (Exhibit B-1, p. 90 Table 6-2 and Appendix N). The rate impact analysis included in the Application does not include any allowance for trade benefits, which BCTC concluded would not be material (Exhibit B-7, BCOAPO 1.22.a).

Relative to current revenue requirements and net of reduced energy losses, BCTC estimates the F2015 forecast revenue requirement impact of the ILM Project represents 1.2 percent of the approved total F2008 BC Hydro Revenue Requirement. On a present value basis through F2030, net of the present value of reduced energy losses, BCTC estimates the impact of the ILM Project is forecast to be approximately one percent relative to the present value of BC Hydro Revenue Requirements (Exhibit B-1, p. 11).

BCTC's rate impact is based on a nominal discount rate of 5.25 percent or real discount rate of 3.15 percent, consistent with updated assumptions about interest rates filed as part of BC Hydro/Alcan 2007 Energy Purchase Agreement proceeding (Exhibit B-1, p. 91). In response to IPPBC 2.8.1 (Exhibit B-10), BCTC filed an updated rate impact analysis reflecting its understanding of the effects of OIC 28. Specifically, in its response to IPPBC 2.8.1, BCTC assumed a deemed equity of 30 percent for the purposes of calculating the revenue requirements for 5L83. This change increased the revenue requirement for 5L83 by $13.5 million. BCTC's filing also corrected an error in a formula related to the treatment of interest during construction within debt, which it had noted in response to BCUC 2.167.1 (Exhibit B-10).

BCTC also provided a rate impact analysis for two alternative sequences: (a) 5L83 followed by partial UEC (Sequence 1); and (b) UEC followed by 5L83 (Sequence 2). The analysis reflects the September 2007 project cost estimate for 5L83 as filed in the Application and an estimate for the UEC alternative adjusted to reflect capital overhead and interest during construction consistent with the September 2007 5L83 forecast. The analysis suggest that the PV of the revenue requirement for Sequence 1 is $59 million lower than Sequence 2, which BCTC indicates is largely attributable to the transmission loss savings associated with having 5L83 in-service 6 years earlier (Exhibit B-5-1, BCUC 1.67.3).

BCTC also noted that OIC 27 and 28 give rise to higher nominal and real discount rates of 8 percent and 6 percent, respectively. BCTC estimated that the additional net impact on the PV of BC Hydro's Revenue Requirements is 0.08 percent (Exhibit B-14, BCUC 3.217.1).

BCTC filed a summary of its financial assumptions (Exhibit B-1, Appendix M) and updated financial assumptions (Exhibit B-14, BCUC 3.217.2) for the rate impact analysis, and noted that for planning purposes, its F2009 forecast of debt cost for a term longer than 10 years is 5.04 percent, which includes the cost of issuance (Exhibit B-14, BCUC 3.217.3). BCTC indicated that BC Hydro's current allowed rate of return on a pre-income tax basis, based on Terasen Gas' approved 2008 ROE and tax rates, is 11.78 percent (Exhibit B-14, BCUC 3.217.6).

Based on the fact the ILM Project is needed, BCTC submits that "the revenue requirement impacts associated with the ILM Project are a necessary and, in the circumstances, reasonable consequence of undertaking the Project" (BCTC Argument, para. 46).

No Intervenor challenges BCTC's rate impact analysis.

Commission Determination

The Commission Panel agrees with BCTC that, given the comprehensive environmental review and approval processes that ILM Project must satisfy, a detailed examination of socioeconomic and environmental impacts is not necessary in this proceeding. However, a high level review of the potential ILM Project impacts is still necessary for the Commission to determine whether the ILM Project is in the public interest. The Commission Panel must have sufficient information to be assured that the ILM Project is likely to receive environmental approvals in a timely manner and that expected compensation and/or mitigation costs would not cause the ILM Project to become less cost-effective than another alternative.

In the VITR Decision, the Commission directed BCTC to file a public report with the Commission every two years or sooner, that summarizes the latest results of EMF risk assessments and any changes in guidelines developed by the WHO, ICNIRP, Health Canada and others where relevant. The Commission Panel concludes that the 2007 Exponent report included in the Application meets that requirement.

The Commission Panel accepts BCTC's use of the IEEE electric field limits set out in IEEE Standard C95.6-2002, and accepts BCTC's approach to addressing the higher field values at two locations. The Commission Panel also accepts BCTC's estimates of the magnetic field levels and its submission that the levels will be well below the limits for public exposure published by ICNIRP and ICES. Therefore, the Commission Panel finds that it is reasonable to include the BCTC-proposed EMF mitigation measures in the ILM Project.

The Commission Panel considers the environmental impacts of the ILM Project manageable and concludes that they are not impediments to the ILM Project. The Commission Panel is confident that the EA process will include a detailed environmental impact assessment and enable BCTC to avoid or mitigate most environmental impacts.

Because the First Nations Intervenors did not lead or elicit evidence, BCTC and BC Hydro's submissions that First Nations risk and potential costs are manageable is uncontradicted. Further, as discussed in Section 3 of this Decision, the Commission Panel concludes that the EA process provides a satisfactory means of addressing First Nations concerns. However, given BCTC's view that the First Nations risks are higher than anticipated in April 2007, and the fact that the First Nations groups have challenged the scope of this proceeding, the Commission Panel cannot conclude that the First Nations impacts will not be an impediment to the ILM Project.

The only Intervenor that raised issues concerning the socioeconomic and environmental impacts of the ILM Project focused primarily on the impacts on affected landowners during construction and maintenance of the transmission line, and many of the concerns were related to practices used to construct the existing line, 5L82. The Commission Panel considers BCTC's public and landowner consultation efforts for the ILM Project entirely satisfactory.

The Commission Panel has considered Harris/Casselman's recommendations, but finds that the existing ROW agreements, BCTC's use of Best Management Practices, and its current level of communication with landowners adequately address the concerns raised by the Intervenor, and that ROW Prescription Agreements are unnecessary. The Commission Panel considers the private property impacts manageable and concludes that they are not impediments to the ILM Project and that the EA process will address the detailed mitigation and possible compensation required.

