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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER C-1-05

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

and

An Application by the British Columbia Transmission Corporation
for Approval of the System Control and Modernization Project

BEFORE: R.H. Hobbs, Chair February 14, 2005

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

WHEREAS:

A. On October 15, 2004 the British Columbia Transmission Corporation ("BCTC") applied for a Certificate of Public Convenience and Necessity ("CPCN") to replace and upgrade the system which controls the Transmission and Distribution Network of British Columbia Hydro and Power Authority ("BC Hydro"); and

B. The project is referred to as the System Control and Modernization Project and consists of the construction of two new control centres, the replacement of the Energy Management System ("EMS"), and various telecommunication upgrades at an estimated cost of $133 Million; and

C. On November 5, 2004, by Letter No. L-54-04 (Exhibit A-1), the Commission issued an information request to BCTC. By copy to Registered Intervenors in the BCTC Capital Plan and the BC Hydro Revenue Requirements applications, the Commission requested comments as to what further process should be established to review the Application; and

D. The Commission received responses to the information requests from BCTC on November 19, 2004 (Exhibit B-2). In its response, BCTC requested that the responses to certain questions be kept confidential for commercial reasons. Similarly, in its Application, BCTC requested that a report prepared by KEMA Consulting Canada Ltd. ("KEMA") be kept confidential for security reasons; and

E. On November 26, 2004, the Commission received comments from BC Hydro (Exhibit C1-1), and from Bull, Housser & Tupper on behalf on the Joint Industry Electricity Steering Committee or ("JIESC") (Exhibit E-1); and

F. On December 8, 2004, the Commission issued Letter No. L-59-04 (Exhibit A-2) setting down a written hearing process and regulatory timetable; and

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G. BC Hydro and the Commission issued a second round of information requests on December 20, 2004 and December 16, 2004 respectively. BCTC replied on December 31, 2004 (Exhibit B-5). The written proceeding concluded with a final response to intervenor submissions by BCTC on January 17, 2005 (Exhibit B-7); and

H. The Commission has considered the application, responses to information requests and intervenor and applicant arguments and finds that the project is in the public interest and should be approved.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to Section 45 of the Utilities Commission Act, the Commission issues a CPCN to BCTC for the System Control Modernization Project as defined by the Application.

2. The BCTC will comply with all directions as set forth in the attached Reasons For Decision (Appendix A).

DATED at the City of Vancouver, in the Province of British Columbia, this 14 day of February 2005.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

BRITISH COLUMBIA TRANSMISSION CORPORATION
An Application for a
Certificate of Public Convenience and Necessity
System Control Modernization Project

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

The British Columbia Transmission Corporation ("BCTC") is a provincial Crown Corporation that began operations August 1, 2003. Under a Master Agreement with the British Columbia Hydro and Power Authority ("BC Hydro"), BCTC is responsible for operating, managing, and maintaining BC Hydro's transmission system. BCTC is also responsible for planning, obtaining regulatory approvals for, and constructing projects that sustain or enhance the transmission system's capability to transport electric power, and for entering into commitments and incurring expenditures for such projects. Under the Master Agreement and separate services agreements, BCTC also provides generation control and distribution operations services. BC Hydro is required to fund capital expenditures for core transmission assets (which BC Hydro continues to own) if such expenditures are approved by the British Columbia Utilities Commission ("BCUC" or "Commission"). Certain other capital assets, such as control centres, are funded and owned by BCTC.

1.2 The Application

On October 15, 2004, the Commission received an Application from BCTC under Section 45 of the Utilities Commission Act ("UCA") seeking a Certificate of Public Convenience and Necessity ("CPCN") for a System Control Modernization Project ("SCMP"). BCTC proposes to replace the current System Control Centre ("SCC") with a new System Control Centre located in the Lower Mainland and to construct a Backup Control Centre ("BCC") in the South Interior. The project includes two new buildings to house the control centres, a new Energy Management System ("EMS"), and communication upgrades at an estimated total cost of $133 million (Application [Exhibit B-1], p. 1-5). BCTC stated that the SCMP is intended to: replace obsolete technology; resolve seismic criteria issues at the SCC and Area Control Centres ("ACCs"); provide geographically separate backups for the SCC and ACCs; streamline control and operating infrastructure; and address certain limitations of the existing SCC facility (Exhibit B-1, pp. 1-2, 1-3).

On November 5, 2004, by Letter No. L-54-04 (Exhibit A-1), the Commission issued an information request to BCTC. By copy to Registered Intervenors in the BCTC Capital Plan and the BC Hydro Revenue Requirements

applications, the Commission requested comments as to what further process should be established to review the Application.

The Commission received responses to the information requests from BCTC on November 19, 2004 (Exhibit B-2). In its response, BCTC requested that the responses to certain questions be kept confidential for commercial reasons. Similarly, in its Application, BCTC requested that a report prepared by KEMA Consulting Canada Ltd. ("KEMA") be kept confidential for security reasons.

On November 26, 2004, the Commission received comments from BC Hydro (Exhibit C1-1) and from Bull, Housser & Tupper on behalf of the Joint Industry Electricity Steering Committee or "JIESC" (Exhibit E-1). The JIESC concluded that, because of the unique and highly complex technical evaluations that would be required, and because of the commercial sensitivity and confidentiality arguments in response to information requests, it was not in a position to evaluate the representations of BCTC or the project alternatives in this matter (Exhibit E-1, p. 1). The JIESC suggested that the Commission retain an independent reviewer to monitor and evaluate the project, and that in any case the Commission should require BCTC to quantify the benefits and savings from the SCMP and commit to achieving them (Exhibit E-1, p. 3). BC Hydro commented that the proposed cost of the project would have a significant impact on its customers and that the Commission should establish a written hearing process to review the Application (Exhibit C1-1).

In response to these comments, the Commission issued Letter No. L-59-04 (Exhibit A-2) setting down a written hearing process and regulatory timetable. BC Hydro and the Commission issued a second round of information requests on December 20, 2004 and December 16, 2004 respectively. BCTC replied on December 31, 2004 (Exhibit B-5). The written proceeding concluded with a final reply to intervenor submissions by BCTC on January 17, 2005 (Exhibit B-7).

2.0 THE SYSTEM CONTROL MODERNIZATION PROJECT

2.1 Existing Control Centre Facilities

BCTC currently operates the transmission system through the Burnaby Mountain SCC and four ACCs: the Lower Mainland Control Centre ("LMC") in Vancouver; the Vancouver Island Control Centre ("VIC") near Duncan; the South Interior Control Centre ("SIC") in Vernon; and the Northern Control Centre ("NCC") near Prince George. There is also a local control facility at the GM Shrum Generating Station on the Peace River. All substations, and all generating stations other than GM Shrum and the Lower Mainland's Burrard Generating Station, operate unattended under the control of the SCC or an ACC.

In its Application (Section 1), BCTC described several problems associated with the present control centres.

- Seismic risk reduction studies performed by BC Hydro in the early 1990s identified significant structural deficiencies regarding compliance with the existing seismic code for the VIC, the SCC, and several telecommunications buildings. BCTC noted that new and more stringent seismic standards are expected in the 2005 revision of the National Building Code of Canada (Exhibit B-5, BC Hydro IR 3.1), and that neither the SCC nor any of the ACCs will meet the new code.

