6.0 SUSTAINING CAPITAL PORTFOLIO

PRE-FILED EVIDENCE OF LARRY HAFFNER, MANAGER, ASSET PROGRAM DEFINITION

In the F2009 TSCP Decision, the Commission approved Sustaining Capital expenditures of $105 million and $107 million for F2009 and F2010, respectively. In response, BCTC has reduced its planned Sustaining Capital expenditures for F2009 to the approved level by deferring some projects to F2010 or beyond and by changing the scope or timing of others, as discussed in Section 6.3.1.1.1. BCTC would also be able to meet the approved F2010 Sustaining Capital funding levels through the deferral or cancellation of additional projects as described in Section 6.3.1.1.2.

While the deferral of projects is a feasible short-term means of reducing Sustaining Capital expenditures, following this approach in the long-term will create a growing backlog of Sustaining Capital projects and programs, which will significantly increase risks to the reliability of the system, and other risks such as life-safety, environment, extreme weather, seismic, fire, and security. The nature and effect of this backlog is discussed below and illustrated in Figure 6-1. As the risks to reliability increase, the system will see increased deterioration of equipment performance, increased corrective and emergency repair and thus increased outages to customers. BCTC believes that these deferred projects will eventually have to be addressed under the Sustaining Capital portfolio on an expedited basis to restore reliability to reduce risk, or as emergency repairs. Further, BCTC believes that if Sustaining Capital activity is not addressed in a planned and prioritized manner, this will ultimately result in higher costs and more significant outages for customers.

In summary, BCTC believes that continuing at the current level of expenditures presents unacceptable risks to the transmission system at a higher cost. BCTC is therefore respectfully requesting approval of a Sustaining Capital program that will avoid a backlog of Sustaining Capital activities and that will result in safe, reliable, and secure transmission service at predictable levels of spending.

Using the amounts approved in the Commission's F2009 TSCP Decision as a baseline, BCTC believes this Sustaining Capital plan includes appropriate evidence related to asset reliability, risks and Third Party requested activity to justify the identified increase in Sustaining Capital expenditures to $119.0 million in F2010 and $122.3 million in F2011. Accordingly, BCTC is respectfully requesting a $12 million increase to the currently allowed Sustaining Capital expenditures of $107 million for F2010, and a further $3.3 million increase in F2011, which is primarily to address approved inflation of $2.5 million. BCTC considers the requested expenditures necessary to maintain the transmission system to acceptable levels of reliability, safety, and environmental performance, and is consistent with BCTC's Sustainment Investment Model.

The Sustaining Capital portfolio includes capital for sustaining existing assets, risk mitigation programs, and Third Party requested projects. In preparing the Sustaining Capital portfolio, BCTC uses a bottom-up approach to identify specific asset issues and risks that must be addressed (see Section 4.4.3.1.1). BCTC also uses a top-down approach to understand the longer-term trends in asset health and end of life asset expectations considering reliability-centred maintenance impacts (see Section 4.4.3.2). By combining these approaches, BCTC ensures that the highest priority work is addressed, while planning this work in a strategic context which considers impact to ratepayers, resource management, and opportunities to align system Sustaining Capital projects with Growth projects with the objective of maximizing value to the transmission system.

The requested Sustaining Capital expenditure levels for F2010 and F2011 are supported by a number of programs and projects outlined in Section 6.5. These programs are developed from an analysis of the assets that require attention in the next 2-year planning period, and are aligned with the results of the top-down planning approach discussed above. The Sustaining Capital portfolio is therefore designed to address the assets that are most likely to fail, to ensure that, in the short-term, assets are replaced or refurbished just prior to failure. These assets are then grouped into programs and prioritized to determine the Sustaining Capital portfolio. The prioritization model assists BCTC in determining when to replace or refurbish the assets in a manageable and sustainable manner to ensure the assets that need replacement due to end of life condition are addressed and do not negatively impact the transmission system.

BCTC also has to determine if the amounts requested in the short-term are adequate for the long-term management of the transmission assets and match the long-term trends in asset deterioration being experienced on the transmission system; in other words, attempting to ensure that the level of Sustaining Capital investment is appropriate for the long-term health of the transmission system. To understand those long-term trends in assets reaching end of life condition, BCTC has developed, and continues to enhance, a Sustainment Investment Model which is based on an analysis of asset survival curves determined from the past performance of assets. The Sustainment Investment Model shows a significant increase in end-of-life asset condition that is driving higher capital investment in future periods. Given these increasing future needs, BCTC believes that it is particularly important to continue to adequately address current Sustaining Capital issues to attempt to avoid resource-related constraints, potential increased costs and larger than necessary future increases in the level of Sustaining Capital expenditures.

Figure 6-1, which is also produced in Section 3.6.5, indicates the required level of Sustaining Capital expenditures needed to meet the expected asset replacement or refurbishment as predicted by the Sustainment Investment Model. In reviewing Figure 6-1, it should be noted that, as discussed in Section 3.6.4, the Sustainment Investment Model only considers the Sustaining Capital activity necessary to meet the forecast replacement or refurbishment of assets to maintain the transmission system at or near its designed reliability. However, the overall approved and planned Sustaining Capital expenditures include requirements beyond the asset replacement or refurbishment needs predicted by the Sustainment Investment Model, including risk-related capital requirements, Third Party requested projects and emergency capital expenditures.

Figure 6-1 also compares the results of the Sustainment Investment Model to the F2010 TSCP 10-year forecast Sustaining Capital expenditures and the Sustaining Capital expenditures based on the approved levels in the F2009 TSCP Decision, inflated at BC CPI.

Figure 6-1. Cumulative Sustaining Capital Requirements

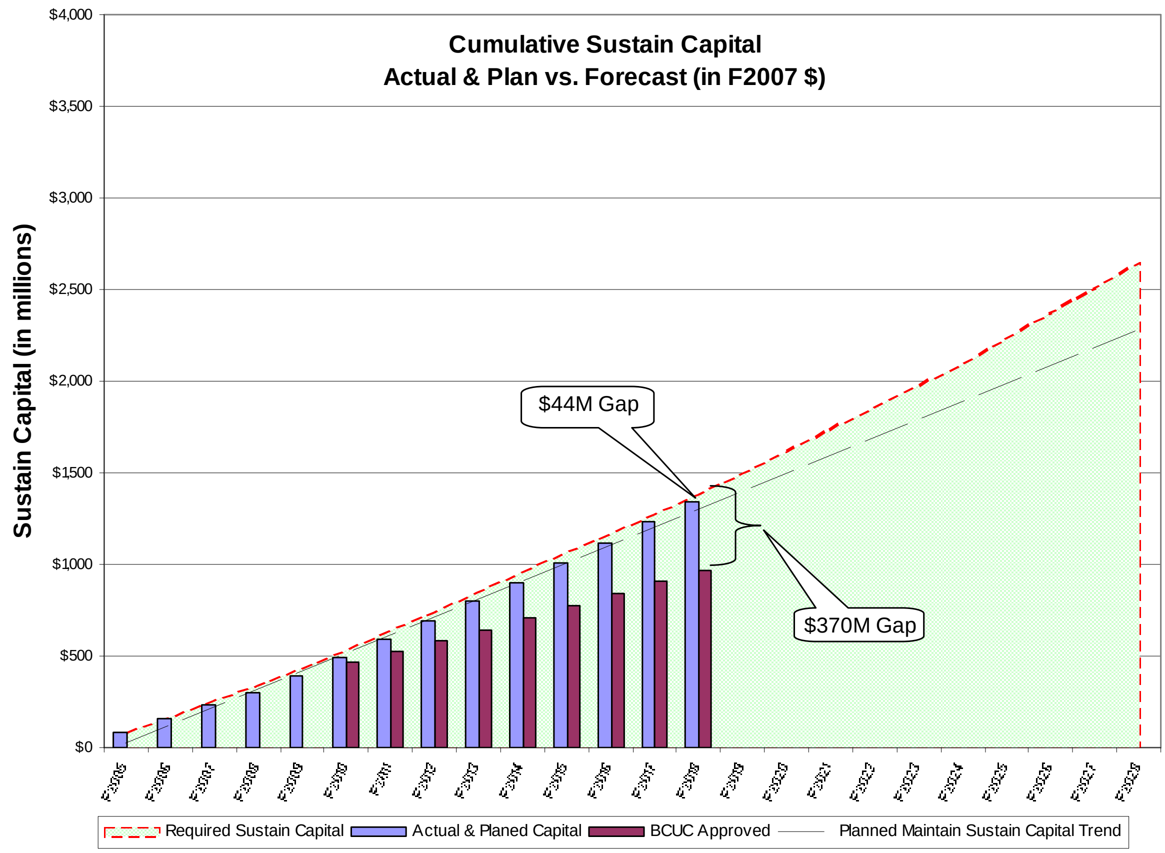


Figure 6-1 shows a projected $44 million cumulative shortfall (backlog of asset replacement or refurbishment capital work) by F2018 between the expenditures predicted by the Sustainment Investment Model and BCTC's current 10-year forecast of Sustaining Capital expenditures. BCTC believes that this shortfall is within the level of forecast error, and provides comfort that the Sustaining Capital expenditures forecast in this TSCP are appropriate and required. However, it should also be emphasized that the forecast amount over the 10-year planning period includes a provision for other risk-related projects and Third Party requests, whereas the required capital expenditures predicted by the Sustainment Investment Model does not include these categories of expenditures.

Figure 6-1 also shows that, even ignoring risk-related, Third Party and emergency expenditures, the cumulative backlog of replacement or refurbishment Sustaining Capital activity would grow to approximately $370 million by F2018 if the Sustaining Capital expenditures were held to the F2009 approved level, adjusted for inflation over the 10-year period. As a result, BCTC submits it will be facing a backlog of Sustaining Capital work that will result in a significant increase in assets reaching end of life that BCTC will be unable to address efficiently – or, depending on funding levels, may not be able to be addressed at all - resulting in the transmission system operating at a higher level of risk than what BCTC believes is acceptable, and resulting in higher cost. BCTC also believes that the magnitude of risks that materialize due to the deferral of projects may result in the need for more projects than BCTC is able to complete in time to maintain transmission system reliability because of resource availability, availability of long lead time equipment, and the availability of system outages to accommodate asset replacement without impacting service to customers.

BCTC uses a number of tools and methods to support data collection, synthesis, and analysis to enable efficient and effective Sustaining Capital planning. Some examples of tools that are used include: Indus Passport (asset management system for Stations); Oracle and STARR (asset management for lines and cables); IMAX (data collection system); DOBLE (analysis of insulation testing results); LabSys (gas in oil analysis); and Meridium (asset performance analysis). The tools that are used are supported by industry-recognized analysis methodologies including Present Value (financial justification), Mean Time Between Failure (asset performance analysis), Asset Health Assessments (asset condition), and Root Cause Analysis (asset failures). In addition to the above, BCTC also relies on its accumulated experience, industry standards and practices, and manufacturer recommendations in deciding to proceed with any given project. The specific tools and methods that are used to identify proposed transmission infrastructure capital investments are specific to each case.

To provide the Commission with a better understanding of the analysis undertaken before proposing a particular project, BCTC has provided two case studies that set out its decision-making process to replace, refurbish or enhance existing system assets or address risk-related issues. The first case study, found in Appendix D-1, demonstrates the decision-making process to replace the existing 230 kV double pressure SF6 circuit breakers as an example of a replacement driven by poor asset health which is resulting in reliability and environmental concerns. The second case study, included as Appendix D-2, is an example of an analysis used to address risk-related system impacts. This case study addresses the risk associated with the build-up of ice on transmission lines and the risk of tower failure along critical transmission circuit corridors that provide transmission service to the Lower Mainland and Vancouver Island. Although BCTC undertakes similar analyses to support the other projects put forward in this TSCP, the same level of narrative is not generally prepared.

In developing the F2010 to F2019 Sustaining Capital plan, in addition to some of the top-down issues discussed above, BCTC considered the following key drivers:

(a) A large number of circuit breakers originally installed in the mid-1960's were refurbished in the early 1990's. This took place as an urgent remedy to a maintenance backlog that arose as a result of insufficient funding of maintenance programs over a long period. This action resulted in creating a large number of assets that are now reaching end of life conditions at the same time and, as a result, now all require capital investment which needs to be completed by F2015 (see Section 6.5.2.2).

(b) Transmission cable assets that were installed in the 1960s are now reaching end-of-life condition, having deteriorated through use and age. These assets require attention in this TSCP, and will require even higher investment levels in the long-term. Examples include the Cable Refurbishment Program (see Section 6.5.7.2.4).

(c) All existing assets will require programs to address end-of-life condition and programs will also have to be developed to address issues where the full program has yet to be defined, including programs associated with spacer dampers, bridges, access roads, corrosion, and other known risks. As an example, there is approximately three-hundred thousand spacer dampers located mid-span on transmission lines that have deteriorated and now have the potential of causing serious damage to the transmission line conductors. These will require replacement within the next decade and BCTC has a program to address the replacement of spacer dampers starting in F2010 and continuing over the 10-year planning period. The full scope of these projects and the impact they will have on the TSCP in future years is unknown at this time.

(d) BCTC has identified a number of other risks that threaten the integrity of the transmission system including life-safety, environment, extreme weather, fire, seismic, and security hazards. These risks need to be addressed to enable the transmission system to provide long-term safe, reliable, and secure service.

BCTC believes that without adequate funding, the above issues cannot be adequately addressed, resulting in the continued deferral of important and required projects that provide for the safe, reliable operation of the transmission system, and present an unacceptable level of risk to the system and stakeholders. BCTC prioritizes its projects such that the most important projects always get done. As a result, other required but currently less critical programs and projects are deferred with the result that system risk increases incrementally over time. This risk to the transmission system of continued deferral of important projects is difficult to quantify, but is cumulative. The level of risk will not be apparent until the transmission system is in a critical state because each year, the level of risk increases only marginally with further project deferrals.

Notwithstanding the request for additional funding, as mentioned above, BCTC has closely considered the Commission's approved funding level and, to attempt to reduce Sustaining Capital expenditures as far as it considers reasonable, BCTC has closely reviewed and reprioritized the overall Sustaining Capital expenditures. As a result of these efforts, some projects have been reduced in scope, some have been cancelled and some have been postponed indefinitely. Therefore, the Sustaining Capital plan put forward for F2010 and F2011 assumes more risk of equipment and risk-related events than the proposed funding levels in last year's TSCP.

6.1 Sustaining Capital Portfolio Table

For planning and management purposes, the Sustaining Capital portfolio is divided into 11 programs:

(a) Stations:

i. Auxiliary Equipment;

ii. Circuit Breakers;

iii. Other Power Equipment;

iv. Stations Risk Mitigation;

v. Protection and Control; and

vi. Telecommunications.

(b) Lines:

i. Cable Sustainment;

ii. Overhead Lines Life Extension;

iii. Overhead Lines Performance Improvements;

iv. Overhead Lines Risk Mitigation; and

v. Right-of-Way Sustainment.

Table 6-1. Sustaining Capital Portfolio

Sustaining Capital Portfolio $'000 (Escalated) STATIONS	Page	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)	F2019 ($'000)
Auxiliary Equipment											
For Approval											
Annual Program		7,450	7,261								
Future Program				8,133	7,787	7,952	8,686	8,291	8,466	8,645	8,828
Total for Auxiliary Equipment		7,450	7,261	8,133	7,787	7,952	8,686	8,291	8,466	8,645	8,828
Circuit Breakers											
For Approval											
Annual Program		28,430	37,976								
Future Program				32,133	27,710	30,511	31,152	37,011	37,788	38,582	39,392
Total for Circuit Breakers		28,430	37,976	32,133	27,710	30,511	31,152	37,011	37,788	38,582	39,392
Other Power Equipment											
For Approval											
Annual Program		8,901	6,358								
Future Program				4,251	5,326	777	5,324	5,436	5,550	5,667	5,786
Total for Other Power Equipment		8,901	6,358	4,251	5,326	777	5,324	5,436	5,550	5,667	5,786
Protection and Control											
For Approval											
Annual Program		14,131	10,931								
Third Party Requested Projects		2,575	1,778								
Future Approval											
Annual Program				11,124	15,531	16,024	17,977	18,253	19,372	10,950	11,180
Third Party Requested Projects				1,831	1,886	1,943	2,001	2,061	2,123	2,186	2,252
Total for Protection and Control		16,706	12,709	12,955	17,417	17,967	19,978	20,314	21,495	13,137	13,432
Risk Mitigation											
For Approval											
Annual Program		7,137	7,408								
Future Program				8,442	9,793	8,889	9,076	9,267	9,461	9,660	9,863
Total for Risk Mitigation		7,137	7,408	8,442	9,793	8,889	9,076	9,267	9,461	9,660	9,863
Telecommunications											
For Approval											
Annual Program		5,373	4,409								
Future Program				7,434	7,754	6,587	5,339	5,525	5,674	5,802	4,778
Total for Telecommunications		5,373	4,409	7,434	7,754	6,587	5,339	5,525	5,674	5,802	4,778
TOTAL Stations		**73,997**	**76,121**	**73,348**	**75,787**	**72,683**	**79,555**	**85,843**	**88,434**	**81,492**	**82,078**

Table 6-1. Sustaining Capital Portfolio Table (continued)

TRANSMISSION									
Cable Sustainment									
For Approval									
Annual Program	5,254	4,852							
Future Program			6,501	5,655	16,373	16,765	17,166	27,024	45,729
Total for Cable Sustainment	5,254	4,852	6,501	5,655	16,373	16,765	17,166	27,024	45,729
OH Lines Life Extension									
For Approval									
Annual Program	16,017	16,366							
Future Program			18,440	20,044	23,260	24,100	26,115	25,588	26,359
Total OH Lines Life Extension	16,017	16,366	18,440	20,044	23,260	24,100	26,115	25,588	26,359
OH Lines Performance Improvement									
For Approval									
Annual Program	4,793	2,145							
Future Program			2,362	1,216	1,253	1,291	1,329	1,369	1,410
Total OH Lines Performance Improvement	4,793	2,145	2,362	1,216	1,253	1,291	1,329	1,369	1,410
OH Lines Risk Mitigation									
For Approval									
Annual Program	8,663	12,637							
Future Program			13,783	14,041	11,017	10,622	11,474	11,796	12,557
Total for OH Lines Risk Mitigation	8,663	12,637	13,783	14,041	11,017	10,622	11,474	11,796	12,557
Right-of-Way Sustainment									
For Approval									
Annual Program	8,129	7,914							
Third Party Requested Projects	2,191	2,235							
Future Approval									
Annual Program			9,195	9,494	9,798	10,116	10,442	10,780	11,264
Third Party Requested Projects			2,282	2,330	2,379	2,429	2,480	2,532	2,585
Total for ROW Sustainment	10,320	10,149	11,477	11,824	12,177	12,545	12,922	13,312	13,849
TOTAL Transmission	**45,048**	**46,149**	**52,563**	**52,780**	**64,080**	**65,323**	**69,006**	**79,089**	**99,904**
TOTAL SUSTAINING PORTFOLIO	**119,045**	**122,271**	**125,910**	**128,567**	**136,763**	**144,878**	**154,849**	**167,523**	**181,397**
Future CPCN									
Murrin - Substation Reconfiguration and Seismic Upgrade	**-**	**3,127**	**5,321**	**16,300**	**27,738**	**22,656**	**-**	**-**	**-**

6.2 Historical and Trend Explanations

Table 6-2. Sustaining Capital Portfolio History and Trends

	Sustaining Capital Portfolio ($M)	Actual* F2006	Actual F2007	Actual F2008	Forecast F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
	Stations														
1	Auxiliary Equipment	5.3	5.2	3.3	7.3	7.4	7.3	8.1	7.8	8.0	8.7	8.3	8.5	8.6	8.8
2	Circuit Breakers	17.3	11.6	25.7	24.0	28.4	38.0	32.1	27.7	30.5	31.2	37.0	37.8	38.6	39.4
3	Other Power Equipment	1.3	5.5	3.0	4.0	8.9	6.4	4.3	5.3	0.8	5.3	5.4	5.6	5.7	5.8
4	Protection and Control	8.7	7.7	5.2	10.9	16.7	12.7	13.0	17.4	18.0	20.0	20.3	21.5	13.1	13.4
5	Risk Mitigation	4.9	5.2	5.8	8.2	7.1	7.4	8.4	9.8	8.9	9.1	9.3	9.5	9.7	9.9
6	Telecommunications	10.8	8.3	7.2	7.3	5.4	4.4	7.4	7.8	6.6	5.3	5.5	5.7	5.8	4.8
7	**TOTAL Stations**	48.3	43.5	50.3	61.6	74.0	76.1	73.3	75.8	72.7	79.6	85.8	88.4	81.5	82.1
	Transmission														
8	Cable Sustainment	6.4	2.9	2.6	5.0	5.3	4.9	6.5	5.7	16.4	16.8	17.2	27.0	45.7	55.3
9	OH Lines Life Extension	16.1	20.1	13.9	13.9	16.0	16.4	18.4	20.0	23.3	24.1	26.1	25.6	26.4	26.9
10	OH Lines Performance Improvement	5.0	6.4	3.4	4.5	4.8	2.1	2.4	1.2	1.3	1.3	1.3	1.4	1.4	1.4
11	OH Lines Risk Mitigation	6.4	6.0	5.4	9.4	8.7	12.6	13.8	14.0	11.0	10.6	11.5	11.8	12.6	13.0
12	Right-of-Way Sustainment	5.5	9.8	6.9	16.8	10.3	10.1	11.5	11.8	12.2	12.5	12.9	13.3	13.8	14.1
13	**TOTAL Transmission**	39.4	45.4	32.3	49.6	45.0	46.1	52.6	52.8	64.1	65.3	69.0	79.1	99.9	110.7
14	**TOTAL SUSTAIN PORTFOLIO (a)**	**87.7**	**88.8**	**82.5**	**111.2**	**119.0**	**122.3**	**125.9**	**128.6**	**136.8**	**144.9**	**154.8**	**167.5**	**181.4**	**192.8**
15	**Adjustment for Inflation**	5.6	3.8	1.7	-	(2.4)	(5.0)	(7.6)	(10.3)	(13.5)	(17.0)	(21.0)	(25.7)	(30.9)	(36.2)
16	**TOTAL SUSTAIN PORTFOLIO (a)*(b) (in constant F2009 $)**	**93.3**	**92.6**	**84.3**	**111.2**	**116.6**	**117.3**	**118.3**	**118.3**	**123.3**	**127.9**	**133.9**	**141.9**	**150.5**	**156.6**
17	**Annual Inflation Rate****	2.0%	2.0%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%	2.1%
18	**Adjustment Factor (F2009 Base) (b)**	106%	104%	102%	100%	98%	96%	94%	92%	90%	88%	86%	85%	83%	81%

Emergency Capital Projects and Third Party Funded Projects Included Above

	Commission Category	Actual F2006	Actual F2007	Actual F2008	Forecast F2009	Forecast F2010	Project Name	BCUC Approval
19	Circuit Breakers	0.2	-	-	-	-	Walters 230kV CB Replacement of B2B2 230 kV Circuit Breaker	L-70-05
20	Other Power Equipment	0.2	2.5	-	-	-	Selkirk - T1B Emergency Replacement	L-70-05
21	Circuit Breakers			0.4	0.0	-	BUT 2CB1 Failed Circuit Breaker Replacement	
22	Circuit Breakers			1.1	0.3	-	3CB1 & 3CB2 - Circuit Breaker Replacement at Rosedale - (Emergency)	
23	Circuit Breakers			0.1	0.3	-	CKY 2CB10 Failed Cricuit Breaker Replacement - (Emergency)	
24	Circuit Breakers			0.0	0.3	-	Keogh - Replace 1CB8 and Install 1SA22 an d1SA24 - (Emergency)	
25	Circuit Breakers			0.4	0.1	-	MIN 2CB5 Failed Circuit Breaker Replacement	
26	Circuit Breakers			-	0.4	0.7	Kootenay Canal (KCL) & Barlow (BLW) 230kV CB Replacements - (Emergency)	
27	**Emergency Capital Projects Subtotal**	**0.4**	**2.5**	**2.1**	**1.4**	**0.7**		
28	Third Party Funded Projects (CIA)	**0.6**	**4.9**	**1.7**	**6.5**	**2.2**	Various Projects with Third Party Contributions	
29	**Total**	**1.0**	**7.4**	**3.8**	**7.9**	**2.9**		

* Sustain F2006 Actuals adjusted for misapplied accrual of $1.1M
** F2006 to F2007 Source: Statistics Canada Electric Utility Construction Price Indexes. For F2008 onwards, rates are based on BC CPI rates as issued by BC Ministry of Finance

Table includes a forecast of F2009 and F2010 Emergency Capital expenditures for Circuit Breaker Replacements at Rosedale, Cheekeye, Keogh, and Minette substations. Although these are shown as forecast expenditures, these are all fully committed and will be incurred in F2009. The circuit breaker replacements at Kootenay Canal forecast in F2010 are also fully committed and will be incurred in F2010.

Table 6-2 lists the historical and proposed Sustaining Capital investments for the period F2006 to F2019. The general trend in Sustaining Capital expenditures is discussed below. Specific changes for F2010 and F2011 are discussed in Section 6.3 and Section 6.5.

BCTC is forecasting Sustaining Capital expenditures to increase from $111.2 million in F2009 (including emergency capital and Third Party requested initiatives) to $192.8 million by F2019. The most significant year-over-year program level changes are as follows:

(a) A short-term increase in the Circuit Breaker program will address the major overhaul required for the Horsey Gas Insulated Switchgear (GIS), which is planned for implementation in F2010 and F2011. This station is a transmission source for downtown Victoria and the project will address end of life condition issues for Horsey GIS assets, along with addressing environmental concerns with leaking SF6 gas. There is a longer term increase in the Circuit Breaker program to address additional assets that are reaching end of life. Currently, work is focused on the 500 kV Air-blast Circuit Breakers that are expected to reach end of life by F2016. In subsequent years, other asset classes will be replaced to address specific asset health issues.

(b) An increase arising from the implementation of the Murrin Substation Reconfiguration and Seismic Upgrade Project (Risk Mitigation) beginning in F2011 and completing in F2016. This project will replace four end-of-life 230 kV circuit breakers as well as other assets nearing end-of-life condition. The reconfiguration and upgrade work will also reduce the supply risk in the Vancouver area following a seismic event. This project is being coordinated with BCTC's overall Metro Vancouver Supply Plan and will be the subject of a separate CPCN application.

(c) An increase in the SCADA Remote Terminal Unit (RTU) program over the ten-year period in order to accelerate the program. This program is driven by a need to provide enhanced operational visibility and control of the substations from control centres. These RTU's are at end of life and are now obsolete.

(d) Increasing expenditures to address overhead line components as more classes of assets associated with overhead lines reach end of life. This program will address end-of-life components including wood poles, lattice steel towers and spacer dampers, and will extend the life of steel towers by applying corrosion protection.

(e) A planned increase arising from the addition of a cable replacement program planned to start in F2014. It is expected that end-of-life cable issues will become prevalent and replacements will be based on failures.

6.3 Changes from Previous Plan

Table 6-3 provides a breakdown of the Sustaining Capital funding level based on Commission Order G-107-08. Table 6-3 also shows expected Third Party requested projects, and additional funding proposed in F2010 and F2011 compared to previous TSCP approvals.

Table 6-3. Reconciliation of F2010 Sustaining Capital Plan Portfolio Expenditures to Approved F2009 Level

	Sustaining Capital Portfolio ($M)	**F2010**	**F2011**	**F2012**	**F2013**	**F2014**	**F2015**	**F2016**	**F2017**	**F2018**	**F2019**
1	F2010 level - per G-107-08*	102.2	103.1	103.1	103.0	103.0	103.0	103.0	103.0	103.0	102.9
2	Third Party Requested Projects (unescalated)	4.8	3.9	3.9	4.0	4.0	4.0	4.0	4.0	4.0	4.1
3	Other changes in work	9.6	10.3	11.3	11.3	16.3	20.9	26.9	34.9	43.5	49.6
4	**Subtotal Sustain Portfolio before Inflation**	**116.6**	**117.3**	**118.3**	**118.3**	**123.3**	**127.9**	**133.9**	**141.9**	**150.5**	**156.6**
5	Adjustment for Inflation $ (from F2009)**	2.4	5.0	7.6	10.3	13.5	17.0	21.0	25.7	30.9	36.2
6	**F2010-2019 Capital Plan**	**119.0**	**122.3**	**125.9**	**128.6**	**136.8**	**144.9**	**154.8**	**167.5**	**181.4**	**192.8**

* Order G-107-08 Directive 4 states that Sustaining Capital Portfolio budget is $107.0 million for the F2010 Sustaining Capital expenditures, expressed in nominal dollars and including Third-Party requested and funded expenditures

** For F2008 onwards, rates are based on BC CPI rates as issued by BC Ministry of Finance

6.3.1 Explanation for Variance from F2009 Sustaining Capital Portfolio

In this Application, BCTC is seeking approval of forecast Sustaining Capital expenditures of $119.0 million in F2010 and $122.3 million in F2011. BCTC considers these amounts to be appropriate, prudent, and required to manage the transmission system reliability risks, other risks, and Third Party requests. These amounts are also consistent with the forecast annual Sustaining Capital expenditures predicted by the Sustainment Investment Model which is derived from asset survival curves and is the basis for establishing the long-term trend for the Sustain Capital envelope of expenditures. The following section describes the requested expenditure level, reconciled to the Commission's directives on inflation adjustment, and how programs and projects have been adjusted to align with this long-term trend.

6.3.1.1 Plan-over-plan Analysis

In the F2009 TSCP Decision, the Commission approved the suite of Sustaining Capital programs described in the BCTC F2009 TSCP, subject to a reduction in overall expenditure levels. BCTC believes that the most appropriate means of reviewing the F2010 Sustaining Capital portfolio is to compare it to the programs and projects included in the previously-approved F2009 TSCP, and to understand the changes that result from the approved expenditure levels, changing risk environments, and safety and reliability concerns related to the transmission system.

6.3.1.1.1 Forecasted F2009 Sustaining Capital Expenditure vs Commission Approved F2009 Funding Level

BCTC is forecasting Sustaining Capital expenditures for F2009 of $105 million (excluding increases in Third Party requested initiatives and emergency capital), which is consistent with the Commission approved funding level for that year.

To meet the Commission approved expenditure level, BCTC prioritized the F2009 Sustaining Capital work plan. To ensure actual expenditures for F2009 would be at or near the approved funding level of $105.0 million, BCTC reviewed all Sustaining Capital projects planned for F2009 and determined which of those projects could be partially or fully deferred to F2010 or future periods. This process identified that it was not economical to defer a number of projects as some commitments were already made, or work was currently underway, at the time of the Commission's Decision. Therefore, BCTC determined that the following projects provided an opportunity to manage Sustaining Capital activity levels in F2009, and were appropriate to defer from F2009 to F2010 or beyond, which enabled BCTC to accommodate the Commission approved Sustaining Capital funding level:

(a) Cathedral Square – Relocation of 2L31/2L32 Line Terminations. The Cathedral Square CO2 fire suppression system was redesigned resulting in a portion of planned activity for F2009 being cancelled, and the remainder of the planned activity being deferred to F2012 or later. The immediate life safety risks associated with this project were addressed through an SDA project in F2009. The fire hazard related to the cables terminations for circuits 2L31 and 2L32 have been addressed through a design change in the fire protection system in the GIS room;

(b) Murrin Substation Reconfiguration and Seismic Upgrade – The Murrin Seismic Upgrade Project has been deferred beyond F2011 and, due to the size and complexity of the project, will be the subject of a separate CPCN application;

(c) Chapman's Fibre Optic Cable Replacement – BCTC deferred a portion of the planned construction project from F2009 to F2010 due to winter construction constraints (i.e., construction has to occur during late spring and summer months in the higher elevations);

(d) VIT SC3 and SC4 Overhaul – BCTC was able to defer the VIT SC3 and SC4 overhaul project from F2009 to F2010, as the project had not been initiated at the time the F2009 TSCP approval was issued;

(e) Programmable Logic Controller Replacement – BCTC was able to reduce the activity level in F2009, partially deferring work that was scheduled for F2009 to F2010;

(f) Voltage and VAR Optimization project – This Third Party (BC Hydro) Requested initiative has been partially deferred from F2009 to F2010 to accommodate the approved F2009 funding level; and

(g) Protection & Control Replacement project - BCTC was able to reduce the activity level in F2009, partially deferring work that was scheduled for F2009 to F2010.

6.3.1.1.2 Proposed F2010 Sustaining Capital Expenditure vs Commission Approved F2010 Funding

For F2010, the proposed Sustaining Capital expenditure is $119 million, which is $12 million higher than the Commission approved funding level of $107 million. The requested increase is in part to accommodate the funding of projects that were partially or fully deferred from F2009 to F2010 to meet the Commission approved funding level of $105 million. In addition, the proposed F2010 capital expenditures includes a provision to address increased activity levels for previously approved projects and new projects required to address issues identified during F2009 that were not included in the F2009 TSCP.

In developing the F2010 and F2011 Sustaining Capital portfolio, BCTC's prioritization process considered the overall population of projects and ranked the projects in order of priority for completion in any given period. The results of the prioritization process established the proposed F2010 portfolio of Sustaining Capital projects and the proposed expenditure level of $119 million, inclusive of Third Party requested initiatives and emergency capital.

The proposed additional expenditure of approximately $12 million above the Commission approved funding level of $107 million is primarily due to deferred projects from F2009 to F2010 totaling approximately $5 million; an increase in funding of approximately $2.3 million for the acceleration of the Circuit Breaker Replacement program; and, an additional amount of approximately $5 million to address new high-priority projects that were identified during F2009 and are proposed for initiation in F2010 and F2011.

BCTC recognizes and respects that the Commission has approved funding for F2010 of $107 million. Although BCTC is proposing Sustaining Capital expenditures of $119 million, BCTC has completed a scenario analysis of the Sustaining Capital portfolio at the Commission approved $107 million funding level. The results of this scenario analysis are shown in Table 6-4 where projects have been identified that could be partially or fully deferred to F2011 or future periods. In general, these are risk-related projects which address other risks such as life-safety, environment, extreme weather, seismic, fire, and security.

Table 6-4. Projects to be Considered for Deferral to F2011 to Meet $107.0 Million Approved Capital Expenditures for Sustain Capital Portfolio in F2010

	Project Description	Section Reference
1	Stations:	
2	Telecom Fire Protection	6.5.6.2.5
3	Oil Spill Containment	6.5.4.2.1
4	Gravel Replacement	6.5.1.2
5	Seismic Structural Upgrade	6.5.4.2.2
6	Lines:	
7	Deficient ROW Study and Acquisition	6.5.11.2
8	Wood Pole Replacements	6.5.8.2
9	EGIS Enhancement	6.5.11.2
10	Road and Bridge Programs	6.5.11.2.1
11	Above Ground Structural Corrosion Protection	6.5.8.2.2
12	Cable Partial Discharge Addition	6.5.7.2.4

For example, BCTC recommends the above risk mitigation projects to address the potential for:

(a) Risk of fires in its telecom facilities. Many telecom facilities are located in geographically remote locations and are not easily accessible, so fires present high risk of significant damage to facilities. The telecom system supports several critical functions that enable the transmission system to operate in a safe and reliable manner, including: teleprotection of circuits, telecontrol of substations from control centres, and telemetry which provides operational visibility of the grid. Loss of telecommunications results in loss of the above functions, that can curtail operation and capacity of the transmission system.

(b) Risk of oil spills in substations could result in significant environmental incidents. Transformers contain large quantities of oil used as a coolant and insulator, and are subject to oil leakage. To mitigate the risk of environmental damage, BCTC is implementing a program of installing oil spill containment systems.

(c) Risk of life safety incidents at substations due to poor quality of substation gravel. Substation gravel serves as an insulator to mitigate step and touch potential electrical hazards to personnel working within the substations. Over time, gravel becomes contaminated and loses its insulating properties, leading to life-safety risks for personnel and the public, which BCTC finds unacceptable.

(d) Risk of the significant damage or total loss of critical substation control room buildings that are not currently rated for seismic events. Substation control rooms house protection and control systems vital for the local and remote safe and reliable operation of substation infrastructure and the transmission system. The loss of a control building can also result in potential damage to transmission infrastructure, but more importantly possible injury to personnel working within the substation.

(e) Various transmission line risks that address deficient property rights, degrading transmission wood poles, insufficient data records, and road and bridge risks.

i. Rotting wood poles and deteriorating bridge and access roads pose significant life-safety risk for personnel and general public safety. In addition, deteriorating wood poles can also result in increased risk of reliability to the transmission system, due to potential for the loss of a circuit;

ii. Deficient Rights of Way may undermine the ability of BCTC to maintain and operate impacted facilities;

iii. Lack of sufficient or accurate geographical information related to the transmission system could lead to inefficient planning, higher costs, and potential environmental incidents;

iv. Deterioration of transmission support structures through corrosion pose a risk to life-safety and system reliability as failure of a transmission tower would result in loss of circuits, and increased cost for repair;

v. Partial discharge is an indicator of cable health. Increasing levels of partial discharge indicate that a cable joint requires attention or replacement. Not addressing a deteriorating cable joint can result in loss of the cable circuit impacting system reliability, and the potential for explosive failure of the cable joints, resulting in life-safety risk for personnel working in cable enclosures and the public.

6.3.1.1.3 Proposed F2011 Sustaining Capital Expenditures

BCTC is forecasting Sustaining Capital expenditures of $122.3 million for F2011, inclusive of Third Party requests and emergency capital expenditures. This represents a $3.3 million increase over the proposed F2010 Sustaining Capital expenditure of $119 million, which is primarily the result of inflation and escalation at the BCCPI level of 2.1% and small net increase of $0.8 million to address minor activity changes across all programs within the Sustaining Capital portfolio. A more detailed review of the variances in the projects between F2010 and F2011 is addressed in Section 6.5.

BCTC also completed a scenario analysis for the F2011 Sustaining Capital portfolio at an F2011 expenditure level of $109.2 million - representing the approved F2010 funding level of $107.0 million plus an inflation adjustment of 2.1%. To provide the Commission with an understanding of what projects would have to be partially or fully deferred at that expenditure level, BCTC has identified the following list of projects, as listed in Table 6-5.

Table 6-5. Projects to be Considered for Deferral to F2012 to Meet $109.2 Million Approved Capital Expenditures for Sustain Capital Portfolio in F2011

	Project Description	Section Reference
1	Stations:	
2	Nelway to Metaline Telecom Upgrade	6.5.6.2.8
3	Oil Spill Containment	6.5.4.2.1
4	Gravel Replacement	6.5.1.2
5	Seismic Structural Upgrade	6.5.4.2.2
6	Spare System Transformer	6.5.3.2.10
7	500 kV CB Replacements (MDN 5CB1 2 3 4 7 8)	6.5.2.2.1
8	230 kV Air Blast CB Replace (VIT 2CB4 8 9 10 11 12)	6.5.2.2.1
9	Station 24 V Battery Charger Replacements	6.5.1.2
10	Station Roofing	6.5.1.2
11	Lines:	
12	Deficient ROW Study and Acquisition	6.5.11.2
13	Wood Pole Replacements	6.5.8.2
14	EGIS Enhancement	6.5.11.2
15	Road and Bridge Programs	6.5.11.2.1
16	Transmission Line Seismic Upgrades	6.5.10.2.1
17	Transmission Wood Structure Bonding Program	6.5.10.2
18	230 kV Pothead Protection Program	6.5.7.2.5
19	Above Ground Structural Corrosion Protection	6.5.8.2.2
20	Cable Partial Discharge Addition	6.5.7.2.4

If no increase was granted in either F2010 or F2011, this list would be cumulative with the expenditures on the projects identified in Table 6-4.