The Commission Panel notes Directive 25 from the 2006 IEP/LTAP Decision which states that while two tests may be considered for project evaluation, the first and most important test uses the incremental cash flows, while the second and less material test is a ratepayer impact analysis.

The Commission Panel accepts BCTC's analysis of the rate impacts for the ILM Project and notes that the results from the comparison of the two planning sequences is consistent with the economic analysis discussed previously.

The Commission Panel notes there is still some ambiguity with respect to the effect of OIC 27 and 28 on rates. The Commission Panel has relied on the economic analysis for its determinations with respect to the public interest of the ILM Project and makes no determinations with respect to the validity of the rate impact analysis here.

10.0 UPDATE REPORT AND FURTHER REGULATORY REVIEWS

BCTC proposes to file a report ("Update Report") on the result of the EA process and additional Project Definition and Implementation work, including final route alignment, environmental commitments and assurances for mitigation, habitat compensation, consultation, environmental compliance reporting, updated project cost estimate, the P3 assessment, First Nations consultation and accommodation status, and anticipated cost impact from results of tenders for major components of work (respecting confidentiality of tender process) (BCTC Reply, Footnote 48; Exhibit B-5, BCUC 1.23.2 and 1.84.1). BCTC only proposes to apply to the Commission for further approvals or amendments if it determines further approvals or amendment are necessary after:

- the EAC application review process, which will reduce the ILM Project's uncertainty by finalizing a route alignment and determining costs for avoidance, mitigation and compensation of project impacts as part of the EAC process, as well as the cost of First Nations accommodation;
- a P3 business case assessment to determine if a form of P3 arrangement would be an effective procurement strategy for the ILM Project; and
- competitive tenders for the major components of the ILM Project are received (BCTC Reply, para. 9; Exhibit B-5, BCUC 1.84.1).

BCTC submits that the factors which could cause the ILM Project to be deferred past its earliest ISD may be more hypothetical than real and it would be implausible that a combination of reduced load and increased Coastal region resources will occur over the next year that would justify a deferral of the ILM Project. However, BCTC does not have to make a decision to start construction until next year and new information will be available at that time. Accordingly, BCTC believes that it is prudent to defer the decision on the project timing until that time. (BCTC Reply, para. 8)

BCTC stated that if its Update Report suggests that no further approvals or amendments to the CPCN are necessary, it would identify its plan to implement the ILM Project consistent with the CPCN granted. In any event, upon receipt of BCTC's Update Report the Commission will be in a position to assess whether or not it considers that any further public review process is required (Exhibit B-5, BCUC 1.84.1).

BCTC stated that it considers an increase of 10 percent outside the forecast range of overall capital costs presented in the CPCN Application or subsequently approved by the Commission to be a material change to the cost estimate. That is, if the cost of the ILM Project was estimated to be $602 million plus 40 percent ($843 million) or more, BCTC would report its latest cost estimate to the Commission and indicate any recommended action to control costs. (Exhibit B-5-1, BCUC 1.43.1)

BC Hydro has filed an updated LTAP and is expected to file a new NITS application in 2008, and BCTC notes that the updated LTAP and new NITS application should provide further information to assist in confirming or deferring a decision to proceed with a 2014 ISD (BCTC Argument, para. 20).

BC Hydro states that it does not support BCTC's recommendation to return to the Commission for further approvals or amendments in respect of project timing. BC Hydro submits that the need for ILM grid reinforcement is in fact more urgent than is portrayed by BCTC due to the very restrictive generation dispatch assumptions used throughout its analyses and that allowing the possibility of additional regulatory proceedings for the re-examination of need is not warranted and introduces unnecessary risks for project delay. BC Hydro further submits that the Update Report should be confined to confirmation of final routing alignment, an updated project cost, and any proposed P3 arrangements. (BC Hydro Argument, pp. 7-8)

Commenting on BCTC's proposal to provide its Update Report for the Commission to "review", BCOAPO submits that the problem with this process is that if the updated information has a significant adverse impact on the merits of the ILM Project, it does not provide any mechanism to revisit the question whether the project should proceed. BCOAPO submits that an ex post facto prudency review is an inadequate mechanism to hold utilities accountable for the management of their capital projects and results in the opportunity being lost to "ensure that the course that is selected is in fact the best one for ratepayers and the people of the province as a whole."

BCOAPO cites section 89 of the Act, which states: "On an application under this Act, the commission may make an order granting the whole or part of the relief applied for or may grant further or other relief, as the commission considers advisable." BCOAPO submits that the Commission should approve all aspects of the ILM Project up to the point of commencement of construction, prior to which BCTC would be at liberty to apply for a CPCN for the full project if it considers that it has sufficiently robust financial information to provide a foundation for the ILM Project or any alternative it wishes to advance at that time.

BCOAPO submits that this approach would allow BCTC to proceed with its development, pursue the resolution of First Nations concerns, fix the route, track the changing load growth and timing issues, and obtain a firmer sense of the real construction cost; and so enable BCTC to compare the proposed project with its alternatives; and thus to satisfy the Commission and stakeholders "that they had not signed a blank cheque payable to BCTC" (BCOAPO Argument, pp. 4-5).

JIESC submits that its principal concern is cost control and that if the Commission decides not to impose an incentive/penalty mechanism in this case, the Commission should ensure that BCTC's Update Report on final alignment, the updated project cost and any proposed P3 arrangement to be made prior to the awarding of major contracts or proceeding with construction "not be a simple passive filing, but rather a meaningful final check point before proceeding, at which time the Commission must be expressly satisfied that the information provided is reasonable and not materially different from the Commission's view at the time of approving the Project" (JIESC Argument, pp. 1-2).

IPPBC states that it opposes a CPCN that contains a provision that allows BCTC to provide the BCUC with additional information about the ILM Project as it becomes available without the necessity of a formal review process. IPPBC characterizes this process as a "Rolling CPCN Review Process." IPPBC lists the proposed contents of BCTC's Update Report, and submits that these examples of the type of information that BCTC might provide as part of a "rolling review" process are additional evidence of why a formal review process should be required in each instance. IPPBC submits that under its "rolling review" approach to a CPCN, BCTC could provide comments to the Commission about BC Hydro's latest load forecast without IPPBC having the ability to comment on this forecast's efficacy, and cites the Province's initiatives and legislation on greenhouse gas emissions as an example of something not yet factored into BC Hydro's load forecast, and submits that it is possible that when the forecast does take into account the Province's initiatives and legislation, the need for transmission capacity may increase and the issue might not just be an "adjustment to the project timing." IPPBC submits that any "rolling review" process must provide stakeholders such as the IPPBC with a formal opportunity to comment on any new information provided by BCTC (IPPBC Argument, pp. 13-14).