- Having multiple control centres raises building costs, computer system costs, and operating and maintenance ("O&M") staff costs. Further, compared to having fewer control centres, workforce planning is more difficult, co-ordination of operations across the power system takes more effort, and uniformity of culture and operations is difficult to achieve.

- There is little or no backup for many of the functions performed by the individual control centres.

- The existing SCC is located on land leased from Simon Fraser University ("SFU"). The lease expires in 2016, there is no renewal option, and SFU has indicated that it does not want a renewal. The SCC is being enveloped by SFU's UniverCity residential and commercial development, creating additional security risks. There is no room to expand and the building cannot accommodate the equipment needed to permit consolidation of the control centres.

2.2 Existing Computer and Communications Systems

The SCC controls the transmission system using an Energy Management System ("EMS"), which includes a supervisory control and data acquisition ("SCADA") system for direct control and monitoring of the power system. The EMS also includes certain advanced applications (e.g., state estimator, voltage stability analyzer, transient stability analyzer, and contingency analyzer) that are used to ensure the security of the bulk transmission system. The ACCs have SCADA systems, but only for the portion of the distribution system within high voltage substations. The advanced EMS applications are not available at the ACCs, and each ACC's database is area-specific. The EMS/SCADA system, which is based on 1980's technology, is no longer supported by the vendor. As a result, all hardware and software maintenance must be performed by BCTC staff or contractors. In BCTC's view the system is prone to database errors that can lead to customer outages, is difficult and expensive to maintain, is unable to accommodate changing functional requirements, and is effectively at the limits of its capacity.

The SCC normally controls critical transmission equipment, including the 500 kV grid, certain 230 kV transmission lines, all generation facilities with a plant capacity greater than 400 MW, all tie lines, and voltage control equipment at any voltage level. The ACCs normally perform control actions for lower-voltage equipment

in their respective areas, including distribution equipment within substations. Because of the uniqueness of their databases, the ACC's control functions cannot be transferred to the SCC or another ACC.

An ACC can assume control of its area's critical equipment from the SCC, but when it does so, the advanced EMS applications cannot be executed. Because of the limited visibility afforded each ACC's SCADA system, work on the distribution networks must be tracked on paper maps at each control centre, which has the potential to introduce errors and does not accommodate backup access from other locations. In BCTC's view, operating multiple control centres with overlapping responsibilities and multiple hardware/software platforms makes it difficult to achieve standardization, ensure security and disaster resilience, and optimize human and financial resources.

The SIC acts as a backup for the automatic generation control ("AGC") functionality at the SCC, and therefore has access to data from some major generating stations and tie lines. To provide data to both the SCC and the SIC, Remote Terminal Units ("RTUs") are either dual-ported (have two outputs) or installed in pairs. These RTUs are of recent vintage and exhibit acceptable performance, but some of the ACC RTUs are older, less reliable, and limited in performance.

BC Hydro owns the microwave/fibre-optic system that provides the main communications facility for control of the transmission system. BCTC operates the system from the Telecom Network Operations ("TNO") centre located at the BC Hydro office in Burnaby, and a backup facility is located at the SCC. The telecommunications system is currently being improved by completing a high capacity loop (sometimes called the "Carson ring") connecting the Lower Mainland to the Carson microwave station near Cache Creek through two separate routes. The telecommunications system also includes several smaller communication loops in the Lower Mainland. Certain key parts of the power system, such as the large generation facilities in the Peace and Columbia regions and the 500kV system serving the North Coast, are currently, and will continue to be, reached by radial spurs from the main communications loop.

2.3 Objectives

The Application cited several studies that, in BCTC's view, indicate a need to modernize the control facilities and associated technology. A BC Hydro report dated July 2001, entitled Control Centre Consolidation Update (Exhibit B-5, BCUC IR 1.1) reviewed consolidation and showed that a reduction in the number of transmission control centres would reduce operating and technology costs without compromising safety or reliability. A second BC Hydro report dated March 20, 2002, entitled EMS Technology Assessment Project (Exhibit B-6),

concluded that the EMS is outdated, unable to accommodate changing functional requirements, effectively at the limits of its capacity, and orphaned by its supplier.

BCTC continued BC Hydro's work by establishing the SCMP in 2003. KEMA Consulting and Robert E. Lamb, Inc. were selected by BCTC to assist with the work. KEMA issued a report in April 2004 entitled Review of Control Facilities and EMS Requirements Findings Report, which included Lamb's report on control-centre facility design. In the report, KEMA stated that it agrees with the analysis and conclusions contained in the aforementioned BC Hydro documents. KEMA further stated that, while the ACCs were not explicitly addressed in the reports, they suffer from the same technology shortcomings that the SCC does. Further, the likelihood that EMS equipment will not survive a seismic event of the magnitude contemplated by the 2005 building code means that a backup control centre should be located sufficiently far from the primary control centre to minimize the possibility that a single event would incapacitate both centres.

Based on these studies, BCTC has concluded that the SCMP is necessary and that it should meet the following objectives (Exhibit B-1, pp. 1-2, 1-3).

1. Replace Obsolete Technology

As discussed in Section 2.2, BCTC has stated that the EMS is near the end of its useful life and near the limits of its capacity to accommodate database and programming changes. Because the system is no longer supported by the vendor, BCTC is supporting it by hiring extra staff and making capital improvements that would normally be handled by routine upgrades. BCTC stated that problems with the system include database errors resulting in customer outages, the inability to respond quickly to changes in market needs, and the inability to implement new stations and displays effectively. BCTC therefore submitted that there is a clearly identified need for the EMS at the SCC, and the SCADA systems at the ACCs, to be replaced by more current and functional technology.

2. Resolve Seismic Criteria Issues at the System Control Centre and Area Control Centres

BCTC noted that the SCC and the ACCs, particularly the Vancouver Island Control Centre, meet neither present nor expected future seismic criteria for post-disaster facilities. BCTC submitted that control centre facilities ought to meet those criteria to ensure that they are available following a seismic event.

3. Provide a Geographically Separate Backup for the System Control Centre

While certain control operations carried out by the SCC can be partially backed up by the relevant ACC, advanced applications that are critical to the operational security of the system cannot be backed up using the current system. BCTC submitted that these applications are becoming increasingly critical to ensuring the reliable operation of the system, and therefore that backup systems should be installed in geographically separate locations to minimize the risk of disruption from the same event (e.g., an earthquake).

4. Provide Geographically Separate Backup for Area Control Centres

BCTC stated that there is no effective backup for any of the four ACCs, and noted that the LMC controls a significant portion of the transmission system and all of the distribution system that will supply the 2010 Olympic venues.

5. Streamline the Control and Operating Infrastructure

BCTC submitted that there is an industry trend toward consolidation of multiple control centres and that the reasons cited by other utilities for such consolidation include: reduced control centre building costs; reduced computer system costs; reduced O&M staff costs; improved workforce planning; better co-ordination of operations across the power system; and uniformity of operations and culture. BCTC submitted that the SCMP would provide similar benefits.

6. Address Limitations of the Existing SCC Facility

The intent of this objective is to address the expiry of the lease on the existing SCC, the inability of the structure to meet seismic standards (see Objective 2) or to expand to permit control centre consolidation, and possible security problems resulting from the encroachment of development on SFU land surrounding the SCC.