6.3.1.2 Projects Deferred to F2012 and Future Periods

To accommodate the proposed Sustaining Capital expenditures of $119 million for F2010 and $122.3 for F2011, BCTC had to partially or fully defer important projects to F2012 and future periods.

Every year, BCTC determines a number of Sustaining Capital projects that are required to address known issues for system reliability, safety improvements, environmental protection, efficiency, and deteriorating asset health. All identified projects are prioritized. If these projects meet minimum criteria, as described in Section 4.7.3.4, then the projects are considered for the Sustaining Capital portfolio. Projects that do not meet the minimum criteria, although still considered important, are deferred or reduced in scope and will enter the Capital Planning process in later periods (F2012 and beyond). Table 6-6 lists those projects that did not meet the minimum criteria in F2010 and F2011.

Generally, the projects that tend to be deferred are those projects that mitigate other risks such as life-safety, environment, extreme weather, seismic, fire, and security. Projects associated with other risk mitigation are important for the safe, secure, and reliable operation of the transmission system, but do not necessarily result in the same immediate level of system reliability impacts provided by those projects that address specific reliability issues such as assets that are worn-out, obsolete, or in very poor condition, and are at risk of immediate failure.

As part of the F2010 and F2011 prioritization process, the following projects listed in Table 6-6 were identified with lower relative priority than those projects put forward in the F2010 and F2011 Sustaining Capital portfolio.

Table 6-6. Projects Deferred to F2012 or Future Periods

	Project Name	**Reduced in Scope / Deferred to Future Years**
1	230 kV Oil CB Replacements CKY 2CB2 6 20 KCL 2CB3 6	Partially Deferred to F2012
2	230 kV Air-Blast CB Replacements ING 2CB5 8 9 12 GLN 2CB1 2	Partially Deferred to F2012
3	500 kV CB Replacements MDN 5CB1 2 3 4 7 8	Partially Deferred to F2012
4	500 kV CB Replacements Replacements SEL 5CB 3 4 5 8 9 11 GMS 5CB11	Partially Deferred to F2012
5	Horsey Substation Gas Insulated Switches (GIS) Replacement	Partially Deferred to F2012
6	Maintenance-free Dehydrating Breathers on Transformers	Deferred Indefinitely
7	Seismic Upgrade of Telecom Microwave Buildings	Deferred Indefinitely
8	Stations Facilities Upgrade	Reduced in Scope
9	Stations Roofing	Reduced in Scope
10	Substation Gravel Replacement	Reduced in Scope
11	Transformer Electronic Temperature Monitor (ETM) Upgrade	Deferred Indefinitely
12	Transformer LTC Oil Filtration System Upgrade	Deferred Indefinitely
13	Restore Rating 60L27 and 60L30 Cable Section	Deferred Indefinitely
14	STER Conductor Inventory Reduction Program	Deferred Indefinitely
15	Murrin Reconfiguration and Seismic Upgrade	Partially Deferred to F2012 and beyond

6.4 Prioritization Results

In the prioritization process, all potential projects that are considered for the Sustaining Capital portfolio are assessed for value and risk, where value and risk are measured relative to cost, providing a cost-weighted score. Projects with both high value and risk cost-weighted scores, relative to projects that score highly on only one of these attributes, form part of the Sustaining Capital portfolio. Projects that score highly on only one attribute are considered to be marginal projects, which are then reassessed to determine which of them should be undertaken, and which should be deferred to later periods. For example, Table 6-5 provides a list of those projects that would be considered for deferral if the Commission were to reduce the Sustaining Capital expenditures from the requested amounts, due to their lower overall cost-weighted scores. This process is supported by the prioritization model in Section 4.4.

Once the projects have been scored, BCTC prepares a base case portfolio, and then performs optimization scenarios against the base case that consider other constraints, such as capital expenditure levels, availability of resources, scheduled outages, lead time for materials and equipment purchases, strategic alignment with related or dependent projects, alignment with BC Energy Plan objectives, and BCTC strategic objectives.

In the context of this Application, BCTC is presenting the recommended Sustaining Capital portfolio of projects for F2010 and F2011 at $119.0 million and $122.3 million respectively. The development of the Sustaining Capital portfolio resulted in the full or partial deferral of the projects in Table 6-6. Table 6-7 provides the results of the value and risk assessment.

Table 6-7. Sustaining Capital Prioritization Table

				Value Scores						Risk of Deferral					
CRN		**BCUC Category**	**Mandatory Category**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Value Score**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Risk Score**
9002	230 kV Replacement Double Pressure Type BUT 2Cb10 11 12 14 16 ARN 2CB1 16	Circuit Breakers		-2.96	4.39	0.00	0.20	2.00	**1.36**	0	20	0	6	15	**20**
9011	Below 230 kV CB Replacements BR1 60CB2 PVO 60CB3 KI2 60CB10 PLUS 1 UNIDENTIFIED	Circuit Breakers		-2.64	4.39	0.00	0.00	3.70	**1.59**	0	20	0	0	10	**20**
3429	Horsey Substation Gas Insulated Switches (GIS) Replacement	Circuit Breakers		-0.99	1.34	0.00	0.00	0.56	**0.39**	0	25	0	0	15	**25**
9009	12 kV Reactor CB Replacements WSN 12CB13 plus 2 others unidentified	Circuit Breakers		-2.39	4.88	0.00	0.00	3.73	**1.83**	0	25	0	0	10	**25**
4012	500 kV CB Replacements MDN 5CB1 2 3 4 7 8	Circuit Breakers		-3.32	4.88	1.25	0.00	3.73	**1.89**	0	25	0	0	5	**25**
3617	500 kV CB Replacements ING 5CB8 8 9 10 12	Circuit Breakers		-3.12	4.88	1.25	0.00	3.73	**1.93**	0	25	0	0	5	**25**
9000	500kV CB Replacements GLN 5CB2 3 12 13 TKW 5CB2 12 13 23	Circuit Breakers		-2.95	3.90	1.25	0.00	2.10	**1.40**	0	20	0	0	5	**20**
9001	500kV CB Replacements Replacements SEL 5CB 3 4 5 8 9 11 GMS 5CB11	Circuit Breakers		-2.88	4.88	1.25	0.00	2.10	**1.79**	0	25	0	0	5	**25**
9003	230 kV Double Pressure Type Replacement MAN 2CB1 2 6 KI2 2CB5 6 13	Circuit Breakers		-2.93	3.90	0.00	0.20	2.00	**1.18**	0	20	0	6	15	**20**
9005	230 kV Oil CB Replacements CKY 2CB2 6 20 KCL 2CB3 6	Circuit Breakers		-2.85	3.90	0.00	0.20	3.23	**1.33**	0	20	0	8	15	**20**
9004	230 kV Oil Circuit Breaker Replacements BUT 2CB2 5 6 CKY 2CB6	Circuit Breakers		-2.76	3.90	0.00	0.20	3.73	**1.40**	0	20	0	8	25	**25**
9006	230kV AirBlast CB Replacements ING 2CB5 8 9 12 GLN 2CB1 2	Circuit Breakers		-2.62	4.88	0.00	0.00	2.10	**1.61**	0	25	0	0	5	**25**
9007	230kV AirBlast CB Replacements VIT 2CB4 8 9 10 11 12	Circuit Breakers		-2.64	2.93	0.00	0.00	2.10	**0.84**	0	15	0	0	5	**15**
9008	12 kV Reactor CB Replacements CBK 12CB32 TKW 12CB3 KLY 12CB4	Circuit Breakers		-2.43	4.88	0.00	0.00	3.73	**1.82**	0	25	0	0	10	**25**
9010	Below 230 kV CB Replacements CRD 60CB5 CMX 1CB3 MON 1CB5	Circuit Breakers		-2.57	3.90	0.00	0.00	3.73	**1.42**	0	20	0	0	10	**20**
9012	Life Extension of HV Disconnect Extension	Other Power Equipment		-2.00	4.88	0.00	0.00	0.00	**1.50**	0	25	0	0	0	**25**
3678	Maintenance-free Dehydrating Breathers on Transformers	Other Power Equipment		-2.03	0.20	0.00	0.00	1.60	**-0.33**	0	10	0	0	1	**10**
4010	Surge Arrester Replacements	Other Power Equipment		-2.93	3.90	0.00	0.00	2.00	**1.16**	6	20	0	0	0	**20**
3975	Transformer Electronic Temperature Monitor (ETM) Upgrade	Other Power Equipment		-2.12	2.80	0.00	0.00	0.00	**0.67**	3	16	0	0	0	**16**
9301	Transformer LTC Oil Filtration System Upgrade	Other Power Equipment		-1.83	2.20	0.00	0.00	0.00	**0.49**	3	16	0	0	0	**16**
3602	VIT PCB-filled Equipment Removal and Replacement	Other Power Equipment		-2.91	0.50	0.00	0.00	4.50	**0.11**	0	10	0	0	8	**10**
3601	VIT SC3 Refurbishment	Other Power Equipment	Mandatory - Environmental	-2.36	2.48	0.00	1.05	0.00	**0.61**	5	15	0	1	0	**15**
3979	Spare System Transformer	Other Power Equipment		-2.74	1.80	0.00	1.70	0.00	**0.34**	0	0	0	4	0	**4**
9303	Transformer Electronic Temperature Monitor (ETM) Upgrade	Other Power Equipment		-2.11	2.80	0.00	0.00	0.00	**0.67**	3	16	0	0	0	**16**
9300	Maintenance-free Dehydrating Breathers on Transformers	Other Power Equipment		-2.02	0.20	0.00	0.00	1.60	**-0.32**	0	10	0	0	1	**10**
9302	Transformer LTC Oil Filtration System Upgrade	Other Power Equipment		-1.81	2.20	0.00	0.00	0.00	**0.49**	3	16	0	0	0	**16**
9013	Life Extension of HV Disconnect Extension	Other Power Equipment		-2.06	4.88	0.00	0.00	0.00	**1.49**	0	25	0	0	0	**25**
9104	Digital Fault Recorder (DFR) Replacements Stage 1	Protection & Control	Mandatory - WECC	-2.34	5.00	0.00	0.00	0.00	**1.48**	0	25	0	0	0	**25**
9106	PLC 984 Replacements Stage 2	Protection & Control		-2.17	3.90	0.00	1.75	0.00	**1.28**	4	20	0	16	0	**20**
4076	Protection Control and Metering Upgrade Project Phase 2	Protection & Control	Mandatory - Third Party	-2.09	0.00	0.00	0.00	0.00	**-0.42**	0	0	0	0	0	**0**
4034	SCADA RTU Replacements Stage 5	Protection & Control		-2.15	3.80	0.00	0.00	0.00	**1.05**	0	20	0	0	0	**20**
4019	Tx Gas Relay Stage 5	Protection & Control		-1.46	3.80	0.00	0.95	0.00	**1.30**	0	20	0	3	0	**20**
9102	Tx Gas Relay Stage 6	Protection & Control		-2.09	1.11	0.00	0.78	0.00	**0.10**	0	15	0	3	0	**15**
4018	Tx System Tie Stage 4	Protection & Control		-1.96	2.13	0.00	0.71	0.00	**0.52**	0	15	0	3	0	**15**
4015	Under 500 kV Line Protection Stage 10	Protection & Control		-2.42	3.49	0.00	0.87	0.00	**0.97**	0	20	0	3	0	**20**
9100	Under 500 kV Line Protection Stage 11	Protection & Control		-0.04	0.05	0.00	0.01	0.00	**0.01**	0	20	0	3	0	**20**
3218	Under 500 kV Protection Stage 9	Protection & Control		-0.26	3.80	0.00	0.95	0.00	**1.53**	0	20	0	3	0	**20**
4023	VVO Phase 4	Protection & Control	Mandatory - Third Party	-2.50	0.00	0.00	0.00	0.00	**-0.50**	0	0	0	0	0	**0**
9101	Tx System Tie Stage 5	Protection & Control		-2.51	2.85	0.00	0.95	0.00	**0.71**	0	15	0	3	0	**15**
9103	SCADA RTU Replacements Stage 6	Protection & Control		-2.48	3.80	0.00	0.00	0.00	**0.99**	0	20	0	0	0	**20**
9105	Digital Fault Recorder (DFR) Replacements Stage 2	Protection & Control	Mandatory - WECC	-2.31	5.00	0.00	0.00	0.00	**1.49**	0	25	0	0	0	**25**
9107	PLC 984 Replacements Stage 3	Protection & Control		-2.15	3.90	0.00	1.75	0.00	**1.28**	4	20	0	16	0	**20**
3210	500 kV Line Protection Stage 7	Protection & Control		-2.43	3.80	0.00	1.25	0.00	**1.13**	0	20	0	4	0	**20**
4013	500 kV Line Protection Stage 8 (Final Stage)	Protection & Control		-2.04	3.03	0.00	0.80	0.00	**0.86**	0	20	0	4	0	**20**
4041	VVO Phase 5	Protection & Control	Mandatory - Third Party	-2.46	0.00	0.00	0.00	0.00	**-0.49**	0	0	0	0	0	**0**
4077	Protection Control and Metering Upgrade Project Phase 3	Protection & Control	Mandatory - Third Party	-2.08	0.00	0.00	0.00	0.00	**-0.42**	0	0	0	0	0	**0**
9109	Minor Capital - Protection and Control	Protection & Control	Forced	-2.05	0.90	0.00	0.00	0.00	**-0.06**	0	15	0	0	0	**15**
9108	Minor Capital - Protection and Control	Protection & Control	Forced	-2.17	0.90	0.00	0.00	0.00	**-0.08**	0	15	0	0	0	**15**

Table 6-7. Sustaining Capital Prioritization Table (continued)

				Value Scores						Risk of Deferral					
CRN		**BCUC Category**	**Mandatory Category**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Value Score**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Risk Score**
3333A	Air Compressor Replacements Prioirty A	Station Auxiliary Equipment		-1.29	3.70	0.00	0.00	2.00	**1.41**	9	15	0	0	6	**15**
3333B	Air Compressor Replacements Prioirty B	Station Auxiliary Equipment		-1.32	2.78	0.00	0.00	2.00	**1.04**	6	15	0	0	6	**15**
3111E	Pin and Cap Insulator Replacements F2010	Station Auxiliary Equipment		-2.66	1.13	0.00	0.00	2.50	**0.18**	4	20	0	0	15	**20**
4008E	Pin and Cap Insulator Replacements Priority B	Station Auxiliary Equipment		-1.46	0.57	0.00	0.00	1.26	**0.07**	4	20	0	0	15	**20**
3991E	Station Battery Bank Replacements Priority A	Station Auxiliary Equipment		-2.16	1.13	0.00	0.00	3.60	**0.40**	12	20	0	0	6	**20**
4003E	Station Battery Bank Replacements Priority B	Station Auxiliary Equipment		-2.16	0.88	0.00	0.00	3.60	**0.30**	9	15	0	0	6	**15**
4003C	Station Battery Bank Replacements Priority C	Station Auxiliary Equipment		-2.16	0.88	0.00	0.00	3.60	**0.30**	6	15	0	0	6	**15**
4006C	Stations Facilities Upgrade Priority C	Station Auxiliary Equipment		-2.21	0.53	0.00	0.25	2.50	**0.07**	0	10	0	3	8	**10**
3992E	Stations Facilities Upgrade	Station Auxiliary Equipment		-2.17	2.18	0.00	0.25	2.50	**0.72**	5	15	0	3	12	**15**
4007C	Stations Roofing Prioirty C	Station Auxiliary Equipment		-2.15	2.03	0.00	0.00	2.00	**0.58**	1	10	0	0	4	**10**
4005E	Substation Gravel Replacement Prority B	Station Auxiliary Equipment		-1.99	0.20	0.00	0.63	2.50	**0.02**	1	10	0	2	6	**10**
4005C	Substation Gravel Replacement Prority C	Station Auxiliary Equipment		-2.00	0.61	0.00	0.00	0.00	**-0.16**	0	10	0	0	0	**10**
3145E	Substation Gravel Replacement F2010	Station Auxiliary Equipment		-2.10	0.90	0.00	0.40	5.00	**0.53**	3	15	0	3	10	**15**
9204	Substation Ground Grid Upgrade	Station Auxiliary Equipment		-2.03	0.00	0.00	0.45	2.50	**-0.08**	0	0	0	4	25	**25**
9206	Wood Pole Substation Remediation	Station Auxiliary Equipment	Mandatory - Third Party	-1.89	0.68	0.00	0.15	2.50	**0.18**	0	10	0	0	4	**10**
4006E	Stations Facilities Upgrade	Station Auxiliary Equipment		-2.10	2.03	0.00	0.25	2.50	**0.67**	4	15	0	3	8	**15**
9207	Wood Pole Substation Remediation	Station Auxiliary Equipment	Mandatory - Third Party	-1.88	0.68	0.00	0.15	2.50	**0.18**	0	10	0	0	4	**10**
3804E	Stations Minor Capital F2010	Station Auxiliary Equipment	Forced	-2.70	0.90	0.00	0.00	0.00	**-0.19**	5	15	0	0	0	**15**
4004E	Stations Minor Capital F2011	Station Auxiliary Equipment	Forced	-2.70	0.90	0.00	0.00	0.00	**-0.19**	5	15	0	0	0	**15**
3990E	Stations Roofing	Station Auxiliary Equipment		-2.10	2.18	0.00	0.00	2.00	**0.65**	3	15	0	0	8	**15**
4007E	Stations Roofing	Station Auxiliary Equipment		-2.15	2.10	0.00	0.00	2.00	**0.61**	2	10	0	0	4	**10**
3824	Fire Protection/Diesel Generator - Upgrade at Cable Terminal Sites	Station Risk Mitigation		-1.31	2.13	0.00	0.00	2.66	**0.86**	12	20	0	0	12	**20**
3987E	Oil Spill Containment Priority A	Station Risk Mitigation		-1.39	0.00	0.00	0.20	1.24	**-0.12**	4	0	0	12	15	**15**
4009B	Oil Spill Containment Priority B	Station Risk Mitigation		-1.39	0.00	0.00	0.20	1.24	**-0.12**	4	0	0	12	15	**15**
9200	Seismic Upgrade of Telecom Microwave Buildings	Station Risk Mitigation		-2.34	0.40	0.00	1.70	2.50	**0.15**	0	10	0	4	0	**10**
4039	Stations and Microwave Sites Security Upgrade	Station Risk Mitigation		-2.73	2.00	0.00	0.45	4.50	**0.78**	0	25	0	3	25	**25**
9202	Substation Seismic Structural Upgrade	Station Risk Mitigation		-2.73	0.40	0.00	1.70	2.50	**0.07**	0	10	0	4	0	**10**
9201	Seismic Upgrade of Telecom Microwave Buildings	Station Risk Mitigation		-2.15	0.40	0.00	1.70	2.50	**0.19**	0	10	0	4	0	**10**
9203	Substation Seismic Structural Upgrade	Station Risk Mitigation		-2.70	0.40	0.00	1.70	2.50	**0.08**	0	10	0	4	0	**10**
9205	Substation Ground Grid Upgrade	Station Risk Mitigation	Mandatory - Other	-2.02	0.00	0.00	0.45	2.50	**-0.08**	0	0	0	4	25	**25**
4038	Stations and Microwave Sites Security Upgrade	Station Risk Mitigation		-2.71	2.00	0.00	0.45	4.50	**0.78**	0	25	0	3	25	**25**
9208	Kidd 1 Crib Wall Reinforcement with Rip Rap Wall	Station Risk Mitigation		-2.64	0.80	0.00	1.90	2.50	**0.27**	5	15	0	10	10	**15**
3333	Murrin Reconfiguration and Seismic Upgrade	Station Risk Mitigation		-0.16	0.04	0.00	0.08	0.10	**0.00**	0	20	0	5	0	**20**
3100	Leased Line Entrance Protection Replacements	Telecommunications	Mandatory - Other	-2.42	0.00	0.00	0.00	2.50	**-0.21**	0	0	0	0	5	**5**
3985E	MW Fire Protection	Telecommunications		-2.02	0.00	0.00	0.00	2.24	**-0.16**	12	0	0	0	10	**12**
9154	Nelway to Metaline Telecommunication Upgrade	Telecommunications		-0.08	0.04	0.00	0.00	0.00	**0.00**	0	15	0	0	0	**15**
4081	Stations Access	Telecommunications		-1.74	0.19	0.00	0.44	4.84	**0.31**	2	10	0	9	16	**16**
4020	Test and Tone Telecommunication Replacement (Priority A)	Telecommunications		-2.25	3.80	0.00	0.20	0.00	**1.05**	0	20	0	0	0	**20**
9151	Test and Tone Telecommunication Replacement (Priority B)	Telecommunications		-2.26	3.80	0.00	0.20	0.00	**1.05**	0	20	0	0	0	**20**
4081b	Stations Access	Telecommunications		-1.81	0.19	0.00	0.44	4.84	**0.29**	2	10	0	9	16	**16**
9153	Leased Line Entrance Protection Replacements	Telecommunications	Mandatory - Other	-2.40	0.00	0.00	0.00	2.50	**-0.21**	0	0	0	0	5	**5**
9152	Minor Capital - Telecommunication	Telecommunications	Forced	-1.98	0.90	0.00	0.00	0.00	**-0.05**	0	15	0	0	0	**15**
3096	Minor Capital - Telecommunication	Telecommunications	Forced	-2.33	0.90	0.00	0.00	0.00	**-0.11**	5	15	0	0	0	**15**
3093	Station 24 V (Telecom) Battery Charger Replacements (Priority A)	Telecommunications		-2.28	0.90	0.00	0.00	1.60	**0.07**	8	15	0	0	4	**15**
9150	Station 24 V (Telecom) Battery Charger Replacements (Priority B)	Telecommunications		-2.00	0.71	0.00	0.00	1.60	**0.05**	8	10	0	0	4	**10**
4024EE	Spares Program (Emergency Preparedness)	Cable Sustainment		-2.16	0.97	0.00	1.65	0.00	**0.13**	6	20	0	8	0	**20**
4032E	Cable Refurbishment Program	Cable Sustainment		-2.72	2.32	0.00	0.17	2.42	**0.65**	0	15	0	25	12	**25**
4031E	230 kV Pothead Protection Program	Cable Sustainment		-2.04	1.94	0.00	-0.17	0.00	**0.33**	0	5	0	1	0	**5**

Table 6-7. Sustaining Capital Prioritization Table (continued)

				Value Scores						Risk of Deferral					
CRN		**BCUC Category**	**Mandatory Category**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Value Score**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Risk Score**
4029E	5L029 and 5L031 DTS System Upgrade	Cable Sustainment		-1.98	3.30	0.00	0.00	0.00	**0.89**	0	25	0	0	0	**25**
4030E	5L029 and 5L031 Pumping Plants Upgrade	Cable Sustainment		-2.24	3.12	0.00	0.17	2.42	**1.06**	0	16	0	3	4	**16**
4028E	Circuit 1L0CX Removal	Cable Sustainment		-1.98	0.00	0.00	0.00	2.42	**-0.13**	0	0	0	9	12	**12**
3574E	Restore Rating 60L27 and 60L30 Cable Section	Cable Sustainment		-2.49	1.19	0.00	0.58	0.00	**0.03**	0	10	0	6	0	**10**
4024E	Spares Program (Emergency Preparedness)	Cable Sustainment		-2.19	1.94	0.00	1.65	0.00	**0.50**	6	20	0	15	0	**20**
4017E	Cable Terminating Substation Oil Spill Containment	Cable Sustainment	Mandatory - Other	-2.27	0.00	0.00	0.75	2.42	**-0.10**	0	0	0	12	20	**20**
3551E	Cable Partial Discharge System Addition	Cable Sustainment		-2.60	1.94	1.21	0.48	2.42	**0.79**	0	15	0	6	5	**15**
3135E	60L093 and 60L094 Cable Section Replacement	Cable Sustainment		-2.66	3.51	0.00	1.07	0.00	**0.95**	0	25	0	20	0	**25**
3163E	Circuit Refurbishments program	OH Life Extension		-2.34	3.07	0.00	0.85	0.00	**0.82**	5	20	0	15	0	**20**
4064E	F2010-4064E-OH Structural Corrosion Protection Program - TLob	OH Life Extension		-2.60	1.45	0.48	1.91	4.77	**0.87**	0	15	0	2	9	**15**
4065E	F2010-4065E-UG Structural Corrosion Protection Program - TLob	OH Life Extension		-2.34	2.18	1.21	1.40	4.84	**1.30**	0	25	0	1	3	**25**
4066E	F2010-4066E-OCAS - Crossing Marker Program - TLob	OH Life Extension	Mandatory - Public Safety Standards and Regulations	-2.22	0.97	1.21	0.58	2.42	**0.49**	10	20	0	10	10	**20**
4068E	F2010-4068E-Wood Structure Framing Replacement Program - TLob	OH Life Extension		-1.86	3.78	1.21	1.57	3.49	**1.89**	4	20	0	2	12	**20**
4072E	F2010-4072E-Multiple Circuits - TL Recurring Capital Program - TLob	OH Life Extension		-3.15	1.33	0.48	1.57	3.97	**0.59**	10	20	0	2	12	**20**
4043E	Insulator Replacement Program	OH Life Extension		-2.17	2.81	0.00	0.94	0.00	**0.77**	5	20	0	6	0	**20**
3562E	Long Span Crossing Refubrishment	OH Life Extension		-1.72	3.39	0.00	0.94	0.00	**1.08**	0	20	0	9	0	**20**
4045E	Marker Crossing	OH Life Extension	Mandatory - Public Safety Standards and Regulations	-2.22	0.97	0.00	0.58	2.42	**0.26**	10	20	0	10	10	**20**
4046E	Spacer Damper Replacement Project	OH Life Extension		-1.86	2.78	0.00	0.94	0.00	**0.82**	0	20	0	6	0	**20**
4047E	Transmission Disconnect Switch Replacement	OH Life Extension		-2.41	2.78	0.00	0.94	1.45	**0.87**	4	20	0	9	9	**20**
3560Eb	500 kV Polymer Replacement Program	OH Life Extension		-1.78	3.39	0.00	0.94	0.00	**1.07**	0	20	0	9	0	**20**
4044E	F2011-4044E-Transmission Steel Structural Replacement Program - TLob	OH Life Extension		-2.43	1.82	1.21	2.15	4.36	**1.17**	0	20	0	6	6	**20**
4064Eb	F2011-4064E-OH Structural Corrosion Protection Program - TLob	OH Life Extension		-2.58	1.45	0.48	1.91	4.77	**0.88**	0	15	0	2	9	**15**
4065Eb	F2011-4065E-UG Structural Corrosion Protection Program - TLob	OH Life Extension		-2.31	2.18	1.21	1.40	4.84	**1.30**	0	25	0	1	3	**25**
4068Eb	F2011-4068E-Wood Structure Framing Replacement Program - TLob	OH Life Extension		-1.84	3.78	1.21	1.57	3.49	**1.89**	4	20	0	2	12	**20**
4072Eb	F2011-4072E-Multiple Circuits - TL Recurring Capital Program - TLob	OH Life Extension		-3.11	1.33	0.48	1.57	3.97	**0.60**	10	20	0	2	12	**20**
3560E	500 kV Polymer Replacement Program	OH Life Extension		-1.79	2.86	0.00	0.94	0.00	**0.86**	5	20	0	6	0	**20**
4046Eb	Spacer Damper Replacement Project	OH Life Extension		-2.10	2.78	0.00	0.94	0.00	**0.77**	0	20	0	6	0	**20**
4043Eb	Insulator Replacement Program	OH Life Extension		-2.26	2.78	0.00	0.94	0.00	**0.74**	5	20	0	6	0	**20**
4047Eb	Transmission Disconnect Switch Replacement	OH Life Extension		-2.40	2.78	0.00	0.94	1.45	**0.87**	4	20	0	9	9	**20**
4055E	Transmission Wood Structure Bonding Program	OH Life Extension		-2.14	1.82	1.21	0.94	1.45	**0.77**	3	12	0	12	6	**12**
3562Eb	Long Span Crossing Refubrishment	OH Life Extension		-1.72	3.39	0.00	0.94	0.00	**1.08**	0	20	0	9	0	**20**
4045Eb	Marker Crossing	OH Life Extension	Mandatory - Public Safety Standards and Regulations	-2.19	0.97	0.00	0.58	2.42	**0.27**	10	20	0	10	10	**20**
4066Eb	F2011-4066E-OCAS - Crossing Marker Program - TLob	OH Life Extension	Mandatory - Public Safety Standards and Regulations	-2.19	0.77	1.21	0.51	2.42	**0.42**	0	15	0	10	10	**15**
4067Eb	F2011-4067E-Transmission Minor Capital Program - TLob	OH Life Extension	Forced	-1.89	0.87	0.00	0.00	0.00	**-0.04**	0	15	0	0	0	**15**
4067E	F2010-4067E-Transmission Minor Capital Program - TLob	OH Life Extension	Forced	-1.91	0.87	0.00	0.00	0.00	**-0.04**	0	15	0	0	0	**15**
4049E	Transmission Arcing Horn	OH Performance Improvement		-2.70	2.78	1.21	0.94	0.00	**0.88**	5	20	0	6	0	**20**
4049Eb	Transmission Arcing Horn	OH Performance Improvement		-2.44	2.78	0.00	0.94	0.00	**0.70**	5	20	0	6	0	**20**
4050E	Automatic Splice Replacement Program	OH Risk Mitigation		-1.83	2.78	0.00	0.94	0.00	**0.82**	0	20	0	6	0	**20**
4051E	Copper Conductor Replacement	OH Risk Mitigation		-2.08	2.78	0.00	0.94	0.00	**0.77**	5	20	0	15	0	**20**
4074E	F2010 4074E-TL Civil Protective Program - TLob	OH Risk Mitigation		-2.64	1.84	0.48	1.57	4.84	**0.99**	12	20	0	12	16	**20**
4073E	F2010-4073E-TL Structure Seismic Upgrades - TLob	OH Risk Mitigation		-1.76	0.68	0.45	1.41	2.93	**0.48**	5	15	0	0	0	**15**
4075E	F2010-4075E-STER Tower and Equipment Replacement Program - TLob	OH Risk Mitigation		-1.94	1.21	1.21	1.77	0.00	**0.51**	0	25	0	3	0	**25**
4078E	F2010-4078E-Tower Climbing Barrier and Signage Program - TLob	OH Risk Mitigation	Mandatory - British Columbia and Canadian Electric Code	-1.91	0.00	1.21	1.04	2.42	**0.23**	8	0	0	12	25	**25**

Table 6-7. Sustaining Capital Prioritization Table (continued)

				Value Scores						Risk of Deferral					
CRN		**BCUC Category**	**Mandatory Category**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Value Score**	Financial	Reliability	Market Efficiency	Relationships	Environment & Safety	**Overall Risk Score**
4079E	F2010-4079E-TL Ice Hazard Risk Reduction Program - TLob	OH Risk Mitigation	Mandatory - Other	-2.72	1.33	1.21	2.15	4.36	**0.92**	0	20	0	6	6	**20**
4052E	OHGW Refubishment Program	OH Risk Mitigation		-1.94	0.97	0.00	0.87	0.00	**0.09**	0	20	0	15	0	**20**
4053E	Overhead Rating Restoration	OH Risk Mitigation		-2.13	2.78	0.00	0.94	1.45	**0.92**	5	20	0	6	10	**20**
3564E	2m Line Post Insulator Replacement	OH Risk Mitigation		-1.83	0.97	0.00	0.94	0.00	**0.12**	0	20	0	15	0	**20**
4050Eb	Automatic Splice Replacement Program	OH Risk Mitigation		-1.82	2.78	0.00	0.94	0.00	**0.83**	0	20	0	6	0	**20**
3163Eb	Circuit Refurbishments program	OH Risk Mitigation		-2.32	3.07	0.00	0.85	0.00	**0.83**	5	20	0	15	0	**20**
4051Eb	Copper Conductor Replacement	OH Risk Mitigation		-2.07	2.78	0.00	0.94	0.00	**0.78**	5	20	0	15	0	**20**
4073Eb	F2011-4073E-TL Structure Seismic Upgrades - TLob	OH Risk Mitigation		-2.97	0.73	0.48	1.50	3.12	**0.29**	0	15	0	0	0	**15**
4074Eb	F2011 4074E-TL Civil Protective Program - TLob	OH Risk Mitigation		-2.61	1.84	0.48	1.57	4.84	**0.99**	12	20	0	12	16	**20**
4075Eb	F2011-4075E-STER Tower and Equipment Replacement Program - TLob	OH Risk Mitigation		-1.92	1.21	1.21	1.84	0.00	**0.52**	0	25	0	3	0	**25**
4079Eb	F2011-4079E-TL Ice Hazard Risk Reduction Program - TLob	OH Risk Mitigation	Mandatory - Other	-2.64	1.33	1.21	2.15	4.36	**0.94**	0	20	0	6	6	**20**
4053Eb	Overhead Rating Restoration	OH Risk Mitigation		-2.12	2.78	0.00	0.94	1.45	**0.93**	5	20	0	6	10	**20**
4054E	STER Conductor Inventory Reduction Program	OH Risk Mitigation		-2.03	0.00	0.00	0.87	0.00	**-0.31**	0	0	0	9	0	**9**
4078Eb	F2011-4078E-Tower Climbing Barrier and Signage Program - TLob	OH Risk Mitigation	Mandatory - British Columbia and Canadian Electric Code	-1.91	0.00	1.21	1.04	2.42	**0.23**	8	0	0	12	25	**25**
4027	Deficient and Miscellaneous Rights Acquisitions	ROW Sustainment		-2.65	0.00	0.00	2.03	0.00	**-0.31**	10	0	0	20	0	**20**
4035	EGIS	ROW Sustainment		-1.85	0.59	1.21	1.72	4.84	**0.81**	0	10	0	12	20	**20**
4036	Helipad Program	ROW Sustainment		-1.95	0.69	0.00	0.00	4.84	**0.41**	8	15	0	0	10	**15**
4042	LiDAR Survey and PLS-CADD Modelling of the Transmission System	ROW Sustainment		-2.04	0.59	1.21	0.00	0.00	**0.05**	4	10	0	0	0	**10**
4080	Road and Bridge Programs	ROW Sustainment		-2.30	0.39	0.00	0.56	4.84	**0.29**	9	10	0	9	16	**16**
4027b	Deficient and Miscellaneous Rights Acquisitions	ROW Sustainment		-2.64	0.00	0.00	2.03	0.00	**-0.30**	10	0	0	20	0	**20**
4035b	EGIS	ROW Sustainment		-1.84	0.59	1.21	1.72	4.84	**0.82**	0	10	0	12	20	**20**
4042b	LiDAR Survey and PLS-CADD Modelling of the Transmission System	ROW Sustainment		-2.14	0.59	1.21	0.00	0.00	**0.03**	4	10	0	0	0	**10**
4080b	Road and Bridge Programs	ROW Sustainment		-2.31	0.39	0.00	0.56	4.84	**0.28**	9	10	0	9	16	**16**
4036b	Helipad Program	ROW Sustainment		-1.98	0.69	0.00	0.00	4.84	**0.41**	8	15	0	0	10	**15**
4070b	Third Party Funded Projects and Highway Relocations	ROW Sustainment	Mandatory - Third Party	-2.50	0.00	0.00	1.86	0.00	**-0.29**	20	0	0	8	0	**20**
4070	Third Party Funded Projects and Highway Relocations	ROW Sustainment	Mandatory - Third Party	-2.51	0.00	0.00	1.86	0.00	**-0.30**	20	0	0	8	0	**20**

6.5 Sustaining Capital Portfolio Descriptions

The Sustaining Capital portfolio is described by program and project in the following sections. Ongoing projects which generally remain unchanged are referenced to the previous TSCP. More detailed descriptions are provided of new projects or projects with material changes.

As with previous TSCP's, BCTC requests that the Commission approve the full annual Sustaining Capital forecast of expenditures for F2010 and F2011, as shown in Table 6-1, and not provide project by project approvals. BCTC will then work towards achieving the total Sustaining Capital portfolio of programs and projects listed here within the general level of expenditure approved by the Commission.

All proposed programs and projects have been prioritized. The prioritization process, described in Section 4.4, includes an evaluation of the risk of deferral of projects deemed by BCTC to be of high importance.

As indicated in Section 6.1, BCTC believes that the programs and projects presented are required as the minimum expenditure necessary to ensure the safe and reliable operation of the transmission system, address unacceptable risks, and address third-party requested projects.

6.5.1 Auxiliary Equipment

Auxiliary Equipment includes any station equipment used to support the transmission system, including station cables, bus-work and insulators, steel structures, equipment foundations, grounding systems, station power supplies, batteries and chargers, air compressors and dryers, buildings and HVAC equipment, perimeter fences, drainage systems, and gravel. Auxiliary Equipment does not include circuit breakers, transformers, or other power equipment.

The key drivers for the Auxiliary Equipment program are:

(a) Maintain System Reliability (Asset Health); and

(b) Manage Risks (Safety).

Table 6-8 summarizes the proposed capital expenditure for the Auxiliary Equipment program for F2010 and F2011. Table 6-8 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-8. Annual Forecast of Auxiliary Equipment Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$7.1	$7.4	$0.4	$7.1	($0.3)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$7.1	$7.4	$0.4	$7.1	($0.3)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.1.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 do not vary materially from the expenditure requested in the F2009 TSCP. The plan-over-plan variance of $0.4 million is primarily the result of an increase in expenditures to accommodate the initiation of a new project, Wood Pole Replacements, described in Section 6.5.1.2.2.

The proposed capital expenditures planned for F2011 do not vary materially from the forecast expenditure level proposed for F2010, and are explained by a decrease in expenditures for the Pin and Cap Replacements project to accommodate other projects of higher priority in the Sustaining Capital portfolio.

6.5.1.2 Auxiliary Equipment Projects

This section provides a description of the projects which comprise the Auxiliary Equipment program.

The following projects were described in the F2009 TSCP and are ongoing initiatives for the 10-year planning period. BCTC expects the activity level for these projects to remain relatively similar year-over-year:

(a) Roofing Replacements

(b) 24 Volt Battery Bank Replacements

(c) Gravel Replacements

(d) Facility Upgrades

(e) Auxiliary Equipment Minor Capital

(f) Grounding Upgrades

(g) Air Compressor Replacements

New projects and material changes to existing projects are described below:

6.5.1.2.1 Pin and Cap Insulator Replacements

This project was described in the F2009 TSCP. The project is an ongoing initiative for the 10-year planning period. The level of activity for this project has been reduced marginally for F2010 and F2011 and the remainder of the 10-year planning period to accommodate other projects of higher priority in the Sustaining Capital portfolio, including the introduction of the Wood Pole Replacement project. BCTC remains committed to replacing all pin and cap insulators due to a known asset class failure.

6.5.1.2.2 Wood Pole Replacements

This is a new project which will be initiated in F2010 and is expected to continue for the 10-year planning period. The F2011 funding for this project and future years is provided by a marginal reduction in the annual activity level for the Pin and Cap Insulator Replacement Project.

Approximately 12 percent of substations in the system use wood poles as support structures for substation equipment and bus work. The wood pole support structures are used primarily for SDA equipment; however, a portion of the infrastructure supports transmission asset equipment. An ongoing SDA project is in place to address the replacement of all wood pole substations found to be in very poor condition (i.e., excessive rot found on timbers and where the timbers connect to the poles) identified through an asset condition assessment process. The assessment process involves taking core samples to determine the extent of wood rot infiltration. This project is required to cover the transmission component (~5%) of the SDA Wood Pole Replacement Project. In prior years, the generally minor transmission component of this type of expenditure was recorded as SDA costs, and not transmission.