BCTC addresses BCOAPO's submission that the Commission should not grant permission to proceed with construction but rather grant BCTC the liberty to apply for a CPCN at any time prior to the start of construction once BCTC considers that "it has sufficiently robust financial information to provide a foundation for the ILM [Project] or any alternative that it wishes to advance at that time", and rejects IPPBC's submission regarding of "rolling review" process (BCTC Reply, para. 38, 54).

BCTC submits that it is premature for the Commission to establish the regulatory process it would use when BCTC provides its Update Report to the Commission; depending on what BCTC reports, there may be no need for any review process. Accordingly, there is simply no need to make that determination at this point in time and in doing so, BCTC respectfully submits that the Commission risks ordering a process, along with attendant costs and time, that might not otherwise be needed (BCTC Reply, para. 40).

BCTC also rejects BCOAPO's submission that the mechanism that BCTC has proposed to arrive at a final project decision before proceeding does not have the flexibility to revisit whether the ILM Project should proceed. BCTC will undertake a full project review prior to making a decision to proceed with the ILM Project. BCTC will then submit its Update Report and conclusions to the Commission and the Commission will be in a full position to assess whether or not it considers that any further public review process is required. The Commission has every opportunity to hold a further process if it determines that this is necessary based on the information in the Update Report (BCTC Reply, para. 40).

BCTC submits that BCOAPO is essentially proposing two CPCN proceedings and a "process [that] would simply add more cost and uncertainty for the ratepayer" (BCTC Reply, p. 41).

Commission Determination

In the first Procedural Conference the Commission Panel heard submissions from all parties on how it should proceed. At that time it rejected submissions by counsel for BCOAPO for a bifurcated process, and chose to proceed with the review of the Application, and then to either grant, perhaps with conditions, or deny the Application. The Commission Panel has not heard any evidence or submissions since that time that are convincing support for a bifurcated process. Accordingly, the Commission Panel rejects BCOAPO's submission that it "grant BCTC the liberty to apply for a CPCN at any time prior to the start of construction" and IPPBC's submissions regarding a "rolling review" process.

Earlier in this Decision, the Commission Panel reviewed the need for reinforcement of the ILM grid, the ranking of the alternatives, and the estimated costs and benefits of the alternatives, and concluded that the need exists and that 5L83 is the most cost-effective project to meet the need, and that BCTC should plan to meet the earliest ISD of October 2014. **Accordingly, it grants a CPCN for the ILM Project conditional on BCTC filing the Update Report, and provided that an updated P50 cost estimate ($2014) in the Update Report is equal to or less than $725 million ($2014). The Update Report should be as defined by BCTC in the evidence in this proceeding, and should update the evidence in this proceeding arising from material changes in circumstances relevant to need, including consideration of the most recent load forecast, the NITS application, and the 2008 LTAP proceeding evidence or Decisions, or both.**

For clarity, this P50 cost estimate provision should be considered to be a condition precedent to the CPCN. That is, the Commission Panel concludes that only if the P50 cost estimate in the Update Report is equal to or less than $725 million may BCTC proceed with the ILM Project in accordance with the CPCN granted with this Decision. It follows that the Commission Panel has also concluded that no further regulatory review is necessary if the P50 cost estimate in the Update Report is equal to or less than $725 million. Therefore, the Update Report will be filed for information purposes only, if the P50 cost estimate condition precedent has been satisfied. However, in the event that the cost estimate in the Update Report is greater than $725 million, BCTC may seek relief from the P50 cost estimate condition precedent to the CPCN. If BCTC does seek relief from the P50 cost estimate condition precedent, then BCTC should consider including evidence providing further justification of the ILM Project as compared to the alternatives, particularly an updated estimate of the cost of UEC and loss savings attributable to 5L83.

The P50 cost estimate, which is the subject of the condition precedent, is to include estimates for First Nations accommodation costs, costs arising from the EAC requirements, and legal costs arising from CPCN or EAC appeals. It should reflect updated tender costs and include a P50 contingency for any outstanding uncertainties, developed using a similar methodology as the one used in BC Hydro's Cost and Schedule Report filing in this Proceeding (Exhibit B-1, Appendix C). The Commission Panel acknowledges that the P50 cost estimate to be used for the condition precedent to the CPCN is not comparable to the P50 cost estimate in the Application, and further acknowledges that a detailed explanation of the derivation of the amount of $725 million is not being provided with this Decision. The P50 cost estimate in the condition precedent should be calculated consistent with the calculation of the P50 cost estimate in the Application, although for reasons mentioned above, the P50 cost estimates will not be comparable.

In establishing this condition precedent, the Commission Panel does not accept the evidence of BCTC, particularly in the absence of an incentive/penalty mechanism, that a "material change" is an increase of 10 percent outside the forecast range of overall capital costs presented in the Application.

Even if the P50 cost estimate condition precedent is satisfied, BCTC should consider opportunities to defer the ILM Project before proceeding with the project and, if so, whether such a deferral would be prudent (BCTC Argument, para. 20). The Commission Panel concludes that further regulatory review of the need for the ILM Project by the earliest ISD is unnecessary unless BCTC concludes that it would be prudent to defer the ILM Project for more than one year, i.e. beyond the fall of 2015, in which case BCTC should seek approval for a deferral of the ISD. BCTC should also seek approval for a deferral of the ISD beyond the fall of 2015 for any other reason, including a change in circumstances arising from the EA process and First Nations consultation. In considering the merits of a deferral, the Commission Panel expects BCTC to take into account the economic benefits of advancing the ILM Project as a result of loss savings and other benefits, even if it is no longer required at its earliest ISD based on system planning standards.

Dated at the City of Vancouver, in the Province of British Columbia, this 5th day of August 2008.