2.4 Options

Under Tab 4 of its Application, BCTC proposed a number of options to address the shortcomings of the existing control centre facilities and control systems. Briefly, these options are as follows.

1. Delay the replacement of the EMS/SCADA technology and new buildings until 2016 (Exhibit B-1, Section 4.1).

2. Replace the existing EMS at the SCC and the SCADA system at each of the four ACCs in 2008, and construct new main and backup control centre buildings to open in 2016 (Exhibit B-1, Section 4.2).

3. Replace the existing EMS at the SCC, replace the SCADA at the SIC with an EMS, replace the SCADA systems at the LMC, the VIC, and the NCC in 2008, and construct new main and backup control centres to open in 2016 (Exhibit B-1, Section 4.3).

4. Replace the EMS at the SCC, replace the SIC SCADA system with an EMS, replace the SCADA systems at the LMC, the VIC, and the NCC with remote consoles connected to the EMS at the SCC and the SIC, and construct new primary and backup control centres to open in 2016 (Exhibit B-1, Section 4.4).

4a. Replace the existing EMS at the SCC, replace the SIC SCADA with an EMS, replace the SCADA systems at the LMC, the VIC, and the NCC with remote consoles connected to the EMS at the SCC and the SIC, construct a new backup control centre to open in 2008, and construct a new primary control centre to open in 2016 (Exhibit B-1, Section 4.5).

6a. Replace the five existing control centre buildings, the EMS at the SCC and the SCADA systems at each of the four ACCs with two control centre buildings, each with an EMS, all in 2008 (Exhibit B-1, Section 4.6).

BCTC's Application (Exhibit B-1, p. 1-4) stated that several other options had been considered but were rejected. Option 6, which provided for the construction of main and backup control centres in the Lower Mainland, was rejected because of a lack of geographical separation between the centres. Option 6b, with the main control centre and an unstaffed emergency centre in the Lower Mainland, and an unstaffed backup centre in the Southern Interior, was also rejected because it would require operating staff from the Lower Mainland to relocate to the backup centre for it to be operational, but there would be no assurance that staff could relocate quickly or easily. An Option 5, which contemplated a single control centre with upgraded technology, was rejected by BCTC because it did not contain a backup facility. BCTC also considered an option which located the main control centre in the South Interior near Kamloops, but rejected it because of concerns with respect to employee retention (Exhibit B-2, BCUC IR 1.8).

The following chart (derived by the Commission based on information in Section 4 of the Application) summarizes the options and highlights differences between the options. A column entry of "EMS" means that a new EMS system is made available in 2008; "SCADA" means that a new SCADA system is made available in 2008; "Console" means that a remote EMS console is made available in 2008; and "X" means that the control centre is abandoned.

Table 1: Summary of Options

	OPTION					
LOCATION	**1**	**2**	**3**	**4**	**4a**	**6a**
System Control Centre (SCC)	NO CHANGES TILL 2016	EMS	EMS	EMS	EMS	X
South Interior Control Centre (SIC)		SCADA	EMS	EMS	EMS	X
Lower Mainland Control Centre (LMC)		SCADA	SCADA	Console	Console	X
Vancouver Island Control Centre (VIC)		SCADA	SCADA	Console	Console	X
Northern Control Centre (NCC)		SCADA	SCADA	Console	Console	X
(New) Main Control Centre with EMS		2016	2016	2016	2016	2008
(New) Backup Control Centre with EMS		2016	2016	2016	2008	2008

2.5 Ability of Options to Meet Objectives

The following table illustrates BCTC's assessment of the ability of each option to meet each of the stated objectives. An X means the option does not meet the objective, a small checkmark means that the option partially meets the objective, and a large checkmark means that the option fully (or almost fully) meets the objective. Note that this table is intended to reflect BCTC's, and not the Commission's, assessment of the options. The Commission's views on both the options and the objectives are set out later in this document.

Table 2: Evaluation of Options Against Objectives

	OPTION					
OBJECTIVE	**1**	**2**	**3**	**4**	**4a**	**6a**
Replace obsolete technology	X	✓	✓	✓	✓	✓
Resolve seismic criteria at SCC, ACCs	X	X	X	X	✓	✓
Geographically separate backup for SCC	X	X	X	X	✓	✓
Geographically separate backup for ACCs	X	X	X	X	✓	✓
Streamline control/operating infrastructure	X	X	X	✓	X	✓
Address limitations of existing SCC	X	X	X	X	X	✓
Net Present Value of Options ($ in Thousands), from Exhibit B-1, Table 1, p. 4-17	222,303	229,312	232,475	229,815	242,661	241,591

2.6 BCTC's Recommendation

Based on its review, BCTC has recommended Option 6a, which includes a new main System Control Centre to be constructed in the Lower Mainland (likely in the Fraser Valley), and a new or expanded backup control centre in the South Interior. Each of the geographically separated control centres would meet the 2005 building code and, because they would have full EMS systems, would be capable of carrying out the functions currently performed by the SCC and all four ACCs. Under this option, both the existing SCC and the existing ACCs would be closed and their operations consolidated into the new main and backup control centres. Both new control centres would be connected to the Carson ring (the high capacity communications loop), which would provide for automatic re-routing if a main trunk path is lost to ensure uninterrupted control of the power system for many communication contingencies. BCTC submitted that this option also provides operating efficiencies and greater workforce flexibility.

The cost of the various project components is estimated to be as follows:

Table 3: Cost by Project Component

Description	Estimated Cost (millions)
New System Control Centre Building	$40
New Backup Control Centre Building	$33
New Energy Management System	$44
Communication Systems Upgrades	$9
Other Project Costs	$7
Total Capital Cost	**$133**

Using the estimated capital cost of $133 million and the expected savings in O&M costs, BCTC has analyzed the anticipated impact of the recommended option on transmission rates. The following table (Exhibit B-1, p. 4-18) shows the impact on the transmission revenue requirement and transmission rates as compared to F2005 rates based on the June Evidentiary Update in BC Hydro's 2005/2006 Revenue Requirements Application. The period runs from F2006 to F2024, at which time the assets constructed or acquired under the SCMP are anticipated to reach the end of their useful lives. Rate impacts commence in F2006 because, once the SCMP is approved, the depreciation on existing control centre assets will be accelerated. BCTC estimates that a 1 percent increase in transmission rates translates into approximately a 0.2 percent increase in BC Hydro's retail rates. On that basis, the estimated impact of the recommended SCMP option will be less than 1 percent at the retail level through 2024.