6.5.2 Circuit Breakers

High voltage circuit breakers are used to isolate sections of the transmission system and to interrupt high currents under fault conditions. They are the ultimate protection device on the transmission system and must be capable of reliably interrupting both load currents and fault currents. The transmission system currently has over 1,000 circuit breakers made up of a variety of different equipment in terms of voltage classes (from 12 kV to 500 kV).

The key driver for the Circuit Breaker Program is:

(a) Maintain System Reliability (Asset Health, Asset Performance).

Table 6-9 summarizes the proposed capital expenditures for the Circuit Breaker program for F2010 and F2011. Table 6-9 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditure have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-9. Annual Forecast of Circuit Breaker Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$24.9	$27.7	$2.8	$37.2	$9.5
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.7	$0.7	$0.0	($0.7)
4	Total	$24.9	$28.4	$3.5	$37.2	$8.8

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.2.1 Expenditure Variance Analysis

The proposed plan-over-plan capital expenditures for F2010 vary from the expenditures presented in the F2009 TSCP due to increased costs for the 500 kV and 230 kV Air-blast Circuit Breaker and 500 kV Circuit Switcher Replacements Project. This increase is required to replace 500 kV air-blast circuit breakers at Ingledow Substation with replacement circuit breakers that combine the function of the existing breakers, disconnect switches and instrument transformers and are more seismically robust.

Emergency capital expenditures that were committed to in F2009 will be incurred in F2010, due to the need to replace circuit breakers at Kootenay Canal and Barlow that pose an immediate life safety risk.

The proposed capital expenditures planned for F2011 vary from the expenditures proposed for F2010. The increase is the result of the deferral of the Horsey GIS Replacement Program from F2010 to F2011 and increased activity in the 230 kV Double-Pressure SF6 Circuit Breaker Replacement Project and the 230 kV Bulk Oil Circuit Breaker Replacement Project.

6.5.2.2 Circuit Breaker Projects

This section provides a description of the projects which comprise the Circuit Breaker program.

6.5.2.2.1 500 kV and 230 kV Air-Blast Circuit Breaker and 500 kV Circuit Switcher Replacements

The project was described in the F2009 TSCP and is an ongoing initiative that is expected to be completed in F2014. The forecast activity level for F2010 and F2011 remains constant but forecast costs have increased due to higher costs than previously estimated for the replacement of the 500 kV air-blast circuit breakers at Ingledow.

6.5.2.2.2 230 kV Double Pressure SF6 Circuit Breaker Replacement

This project was described in the F2009 TSCP and was projected to be completed in F2015. Due to increasing failures, the project has been accelerated to complete the replacement program in F2013, resulting in an increased activity level in F2011 that is anticipated to remain constant year-over-year until the completion of the project. Please refer to the case study for 230 kV Double Pressure SF6 Circuit Breakers in Appendix D-1 of this TSCP.

6.5.2.2.3 12/25/60/138 kV Reactor Circuit Breaker

This project was described in the F2009 TSCP and is scheduled to be completed in F2011 with a similar level of activity as was previously forecast.

The project will address replacement of reactor circuit breakers at Cranbrook (12CB32), Telkwa (12CB3), and Kelly Lake (12CB4) in F2010 and Williston (12CB13) in F2011.

6.5.2.2.4 Spare Circuit Breaker Purchase

This project was described in the F2009 TSCP and is expected to be completed in F2010. Two 230 kV spare circuit breakers will be purchased in F2010.

6.5.2.2.5 Mica Gas Insulated Switchgear Replacement

This project was described in the F2009 TSCP and will be completed in F2009.

6.5.2.2.6 Gas Insulated Switchgear (GIS) Betterment

This project was described in the F2009 TSCP and will be completed in F2010. There is no change to activity levels.

6.5.2.2.7 Horsey GIS Replacement Program

This project was described in the F2009 TSCP. The project was deferred from F2009 to F2010 to accommodate other projects of higher priority in the Sustaining Capital portfolio within the reduced level of approved expenditures for F2009. The project is scheduled for completion in F2012.

6.5.2.2.8 60 kV to 138 kV Circuit Breaker Replacement

This project was described in the F2009 TSCP. The project is an ongoing project for the remainder of the 10-year planning period. The forecast activity level for the project in F2010 and F2011 has been reduced to accommodate other projects of higher priority within the Sustaining Capital portfolio and to distribute the project over a multi-year program.

6.5.2.2.9 230 kV Bulk Oil Circuit Breaker Replacement

This project was described in 2009 TSCP and is an ongoing project for the remainder of the 10-year planning period. The activity level is anticipated to remain generally constant year-over-year until the completion of the project.

6.5.2.2.10 Kootney Canal & Barlow 230 kV Circuit Breaker Replacement

This is a new project that was initiated as an emergency project in F2009 and is scheduled for completion in F2010. The project is required to address safety requirements put in place for the existing circuit breakers, and to ensure future reliability. BCTC has entered into a contract to replace the circuit breakers.

6.5.3 Other Power Equipment

Other Power Equipment consists of disconnect switches, surge arrestors, power transformers, instrument transformers, shunt reactors, shunt capacitors, synchronous condensers, HVDC systems, series capacitor stations, cable terminations, and load tap changers.

The key drivers for the Other Power Equipment program are:

(a) Maintain System Reliability (Asset Health, Asset Performance); and

(b) Manage Risks (Safety, Environment).

Table 6-10 summarizes the proposed capital expenditures for the Other Power Equipment program for F2010 and F2011. Table 6-10 also provides the proposed plan-over-plan expenditures, the variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-10. Annual Forecast of Other Power Equipment Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$14.7	$8.9	($5.8)	$6.2	($2.7)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$14.7	$8.9	($5.8)	$6.2	($2.7)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.3.1 Expenditure Variance Analysis

The proposed plan-over-plan capital expenditures for F2010 vary from the expenditures presented in the F2009 TSCP. The decrease is due to the cancellation of the Cathedral Square – Relocation of 2L31/2L32 Line Terminations Project and the deferral of the VIT SC4 and SC3 Overhaul Project from F2009 to F2010 to accommodate higher priority projects within the approved level of expenditures for F2009.

The proposed capital expenditures planned for F2011 vary from the planned expenditures for F2010 due to a decrease in expenditures as a result of the scheduled completion of the VIT PCB Equipment Replacement project in F2010 and a deferral of the Mechanical Transformer Electronic Temperature Monitor (ETM) Upgrades Project to accommodate other higher priority expenditures.

6.5.3.2 Other Power Equipment Projects

This section provides a description of the projects which comprise the Other Power Equipment program.

For ease of comparison, BCTC has set out the projects in the program in the same order as presented in the F2009 TSCP. Existing projects are set out first, followed by new projects within the program.

6.5.3.2.1 Mechanical Transformer Electronic Temperature Monitor (ETM) Upgrades

This project was described in the F2009 TSCP. To accommodate projects of higher priority in the Sustaining Capital portfolio, the project has been deferred outside of the 10-year planning period.

6.5.3.2.2 Surge Arrestor Replacements and Additions Program

This project was described in the F2009 TSCP. There is no change to activity level for this project, which will be completed in F2011.

6.5.3.2.3 Disconnect Switch Rebuild (230 kV and 500 kV)

This project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. BCTC expects the activity level for this project to remain similar year-over-year.

6.5.3.2.4 Cathedral Square – Relocation of 2L31/32 Line Terminations

This project was described in the F2009 TSCP.

The first part of this project addressed the removal of the existing CO2 fire suppression system that presented an unacceptable life-safety risk for personnel working in Cathedral Square due to a high volume of CO2 in an underground substation. This part of the work will be completed in F2009.

The second part of the project was intended to address the removal of a fire hazard in the gas insulated switchgear room of the substation where the oil-filled cables for Circuits 2L31 and 2L32 terminate. This part of the project was scheduled to be completed in F2010; however, upon further investigation, it was found that the fire risk could be reduced without re-terminating the cables. The revised solution called for the installation of a localized water sprinkler system and installation of gravel for fire suppression in the GIS room. This work was completed in F2009.

6.5.3.2.5 VIT SC4 and SC3 Overhaul

This project was described in the F2009 TSCP. The overhaul of Vancouver Island Terminal SC3 and 4 was scheduled to be completed in F2009; however, in order to accommodate projects of higher priority in the Sustaining Capital portfolio within the approved F2009 funding levels, the project was deferred to F2010.

6.5.3.2.6 Dehydrating Breathers on Transformers

This project was described in the F2009 TSCP. To accommodate projects of higher priority in the Sustaining Capital portfolio, this project has been deferred outside of the 10-year planning period.

6.5.3.2.7 PCB Equipment Replacement

This project was described in the F2009 TSCP and will be completed in F2010. There is no change to the activity levels of this project.

6.5.3.2.8 CHP MLS KDY Control System Upgrade

This is a new project that will be initiated in F2011 and is scheduled for completion in F2013.

The Chapman's (CHP), McLeese (MLS) and Kennedy (KDY) series capacitor banks perform a vital function in maximizing the capability of the transmission system. The series capacitor banks at these stations provide increased energy transfer capability from the Peace area generating stations to the Lower Mainland and Vancouver Island. For example, the failure of the series capacitor bank at Chapman's would result in a reduction of energy transfer capability of 400 MW. The consequence of failure would mean that transfers to Lower Mainland and Vancouver Island may have to be reduced.

The control systems at these stations allow the series capacitor banks to function. The control systems are at end-of-life asset condition and are experiencing a high failure rate, cannot be repaired, and are no longer supported by the Original Equipment Manufacturer (OEM). The redundant design of the control systems have meant that past failures have not resulted in loss of the function of the series capacitor banks. However, BCTC believes that the increasing failures of the units from 1 to 9 failures per year indicate that there is an increased risk that both control units could fail at the same time, reducing the ATC of the transmission system to the Lower Mainland, which BCTC considers to be unacceptable.

6.5.3.2.9 Transformer Deficiency Upgrades

This is a new project that will be initiated in F2010 and is forecast to continue at a constant level of activity for the remainder of the 10-year planning period.

This project will deal with the capital upgrades to transformer components that fail. In prior years, these replacements and upgrades were charged to the Other Power Equipment program. BCTC is initiating a separate project to address an increasing number of failures. When replaced, the new components will extend the useful life of the transformer or enhance its functionality. Examples of component upgrades include the replacement of failed transformer temperature monitoring devices, transformer load tap changers, and transformer composite bushings.

6.5.3.2.10 System Spare Transformers

This is new project that will be initiated in F2011 and completed in F2013.

BCTC’s current strategy for transformer replacements is to use system spare transformers to replace a failed transformer within 14 days of the failure. This strategy calls for an inventory of spare transformers that can be deployed across all system transformer asset classes.

During F2009, BCTC conducted an inventory and analysis of transformers on the system and available spare transformers that can be used for emergency deployment. The study identified the need to purchase 3 system spare transformers to address identified gaps in the system spare transformer inventory. These will be used to support substations at Gordon M. Shrum and Skeena, as well as a spare station-service transformer that can be deployed throughout the province.

6.5.4 Stations Risk Mitigation

The Stations Risk Mitigation program addresses safety, seismic, environment, severe weather, and security risk. Each risk is evaluated based on business impact (e.g., reliability, financial, environmental, safety, relationships) and probability of occurrence to determine the appropriate magnitude and duration of investment that is required to mitigate the risk to acceptable levels.

The key drivers for the Stations Risk Mitigation program are:

(a) Manage Risks (safety, seismic, environment, extreme weather, and security); and

(b) Maintain System Reliability.

Table 6-11 summarizes the proposed capital expenditures for the Stations Risk program for F2010 and F2011. Table 6-11 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-11. Annual Forecast of Stations Risk Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$8.3	$7.1	($1.2)	$7.0	($0.1)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$8.3	$7.1	($1.2)	$7.0	($0.1)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.4.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 of $7.1 million are $1.2 million lower than the planned expenditures presented in the F2009 TSCP. This decrease is due to deferral of the Murrin Substation Reconfiguration and Seismic Upgrade Project and the deferral of the Seismic Upgrade to the Telecom Buildings Project from F2010 to F2013. This is partially offset by the addition of the Kidd 1 Crib Wall Reinforcement with Rip Rap Wall, the Overhead Groundwire Replacement, and the Station Safety Upgrades at Britt Creek (BCK), Elkford (EKL) and Kimberley (KBY) Projects.

The proposed capital expenditures planned for F2011 do not vary materially from the proposed expenditures for F2010.

6.5.4.2 Stations Risk Mitigation Projects

This section provides a description of the projects which comprise the Stations Risk Mitigation program.

The following projects were described in the F2009 TSCP, are ongoing over the 10-year planning period, and are expected to have similar activity levels year over year:

(a) Security; and

(b) Fire Protection.

6.5.4.2.1 Oil Spill Containment

This project was described in the F2009 TSCP and is ongoing for the 10-year planning period. However, BCTC is intending to reduce the activity level for this project in F2010 and for activity levels then to remain constant year over year. The decreased activity level is required to accommodate other projects of higher priority in the Sustaining Capital portfolio.

6.5.4.2.2 Stations Seismic Structural Upgrade

This project was described in the F2009 TSCP and is ongoing for the 10-year planning period. However, the project activity level has been decreased to accommodate other projects of higher priority in the Sustaining Capital portfolio.

6.5.4.2.3 Seismic Upgrade to Telecom Buildings

This project was described in the F2009 TSCP and is ongoing for the 10-year planning period. However, the project activity level has been decreased to accommodate other projects of higher priority in the Sustaining Capital portfolio.

6.5.4.2.4 Murrin Substation Reconfiguration and Seismic Upgrade

This project was described in the F2009 TSCP and has been removed from the Stations Risk Mitigation program. It will be submitted to the Commission as a separate CPCN application.

6.5.4.2.5 Drop-in Substation Control Building

This project was competed in F2009.

6.5.4.2.6 KIDD 1 Crib Wall Reinforcement with Rip Rap Wall

This is a new project proposed to start and be completed in F2010.

KIDD 1 Substation is adjacent to the Fraser River. The project is required to replace the existing deteriorated crib wall at the substation. The crib wall forms a vital structural component of the substation and is used to protect the substation property from erosion by the Fraser River. Failure to protect the substation property from erosion will result in damage to substation infrastructure and potential impacts to reliability.

Temporary repairs were completed to the crib wall in F2008 that allowed permanent repairs to be deferred to F2010.

6.5.4.2.7 Overhead Groundwire Replacement

This is a new project proposed to start in F2010 and that would continue for the remainder of the 10-year planning period. The activity level for this project is generally anticipated to remain constant year over year.

Overhead groundwire is used for lightening protection at substations to prevent substation equipment from being damaged by lighting strikes. Because the groundwire is overhead, failure of the wire will most likely result in a total station outage as the failed groundwire would fall across substation live bus work, causing a fault to occur. In addition, the potential failure of a groundwire poses a life-safety risk for personnel working in the substation.

The condition of groundwire is determined by inspection. The inspections show that some groundwires are deteriorated and are now at end-of-life condition and have been assessed with a high risk of failure and require replacement.

6.5.4.2.8 Kimberley, Britt Creek and Elkford Substation Safety Mitigation

This is a new project that is proposed to start in F2010 and be completed in F2011.

Kimberley, Britt Creek and Elkford Substations were originally built by other utilities and were subsequently acquired by BC Hydro.

BCTC completed an on-site assessment of the substations in F2009. The assessment considered worker and public safety hazards relative to BCTC's current safety standards and found deficiencies.

This project is required to upgrade these substations to current BCTC safety standards to mitigate identified safety issues associated with low clearance high-voltage bus work, inadequate substation grounding, and deteriorated perimeter fencing.

6.5.5 Protection and Control

Protection and Control (P&C) assets consist of all protective relaying and control systems at transmission stations. P&C assets isolate transmission equipment from electrical faults, ensure stability and reliability of the transmission system, and provide local and remote control and monitoring of the transmission system.

The key drivers for the Protection and Control program are:

(a) Maintain System Reliability (Asset Condition, Asset Performance); and

(b) Third-party Requested Initiatives.

Table 6-12 summarizes the proposed capital expenditures for the Protection and Control program for F2010 and F2011. Table 6-12 also shows the proposed plan-over-plan variance for F2010, and the year-over-year variance for F2011 (F2011

expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-12. Annual Forecast of Protection and Control Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$10.1	$14.1	$4.0	$10.6	($3.5)
2	3rd-Party	$1.1	$2.6	$1.5	$1.8	($0.8)
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$11.2	$16.7	$5.5	$12.4	($4.3)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.5.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 of $16.7 million vary from the planned expenditures of $11.2 million presented in the F2009 TSCP. The variance of $5.5 million is a result of an increase in F2010 due to deferral of the following projects from F2009 to F2010 to accommodate the approved F2009 funding level for the Sustaining Capital portfolio:

(a) Programmable Logic Controller Replacement project;

(b) a portion of the Voltage and VAR Optimization project; and

(c) a portion of Protection & Control Replacement project.

BCTC is also forecasting an increase in activity of $1.5 million to previously described Third Party requested projects in F2010 (Voltage and VAR Optimization and Protection, Control, Metering Upgrade projects).

The proposed capital expenditures in F2011 are forecast to decrease by $4.3 million as work deferred from F2009 to F2010 is completed.

6.5.5.2 Protection and Control Projects

This section provides a description of the projects which comprise the Protection and Control program.

The following projects were described in the F2009 TSCP. These projects are ongoing initiatives for the 10-year planning period, with the exception of the 500 kV Digital Fault Recorder Replacement Project, which is expected to be completed in F2014. BCTC expects that the activity levels for the following projects will remain similar from year to year:

(a) Station SCADA Remote Supervisory/Telemetry System Refurbishments and Replacements;

(b) P&C Minor Capital Add and Replace Program; and

(c) 500 kV Digital Fault Recorder Replacements.

6.5.5.2.1 Protection and Control Replacements

This project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The proposed activity level for this project is generally anticipated to remain constant year-over-year, except for F2010 where the activity level includes carry-forward of work partially deferred from F2009 to accommodate approved funding limits.

6.5.5.2.2 Programmable Logic Controller Replacement

The project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The proposed activity level for this project is generally anticipated to remain constant year-over-year, except for F2010 where the activity level includes carry-forward of work deferred from F2009 to accommodate approved funding limits.

6.5.5.2.3 Voltage and VAR Optimization

This Third Party requested project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The proposed activity level for this project is generally anticipated to remain constant year-over-year, except for F2010, where activity includes carry-forward of work partially deferred from F2009 to accommodate approved funding limits.

6.5.5.2.4 Protection, Control, and Metering Upgrades

This Third Party requested project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The proposed activity level for this project is generally anticipated to remain constant year-over-year, except for F2010, where activity includes carry-forward of work partially deferred from F2009 to accommodate approved funding limits.

6.5.6 Telecommunications

BCTC operates a telecommunications system to support transmission system protection, control, voice, and data communications. The telecommunications system infrastructure includes microwave radio, powerline carrier, fibre-optic cable, copper pairs, leased line, and VHF/UHF radio. The primary purpose of the telecommunications system is to protect the transmission system.

The key driver for the Telecommunications program is:

(a) Maintain System Reliability (Asset Condition, Asset Performance).

Table 6-13 summarizes the proposed capital expenditures for the Telecommunications program for F2010 and F2011. Table 6-13 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-13. Annual Forecast of Telecommunications Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$5.3	$5.4	$0.1	$4.3	($1.1)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$5.3	$5.4	$0.1	$4.3	($1.1)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.6.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 do not vary materially from the planned expenditures presented in the F2009 TSCP.

The proposed capital expenditures planned for F2011 decrease $1.1 million from the forecast F2010 expenditures due to the completion of the Chapman’s Fibre Optic Cable Replacement Project, partially offset by the addition of the Nelway-Metaline Microwave Radio Replacement Project.

6.5.6.2 Telecommunications Projects

This section provides a description of the projects which comprise the Telecommunications program.

For ease of comparison, BCTC has set out the projects in the program in the same order as presented in the F2009 TSCP. Existing projects are set out first, followed by new projects within the program.

The following projects were described in the F2009 TSCP and are expected to have similar activity levels year over year:

(a) Access Roads, Bridges, and Helipads Work for Microwave Stations;

(b) Telecommunications Minor Capital; and

(c) High Voltage Entrance Protection Replacement.

6.5.6.2.1 Chapmans (CHP) Fibre Optic Cable Replacement

This project was described in the F2009 TSCP. A portion of the project was deferred to F2010 due to a change in project schedule. The project is expected to be completed in F2010.

6.5.6.2.2 24 Volt Battery / Charger Replacement

This project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The activity level for this project has been reduced in F2011 and then held generally constant for the remainder of the 10-year planning period. The decrease accommodates other higher priority projects with the Sustaining Capital portfolio.

6.5.6.2.3 Tone and Test Equipment Panel Replacements

This project was described in the F2009 TSCP and is an ongoing initiative until F2014. Activity levels for this project are expected to remain similar from year to year until completion.

6.5.6.2.4 Power Line Carrier Replacement

This project will be completed in F2009.

6.5.6.2.5 Fire Protection

This project was described in the F2009 TSCP and is expected to be completed in F2010.

6.5.6.2.6 Lower Mainland Network Robustness

This project will be completed in F2009.

6.5.6.2.7 Point to Multipoint Radio

This project was described in the F2009 TSCP and has been cancelled to accommodate projects of higher priority in the Sustaining Capital portfolio. The asset replacement strategy now is to remove existing point to multipoint radio infrastructure at substations when telecommunications upgrades are required to accommodate other Protection and Control upgrade projects. The point to multipoint radio will be replaced with alternative telecommunication infrastructure, for example, leased lines.

6.5.6.2.8 Nelway-Metaline Microwave Radio Replacement

The Nelway-Metaline Microwave Radio link provides telecommunications circuits required to support teleprotection, Remedial Action Schemes, SCADA, and telephone trunks connecting the transmission system with BPA. The radio link is required to ensure that system reliability and system transfer capability is maintained. If there is a loss of teleprotection, at a minimum, the affected circuits would be de-rated which would result in reduced energy transfer capability and there is a possibility that the affected circuits may need to be taken out of service.

The need for this project was described in the 2007 STSR. The existing radio system is functional but now obsolete. The system is no longer supported by the Original Equipment Manufacturer and repair of the system is not a viable option. This project will replace the existing radio system with a new radio system to mitigate the risk of failure due to no spare parts being available. During the year, BCTC entered into a commitment with BPA to start the project jointly in F2010, with completion expected to be in F2011.

6.5.7 Cable Sustainment

Underground and submarine cables are generally used where overhead lines are not feasible or where there is a particular siting reason to use cables. There are over 400 km of underground or submarine cables on the transmission system. Most of these circuits are located in Vancouver, Burnaby, Coquitlam and Victoria, and include 69 kV, 138 kV, 230 kV and 500 kV voltage levels.

The key drivers for the Cable Sustainment program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

Table 6-14 summarizes the proposed capital expenditures for the Cable Sustainment program for F2010 and F2011. Table 6-14 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011

expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-14. Annual Forecast of Cable Sustainment Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$5.5	$5.3	($0.2)	$4.8	($0.5)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$5.5	$5.3	($0.2)	$4.8	($0.5)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.7.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 do not vary materially from the planned expenditures presented in the F2009 TSCP.

The proposed capital expenditures planned for F2011 decrease marginally ($0.5 million) from the planned F2010 expenditure levels due to the scheduled completion of the following projects:

(a) Oil Containment Installation at Submarine Cable Terminating Stations;

(b) Stop Joint Monitoring – Risk Mitigation; and

(c) Cable Replacements for 60L93 and 60L94 project.

The completion of these projects is partially offset by the addition of the following new projects:

(d) 5L29/5L31 Distributed Temperature Sensing;

(e) 5L29/5L31 Pumping Plan Upgrade;

(f) Cable Refurbishment Program; and

(g) 230 kV Pothead Protection Program.

6.5.7.2 Cable Sustainment Projects

This section provides a description of the projects which comprise the Cable Sustainment program.

The following projects were described in the F2009 TSCP and were completed in F2009:

(a) 2L51 Life Extension.

(b) 2L31 Cable Restoration – Life Extension;

(c) Stop Joint Explosion Protection – Risk Mitigation;

(d) 5L29 and 5L31 Corrosion Protection; and

(e) Manhole Oil Containment – Risk Mitigation.

The following projects have been described in the F2009 TSCP and, as indicated above, will be completed in F2010:

(a) Oil Containment Installation and Submarine Cable Terminating Stations;

(b) Cable Replacements for 60L93 and 60L94; and

(c) Stop Joint Monitoring.

The other projects in this category are as follows:

6.5.7.2.1 Cable Emergency Preparedness

This project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The activity level for this project is generally anticipated to remain constant year over year.

6.5.7.2.2 5L29/31 Distributed Temperature Sensing (DTS) Monitoring System Upgrade

This is a new project proposed to start in F2011 and be completed in F2011.

A distributed temperature sensing (DTS) monitoring system consists of a fibre optic cable, which acts as a temperature sensor, and various electronics and computers used for monitoring and trending. DTS monitoring systems are useful for monitoring the temperature of the cables in a circuit as well as in the implementation of dynamic thermal rating systems that allow circuits to operate more closely to their thermal rating and therefore at a higher capacity, deferring other capacity additions or enhancements.

The 500 kV submarine circuits to Vancouver Island (5L29 and 5L31) have utilized DTS monitoring systems for several years. These are used to measure the temperature of the cable in real time which allows an incremental increase of 150 MW in capacity from what would otherwise be available.

Two recent DTS monitoring system failures have highlighted the need to replace the electronics and computers that manage the DTS system. If the DTS system does not function this would result in the loss of 150 MW of capacity to Vancouver Island.

6.5.7.2.3 5L29/31 Pumping Plant Upgrade

This is a new project proposed to start and be completed in F2011.

Circuits 5L29 and 5L31 rely on eight pumping plants to maintain oil flow and pressure inside the cables. Pumping plants consist of a large fluid reservoir tank, pumps, motors, valves, nitrogen bottles, and a control panel with alarms and gauges. These systems are designed to be highly reliable and have the ability to communicate the cable system status to either a system operator at the Control Centre or to a local operator at the pumping plant location.

The pumping plants were manufactured in 1983 and spare parts are becoming increasingly difficult to obtain or, in some cases, are not available. Because of the obsolescence issue, it is necessary to replace and upgrade components (identified above) of the pumping plants identified to be in poor condition to ensure their continued reliability and functionality. Failure of a pumping system could result in cable damage.

6.5.7.2.4 Cable Refurbishment Program

This is a new program proposed to start in F2011 that was previously conducted as a number of small discrete projects. The program will be ongoing with planned activity level generally at the same level as prior years and over the remainder of the 10-year planning period.

The objective of the program is to refurbish sections of cable circuits in order to extend the life of the entire asset.

Cable circuits suffer from three major causes of failure: corrosion due to compromised cable jackets; cracks caused by sheath fatigue; and partial discharge in joints. Cable defects are identified through regular routine maintenance performed periodically throughout the year, including inspections and regular testing, such as dissolved gas analysis. Condition assessment studies are performed on circuits when regular maintenance uncovers significant problems or the cables approach end of life. These studies go into significantly more detail than regular inspections and may include dye penetrate testing, eddy current testing, and metallurgical analysis.

Based upon routine maintenance and condition assessment studies, 300 m of Circuits 2L143 and 2L146 are proposed to be refurbished in F2011 as part of this program. Refurbishment will consist of replacing sections of cable exhibiting corrosion or fatigue, and replacing cable joints that are exhibiting high levels of partial discharge.

Program work may involve refurbishment or replacement of sections of a cable or replacement of stop joints experiencing unacceptable performance characteristics.

6.5.7.2.5 230 kV Pothead Protection Program

This is a new project proposed to start in F2011 and to be completed in F2012.

Potheads - also called terminations or sealing ends - are required for circuits to transition from underground cables to overhead lines. They provide electrical stress control, insulation between the conductor and ground, and a seal against the environment.

Six 230 kV pothead sites are vulnerable to vandalism due to their location. Three of these potheads have suffered damage in the past 5 years due to vandalism. To mitigate the impacts of vandalism, this project would install mesh fence barriers providing a cost effective solution to protect the potheads and cables.

6.5.8 Overhead Lines Life Extension

The overhead transmission network consists of conductor systems, metal support structures, wood poles, and associated equipment which includes spacer dampers, aircraft warning markers, and disconnect switches. The overhead network has a total of 18,000 km of transmission lines with a replacement value of approximately $6 billion. These circuits include approximately 22,000 metal support structures and approximately 100,000 wood poles.

The key drivers for the Overhead Lines Life Extension program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

Table 6-15 summarizes the proposed capital expenditures for the Overhead Lines Life Extension program for F2010 and F2011. Table 6-15 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditure have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-15. Annual Forecast of Overhead Lines Life Extension Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$15.1	$16.0	$0.9	$16.0	$0.0
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$15.1	$16.0	$0.9	$16.0	$0.0

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%
Note 2: Amounts are stated in F2010 real dollars

6.5.8.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 are approximately $0.9 million higher than the previously planned F2010 expenditures. This increase is due to minor increases in expenditures associated with a number of projects in the program such as the Insulator Replacements, the Aircraft Marker Crossings Refurbishment, Upgrade or Replacements, and the Disconnect Switch (69kV and 138 kV) Replacements projects and the addition of a new project, the 500 kV Polymer Replacement Project.

The proposed capital expenditures planned for F2011 do not vary from the expenditures proposed for F2010.

6.5.8.2 Overhead Lines Life Extension Projects

This section provides a description of the projects which comprise the Overhead Lines Life Extension program.

The following projects were described in the F2009 TSCP and are ongoing over the 10-year planning period with similar activity levels year over year:

(a) Wood Pole Replacements;

(b) Circuit Refurbishments;

(c) Disconnect Switch (69 kV and 138 kV) Replacements;

(d) Spacer-Damper Replacements;

(e) Overhead Lines Minor Capital;

(f) Insulator Replacements; and

(g) Long Span Crossing Refurbishment.

6.5.8.2.1 Aircraft Marker Crossings Refurbishment, Upgrade or Replacements

This project was described in the F2009 TSCP and is ongoing over the 10-year planning period. The proposed activity level for this project is generally anticipated to remain constant year over year.

In Directive 20(a) of the F2009 TSCP Decision (p. 87), the Commission directed BCTC to “report in future capital plan filings, and until directed otherwise, the total costs-to-date for each of the six OCAS installations anticipated in F2009 along with a comparison to the original life cycle cost analysis.”

The description of this project in the F2009 TSCP stated that “The project will implement approximately six marked crossings in each of F2009 and F2010”. For clarity, the six crossings planned for marking include both traditional marker balls and OCAS. Two OCAS systems were installed in F2008 and the plan for F2009 is to install two further OCAS systems.

In response to Directive 20(a), the actual cost to date per OCAS unit installed in F2008 is $267 thousand.

For the F2008 program, the projected PV life cycle costs for the comparison of Marker Ball / OCAS is 1.27. Based on actual costs, the actual PV life cycle costs for the comparison of Marker Ball / OCAS is 1.12.

For the F2009 program, the projected PV life cycle costs for the comparison of Marker Ball / OCAS is 1.16. Actual costs for F2009 will be available when the installations are completed.

6.5.8.2.2 Above Ground Structural Corrosion Protection

This project was described in the F2009 TSCP as Transmission Tower Corrosion Protection, but has been renamed. The project is an ongoing initiative for the 10-year planning period. The proposed activity level for this project is generally anticipated to remain similar year over year.

6.5.8.2.3 Underground Structural Corrosion Protection

This project was described in the F2009 TSCP as Guy and Anchor Rod Replacement, but has been renamed. The project is an ongoing initiative for the 10-

year planning period, and the proposed activity level is generally anticipated to remain similar year over year.

6.5.8.2.4 Transmission Wood Structure Framing Replacements

This project was described in the F2009 TSCP as Single Wood Crossarm with Line Posts Replacement, and has been renamed. The project is an ongoing initiative for the 10-year planning period and the proposed activity level is generally anticipated to remain similar year over year.

6.5.8.2.5 Transmission Structural Steel Replacement Project

This is a new project proposed to start in F2011 and to continue for the remainder of the 10-year planning period.

This program is to refurbish steel transmission towers and structures in order to mitigate the risk of weakened, aged or vulnerable structures falling over and leading to potential forced outages. This progam will ensure the continued serviceability of these key infrastructure assets at a lower cost than would result if the structures were allowed to deteriorate and fail.

Galvanized steel structures have an average design in-service life of 50 years in benign environments. Currently, it is estimated that a significant number of structures are close to 90% or more of their theoretical design loading capacity due to the fact that structures are originally designed efficiently to use most of their capacity. The average age of steel structures on the transmission system is 32 years and maintenance and inspection records indicate several defects due to use and age. The defects range from foundations to structural steel and connections. Definition work will provide a better idea of specific numbers, risks, and what methods would be most effective in mitigation and extending tower life.

Refurbishments due to corrosion, environmental-related loadings or civil defects are covered under other programs; whereas this program is proposed to capture purely structural upgrades and replacements. In some instances, steel members may be replaced, reinforced or modified and even complete structure replacements may be carried out if this is the most cost-effective option in order to extend the life of the structures.

An internal definition study will be carried out in F2010 to determine the scope and scale of the required investments and this will drive the F2011 replacement program planning, costs and schedule.

6.5.8.2.6 500 kV Polymer Replacement Project

This is a new project proposed to start in F2010 and to be completed in F2011.

The project will address the replacement of all 500 kV polymer insulators that are in the transmission system. 500 kV polymer insulators were installed in the 1980's and have a life expectancy of 25 years. Failure of insulators results in energized conductors falling to the ground resulting in reduced reliability and public and worker safety issues. As insulating properties degrade, reliability is also impacted due to flashunder caused by switching surges or lightning.

The asset condition of the 500 kV polymer insulators presents an unacceptable life-safety risk for workers that perform "live-line" activities. It is not safe to perform live-line activities on these insulators and, therefore, maintenance requires circuit outages, which are very difficult to schedule for the 500 kV lines. Most other Canadian utilities have experienced flashunder failures with this class and vintage of polymer insulator. A program to remove the end-of-life/defective insulators is required to mitigate the risk of insulator failure.

6.5.9 Overhead Lines Performance Improvements

Transmission lines may be deficient due to localized climate issues, which were not identified when the line was built, and require work to bring that section of the line back to the reliability level designed into the line as a whole. Examples of this are local unequal ice loading, lightning-prone sections, or salt fog on a short section of line. Currently, the focus of this program is on reducing lightning caused outages.

Transmission lines that traverse through seasonally dry high elevation areas are subject to repeated lightning strikes. The regions of Prince George, Kootenay and the Southern Interior are most affected by lightning strikes. Lightning strikes, and even switching operations in some cases, can cause power surges that may result in significant impacts, such as transmission line outages, customer outages, insulator damage, and damage to other transmission equipment.

On a system-wide basis, approximately 2 percent of the total System Average Interruption Duration Index (SAIDI) is caused by lightning.

The key drivers for the Overhead Lines Performance Improvements program are:

(a) Maintain System Reliability (Asset Condition, Asset Performance); and

(b) Risk Mitigation (Safety, Environment).

Table 6-16 summarizes the proposed capital expenditures for the program for F2010 and F2011. Table 6-16 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-16. Annual Forecast of Overhead Lines Performance Improvements Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$5.1	$4.8	($0.3)	$2.1	($2.7)
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$5.1	$4.8	($0.3)	$2.1	($2.7)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.9.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 are marginally lower than the previously planned expenditures. This decrease is due to minor changes in planned activity for arcing horn installations to address other higher priority projects within the Sustaining Capital portfolio.

The proposed capital expenditures planned for F2011 are $2.7 million lower than the expenditures proposed for F2010, and is again due to changes in planned activity for arcing horn installations as discussed in previous TSCPs , and to address other higher priority projects within the Sustaining Capital portfolio.

6.5.9.2 Overhead Lines Performance Improvement Projects

This section provides a description of the projects which comprise the Overhead Lines Performance Improvement program.

6.5.9.2.1 Arcing Horn Installations

This project was described in the F2009 TSCP and is an ongoing initiative for the 10-year planning period. The activity level for this project is being reduced in F2011 as discussed in the F2009 TSCP and to accommodate other projects of higher priority in the Sustaining Capital portfolio. It is then generally anticipated to remain constant year over year for the remainder of the planning period.

6.5.10 Overhead Lines Risk Mitigation

The Overhead Lines Risk Mitigation program addresses issues and potential events which could put the system at risk of a prolonged outage or pose safety concerns. The risk of forest fires sparked by pole-top fires is mitigated under this program as well as risks to the public safety and operating concerns associated with end-of-life overhead conductors and deficient transmission line-to-ground clearances. Civil protective work is included to ensure the long-term stability of transmission structures. Potential low-probability high-consequence events, such as seismic and wind and ice storms, are also addressed by this program.

The key drivers for the Overhead Lines Risk Mitigation program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

Table 6-17 summarizes the proposed capital expenditures for the Overhead Lines Risk Mitigation program for F2010 and F2011. Table 6-17 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-17. Annual Forecast of Overhead Lines Risk Mitigation Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$9.4	$8.7	($0.7)	$12.4	$3.7
2	3rd-Party	$0.0	$0.0	$0.0	$0.0	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$9.4	$8.7	($0.7)	$12.4	$3.7

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.10.1 Expenditure Variance Analysis

The proposed capital expenditures for F2010 of $8.7 million are $0.7 million lower than the planned expenditure presented in the F2009 TSCP due to the deferral of the Seismic Withstand Project from F2010 to F2011. The proposed capital expenditures planned for F2011 are $3.7 million higher than the proposed expenditures for F2010, due to the deferral of the Seismic Withstand project from F2010 to F2011 and an increase in scope for this project in F2011. The deferral of the project was required to accommodate other projects of higher priority within the Sustaining Capital portfolio within the reduced F2009 level of expenditures.

6.5.10.2 Overhead Lines Risk Mitigation Projects

This section provides a description of the projects which comprise the Overhead Lines Risk Mitigation program.

The following projects were described in the F2009 TSCP, are ongoing, and are expected to have similar activity levels year over year:

(a) Bonding Installations;

(b) Civil Protective Works;

(c) Clearances for Circuits;

(d) Ice Hazard Reduction;

(e) Automatic Splice Replacement Program;

(f) Copper Conductor Replacement Program;

(g) STER Tower and Equipment Replacement Program; and

(h) Tower Barrier and Signage Program.

6.5.10.2.1 Transmission Lines Seismic Withstand

This project was described in F2009 TSCP as Seismic Withstand and has been renamed.

The focus of this project was to reinforce the Second Narrows Crossing tower as an essential system component that carries two 230 kV circuits between Vancouver and the North Shore. The project commenced in F2007 and was to be completed in F2009. However, Definition work completed in F2008 provided new information on property rights, geotechnical suitability, and project execution costs and methods, resulting in a re-evaluation of the preferred solution. Following the review and input of third party consultants, the analysis has been completed and the preferred solution provides for an effective reinforcement from a technical and planning perspective.

Additionally, the terminal tower (2L56) located west of the Knight Street bridge, adjacent to the north arm of the Fraser River, is located in seismically unstable soil and may be subject to liquefaction during a seismic event. Initial Definition work commenced in F2009 and will be completed in F2010. The Definition Phase analysis defined the feasibility and costs for the execution phase of the project, which is scheduled to be completed in F2011 to F2012.

Future seismic withstand projects may become known as BCTC continues its review of transmission lines seismic preparedness.

6.5.10.2.2 Overhead Ground Wire Replacement Program

This project was described in the F2009 TSCP to address current transmission line overhead ground wire issues and is expected to be completed in F2010. The proposed activity levels are generally expected to remain similar year-over-year.