Original signed by:

Robert H. Hobbs
Panel Chair and Commissioner

Original signed by:

Nadine F. Nicholls
Commissioner

Original signed by:

A.J. (Tony) Pullman
Commissioner

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

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

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

and

An Application by British Columbia Transmission Corporation
for a Certificate of Public Convenience and Necessity for the
Interior to Lower Mainland Transmission Project

BEFORE: R.H. Hobbs, Panel Chair and Commissioner
N.F. Nicholls, Commissioner
A.J. Pullman, Commissioner

August 5, 2008

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On November 5, 2007, the British Columbia Transmission Corporation ("BCTC") applied (the "Application") pursuant to sections 45 and 46 of the Utilities Commission Act (the "Act") for a Certificate of Public Convenience and Necessity ("CPCN") for the Interior to Lower Mainland ("ILM") Transmission Project (the "ILM Project"); and

B. The purpose of the ILM Project is to reinforce the electric transmission system to increase the transmission capability of the ILM grid, and consists of a proposed new 500 kV alternating current transmission line, designated 5L83, between Nicola substation near Merritt and Meridian substation in Coquitlam, a new 500 kV series capacitor station which would be located approximately at the midpoint of the new 500 kV circuit, circuit terminations at each of Nicola and Meridian substations, and necessary telecommunications, protection and control equipment.; and

C. The new transmission line would parallel the existing 5L82 transmission line for most of the new circuit's approximately 246 km length and would be primarily on existing Right of Way, however, the specific alignment will be determined after the Environmental Assessment Certificate Application process and further public and First Nations consultation; and

D. The ILM Project has an estimated cost of $602 million, excluding First Nations accommodation costs, environmental mitigation and compensation costs, and costs for legal challenges, with an accuracy level of +30 percent to -10 percent, which is also the P50 estimated cost, and a target in-service date of fall 2014; and

E. By Order G-137-07 dated November 7, 2007 the Commission determined an Oral Public Hearing was required for regulatory review of the Application, and scheduled a Procedural Conference for December 20, 2007 to address certain procedural issues; and

F. By Order G-172-07 dated December 21, 2007 the Commission established an amended regulatory timetable that included three community input sessions, a second Procedural Conference for March 25, 2008 and an Oral Public Hearing to commence April 14, 2008; and

G. By letter dated February 21, 2008 the Commission determined that it need not consider the adequacy of consultation and accommodation efforts on the ILM Project as part of its determinations in deciding whether to grant a CPCN for the ILM Project, which letter was followed by Reasons for Decision contained in Letter L-6-08 dated March 5, 2008; and

H. By letters dated March 4, 2008 and March 12, 2008 the Commission cancelled the community inputs sessions at Harrison Hot Springs, Coquitlam, and Merritt because of the low number of scheduled presentations and provided for those parties interested in making presentations the opportunity to do so at the Oral Public Hearing; and

I. By letter dated March 13, 2008 the Commission denied the request of the Kwikwetlem First Nation for the Commission to exercise its discretion, pursuant to section 102(2) of the Act, to suspend the hearing; and

J. By Order G-61-08 dated March 28, 2008 the Commission determined that the ILM proceeding could be completed as a written process, and issued an amended regulatory timetable without an Oral Public Hearing component; and

K. BC Hydro, the Independent Power Producers Association of British Columbia, the British Columbia Old Age Pensioners' Organization et al. ("BCOAPO"), the Joint Industry Electricity Steering Committee, the City of Abbotsford, Messrs. Harris and Casselman, and the Nlaka'pamx filed Final Submissions; and

L. By letter dated May 21, 2008 the Commission denied the application of BCOAPO for an adjournment of the proceeding pending the outcome of certain B.C. Court of Appeal decisions; and

M. BCTC filed its Reply Submission on June 3, 2008; and

N By letter dated June 17, 2008 the Commission cancelled the Oral Phase of Argument, and determined that the proceeding was concluded subject to the disposition of a leave application from Messrs. Harris and Casselman; and

O. By Letter L-30-08 dated June 23, 2008 the Commission denied the application for leave from Messrs. Harris and Casselman; and

P. The Commission has considered the ILM Project Application and the evidence and submissions presented on the Application and has determined that it is in the public interest that a CPCN be issued to BCTC for the ILM Project subject to the conditions and directions set out in the Order and Decision.

NOW THEREFORE pursuant to sections 45 and 46 of the Act the Commission orders as follows:

1. A Certificate of Public Convenience and Necessity is granted to BCTC for the ILM Project as described in the Application, subject to the following conditions:

   1.1 BCTC is to file the Update Report in accordance with the Decision issued concurrently with this Order, and

   1.2 the P50 cost estimate ($2014) that is to be filed with the Update Report is equal to or less than $725 million ($2014). The P50 cost estimate is to be calculated on a basis consistent with the calculation of the P50 cost estimate in the Application, and is to include First Nations accommodation costs, costs arising from the EAC requirements, and legal costs arising from CPCN or EAC appeals.

2. BCTC is directed to file with the Commission Quarterly Progress Reports on the ILM Project showing planned vs. actual schedule, planned vs. actual costs, and any variances or difficulties that the ILM Project may be encountering. The Quarterly Progress Reports will be filed within 30 days of the end of each reporting period.

3. BCTC is directed to file with the Commission a Final Report within six months of the end or substantial completion of the ILM Project that provides a complete breakdown of the final costs of the ILM Project, compares these costs to the P50 cost estimate that is to be filed with the Update Report and provides a detailed explanation and justification of all material cost variances.

5. BCTC is directed to comply with the directions of the Commission set out in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of August 2008.