Table 4: Estimated Rate Impacts by Year

Year	Change [M$]	Point-to-Point	NITS
F2006	8.4	1.37%	1.75%
F2007	0.8	0.14%	0.17%
F2008	2.7	0.44%	0.56%
F2009	6.8	1.09%	1.38%
F2010	2.6	0.42%	0.53%
F2011	0.5	0.09%	0.11%
F2012	0.5	0.08%	0.10%
F2013	0.4	0.07%	0.09%
F2014	-3.3	-0.52%	-0.66%
F2015	1.3	0.21%	0.26%
F2016	-1.9	-0.31%	-0.39%
F2017	0.3	0.05%	0.07%
F2018	0.3	0.05%	0.07%
F2019	-0.6	-0.09%	-0.12%
F2020	0.3	0.06%	0.07%
F2021	0.2	0.04%	0.05%
F2022	0.2	0.03%	0.04%
F2023	0.2	0.03%	0.04%
F2024	0.2	0.03%	0.04%
Cumulative Impact	**20.2**	**3.33%**	**4.26%**

3.0 EXAMINATION OF ISSUES AND INTERVENOR ARGUMENTS

3.1 Project Justification

3.1.1 Energy Management System

In its Application, BCTC cited several problems with the existing EMS system (Exhibit B-1, Section 3.2.3). BCTC submitted that:

- the security and reliability of the existing system are becoming increasingly difficult to sustain, and there is limited disaster resilience;
- the EMS is no longer supported by the vendor and it is becoming increasingly difficult to extend the functionality of the system or to implement new RTUs or displays;
- the total annual cost (capital and O&M) of keeping the system running is increasing; and
- there is no backup for certain advanced applications that are critical to the operation of the power system.

3.1.1.1 Control System Security and Reliability

While the overall performance of the existing EMS has been acceptable to date (Exhibit B-1, p. 3-5), BCTC cited several reasons why the EMS cannot be sustained at its current level of reliability and security for some years into the future (Exhibit B-2, BCUC IR 1.2). These reasons include:

- facilities, particularly the VIC and the SCC, are ageing, and facility failures or the upheaval created by upgrades would affect the computer systems;
- an increased failure rate can be expected on control system equipment that has been in service since the early 1990s, and when failures do occur, it will take significant time to implement alternative arrangements because some of the equipment is no longer replaceable;
- a major change in computer platforms will be required in the near future;
- the lack of vendor support for the existing system means that BCTC must rely on the small number of ageing staff who are familiar with it, and attracting new staff who are interested in maintaining computer systems that are several generations old is difficult;
- the increasing complexity of new applications and the difficulty of integrating them into an ageing EMS can reasonably be expected to cause problems; and
- constraints on various database parameters have been reached, and error-prone workarounds have necessarily been implemented.

BCTC submitted that the SCMP will improve the reliability and security of the control system through the implementation of a full-capability backup control centre and EMS (Exhibit B-2, BCUC IR 1.3). Even in the event of a catastrophic failure of the primary centre, all EMS functionality will be preserved. Computer system security will be improved through the implementation of modern functionality and methods including secure logon schemes, encryption and authentication, recording and reporting of unusual logon attempts, and physical security at the control centres. BCTC noted that the existing EMS was designed well before many of the current cyber-security threats existed.

In its final submission, BC Hydro stated that there is no evidence that the security and reliability of the control system has been decreasing, and also noted that BCTC did not assess the value of any additional reliability benefits that would be derived from the SCMP. BC Hydro further stated that there is no evidence that the risk of an EMS failure would be any greater in 2012 or 2016 than it would be in 2008 (Exhibit C1-3, p. 2).

In its final reply to intervenor submissions, BCTC acknowledged that it did not assess the value of additional reliability benefits because improved reliability is a by-product, rather than a driver, of the SCMP. BCTC rejected BC Hydro's view that the risk of an EMS failure would be no greater in 2012 or 2016 than it would be in 2008. It stated that there will be an increasingly negative impact on customers as the control system ages and becomes less reliable, and that both BCTC and KEMA believe delaying the project creates an ever-increasing risk that a failure of the existing EMS will cause a major power system outage (Exhibit B-7, p. 5). BCTC stated that it would attempt to mitigate the risk of system failure, but that it is becoming increasingly difficult to do so.

Commission Findings

The Commission notes that the EMS is no longer supported by the vendor, which is an indication of the obsolescence of the EMS. The Commission also notes that planning to replace the EMS began in 1998, and that the original date for migrating to a new system was 2003 (Exhibit B-5, BCUC IR 6.3). The Commission accepts BCTC's submission that, in the absence of an upgrade to the EMS, the security and reliability of the control systems will likely decline over time and the security and reliability of the power system itself will increasingly be at risk as a result.

3.1.1.2 Lack of Extensibility

In its Application (Exhibit B-1, p. 3-3), BCTC submitted that a 2002 BC Hydro report entitled EMS Technology Assessment concluded that the EMS is unable to accommodate changing functional requirements. BCTC stated that in a market structure, especially a new market, changes in market rules, data exchange requirements, and applications are common. The existing EMS is built on 1980s computer technology, and making changes to applications or adding new functionality typically requires the development of customized software. In addition, data is stored in a proprietary database and access to data is limited. In BCTC's view, all of the revisions to the EMS for market requirements (including revisions to accommodate the purchase and sale of operating reserves, the self-supply of operating reserves, and dynamic scheduling) have taken extensive time and effort because the EMS software development tools are poor and the existing software is poorly written and organized (Exhibit B-2, BCUC IR 1.15). The lack of extensibility is problematic because there are large gaps in EMS functionality

(Exhibit B-2, BCUC IR 1.16), and the cumbersome tools for database update can lead to customer outages or the incorrect operation of power system equipment (Exhibit B-2, BCUC IR 1.10).

KEMA reviewed the EMS Technology Assessment Report and concurred with its analysis and conclusions. It noted that the EMS used at BCTC is actually five separate systems rather than a single distributed system, and that each system must be maintained separately. KEMA stated that maintenance of this complex architecture is problematic and time-consuming, and that the modernized system control project will be developed to improve the efficiency of computer system support staff and improve the system's ability to accommodate new requirements.

BC Hydro submitted that the evidence in this proceeding confirms that applications can be changed and functionality can be added to the existing EMS, though such modifications may take longer than they would with a new EMS (Exhibit C1-3, p. 2). The JIESC does not accept that British Columbia's electricity market has changed sufficiently to require new control and management systems (Exhibit E-1, p. 2).

In reply to BC Hydro's comments BCTC stated that, while it is able to make certain modifications to the EMS, these changes are extremely time-consuming, there is a significant risk of errors, and the system is in danger of reaching both known and unknown limits (Exhibit B-7, p. 4).

Commission Findings

The Commission accepts BCTC's submission that there is limited extensibility of functionality in the existing EMS, and that making modifications is difficult and time-consuming.

3.1.1.3 Increasing Costs

BCTC submitted that, because of the increasing age and the difficulty of extending the functionality of the existing EMS, total expenditures, capital and O&M, are rising (Exhibit B-2, BCUC IRs 2.10 and Exhibit B-5, BCUC IR 10.2). BCTC further stated that, if the SCMP goes ahead for 2008, O&M expenses from now until 2008 would not necessarily go down because "the existing system is obsolete and at the end of life requires significant technical engineering to keep it operating to meet reliability, market and customer requirements" (Exhibit B-2, BCUC IR 2.11). However, BCTC does project a decrease in annual capital expenditures from $4.0M per year to $1.5M in F2006 and F2007, and to $0.8M in F2008.

BC Hydro submitted that the incremental cost of deferring the SCMP is very low compared to the cost of implementing it now (Exhibit C1-3, p. 2). In reply, BCTC stated that, because the EMS will need to be replaced,

any additional costs spent on maintaining the existing EMS are purely incremental and ultimately can be considered to be part of the final costs but, in the meantime, do not mitigate any of the substantial risks associated with continuing to operate the existing system. BCTC further commented that, despite many years of running the transmission system and studying the replacement of the existing control systems, including retaining experts to review this issue, BC Hydro has not put forward any proposal in this regard (Exhibit B-7, p. 4).