6.5.10.2.3 2 Metre (m) Line Post Insulator Replacement

This is a new project proposed to start in F2011 which is expected to be completed in F2015.

There are many 69 kV structures that have a non-standard 138 kV insulator (2 m line post insulator) installed to increase ground clearance. The 2 m line post insulator is approximately twice the length of a standard 69 kV insulator. The extra length causes a load increase which results in pole and cross arm deflection or damage, which can cause the cross arm to fail and, in the worst case, could cause the conductor to fall to the ground. Cross arm damage and deflections are generally found during maintenance inspections. An inspection completed in F2008 has identified many of these defects.

The scope of the project is to replace the existing non-standard 2 m line post insulators with standard 69 kV line post insulators and taller poles, should they be required, for ground clearance.

6.5.11 Rights-of-Way Sustainment

BCTC is responsible for managing the rights-of-way (ROW) and assets that allow access to and work to be performed on the system. ROW Sustainment provides infrastructure for overhead transmission lines, relocates transmission assets due to highway rerouting according to the protocol with the Ministry of Transportation, acquires and renews legal status of rights-of-way for overhead transmission lines throughout the province, and identifies, assesses, and restores rights-of-way assets that are in poor condition.

The key drivers for the ROW Sustainment program are:

(a) Maintain System Reliability (Asset Condition); and

(b) Risk Mitigation (Safety, Environment).

Table 6-18 summarizes the proposed capital expenditures for the ROW Sustainment program for F2010 and F2011. Table 6-18 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011

expenditures have been restated in F2010 dollars to aid in comparison of year-over-year variance analysis).

Table 6-18. Annual Forecast of Rights-of-Way Sustainment Expenditures ($ Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$7.7	$8.1	$0.4	$7.7	($0.4)
2	3rd-Party	$2.2	$2.2	$0.0	$2.2	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$9.9	$10.3	$0.4	$9.9	($0.4)

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.11.1 Expenditure Variance Analysis

The proposed capital expenditures for this program in F2010 and F2011 do not vary materially from the activity level described in the F2009 TSCP. The small year over year variances in F2010 and F2011 reflect minor changes in planned activity over a number of projects, including the cancellation of the 5L30 and 5L32 McNabb Creek Road Licence Project (planned for F2010).

6.5.11.2 Rights-of-Way Sustainment Projects

This section provides a description of the projects which comprise the Rights-of-Way Sustainment program.

The following projects were described in the F2009 TSCP, are ongoing over the 10-year planning period, and are expected to have similar activity levels year-over-year:

(a) Transmission Highway Relocations;

(b) Acquire Miscellaneous Rights-of-Way;

(c) Deficient Rights-of-Way Study and Acquisition;

(d) Rights-of-Way Access Program Definition and Refurbishment; and

(e) Enterprise Geographic Information System (EGIS) Enhancement.

6.5.11.2.1 5L30 5L32 McNab Creek Road License

This project was described in the F2009 TSCP and has been cancelled due to work undertaken by the Ministry of Forests. No further activity is planned for this project.

6.5.12 Right-of-Way Sustainment Programs – Third Party Funded Projects

Third-party requested line relocations are those projects for which BCTC enters into an agreement with a third-party who wishes to have transmission lines relocated and who will pay for all costs incurred under the project, resulting in an offsetting Contribution in Aid of Construction for the capital expenditure. Approval is sought only for the projects that have a signed agreement with the third-party. Funding for future third-party projects has been estimated based on anticipated projects and historical investment levels. BCTC is not exposed to any of the costs for third-party funded projects. Any costs above or below the estimate are managed through the contract language in the third-party Transmission Line Relocation Agreement (i.e., refund or invoice).

Key drivers are:

(a) Risk Mitigation (Safety); and

(b) Third-Party (Relationships).

Table 6-19 summarizes the proposed capital expenditures for the program for F2010 and F2011. Table 6-19 also shows the proposed plan-over-plan variance for F2010, and the proposed year-over-year variance for F2011 (F2011 expenditures have been restated in F2010 dolllars to aid in comparison of year-over-year variance analysis).

Table 6-19. Annual Forecast of Rights-of-Way Sustainment Programs – Third Party Funded Projects Expenditures ($Millions)

		TSCP F2009-F2018 F2010 (note 1)	TSCP F2010-F2019 F2010	Plan-over-Plan Variance	TSCP F2010-2019 F2011 (note 2)	F2011-over-F2010 Variance (note 2)
		(a)	(b)	(c)=(b)–(a)	(d)	(e)=(d)–(b)
1	Core	$0.0	$0.0	$0.0	$0.0	$0.0
2	3rd-Party	$2.2	$2.2	$0.0	$2.2	$0.0
3	Emergency	$0.0	$0.0	$0.0	$0.0	$0.0
4	Total	$2.2	$2.2	$0.0	$2.2	$0.0

Note 1: Amounts are adjusted to reflect approved inflation rate of 2.1%

Note 2: Amounts are stated in F2010 real dollars

6.5.12.1 Expenditure Variance Analysis

The proposed capital expenditures planned for F2010 and F2011 do not vary from the planned expenditure presented in the F2009 TSCP.

6.5.12.2 Rights-of-Way Sustainment – Third Party Funded Projects

This section provides a description of the projects which comprise the Rights-of-Way Sustainment – Third Party Funded Projects program.

For ease of comparison, BCTC has set out the projects in the program in the same order as presented in the F2009 TSCP. Existing projects are set out first. Since there are many third party funded projects annually, only noteworthy new projects are described for initiation in F2010.

The following projects were described in the F2009 TSCP and are expected to be completed during F2009:

(a) RAV (Canada) Line: Cambie Cut and Cover Relocations; and

(b) Sea to Sky Highway Project Relocations.

6.5.12.2.1 Blackstone Relocation

This is a new third-party funded project to start in F2010.

The definition of this project was initiated in F2009 and the execution is expected to commence in late F2009 or early F2010. The project is to relocate portions of Circuits 60L281 and 60L292 (which are presently in trespass) in Fernie to accommodate the Blackstone development.

6.5.12.2.2 Port Mann Bridge Twinning Relocation

This is a new third-party funded project proposed to start in F2010.

The project is required to accommodate the proposed twinning of the Port Mann Bridge under the TransLink Gateway project. The scope of this project will depend upon the final design of the new bridge and approach roads which is expected in late 2008 or early 2009. The transmission assets that are being affected are currently located on BC Hydro rights-of-way, and so will be fully-funded. The new bridge construction will be conducted by a third party concessionaire to TransLink.

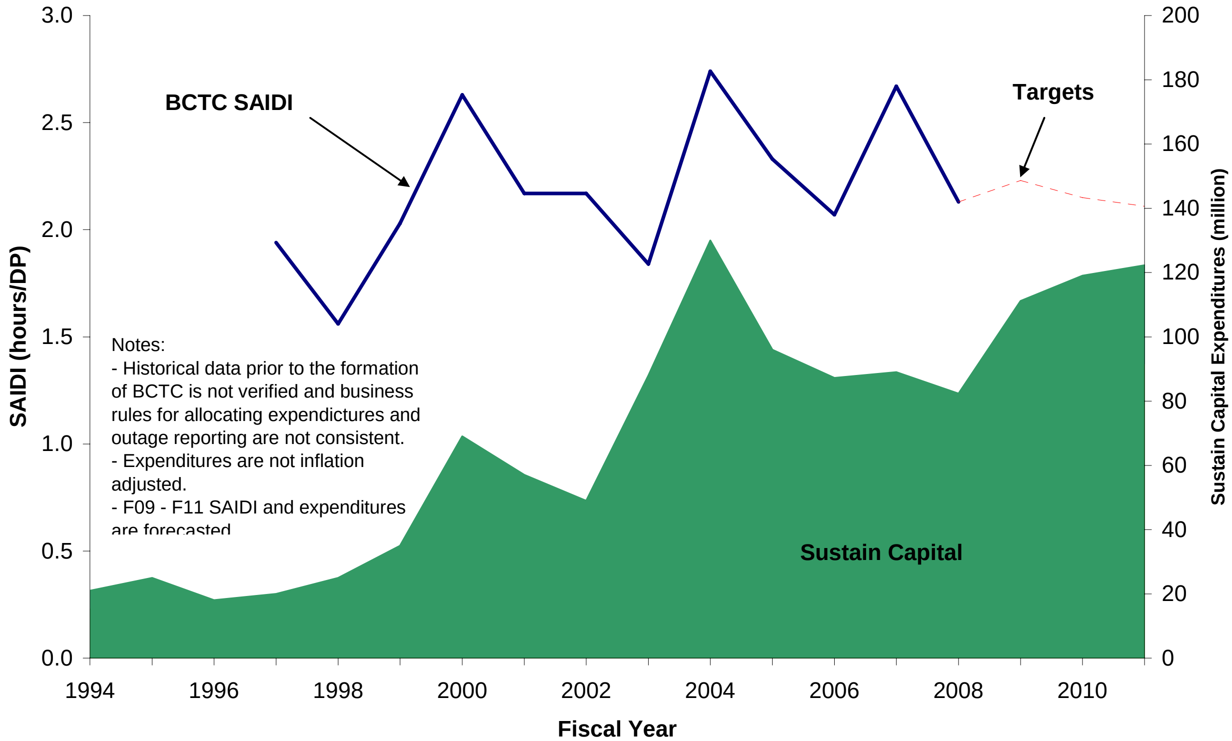
6.6 Commission Directives

6.6.1 Directive 10 in Order G-69-07 Graph of SAIDI vs Capital Expenditures

BCTC continues to recognize the value that a direct correlation between transmission system reliability and Sustaining Capital investments would provide to BCTC, the Commission, and other stakeholders. The correlation of reliability and the need to replace assets is evidenced by increasing equipment failures and corrective activity on an asset by asset basis that may or may not directly impact SAIDI, but will impact transmission system integrity.

Figure 6-2 shows trends in SAIDI and Sustaining Capital expenditures. Figure 6-2 is provided for information purposes only as a response to a directive from the Commission in its last Decision. BCTC does not rely in any way on this graph for planning purposes.

1 **Figure 6-2. Historical SAIDI and Sustain Capital Expenditures**



2

7.0 BCTC CAPITAL PORTFOLIO

The BCTC Capital portfolio encompasses all capital required for Information Management and Facilities assets.

The following sections are contained in Section 7: BCTC Capital Table (Section 7.1); Historical and Trend Explanations (Section 7.2); Background (Section 7.3); Proposed Formulaic Approach (Section 7.4); Commission Directives (Section 7.5); Exceptional Projects for Approval (Section 7.6.1); Anticipated Future Exceptional Projects (Section 7.6.2)

7.1 BCTC Capital Table

Table 7-1. BCTC Capital Portfolio

	BCTC Capital Portfolio	IS Date	Project Total ($'000)	Prior Years ($'000)	F2010 ($'000)	F2011 ($'000)	F2012 ($'000)	F2013 ($'000)	F2014 ($'000)	F2015 ($'000)	F2016 ($'000)	F2017 ($'000)	F2018 ($'000)	F2019 ($'000)
1	**Projects in Progress**		**10,498**	**5,098**	**5,400**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	For Approval													
2	Base Program		12,425	0	3,666	8,959	0	0	0	0	0	0	0	0
3	IFRS Financial System Project	Mar 2010	1,249	0	1,249	0								
4	Market Operations (MO) Business System Upgrade	Mar 2011	10,095	0	7,550	2,545								
5	TDS4 Upgrade	Mar 2011	1,854	0	1,114	740								
6	**Subtotal**		**25,623**	**0**	**13,579**	**12,244**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
	Future Approval													
8	Future Base Program		79,200	0	0	0	9,200	9,400	9,600	9,800	10,000	10,200	10,400	10,600
7	Future Exceptional Projects		20,000	0			3,000	4,000	3,000	2,000	2,000	2,000	2,000	2,000
9	**Subtotal**		**99,200**	**0**	**0**	**0**	**12,200**	**13,400**	**12,600**	**11,800**	**12,000**	**12,200**	**12,400**	**12,600**
#	**TOTAL BCTC PORTFOLIO**		**135,321**	**5,098**	**18,979**	**12,244**	**12,200**	**13,400**	**12,600**	**11,800**	**12,000**	**12,200**	**12,400**	**12,600**

7.2 Historical and Trend Explanations

Table 7-2. BCTC Capital Portfolio Trends

	Program Trends (millions)	Actual F2006	Actual F2007	Actual F2008	Forecast F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
1	Base Program					8.8 [1]	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6
2	System Control Modernization Project (SCMP)	10.1	45.1	62.9	8.4										
3	Facilities build out F2008			1.9											
4	Other BCTC Projects[1]	11.3	5.0	5.3	9.7	0.2									
5	IFRS Financial System Project					1.2									
6	TDS4 Upgrade					1.1	0.7								
7	Market Operations (MO) Business System Upgrade					7.6	2.5								
8	Future Exceptional Projects							3.0	4.0	3.0	2.0	2.0	2.0	2.0	2.0
9	**Total BCTC Capital Portfolio**	**21.4**	**50.0**	**70.1**	**18.1**	**18.9**	**12.2**	**12.2**	**13.4**	**12.6**	**11.8**	**12.0**	**12.2**	**12.4**	**12.6**

[1] Includes 5.1 million approved in Order No. G-107-08

As shown in Table 7-2, and discussed further below, the BCTC Capital portfolio historical capital expenditures have been relatively stable year over year except for non-recurring projects such as the System Control Modernization Project (SCMP). The SCMP Project accounts for the majority of expenditures between F2006 and F2009 and does not reflect the types of projects that routinely occur in the BCTC Capital portfolio.

Expenditures were relatively higher in F2006 and relatively lower in F2007 when the SCMP project is excluded. BCTC requested approval for F2006 and F2007 projects together in its F2006 TSCP Application. The Commission subsequently directed BCTC to reduce aggregate expenditures in F2006 and F2007 by $2.4 million, to be allocated among projects as BCTC saw fit. BCTC managed these two years of projects together as one portfolio and decided to do the majority of the projects in F2006 and reduce the expenditures in F2007, with the result that F2006 has a much higher approved expenditure than F2007.

With respect to forecast expenditures, BCTC is proposing a formulaic approach that would result in BCTC Capital portfolios expenditures of $8.8 million in F2010 increasing by inflation thereafter, not including exceptional projects. This level of spending reflects the on-going costs associated with both sustainment and short-term cyclical projects. BCTC has three significant new projects in the next two years which are of a non-cyclical, mandatory or end- of-life nature and that are considered exceptional. These are the International Finance Reporting Standards Project, the Transmission Desktop Services 4 Replacement Project, and the Market Operations and Development Business System Upgrade project with forecast expenditures of $1.24 million, $1.85 million, and $10.1 million, respectively. High level estimates of potential future exceptional projects are set out in Table 7-1.

7.3 Background

In earlier TSCPs, expenditures in the BCTC Capital portfolio were categorized into Information Technology, Control Centre Technologies and Facilities. As BCTC moves into its next level of maturity, as described in Section 4.5, the projects within this portfolio have been reclassified into categories more reflective of an Information Management paradigm. The reclassified project categories are Facilities, Infrastructure and Applications.

(a) Facilities – Projects in this group relate to the sustainment and expansion of BCTC's Facilities. Expenditures on these projects have remained consistent year over year, excluding facilities changes to accommodate staff growth.

(b) Infrastructure – Projects in this group relate to underlying information and Control Center technology infrastructure. These projects represent primarily the hardware components of Information Management, such as desktop and laptop personal computers and servers.

(c) Applications – Projects in this group relate to sustaining and making minor enhancements to existing applications, and acquisition or development of new applications. These are primarily software projects required to sustain and enhance existing applications, such as the Stations Information System Filenet Upgrade, the CROW System Upgrade and the new Dynamic Scheduling Application.

Across these three categories, projects generally have three common drivers: sustainment, compliance and efficiency.

Projects driven by sustainment issues are of an ongoing and cyclical nature, and are required to support system reliability and asset health. Examples include replacement of personal computers and maintenance of the condition of facilities equipment. Sustainment projects typically make up about three quarters of the total BCTC Capital portfolio expenditures, excluding exceptional projects, but can vary from year to year as a result of asset replacement cycles.

Projects undertaken to ensure that BCTC is in compliance with applicable regulations and legislation include the security of the transmission system through projects required to support the implementation of NERC Critical Infrastructure Protection standards and FERC Order No. 890.

BCTC also seeks out opportunities to improve the efficiency of its business operations, such as projects to support the implementation of a workflow management system to streamline the Standard Generator Interconnection Procedures.

7.4 Formulaic Approach

In the Commission's F2009 TSCP Decision (Order G-107-08), the Commission stated at page 90:

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

BCTC agrees that the BCTC Capital expenditures have been reasonably stable, except for some significant projects, and also agrees with the Commission that there are likely benefits to adopting a formulaic approach to requesting approval for the BCTC Capital portfolio. As a result, BCTC has reviewed its historical expenditures and the types of projects and programs that comprise the portfolio, and looked at its future trends to determine an appropriate formulaic approach. BCTC proposes to adopt an approach that:

(a) identifies a base level of expenditures for the BCTC Capital portfolio that is reflective of recently-approved BCTC Capital expenditures and forecast expenditures, excluding exceptional projects; and

(b) identifies and justifies exceptional projects, as suggested by the Commission, which cannot be accommodated in the base level.

BCTC believes that this approach, described in the following sections, will reduce regulatory costs and effort in applying for and reviewing the BCTC Capital portfolio, and will also allow BCTC to better manage expenditures by providing a consistent base to meet BCTC business needs while allowing for the flexibility to address exceptional projects.

7.4.1 Base Program and Exceptional Projects

Under BCTC's proposed formulaic approach, projects within the BCTC Capital portfolio would be categorized into those that make up the 'Base' and those that are 'Exceptional'.

The Base program would be comprised of those projects that support or enhance BCTC's ongoing business needs, including the sustainment of existing technologies and systems. These projects make up the relatively stable base of historical and forecast BCTC Capital expenditures noted by the Commission.

Exceptional projects are those projects whose scope and cost would be considered non-routine or non-recurring relative to BCTC's base expenditures and would therefore introduce variability in the base or otherwise compromise regular ongoing capital projects. BCTC expects exceptional projects to include significant system or facility expansion or change and which would result from factors such as:

(a) expanding or substantial changes to business activities;

(b) new technological advancements or obsolescence of current technologies which significantly impact current business operations; and

(c) major legislative or otherwise mandated requirements.

Historically, BCTC considers the BCTC Capital portfolio expenditures in F2004 and F2005 to be anomalous and which should not be taken into account when considering the formulaic approach. In F2004 and F2005, expenditures in the BCTC Capital portfolio were primarily driven by the establishment of BCTC. During this time, BCTC focused on ensuring that the necessary technology tools, techniques and facilities to establish the corporation were delivered and implemented to support the start up. For this reason, BCTC believes that these years were unique and do not reflect any trends in expenditures.

Within the F2006 to F2009 timeframe, BCTC considers the SCMP and the F2008 Facilities Build-out to be exceptional projects.

Based on the above, Table 7-3 presents the approved expenditures on base and exceptional projects within the BCTC Capital portfolio for F2006 to F2009.

Table 7-3. Approved BCTC Capital Portfolio Expenditures

	Approved Capital Expenditures ($ million)	Project Total	F2006	F2007	F2008	F2009
1	Previous approved for base projects		13.4	5.1	6.0	8.9
2	SCMP	133.0 (note 4)				
3	Facilities Buildout F2008				0.9	
4	Total Approved Projects		13.4 (note 1)	5.1 (note 1)	6.9 (note 2)	8.9 (note 4)

Note 1: Order G-91-05

Note 2: Order G-69-07

Note 3: Order G-107-08

Note 4: Order C-1-05

7.4.2 Rationale and Results for the Approach

Building on the relative stability of BCTC Capital expenditures on the base program, BCTC's proposed formulaic approach uses the average of the prior-approved capital expenditures, adjusted for inflation, to forecast future expenditures on the base program.

BCTC has selected a four-year timeframe, from F2006 to F2009, to calculate the average base program expenditures to ensure that the average captures the longest of the BCTC Capital portfolio's asset replacement cycles – four years. A shorter timeframe would neglect a significant portion of ongoing replacement costs; thereby understating the total amount required for base level expenditures.

Additionally, as noted above, expenditures in years prior to F2006 were mainly focused on establishing BCTC as a corporation and are generally not representative of the types or magnitude of the base level expenditures that comprise the portfolio going forward and were therefore excluded from the base calculation. Consequently, the four year period from F2006 to F2009 was used to calculate the average.

As shown in Table 7-4, the approved base level expenditures have averaged $8.8 million when escalated to F2010 dollars.

Table 7-4. Calculation of Base Capital Expenditures

	Capital Expenditure on Base Projects ($ million)	F2006	F2007	F2008	F2009	Average
1	Previous approval for base projects	13.4	5.1	6.0	8.9	
2	Adjustment for inflation	1.1	0.3	0.2	0.2	
3	Total approved adjusted to F2010 dollars	14.5	5.4	6.2	9.1	8.8
4	Inflation rate (BCCPI)	2.1%	2.0%	2.0%	2.1%	

BCTC has included inflation at the currently forecasted BCCPI. As BCCPI changes, BCTC proposes to update the inflation rate, recalculating the base program expenditures, in future applications.

In arriving at its proposed formulaic approach, BCTC acknowledges the Commission’s suggestion to consider cut off values for deferral risk and value in its approach. BCTC notes that it has used and will continue to use the prioritization method as a management tool in determining its portfolio of base and exceptional projects. However, as described in previous TSCPs, the prioritization method is used in conjunction with other business considerations, such as the analysis of interdependency between projects and assessment of technical feasibility, in developing its proposed portfolio. Consequently, setting cut off values for deferral impact and value in calculating a base level of capital expenditures would not allow BCTC the flexibility to consider the other critical factors in its portfolio development.

In addition to improved regulatory efficiency, BCTC believes that the use of a predictable base to forecast capital expenditures on an ongoing base program will allow for improved ability to plan the BCTC Capital portfolio. For instance, a predictable base will allow BCTC to incorporate and normalize ongoing and cyclical spending requirements that make up a large percentage of the total portfolio, as well as to prioritize and schedule future initiatives, including multi-year programs. A more predictable base will also result in predictable resource requirements, which will further benefit BCTC’s planning process. A predictable base for the portfolio provides for increased flexibility to accommodate projects resulting from changing business requirements due to unforeseen circumstances. This will allow BCTC to reprioritize its portfolio of projects during the course of the execution of its annual capital program to meet new higher priority requirements which may arise during the course of a planning cycle.

By adopting this formulaic approach, BCTC is assuming the risk in any given year that there may be more business requirements for non-exceptional projects than what may be accommodated within the proposed formulaic base. BCTC will manage these projects internally and would either defer or cancel projects based on the prioritization process and evaluation criteria. Risk factors that do not significantly impact business operations, but would impact the formulaic base, are regulatory and legislative changes, technological advancements, fluctuating inflation and exchange rates, and stakeholder pressures for new services. BCTC will manage these risks using its internal approval processes to ensure that project capital expenditures are within the formulaic base.

By the very nature of the Information Management business, small year-over-year variances will occur as a result of changing business needs, whereby variances for actual spend may be attributable to deferral and/or cancellation of some projects, laptop replacement cycles with peaks, and minor enhancement requirements. Technology can change rapidly and it is not uncommon to see cost variances of a technological solution for a project from the time of approval by the Commission to the time of implementation.

Overall, as shown in Table 7-5, BCTC has successfully managed the BCTC Capital portfolio over the last 4 years with an average actual spend, adjusted for inflation, within 6 percent of the average approved amount. The slight variance of $0.5 million from the average approved amount can be attributed to BCTC's improved processes in project cost estimates. BCTC's cost estimation process has evolved to allow for more accurate cost estimates. Additionally, BCTC has implemented strong project management practices and IT governance to manage its portfolio. Based on the above, BCTC believes that the proposed base level would provide BCTC with the ability to accommodate growth.

Table 7-5. Four Year Average Actual and Approved Amounts Adjusted for Inflation

	Description	Average
1	Total Previous Approvals ($ million)	8.8
2	Total Actual Spend ($ million)	8.3
3	Variance ($ million)	0.5
4	% Variance	6%

Although BCTC's TSCP applications will now reflect the proposed formulaic approach, internally BCTC will continue to follow and continuously improve its management and control processes. Key aspects of these processes include:

(a) Developing individual justifications for each project to support the business. Each project will continue to have to stand on its own merits and provide business value to BCTC, regardless of the formulaic approach, before proceeding to the next step in the process;

(b) Performing a deferral impact and value score assessment of each project, as well as a prioritization of all proposed projects, as described in Section 4.1;

(c) Evaluating the prioritized list of proposed projects to determine which projects should be included in the base level of expenditures; and

(d) Reviewing all proposed projects by a senior management team for further prioritization and rationalization before receiving final internal approval to proceed with the project within the base program.

BCTC is currently seeking approval of $8.8 million for F2010 under the proposed formulaic approach for the base program, $5.1 million of which was previously approved by Order G107-08 in the F2009 TSCP. BCTC requested capital funding of $5.1 million in the F2009 TSCP for F2010 which reflected only a portion of the total funding requirement for F2010. BCTC is also seeking approval of $9.0 million for F2011 under the proposed formulaic approach as shown in Table 7-6.

Table 7-6. Forecast Base Program Expenditures ($ million)

		F10	F11	F12	F13	F14	F15	F16	F17	F18	F19
1	4 Year Average	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
2	Inflation at 2.1%	-	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8
3	Total Base Projects	8.8 (note 1)	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6

Note 1: Includes $5.1 million approved by Order No. G-107-08 in F2009 TSCP

Based on BCTC's current and forecast business operations, BCTC expects that the proposed expenditure level will meet its future business requirements. However, significant business changes may drive the need to re-evaluate the formulaic approach to re-base capital expenditure levels in future applications. Accordingly, as BCTC gains more experience with this new approach, it may apply to adjust and enhance this formulaic approach in future applications.

7.5 Prior Commission Directives

There are three Commission Directives that presently apply to the BCTC Capital portfolio and direct BCTC to report on project detail for costs and prioritization results. However, the proposed formulaic approach provides a methodology for approval of an on-going capital expenditure base rather than a detailed justification on a project-by-project basis. Therefore, BCTC believes that using this proposed approach would be inconsistent with these prior Commission Directives. Accordingly, BCTC requests relief from the following Directives for both the present and future TSCP applications:

(a) Changes from Previous Capital Plan

> "In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 Capital Plan, modified to show the total dollar amount of each project and the relative priority at the time of approval." (Order G-69-07 Directive 34)

(b) Prioritization Results

> "Therefore, the Commission Panel directs BCTC to include in its next capital plan filing, tables, for each of the Portfolios listing the projects brought for approval, their risk and value scores, by category, and the priority numbers and quadrant values, where applicable."(Order G-69-07, Directive 16)

(c) Project Expenditure Exceeding $250,000

> "The Commission Panel therefore directs BCTC to provide, in future capital plan applications, a summary of the previous three years' activities and expenses for each ongoing project whose annual costs exceed $250,000." (Order G-91-05, Directive 37)

Changes from previous TSCPs, results of the prioritization process, or project expenditures exceeding $250,000 would be made available to the Commission upon request.

7.6 Exceptional Projects

There are three projects that BCTC considers to be exceptional projects applying the criteria identified in Section 7.4.1 and, therefore, not part of the base program. As such, BCTC is seeking approval for the following three projects: International Finance Reporting Standards (IFRS) Project, Transmission Desktop Services 4 Replacement (TDS4) Project, and Market Operations and Development Business System Upgrade (MOD) Project.

BCTC considers the IFRS Project to be an exceptional project as the change to new reporting standards is required to comply with Canadian Generally Accepted Accounting Principles. These requirements will result in a significant change to BCTC's financial accounting and reporting.

BCTC considers the TDS4 Project to be an exceptional project due to significant technological changes. The suppliers have chosen to discontinue support for BCTC's corporate desktop services, thus jeopardizing the stability of BCTC's desktop platform.

BCTC considers the MOD Project to be an exceptional project due to significant technological changes as the current systems cannot meet the growing business requirements of the Market Operations and Development department. Additionally, the current MOD systems have reached their end of life since the technology has become obsolete and, as a result, maintaining and updating current systems are complex and costly.

These projects are described in the following sections.

7.6.1 Exceptional Projects for Approval

7.6.1.1 Finance IFRS and Reporting F2010

Total Capital Cost: This is a new project for approval that BCTC is identifying as an exceptional project. The total capital cost is estimated to be $1.24 million.

Accuracy of Estimate: -10%/+50%

Schedule: This project is scheduled to commence on or about 1 April 2009 for completion on or before 31 March 2010.

In-Service Date: 31 March 2010.

Description

Implement and embed changes to the Oracle financial system required to operate in compliance with the new International Financial Reporting Standards (IFRS).

Justification

In January 2006, the Canadian Accounting Standards Board (AcSB) approved a plan to adopt globally-accepted accounting standards by converging Canadian Generally Accepted Accounting Principles (GAAP) with International Financial Reporting Standards (IFRS) over a proposed timeline with milestones and deliverables.

In February 2008, the AcSB confirmed the requirement to adopt IFRS in 2011 for all publicly accountable enterprises, including Government Business Enterprises such as BCTC and BC Hydro.

F2012 (1 April 2011 to 31March 2012) will be the first full year of financial reporting under IFRS. In preparation for this conversion, BCTC will be required to comply with IFRS disclosure requirements for the years ending 31 March 2009 and 2010 and will also be required to report F2011 comparatives under IFRS for F2012 reporting.

Experience in other countries who have adopted IFRS have shown that there can be significant changes to financial systems in order to properly embed IFRS accounting. To better define the requirements for IFRS, BCTC is undertaking a Definition Phase to assess the differences between the current Canadian GAAP and the IFRS and how they will impact BCTC's systems and business.

To date, the Definition Phase has identified that there are significant differences that directly impact BCTC. Once fully identified, these changes will result in a need to modify BCTC's existing Oracle Financial System components. Anticipated changes include but are not limited to the following:

(a) Conversion of historical information and opening balances;

(b) Changing how Oracle captures data in response to new IFRS policy choices;

(c) Adding new data sources and changing existing data and interfaces including those with BC Hydro for transmission capital expenditures;

(d) Changes to reporting tools and applications;

(e) Revising and updating business processes with respect to the Financial System;

(f) Potentially running two sets of accounting records as IFRS does not permit rate regulated accounting;

(g) Revising existing accounting structures (e.g., Chart of accounts, coding etc.) to meet IFRS requirements; and

(h) Identifying and incorporating new IT and application system needs.

The Definition Phase will detail the plan to design, build and implement the IFRS changes and will form the basis of the IFRS Project.

The IFRS Project is scheduled to be completed in F2010, ahead of the final AcSB convergence timeline of F2012, to allow BCTC to run comparative reporting and to ensure that IFRS is implemented and functioning as mandated.

<u>Review of Alternatives</u>

BCTC assessed two other alternatives.

(a) Manually create IFRS financial statements off-line. A manual process would put at risk the completeness, accuracy and timeliness of accounting information. Additionally, a manual process would prevent a proper audit trail from the reported information back to the source data. Meaningful analyses of data required for reporting would be at risk. As a result, BCTC believes a manual process is neither feasible nor sustainable as a long-term solution.

(b) Replace existing version of Oracle Financial System with a financial system with IFRS incorporated. Implementing a new version would require an investment of over $6 million.

These two alternatives were rejected due to their cost and high risk of implementation.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects. BCTC's conversion will be co-ordinated with BC Hydro's IFRS conversion.

7.6.1.2 Transmission Desktop Services 4 Replacement Project

Total Capital Cost: This is a new project for approval that BCTC is identifying as an exception project. The total capital cost is estimated to be $1.85 million.

Accuracy of Estimate: ±25%

Schedule: This project is scheduled to commence on or about 1 April 2009 for completion on or before 31 March 2011.

In-Service Date: 31 March 2011.

Description

This project is to upgrade and implement new standard desktop software applications for BCTC.

Justification

BCTC proposes to invest $1.85 million to upgrade and implement new standard desktop software applications for all BCTC employees. Microsoft is discontinuing support of all of the current Microsoft components of TDS3 (Transmission Desktop Services 3) by the calendar year 2010. This project is expected to keep the corporate desktop computing environment sustained with proper support from Microsoft, to maintain independent software vendor support, and to remain compatible with BCTC's business partners, such as BC Hydro.

Microsoft is discontinuing support for Office 2003, Exchange 2003, Outlook 2003, and Windows XP in 2009. Once a Microsoft product is out of support, only rudimentary support is available – no bug fixes, extended support would have to be purchased from Microsoft, best-effort only for extended support, security patches will only be available for major security breaches, and security patch release frequency is much lower. As such, the risk of continuing to use out of support software product(s) is very high in terms of not being able to fix problems with help from Microsoft, not having security patches implemented in a timely manner, and experiencing higher operating and maintenance costs as solutions to software issues are less readily available.

Additionally, other software applications supplied by Independent Service Vendors (ISV) that run within the Microsoft environment may not operate under older versions of Microsoft. Therefore, BCTC may not be able to move to newer versions of third party applications needed for its business. BCTC needs to mitigate this risk by planning ahead and migrating to newer versions of third party applications in time so as to avoid any forced migration which would be more expensive and incur higher risks. The recommended industry practice is to stay on the application support cycle so that bug fixes and security patches along with ISV support are readily available.

BCTC's desktop computing environment also leverages that of its largest business partner, BC Hydro, which is planning to move to new versions of Microsoft Office and Exchange in F2009. The upgrade to TDS4 would be completed by Accenture Business for Utilities (ABSU) and will facilitate file exchange between the two companies and minimize any potential file incompatibility issues. The cost estimate, along with proposed timing for software migration, is based on BC Hydro proceeding with similar initiatives so that BCTC can leverage on the ABSU work done for BC Hydro.

In addition, as BCTC is part of the BCH/ABSU support contract, when the migration is completed, BCTC would be aligned with BC Hydro on the corporate desktop environment for ABSU support. This project would maintain the security, reliability, manageability and supportability of the BCTC computing environment.

BCTC proposes to implement the various TDS4 components over a period of two years. This would ensure successful deployment and proper rollout of training to the end users to maximize the benefits of the new tools and applications. Additionally, a phased implementation would provide the flexibility to take advantage of external implementation experience, especially that of BC Hydro and ABSU.

In summary, the TDS4 Project is expected to maintain the health of the corporate desktop applications for BCTC, thus reducing the potential risk of compromising the corporate desktop computing environment. The project would also:

(a) Maintain mainstream Microsoft support (Exchange 2003 support will end in April 2009);

(b) Keep the e-mail communication environment up-to-date with functionalities and proper sustainment;

(c) Improve protection at the client-seat level (anti-spam, antivirus, compliance, clustering with data replication, improved security and encryption);

(d) Implement improved collaboration and interfacing capabilities with other Microsoft applications;

(e) Keep BCTC corporate desktop operating system software properly sustained, with readily available bug fixes; and

(f) Maintain independent software vendor support on their applications which operate under the Microsoft desktop Operating System.

<u>Review of Alternatives</u>

BCTC assessed two other alternatives.

(a) Delay Migration until F2012. BCTC would delay migration and risk receiving limited or no support from Microsoft for its corporate desktop applications until that time. BCTC would risk not receiving supported security patches and file incompatibility issues due to non-supported software. Under this operating environment, any virus attack would result in productivity losses to BCTC and support from ABSU would be more expensive. In delaying the migration, BCTC would shift the expenditure out in time and result in higher migration costs due to missing the opportunity to leverage the work and resources available from BC Hydro's implementation of these corporate desktop services. Meanwhile, the risks identified would not be addressed. The cost of this alternative is estimated to be $3.0 million.

(b) Do Nothing. BCTC would forego upgrading to supported Microsoft Applications. By not upgrading, BCTC would have similar risks to alternative 1 whereby BCTC would be exposed to productivity losses due to potential virus attacks and higher ABSU support costs. The loss of labour productivity is estimated at $246K for each year BCTC has not upgraded to currently-supported Microsoft Applications.

These two options were rejected due to their cost and risk of implementation.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

There are no dependent projects. BCTC would leverage the ABSU work done for BC Hydro.

7.6.1.3 Market Operations and Development Business System Upgrade Project F2010 to F2011

Total Capital Cost: This is a new project for approval that BCTC is identifying as an exception project. The total capital cost is estimated to be $10.1 million; $7.55 million in F2010 and $2.55 million in F2011.

Accuracy of Estimate: -10%/+10%

Schedule: This project is scheduled to commence on or about 1 April 2009 for completion on or before 31 March 2011.

In-Service Date: 31 March 2011.

Description

This project is to replace and upgrade the existing Market Operations Business Systems with a new consolidated and integrated suite of Market Operations business applications.

Justification

The Market Operations and Development (MOD) Business System Upgrade Project is essential to allow BCTC to deliver open access to the transmission system and to invoice and collect Network Integration Transmission Services (NITS) and Point-to-Point (PTP) revenue consistent with BCTC's OATT. These systems are critical to BCTC and its customers in providing transmission and energy scheduling, tariff and contract compliance, and customer services.

The current MOD suite of applications includes Transmission Scheduling System (TSS), Open Access Same-Time Information System (OASIS), Energy Trading System (ETS/eTag), Settlements and Billing System (S&B/Lodestar), Market Operations Data Warehouse (MODW), Pricing Application, and the Interconnections Workflow Application (K2/SGIP). This suite of applications has evolved over time, with new functionality and applications being added as required. Applications such as TSS and S&B were custom built in the late 1990's at a time when there were very few off-the-shelf scheduling systems that met MOD's business requirements.

The TSS system, along with its market interface, OASIS and eTag systems, is one of the most critical systems in the MOD suite of applications. TSS allows customers to reserve transmission for short-term and long-term PTP service and schedule energy on their transmission rights. TSS facilitates the automated processing of transmission service requests submitted by customers, and validates requests based on current business practices and the OATT.

Since 2001, BCTC's customer base has expanded and BCTC has introduced many new transmission services. As a result, TSS has undergone a wide range of modifications, enhancements, and additions to its core functionality, as well as major infrastructure changes. Many of these software upgrades and enhancements changes were driven by regulatory (OATT tariff implemented in F2006 costing $1.2 million and Network Economy Tariff implementation F2007/08 costing $1.4 million) and market requirements (Dynamic Scheduling and NERC eTag). The required changes introduced since 2001 have resulted in the original TSS architecture design being pushed beyond its limits. Combined with the obsolete nature of the system, this has resulted in TSS requiring significant investment in capital and OMA resources to maintain stable operations of the system.

Other MOD applications have also undergone a variety of modifications and enhancements. These custom applications have become overly complex and are also costly to upgrade and sustain.

There are now several companies that offer commercial off-the-shelf (COTS) solutions which offer a full suite of capabilities and reduce the need for customized software applications.

To assist BCTC in determining the best business direction, a Definition project was undertaken. The purpose of the Definition project was threefold: to identify the existing functionality of the applications; to identify gaps in the current applications which hinder BCTC from providing exceptional service to customers; and to determine the approximate costs to implement a new consolidated and integrated suite of applications based on available third party software and/or customization. This assessment was completed in April 2008 and, as a result, BCTC determined that the existing systems have reached their end of life with the following major gaps:

(a) lacks flexibility and scalability preventing BCTC from making changes in an efficient and cost effective manner;

(b) lacks accurate and up to date data for customers and internal BCTC staff such as the management of rates, forecasts and refunds;

(c) lacks automated processes for consolidating and integrating existing functionality;

(d) lacks integration with other business areas such as the Oracle Financial System;

(e) lacks robust decision support for reporting and forecasting; and

(f) lacks granularity on curtailments, outages and TTC information to allow marketers to make more informed decisions.