BY ORDER

Original signed by:

Robert H. Hobbs
Panel Chair and Commissioner

ACRONYMS AND ABBREVIATIONS

2002 CPR	2002 Conservation Potential Review
2006 Amended LTAP	BC Hydro's 2006 Amended LTAP
2007 CPR	Conservation Potential Review
2007 Energy Plan	BC Energy Plan – A Vision for Clean Energy Leadership
2007 TSCP	May 2004 Transmission System Capital Plan
5L83	500 kV AC Transmission Line
AACE	American Association of Cost Engineers
ac	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
Act	*Utilities Commission Act*
Alternatives Report	BCTC's October 2007 Report entitled 'Reinforcement Alternatives for the Interior to Lower Mainland Transmission Grid'
AMC	American Creek
Application	Application by BCTC with the Commission for an Order Issuing a CPCN for its Proposed Project to Increase the Transfer Capability of the Interior to Lower Mainland Grid
ARN	BC Hydro's Aboriginal Relations and Negotiations department
ATC	Available Transmission Capacity
BC Hydro	BC Hydro and Power Authority
BCEAA	*British Columbia Environmental Assessment Act*
BCOAPO	British Columbia Old Age Pensioners *et al.*
BCTC	British Columbia Transmission Corporation

BCUC	British Columbia Utilities Commission
BIL	Basic Impulse Level
Burrard	Burrard Thermal Generating Station
CBN	Clayburn Substation
CE	Canadian Entitlement
CHP	Chapmans
CKY	Cheekye Substation
Coastal region	Lower Mainland and Vancouver Island
Commission	British Columbia Utilities Commission
Cost and Schedule Report	Nicola to Meridian 500 kV Transmission Line Alternative Cost and Schedule Report
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CRK	Creekside
CRPs	Contingency Resource Plans
DCI	DC Interconnect Inc.
DCI Report	DC Interconnect Inc. Report
DSM	Demand Side Management
EA	Environmental Assessment
EAC	Environmental Assessment Certificate
EAO	Environmental Assessment Office
EENS	Expected Energy Not Served
ELF	Extremely Low Frequency
EMF	Electric and Magnetic Fields, or Electromagnetic Field(s)

ERM	Enterprise Risk Management
F2008 TSCP Decision	F2008-F2017 Transmission System Capital Plan Decision
F2009 TSCP Decision	F2009-F2018 Transmission System Capital Plan Decision
GAAP	Generally Accepted Accounting Principles
government	Government of the Province of British Columbia
GUI	Guichon
Harris/Casselman	Messrs. Casselman and Harris
HC1 and HC2	Special Directions HC1 and HC2
HVDC	High Voltage Direct Current
ICES	International Committee for Electromagnetic Safety
ICNIRP	International Commission on Non-Ionizing Radiation Protection
IDC	Interest During Construction
IEEE	Institute of Electrical and Electronics Engineers
IEP	BC Hydro’s 2006 Integrated Electricity Plan
ILM	Interior to Lower Mainland
ILM Project	Interior to Lower Mainland Project
ING	Ingledow
IPPBC	Independent Power Producers of B.C.
IRs	Information Requests
ISD	In-Service Date
JIESC	Joint Industry Electricity Steering Committee

Joint First Nations	Nlaka'pamux Nation Tribal Council, Okanagan Nation Alliance, and Upper Nicola Indian Band
KLY	Kelly Lake substation
kV/m	Kilovolts Per Metre
Kwikwetlem	Kwikwetlem First Nation
LM	Lower Mainland
LM-VI	Lower Mainland and Vancouver Island
LTAP	Long-Term Acquisition Plan
LTEPA+	Amended and Restated Long-Term Energy Purchase Agreement
MDN	Meridian substation
mG	Milligauss
MMK	MMK Consulting Inc.
MSC	Mechanically Switched Capacitor
N-0	Pre-Contingency Conditions
N-1	Single Contingency Planning Criteria
NERC	North American Electric Reliability Corporation
Network Upgrades	Upgrades to the System
NIC	Nicola Substation
NITS	Network Integrated Transmission Service
Nlaka'pamx	Nlaka'pamx Nation
NNTC	Nlaka'pamux Nation Tribal Council
NSK	North Skeemis
O&M	Operating and Maintenance
OIC	Order(s) in Council

ONA	Okanagan Nation Alliance
P3	Public Private Partnership
PLOSS	BCTC's Power Loss Program
PMO	Project Management Office
Province	Government of the Province of British Columbia
PV	Present Value
REAP	BC Hydro's Resource Expenditure and Action Plan
Review	Interior to Lower Mainland Transmission Project Cost Estimate Review
ROE	Return on Equity
ROW	Right-of-Way
RYC	Ruby Creek
SAW	Sawmill Creek
SD 10	Special Direction 10
SD 9	Special Direction 9
SVCs	Static VAr Compensators
TOR	Terms of Reference
TTC	Total Transfer Capability
UCA	*Utilities Commission Act*
UCAA 2008	*Utilities Commission Amendment Act 2008*
UEC	Upgrade Existing Circuits
UNIB	Upper Nicola Indian Band
Update Report	Report on the Result of the EA Process
VI	Vancouver Island

VIGP	Vancouver Island Generation Project
VITR	Vancouver Island Transmission Reinforcement Project
WECC	Western Electricity Coordinating Council
WHO	World Health Organization

LIST OF APPEARANCES

G. FULTON P. MILLER	Commission
S. CARPENTER D. CURTIS	British Columbia Transmission Corporation
K. BERGNER C. GODSOE	British Columbia Hydro and Power Authority
J. QUAIL L. WORTH	BCOAPO - B.C. Old Age Pensioners' Organization, Active Support Against Poverty, B.C. Coalition of People with Disabilities, Counsel Of Senior Citizens' Organizations of B.C. End Legislated Poverty, Federated Anti-Poverty Groups of B.C. TRAC (Tenants Rights Action Coalition)
S. CROCKER	Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc.
D. AUSTIN	Independent Power Producers of B.C.
R.B. WALLACE I. CHANG	Joint Industry Electricity Steering Committee
J. YARDLEY	City of Abbotsford
R. PHILLIPS	Nlaka'pamx Nation Communities: Boston Bar, Siska, Lytton, Nicomen, Cook's Ferry, Shacken and Coldwater Indian Bands
G. McDADE L. GIRODAY	Kwikwetlem First Nation
B. STADFELD	Upper Nicola Indian Band, Nlaka'pamux Nation Tribal Council, Okanagan Nation Alliance
B. HARRIS	Mr. Casselman and Mr. Harris

LIST OF APPEARANCES
(continued)

E. Switlishoff G. Isherwood T. Berry	Commission Contract Staff
T. Roberts D. Flintoff	Commission Staff
H.H. Bemister	Allwest Reporting Ltd./Hearing Officer