Commission Findings

The Commission accepts that the costs of maintaining the existing EMS are rising.

3.1.1.4 Backup for Advanced Applications

On page 1-2 of its Application, BCTC stated that one of the problems with the existing EMS is that there is no backup for certain advanced applications that are critical to the operational security of the system. These applications include State Estimation, Transient Stability Analysis, Voltage Stability Analysis, and Contingency Analysis (Exhibit B-1, p. 3-2). In addition, the ACCs cannot back up each other's SCADA systems, and backup for Automatic Generation Control is limited (Exhibit B-5, BCUC IR 22.1). BCTC stated that the loss of these automated functions would result in increased risk of system collapse and a very conservative mode of operation with excess generation on line, greatly curtailed intertie capabilities, and restrictions on the number of changes to generation patterns and the rate of change of intertie schedules. In addition, the loss of any ACC will result in loss of supervisory control of most of the stations controlled by that ACC, which could lead to developing problems or overloads not being detected and longer outage restoration times (Exhibit B-5, BCUC IR 22.1).

BC Hydro submitted that the record is clear that the current control system can tolerate the loss of any one of the ACCs, that the consequence of such a loss would be that the system would need to be operated more conservatively than it otherwise would be, and that such a loss would not result in the loss of service to BC Hydro's ratepayers. In BC Hydro's view, the necessary inference from this evidence is that the principal consequence of losing any one of the current control centres would be a purely economic cost (Exhibit C1-3, p. 3).

In reply, BCTC stated that BC Hydro's understanding of the consequences of the loss of any one of the control centres and the consequent need for effective backup systems and facilities is not correct. While BCTC would continue to operate the power system under such circumstances, it would not be a safe, reliable, or reasonable mode of operation, and there would be a complete loss of the capability to monitor and control significant

portions of the system, an increased risk of system collapse, safety risks to both the public and BC Hydro employees, and the loss of service to BC Hydro ratepayers (Exhibit B-7, p. 6).

Commission Findings

The Commission accepts BCTC's submissions concerning the potential problems associated with the loss of certain advanced functions, and accepts the need for appropriate backup for these functions.

3.1.1.5 Summary

In Sections 3.1.1.1 through 3.1.1.4, the Commission found that:

- in the absence of an upgrade to the EMS, the security and reliability of the control systems will likely decline over time and the security and reliability of the power system itself will increasingly be at risk as a result;
- there is limited extensibility of functionality in the existing EMS, and making modifications is difficult and time-consuming;
- the costs of maintaining the existing EMS are rising;
- there is a need for appropriate backup for certain advanced functions.

For all these reasons, the Commission finds that there is a need to replace the existing EMS, and provide a backup EMS system.

3.1.2 Control Centres

BCTC's Application (Exhibit B-1, Section 3.2.3) noted several problems with the existing control centre configuration:

- the existing configuration has limited disaster resilience;
- there are security and lease issues associated with the existing Burnaby Mountain control centre;

- multiple control centres with overlapping responsibilities make it difficult to achieve standardization across the organization, maintain the (multiple) control systems, and optimize the use of skilled staff; and

- the existing configuration makes it difficult to provide backup for all of the functions that are critical to the ongoing operation of the power system.

3.1.2.1 Disaster Resilience

BCTC noted in its Application (Exhibit B-1, p. 1-2) that the SCC and the ACCs, particularly the VIC, do not meet present seismic criteria for post-disaster facilities (though that by itself would not be sufficient justification for the SCMP) (Exhibit B-7, p. 8). A revision to the National Building Code of Canada is expected in 2005, and indications are that it will include more stringent seismic ground motion design criteria (Exhibit B-2, BCUC IR 1.8). BCTC stated that, to ensure that control centre buildings are available following a seismic event, they should meet the most stringent seismic criteria for their location (Exhibit B-1, p. 1-2). BCTC also noted that the seismic withstand capability of the core technology used at the control centres remains a major concern (Exhibit B-1, p. 3-4). Because of the limited ability to back up certain ACC and advanced SCC functions, a major seismic event has the potential to disable functions required for the safe and reliable operation of the power system.

As noted in Section 3.1.1.4, BC Hydro submitted that the current control system can tolerate the loss of any one of the ACCs and suffer only an economic cost. Also as noted in that section, BCTC disagreed, stating that there would be an increased risk of system collapse, safety risks to both the public and BC Hydro employees, and the loss of service to customers.

Commission Findings

The Commission notes that it is imperative that the facilities and systems that control British Columbia's power system survive, to the greatest extent possible, a significant seismic event. It is also imperative that control of undamaged portions of the power system be restored as quickly as possible following an event that incapacitates the SCC, and that action be taken immediately to begin restoration of damaged portions of the power system. The Commission therefore accepts BCTC's view that, in order to ensure that control centre buildings are available following a seismic event, they should meet the most stringent seismic criteria for their locations.

3.1.2.2 Security and Lease Issues

BCTC noted in its application (Exhibit B-1, pp. 1-2, 1-3) that the Burnaby Mountain control centre is on land leased from Simon Fraser University. It is being enveloped by SFU's "UniverCity" residential and commercial development, which creates additional security risks. Multifamily three-storeys and high-rise condominiums are being built within a few hundred feet of the control centre, and later phases of the UniverCity project will see large developments closer to the control centre. Further, two sides of the present control centre are located on the lease boundary, and there is no room to establish any sort of boundary control on these two sides. These and other changes have turned a relatively isolated location into a high traffic area that violates most prudent recommendations for the siting of a critical facility such as the control centre (Exhibit B-2, BCUC IR 1.9).

The lease on the land containing the SCC expires on December 31, 2016. There is no renewal option, and SFU has indicated that it does not want to renew the lease. At expiry, the SCC building reverts to SFU and market-based rents (which are much higher than rent under the current lease) would apply, and SFU has stated that the current use of the land is not compatible with its long-term plans (Exhibit B-2, BCUC IR 1.9).

In its final comments, BC Hydro noted that there are still a few hundred feet between the SCC and the new developments, and that while the SFU site does not appear to be appropriate for expansion or redevelopment of the SCC, there is no reason why the SCC could not remain there until 2016 (Exhibit C1-3, p. 4). BCTC agreed that, in the absence of other issues, the issues associated with the SCC's location or the lease from SFU would not justify putting in place the SCMP. However, continuing to use the existing control centre would mean that other aspects of the SCMP, including the ability to have back-up technology in place, would not be addressed (Exhibit B-7, p. 8).

Commission Findings

The Commission accepts BCTC's explanation that, in isolation, neither security concerns nor pending lease expiry at the Burnaby Mountain site would justify the SCMP, and accepts BC Hydro's position that (strictly from the perspective of these issues) there is no reason why the SCC could not remain on Burnaby Mountain through 2016. The Commission notes, however, that these issues, in addition to other benefits, contribute to the need for the SCMP. The Commission also notes that remaining at this site would necessitate the additional expenditures for seismic upgrades.