Following the project Definition and gap assessment, BCTC undertook a Request for Information (RFI) to further refine and verify the business requirements. Through the RFI process, BCTC was able to confirm that the scope of the project is achievable while gaining a better understanding of the standard off-the-shelf offerings and overall costs. Based on the submissions received, approximately 75% of BCTC's business requirements could be met by vendors using COTS products and the remaining business requirements could be met by minor customization of COTS products. The pricing information submitted by vendors in the RFI was also used to support the cost estimates for a full replacement alternative and a TSS-only alternative.

BCTC is proposing to spend $10.1 million over F2010 and F2011 to replace the existing disparate MOD business applications with a new integrated set of systems. BCTC determined that a COTS solution would substantially reduce the investment required to implement industry changes affecting Balancing Authorities and Transmission Providers, such as FERC Orders, NERC tagging requirements and WECC practices.

The proposed consolidated and integrated business system will enable BCTC to meet its current and future business and regulatory requirements while providing a more robust and streamlined process for its customers and achieve the following benefits:

(a) efficiency of staff due to more automated use of tools and productivity;

(b) accuracy in reconciling issues between the various existing systems;

(c) customer satisfaction and alignment with industry standards, due to more efficient processes thus improving third party benefits;

(d) customer transparency, which will provide marketers with the ability to track issues through to resolution, and facilitate Long Term PTP and Interconnections processes by introducing workflow capabilities through new management tools;

(e) efficiency for compliance and administration of the OATT and other regulatory orders from FERC, NERC, NAESB, and WECC; and

(f) ensure systems are readily available at all times.

The new proposed consolidated system envisions making extensive use of the COTS solutions which would enable BCTC to reduce the total cost of ownership of the MOD systems. BCTC expects to reduce OMA costs by $129K in both F2012 and F2013 and, starting in F2014, OMA costs are forecasted to be reduced by $591K each year thereafter. This reduction in OMA is due to lower sustainment costs and efficiency gains.

Review of Alternatives

BCTC assessed two other alternatives:

(a) Do-Nothing. The Do-Nothing alternative of continuing to customize the existing systems has the highest cost and fewest benefits. In this alternative, BCTC would make no provision for the replacement of TSS or other applications. The total cost of maintaining the existing systems to F2016 is estimated at $18.4 million which is more expensive than a full replacement. Benefits for the Do-Nothing alternative would be negligible. The existing system would continue to be enhanced and maintained through current capital expenditure requests and OMA. Integration of new business requirements, such as tariff amendments in accordance with FERC Order No. 890, would be very difficult and costly. BCTC has found that costs and time to implement changes are increasing as a result of end of life technology.

The financial risk to BCTC under this alternative will become greater over time due to the inability to effectively meet OATT requirements. The Do Nothing alternative would also not enable MOD to meet changing customer needs, regulatory rules and changes in BCTC's operational requirements. Therefore, the Do Nothing option was rejected.

(b) Replacing the TSS system only. In this alternative, BCTC would replace the existing TSS system with a standard COTS scheduling system while leaving all other MOD systems unchanged. This alternative is less costly, but does not provide all of the benefits of COTS and has a higher risk for consolidation and integration of the various existing applications.

The total cost of ownership under this option to F2016 is forecast to be $10.6M. This is due to the fact that replacing the TSS alone would require significant investment and enhancements to dependent systems such as S&B, pricing applications, MODW, EIDE and web services. There is a high degree of risk that a new stand alone TSS will not integrate effectively with existing dependent market operation applications due to the complexity of the existing customization. This may result in additional investments to fix integration issues. This alternative would not allow for consolidation and integration with other business units, and would not reduce the costs to maintain and enhance the existing MOD business systems. Therefore, this alternative was also rejected.

On an overall benefit basis, the preferred alternative is estimated to have the greatest benefits given the significant reduction in OMA cost as a result of reduced ABSU support costs and personnel efficiency. The preferred alternative provides benefits estimated at $14.2 million with a total cost of ownership to F2016 of $13.0 million. The Replace TSS Only option provides an estimated benefit of $9.7 million with a total cost of ownership to F2016 of $10.6 while the Do-Nothing Option has a total cost of ownership of $18.4 million with no benefits.

Project Risks / Impacts

There are no high or extreme implementation risks for this project.

Related / Dependent Projects

Components of the implementation of this project are dependent upon the Commission approving the application for BCTC tariff changes related to FERC Order No. 890 and a new short-term point-to-point rate design. Delay in the approval of the application may cause delays in the full implementation of the new business system.

7.6.2 Anticipated Future Exceptional Projects

The projects listed below are in their early stages of definition and are expected to develop into BCTC Capital portfolio projects. Since these projects are still in their definition stage, the costs are very high level estimates at this point. Given the significant costs and unique nature of these projects, they are presented as exceptional projects in Table 7-1 and are described below.

7.6.2.1 Enterprise Asset Management Program – Future

The current Asset Management tools are comprised of several poorly integrated tools which are currently not meeting the business needs of BCTC. As BCTC moves forward, these individual tools will increasingly fall short of supporting their business objectives. Further, several of the components are now nearing their end of life.

BCTC is assessing the current Asset Management processes and systems to determine what processes and tools are required to fulfill the Asset Management requirements and functions for all assets under BCTC's responsibility. Future expenditures will be required to renew, replace and enhance the Asset Management Program tool set to maintain its functional and technical health to support BCTC's business operations.

7.6.2.2 Enterprise Business Intelligence – Future

As BCTC's decision-making evolves to address internal and external business requirements, BCTC requires a comprehensive approach to mining and analysing its business information (i.e., "business intelligence"). Future expenditures will be required to provide business intelligence capability and tool sets. These tools sets are expected to include data repositories coupled with analytics and discovery toolsets that can be leveraged for reporting, decision support and operations by BCTC across multiple business areas.

7.6.2.3 Enterprise Content and Document Management – Future

BCTC has experienced significant growth in the quantity and diversity of documents being generated and accessed to support business operations. This increase in documentation has resulted in difficulties efficiently and effectively indexing and retrieving documents and document sub-contents.

Future expenditures will be required to improve content and document and records management processes and to provide an Enterprise Document and Content Management System to optimize content and document management at BCTC. This initiative may involve the replacement of a number of current applications and the conversion of current disparate document and content management schemes.

7.6.2.4 Enterprise Collaboration Unified Communications – Future

As BCTC expands, communications and collaboration has increasingly become more important for BCTC's business areas and its service delivery partners and customers. However, there currently is a limited and inconsistent set of tools deployed by BCTC to ensure communications and collaboration internally and externally are efficient and effective.

Future expenditures will be required to implement an Enterprise Collaboration Unified Communications tool set that will allow diverse groups of people to work together in secure but common forums.

7.6.2.5 Enterprise Project Management Tool – Future

BCTC's TSCPs continue to expand due to an increasing number of Growth and Sustainment projects. There is an increasing need for project management tools to enable several hundred projects to be managed in a consistent manner regardless of the scale of the projects and regardless of the nature of the projects (i.e., major projects, Growth, Sustainment or BCTC portfolio). Additionally, for projects managed with or by BC Hydro, BCTC currently relies on BC Hydro's InfoPM tool for managing projects delivered by BC Hydro staff for BCTC. InfoPM is near the end of its software lifecycle and BC Hydro has indicated its intention to replace this system.

BCTC will require future capital expenditures to implement an Enterprise Project Management Tool to effectively and consistently manage all projects at BCTC, regardless of where they originate within BCTC and whether they are with or through BC Hydro, or with or through BCTC's other service providers.

8.0 TRANSMISSION REVENUE REQUIREMENT IMPACTS

PRE-FILED EVIDENCE OF PATTI JER, MANAGER, COSTING AND REGULATORY SUPPORT

BCTC has prepared a forecast of the Capital Plan in-service additions impact on the Transmission Revenue Requirement (TRR).

The expenditures in the Growth and Sustaining Capital portfolios will impact the BC Hydro Owner's Revenue Requirement, reflecting BC Hydro's capitalization costs as these asset additions are funded and owned by BC Hydro. BCTC Capital expenditures will impact the BCTC Revenue Requirement and reflect BCTC's capitalization costs as these asset additions are funded and owned by BCTC. The BC Hydro Owner's Revenue Requirement and the BCTC Revenue Requirement are components of the TRR.

In consultation with BC Hydro and in accordance with Order in Council No. 28 dated 17 January 2008 amending Special Direction HC2, the forecast reflects the assumption that assets placed in service for the Growth and Sustaining Capital portfolios are financed at 100% debt[24] and incur a return based on 30% deemed equity[25]. The TRR impacts related to assets in service from the BCTC portfolio reflect BCTC's deemed capital structure. The financial assumptions used in the TRR impact forecast are set out in Table 8-1.

[24] Special Direction HC2, Section 4(b)
[25] Special Direction HC2, Section 1

Table 8-1. Financial Assumptions for Revenue Requirement Impact Analysis

Line No.		F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	BC Hydro										
1	ROE	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%
2	Blended CDN Long and Short Term Interest Rate[1]	3.94%	4.63%	5.56%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%	6.18%
3	Retained Earnings	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
4	Deemed Equity	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
5	Debt	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
	BCTC										
6	ROE	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%	11.78%
7	Weighted Average Cost of Borrowing[1]	4.86%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%	4.71%
8	Retained Earnings	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
9	Deemed Equity	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%	40.7%
10	Deemed Debt	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%	59.3%

Note 1: BC Hydro and BCTC use the economic planning assumptions provided by the provincial Treasury Board as of October 2008. Finance charges relating to asset additions for Growth and Sustaining Capital Portfolios are calculated based on a blend of the long (64%) and short (36%) term interest rates and for the BCTC Portfolio are a the blend of long term and short term interest rates based on BCTC's borrowing forecast.

The forecast TRR impact associated with the Capital Plan additions is shown in Table 8-2. Columns (e) and (g) of Table 8-2 explain the determination of Column (h) “Annual % Change” for each year. Column (f) is the F2008 TRR plus the incremental change shown in Column (d). The Annual % Change represents the year-to-year TRR change.

Table 8-2. Estimated Capital Plan Impact on TRR

Line No.	Annual Impact - $ millions	BC Hydro Growth	BC Hydro Sustain	BCTC	Total Change	Ref. 1	TRR (Note 1)	Ref. 2	Annual % Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**F2009**						566.8		
2	**F2010**	28.2	8.1	(1.5)	34.8	1f + 2d	601.6	(2f ÷ 1f) - 1	6.1%
3	**F2011**	22.4	7.9	3.1	33.5	2f + 3d	635.0	(3f ÷ 2f) - 1	5.6%
4	**F2012**	39.0	9.5	4.1	52.6	3f + 4d	687.6	(4f ÷ 3f) - 1	8.3%
5	**F2013**	38.5	13.1	(0.2)	51.4	4f + 5d	739.0	(5f ÷ 4f) - 1	7.5%
6	**F2014**	39.9	10.8	(1.9)	48.8	5f + 6d	787.8	(6f ÷ 5f) - 1	6.6%
7	**F2015**	68.4	10.7	(1.0)	78.1	6f + 7d	865.9	(7f ÷ 6f) - 1	9.9%
8	**F2016**	51.0	15.5	(1.1)	65.5	7f + 8d	931.3	(8f ÷ 7f) - 1	7.6%
9	**F2017**	8.1	9.9	(2.3)	15.7	8f + 9d	947.0	(9f ÷ 8f) - 1	1.7%
10	**F2018**	(2.6)	12.8	0.1	10.3	9f + 10d	957.4	(10f ÷ 9f) - 1	1.1%
11	**F2019**	(3.4)	11.6	0.3	8.5	10f + 11d	965.9	11f ÷ 10f) -	0.9%
12	**Cumulative TRR Change over 10 Years:**	**289.5**	**109.9**	**(0.3)**	**399.1**	1f + 12d	**965.9**	(12f ÷ 1f) - 1	**70.4%**

Note 1: Numbers may not add due to rounding.

Note 2: ( ) = reduction in revenue requirement.

The year-over-year changes are relative to the prior year, beginning with the F2009 TRR approved in Order No. G-105-08, subject to Commission approval of the BC Hydro Owner’s Revenue Requirement, and reflects the forecast of asset additions in each year from F2010 to F2019.

As noted in Section 5.2, few Growth expenditures have been identified for F2015 and beyond due to the higher level of uncertainty associated with long range planning.

9.0 COMMISSION DIRECTIVES

The Commission issued the following Directive under Order G-91-05:

> "The Commission Panel therefore directs BCTC to provide, in each future capital plan, a section describing its response to Commission directives from previous capital plans. The status of compliance with each directive is to be reported in each capital plan until such time as BCTC has complied with the directive." (Directive 7)

In addition, the Commission issued the following Directives under Order G-107-08:

> "The Commission Panel directs BCTC to specifically report compliance with the directives described in Sections 9.4, 9.6, 9.9, 9.13, 9.20, 9.29, 9.30, 9.34, 9.39, and 9.40 of the F2008 TSCP Application in future filings. This should be reported along with the reporting on the concordance with all other directives pursuant to the directive described in Section 9.9 of the F2008 TSCP Application." (Directive 5)

> "The Commission Panel directs BCTC to comment on all Directives contained in past Decisions, even if such reporting confirms that no update is required, or the requested information is not applicable." (Directive 10)

Section 9.1 provides status information as well as a reference to BCTC's response to the Directives issued under Orders G-107-08 (F2009 TSCP), G-69-07 (F2008 TSCP), G-67-06 (F2006 TSCP Update), G-91-05 (F2006 TSCP) and G-103-04 (F2005 TSCP).

BCTC requests that the Commission confirm that the Directives listed in Table 9-1 as complete are complete, and those that are shown as superseded are superseded.

9.1 Concordance Table

Below is Table 9-1, the Directive Concordance Table.

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-107-08				
11	1	The Commission Panel directs BCTC to continue identifying in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for single contingency events.	Ongoing; Supersedes G-69-07 Directive 1	F2010 TSCP Section 5.6.2, page 5-123
14	2	The Commission Panel directs BCTC to continue to track past years' Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures.	Ongoing; Supersedes G-69-07 Directive 6	F2010 TSCP Table 6-2, page 6-11
18	3	The Commission Panel expects that in the future such expenditures [UMS report] will be provided with greater transparency in both the capital planning and revenue requirement processes.	Complete	F2010 TSCP Section 9.2.1, page 9-35
24	4	BCTC is directed to comment on the following concerns in its next filing: applicable and appropriate constraints or thresholds within the Prioritization Methodology for project selection, continued optimization of the Prioritization Methodology to better reflect the results achieved by expert judgement intervention, and the allocation of dollar cost savings within the Prioritization Methodology.	Complete	F2010 TSCP Section 9.2.2, page 9-35

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-107-08				
25	5	The Commission Panel directs BCTC to specifically report compliance with the directives described in Sections 9.4, 9.6, 9.9, 9.13, 9.20, 9.29, 9.30, 9.34, 9.39, and 9.40 of the F2008 TSCP Application in future filings. This should be reported along with the reporting on the concordance with all other directives pursuant to the directive described in Section 9.9 of the F2008 TSCP Application.	Complete	F2010 TSCP Table 9-1 Commission Order G-91-05 Directives 3 (9.4), 5 (9.6), 7 (9.9), 15 (9.20), 28 (9.29), 29 (9.30), 37 (9.40) and items listed for Decision Pages Nos. 17 (9.13), 54 (9.34) and 62 (9.39). The last three items were not directives of Order G-91-05.
39	6	In future capital plans, and until directed otherwise, the Commission Panel directs BCTC to provide a thorough evaluation of options in situations where the cost of the preferred solution for an approved project changes by more than 100 percent.	Ongoing	F2010 TSCP Section 5.6.4, page 5-125
40	7	The Commission Panel approves an amount of $105.0 million for the F2009 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the $101.4 million forecast F2009 Sustaining Capital expenditures expressed in F2007 dollars, escalated at 2 percent inflation for two years, less an amount of $0.5 million to account for the re-allocation of costs associated with the Emergency Drop-in Control Building project. The Commission Panel approves an amount of $107.0 million for the F2010 Sustaining Capital expenditures, expressed in nominal dollars, consisting of the approved F2009 Sustaining Capital expenditures plus a 2 percent increase for inflation, less a $0.1 million adjustment for a reduced amount of third-party requested projects.	Complete; Supersedes G-69-07 Directive #30 and #32; Supersedes G-91-05 Directive #35	F2010 TSCP Section 6.3.1 page 6-15

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-107-08		
41	8	The Commission Panel directs BCTC to report in future capital plans the specific instances where non-wires options have been considered in project option evaluations.	Ongoing; Supersedes G-91-05 Directive #10b	F2010 TSCP Section 5.6.3 page 5-124
44	9	The Commission Panel directs BCTC to identify in the next capital plan application the industry benchmarking surveys to which it provides data, and to identify those in which it participates more fully, and to report the results of those surveys, including the utility-specific reports from CEA. BCTC is also directed to provide, in the next capital plan application, a summary report that identifies a representative cross-section of surveys being performed in the electric utility sector.	Complete	F2010 TSCP Section 9.2.3 page 9-37 and Appendices E and F
46	10	The Commission Panel directs BCTC to comment on all Directives contained in past Decisions, even if such reporting confirms that no update is required, or the requested information is not applicable.	Complete	F2010 TSCP Concordance Table 9-1
54	11	The Commission Panel directs BCTC to continue to use an inflation adjustment equal to the BCCPI.	Ongoing	F2010 TSCP Section 9.2.4 page 9-40
58	12	The Commission Panel also acknowledges the effort being made by both BCTC and BC Hydro towards developing a common understanding regarding the dispatch assumptions of resources identified in the NITS application, and encourages BCTC to continue assessing how the existing transmission system can be best utilized through re-dispatch of NITS-nominated resources. The Commission Panel directs BCTC to file a report describing these assumptions with the earlier of the next capital plan application or following BC Hydro's next NITS application.	Complete	F2010 TSCP Section 9.2.5 page 9-40
60	13	The Commission Panel directs BCTC to provide in future capital plans an estimate of all generation interconnection costs, except those which are 100 percent third party funded and will remain owned by and the responsibility of the third party.	Ongoing	F2010 TSCP Table 5-1 pages 5-2 to 5-5 and Section 5.5.5 page 5-106

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-107-08		
65	14	The Commission Panel approves the Definition Phase expenditures for the Golden 69 kV System Reinforcement project, but directs BCTC to provide with any request for approval of Implementation Phase expenditures for this project, a thorough examination and comparison of the TEP alternative, the preferred alternative, and the next highest ranked alternative. In the event that the TEP alternative is either the preferred alternative or the next highest ranked alternative, the comparison shall include the top three ranked alternatives.	Outstanding	Future CPCN filing
67	15	Notwithstanding the above concerns, the Commission Panel approves the expenditures for Ashton Creek Substation Capacitor Bank project, but is concerned about the timing and full scope of the project. The Commission Panel expects BCTC to advise the Commission of changes, if any, to the timing and scope of the project prior to construction of the project and to consider the timing of South Interior resource additions and load forecasts that are contained in BC Hydro's 2008 Long-Term Acquisition Plan Application. If BCTC concludes that changes to the timing or scope of the project are appropriate, then BCTC should justify the changes in a report to the Commission with a probabilistic analysis of the duration of outages for the specific seasonal dispatch conditions considered in the report.	Complete	F2010 TSCP Section 9.2.6 page 9-41
68	16	The Commission Panel encourages BCTC to continuing working with FortisBC to develop a solution that would be beneficial to the ratepayers of both utilities, and approves Definition Phase expenditures associated with Woods Lake Area Reinforcement project.	Complete	F2010 TSCP Section 9.2.7 page 9-42
75	17	The Commission Panel directs BCTC to confirm with BC Hydro the probability of the projected spot load increases that are driving the need for the replacement of two transformers in 2011 for the option consisting of the feasible addition of a third 25 MVA transformer for the Tumbler Ridge - Transformer Replacement project, and to provide a letter to the Commission confirming the selection of the preferred alternative after a careful examination of the forecast load increases and other factors that may reduce the load on the Tumbler Ridge Substation.	Complete	F2010 TSCP: Not Applicable Letter filed with the Commission on November 4, 2008

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-107-08				
86	18	The Commission Panel rejects the use of the MTBF criterion in its current form as BCTC's minimum reliability criterion, and directs BCTC to revise this criterion and submit it in the next capital plan filing.	Complete	F2010 TSCP Section 9.2.8 page 9-42
86	19	The Commission Panel notes the contradictory evidence regarding the need for the VIT capacitors and directs BCTC to submit a clarification in the next capital plan filing.	Complete	F2010 TSCP Section 9.2.9 page 9-43
87	20	The Commission Panel directs BCTC to report in future capital plan filings, and until directed otherwise, the total costs-to-date for each of the six OCAS installations anticipated in F2009 along with a comparison to the original life cycle cost analysis.	Ongoing	F2010 TSCP Section 6.5.8.2.1 page 6-55
90	21	The Commission Panelfinds the requested F2008 and F2009 capital epxenditures for the BCTC Capital Portfolio are in the public interest.[1] Note 1: BCTC assumes the above approval is for F2009 and F2010 as requested in BCTC F2009 Transmission Systems Capital Plan.	Complete	F2010 TSCP: Not Applicable

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-69-07		
14	1	The Commission Panel directs BCTC to identify in future capital plans those projects that are being proposed to avoid generation shedding for first contingency events, and to identify any transmission service or interconnection requests that trigger the need for upgraded facilities to avoid generation shedding for first contingency events.	Superseded by G-107-08 Directive #1, page 11	
14	2	The Commission Panel directs BCTC to submit with its next capital plan a comprehensive description of the planning assumptions used in the IEP portfolio evaluations, LTAP analysis, and analysis of BC Hydro’s NITS application.	Complete	F2010 TSCP: Not Applicable; F2009 TSCP: Section 9.2, page 378; Appendix K; Section 4.6.2.3 page 80.
		Future capital plan filings should either re-affirm the previous planning assumptions or describe any changes made to the previously described planning assumptions.	Ongoing	F2010 TSCP: Section 4.3.2.3 page 4-38
15	3	The Commission Panel directs BCTC to submit as part of future capital plan filings an assessment of which transmission reinforcements could be delayed or deferred through the reasonable re-dispatch of generation resources nominated in NITS applications.	Superceded by G-107-08 Directive 12	
		BCTC should also identify in this assessment the mechanisms under OATT that allow the re-dispatch of generation around transmission constraints, and comment on whether these mechanisms are available for operating purposes, planning purposes, or both.	Complete	F2010 TSCP: Not Applicable; F2009 TSCP: Section 9.3.4 page 381

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-69-07				
16	4	BCTC is directed to provide with its next capital plan its position as to the disposition of costs for Definition Phase project costs, in circumstances where the need for the project is either established in the Planning Phase or assumed for the purposes of completion of the Planning Phase, but the project is no longer needed by the time of completion of the Definition Phase, either due to changed circumstances within the control of BCTC or due to further analysis completed after the Planning Phase.	Complete	F2010 TSCP: Not Applicable; F2009 TSCP: Section 9.4, page 381-382
17	5	The Commission Panel specifically denies Definition Phase funding in F2009 for the Golden 69 kV System Reinforcement and North Thompson 138 KV System projects. If BCTC applies for Definition Phase funding for these projects before or as part of the next capital plan, it should be prepared to show how it has considered existing transmission expansion policies for the identification of project alternatives during the Planning Phase evaluation.	Complete (Golden projects - now called CVT) Outstanding (North Thompson project)	F2010 TSCP: Not Applicable; F2009 TSCP: Section 9.5, page 382 F2010 TSCP: Not Applicable; Future filing
19	6	The Commission Panel directs BCTC to track past years' approved Emergency Capital Expenditures and report these as a separate line item when tracking Sustaining Capital Expenditures, as was done in Table 9-1 of the Application.	Superseded by G-107-08 Directive #2	

Table 9-1. Directive Concordance Table

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		Commision Order G-69-07		
20	7	the Commission Panel directs BCTC to annually review projects with a budget in excess of $10 million, where the budgeted costs differs from actual by 20 percent or more, or where the project in-service date changed by in excess of six months, and prepare an internal report of the lessons, if any, that were learned from the project implementation and that may be applicable to future projects. The report should make reference to the Project Implementation Risk Matrices, and how this tool influenced the outcome. The report could also address issues such as project management, contracting and external matters that were contributing factors to the outcome. The Commission Panel directs BCTC to provide a list of those projects for which a report was prepared in its next capital plan.	Complete	F2010 TSCP: Not Applicable; F2009 TSCP:Section 9.7, pages 383-385
20	8	The Commission Panel agrees with BCOAPO's submission on variance reporting, and accepts BCTC's proposal to provide information in its next capital plan filing regarding variances exceeding both 10 percent and $100,000 of budgeted amounts submitted in this Application for approved projects, and to continue such reporting in future capital plan filings until directed otherwise.	Ongoing; Supersedes G-91-05 Directive #15	F2010 TSCP, Table 5-3 pages 5-11
30	9	The Commission Panel encourages BCTC to suggest changes to the frequency of the STSR if BCTC determines the existing frequency does not serve a useful purpose,	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.9
		but directs BCTC to submit an updated STSR with future capital plan applications until directed otherwise.	Ongoing; Supersedes G-103-04 page 8	F2010 TSCP Section 3

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		Commision Order G-69-07		
30	10	The Commission Panel directs BCTC to continue reporting performance measures in future capital plans, largely as they are provided in the 2006 STSR. BCTC should report its performance measure with and without planned outages in order to make the comparison against CEA statistics more relevant.	Ongoing; Supersedes G-91-05 Directive #29 (data collection); Supersedes G-103-04 page 15	F2010 TSCP Section 3.8 pages 3-71 to 3-79
		The Commission Panel also considers the trend graph supplied in response to BCUC 1.131.1 (Exhibit B-6) to be a useful long-term indicator, and directs BCTC to file this trend information in future capital plans.	Ongoing	F2010 TSCP Figure 6.2, page 6-67
32	11	In all future capital plan applications, BCTC is to provide a modified table in the format of the “Projects in Progress” portion of Table 5-1 in this Application. For each year during the Implementation Phase of a project BCTC is to include the approved total annual expenditures, the revised total annual expenditures, and the difference between the approved and revised annual expenditures, as well as the approved and revised in-service dates. The Commission Panel further directs BCTC to provide a modified table in the format of Table 5-3 in this Application, modified to include the total dollar value for each project, as well as the priority ranking of the project when the project was approved.	Ongoing	F2010 TSCP, Table 5-3 pages 5-11 and Table 5-4, pages 5-17 to 5-19
35	12	The Commission Panel concurs with BCTC that the provisions in the OATT adequately address future IPP interconnections, and accepts BCTC’s proposal to forecast capital for the interconnection of IPP projects for the upcoming year; however, where possible, BCTC should assign such amounts to specific IPP projects.	Ongoing	F2010 TSCP, Table 5-1 pages 5-2 to 5-5 and Section 5.5.5, pages 5-106
		For projects identified in the F2006 TSCP Update Decision as requiring further approval, the Commission Panel accepts BCTC’s proposal that it will sign facilities agreements with IPP customers, will proceed with study work and the interconnection process, and will seek Commission approval or file a letter with the Commission.	Ongoing	F2010 TSCP: Not Applicable

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		Commision Order G-69-07		
37	13	The Commission Panel considers that BCTC is complying with the second outstanding Directive and expects BCTC to report on the progress of establishing correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI.	Complete; Supersedes G-91-05 Directive #14	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.13, page 388
37	14	The Commission Panel directs BCTC to provide in future capital plans equipment reliability data as selected by BCTC and provide the CEA averages, and in the case of Line-related Forced Sustained Outages (as defined in the 2006 STSR, Section 8.3), to separate equipment failure outages from those outages caused primarily by weather or vegetation.	Ongoing	F2010 TSCP Tables 3-1 and 3-2 pages 3-78 and 3-79
45	15	the Commission Panel directs BCTC to file a report that could be described as the "operator's manual" for the Prioritization Model. This report should contain all weightings and probabilities for each category and criteria and any sub criteria, as well as a full description of the methodology employed in determining the weights and probabilities. The report should describe key assumptions, particularly those used to derive values as a result of a judgment process, as opposed to quantitatively. The report should contain a detailed example, including all numeric calculations for at least one project in each of the Growth, Sustaining, or BCTC Capital Portfolios. If BCTC cannot provide the information for proprietary reasons, it is encouraged to select examples from the beta testing of the model. The report should be filed with the next capital plan.	Complete	F2010 TSCP: Not Applicable; F2009 TSCP: Appendix J

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-69-07		
45	16	the Commission Panel directs BCTC to include in its next capital plan filing, tables for each of the Portfolios listing the projects brought for approval, their risk and value scores by category, and the priority numbers and quadrant values, where applicable. For projects with alternatives that are considered feasible or for which there is evidence that a more detailed and costly assessment should be undertaken prior to eliminating the alternative completely, those alternatives should be listed, along with their total (only) risk and value scores, and priority numbers and quadrants, where applicable.	Complete Exempted per G-107-08 page 46	F2010 TSCP: BCTC continues to report this information in Table 5-5, page 5-30 and Table 6-7, pages 6-24 to 6-27 F2009 TSCP: Section 5.4 pages 126-128, Section 6.4 pages 202-206, Section 7.4 page 323 and BCUC IR 1.18.1
46	17	The Commission Panel notes that many of the quadrant four sustaining projects that were not deferred appear to be justified not on the model results but for safety or reliability considerations. This suggests to the Commission Panel that there may be threshold values for the safety and reliability metrics beyond which projects become mandatory much as they currently become mandatory for legislative or NERC reliability reasons. The Commission Panel directs BCTC to comment on this issue in the next capital plan.	Complete	F2010 TSCP: Not Applicable F2009 TSCP, Section 9.17, pages 390-391
46	18	Since corporate risks may ultimately be reflected in costs which will impact rates, BCTC is directed to include its Corporate Risk Matrix in its next capital plan filing.	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Appendix D

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Commision Order G-69-07				
46	19	Since a growth project by definition results from an anticipation of growth, the Commission Panel is concerned that BCTC cannot estimate the likely revenues, and hence includes in the heavily weighted financial category, a value for rate impact which it knows to be inaccurate. The Commission Panel encourages BCTC to comment on this issue in its next capital plan.	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.19, page 392
48	20	the Commission Panel directs BCTC to include in future capital plans a summary table by project, showing the average load growth for the most recent five historical years, preferably weather normalized if possible, and the growth rates projected for future years. The table should also show the planning region in which the project resides and the regional load growth rates for the same periods. If there is significant divergence between the load growth rate upon which the project need is determined, and that of the planning region, BCTC is to provide an explanation of the divergence.	Ongoing	F2010 TSCP Sections 5.5.2 and 5.5.3
53	21	The Commission Panel directs BCTC to prioritize potential TEP projects with other projects using the Prioritization Model. The Commission Panel directs BCTC to report on potential TEP projects in the next capital plan, and provide a detailed description of the highest ranked potential TEP project. In the event that BCTC identifies a potential TEP project and then decides that the project should be implemented, BCTC should seek approval of the project prior to the next capital plan.	Ongoing Complete	F2010 TSCP: Not Applicable (no TEP project) F2009 TSCP: Section 9.21, page 393
55	22	The Commission Panel directs BCTC to provide a detailed description of the highest ranked intertie expansion project in the next capital plan. The description should include, if possible, the identification and quantification of potential benefits accruing to ratepayers.	Complete	F2010 TSCP: Not Applicable F2009 TSCP, Section 9.22, page 394

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		Commision Order G-69-07		
56	23	For future capital plans, the Commission Panel directs BCTC to identify separately those projects and corresponding expenditures that are directly attributable to specific generation additions.	Ongoing	F2010 TSCP Section 5.6.1 page 5-123
56	24	The Commission Panel approves BCTC's request for a determination under Section 45(6.2)(b) of the Act that capital expenditures on the Selkirk 500/230 kV Transformer T4 Addition, the Ashton Creek 2x250 MVAr, 500 kV Shunt Capacitors – Definition Phase, and the 5L91/5L98 Series Compensation – Definition Phase projects are in the public interest.	Complete	F2010 TSCP: Not Applicable
58	25	The Commission Panel accepts BCTC's proposal in its letter of March 30, 2007, that upon reaching an agreement with the District of Mission regarding the potential rerouting of a portion of the 69 kV transmission facilities associated with the Mission and Matsqui Area Supply project in the vicinity of Mission, BCTC will apply to the Commission to find the revised project to be in the public interest.	Complete	F2010 TSCP Section 9.2.10, page 9-43
66	26	If and when BCTC submits a CPCN application for the 5L91/5L98 Series Compensation project, the Commission Panel directs BCTC to submit a study that analyzes and describes the anticipated amount of seasonal and hourly reliability-driven Canadian Entitlement utilization. In order to assist in the determination of whether or not the anticipated seasonal and hourly Canadian Entitlement utilization from the requested study is consistent or inconsistent with past utilization of the Canadian Entitlement, the Commission Panel also directs BCTC to provide historical data of the reliability-driven utilization of the Canadian Entitlement in a format that allows for a reasonable comparison to the anticipated seasonal and hourly Canadian Entitlement utilization.	Outstanding	F2010 TSCP: Not Applicable; Future CPCN filing

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Commision Order G-69-07				
67	27	The Commission Panel directs BCTC to submit as part of its next capital plan a report that provides an analysis of, and a proposal for, the Lower Mainland's reactive power requirements. This report should describe and attempt to quantify the various benefits associated with the options for the Lower Mainland's reactive power requirements, and also contain a comprehensive description of the planning assumptions used in the analysis.	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.27, page 398-400
73	28	The Commission Panel directs BCTC to submit by September 30, 2007, a report for the Fox Creek Project detailing changes to project scope, schedule and cost between the request for approval and the completed project. The report should explain and justify changes to the project scope and schedule, provide explanations for all material cost variances, and include a discussion of changes to its capital planning process that BCTC has implemented or recommends based on experience with this project.	Complete	F2010 TSCP: Not Applicable; Report filed with the Commission on 23 October 2007
77	29	The Commission Panel does not approve the Chapman Fibre Optic Cable Replacement project as proposed because absent an explanation of the large expenditure in F2012, it is higher cost than a potential alternative and does not appear to be justified by safety, environmental, or compliance considerations.	Complete (approved in G 107-08 page 88)	F2010 TSCP: Not Applicable; F2009 TSCP: Section 9.29, page 401
82	30	Therefore, the Commission Panel directs BCTC to conform to the directives made in the F2006 TSCP Decision and the F2006 TSCP Update Decision with respect to Sustaining Capital expenditures.	Superseded by G-107-08 Directive #7	
83	31	The Commission Panel directs BCTC to use an inflation factor of 2.0 percent for each of F2008 and F2009 to budget for Sustaining Capital based on the forecast of BCCPI. The Commission Panel invites BCTC to provide comprehensive justification of any other inflation adjustment it may propose for F2009 and beyond, as part of its next capital plan filing.	Superseded by G-197-08 Directive #11 Outstanding	 F2010 TSCP: Section 9.2.4 page 9-40

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		Commision Order G-69-07		
83	32	For clarity, the Commission Panel approves as being in the public interest Sustaining Capital expenditures of $83.1 million in each of F2008 and F2009 when expressed in F2007 dollars, and further Third-Party Funded expenditures of $2.9 million and $1.9 million expressed on the same basis. The same amounts expressed in nominal dollars are Sustaining Capital expenditures of $84.8 million and $86.5 million in F2008 and F2009 respectively, and Third-Party Funded expenditures of $3.0 million and $2.0 million in F2008 and F2009, respectively.	Superseded by G-107-08 Directive #7	
87	33	The Commission Panel finds that the requested F2008 capital expenditures for the BCTC Capital Information Technology projects, except for the Corporate Network Segmentation project and Backup Environment Separation project, are in the public interest, and directs BCTC to investigate the cost of a secure IT environment integrated with BC Hydro's IT systems. If BCTC is unsuccessful in negotiating the security it believes it needs within BC Hydro's IT system, BCTC is directed to report on the efforts made to reach an agreement with BC Hydro in the next capital plan. In the report, BCTC should describe its concerns about BC Hydro's IT systems, provided that it is not necessary to disclose confidential negotiations or commercial interests to do so.	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.33, page 403-404
87	34	In all future capital plan applications, the Commission Panel directs BCTC to provide a table in the format of Table 7-4 of the F2008 TSCP, modified to show the total dollar amount of each project and the relative priority at the time of approval.	Ongoing	F2010 TSCP: Section 7.5 page 7-12
88	35	The Commission Panel finds the requested F2008 capital expenditures for the BCTC Capital Control Centre Sustainment project are in the public interest.	Complete	F2010 TSCP: Not Applicable
89	36	The Commission Panel finds the requested F2008 expenditures for the BCTC Capital Facilities assets projects are in the public interest.	Complete	F2010 TSCP: Not Applicable

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Commision Order G-69-07				
92	37	The Commission Panel directs BCTC to file a report related to Policy Action 12 and Policy Action 13 on or before December 1, 2007. The report should comment on the progress of consultation initiatives and further steps that BCTC considers to be appropriate to implement Policy Action 12 and Policy Action 13. In the filing, BCTC may also seek regulatory comments or direction that may be useful for the creation of the Congestion Relief Policy and the evolution of the TEP. If BCTC does seek such regulatory comments or direction, it may be helpful for BCTC to include a policy discussion paper that could be circulated to stakeholders for comment prior to Commission comments or directions.	Complete	F2010 TSCP: Not Applicable; Report filed with the Commission on 3 December 2007
93	38	To continue to satisfy the reciprocity requirements under the pro-forma OATT, BCTC must carefully assess the implications of FERC Order No. 890, and therefore the Commission Panel directs BCTC to bring its assessment of FERC Order No. 890 forward to the Commission once its consultations and assessments are concluded.	Complete	F2010 TSCP: Section 9.2.11 page 9-44
97	39	The Commission Panel directs BCTC to file a report on or before December 1, 2007 that first identifies congested paths, if any, that might be economically resolved by generation re-dispatch, and then assesses opportunities for resolving congestion by re-dispatching generation. This report may form part of the report related to Policy Action 12 and Policy Action 13.	Complete	F2010 TSCP: Not Applicable Report filed with the Commission on 21 December 2007

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		Commision Order G-67-06		
13		The Commission Panel notes BCTC's observation that it is still analyzing different approaches to IPPs, and expects to provide a recommended approach on how to treat the uncertain nature of IPP interconnections in its next Capital Plan Application. The Commission Panel directs BCTC to address this issue in its proposed November 2006 application.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.41, page 279
13		The Commission Panel notes its directive in the Commission Order No. G-103-04 directing BCTC to file Certificate of Public Convenience and Necessity ("CPCN") applications for projects involving Metro Vancouver 230 kV supply projects and is of the opinion that BCTC should include this project (the Sperling Feeder Section Addition Project) in its proposed November 2006 application.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.42, page 280
14		The Commission Panel has considered the evidence and submissions concerning the TMPSE project and shares the JIESC's concerns about the lack of information concerning the Project revenues and costs and the application of BC Hydro's contribution policy. The Commission Panel is prepared to find this project to be in the public interest on the condition that within 10 working days of the date of this Decision, BCTC and BC Hydro jointly respond to the JIESC's Information Requests 4.2 and 4.3, and that BC Hydro sets out its customer contribution policy and confirms that the TMPSE project complies with it and that the JIESC be afforded an opportunity to comment on the joint response. The Commission Panel directs BCTC to address the JIESC's concerns with the existing regulatory process in its proposed November 2006 application.	Complete; Commission letter dated 1 August 2006 Complete	F2010 TSCP: Not Applicable F2010 TSCP: Not Applicable F2008 TSCP: Section 9.43, page 280-281