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

and

British Columbia Transmission Corporation

Application for a Certificate of Public Convenience and Necessity (CPCN) For the Interior to Lower Mainland Transmission Project (ILM Project)

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated November 7, 2007 and Order No. G-137-07 establishing a Procedural Conference, Oral Public Hearing and Regulatory Timetable
A-2	Letter dated December 7, 2007 issuing Information Request No. 1 to BCTC
A-3	Letter dated December 13, 2007 issuing a supplementary Information Request No. 1 to BCTC
A-4	Letter dated December 19, 2007 outlining the issues that the Commission wishes BCTC and Intervenors to discuss in their Opening Statements at the Procedural Conference
A-5	Letter dated December 21, 2007 and Order No. G-171-07 amending the Regulatory Timetable and establishing Community Input Sessions
A-6	Letter dated January 8, 2007 to Mr. Bruce Stadfeld, Counsel for Upper Nicola Indian Band, providing clarification of the Community Input Sessions (Exhibit A-5)
A-7	Letter dated February 8, 2008, issuing Information Request No. 2 to BCTC
A-8	Letter dated February 21, 2008 cancelling the oral argument phase regarding the First Nations Scoping issue
A-8A	Letter No. L-6-08 dated March 5, 2008 issuing Reasons for Decision regarding the First Nations Scoping issue
A-9	Letter dated March 4, 2007 cancelling the Harrison Hot Springs and Coquitlam Community Input Sessions
A-10	Letter dated March 5, 2008 providing procedural information to Intervenors for the proceeding

Exhibit No.	Description
A-11	Letter dated March 7, 2008 requesting participants to comment on the Kwikwetlem First Nation request to suspend the hearing process pursuant to Section 102(2) of the UCA (Exhibit C5-4)
A-12	Letter dated March 12, 2008 cancelling the Merritt Community Input Session
A-13	Letter dated March 13, 2008 denying request from the Kwikwetlem First Nation to stay the proceeding (Exhibit C5-4)
A-14	Letter dated March 19, 2008 requesting participants to advise the Commission of any Agenda items for Procedural Conference No. 2
A-15	Letter dated March 20, 2008 confirming Procedural Conference No. 2
A-16	Letter dated March 19, 2008 to Raymond Philips, counsel on behalf of the Nlaka'pamx Communities responding to his participant assistance inquiry (Exhibit C4-5)
A-17	Letter dated March 28, 2008 and Order No. G-61-08 providing Reasons for Decision and an amended Regulatory Timetable changing the oral public hearing to a written public hearing process
A-18	Letter dated April 14, 2008 issuing Information Request No. 3 to BCTC
A-19	Letter dated May 2, 2008 approving BCTC's request for an extension to the filing date for responses to Information Requests No. 3
A-20	Letter dated May 7, 2008 issuing a revision to the date for the Oral Phase of Argument set out in Exhibit A-19
A-21	Letter dated May 21, 2008 denying the application of BCOAPO for an adjournment
A-22	Letter dated June 17, 2008 cancelling the oral phase of Argument

APPLICANT DOCUMENTS

B-1	Letter dated November 5, 2007 filing the Application for a Certificate of Public Convenience and Necessity (CPCN) For the Interior to Lower Mainland Transmission Project (ILM Project)
B-1-1	Letter dated December 5, 2007 filing an Errata and replacement pages to the Application (Exhibit B-1)

Exhibit No.	Description
B-2	Letter dated November 22, 2007 filing response to letter from Robert Weeks, Mission, BC (Exhibit E-1)
B-3A	Letter dated December 6, 2007 filing set of orthophotos of the ILM Project route
B-3B to B-3E	Attached zip files with set of orthophotos of the ILM Project route
B-4	Letter dated January 9, 2008 filing Notice of Process to determine scope of ILM Proceeding on First Nations consultation and accommodation
B-5	Letter dated January 10, 2008 filing response to Commission's Information Request No. 1
B-5-1	Letter dated January 18, 2008, filing responses to the outstanding Information Request No. 1 from the Commission (Exhibit B-5)
B-6	Letter dated January 21, 2008 filing submission regarding the issue of the adequacy of consultation and accommodation efforts as part of its determination in deciding whether to grant a CPCN
B-7	Letter dated January 28, 2008 filing response to the Commission and Intervenor Information Request No. 1
B-7-1	Letter dated January 29, 2008 filing the "Electric and Magnetic Field Baseline Survey & Modeling" report from DVT Solutions Inc., and updated responses to the Commissions Information Request No. 1.8.2.1 and 1.8.2.2
B-7-2	Letter dated June 5, 2008 filing response to the Commission's Information Request No. 1.6.2
B-8	Letter dated February 13, 2008 filing reply submission to First Nations
B-9	Email dated February 19, 2008 filing advertising publication schedule and Notice of Community Input Sessions in Merritt, Harrison Hot Springs and Coquitlam
B-10	Letter dated March 6, 2008 filing Responses to Information Requests No. 2
B-11	Letter dated March 11, 2008 filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)
B-12	Letter dated March 20, 2008 response regarding necessity of Procedural Conference No. 2

Exhibit No.	Description
B-13	Letter dated May 1, 2008 requesting extension to file responses to Commission Information Request No. 3
B-14	Letter dated May 5, 2008 filing responses to Commission Information Request No. 3
B-14-1	Letter dated May 7, 2008 filing an Errata to the responses to Commission Information Request No. 3 (Exhibit B-14)

INTERVENOR DOCUMENTS

C1-1	**BRITISH COLUMBIA HYDRO & POWER AUTHORITY (BCHYDRO) –** Online web registration received November 9, 2007 filing request for Intervenor status
C1-2	Letter dated December 13, 2007 filing Information Request No. 1 to BCTC
C1-3	Letter dated January 10, 2008 filing response to the Commission's Information Request No. 1
C1-4	**CONFIDENTIAL** - Letter dated January 10, 2008 filing response to the Commission's Information Request No. 1
C1-5	Letter dated January 21, 2008, filing submission regarding the issue of the adequacy of consultation and accommodation efforts as part of its determination in deciding whether to grant a CPCN
C1-6	Letter dated February 8, 2008 filing Information Request No. 2 to BCTC
C1-7	Letter dated February 13, 2008 from Keith Bergner, Lawson Lundell, legal counsel, filing reply submission on Scope of Hearing and the role of the Commission in respect of the Crown duty to consult and accommodate First Nations
C1-8	Letter dated March 6, 2008 with Responses to Information Request No. 2 forwarded from BCTC
C1-9	**CONFIDENTIAL** – Letter dated March 6, 2008 filing response to Commission Information Request No. 2.186.1
C1-10	Letter dated March 11, 2008, from Lawson Lundell, legal counsel, filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)