3.1.2.3 Consolidation

BCTC stated in its Application (Exhibit B-1, p. 1-2) that there is an industry trend toward consolidation of multiple control centres. The reasons advanced by other utilities for consolidation include reduced control centre building costs, reduced computer system costs, reduced O&M staff costs, improved workforce planning, better co-ordination of operations across the power system, and uniformity of operations and culture. BCTC submitted that consolidation of its control centres would provide similar benefits, though it acknowledged that consolidation is not one of the major drivers for the SCMP (Exhibit B-7, p. 7). BCTC cited BC Hydro's 2001 Control Centre Consolidation Study Status Update (Exhibit B-5, BCUC IR 1.1), which concluded that reducing the number of control centres would reduce operating and technology costs without compromising safety and reliability.

BCTC evaluated the benefits of each proposed SCMP option against the goal of streamlining the control and operating infrastructure (Exhibit B-1, Sections 4.1.5, 4.2.5, 4.3.5, 4.4.5, 4.5.5, and 4.6.5); the results of that evaluation are shown, at a high level, in Table 2 in Section 2.5 of this Reasons for Decision. On page 1-7 of the Application, BCTC presented a table showing that the estimated net present value of O&M expenses was lowest for BCTC's recommended SCMP option, which provides for control centre consolidation. BCTC stated that manpower savings would result from the streamlining of processes for which there are presently overlapping responsibilities, and from the consolidation of roles outside the Monday-to-Friday daytime shifts (Exhibit B-5, BCUC IR 17.4).

KEMA stated that it had completed several assignments over the past few years where control centre rationalization was an element of the consultancy. As part of some of those assignments, KEMA completed surveys that showed a clear trend to reduce the number of control centres to a minimum, typically one with a backup. KEMA has had further contact with two of the survey participants subsequent to their distribution control centre consolidations, and in both cases the consolidations proved successful and the companies are planning further consolidations.

BC Hydro submitted that BCTC had not provided an objective assessment of whether a single control centre and a single backup control centre is the most cost-effective or appropriate approach for BCTC given its existing multiple control centre configuration. BC Hydro further submitted that there is no consideration on the record of alternatives to control centre consolidation, such as using the ACCs for distribution system control, nor is there an assessment of the trade-offs associated with consolidation versus maintaining a disaggregated network of control centres. BC Hydro also stated that BCTC did not quantify any increases in reliability or security of system controls and facilities from consolidation of control centres by other utilities (Exhibit C1-3, p. 3). The JIESC submitted that, in advance of being allowed to proceed, BCTC should be required to quantify the benefits and savings from the SCMP and to commit to achieving them or bearing the costs (Exhibit E-1, p. 3).

In response to intervenor comments, BCTC submitted that it considered maintaining a disaggregated network along with upgrading the existing ACCs and providing backup for these operations, but because none of the existing control centres have surplus space and most do not meet seismic standards, these options were not investigated in further detail. BCTC further submitted that using the ACCs for distribution control may make things worse: there would still be no backup for the ACCs, seismic concerns would remain, technology maintenance would still be required at multiple sites, and some existing efficiencies for the off-shifts when one person fills multiple roles would be lost (Exhibit B-7, p. 7). The single control centre option (the original Option 5) was rejected because it did not contain a backup facility.

Commission Findings

The Commission accepts the position of BCTC that there are likely to be benefits to control centre consolidation, although such benefits were not quantified by BCTC.

3.1.2.4 Summary

In Sections 3.1.2.1 through 3.1.2.3, the Commission has found that BCTC's control centres should meet the most stringent seismic criteria for their locations, that security and lease issues at the existing SCC must be addressed (though, in isolation, not before 2016), and that there are likely to be economic and operational benefits to control centre consolidation. **The Commission therefore finds that replacing the existing control centres with a smaller number of seismically sound control centres is appropriate.**

3.2 Configurations/Options for Project

3.2.1 Control Centre Configuration

BCTC's recommended option for the SCMP consists of:

- a new SCC to be constructed in the Lower Mainland, likely in the Fraser Valley;
- a new (or expanded) BCC to be constructed in the South Interior, which would replicate nearly all of the functions available at the SCC and would be available on a few minutes notice;
- full EMS technology installations, each capable of carrying out the functions currently performed by both the existing SCC and all four ACCs; and

- connections between both control centres and the Carson ring communications network.

Each EMS provides backup for the other, and the main and backup control centre buildings are geographically separate so that no reasonably conceivable single environmental, accidental, or terrorist event would disable both centres. Both buildings would be built to meet the 2005 building code. The redundant communication system has automatic re-routing of communications if a main trunk path is lost, which ensures uninterrupted control of the power system for many communication contingencies (Exhibit B-1, pp. 4-14, 4-15).

BCTC proposes to operate both control centres routinely (for example, one during nights or weekends) as a way of maintaining the operational readiness of the backup control centre and to reduce cutover time during an emergency. The minimal staff at the back-up centre will routinely perform some of the day-to-day power system control functions, augmenting the staff at the primary site. This staff will operate normally using control consoles connected to the primary computer system. The operating staff required for the operation of the power system will be divided between the control rooms to ensure that sufficient staff with appropriate skills to operate the system in at least a minimal fashion are always available at either centre should the other centre be rendered inoperative. Other activities, such as periodically switching the primary and backup computer systems or moving operations to the backup facility for one or two days, will also be used to ensure the operational readiness of the backup facility (Exhibit B-2, BCUC IR 2.16).

In addition to running primary and backup control centres, BCTC proposes to have remote workstations available at a site (such as an existing office or emergency centre) near the SCC. The purpose of the remote workstation facility is to assist in the transition to the backup control centre, or to handle incidents in which the SCC systems remain functional but staff must evacuate the facility (Exhibit B-1, p. 5-2; Exhibit B-5, BCUC IR 9.1; Exhibit B-5, BC Hydro IRs 4.1 and 4.2).

BCTC considered other options for the configuration of primary and backup control centres, including: status quo through 2016; installing upgraded EMS systems at one or two existing control centres and either new SCADA systems or remote EMS consoles at the remaining ACCs, with further upgrades in time for new main and backup control centres in 2016; a variation on the previous option in which a backup control centre would be built in 2008; a single new control centre with new control technology; and several variations on the option of constructing new main and backup control centres (Exhibit B-1, Section 1.3). BCTC also considered having backup functions provided by the Alberta Electric System Operator, the Bonneville Power Administration, or another control area operator. BCTC rejected these alternate-backup options because of the difficulty in

providing redundant reliable communications connections to the Carson ring and the difficulty of maintaining trained staff at a backup location outside the province (Exhibit B-5, BCUC IR 8.2).

KEMA recommended that BCTC consolidate its distribution and transmission operations into a single primary control centre and establish a staffed backup control centre equipped with the same functional capability as the primary centre, with the centres sufficiently far apart to minimize the possibility of a single catastrophic event simultaneously incapacitating both centres.

BC Hydro commented that there is no information on the record concerning whether a BCC with full long-term functionality on very short notice is required in light of an extremely robust SCC. BC Hydro stated that the proposed SCC would be constructed to withstand a magnitude 9 megathrust subduction earthquake, an event that would probably destroy the rest of the transmission system (Exhibit C1-3, p. 6). The JIESC submitted that consideration should be given to other backup arrangements, including arrangements in other control areas or arrangements with a data centre or service provider (Exhibit E-1, p. 2).