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		Commision Order G-91-05		
6	1	The Commission Panel directs BCTC to provide a clear statement of where, in the overall identification, design, and construction process, it expects the Commission's approval of the need for a Growth Capital project.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.2, page 257-258
7	2	The Commission Panel therefore directs BCTC to refine the Growth Capital ranking system to better discriminate between growth capital projects. The ranking system should consider the factors that BCTC has set out in Section 2 of the F2006 TSCP, but should also consider factors such as lead-time, forecast uncertainty, and probabilistic measures such as Expected Energy Not Served ("EENS") (see Section 3.2).	Complete; Supersedes G-103-04 page 9	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.3, page 258
8	3	The Commission Panel therefore directs BCTC to include path utilization forecasts in its capital plans whenever transmission capacity upgrades are proposed. The Commission Panel expects that, in providing such forecasts, BCTC will comply with the directions given on page 12 of the F2005 Reasons for Decision.	Ongoing	F2010 TSCP: Section 9.2.12 page 9-44 F2008 TSCP: Section 9.4, page 259
8	4	The Commission Panel notes that BCTC has initiated a dialogue with stakeholders on whether to expand its role to include forecasting future customer requirements in advance of service contracts, and then planning to meet these requirements (Exhibit B-1, p. 19). The Commission Panel directs BCTC to report on the status and outcome of those discussions in its next capital plan application.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.5, page 259-261

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Commision Order G-91-05				
9	5	The Commission Panel directs BCTC to report the indices applicable to it from Order No. G-103-04 and their associated trends for at least the past five years in the next capital plan. The reporting of these indices should also state the targets for the specific years against which each indicator was measured.	Complete	F2010 TSCP: BCTC continues to report this information in Section 3.8, pages 3-71 to 3-76
11	6a	The Commission Panel directs BCTC to comply with the directive given on page 17 of the F2005 Reasons for Decision in its next capital plan.” The Directive on page 17 of the F2005 Reasons for Decision states: “The Commission Panel therefore directs BCTC to submit, with its next Capital Plan, performance indices that are capable of providing an indication of when and where Growth Capital spending may be necessary."	Complete; Supersedes G-103-04 page 17	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.7, page 262-263
11	6b	The Commission Panel also directs BCTC to submit the investment policy that it is developing in conjunction with TPAC for Commission review before such policy is implemented. The Commission Panel expects that, at the time the investment policy is submitted, BCTC will be prepared to discuss its "no congestion for firm transmission" policy and DSM options, both of which may affect the policy.	Complete	F2010 TSCP: Not Applicable Letter filed with the Commission on 23 December 2005
11	7	The Commission Panel therefore directs BCTC to provide, in each future capital plan, a section describing its response to Commission directives from previous capital plans. The status of compliance with each directive is to be reported in each capital plan until such time as BCTC has complied with the directive.	Ongoing	F2010 TSCP Section 9
16	8	The Commission Panel directs BCTC to consider economics in its assessment of whether transmission upgrades should proceed. The Commission Panel does not consider that the simple existence of a NERC/WECC Planning Standards violation is sufficient justification for transmission upgrades in every case.	Ongoing	F2010 TSCP: Section 5.5 F2008 TSCP: Section 9.11, page 265-266

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Commision Order G-91-05				
17	9	The Commission Panel directs BCTC to review Attachment J to determine whether any changes are warranted, given the Commission Panel's directives herein on system planning and the interpretation of reliability standards.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.12, page 266
17		Future applications should identify whether any capital projects are driven by the need to conform to Section I.A.M2 during maintenance outages.	Ongoing	F2010 TSCP: Section 9.2.13 page 9-45
19	10a	The Commission Panel therefore directs BCTC, if it has not already done so, to initiate discussions with customers (including BC Hydro) on potential customer-provided solutions to transmission constraints, and to report to the Commission on the outcome of those discussions in its next capital plan. Without limiting the scope of the discussions, the Commission Panel expects BCTC will examine the following in conjunction with BC Hydro: • options for general (i.e., system- or area-wide) demand reductions, to the extent they are not already covered by existing DSM initiatives such as PowerSmart; • options for location- or area-specific demand reductions, either planned or in response to system events (e.g., by arming customer-specific remedial action schemes); • demand reduction timing requirements (e.g., all hours, peak months or hours, or only when armed); • mechanisms for compensating customers, such as reduced rates, direct payments through commercial contracts, or investment deferral credits; • options for customer-supplied transmission services, such as reactive power or reliability must-run generation.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.14, page 266-267

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		Commision Order G-91-05		
20	10b	The Commission Panel further notes that, as the entity responsible for developing solutions to transmission constraints, BCTC is in the best position to identify the extent to which customer- or third-party-provided solutions could defer or eliminate the need for Growth Capital investments. Without pre-judging whether BCTC or BC Hydro (or both) should ultimately contract for non-wires solutions, the Commission Panel expects that BCTC will identify potential non-wires solutions in future studies and capital plan applications.	Superseded by G-107-08 Directive 8	
26	11	The Commission Panel finds that the three-year interval between asset condition audits is appropriate. However, increasing amounts of asset data should be available at each interval. BCTC's data monitoring, collation and analysis activity should be sufficient to ensure that an adequate data-based condition assessment is available for at least 90 percent of the assets within each class meeting the 70 Percent Rule by the third audit.	Exempted (Letter L-92-07)	F2010 TSCP: Not Applicable F2009 TSCP: Section 9.40, page 406-407
26	12	The Commission Panel encourages the preparation and use of a rigorous financial comparison of continued maintenance versus equipment replacement as a key driver in asset management planning. Where possible and practical, this analysis should be done for individual pieces of equipment, with maintenance costs for that piece of equipment based on its actual condition and its required reliability in its specific application. The Commission Panel expects that such financial evaluations will include a comparison against options that were considered but not selected, rather than only an evaluation of the selected option.	Complete	F2010 TSCP: Section 4.4.3.3, page 4-53 F2008 TSCP: Section 9.17, page 268
26	13	The Commission Panel recommends that the "fatal flaw" factor only be used on individual assets that meet the 70 Percent Rule, and not be applied to entire populations for which valid data may not exist.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.18, page 268-269

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		Commision Order G-91-05		
27	14	The Commission Panel therefore recommends that, during the design and development of its asset management information systems, BCTC consider the data collection and analysis processes necessary to establish the correlations among asset classes' health index values, failure rates, expected remaining lifetimes, and impacts on reliability indicators such as SAIDI.	Superseded by G-69-07 Directive 13	
30	15	The Commission Panel directs BCTC to file, with each future capital plan, a table showing the changes from one capital plan to the next. The table may be in a form to be determined by BCTC, but must note any projects that have been accelerated, deferred, or cancelled, and must show any changes in expenditure patterns.	Superseded by G-69-07 Directive 8	
37	19	The Commission Panel therefore rejects BCTC's application for definition-phase funding (for the Ingledow SVC project). BCTC is at liberty to re-file its request whenever it chooses, but if it does so, it must provide either: (a) a justification for the project that addresses the issues raised by the Commission Panel; or (b) a plan to develop the justification and a statement as to why the associated costs should be capitalized.	Outstanding	F2010 TSCP: Not applicable (the project is not in the F2010 TSCP)
41	21	The Commission Panel therefore denies BCTC's application for approval of the Growth Capital projects on the South Interior bulk transmission system. Instead, the Commission Panel directs BCTC to submit, at the time of its next capital plan, or sooner should it so wish, a comprehensive System Development Plan ("SDP") for the South Interior bulk transmission system. The SDP must address the issues noted by the Commission Panel in this section and Section 2.1, and must clearly illustrate the relationship between the proposed Growth Capital projects.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.22, page 270
42	22	In the Commission Panel's view, the advisability of the multiple-contingency RAS is clear; the project is therefore approved. The Commission Panel also accepts BCTC's view that RAS may be the appropriate solution to certain system problems, and therefore approves the Unidentified RAS Additions project for F2006 and F2007. The Commission Panel expects that actual expenditures on this project will be reported in BCTC's next capital plan application.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.23, page 270-271

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-91-05		
44	23	However, given the projected cost, geographic extent, environmental issues, and range of customers affected, the Commission Panel directs that BCTC submit a CPCN application for the East Kootenay project should BCTC decide to proceed.	Outstanding	F2010 TSCP: Not Applicable (the project is not in the F2010 TSCP) F2008 TSCP: Section 9.24, page 271
45	24	The Commission Panel therefore accepts BCTC's recommendation that the Goward project be approved under the assumption that the proposed 230/138 kV transformer is the best option, and expects that BCTC will make a new application to the Commission if an alternate solution is selected.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.25, page 271
45	25	The Commission Panel ...grants approval for the Area Planning Definition Work for F2006 only. For F2007 and beyond, area planning activities should be treated in accordance with the process(es) that BCTC proposes (and that the Commission ultimately approves) in response to the directives given in Section 2.2.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.26, page 271-272
47	26	The Commission Panel approves the definition-phase expenditures (for the Horne Payne transformer replacement). The Commission Panel directs BCTC to consider and report on the appropriate treatment of this project when complying with the directives in Section 2.2.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.27, page 272

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-91-05				
49	28a	The Commission Panel expects that future revenue requirements applications will contain the best available information of the pattern and amount of expenditures. Specifically, where the information in such future applications is different than the forecasts supplied in this Application, the Commission Panel expects BCTC will provide commentary as to the source of the differences.	Complete	F2010 TSCP: Not Applicable (this is an ongoing directive for the RRA) F2008 TSCP: Section 9.28, page 272
49	28b	The Commission Panel directs BCTC to report future Sustaining Capital Portfolios in a manner that preserves the ability to track and trend annual Sustaining Capital spending as far back as F2001, and facilitates comparisons and identification of trends in spending for individual Sustaining Capital Programs.	Ongoing	F2010 TSCP: Table 6-2 page 6-11
51	29	The Commission Panel expects BCTC to collect sufficient data to allow the identification of the worst performing asset classes by quantification of the effect of equipment failures on the reliability indices, and to present this data in support of future Sustaining Capital Portfolios and programs. The Commission Panel reaffirms the following direction from Order G-103-04: The Commission therefore directs BCTC to provide, in future Capital Plans, a classification of transmission failures by equipment type and age, as well as an indication of the impact of transmission failures on reliability indices. Statistics should be included for as many years in the past as are reasonably available in order that trends may be observed. Should the requested statistics not exist, BCTC is to file a plan for collecting the necessary data in the future.	Superseded by G-69-07 Directive 10 ; Supersedes G-103-04 page 16	F2008 TSCP: Section 9.30, page 273

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-91-05				
52	30	The NERC/WECC Planning Standards appear to have some flexibility for interpretation and application, especially with respect to system performance impacts that can remain confined to one's own system and are not on the WECC-rated bulk transmission facilities. Again, with the objective of reducing the rate increase associated with the rapid rise in the overall Sustaining Capital Portfolio, the Commission Panel encourages the use of this flexibility to defer or eliminate the need for projects driven by a conservative application of the standards.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.32, page 274-275
53	31	The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,000,000 and $3,500,000, respectively, in the Protection and Control Sustaining Capital Programs.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.33, page 275-276
54		The Commission Panel expects that future capital plans will contain economic evaluations that compare increased and extended maintenance against equipment replacement for such large programs.	Ongoing	F2010 TSCP: Section 6.5 and Appendix D-1 F2008 TSCP: Section 9.34, page 276-277
55	32	The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $2,500,000 and $4,500,000 respectively, in the Stations Sustaining Capital Programs.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.33, page 275-276

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-91-05				
56	33	The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $1,000,000 and $2,500,000, respectively, in the Telecommunications Sustaining Capital programs.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.33, page 275-276
58	34	The Commission Panel directs BCTC to implement reductions in F2006 and F2007 of $3,500,000 and $4,500,000, respectively, in the Overhead Lines and Rights of Way Sustaining Capital Programs.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.33, page 275-276
59	35	The Commission Panel suggests that BCTC re-evaluate the key driver criteria in order to yield an ongoing lower level of sustaining capital expenditures. The Commission Panel anticipates that the reductions of approximately 10 percent in the F2006 and 15 percent in the F2007 Sustaining Capital Portfolios directed above are sustainable through re-evaluation, re-prioritization and re-distribution of programs. Therefore, the 15 percent reduction should apply to future years' forecasts until changes in the trends of the reliability indices or asset health assessments suggest the need for changes from the status quo in the size of the Sustaining Capital Portfolio.	Superseded by G-107-08 Directive #7	
62	36	The Commission Panel directs BCTC to reduce aggregate F2006 and F2007 expenditures by $2,400,000.	Complete	F2010 TSCP: Not Applicable F2008 TSCP: Section 9.38, page 278

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-91-05		
62		The Commission Panel expects that (BCTC Capital) project priorities will be provided in future capital plans.	Ongoing	F2010 TSCP: Section 7.5 page 7-12 F2008 TSCP: Section 9.39, page 278
63	37	The Commission Panel therefore directs BCTC to provide, in future capital plan applications, a summary of the previous three years' activities and expenses for each ongoing project whose annual costs exceed $250,000.	Ongoing; Supersedes G-103-04 page 39	F2010 TSCP Section 7.5 page 7-12

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-103-04		
8		To help clarify the relationship between individual capital projects and BCTC's overall plan for the transmission system, the Commission Panel directs BCTC to provide a "state of the transmission system" report in future Capital Plans.	Superseded by G-69-07 Directive #9	
9		In addition to the "state of the transmission system" report, the Commission Panel accepts the suggestion of IPPBC that a common framework for the evaluation of transmission capital projects would be useful. The project evaluation framework should incorporate the criteria noted by BCTC throughout its Application and some of the suggestions made by Intervenors.	Superseded by G-91-05 Directive 2	
12		In line with direction given to BC Hydro in the VIGP Decision (pp. 12 and 71), the Commission Panel expects BCTC to include the following components of the transmission usage forecast in future Capital Plan applications: • a detailed explanation of the appropriateness of the selected forecast methodology compared to other alternative methodologies; • an explicit listing of underlying assumptions and comments on the quality of input data and their sources of information; • intermediate outputs of the modelling process and the verification procedures carried out to validate the models; and • commentary on historical growth trends and implied growth rates and reasons for deviations from trends. The Commission Panel also expects BCTC to use forecasting models that can be made public so that the various components and assumptions can be assessed and tested by intervenors.	Complete Partly superseded by G-91-05 Directive 3 and G-69-07 Directive 20	F2010 TSCP: Not Applicable; F2006 TSCP: Section 2.3.2.1

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-103-04				
15		The Commission Panel expects BC Hydro and BCTC to present their reliability indices (SAIFI, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forced outages, availability, and the generation outage rates), both combined and disaggregated (where applicable), on an annual basis with comparisons to CEA averages. The Commission Panel directs BCTC to report these indices, as available, in its annual Capital Plan.	Superseded by G-69-07 Directive 10	
16		The Commission therefore directs BCTC to provide, in future Capital Plans, a classification of transmission failures by equipment type and age, as well as an indication of the impact of transmission failures on reliability indices. Statistics should be included for as many years in the past as are reasonably available in order that trends may be observed. Should the requested statistics not exist, BCTC is to file a plan for collecting the necessary data in the future.	Superseded by G-91-05 Directive 29	
16		The Commission Panel expects that reliability-driven expenditures will be tracked so that the effectiveness of such expenditures at reducing outages or otherwise increasing reliability can be assessed.	Complete	F2010 TSCP: Not Applicable F2009 TSCP: Appendix H
16		The Commission Panel therefore finds that the Baseline Study and subsequent follow-up audits should be incorporated into the “state of the transmission system” report that the Commission Panel has directed be included with future Capital Plans. The Commission Panel expects that any recommendations in the Baseline Study will be considered by BCTC in formulating its future Capital Plans. The Commission Panel notes that this direction may delay the filing of the next Capital Plan beyond February 2005, and therefore directs that BCTC propose a revised filing date at the time the Baseline Study is released.	Complete	F2010 TSCP: Not Applicable; Baseline Study filed May 6, 2005 Subsequent Audit: Superseded (Letter L-92-07)
17		The Commission Panel therefore directs BCTC to submit, with its next Capital Plan, performance indices that are capable of providing an indication of when and where Growth Capital spending may be necessary.	Superseded by G-91-05 Directive #6a	

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-103-04				
19		The Commission accepts the view of those Intervenors that believe mechanisms to prioritize capital expenditures are necessary. In Section 2.2 of the Reasons for Decision, the Commission Panel directed BCTC to develop, and to file with its next Capital Plan, a capital project evaluation framework. The Commission Panel expects that the framework will clearly set out, among other things, the criteria by which project priorities are established. In addition, the Commission Panel expects that each project included in the next Capital Plan will have an associated priority ranking.	Complete	F2010 TSCP: Not Applicable F2006 TSCP: Section 2.3.3 page 22, Section 2.4.5 page 26; Priority ranking is in Sections 3.3 and 4.4.
20		However, the Commission Panel notes that rate impact information by project priority and capital portfolio would be useful, and directs BCTC to provide such information in future applications.	Ongoing	F2010 TSCP Section 8 pages 8-1 to 8-3
21		The Commission Panel accepts IPPBC's suggestion that the party funding a capital project and the amount it is paying should be identified, and it directs BCTC to provide such information in future Capital Plans, subject to confidentiality requirements.	Ongoing	F2010 TSCP: Section 5.5.4, page 5-102 and Section 6.5.12, page 6-64
21		The Commission Panel notes BCTC's support for the JIESC suggestion to categorize projects as recurring or non-recurring, and directs that such categorization be reported in future Capital Plans.	Superseded by G-91-05 Directive 28(b)	

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-103-04				
27		In the interest of further exploring the DC and 230 kV AC supply options for Vancouver Island, the Commission Panel also directs BCTC to answer the following questions. 1. What alternatives for Vancouver Island supply were considered? 2. What is the basis for the conclusion that the 230 kV line is the best transmission reinforcement option? Please cite any reports that were prepared by either BCTC or BC Hydro. 3. What issues were raised with Sea Breeze's HVDC consultants (Exhibit B-6, p. 9), and what are the relative merits of the 230 kV and HVDC options in addressing them? 4. Were characteristics other than the alternatives' power transfer capabilities (e.g., voltage support, power flow control) considered in the evaluations? If so, what are the relative merits of the 230 kV and DC options in this regard? 5. What would be the impact on the transmission system of: (i) a permanent, 7×24 demand reduction of 140 MW on Vancouver Island, and (ii) the construction of an 1100 MW HVDC facility between the island and the Olympic Peninsula? Would the requirement for the 230 kV line, or for any other major capital project proposed by BCTC, be deferred or eliminated? 6. What are the expected peak and average loads on the proposed 230 kV line, and what are the assumptions upon which these values are based? 7. What are the expected 230 kV losses under peak and average loading conditions? If study-based values are not available, the Commission Panel will accept reasonable estimates based on BCTC's expectation that the submarine cable will be of the self-contained fluid-filled type with a copper cross section of 1400 mm2. 8. Have the geotechnical studies that were underway at the time of the Capital Plan Application been completed? If so, what were the main findings and recommendations of the study?	Complete	Letters dated 20 December 2004 and 8 April 2005; VITR CPCN proceeding

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
		Commision Order G-103-04		
		BCTC is to provide its response to these questions within 30 days of the release of the Reasons for Decision. Should this period be considered too short by BCTC, it must notify the Commission within 7 days and propose an alternative date for its response. BCTC's responses are not to be considered part of this proceeding, and a regulatory review of BCTC's response is not contemplated at this time. The purpose of this direction to BCTC is to ensure that the information is made available to Sea Breeze for its review and consideration.		
31		The Commission Panel therefore directs BCTC to file CPCN applications for the following projects: • Mount Pleasant 230/12 kV Substation; • Cathedral Square to Sperling 230 kV cable; • 230 kV and related projects that may arise from the Metro Vancouver 230 kV Reinforcement Development Project; and • 2L45, Camosun to Sperling (if BCTC ultimately proposes this project).	Outstanding	F2010 TSCP: Not Applicable; Future filing
34		Therefore, the Commission Panel directs BCTC, in conjunction with BC Hydro if necessary, to fully evaluate the proposal and to submit a report to the Commission within 30 days of the release of the Reasons for Decision. If BCTC finds the NorskeCanada proposal unacceptable, the report must specify the rationale for its rejection and state which planning criteria would be violated by the proposal's implementation. If the 30-day response period is determined by BCTC to be inadequate, then it should notify the Commission and propose an alternative schedule within 7 days of the release of the Reasons for Decision. BCTC's responses are not to be considered part of this proceeding, and a regulatory review of BCTC's response is not contemplated at this time. The purpose of this direction to BCTC is to ensure that the information is made available to NorskeCanada for its review and consideration.	Complete	Letter dated 20 December 2004; Report filed 23 December 2004; F2006 TSCP page 4 lines 5 to 19 inclusive

Table 9-1. Directive Concordance Table

Decision Page No. (a)	Directive No. (b)	Topic (c)	Status (Complete, Ongoing, Exempted, Outstanding, Superseded) (d)	Reference to BCTC's Response (e)
Commision Order G-103-04				
		If BCTC finds the NorskeCanada proposal unacceptable, then by the time of its next Capital Plan application, it must provide a statement of the minimum demand management proposal (minimum volume, minimum number of hours of availability, etc.) that it would find acceptable, along with a statement by NorskeCanada that it cannot or chooses not to meet the minimum requirements. The Commission Panel views the above DSM directions as appropriate under the present circumstances. DSM solutions to transmission issues may be in the public interest and the role of BC Hydro and BCTC regarding the DSM solutions to transmission issues remains an outstanding issue.		
37		However, the Commission Panel does accept that the ability to track and identify the causes of congestion is important, and directs that the required data be provided as part of future Capital Plans. The Commission Panel provided related directions in Section 2.3.4 of the Reasons for Decision.	Ongoing	F2010 TSCP Section 3.9 page 3-80
39		The Commission Panel directs BCTC to provide a status report on each IT project for which the expected duration of the combined development and implementation phases (with any necessary schedule updates included) is greater than one year. These status reports, which shall include budgeted and actual expenditures to date, estimated cost to completion, and an analysis of any variance between budgeted and actual costs, are to be submitted with BCTC's annual Capital Plan.	Superseded by G-91-05 Directive 37	

9.2 Specific Directive Responses

Section 9.2 provides detailed comments for Directives referencing Section 9.2 in Table 9-1.

9.2.1 Order G-107-08 page 18 Directive 03

> "The Commission Panel expects that in the future such expenditures [UMS report] will be provided with greater transparency in both the capital planning and revenue requirement processes."

BCTC acknowledges the Commission's expectation regarding the transparency of the UMS report costs. BCTC notes that UMS' proposal, the full cost of the report, and the proposed method of recovery of these costs was disclosed in the F2009 TSCP Proceeding. The UMS costs were then subject to further review in BCTC's F2008 Deferral Accounts proceeding. BCTC submits that the Revenue Requirement and Deferral Account Disposition proceedings are the most appropriate processes for examination of these types of expenditures since these costs are funded by OMA. BCTC commits to continue to disclose these types of expenditures in the Transmission Revenue Requirement and Deferral Account proceedings.

9.2.2 Order G-107-08 page 24 Directive 04

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

BCTC does not believe that it is practical to define applicable and appropriate constraints or thresholds for project selection within the prioritization model. BCTC indicated in its response to BCUC IR 1.109.1 in the F2009 TSCP proceeding that lower value, lower impact of deferral projects will be deferred in response to resource constraints; and that resource constraints include outage, labour and equipment availability and financial limitations such as funding availability and lack of cost-effectiveness. Any threshold based solely on value and impact of deferral scores would not take into account these resource constraints. The resource constraints that are applicable may depend on the specific investments that are being selected. For example, if a large number of investments in one area are selected, then the need for, and availability of, outages would be examined more closely. The identification of all possible constraints, e.g., all outage limitations, for inclusion within the prioritization model would be impractical. The prioritization model would have to be expanded to capture all possible constraints that may be triggered, adding to the complexity of the model; and the data associated with the additional constraints would have to be identified for each investment, whether they are triggering a constraint or not, requiring additional resources. BCTC believes that it is more efficient to use expert judgment to determine whether a constraint may be required and applied in the process of finalizing the portfolio of investments. BCTC also believes that the prioritization method should remain a tool to assist decision-making, rather than to make portfolio decisions through the addition of constraints and thresholds within the method.

BCTC reviews its prioritization method for each Capital Planning cycle. The review considers the experience gained in previous cycles, including an examination of the circumstances where expert judgment was applied. One of the goals of the review is to support the continuous optimization of the model. However, this does not necessarily equate to reducing the application of expert judgment. Expert judgment is applied to make decisions regarding the composition of the portfolios, including where interventions are required to compensate for limitations of the model. Reducing the level of intervention to compensate for the model limitations may necessitate an increase in the level of complexity of the model. The inclusion of constraints within the model, discussed in the paragraph above, is an example where reducing expert judgment is not practical. Notwithstanding the above, continued optimization drove many of the changes that BCTC made to the prioritization method for the F2010 TSCP, and some of those changes have reduced the level of expert judgment intervention. For example, the STER Tower and Equipment Replacement Program ranked low in the F2009 TSCP, but was included in the Sustaining Capital portfolio based upon expert judgment. The changes to the Reliability Category for the F2010 TSCP subsequently improved the ranking of the project eliminating the need for expert judgment intervention. The changes made to the prioritization method for the F2010 TSCP are detailed in Section 4.1.

The prioritization method captures dollar cost savings under the Financial Category and the Market Efficiency Category. Identifiable cost savings accruing to third parties are captured by the Market Efficiency Category while identifiable cost savings affecting BCTC are captured by the Financial Category. This approach is unchanged since the F2008 TSCP.

The Financial Category of the prioritization model measures the impact of an investment on the following four criteria: NPV, Benefit to Cost ratio, Rate Impact and Efficiency Savings. Savings from time, efficiency and effectiveness improvements that impact the bottom line are included in the NPV, BCR and Rate Impact criteria. Efficiency Savings are savings from time, efficiency and effectiveness improvements that do not impact the bottom line. Although identifiable, Efficiency Savings are subjective and not easily quantifiable. BCTC has selected this approach in the prioritization method because it allows BCTC to give a lower weight to Efficiency Savings, which is aligned with how BCTC considers them in its decision-making.

9.2.3 Order G-107-08 page 44 Directive 09

> "The Commission Panel directs BCTC to identify in the next capital plan application the industry benchmarking surveys to which it provides data, and to identify those in which it participates more fully, and to report the results of those surveys, including the utility-specific reports from CEA. BCTC is also directed to provide, in the next capital plan application, a summary report that identifies a representative cross-section of surveys being performed in the electric utility sector."

BCTC gives careful consideration to its participation in benchmarking studies by assessing the work associated with participation in the studies in relation to the anticipated benefits that would be realized. For any benchmarking period, if the resource requirements exceed the anticipated benefits, or if the study duplicates the analysis of another study in which BCTC already participates, BCTC does not participate in that study for that benchmarking period. As a result of this approach, BCTC participates and provides data in four Canadian Electricity Association (CEA) benchmarking studies which are performed annually, and the International Transmission Operations and Maintenance Study (ITOMS) which is performed biennially.

(a) Canadian Electricity Association (CEA):

i. Committee on Performance Excellence (COPE): The scope of this study is to provide a high level cost comparison of Canadian utilities in the area of Power Generation/Supply, Transmission, Distribution and Customer Service.

ii. Bulk Electricity System (BES): This study provides a comparison of the transmission system's reliability performance among Canadian utilities.

iii. Occupational Health and Safety (OHS) Statistics: This data is collected to prepare the annual CEA Safety Incident Statistics Report. Injury and illness incident data is collected for Power Supply, Transmission, Distribution, Customer Services and Corporate Services.

iv. Equipment Reliability Information System (ERIS) – Forced Outage Performance of Transmission Equipment Study: This study collects forced outage data for transmission equipment with an operating voltage of 60 KV and above for utilities across Canada.

(b) International Transmission Operations and Maintenance Study (ITOMS): This study provides a detailed performance assessment of the operations and maintenance functions in a transmission utility.

BCTC participates in CEA studies because CEA is a well-established benchmarking association that provides clear definitions for data collection, and has high participation among Canadian utilities. BCTC participates in the ITOMS because it is specifically designed for transmission utilities and it also provides a detailed focus on Operations and Maintenance costs and reliability at the equipment level that is currently not available in any other study in which BCTC participates. Utilities from around the world participates in the ITOMS study, many of which have used asset management business models for much longer than BCTC, thus providing more opportunities to learn about best practices.

BCTC provides the results of these studies as follows:

(a) A summary of Key Performance Indicators from the COPE, BES and OHS studies which BCTC has included as Appendix E. The primary focus of these studies is for internal utility analysis, and for improving operational performance through the identification of best practices. Caution should be used in interpreting and using the results from these benchmarking studies in a regulatory context as the data collection is performed by each individual utility and therefore the method of collection is not uniform across the industry.

(b) The COPE study does not produce a report and BCTC is bound by confidentiality agreements to keep confidential the utility-specific reports for the BES, OHS and ITOMS studies.

(c) The ERIS study produces a general report, which does not include any utility-specific information. BCTC filed this study with the Commission in the F2009 TSCP proceedings as part of BCTC's response to BCUC IR 1.55.4.

(d) ITOMS produces a "Blind" report, which BCTC has included as Appendix F, which allows for comparison of BCTC's performance with other study participants. BCTC is labeled G in the report provided in Appendix F.

A cross-section of industry benchmarking studies includes two other studies in which members of the Transmission Business Unit of the CEA participate. The two studies are:

(a) Electric User Consultative Group (EUCG): This study collects transmission and distribution cost and operational data with a significant focus on industry best practices.

(b) PA Consulting Group Polaris Transmission & Distribution Benchmarking Program: This study collects operational activity information for electric, gas and water utilities.

BCTC no longer participates in EUCG due to low participation from other utilities (only 5 utilities participate), and the results did not specifically identify the utilities, which made sharing practices with best performers challenging. BCTC has also chosen not to participate in PA Polaris due to poor clarity in their definitions for data collection.

Many regulators across Canada are increasingly requesting data and results from CEA benchmarking studies to assess electric utility performance. Due to this increasing demand, the CEA has formed a task group of utility members who are working together to develop a subset of benchmarking indicators from the CEA studies which could be provided on a yearly basis for trending the performance of that individual utility and the composite value of all the members over time. There will be one or more indicators for Reliability, Safety and Performance/Cost developed and approved by the Transmission Council of CEA.

9.2.4 Order G-107-08 page 54 Directive 11

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

In response to the Commission directive, BCTC has used an inflation adjustment of 2.1% p.a. for the years F2010 to F2019 in the Sustaining Capital portfolio, based on BC CPI.

Although BCTC has used an inflation adjustment based on BC CPI, BCTC's strong perception is that over the past few planning cycles, it has experienced greater underlying cost escalation than the BC CPI rate of inflation. BCTC has therefore initiated an historical analysis of costs and the inflationary impact on the Sustaining Capital portfolio. The ultimate goal of this work is to determine whether this information could be used to evaluate past inflation and arrive at a mechanism which could potentially be used to re-size Sustaining Capital portfolio expenditures. The proposal is to use a simplified CPI approach to calculate weighted baskets of goods and services specific to the Sustaining Capital portfolio. An initial report is provided in Appendix B of this application. The report details a general methodology and high level assumptions needed to further this work, as well as some preliminary results.

BCTC is seeking comments from the Commission on the proposed approach.

9.2.5 Order G-107-08 page 58 Directive 12

> "The Commission Panel also acknowledges the effort being made by both BCTC and BC Hydro towards developing a common understanding regarding the dispatch assumptions of resources identified in the NITS application, and

> encourages BCTC to continue assessing how the existing transmission system can be best utilized through re-dispatch of NITS-nominated resources. The Commission Panel directs BCTC to file a report describing these assumptions with the earlier of the next capital plan application or following BC Hydro's next NITS application."

BCTC and BC Hydro discussed the issues related to the dispatch of the NITS-nominated resources and completed a report in June 2008 describing the integrated power system planning assumptions that BCTC and BC Hydro use in conducting integrated power system studies. This report was filed as Appendix F9 of the BC Hydro's 2008 LTAP Application which was submitted to the Commission on 12 June 2008. A copy of the report is provided in Appendix C.

Prior to the start of the next NITS analysis, BCTC and BC Hydro will review the assumptions and update them if required.

9.2.6 Order G-107-08 page 67 Directive 15

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

BCTC has reviewed the scope and timing of the Ashton Creek - 2x250 MVAr - 500kV Switchable Shunt Capacitor Project with consideration for the timing of the South Interior resource additions and load forecasts in BC Hydro's 2008 LTAP. The timing and scope of the Project remain unchanged.

The original justification for these two capacitors was documented in Appendix F of the F2009 TSCP. Based on the original justification, the new IPPs in the 2006 CFT will increase the transfer demand across the West of Selkirk cut-plane, and the addition of Revelstoke Unit 5 will decrease the transfer capability between Ashton Creek to Nicola unless additional reactive support is provided at Ashton Creek. The two 500 kV shunt capacitor banks at Ashton Creek were proposed to recover the transfer capability that is reduced by Revelstoke Unit 5 and increase the transfer capability to meet the incremental demand from new IPPs.

BCTC has found that, based on the 2008 LTAP, the drivers for the two capacitor banks at Ashton Creek continue to be the integration of Revelstoke Unit 5 and increased transfers demands across the West of Selkirk cutplane.

The addition of these capacitors allows BCTC to meet NERC/WECC Planning Standards as well as BCTC's own standards with respect to generation shedding. The required in-service date for these capacitors remains 2010.

9.2.7 Order G-107-08 page 68 Directive 16

> “The Commission Panel encourages BCTC to continuing working with FortisBC to develop a solution that would be beneficial to the ratepayers of both utilities, and approves Definition Phase expenditures associated with Woods Lake Area Reinforcement project.”

BCTC and FortisBC are continuing to work towards developing a solution for the Woods Lake area. Cost information has been exchanged between the companies and an evaluation of alternatives is in progress. A decision on the preferred alternative is expected by year-end.

9.2.8 Order G-107-08 page 86 Directive 18

> “The Commission Panel rejects the use of the MTBF criterion in its current form as BCTC's minimum reliability criterion, and directs BCTC to revise this criterion and submit it in the next capital plan filing.”

BCTC does not use MTBF as a minimum reliability criterion. BCTC’s current approach is to use MTBF as one of several indicators to trigger a review of the health and performance of an individual asset, which subsequently may result in an investment decision. An investment decision also takes into account further considerations including criticality of the asset in the system, other priorities, and availability of outages. An MTBF of less than three years for individual assets would trigger a review.

9.2.9 Order G-107-08 page 86 Directive 19

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

BCTC's response to BCUC IR 1.62.1 in the F2009 TSCP proceeding stated:

> "Capacitors at VIT currently enable voltage (VAR) support and harmonic suppression for the HVDC system serving Vancouver Island. Once VITR is implemented, the capacitors at VIT will still be required to provide VAR support for Vancouver Island supply. Therefore, capacitive VAR support at VIT is required irrespective of the projected life of HVDC system."

The 2007 update of the baseline audit report, provided in response to BCUC IR 2.117.1 in the F2009 TSCP proceeding, incorrectly provided the following information on page 13:

> "Once Vancouver Island Terminal Reinforcement (VITR) is completed, the shunt capacitors at VIT will no longer be required for voltage support in the system."

To clarify the contradictory evidence with respect to the need for the VIT capacitors, BCTC confirms that there is a long-term need for the VIT capacitors for system voltage support on Vancouver Island after completion of VITR regardless of the future of the HVDC system.

9.2.10 Order G-69-07 page 58 Directive 25

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

During the F2009 TSCP proceeding, BCTC filed a Project Review Report (see BCTC's response to BCUC IR 1.82.1 in the F2009 TSCP proceeding). As discussed in the Project Review Report, following further consultation with the District of Mission and the BC Ministry of Highways, BCTC made the determination with the support of the District of Mission not to reroute the 69 kV transmission facilities because it was not economically feasible to do so. Therefore, the potential rerouting envisioned in the Directive did not occur.

9.2.11 Order G-69-07 page 93 Directive 38

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

BCTC's assessment of FERC Order No. 890 is complete. On 21 November 2008 BCTC filed an application with the Commission to amend its tariff in order to satisfy the reciprocity requirements under the pro-forma OATT.

9.2.12 Order G-91-05 page 8 Directive 3

> "The Commission Panel therefore directs BCTC to include path utilization forecasts in its capital plans whenever transmission capacity upgrades are proposed. The Commission Panel expects that, in providing such forecasts, BCTC will comply with the directions given on page 12 of the F2005 Reasons for Decision."

BCTC's response in Section 9.4 of the F2008 TSCP included the following:

> "BCTC has developed and implemented a Path Utilization Forecast methodology for use in the planning of Capital projects where transmission capacity upgrades are proposed for major paths. …"

The methodology assists in forecasting customer requests for transmission service on the specific path.

The F2010 TSCP is seeking approval of one project involving a major path. This approval is for Definition funding for the 5L71/5L72 Series Compensation Project, which may be required to integrate new generation at Mica. BCTC anticipates a CPCN application for the implementation phase of this project if and when new generation at Mica proceeds. All required studies to justify the project would form part of the CPCN Application. The project is described in Section 5.5.1.1.1.

9.2.13 Order G-91-05 page 17

> "Future applications should identify whether any capital projects are driven by the need to conform to Section I.A.M2 during maintenance outages."

No projects in this Application are driven by the need to conform to NERC/WECC standards during maintenance outages.

Projects driven by such a requirement would be a rare occurrence and there has not been any such project in BCTC's F2008, F2009 and F2010 TSCP applications. Examples of possible projects include a transmission line addition to relieve an existing line that is loaded up to its limits all year long, a circuit breaker addition to allow for N-1 capability when a piece of equipment is taken out for maintenance (if the only way to take the equipment out is to open up a bus, etc.), and a remedial action scheme to ensure security when a piece of equipment is out of service for a long time (e.g., cables).

BCTC provides the drivers for a project in the project justification supporting a request for approval. The project justification would include the need to conform to NERC/WECC standards during maintenance outages if it were a driver.

BCTC is requesting to be relieved from reporting on this Directive separately as the information would be provided in the project justification included in the TSCP.

Appendix A

Growth Planning Standards

1.0 GROWTH PLANNING STANDARDS

BCTC plans Growth projects according to BCTC's planning standards. BCTC's standards incorporate the planning and operating standards and criteria of the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC). BCTC is a member of the WECC, which is a regional member of the NERC.

The system performance requirements of the NERC/WECC standards are summarized in Table A-1. These, and BCTC's own standards, which together represent the performance requirements for the transmission system, are described in more detail in the following pages.

Table A-1. Summary of NERC and WECC Planning Standards

	Event Category	Contingency Description	Mean Time Between Failure (Actual Category Performance)	Loss of Load or Curtailed Firm Transfers	Thermal Limits	Voltage Stability	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard
1	A	All facilities in service		All loads served.	All facilities within applicable ratings				
2	B	Includes most single contingencies (n-1)	0 to 3 years	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.	All facilities within applicable ratings	Voltage stable at 105% of path rating	Not to exceed 25% at load buses or 30% at non-load buses. Not to exceed 20% for more than 20 cycles at load busses.	Not below 59.6 Hz for 6 cycles or more at a load bus.	Not to exceed 5% at any bus.
3	C	Some single contingencies. Most double contingencies (n-2)	3 to 30 years	Planned/controlled interruption of loads, generators, and firm transfers permitted.	All facilities within applicable ratings	Voltage stable at 102.5% of path rating	Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load buses.	Not below 59.0 Hz for 6 cycles or more at a load bus.	Not to exceed 10% at any bus.
4	D	Some double contingencies initiated by very low probability events. Some multiple contingencies (>n-2). Multiple contingencies	30 to 300 years Greater than 300 years	No cascading loss of loads. Evaluate for risks and consequences Evaluate for risks and consequences	Evaluate for risks and consequences				

1.1 Thermal Limits

Excessive current flowing through a transmission line will heat the conductor and associated hardware to a temperature that can damage the conductor or cause it to sag too close to the ground, causing a public safety issue. Similarly, overloading of substation transformers, circuit breakers, and other equipment can damage this equipment, resulting in long outage times until this equipment can be repaired or replaced. To ensure that these conditions do not occur, the line current must be planned and operated to stay within the rated capacity.