Exhibit No.	**Description**
C1-11	Letter dated March 19, 2008 filing comments regarding Procedural Conference No. 2 and Notice to File two Evidentiary aspects at the Oral Hearing
C1-12	Letter dated May 5, 2008 filing responses to Information Request No. 3 forwarded from BCTC
C2-1	**TERASEN GAS INC. –** Letter dated November 16, 2007 filing request for intervenorship
C2-2	Letter dated February 4, 2008 filing comments on the proceeding scope regarding adequacy of First Nation consultation and accommodation
C3-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION ET AL (BCOAPO)** - Letter dated November 20, 2007 from Jim Quail requesting Intervenor Status for Leigha Worth, Counsel, and Bill Harper, Econalysis Consulting
C3-2	Letter dated December 7, 2007 filing Information Request No. 1 to BCTC
C3-3	Letter dated January 29, 2008 filing comments concerning the jurisdiction and role of the Commission regarding projects which may impact on First Nations communities, territories or entitlements
C3-4	Letter dated February 8, 2008 filing Information Request No. 2 to BCTC
C3-5	Letter dated March 11, 2008 filing comments on Kwiltwetlem First Nation's Notice of Application for Leave to Appeal with the BC Court of Appeal and the Commission's request for comments (Exhibit C5-4; Exhibit A-11)
C3-6	Letter dated March 19, 2008 filing comments in support of a second Procedural Conference
C3-7	Letter dated May 16, 2008 filing application for an adjournment pending the outcome of the Kwikwetlem First Nation's Leave of Appeal
C4-1	**NLAKA'PAMX NATION** - Email dated December 5, 2007 from Raymond D. Philips, legal counsel, filing notice of attendance and request for information on the process

Exhibit No.	Description
C4-2	Letter dated January 18, 2007, from Bruce Stadfeld, Mandell Pinder, legal counsel, filing request for Registered Intervenor and interest in making submission to the scoping question **- EXHIBIT WITHDRAWN - REFILED AS EXHIBIT C13-1**
C4-3	Letter dated January 29, 2008 filing comments and Notice to Attend the Community Input Session in Merritt, BC
C4-4	Letter dated March 11, 2008 from Raymond D. Philips, legal counsel, filing comments on the Notice for Leave of Appeal on the process (Exhibit A-11)
C4-5	Letter dated March 12, 2008 from Raymond D. Philips, legal cousel, filing comments on the Merritt Community Input Session scheduled for March 14, 2008
C5-1	**KWILTWETLEM FIRST NATION** – Letter dated December 11, 2007 from Lesley Giroday, of Ratcliff & Company, legal counsel, requesting Intervenor Status
C5-2	Letter dated December 13, 2007, from Lesley Giroday, of Ratcliff & Company, filing Information Request No. 1 to BCTC
C5-3	Letter dated February 4, 2008, from Lesley Giroday, of Ratcliff & Company, filing submissions on the First Nation scoping question
C5-4	Letter dated March 6, 2008 advising that the Kwiltwetlem First Nation has filed a Notice of Application for Leave to Appeal with the BC Court of Appeal and requesting the Commission to suspend the proceedings pursuant to Section 102(2) of the Utilities Commission Act
C5-5	Letter dated March 13, 2008, from Lesley Giroday, of Ratcliff & Company, filing notice that they will not be submitting Evidence and reserve the right to file at a later date
C6-1	**CITY OF ABBOTSFORD –** Letter dated December 12, 2007 from George F. Ferguson filing request for Intervenor Status

Exhibit No.	Description
C7-1	**UPPER NICOLA INDIAN BAND (JFN)–** Online web registration by Clarine Ostrove of Mandell Pinder, legal counsel, filing request for Intervenor Status
C7-2	Email dated January 2, 2008 filing request for more information on the Community Input Session in Merritt
C7-3	Letter dated February 4, 2008, filing submissions regarding the scoping question to consult and accommodate First Nations
C7-4	Facsimile dated February 15, 2008 response to BCTC confidential cost estimate referred to in Commission Information Request No. 2
C7-5	Letter dated March 11, 2008, filing objection on behalf of the Joint First Nation to BCTC's request for the confidential filing of a cost estimate for accommodating First Nations
C7-6	Letter dated March 11, 2008, filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)
C7-7	Letter dated March 14, 2008, filing notice that they will not be submitting Evidence and reserve the right to file at a later date
	UPPER NICOLA INDIAN BAND (C7-1 **OKANAGAN NATION ALLIANCE (ONA) (C12-1)** **NLAKA'PAMUX NATION TRIBAL COUNCIL (NNTC) (C13-1)**
	The above noted are now referred to as the **Joint First Nation Intervenors**
C7-8	Letter dated March 20, 2008 from Clarine Ostrove, Mandell Pinder on behalf of the Joint First Nation Intervenors commenting on the agenda for Procedural Conference No. 2
C8-1	**BOSTON BAR FIRST NATION INDIAN BAND** – Letter dated December 13, 2007 from John Warren, Administrator, filing request for Intervenor Status
C9-1	**HARRIS, DONALD & CASSELMAN, ALAN –** Letter received December 13, 2007, filing Notice to Attend the Procedural Conference and filing request for Intervenor Status
C9-2	Email dated December 19, 2007 filing Notice of Representative of Bruce Harris
C9-3	Letter dated February 8, 2008 filing Information Request No. 1 to BCTC