In its final reply (Exhibit B-7, p. 11), BCTC stated that it had addressed BC Hydro's concern about a BCC available on short notice in responses to BCUC IRs 21.1 (Exhibit B-5) and 2.9 (Exhibit B-2). In the former, BCTC stated that the BCC would provide backup for any event (not just seismic events) that could disable the SCC. BCTC also noted in that IR response that the BCC would still be required to operate the power system outside the seismically affected area and oversee temporary supply measures to the affected area during restoration. In response to BCUC IR 2.9 (Exhibit B-2), BCTC noted that a backup control centre is the accepted industry response to meet NERC's Policy 6E and Section 6.E of WECC's Minimum Operating Reliability Criteria, which state that each control area operator and reliability coordinator shall have a plan to continue reliability operations in the event its control centre becomes inoperable.

BCTC noted that it does not expect that the technology within the SCC will survive a significant seismic event in an immediately operable condition, and that communication links to the SCC may be disrupted for hours to days after a seismic event. In addition, other events can occur that result in the need to evacuate the SCC. Accordingly, BCTC submitted that, notwithstanding the robustness of the SCC, there is a need for a fully functional BCC that is available for full system control on short notice (Exhibit B-7, p. 11).

Commission Findings

In Section 3.1.2.1 above, the Commission noted that it is imperative that the facilities and systems that control British Columbia's power system survive, to the greatest extent possible, a significant seismic event. The

Commission also accepts that there are other events, such as those described in the responses to BCUC IRs 2.9 (Exhibit B-2) and 9.1 (Exhibit B-5), that may disable the SCC. **The Commission accepts the rationale set out by BCTC for rejecting the other backup options, and therefore finds that the proposed configuration consisting of a SCC and a staffed BCC is prudent.**

3.2.2 New Construction versus Redevelopment

BCTC's recommended SCMP option proposes the construction of a new, purpose-built SCC in the Lower Mainland and either a new building in the South Interior or an expanded SIC for the BCC (Exhibit B-1, Section 4.6).

BC Hydro stated that BCTC appeared to have given little consideration to using one or more of the existing control centre buildings for the proposed new SCC or BCC. While BCTC had acknowledged that the existing SIC has the potential to be upgraded, the cost-savings of this alternative are not adequately assessed anywhere in the evidence (Exhibit C1-3, p. 6). The JIESC commented that the Commission should require consideration of options other than purpose-built buildings, and that there was no indication that anything else had been considered by BCTC (Exhibit E-1, p. 2).

In its final reply (Exhibit B-7, p. 12), BCTC stated that it is not the case that little consideration had been given to using one or more of the existing control centre buildings. BCTC stated that the existing SCC was not considered because the problems with the site are among the reasons for the SCMP, the LMC was not considered because R. E. Lamb advised against redeveloping it, and the NCC was not considered because it is a small, older control centre that is not on the Carson ring. BCTC further stated that the VIC is in an old building that contains asbestos and equipment with mercury vapour. On the subject of the SIC, BCTC stated that it has been identified as a potential site for the BCC, but cost savings were not identified because expansion would require the purchase of adjacent property, which has not been secured at this time. BCTC also commented that it would consider retrofitting an acquired building other than one of the existing control centres if the opportunity arose and made sense in the circumstances.

Commission Findings

The Commission accepts BCTC's explanation of the reasons that the existing control centres, other than the SIC, are not being considered for the SCC or BCC facilities. The Commission supports BCTC's investigation of options other than new construction, where appropriate.

3.2.3 Building Size and Associated Functions

BCTC's recommended alternative for the SCMP is for the fully staffed new SCC to be built in the Lower Mainland and the minimally staffed BCC to be located in the South Interior (Exhibit B-1, Section 4.6). The SCC will be a new 6000 m^2 building and the BCC will be a new or expanded 4500 m^2 building. The space requirements were determined by Robert E. Lamb, Inc. (Exhibit B-5, BC Hydro IR 5.1). BCTC stated that the functions that are to be carried out in the SCC and the BCC relate to the day-to-day control of the transmission and distribution systems, generation dispatch operations for BC Hydro and Arrow Lakes Hydro, near-term operational transmission planning, training of control centre staff, technology support for the EMS and business systems at the control centre, and telecontrol equipment maintenance associated with the control centre (Exhibit B-5, BC Hydro IR 5.5). The reasons for the additional 1500 m^2 in SCC compared to the BCC were set out in the response to BC Hydro IR 5.4 (Exhibit B-5).

BC Hydro made several comments on the size of the buildings and the functions to be included in each (Exhibit C1-3, p. 5). It compared the proposed 6000 m^2 and 4500 m^2 buildings with the System Coordination Centre of 2500 m^2 proposed by the Alberta Electric System Operator ("AESO"), and stated that the record does not demonstrate why the SCC building proposed by BCTC would need to be approximately two-and-a-half times the size of the AESO building. BC Hydro also submitted that the buildings proposed in the SCMP would include considerable space for administration, conference rooms, record storage, and other support functions, and that the evidence does not demonstrate why the SCC and BCC should be built to accommodate these support functions. BC Hydro also expressed concern that the record does not demonstrate that R. E. Lamb was directed to develop cost-effective alternatives including optimization of existing buildings (including the SIC and BCTC headquarters) or that the most cost-effective alternative was selected (Exhibit C1-3, p. 6).

In its reply to BC Hydro's comments, BCTC stated that (Exhibit B-7, p. 12):

- the SCC is proposed to accommodate certain support functions directly associated with the SCC;
- the proposed conference rooms are appropriate for a facility with over 100 employees that is located a significant distance from BCTC's main office;
- the records storage will contain records needed for the operation of the system;
- the RTU testing and commissioning facilities are located to allow efficient connection and testing with the EMS;

- the training facilities are located to allow shift personnel easy access to training;

- an EMS development room is provided for EMS staff to quickly and efficiently test modifications to the EMS software; and

- the BCC will consist of only those facilities absolutely necessary to the functioning of the BCC as a backup centre rather than a full-time facility.

With respect to the directions given to R. E. Lamb, BCTC stated that it had provided sufficient information in response to BC Hydro IRs 2.1, 5.5, and 5.9 (Exhibit B-5), and that R. E. Lamb's study had been provided to the Commission. BCTC also stated that "BC Hydro has not put forward any evidence on how the proposed SCC or BCC could be made smaller, how they could be constructed for less money, or how they could better utilize the former BC Hydro system control facilities" (Exhibit B-7, p. 13). BCTC also stated that it does not believe there is any comparison between the SCMP and the AESO project in scope, timing, or complexity (Exhibit B-7, p. 10).

Commission Findings

The Commission accepts the evidence of BCTC that the functions to be included at the SCC and the BCC are those desirable to ensure the safe, reliable, and secure operation of British Columbia's power system. It accepts BCTC's comments that direct comparison with the AESO project is not possible. **While the Commission accepts the expertise of R. E. Lamb, Inc., and the evidence that the preliminary designs for the control centres are functional and cost-effective, it directs BCTC to undertake a final review of the building designs to determine if the overall size and cost can be reasonably reduced. A report is to be provided to the Commission by July 1, 2005.**

3.2.4 Control Centre Locations

As noted previously, BCTC's recommended SCMP option includes the construction of a new SCC in the Lower Mainland and the development of a BCC in the South Interior, either as a new building or an expansion of the SIC (Exhibit B-1, Section 4.6). The geographic separation between the SCC and the BCC is to minimize the risk of simultaneous disruption from a single event (Exhibit B-1, p. 1-2).