The thermal ratings used for planning and operating purposes are specific to individual equipment characteristics, asset condition, and ambient conditions. Individual circuit and equipment ratings are used in all planning studies. In some cases, short-term overload ratings are established. These allow the operator to maintain schedules for a reasonable length of time after an outage to implement remedial action measures or to re-dispatch generation and avoid having to immediately limit the transfer because of thermal restrictions.

1.2 Voltage Limits and Voltage Stability

The transmission system must be able to maintain acceptable voltages after the failure of one or more elements. Immediately following a system disturbance, voltages will swing as the system readjusts to a new stable operating point. Once the system has stabilized, operating voltages will normally be different than prior to the disturbance. Excessive voltage deviations may cause voltage sensitive system elements and other customer equipment to disconnect from the system, or in some cases, damage to equipment.

Voltage stability is the ability of the transmission system to settle at a stable voltage after the failure of system element(s). An unstable system would demonstrate voltage collapse at the receiving end of the system (load end), which would lead to local load loss and could lead to widespread blackouts. Very low voltages can damage equipment, such as motors, due to overheating caused by the resulting high current flow.

To achieve voltage stability, sufficient reactive power sources need to be available to serve the pre-disturbance reactive load plus the extra reactive power required following the loss of the transmission element(s) in a system disturbance. Reactive power is not suitable to be transferred over long distances, and it is preferable to provide reactive resources distributed throughout the system under normal conditions. Voltage levels are managed with equipment such as capacitors, reactors, static VAr compensators (SVC), and other types of reactive equipment. Generators also provide reactive power that is used to control voltages on the system.

1.3 Over-Voltage Line Tripping

The transmission system has many expensive pieces of equipment that can be damaged by excessive voltages. For example, underground cables in Metro Vancouver and the submarine cables to Vancouver Island can be severely damaged if exposed to excessively high voltages. Because of this, a staged protection scheme has been implemented which trips 500 kV lines at specific increasing levels of over-voltage. This system is intended to backup other specific measures that are taken to control voltages to acceptable levels for well-defined contingencies that may occur on the system.

BCTC's planning standard is that the line over-voltage protection scheme shall not be triggered when the system responds to a single (N-1) or double (N-2) contingency. To effect this standard, BCTC requires that sufficient voltage control equipment be installed so that the 500 kV lines do not trip on over-voltage protection for N, N-1, or N-2 contingencies.

Tripping a single line reduces system voltages due to two phenomena. First, because 500 kV lines have some capacitance which tends to support system voltages, the removal of a line will reduce a source of capacitive reactive power and the voltage will fall somewhat. Second, tripping one line also increases the reactive power demand by putting more current onto the remaining lines. The demand for reactive power is proportional to the square of the current on the remaining lines and this is a non-linear effect. Consequently, the reactive power required to maintain a given level of voltage is higher after a line trips than it was before and the sources of reactive power are lower. The net result of these two phenomena is that the voltage stabilizes at a lower value than it had before the line tripping occurred. One alternative to the reliance on line tripping is to install additional reactors on the system.

1.4 Under-frequency Limits (Minimum Transient Frequency Standard)

The WECC system is operated at a frequency of 60 Hz. System disturbances cause frequency deviations. Immediately following a disturbance, frequencies will vary until the system adjusts to a new stable operating point. As the total connected generator output changes in response to the disturbance, the system frequency will gradually return to 60 Hz.

One of the WECC criteria establishes a limit on the dip in frequency for various contingencies. BCTC has adopted, for internal impacts only, an under-frequency limit of 58Hz. Although this limit is lower than the WECC frequency of 59 Hz for the interconnected system, the WECC criteria allow lower limits if the impact is limited to an internal system. The 58 Hz limit is solely for the loss of the BC to US interties when importing from the US. This decision was made because adoption of the WECC standard (for internal purposes) would result in a significant reduction to the historical import limit of 2000 MW from the US. The risk of this event actually occurring is very low and the consequence of this greater frequency dip is acceptable. The trigger event for this under-frequency risk is a double circuit outage on the short interconnections between Vancouver and Blaine, Washington. Furthermore, BCTC can selectively reduce the import limit during higher-risk conditions (e.g., lightning activity in a geographic area that could lead to this contingency) to mitigate the risk of the under-frequency dip. Based on discussions with its Alberta and BC stakeholders, BCTC chose the minimum allowable frequency dip to be 58 Hz within the BC system. BCTC continues to meet the WECC standard of 59 Hz in terms of impacts on its neighbours.

1.5 Transient and Dynamic Stability

Transient stability is the condition in which, following a system disturbance, a generator or group of generators will return to pre-disturbance rotational speed and will not lose synchronism with the integrated system. Transient stability depends upon the physical characteristics of the generators themselves, the controls and excitation systems on these generators, their connections to the system, and the whole power system.

After a disturbance, the generators' output in one area will oscillate against the generators' output in other parts of the large area interconnected system. The interconnected system must have sufficient damping so that power oscillations dissipate quickly and the system remains dynamically stable. WECC requires installation and use of power system stabilizers on individual generating units to provide this damping.

1.6 Safety Nets

The power system, with many interconnected facilities in different geographic areas, is occasionally challenged by unexpected combinations of operating conditions and multiple disturbances. To mitigate the potential impact of these types of disturbances, BCTC has put in place various "safety nets". Some of these are WECC requirements, while others have been put in place at BCTC's initiative. Examples of such safety nets follow.

1.6.1 Underfrequency Load Shedding

The purpose of this "safety net" is to deliberately trip loads during a severe underfrequency situation, the outcome of which is that the frequency in that area should increase towards the required 60 Hz. WECC has identified the amount of load and the underfrequency trip levels which should be incorporated in an underfrequency load-shedding program.

1.6.2 Generation Shedding

BCTC will consider generation shedding for a double contingency and for a single contingency event if one element is already out of service. BCTC has adopted this standard so that the transmission system is more robust and is able to depend on generation shedding for less common and more severe events.

However, BCTC's standard is to avoid the use of generation shedding associated with firm transfers for first contingency events when all facilities are in service. This is based on a number of factors including:

(a) Impact on generation equipment – Excessive generation shedding can lead to advanced ageing of the generator units;

(b) Generation shedding for single contingencies on the transmission system compromises system reliability and could impact capacity reserve requirements;

(c) Generation shedding reduces the flexibility for generation dispatch; and

(d) A deferral of system reinforcements by using generation shedding forgoes the benefits that can occur from reinforcements in one part of the system providing secondary benefits in another part of the system.

Some exceptions to this general standard are made if the amount of shedding is less than the largest unit on the transmission system, and the required investment to avoid the shedding cannot be justified.

Appendix B

Historical Inflation Review: Preliminary Study

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Historical Inflation Review: Preliminary Study

1.0 Introduction

The purpose of this report is to provide an overview of BCTC's preliminary work in the development of a price index for BCTC's Sustaining Capital portfolio (Sustaining Price Index or Sustaining PI). This Report is filed as a supplementary appendix to BCTC's F2010 TSCP and is advanced for the purpose of providing the Commission and stakeholders with an overview of the work that has been undertaken on this initiative to date and to solicit input and feedback at an early stage in the development of the Sustaining PI. BCTC is not seeking approval for the Sustaining PI or its preliminary findings, and instead wishes to use this opportunity to explore the conceptual nature of the Sustaining PI with the Commission and its stakeholders.

2.0 Regulatory Background

For the Sustaining Capital portfolio component of BCTC's TSCP, the total cost of projects is managed by BCTC on an annual basis within an envelope of funding approved by the Commission. Since F2007, the Commission has determined that the annual envelope of funding is comprised of a base amount plus an allowance for inflation. The envelope was first set in F2007, and has been subsequently inflated using a rate of 2% per annum based on BC CPI for up to and including F2010[1]. The approved envelopes are shown in the following table:

	F2007	F2008	F2009	F2010
	G-67-06	G-69-07	G-107-08	G-107-08
Base Work (F2007, $M)	83.1	83.1	97.7	97.7
Total Inflation (F2007 base, 2.0%)		1.7	3.9	5.9
Third Party Requests		3.0	3.4	3.4
Total Approved Envelope	**83.1**	**87.8**	**105.0**	**107.0**

Over time, an inflationary adjustment could have a significant effect on Sustaining Capital expenditures, in either direction, if it does not match experienced price changes.

BCTC's strong perception is that over the past few planning cycles, it has experienced greater underlying cost escalation than the BC CPI rate of inflation. In response to this potential misalignment, BCTC sought to apply a higher inflation rate based on an independently-commissioned report (the MMK Report filed as Appendix E of the F2009 TSCP), supplemented with examples of labour and material cost increases and future expectations due to renewal of expiring equipment contracts. BCTC concluded that it was prudent to assume a higher rate of inflation than the BC CPI over the medium term, and adjusted its F2009 TSCP forecast accordingly. In its Decision on the F2009 TSCP, the Commission rejected this

[1] With some minor annual adjustments due to specific changes in the portfolio, and one major envelope increase in F2009, to allow for additional work.

conclusion and found that the evidence submitted was not persuasive. Accordingly, the Commission directed BCTC to continue applying an inflation rate based on BC CPI.

BCTC respectfully acknowledges the Commission's conclusions and, as directed, has applied an inflation rate of 2.1% (based on forecasted BC CPI)[2] for the purposes of the Sustaining Capital portfolio envelope advanced for approval in the F2010 TSCP.

In order to continue its exploration of the potential misalignment identified above, BCTC has begun work to investigate its recent historical cost escalation experience and the resulting inflationary impact on the Sustaining Capital portfolio. The ultimate goal of this work is to determine whether this information could be used to evaluate past inflation and arrive at a mechanism which could potentially be used to re-size Sustaining Capital portfolio expenditures reflecting actual changes to costs.

For this purpose, BCTC has started to develop a Sustaining Price Index, by measuring the price changes in weighted baskets of goods and services specifically required to undertake Sustaining projects. At this time the study has not been able to overcome substantive issues (outlined below in section 4), and is submitted in its preliminary form for comment.

With respect to the F2010 TSCP application, BCTC did not consider that the study or preliminary results would provide sufficient justification of any increase (or decrease) in the assumed inflation rate into the future. Furthermore, this study involves analysis of price changes experienced in the recent past, and therefore, is not expected to constitute predictive powers for inflation – other than the use of recent history as an indicator. However, BCTC believes that a better understanding of direct and actual historical inflation movements could ultimately be used for re-calculating and adjusting the Sustaining envelope, offsetting the decline in real purchasing power.

3.0 Basis for Approach

The concept behind using a CPI as a proxy to estimate inflation in the Sustaining Capital portfolio is that it is a widely used measure of the rate of change of prices for goods and services in Canada. As prices in one part of the economy change, other goods will experience many of the same drivers and should expect to have increases or decreases of a similar relative magnitude. For example, an increase in the cost of gasoline will likely have a flow through to an increase in the cost of all delivered goods, or the increase in manufacturing in emerging nations may bring down the prices of goods imported from these regions. As a subcomponent of the Canadian index, the BC CPI measures the rate of change of prices experienced in British Columbia.

Advantages in using BC CPI to estimate the rate of changes in prices in the Sustaining programs include:

- It provides a stable measure with low volatility and some ability to forecast; and
- It is consistently measured by an objective group.

[2] BC Ministry of Finance – Budget and Fiscal Plan (2008/09 – 2010/11) issued on February 19, 2008, p. 139.

However, the use of BC CPI may also have disadvantages such as:

- It measures a wide variety of goods and services bought by a typical British Columbian Household, including food, shelter, clothing and healthcare, which are not reflective of BCTC's Sustaining Capital portfolio purchases.
- The typical basket of goods for which the BCTC Sustaining programs is a purchaser (e.g., major electrical equipment) will be underrepresented in the BC CPI. Most of the equipment purchased under the Sustaining program is manufactured outside BC.

Before embarking on the study to evaluate historical inflation in the Sustaining Capital portfolio, BCTC considered and researched a range of alternative indices for use to estimate inflation (found in Appendix 1 to this Report). Several of these have been previously submitted to the Commission through the MMK Consulting report, and commented on in the Commission's decision. The selection was narrowed to contain only Canadian and US indices, as these are the closest markets, although concern that the US indices would be misinterpreted due to exchange rate fluctuations meant that they have not been considered in great detail. The exchange rate is discussed further in section 4 below (Issues and Challenges).

BCTC's initial conclusion from the consideration of alternatively published indices is that no index alone is enough to comprehensibly justify a change to the current inflation assumption. However, through BCTC's development of a Sustaining PI, it may be possible to highlight how BCTC's estimated inflation differs from one or more indices, and use this as a future reference. This theory will be tested once a greater period of BCTC's cost escalation has been measured and can be compared to movements in the alternative indices.

The next section of the Report outlines the methodology used and preliminary results of this work. BCTC wishes to emphasize that this work remains in the initial stages, and as indicated earlier, is seeking input and comments on the proposed approach, methodology and assumptions rather than any implied conclusions.

4.0 Development of Model

To attempt to accurately measure historical inflation and construct a Sustaining PI, BCTC identified the following two requirements:

- Detailed knowledge of the quantity of goods and services bought in connection with the Sustaining Capital portfolio; and
- Detailed knowledge of the costs of these good and services over a period of time (price history).

Theoretically, if these two requirements can be achieved for all expenditures in the Sustaining Capital portfolio, then an exact measure of the level of inflation can be determined. However, the reality is somewhat more complicated as the Sustaining programs change on an ongoing basis as individual projects are completed and new needs are identified, equipment is procured through different processes and externally from multiple contractors, resulting in incomplete or difficult to obtain data. The lack of data requires assumptions to be made throughout the model. Some of these assumptions are discussed further below. In order to prudently identify underlying cost escalation, BCTC has erred on the side of caution by taking a conservative approach for assumptions.

Similar to the process for constructing a CPI, BCTC has structured the Sustaining PI as a combination of several categories each containing a basket of goods and/or services. In this manner, a number of sublevel indices are built up and combined to estimate overall inflation. At this stage in the Sustaining PI development, BCTC selected the following four major categories, commonly used for project estimation, to separate expenditures:

- Engineering (including Project Management);
- Materials;
- Construction; and
- Other.

For a further explanation of these categories and the items that have been selected for use in the preliminary analysis, please refer to Appendix 2.

BCTC's process toward constructing a Sustaining PI remains in progress and involves the collection of information from a variety of internal and external sources. Information is accumulated, processed and analysed, and then submitted for further internal feedback and evaluation. The process used by BCTC to date is outlined below:

- Split historical expenditures into four major categories (Engineering, Materials, Construction and Other) for each of the eleven Sustaining programs;

- Determined relative historical expenditures for each of the eleven Sustaining programs over the period of the study;

- Produced single weights for each of the four major categories by combining, for each of the eleven Sustaining Capital programs, the four major category expenditures and the relative historical expenditures;

- Established suitable goods and services from historical expenditure to be used as basket items in each of the four major categories;

- Determined appropriate weights for basket items in the category and measure the relative price changes for each of the items making up the basket; and

- Calculated the total estimated program inflation by combining the weighted average of each of the four categories.

Issues and Challenges:

The following section illustrates some of the current issues and challenges that BCTC is uncovering as it develops the Sustaining PI.

Data availability: This study requires significant capture and analysis of data to enable accurate measurement of cost increases across the entire Sustaining Capital portfolio. In the cases where BCTC directly handles the purchasing (such as long-term equipment contracts), this is simple, but for areas outside of BCTC's direct management, such as procure & construct contracts, this process is more difficult. In some cases it may not be possible to capture the quality of data to construct a basket and alternative sources may be required. For instance, the Sustaining PI currently uses a construction index created by Statistics Canada[3] to estimate cost escalation for the construction category.

Scope changes: BCTC has been careful to separate the effects of productivity from the effects of inflation, by only measuring cost escalation. However, some consideration is being given to the effect of scope changes on the Sustaining Capital portfolio. For example, as copper theft has become an issue for our construction projects, it has been necessary to provide increased security on site.

Technological Changes: BCTC has not yet considered the effects of technological changes to the rate of cost escalation. In some ways this is related to scope changes (where changes are mandated), but may also be due to changes outside of our control, such as manufactured advances. The construction of CPI uses heuristic adjusters, which may be too complicated for the purposes of this study.

Category Weights: For simplicity it has been assumed that fixed category weights based on historical average expenditure, but further consideration will be given to the changing nature of the Sustaining programs. BCTC thinks that it would be of use to investigate further the possibility of using changing weights to account for program changes, such as the forecast increase in the Circuit Breaker Replacement program, but also considers that this may reduce comparability to alternatively produced indices. The importance of these two considerations needs to be further evaluated.

Preliminary Results

At this stage in the development of the Sustaining PI, BCTC has compiled preliminary results. BCTC acknowledges that several areas of the Sustaining PI model and its underlying assumptions will continue to undergo refinement and improvement over time. The preliminary results are provided here for purposes of discussion and exploration only in terms of drawing some limited conclusions for F2007 and F2008.

[3] Statistics Canada, Non-Residential Building Construction Index (Seven Census Metropolitan Area Composite)

Based on the Sustaining PI:

- Cost escalation in the Sustaining Capital portfolio is about 5 to 6% for each of F2007 and F2008.
- Engineering labour costs have been increasing at 4% per annum on average for F2007 and F2008.
- Materials and equipment have had mixed results, with some items (such as copper based wire products) experiencing rapid escalation, some remaining stable, and some decreasing in cost. The current weighted basket has escalated at 4% per annum on average for F2007 and F2008.
- Construction costs have increased at a faster rate than overall costs, at approximately 8% per annum, although a majority of this category is reliant on an external index, due to data limitations.
- Other costs have escalated at 5% per annum.

For further information on the preliminary findings, please refer to Appendix 3.

As stated previously, BCTC intends to continue its efforts in refining and improving the Sustaining PI model, its related assumptions and inputs, and, over time, to extend the baseline to track experience over a longer period of time. BCTC anticipates that this work will provide a future opportunity to reach further conclusions and, while BCTC believes that the Sustaining PI will not be used as an exact measure, it may ultimately be robust enough to justify a different inflation rate assumption to be used over the period of the study. As this is backward looking, covering years where assumed inflation rates have already been set, one potential approach for the integration of the Sustaining PI may include an adjustment that covers the difference between the total actual approved Sustaining Capital portfolio expenditure and the total Sustaining expenditures using an adjusted inflation assumption.

5.0 Summary

The purpose of this Report is to provide an overview of BCTC's preliminary work in the development of a price index for BCTC's Sustaining Capital portfolio. As noted previously, BCTC is not seeking approval for its preliminary findings, and instead wishes to use this opportunity to explore the conceptual nature of the index. On this basis, BCTC welcomes any comments or input the Commission or stakeholders may have on the methodology and approach, rather than seeking any action from the preliminary results.

BCTC anticipates that a further report will be provided with the its next TSCP. The next report will include further refinement of the Sustaining PI model and assumptions, refined results and a more detailed comparison with available and relevant independently published indices. At that time, BCTC will also consider the impacts and implications of the results of the Sustaining PI work on the assumptions used for the BCTC Sustaining Capital portfolio and may advance further recommendations for the Commission's consideration at that time.

Appendix 1: Indices Considered During Study

Index Name (Source)	Measures	Positives	Negatives
Non-Residential Building Construction Index: Seven Census Metropolitan Area Composite (Statistics Canada)	This index provides a measure of contractors' selling price changes of new non-residential construction (i.e., commercial, industrial and institutional). 7 cities across Canada are weighted to create this index.	• Indicator of non-residential construction across Canada (reduced volatility) • Inherently contains some supply side constraints as "contract bids" are contained within the index.	• While a good indicator of the non-residential building industry, the index is not directly related to electric utility construction.
Non-Residential Building Construction Indices: Vancouver City Index (Statistics Canada)	Same as above but only includes information gathered within Vancouver city.	• Directly related to the non-residential construction industry in the city of Vancouver.	• Increased volatility when compared with the 7 city composite index. • Index could be too narrow considering BCTC conducts work throughout British Columbia.
Electric Utility Construction Price Indices (Statistics Canada)	This index measures the price change for constructing two types of plants, distribution systems and transmission lines systems, representing electric utility capital expenditure construction projects.	• Directly related to construction of Transmission and Distribution systems in Canada. • Canada wide study reduces volatility • Index also contains sub-indices (such as a transmission index less transformers) which may be of use.	• Index considers construction of new systems, cf. replacement and refurbishment of existing assets. • Trends since 2000 do not seem to represent managers' experience. • Delay in publication (2008 data will not be finalised until March 2009)
US Electric Utility Construction Price Indices (US Bureau of Reclamation Construction Costs, and Handy-Whitman Index of Public Utility Construction Costs)	Tracks construction relevant to utility projects in the US.	• Alternative view to Canadian indices in North American market.	• Due to the unknown impact of the US/CAD exchange rate, the use of US indices is limited. US indices were not considered further in this study.
Commodities: Steel, Copper, Aluminium (Statistics Canada)	Specific costs of raw materials.	• Useful as an indicator of expected price changes, for goods that contain significant proportion of these materials	• Index is too narrow for an inclusive measure of inflation in the Sustaining Capital portfolio.

Appendix 2: Major Categories

The amount of capital expenditure assigned to each of these programs is project dependant. Smaller projects tend to have a greater component dedicated to Engineering Design and Project Management, while larger projects involving a greater value of capital expenditure on equipment or installations require a smaller component to be spent on Engineering Design.

Engineering:
Costs attributable to the Engineering category include all engineering design, project management, estimating, contracting, and some commissioning tasks. The current estimate is that engineering accounts for approximately 20% of all Sustaining Capital portfolio costs. All costs in this category are related to either direct labour costs, or overheads attributable to the labour.

Materials:
Costs attributable to the Materials category has been extracted from two different data sources; BCTC's strategic procurement of major electrical equipment including those purchased under long-term fixed blanket contracts such as circuit breakers and surge arresters, and BC Hydro's MMBU[4] site which generally handles lower value/higher volume materials such as copper wire and wood poles. It is estimated that material purchases account for approximately 45% of total project costs. Materials procured for construction, such as concrete, are expected to be captured within the construction category; however, this particular aspect needs further refinement, as this current weighting may be inclusive of materials that should be assigned to construction.

Construction:
Construction costs include the portion of work that relates to the clearing, removal and installation of equipment to sites, including initial grading and clearing, and procurement of materials required during construction, such as concrete, gravel and fences. This work is either completed by BC Hydro Field Services or by third parties through a tendering process.

Other:
A portion of project costs falls outside the above broad categories, and is proposed to be captured under the "other" category. This includes provisions for other services required to support execution of the project, including acquisition of land, land access rights, regulatory services, legal representation and system performance assessment. The portion of project costs attributable to BCTC overheads is included within this category.

[4] Materials Management Business Unit

Appendix 3: Preliminary Results

SUSTAINING PRICE INDEX

	FY2006	FY2007	FY2008
TOTAL	**100.0**	**106.4**	**111.4**
Annual % Change		**6.4%**	**4.7%**

ENGINEERING 20%

		FY2006	FY2007	FY2008
ENGINEERING	**20%**	**100.0**	**107.0**	**108.9**
			7.0%	**1.8%**
BC Hydro Engineering Services	**100%**	$ 101.85	$ 108.97	$ 110.95
		-	7.0%	1.8%

Weighted average fully loaded labour rates for BC Hydro Engineering Services COPE and M&P Employees

MATERIALS 45%

		FY2006	FY2007	FY2008
MATERIALS	**45%**	**100.0**	**105.6**	**108.6**
			5.6%	**2.8%**
Material Purchases:	**100%**			

	Weight (%)	FY2006	FY2007	FY2008
500kV Circuit Breaker	18.2%	$ 358,246	$ 356,796	$ 368,166
69kV Circuit Breaker	18.2%	$ 51,100	$ 52,174	$ 53,267
Protection Relay	10.9%	$ 3,652	$ 3,309	$ 3,272
230kV Circuit Breaker	9.1%	$ 123,820	$ 126,196	$ 128,620
#8 Control Wiring	5.5%	$ 11	$ 13	$ 15
Aluminium Terminal Connector	5.5%	$ 469	$ 522	$ 557
Wood Pole, 55ft	3.6%	$ 1,290	$ 1,424	$ 1,233
Wood Pole, 75ft	3.6%	$ 3,193	$ 6,201	$ 5,967
500kV Surge Arresters (3 phases)	3.6%	$ 41,325	$ 38,745	$ 46,930
138kV Surge Arrester (1 phase)	3.6%	$ 1,710	$ 1,744	$ 1,778
50W PLC	3.6%	$ 34,372	$ 34,372	$ 34,372
Suspension Glass Insulator	1.8%	$ 29	$ 29	$ 28
#6 Bare Copper Wire	1.8%	$ 0.76	$ 1.38	$ 1.37
Timber Crossarm	1.8%	$ 653	$ 688	$ 735
Control Switch	1.8%	$ 217	$ 252	$ 253
125V Adapter	1.8%	$ 1,475	$ 1,463	$ 1,450
5" Insulator Post	1.8%	$ 106	$ 118	$ 130
Galvanised Steel Column	1.8%	$ 523	$ 529	$ 515
4" Tubular Aluminium Bus	1.8%	$ 459	$ 542	$ 579
Total	100.0%			

CONSTRUCTION 30%

		FY2006	FY2007	FY2008
CONSTRUCTION	**30%**	**100.0**	**108.0**	**117.1**
			8.0%	**8.5%**
BC Hydro Field Operations	**15%**	$ 90.25	$ 93.96	$ 97.72
		-	4.1%	4.0%

Average fully loaded labour rates for BC Hydro Field Operations

		FY2006	FY2007	FY2008
Non-Residential Construction Index	**85%**	135.7	147.5	161.1
		-	8.7%	9.2%

Statistics Canada Non Residential Building Construction Index (7 City Composite Index)

OTHER 5%

		FY2006	FY2007	FY2008
OTHER	**5%**	**100.0**	**102.4**	**112.2**
			2.4%	**9.6%**
Land Rights:	**40%**	$ 377,284	$ 452,971	$ 516,958
		-	20.1%	14.1%

BC Average Land Values

		FY2006	FY2007	FY2008
Capital Overheads:	**60%**	$ 3,108,555	$ 2,817,325	$ 3,002,292
		-	-9.4%	6.6%

Capital Overheads as applied to the Sustain Portfolio.

Appendix C

Growth Planning and NITS Assumptions (Appendix F9 from BC Hydro's 2008 Long Term Acquisition Plan)

2008 Long Term Acquisition Plan

BC hydro

APPENDIX F9

Integrated System Planning Assumptions

2008 Long-Term Acquisition Plan

Appendix F, Section 9 Integrated System Planning Assumptions
(Rev: 00b01 (draft); 2008-Jun-112)

Report No. EPxxx EP File: EP-Criteria

Contents

A. INTRODUCTION

This document describes the integrated power system planning assumptions that BCTC and BC Hydro use in conducting integrated power system studies such as those associated with developing Long-Term Acquisition Plans (**LTAP**s).

This document was developed to respond to Directive 14 of the BCUC's 2007-May-11 IEP Decision[1]:

Directive 14:

> *The Commission Panel encourages BCTC to use the same transmission planning assumptions for IEP portfolio evaluations, LTAP analysis and the NITS application review. The Commission Panel directs BC Hydro to provide a description of these planning assumptions in the next LTAP application. The description of the planning assumptions should address coastal capacity reserve requirements in the determination of coastal RMR capacity, including the dispatch of Burrard.*

B. GENERAL

This purpose of this document is to describe the assumptions used in the full range of planning studies from the very high level LTAP studies to the more detailed studies associated with the submission of an application for a Certificate of Public Convenience and Necessity (**CPCN**) for a specific project.
BC Hydro has interpreted "transmission planning assumptions" to be the following integrated system planning assumptions that BC Hydro provides to BCTC:

- Generation dispatch,
- Load forecast,

[1] See: http://www.bcuc.com/DecisionIndex.aspx for the BCUC's 2007-May-11 IEP Decision.

- Demand-Side Management (**DSM**),
- BC Hydro's Import/Export arrangements, and
- BC Hydro's Point-to-Point (**PTP**) transmission commitments.

B.1 THE INTEGRATED SYSTEM PLANNING PROCESS

This section briefly summarizes the various processes in which BC Hydro's planning assumptions are provided to BCTC for the purposes of transmission system analysis.

The treatment of BC Hydro's planning assumptions is expected to be consistent for all transmission planning studies regardless of whether the studies are conducted in or for a Network Integration Transmission Service (**NITS**) Application, a Transmission System Capital Plan (TSCP) or an Application for a CPCN for a specific transmission system reinforcement project. The level of detail simply increases at each stage of the study process.

In a LTAP when BCTC analyzes a wide range of load/resource portfolios that could number in excess of 100, detailed generation dispatch vs transmission system upgrade analyses are not conducted to optimize the level of transmission system upgrades for each portfolio. The transmission reinforcements to meet reliability criteria are simply chosen from a relatively small set of alternatives that have different capabilities and costs.

From the LTAP analysis, BC Hydro develops its Base Resource Plan (**BRP**) and a set of Contingency Resource Plans (**CRP**s) in accordance with the BCUC's Resource Planning Guidelines[2]. The BRP and CRPs are then included in the LTAP that is submitted to the BCUC for approval in accordance with the BCTC's Open-Access Transmission Tariff (**OATT**).

When the BRP and BCUC-approved CRPs are then submitted to BCTC in a NITS Application, a more detailed study is conducted including generation vs transmission trade-off analyses that follow from the re-dispatch options that BCTC identifies in accordance with Section 32.3 of the BCTC's OATT[3].

The NITS studies culminate in a Facilities Study Report that identifies the costs and schedules of each transmission reinforcement project associated with each of the BRP and CRPs. The TSCP and CPCN processes provide further opportunities to optimize the transmission reinforcement plan and the parameters of specific projects.

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[2] BCUC Resource Planning Guidelines: http://www.bcuc.com/Guidelines.aspx

[3] BCTC's Tariff (OATT): http://www.bctc.com/transmission_scheduling/tariff_pricing/

C. GENERATION DISPATCH

C.1 GENERATING PLANT CAPACITY DEFINITIONS

This section provides a brief explanation of the various generating capacity terms. For any particular plant, each of these values may vary seasonally. For example, due to seasonal variations in reservoir elevations, GM Shrum and Mica have higher MCR and DGC values in August than February.

Maximum Continuous Rating **(MCR)**: this is the maximum plant output that can be sustained for at least one hour. The MCR value is the highest output that the plant would be able to produce under the most favourable conditions (eg, maximum head for hydro plants and coldest weather for gas turbines) considering the season.

Dependable Generating Capacity **(DGC)**: this is the capacity that a plant/unit can reliably provide for a required duration (3 hours/day to 16 hours per day depending on the load shape and dispatch order) each weekday during the two-week peak load period of the time of year (month or season) being studied.

Effective Load-Carrying Capability **(ELCC)**: this is the incremental amount of load demand that a plant can supply when it is added to the system based on maintaining the 1 day in 10 years Loss of Load Expectation (**LOLE**) generating capacity adequacy criterion. The ELCC of an intermittent resource like a wind farm is the capacity that is equivalent to that of a conventional generating plant (eg, large reservoir hydro plant) in terms of load supply reliability.

Reliability-Must-Run (**RMR**) Generating Capacity: This is the minimum level of generating capacity that a generator owner commits to have on line during peak load periods. Committing to providing less RMR capacity in a load centre would have the effect of advancing the need to reinforce the transmission system supplying that region.

For each generating resource BC Hydro specifies three plant capacities, DGC, ELCC and MCR.

In accordance with Directive 13 of the BCUC's 2007 IEP/LTAP Decision[4], BC Hydro requested[5] that BCTC undertake a set of integrated system reliability studies, the "**pre-NITS**" studies, to provide a basis for BC Hydro to develop guidelines for specifying generation dispatch assumptions for BCTC's deterministic transmission planning studies.

BCTC's pre-NITS studies are presently underway. Some preliminary results have been used in developing some of the guidelines described in this document.

Presently, the total aggregate RMR value for a region is the sum of the DGC values of all plants in the region with the exception of the Burrard plant (**BGS**). The DGC of the BGS plant is committed as RMR generating capacity only to the extent necessary to support the system until the ILM transmission system is reinforced. Thereafter, BGS capacity will not be committed as RMR. Following the completion of the "pre-NITS" studies, guidelines will be developed for regional RMR commitment limits. Those

[4] Directive 13 of the BCUC's 2007-May-11 IEP Decision (http://www.bcuc.com/DecisionIndex.aspx).

[5] 2007-Jul-31 BCH letter from John Rich to Janet Fraser.

guidelines are expected to define total regional RMR commitment limits that are somewhat less than the sum of the DGCs of the generating plants in a region (in effect assigning generation reserves on a regional basis).

C.2 Generation Dispatch Assumptions

BC Hydro determines future generating capacity requirements by periodically conducting probabilistic generating capacity adequacy studies that determine the generating capacity reserve required to achieve a LOLE of one day in 10 years, a criterion widely used by electric utility resource planners.
BC Hydro's current load and generating resource characteristics indicate that a generating capacity reserve margin of 14% is appropriate for planning purposes.

In the operating time frame BCTC retains control over generation dispatch to protect reliability as per Article 5.4 of the Master Agreement[6] between BCTC and BC Hydro. However, for transmission planning studies, BC Hydro specifies regional generation dispatch requirements. For single- and multiple-contingency studies, BC Hydro specifies which plants could be automatically shed or run-back to meet NERC/WECC and BCTC's transmission planning disturbance performance standards and BC Hydro specifies the required regional aggregate generation dispatch for any prolonged single contingency.

For integrated system studies, the following generation dispatch assumptions are used in deterministic transmission planning studies that define transmission capacity requirements for single-contingency (N-1) conditions:

1. Generating Plants "Upstream" of the Cut-Plane being Studied:

    1.1. Each dispatchable generating plant is modeled as operating at the plant's MCR that is appropriate to the season.

    1.2. Intermittent generating resources (eg, wind farms and run-of-the-river hydro plants) are modeled as operating at their MCR levels in the pre-contingency state, but at their ELCC levels after any single contingency. Note that in actual operation, generator shedding or runback will often be applied to plants other than intermittent plants, but the aggregate effect would be equivalent to each intermittent resource in the upstream region being run-back to its ELCC level following the outage.

    1.3. Each Non-dispatchable plant with a high capacity factor like a co-generation, biomass or municipal solid waste facility is modeled as operating at its MCR level that is appropriate to the season if there are seasonal differences in the plant's output.

2. Each Generating Plant (including intermittents) downstream of the cut-plane being studied is modeled as operating at the greater of (i) the plant's minimum output level (possibly zero) or (ii) the plant's RMR commitment level. In high level studies such as those conducted in the LTAP process, the RMR commitment level is often assumed to be the plant's DGC (with the exception of BGS).

[6] BCH/BCTC Master Agreement: http://www.bctc.com/about_bctc/standards_agreements/designated_agreements/

3. BC Hydro may specify aggregate RMR generation levels that are less than the aggregate total of the DGCs of all generating plants in the regions downstream of the cut-plane being studied, considering the operating costs and reliability risks associated with specific plants and other factors such as guidelines that may be established to assign generating capacity reserves on a regional basis. BCTC is expected to identify the transmission system reinforcement needs consistent with the RMR commitment levels specified by BC Hydro.

4. BC Hydro will continue to commit the 905 MW dependable capacity of BGS as RMR only to the extent necessary to meet transmission planning criteria associated with BC Hydro's domestic load requirements and other contractual commitments until the ILM network can be reinforced. After the ILM grid is reinforced, Burrard capacity will not be committed as RMR.

In the past when BC Hydro's electricity needs were met almost entirely by dispatchable resources like medium- and large-reservoir hydro plants and conventional thermal plants, planning the transmission system to meet single contingency criteria usually determined the bulk system reinforcement requirements. However, intermittent resources like wind farms and small run-of-the-river hydro plants without significant storage are expected to provide a large part of BC's future electricity needs. It is therefore now more important to consider both single-contingency conditions as well as normal system conditions when determining the reinforcement requirements of the bulk electric system.

In general, to meet reliability requirements (ie, economics ignored) in deterministic transmission planning studies conducted to determine transmission requirements for normal system conditions (N-0), the generation dispatch assumptions are:

1. For plants located "upstream" of a cut-plane:

   1.1. dispatchable and non-dispatchable plants are modeled at their MCRs to determine transmission capacity requirements for the most onerous, but normal, system conditions (eg, the load level used in the study would be the level at which the performance criteria would be most difficult to meet).

   1.2. non- dispatchable plants must be able to operate continuously at their ELCC levels following single contingencies (N-1) with Remedial Action Schemes (**RASs**) provided to automatically reduce the aggregate generation in the upstream region from the MCR level to the aggregate ELCC level (ie, each plant need not be reduced to their ELCC level, but the aggregate generation in the entire region is reduced to the sum of the ELCCs of each intermittent plant in the region plus the MCR values of each dispatchable plant).

2. Each plant downstream of a transmission system cut-plane is modeled at the greater of its (i) minimum output level (possibly zero) or (ii) RMR commitment level. In high-level studies such as those conducted in the IEP process, the RMR commitment level is often assumed to be the plant's DGC (with the exception of the Burrard plant).

The results of the pre-NITS studies may refine the following generation dispatch criteria for future integrated system planning studies (ie, IEP, NITS, TSCP & CPCN studies).

- Interior Heritage Hydro Plant Dispatch: Presently Interior Heritage Hydro plants are modeled as operating at their MCR. In determining transmission requirements for N-1 contingencies the transmission system could be planned based on modeling Interior Heritage Hydro plants operating at their slightly lower DGC levels that would require a slightly lower level of transmission system capability.

- Coastal RMR: The current studies effectively hold the 905 MW DGC of BGS in reserve except as needed until 5L83 enters service. Presently, the aggregate DGC of all other Coastal plants is committed as RMR generation. The pre-NITS studies may lead to establishing a specific reliability guideline for load centre RMR commitment limits. Then, committing to lesser RMR amounts that would advance the need for transmission reinforcements would involve an economic trade-off between the cost associated with advancing ILM grid upgrades and the savings associated with committing less regional generating capacity (including Burrard capacity) as RMR.

- Transmission requirements for Intermittent Resources: Currently, when determining N-1 transmission capability requirements, wind and other intermittent resources are modeled at their ELCC levels if they are located "up-stream" of the transmission cut-plane being studied and at their DGC levels if they are located down-stream. The pre-NITS studies are expected to confirm that this practice is prudent, but the actual DGC and ELCC values (as a percentage of the intermittent resource's MCR) may be somewhat higher or lower than the current DGC and ELCC values used for different intermittent plant types.

D. LOAD ASSUMPTIONS

BC Hydro will provide non-coincident load forecasts for each individual transmission and distribution station, coincident load forecasts broken down into the four major regions, NI, SI, LM and VI, and a total integrated system coincident load forecast. The coincident load forecast values will include transmission system losses calculated from transmission loss factors provided by BCTC.