Exhibit No.	Description
C9-4	Letter dated March 11, 2008 filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)
C9-5	Letter dated April 14, 2008, filing Information Request No. 3 to BCTC
C10-1	**INDEPENDENT POWER PRODUCERS ASSOCIATION OF BC (IPPBC) –** Letter dated December 17, 2007 from David Austin, Tupper Jonsson & Yeadon, filing request for late Intervenor Status and comments
C10-2	Letter dated February 8, 2008 filing Information Request No. 1 to BCTC
C10-3	**SUBMITTED AT HEARING** – Document submitted regarding ILM alternatives considered
C10-4	Letter dated April 14, 2008, filing Information Request No. 3 to BCTC
C11-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC) –** Letter dated December 19, 2007 from R. Brian Wallace, Bull Housser & Tupper, filing request filing request for late Intervenor Status and comments
C11-2	Letter dated March 20, 2008 response regarding necessity of Procedural Conference No. 2
C12-1	**OKANAGAN NATION ALLIANCE (ONA) –** Letter dated January 18, 2007, from Brenda Gaertner, Mandell Pinder, legal counsel, filing late request for Registered Intervenor and interest in making submission to the scoping question
C12-2	Letter dated February 4, 2008, filing submissions regarding the scoping question to consult and accommodate First Nations
C12-3	Facsimile dated February 15, 2008 response to BCTC confidential cost estimate referred to in Commission Information Request No. 2
C12-4	Letter dated March 11, 2008, filing objection on behalf of the Joint First Nation to BCTC's request for the confidential filing of a cost estimate for accommodating First Nations
C12-5	Letter dated March 11, 2008, filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)

Exhibit No.	Description
C12-6	Letter dated March 14, 2008, filing notice that they will not be submitting Evidence and reserve the right to file at a later date

PLEASE REFER TO EXHIBIT ID C7

THIS INTERVENOR IS NOW PART OF THE JOINT FIRST NATION INTERVENORS

C13-1	**NLAKA'PAMUX NATION TRIBAL COUNCIL (NNTC)** - Letter dated January 18, 2007, from Bruce Stadfeld, Mandell Pinder, legal counsel, filing request for Registered Intervenor and interest in making submission to the scoping question

(PLEASE REFER TO EXHIBIT C4-2)

C13-2	Letter dated February 4, 2008, filing submissions regarding the scoping question to consult and accommodate First Nations
C13-3	Facsimile dated February 15, 2008 response to BCTC confidential cost estimate referred to in Commission Information Request No. 2
C13-4	Letter dated March 11, 2008, filing objection on behalf of the Joint First Nation to BCTC's request for the confidential filing of a cost estimate for accommodating First Nations
C13-5	Letter dated March 11, 2008, filing comments on the matters raised in the Kwikwetlem letter regarding the scope of the proceeding (Exhibit C5-4; Exhibit A-11)
C13-6	Letter dated March 14, 2008, filing notice that they will not be submitting Evidence and reserve the right to file at a later date

PLEASE REFER TO EXHIBIT ID C7

THIS INTERVENOR IS NOW PART OF THE JOINT FIRST NATION INTERVENORS

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	**BC ENVIRONMENTAL ASSESSMENT OFFICE –** Online web registration submitted by Janet MacKenzie, requesting Interested Party status
D-2	**KOVISH, BARRY** - Letter dated December 3, 2007, filing request for Interested Party status
D-3	**THOMPSON-NOCOLA REGIONAL DISTRICT -** Letter dated December 10, 2007, from Bob Finley, Manager of Planning Services, filing request for Interested Party status
D-4	**ELLIOTT ENERGY SERVICES LTD –** Online web registration from John Elliott filing request for Interested Party status
D-5	**GOLDEN EAGLE GROUP –** Email from Mike Manion, General Manager, filing letter of comment and request for Interested Party status
D-6	**MCCOSH, DAVID –** Online web registration filing request for Interested Party status
D-6-1	**MCCOSH, DAVID –** Email dated May 13, 2008, filing request to withdraw as an Interested Party
D-7	**DIRKS, RON & BRENDA –** Online web registration received January 9, 2008, filing request for Interested Party status
D-7-1	**DIRKS, RON & BRENDA –** Email received January 24, 2008, filing request for withdrawal of Interested Party status
D-8	**KERR WOOD LEIDAL ASSOCIATES LTD. –** Online web registration received January 9, 2008 from Ron Monk filing request for Interested Party status
D-9	**ALTA ENERGY** - Online web registration received January 24, 2008, from Stephen Kukucha filing request for Interested Party status
D-10	**GERRY GARNETT CONSULTING -** Online web registration received January 24, 2008 from Gerry Garnett, requesting Interested Party status

Exhibit No.	**Description**
LETTERS OF COMMENT	
E-1	Email dated November 19, 2007 filing letter of comment and questions from Roberts Weeks, Mission, BC
E-2	Letter dated December 12, 2007 filing Letter of Comment from Matsqui First Nation Lands Department
E-3	Letter dated November 27, 2007 from Paul Peterson, Central Kootenay Regional District, filing Letter of Comment
	***** EXHIBIT REMOVED *****
	POSTED IN ERROR
E-4	Letter dated April 9, 2008, from Joe Gardner, General Manager, Douglas Lake Cattle Co., filing Letter of Comment
E-4-1	Letter dated April 30, 2008 BC Transmission Corporation response to Joe Gardner, General Manager, Douglas Lake Cattle Company's Letter of Comment
E-5	Letter dated April 30, 2008 from John Pichugin, Manager, of The Teal-Hones Group, filing comments
LETTERS OF EXPRESSIONS OF INTEREST	
F-1	**KWIKWETLEM FIRST NATION** – Letter dated January 15, 2008 from Lesley Giroday, Ratcliff & Company, legal counsel, filing interest in making submission to the scoping question
F-2	**VISION FINANCIAL SERVICES –** Email dated January 17, 2008 from Michael Bonshor, CMA, filing interest in consideration of First Nations affected by project
F-3	**STO:LO NATIONS CHIEFS COUNCIL** – Email dated January 18, 2008 from Chief Joe Hall, President, on behalf of Aitchelitz First Nation, Leq'A:Mel First Nation, Skawahlook First Nation, Skowkale First Nation, Tzeachten First Nation and Yakweakwioose First Nation advising interest in making submission to the scoping question