BC Hydro raised several issues associated with the location of the SCC (Exhibit C1-3, pp. 6 and 7). It noted that ground acceleration design parameters for the Lower Mainland are expected to increase to the range 0.45g to 0.55g, and that the parameters for the South Interior are expected to slightly decrease to the range 0.15g to 0.25g. Consequently, in BC Hydro's submission, if the new SCC were built in the Lower Mainland instead of the less seismically active South Interior, the building construction and control technology would need to be more robust (and therefore more expensive). BC Hydro also submitted that other building and land costs would be less if the SCC were built in the South Interior, and that an intentional attack on a control centre is more likely if it is located in the Lower Mainland. It appeared to BC Hydro that relocating the SCC to the South Interior was rejected based on an employee survey, which should not be accepted as an accurate indication of what BCTC staff would actually do if they were given three or more years' notice that the SCC would be relocated to the South Interior.

In response to BC Hydro's suggestion that an SCC in the Lower Mainland would include incremental costs for more robust technology, BCTC stated that the technology would be the same at both the SCC and the BCC, and that neither BCTC nor KEMA believe it is possible to procure and install technology that will remain operational following a large seismic event. BCTC also stated that air conditioning and many other building costs would be comparable or higher in the South Interior (Exhibit B-7, p. 13). On the question of an intentional attack, BCTC replied that while an attack designed to affect the transmission system is more likely to take place in the Lower Mainland if the SCC is located there, if the SCC is located in the South Interior the attack would take place there. BCTC also noted that having both control centres in the South Interior would make the power system vulnerable to an ice storm affecting the Jarvis and Mission microwave sites. As a result, having one control centre in the Lower Mainland and one in the South Interior has a more favourable hazard rating (Exhibit B-7, p. 14).

Commission Findings

In Section 3.2.1.1 above, the Commission found that a configuration consisting of a SCC and a partially staffed BCC is appropriate for ensuring the ongoing operation of British Columbia's power system following an event that incapacitates a control centre. Further, the Commission accepts BCTC's view that the control centres should be geographically separated, preferably in different seismic zones, to minimize the risk that a single event could disable both control centres.

Based on ground acceleration design parameters, it is clear that the seismic hazard is greater in the Lower Mainland. Therefore, the risk that control of the power system may have to be transferred from the SCC to the BCC may be slightly higher if the SCC is in the Lower Mainland. However, the existence of the BCC in a different seismic zone from the SCC suggests that there is virtually no difference in the risk of losing both control centres, and therefore no difference in the overall seismic risk to BCTC's ability to control the power system, whether the SCC is in the Lower Mainland or the South Interior. **Since the evidence suggests that there is no clear cost advantage for one location over the other, and given that BCTC has concerns about employee retention if the SCC were to be located in the South Interior, the Commission finds that having the SCC in the Lower Mainland and the BCC in the South Interior is appropriate.**

3.3 Cost/Timing of Project

In response to BCUC IR 3.1 (Exhibit B-2), BCTC provided a detailed cost estimate of the project for each of the major components, in confidence. The total cost is estimated at $133 million. The project is scheduled for completion in 2008.

In its submission (Exhibit C1-3, p. 1), BC Hydro argued that BCTC has failed to demonstrate that the proposed SCMP is necessary now or that it is the most cost effective proposal. BC Hydro also argued that the cost of maintaining the present EMS is relatively small (Exhibit C1-3, p. 2), and concluded that BCTC should reassess its options with a view to deferring the project and configuring it in a less costly way.

In reply BCTC argued that the costs of sustaining the current EMS are incremental to the final solution and do not mitigate any risks associated with continuing to run the current system (Exhibit B-7, p. 4). BCTC also argued that a decrease in reliability will be the expected consequence of continued operation of the present EMS system (Exhibit B-7, p. 5). BCTC also noted that the difference in present values between Options 4 and 6a is only $12 million.

Commission Findings

The Commission notes that BC Hydro agrees that the present EMS system is aging and will need to be replaced eventually (Exhibit C1-3, p. 2). However, BC Hydro suggests that there is no need for a complete backup to the present system and that a new EMS system can be delayed for some time (Exhibit C1-3, pp. 2, 3).

The Commission believes that the fundamental difference of opinion as to when it is appropriate for a new system to be developed largely turns on the amount of risk that the users of the system are willing to assume for the benefit of deferred costs. In response to BCUC IR 2.3 (Exhibit B-2), which asked what cost would be incurred if BCTC failed to meet any of its objectives, BCTC stated that the financial impact of a single-day outage could be in the order of $40 million and that a system blackout could have much larger societal consequences. In addition, BCTC has stated that the longer it has to manage the present system, the greater the risks of problems occurring become. In response to BCUC IR 1.10, 4.6 and 9.1 (Exhibit B-2), BCTC described a number of incidents and problems occurring with the present system which highlight the potential risks the system faces at present. The application describes a number of options which would defer costs. In particular, Option 1 would delay all replacement of the EMS and construction of new buildings until 2016. The difference in NPV costs between this option and Option 6a, which would see the replacement of the EMS and construction of new buildings in 2008 is approximately $19 million. The Commission believes that the additional risk and the foregone opportunity to create added value and efficiency, in particular occurring at a time of increasing change in the use of the system by user groups, does not justify the potential saving. **The Commission therefore approves the recommended Option 6a, with an in-service date of 2008.**

3.4 Project/Risk Management

BCTC proposes to establish a project management office to provide a focal point for a project management team and has established a project management structure as illustrated by the organization chart provided in response to BCUC IR 7.11 (Exhibit B-2). BCTC has also established an overview responsibility matrix to define the various levels of responsibilities within the project team (Exhibit B-5, BCUC IR 15.1). BCTC anticipates a project management plan will be completed following an approval of the CPCN application and it will contain the objectives and scope of the project, a risk management plan, schedules, a quality assurance plan, the organization of the project team, and reporting and communication requirements (Exhibit B-2, BCUC IRs 7.7, 7.10).
In response to BCUC IRs 7.17 and 7.16 (Exhibit B-2), BCTC provided a Risk Management Plan and the latest report to BCTC's executive. This information was provided in confidence to the Commission to protect

commercial sensitivities; however, the Commission believes that the reports demonstrate a high commitment to project control and risk mitigation.

BCTC has stated that although there are no financial or profit-motivated corporate incentives for cost control, individual performances to contain costs will be part of employee bonus incentives (Exhibit B-2, BCUC IR 3.5; Exhibit B-5, BCUC IRs 3.1, 13.2, 13.3). In response to BCUC IR 3.6 (Exhibit B-2) BCTC proposed a quarterly report to the Board and to the BCUC. The report would include:

- Fiscal performance at a Major Project Element level (e.g., EMS, Control Centre Facilities, Telecommunications, Operations Transition) reviewing actual costs to date, commitments, and forecast-to-completion costs for each element;
- Performance against schedule including general progress and exception reporting;
- Significant milestones achieved during the most recent quarter and those scheduled for the following quarter;
- Exception Issues; and
- An updated Risk Management Watch Summary.

Commission Findings

The Commission accepts that the above level of quarterly reporting to the Commission will be appropriate.