BC Hydro provides P50 (ie, 50% probability of non-exceedance in an individual year) and P90 (ie, 90% probability of non-exceedance in an individual year) for various load forecast scenarios, including the base load forecast scenario before future incremental DSM, and various load forecast scenarios with future incremental DSM. The load forecast confidence levels account for reasonably quantifiable uncertainties including weather, economic growth, electricity rate changes, and future incremental DSM savings as applicable.

BC Hydro provides both P50 and P90 load forecasts for each scenario in order to allow BCTC to choose and document the appropriate level of certainty for various transmission planning studies that assess regional transmission requirements. Typically, P50 load forecasts are used for N-1 contingencies studies and P90 load forecasts are used for system normal studies particularly for radial portions of the system. These studies are associated with a NITS Application or Transmission System Capital Plan (TSCP), but such regional transmission system studies are not part of the high-level LTAP studies that are primarily concerned with transmission requirements associated with future generation resources.

BC Hydro specifies the load forecast scenario(s) applicable to the LTAP BRP and each BCUC-approved CRPs that BC Hydro submits to BCTC in a NITS Update or Application.

E. IMPORTS AND EXPORTS

E.1 LONG-TERM FIRM POINT-TO-POINT (LTFPTP) COMMITMENTS

BCTC models all applicable LTFPTP commitments in each transmission study, including the following BC Hydro LTFPTP contracts:

- BC Hydro's LTFPTP transmission reservation of 230 MW on the BC-US path that includes BC Hydro's Load Forecast delivery of 123 MW to Seattle City Light under the Skagit River Treaty.

- BC Hydro (BCTC customer code BCPS) currently holds 249 MW in LTFPTP transmission reservations on the AB-BC path (TSR #71583712 and 71685250). These reservations have full roll-over rights. The current planning assumption is that BC Hydro will reduce the total generation east of the West of Selkirk (WoS) cut-plane up to the amount BC Hydro is importing on the AB-BC path as necessary to avoid congestion on the BCTC cut-planes west of Cranbrook (ie, WoS, WoAV[7] and ILM).

In addition, the Transmission Reliability Margins (TRMs) of the two WECC paths (65 MW for Path 1, AB-BC and 50 MW for Path 3, BC-US) are modeled in transmission planning studies.

E.2 FORTISBC POWER PURCHASE AGREEMENT (FBC PPA)

BC Hydro's Network Load includes a 200 MW delivery to FortisBC (FBC) under the Power Purchase Agreement (PPA). This 200 MW is delivered from BC Hydro's Network Resources to the Okanagan Point of Interconnection, POI, (170 MW) and the Princeton POI (30 MW).

E.3 COLUMBIA RIVER TREATY DOWN-STREAM BENEFITS

The Canadian Entitlement (**CE**) portion of the Columbia River Treaty Downstream Benefits are not assumed to be equivalent to dependable system capacity or as equivalent to Coastal RMR in transmission planning studies unless it is specified as such by BC Hydro. Except as specifically nominated by BC Hydro, the CE is not considered as a source of either dependable capacity or firm energy for the BRP or CRPs or as Coastal RMR.

However, since the CE is a source of firm energy and dependable capacity and because BC Hydro retains the CE as an "operational contingency" to meet firm load commitments for situations where planned generation or transmission additions are delayed, single-contingency (N-1) transmission capacity is provided to allow CE levels between zero and the full NITS-nominated CE amounts (eg, 1400 MW beyond 2013-Dec-31). This means that, when studying the ILM transmission requirements for the condition of maximum SI generation, maximum CE levels are modeled (ie, maximum inflows on the eastern tie at Nelway, NLY, that would increase ILM loading) with the NI generation reduced to achieve a load/resource balance.

[7] WoAV is the West of Ashton/Vaseux Lake cut-plane

E.4 ALCAN IMPORTS AND EXPORTS

BC Hydro specifies the Firm (equivalent to dependable generating capacity) and Non-Firm import and export limits to assume for the intertie with Alcan (ALN) for transmission planning studies. BC Hydro specifies the level of import from ALN to be assumed coincident with operation of the northern generating plants at the maximum aggregate dispatch level that BC Hydro specifies for defining System Normal (N-0) and Contingency (N-1) transmission requirements for the transmission system south of the Williston substation.

Appendix D

Sustain Portfolio Case Studies

Appendix D-1

Repair or Replacement of SF-6 Filled Double Pressure Circuit Breakers

SUSTAIN PORTFOLIO CASE STUDY

REPAIR OR REPLACEMENT OF SF-6 FILLED DOUBLE PRESSURE CIRCUIT BREAKERS

1.0 BACKGROUND ON SF6 DOUBLE PRESSURE CIRCUIT BREAKERS

230 kV circuit breakers are used extensively throughout the transmission system to connect and protect the components used to transfer energy. Generally, the 230 kV circuit breakers are configured in a ring bus to provide the appropriate back-up so that the system continues to operate when one element of the system is out of service. The benefits of using a ring bus configuration are that:

(a) If a breaker "fails", a customer outage may not occur because another circuit breaker continues to provide service; and

(b) It allows a circuit breaker to be taken out of service for maintenance without interrupting service to customers.

However, when a breaker fails, system reliability is still impacted due to the loss of redundancy and, if another breaker in the ring bus configuration were to fail, then outages would most likely occur. Statistical calculations indicate that system reliability is reduced if the redundancy is removed.

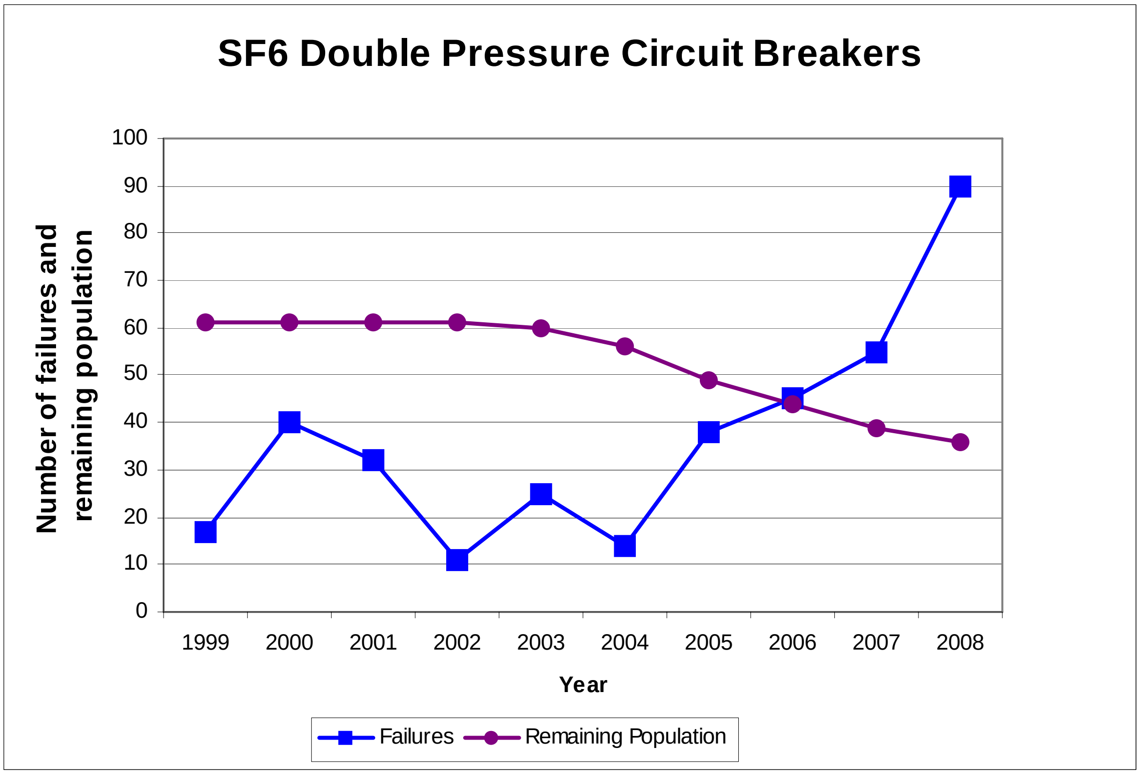
BCTC originally had sixty-one 230 kV double-pressure circuit breakers (36 Westinghouse type SF, and 25 ITE type GA) on the transmission system, which were installed in the 1950's and 1960's. In addition to the 230 kV units, there are also four 500 kV double pressure circuit breakers (ITE type GA) as part of the Gas Insulated Switchgear (GIS) which were installed at Mica Generating Station in the mid-1970's.

The 230 kV and 500 kV double pressure circuit breakers use SF6 gas, both for internal insulation and arc interruption because, at the time of development, this was the state of the art technology for dealing with high voltages and high fault current interruption. A discussion on the development and use of SF6 gas in electric equipment is included as Appendix A. However, notwithstanding that these breakers were designed to rely on SF6 gas, all of these breakers used low technology sealing systems that relied on inaccurately machined flanges and gasket materials that were inappropriate to prevent leaks of SF6 gas. Major SF6 leaks began to develop with these circuit breakers in the 1990's and is a continuing problem which directly affects the reliability of the circuit breakers and also presents an environmental hazard as a greenhouse gas (GHG) emission. The GHG impact of SF6 is 22,500 times the impact of an equivalent amount of CO2.

BCTC monitors the performance of these circuit breakers from various risk perspectives including: safety to personnel (due to the consequences of failure), asset health, frequency of failures, reliability impacts, cost of repair, and environmental impacts of SF6 leakage. The double pressure SF6 breakers have exhibited an increasing number of failures in the last eight years, as indicated in Figure 1 below. These failures are generally serious leaks or control problems that require the breaker to be taken out of service for repairs. These failures impact system reliability while the breaker is out of service as the repair of the breakers normally takes approximately 2 weeks.

As indicated in Figure 1, BCTC has replaced 25 of the original sixty-one double pressure circuit breakers since 2003, reducing the total population of double pressure circuit breakers to 36. At the same time, the number of failures of the remaining circuit breakers is increasing significantly, with the 36 remaining circuit breakers failing approximately 90 times in 2008, or an average of 2.5 failures per breaker. In contrast, there have been no failures of the replacement SF6 circuit breakers to date.

Figure 1. Remaining Double Pressure SF6 Breakers and Failure Rates



BCTC has been replacing the 230 kV double pressure SF6 circuit breakers in an orderly fashion as resources and outage availability permit, and in coordination with other Sustain Capital projects. This initiative is in competition for resources and outage availability with other circuit breaker replacement programs, such as the 500 kV Air-Blast Circuit Breaker Replacement program, and BCTC has therefore optimized the entire portfolio of Circuit Breaker projects. Accordingly, 230 kV double pressure replacements must be prioritized and executed in an appropriate sequence, due to outage availability and construction windows limiting the number of replacements BCTC can perform in any period. Notwithstanding the above, BCTC is proposing to accelerate the 230 kV double pressure replacement project to address the high failure rate.

2.0 BENEFITS OF REPLACEMENT

The benefits of double pressure SF6 circuit breaker replacement are:

(a) Improved System Reliability – Overhauls take approximately 2 weeks to complete. During this time the system is operating in an N-1 state and is at increased risk of an outage due to either failure of another breaker or loss of another system element. The new breakers are readily available and can be installed in approximately 5 days, substantially reducing the reliability risk associated with overhauling the failed breakers. An overhauled breaker does not improve reliability to the same level as a new breaker.

(b) Improved Environmental Performance – The sealing systems of a new SF6 circuit breaker are superior to the seals used on the existing double pressure circuit breakers. The double pressure breaker sealing system design did not focus on minimizing leaks; its function was to retain sufficient gas in the breaker to allow it to insulate the energized parts and interrupt the arc. This design was abandoned by the electrical manufacturing industry in the 1970's in favour of other techniques that use single pressure SF6 gas and make more efficient use of the moving parts in the interrupters. The new breaker design focuses on using minimum volumes of gas for insulation and interruption as well as minimizing leaks to the environment. As discussed below, the leakage rate for new generation design circuit breakers is significantly reduced, minimizing environmental impacts.

(c) Improved Equipment Reliability - The new 230 kV SF6 breakers have an excellent reliability record (over 290 unit-service-years in BC without a failure). The replacement breakers use maintenance-light spring/spring mechanisms, versus the maintenance-intensive compressed air systems used for the old breakers.

(d) Improved Financial Performance – As discussed below, the NPV ratio of replacement is 1.48 times better than overhauling and the continued cost of correcting SF6 leaks.

3.0 ANALYSIS UNDERTAKEN

3.1 NPV Analysis

The cost to repair SF6 gas leaks on these classes of circuit breakers, which generally occurs in the bushing to tank seal, averages $120,000 per breaker per incident. Based on previous experience, the effectiveness of atmospheric emission repairs only lasts two to three years, after which the leaks return and the repair has to be repeated. As discussed below, other problems occur more frequently with other component parts of the breakers.

The double pressure SF6 circuit breakers were also due for major overhauls starting in 2000 due to their deteriorated condition. BCTC estimated that the cost per overhaul would be approximately $300,000 per unit and would include fixing the leaks (not permanently), replacing or repairing the interrupter, and overhauling all auxiliary components, the most significant being the compressors. An overhauled breaker would eventually leak again because of its inherent design characteristics. However, this overhaul was cancelled because the original manufacturers of these circuit breakers were no longer providing utility service, and critical parts were no longer available. In order to overhaul these circuit breakers, parts would have to be re-engineered, adding to the expense of the overhaul and the outage duration for unplanned outages.

BCTC also investigated replacing the double pressure SF6 circuit breakers with new breakers. The full cost of replacement (in 2008 dollars) of a 230 kV breaker is $450,000 per unit.

BCTC conducted a NPV analysis comparing the unit cost of replacement to the cost of overhaul and ongoing leak repair. The results of the NPV analysis show that replacement of the existing double pressure SF6 circuit breakers is more economic than the action of overhaul and continuing to repair leaks every three years. The NPV model (attached as Appendix B and using current cost forecasts) shows that the ratio of circuit breaker replacement at a cost of $450,000, compared to overhaul and continuous leak repair and corrective work at $120,000 every three years is 1.48. Based on the results of the NPV and other analyses (environmental and reliability analyses discussed below), BCTC initiated a program in 2003 to replace the problematic 230 kV double pressure SF6 circuit breakers.

3.2 Environmental Analysis

As described below, a number of international bodies, recognizing the effects of SF6 gas on the environment, are trying to regulate and limit SF6 gas emissions to the atmosphere. Specifically:

(a) SF6 is included under the Kyoto Protocol as a man-made gas that requires monitoring and emission reductions.

(b) The European Commission has placed strict limits on SF6 gas emissions on all users in the European Union. SF6 gas use has been banned for non-essential uses, such as insulation for glass panes, use in car tires, etc. The utility industry established that there are no alternatives to using SF6 gas in electrical equipment at voltages above 48 kV and was exempted, but on the condition that the emissions be stringently monitored, reported annually and major efforts be implemented for reductions.

(c) In the US and Canada, both governments have initiated voluntary agreements with electrical utilities to monitor, report, and reduce SF6 emissions. Environment Canada and CEA have issued Memoranda of Understanding covering these activities. BCTC and BC Hydro are signatories to these agreements.

Due to its unique properties, presently there are no viable alternatives to the use of SF6 gas in high voltage electrical switching apparatus. At lower voltages (below 48 kV) vacuum switching has been substituted for SF6. However, above 48 kV, manufacturers have abandoned other previously-used substances (such as oil or compressed air), as they proved to be unsuitable or extremely costly for the high voltages and interrupting requirements prevalent in power systems today. Therefore, to meet its obligations under the Memoranda of Understanding with Environment Canada and CEA, BCTC is committed to monitoring and reducing greenhouse gas emissions of SF6. Pending legislation designating SF6 gas as a GHG will require BCTC to manage its SF6 emissions.

BCTC conducts an annual survey of the total quantities of SF6 gas in the transmission system, emissions due to leaks, and other losses in kilograms and as a percentage of the total. Statistics are recorded from each individual piece of equipment that uses SF6 gas. Along with monitoring and reporting, this data is used to assist in the prioritization of circuit breakers for replacement, as the equipment with the highest leakage history are considered a higher priority for replacement.

Table 1. SF6 Gas In Service and Leakage

Line of Business	2000	2001	2002	2003	2004	2005	2006	2007
Amount of SF6 in service (kg of SF6)	45888	45888	45888	78350	83790	84224	82970	83208
Equipment leaks (kg of SF6)	2393	1727	1657	2469	1751	1650	1920	1590
Annual Equip. Leakage Rate2	5.2%	3.8%	3.6%	3.2%	2.1%	2.0%	2.3%	1.9%
Maintenance losses (kg of SF6)	178	185	35.7	199	56.4	264	11	130
Failure and Other losses (kg of SF6)	0	45	294	0	120	23	9	66
Decommissioning losses (kg of SF6)	0	0	0	321	575	0	0	114
Total SF6 Releases (kg SF6)	2571	1958	1987	2989	2502	1938	1941	1901
Total SF6 Releases (ktonne of carbon equivalent)	61.5	46.8	47.5	71.4	59.8	46.3	46.4	45.4
Emission rate	5.6%	4.3%	4.3%	3.8%	3.0%	2.3%	2.3%	2.3%

Table 1 shows the total amount of SF6 gas in all BCTC installations along with the annual leakage from SF6-filled equipment, which is mainly the result of emissions from the old double pressure breakers and Mica GIS equipment.

3.3 Reliability Analysis

The double pressure SF6 gas circuit breakers have a history of reliability issues in addition to SF6 gas leaks. As these circuit breakers have aged, they have exhibited failures due to a number of other components that have worn out, including the prevalent wear of compressors and mechanical linkages. Corrosion of pressure relief devices led to the catastrophic release of all SF6 gas from one circuit breaker to the atmosphere in at least one instance in 2008.

In contrast, the new generation of SF6 circuit breakers have registered no in-service failures yet. The new generation 230 kV SF6 breakers have approximately 290 breaker-service-years with no failures in the transmission system. In addition, no gas leaks have been reported from the new generation of SF6 circuit breakers.

The Mean Time Between Failure (MTBF) calculated on the 36 remaining original double-pressure SF6 circuit breakers, has declined from an average of 1523 days to

229 days based on all classes of failures, including SF6 emissions. MTBF cannot be calculated for the replacement circuit breakers, as there are no failure events. However, the manufacturer indicates a minimum 25 years before major internal inspection is recommended. BCTC's experience with new generation SF6 circuit breakers currently indicates that no major internal inspection is necessary before 30 years of service.

Due to their double pressure design, double pressure circuit breakers also suffer from major internal leaks from the high pressure (18 bar) compartment to the low pressure (3 bar) enclosure, leading to frequent alarms and service outages. Generalised wear of major components, such as the SF6 and air compressors, mechanical linkages, valves, interrupters, bushings, tank heaters, control relays and even control wiring contribute to a worsening of their performance. Several major failures affecting these breakers have occurred in the last few years, leading to emergency replacements. Others have been rebuilt with parts from similar failed units, to extend the asset life and allow for orderly replacement.

3.4 Prioritization Study Results

As part of BCTC's overall Circuit Breaker Replacement Program, a Prioritization Study was performed in 2004 on the entire population (close to 3000 units) of circuit breakers, including SF6, Air-Blast, oil and other types. The study assigned weight factors to various maintenance issues affecting circuit breakers performance and outage consequences, including:

(a) Criticality Index, a function of the operating voltage – outages at higher voltages have more serious impact on the transmission system;

(b) Interrupting medium – arc interrupting medium affect the degree of wear, e.g. air-blast and double-pressure circuit breakers require frequent maintenance of compressors and rebuild of interrupters;

(c) Original Equipment Manufacturer (OEM) Support Index – circuit breakers require technical and parts support, which in some cases is no longer available, making maintenance very difficult or impossible;

(d) Collateral Damage Index – circuit breaker failures can inflict various degrees of collateral damage to adjacent equipment, based on the type of breaker (e.g., air-blast and oil breaker failures have potentially higher collateral damage);

(e) Average Annual Maintenance Cost Index – based on the total maintenance costs (Preventive Maintenance and Condition Maintenance) and the number of years in service;

(f) Number of Non-PM Work Orders – issued against each breaker since 2000;

(g) Replacement Cost – based on estimates obtained from BC Hydro Engineering for various breaker types and voltage classes;

(h) Seismic Withstand – certain types of circuit breakers are unsuitable for high seismic areas in some parts of BC, others would not withstand even a low level seismic event (e.g., GE type AT air-blast circuit breakers);

(i) Age of circuit breakers – while age is not the overriding factor, it is an indicator of the level of wear;

(j) Rebuild factor – some circuit breakers (e.g., air-blast) can only be economically rebuilt once in their life; and

(k) Environmental Impact – based on the type of circuit breaker and expected impact to environment in case of failure (e.g., oil and double-pressure SF6 have highest impact).

The results of the Prioritization Study indicated that most double pressure SF6 circuit breakers ranked among the top circuit breakers requiring early replacement. When considered with the annual survey of SF6 gas emissions from SF6-filled equipment, the Prioritization Study helps determine the circuit breaker positions that are most urgent to replace in a given year.

4.0 SELECTED SOLUTION

Based on the analyses performed, the solution was to start a program to replace all 61 double pressure SF6 circuit breakers in the transmission system with new generation SF6 circuit breakers. BCTC cannot allow 230 kV class circuit breakers to run to failure, as to do so results in significant system reliability reductions and potentially widespread customer outages if a second breaker were to fail concurrently. Therefore, in 2003, BCTC initiated an orderly annual program to replace the 230 kV double pressure circuit breakers, based on a system of prioritization of the breakers, available resources, outage availability, and in conjunction with other Sustain Capital initiatives. BCTC is now proposing that this program be accelerated due to the increasing number of failures being experienced with the 230 kV double pressure circuit breakers, as shown in Figure 1 above.

Figure 2 shows a replacement SF6 circuit breaker in the foreground of the picture. A double pressure SF6 circuit breaker is shown in the background to the left of the new breaker installation.

Figure 2. Typical Installation of a 230 kV SF6 Circuit Breaker

5.0 CONCLUSIONS

Due to the high cost of maintenance and poor reliability of the 230 kV double pressure circuit breakers, BCTC has initiated a replacement program of the entire equipment class. To minimize the cost of replacement and obtain maximum benefits, BCTC has obtained favourable prices through the tendering process and a long-term (5 years) blanket purchase order in place for the replacement breakers. The new generation of circuit breakers are of dead tank design (includes current transformers) and are seismically qualified for the high seismic areas of BC. To minimize installation costs, BCTC is re-using the existing foundations and – where possible – control wiring of the old breakers. This ensures that replacement continues to be the best financial alternative.

In addition to the benefits of standardization on a given type, the new 230 kV SF6 breakers have an excellent reliability record (over 290 unit-service-years in BC without a failure). The replacement breakers use maintenance-light spring/spring mechanisms, versus the maintenance-intensive compressed air systems used for the old breakers reducing maintenance requirements. The new breakers can expect higher reliability and longer life than the originally installed units.

Replacement of the 230 kV double pressure circuit breaker with new generation SF6 circuit breakers also provides significant environmental benefits. The manufacturer guarantees very low SF6 gas emissions, thus aligning with the Corporate Strategy to reduce greenhouse gas emissions.

6.0 APPENDIX A: BACKGROUND ON SF6 CIRCUIT BREAKERS

The present technology for circuit breakers requires SF6 gas for internal insulation and arc interruption in high voltage circuit breakers. There is no other alternative economic design mechanism of dealing with high voltages and high fault current interruption found in existing transmission systems.

SF6 (Sulphur Hexafluoride) is colourless, odourless, non-toxic and non-flammable. It is highly stable and un-reactive at room temperature and atmospheric pressure. Because of these qualities, SF6 gas is not easily detectable by humans, and being heavier than air, tends to collect in lower areas. Large quantities of accumulated gas displace air and can lead to suffocation in enclosed areas.

Two very important properties of SF6 gas have led to its extensive use in the Electrical Industry:

(a) High dielectric withstand - at 1 bar (atmospheric pressure) it is comparable with the value of dielectric withstand of insulating oil; and

(b) Electric arc quenching properties – because of its chemical structure, SF6 acts as a sponge in absorbing free electrons from the electric arc, a quality 100 times that of air at the same pressure.

Because of these properties, SF6 gas was first used in instrument transformers in the early 1950’s. By the mid 1950’s SF6 gas was being used for the first time in switchgear apparatus, first at medium voltages, then in switching equipment at higher voltages. In North America, SF6 was first used in switchgear applications by Westinghouse in the late 1950’s, in their double-pressure SF6 circuit breakers. This was followed by ITE Corp. in the 1960’s.

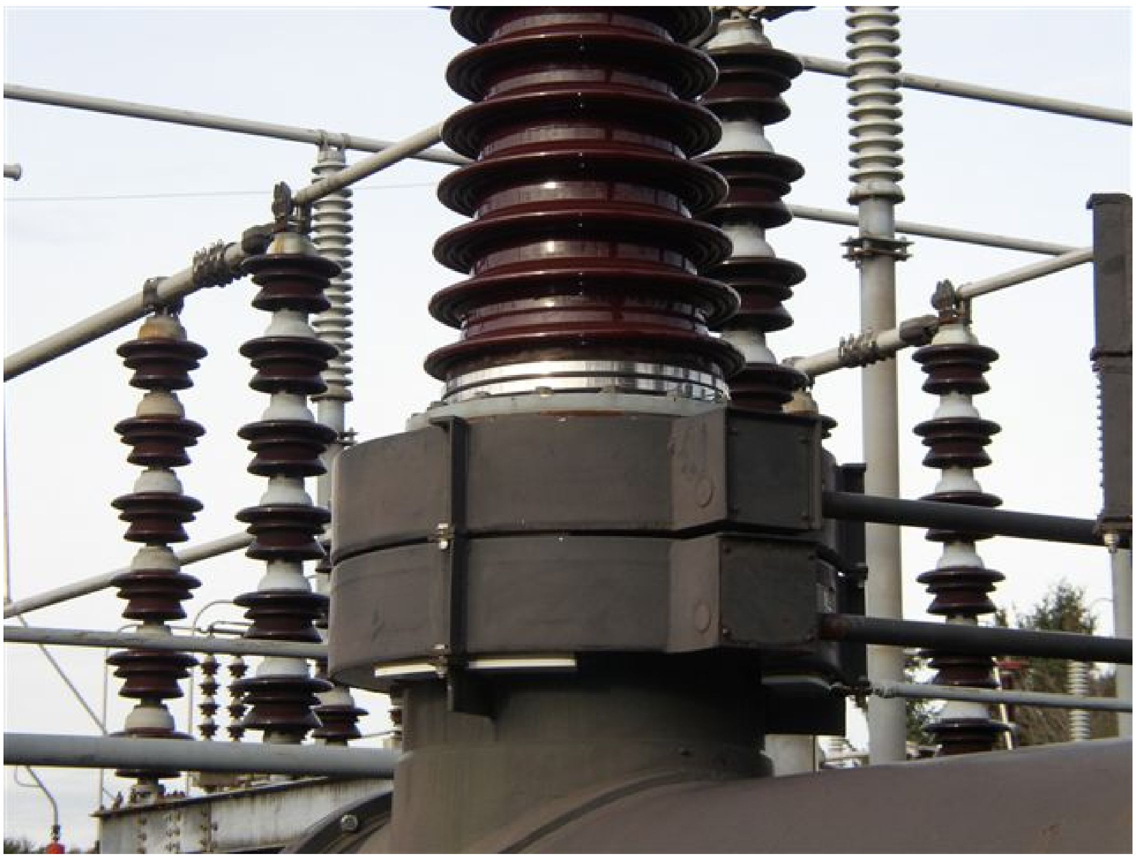
However, at the time this class of breakers was being installed, the effects that gases such as CO2 and SF6 have as greenhouse gases was not known. It was not before the late 1980’s that the effects of a molecule of SF6 gas as a greenhouse gas were quantified as being 23,000 times more detrimental on the atmosphere than that of a molecule of CO2. The main reason for this effect is the very long time period the SF6 molecules survive in the upper atmosphere before they are decomposed by solar radiation. The utility industry has been responsible for approximately one third of the total SF6 gas emissions. As the greenhouse effects of SF6 gas became better known, pressure on those industries using the SF6 gas to limit emissions has grown.

The technology used for the first double-pressure SF6 circuit breakers borrowed from the prevalent bulk oil and air-blast circuit breakers at the time. These breakers were of dead-tank type and designed around similar iron castings used for bulk oil breakers to house the interrupters. The high dielectric withstand of SF6 gas was used to isolate energized parts of the breakers inside the tank, and the pressure in the tanks was at approximately 3 bars. For the interrupters, the designers at the time did not use the full arc-quenching capabilities of the SF6 gas, relying instead on a jet of high pressure SF6 gas (similar to air-blast circuit breakers) to extinguish the arc. The SF6 gas used for interruption was stored in a separate compartment that was pressurised at approximately 18 bars to provide the blast required to extinguish the arc in the interrupter. The energy necessary to operate the double pressure SF6 circuit breakers was delivered by pneumatic mechanisms employing maintenance intensive compressors. Separate compressors were necessary to pressurize the SF6 gas in the high pressure compartment to 18 bars.

The interrupting technology using SF6 gas was pioneering at the time, but primitive in regard to pressure vessel technology of later years. As a result, precision machining of flanges and pressure surfaces was rudimentary, the material and shape of gaskets and seals used were unsuitable to seal in SF6 gas, and, given that the cost of SF6 gas was very low, not much attention was given to prevention of gas leaks. As a result, gas leakage was considered acceptable, to be remedied by periodic gas refills.

In contrast, later designs of new generation SF6 circuit breakers paid particular attention to prevention of gas leaks. The double pressure technique relying on a high pressure jet of gas extinguishing the arc was abandoned in favour of simpler and more efficient designs. New generation SF6 circuit breakers are designed to use the moving contacts in the interrupter in such way to create piston-type action leading to short SF6 gas blasts that de-ionise the arc and extinguish them efficiently. SF6 circuit breaker manufacturers currently test and guarantee their equipment to leaks at a rate of less than 0.5% per year by weight of gas. The actual loss of SF6 gas due to leakage is thought to be even smaller, typically being closer to 0.1% per year, but present detection methods to determine gas leakage do not permit completely accurate verification. The mechanisms used for new generation SF6 circuit breakers are of the spring type (for both tripping and closing) that are highly reliable and require very little maintenance through the life of the breaker.

SF6 gas emissions have been occurring from the transmission system for many years, in spite of frequent initiatives and significant efforts to reduce these emissions. Programs to reduce emissions included total rebuild of major leakage points (e.g. bushings) as well as limited ones (applying rubber bands around leakage areas as shown in the picture below).



In response to environmental concerns, maintenance and reliability issues encountered in equipment that used SF6 gas, equipment manufacturers have invested considerable R&D funds in the design, manufacture and testing methods of electrical equipment to reduce gas leaks. Pressure on electrical utilities to reduce SF6 emissions have resulted in revisions of maintenance activities and procedures that have led to considerable reductions in SF6 gas over time. Some jurisdictions (e.g., European Union) have adopted stringent legislation that has led to the replacement of early design leak-prone equipment, recovery and recycling of used SF6 gas, and a ban of using SF6 gas at lower voltages, where alternatives (e.g. vacuum switchgear) exist. In the US and Canada, both governments have initiated voluntary agreements with electrical utilities to monitor, report, and reduce SF6 emissions. Environment Canada and the Canadian Electrical Association (CEA) have issued Memoranda of Understanding covering these activities. BCTC and BC Hydro are signatories.

Reference

Power Circuit Breaker Theory and Design: Theory and Design
By Charles H. Flurscheim, Institution of Electrical Engineers
Contributor Charles H. Flurscheim
Published by IET, 1982
ISBN 0906048702, 9780906048702

7.0 APPENDIX B: NPV MODEL

The following table provides the NPV analysis and ratio of circuit breaker replacement compared to overhauling the existing double pressure circuit breakers and continuing to repair leaks on an ongoing basis. The current cost of replacement is $450,000 per unit. The current cost of overhaul is forecast to be $300,000 per unit, and the ongoing leak repair is forecast at $120,000 every three years. The NPV ratio based on these assumptions is calculated at 1.48. The table is included below:

<u>NPV Financial Comparison of Options (both recommended and alternative solutions)</u>

Discount Rate is 6%

Recommended Alternative - Replace Circuit Breaker

Type of Cost	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Definition Capital														
Execution Capital		450000												
OMA														
Total	0	450000	0	0	0	0	0	0	0	0	0	0	0	0
$400,498														

Alternative 2 - Continue with overhaul and repair

Type of Cost	F2007	F2008	F2009	F2010	F2011	F2012	F2013	F2014	F2015	F2016	F2017	F2018	F2019	F2020
Capital Cost														
Cost to maintain		300000			120000			120000			120000			120000
	0	300000	0	0	120000	0	0	120000	0	0	120000	0	0	120000
$592,813														

1.48 **NPV Ratio**

Appendix D-2

Transmission Line Ice Hazard Risk Reduction Program

SUSTAIN PORTFOLIO CASE STUDY

TRANSMISSION LINE ICE HAZARD RISK REDUCTION PROGRAM

1.0 INTRODUCTION

Overhead Transmission Lines often face severe ice or wind loads, which may damage lines and affect power supply to customers. Meteorological data and previous ice events indicate that the Fraser Valley and Howe Sound/Pemberton Corridors are particularly susceptible to ice storms. Damage occurs to transmission structures when the loadings from these extreme events exceed the design criteria. Several extreme weather events in BC have demonstrated the extensive damage that can occur to transmission systems, including:

(a) 1935 – the Fraser Valley ice storm, which damaged towers from Langley to Agassiz;

(b) 1972 – the Seabird Island ice storm, which damaged 26 towers east of Agassiz on Circuit 5L41, two towers on Circuit 3L02 in the Fraser Valley, and one tower on Circuit 5L42 in the Stawamus Pass (Howe Sound) due to a snow slide; and

(c) 1997 – the Cheakamus Valley ice storm, which damaged two towers on Circuit 5L42.

Outside of BC, several ice storms have led to significant damage to transmission structures and left customers without power for extended periods of time. Some historical ice storm events that have occurred outside of BC are:

(a) 1998 – the Eastern Canada ice storm, which damaged over 300 transmission towers in Ontario (Hydro One) and 1000 transmission towers in Quebec (Hydro Quebec) causing widespread and extended outages and 28 fatalities; and

(b) 2004 – the Eastern (Maritime) Canada ice storm, which damaged 12 major transmission structures in Nova Scotia (Nova Scotia Power Inc.).

Towers are generally damaged due to ice accumulation on the conductors. The ice accumulation increases the weight of the conductors and, since the conductors and circuits are often already under increased tension due to operating at peak winter electrical loads, maximum structural load conditions occur. When the structural loading on the tower exceeds the design capacity, tower damage results. In addition, failures may occur under lesser loading conditions if the ice storm is followed by wind, causing potential ‘galloping’ (oscillating & stretching) of the conductors and guy wires under steady and moderate wind.

In response to the 1998 Eastern Canada ice storm, BC Hydro assessed the risk of ice hazard damage to the transmission system and prepared the Transmission System Hazard Risk Assessment, Report No. NPP 9809.[1] This assessment involved a consideration of failure risk, load loss, and a financial analysis of the consequences of various hazard scenarios. The Fraser Valley and Pemberton/Howe Sound transmission corridors were considered due to historic ice storm occurrence and data, as well as the importance of these circuits for the supply of electricity to the Lower Mainland and Vancouver Island.

In the Pemberton/Howe Sound and Fraser Valley corridors, BCTC has approximately 3,700 towers that are potentially vulnerable to ice storms. Given the extent of potential damage and the potential consequences if this were to occur, BCTC has developed a program to mitigate the impact of ice storms. The BCTC Transmission Line Ice Hazard Reduction (TLICE) program is intended to investigate how many of these towers are at risk of failure, to determine mitigation strategies, and to determine the preferred alternatives to protect these corridors, which serve the Lower Mainland and Vancouver Island loads.

Through structure modelling, BCTC determined that an event similar to the 2004 Eastern (Maritime) Canada storm, a 1 in 100 year event, would damage structures in either the Fraser Valley corridor or the Howe Sound/Pemberton corridor. In such an event and assuming the interconnection remains intact, BC could import about 2,000 MW from Washington State (less than 1/3 of the current peak load of 7200 MW) for the Lower Mainland and Vancouver Island customers. Existing coastal generation could supply an additional 2100 MW from BC Hydro plants and IPPs. The net effect would be a load curtailment of approximately 3100 MW. Depending on the condition of the distribution system it would be possible to supply customers on a rotating basis, but at great inconvenience to rate payers.

As a result of these risks, BCTC and BC Hydro have studied the risk of tower damage from ice storms extensively. An assessment of the risk was conducted in 2004 and

[1] BC Hydro T & D, Transmission System Hazard Risk Assessment, November 1998

documented in the report entitled 'Ice Storm Risk Analysis',[2] filed with the Commission in BCTC's F2006 TSCP proceeding in response to BCUC IR 2.108.3. Section 2 presents a summary of the analysis from this report, followed by Section 3 that describes the preferred alternative to mitigate the risk. The current implementation plan can be found in Section 4 and progress to date in Section 5. Section 6 discusses next steps followed by conclusions in Section 7.

2.0 ANALYSIS

The Ice Storm Risk Analysis Report investigated the risk due to ice storms in the Fraser Valley and Pemberton/Howe Sound corridors due to the effect of equalized loading for 14 separate reinforcement scenarios and six ice storm event cases. The six ice storm event cases considered were:

(a) 1 in 50 year event for the Fraser Valley Corridor;

(b) 1 in 50 year event for the Pemberton/Howe Sound Corridor;

(c) 1 in 100 year event for the Fraser Valley Corridor;

(d) 1 in 100 year event for the Pemberton/Howe Sound Corridor;

(e) 1 in 200 year event for the combined Fraser Valley and Pemberton/Howe Sound Corridors; and

(f) 1 in 500 year event for the combined Fraser Valley and Pemberton / Howe Sound Corridors.

A key assumption is that the 1 in 50 and 1 in 100 year events affect each corridor independently, while the 1 in 200 and 1 in 500 year events are sufficiently large to affect both corridors.

For each reinforcement scenario, the following were calculated:

(a) Estimated cost to reinforce the circuits;

(b) Impact of event;

[2] Gutwin T., June 2004.

(c) Event probability; and

(d) Benefit/Cost Ratio.

Each of these is discussed below.

2.1 Circuit Reinforcement Cost

Table 1 presents a summary of the 14 reinforcement scenarios considered. The Cost (M$) column shows the total estimated cost ($2004) to implement the reinforcements identified for each circuit to withstand a storm with the return period[3] indicated. The risk estimates for the base case scenario (i.e., the do nothing case, Scenario 0) assume that no reinforcements were made prior to the design ice storm. The reinforcement options considered for various withstand levels were:

Table 1. Scenario Analysis of Reinforcement Levels and Costs

Scenario	Cost ($million)	Reinforcement Level/Return Period (Ice Storm Withstand Years)								
		2L77	2L78	5L30	5L40	5L41	5L42	5L45	5L81	5L82
0	0	-	-	-	-	-	-	-	-	-
1	1.4	50	50							
2	11.3	100	100	100		100			100	
3	10.7	100	100	100		100				100
4	7.2	100	100	100			100		100	
5	6.6	100	100	100			100			100
6	118.9	500	500	500	500	500	500	500		500
7	112.0	500	500	500	500	500	500	500	500	
8	10.3	100*	100*	100*			100*			100*
9	63.9	500	500	500	500	100*	500	500	100*	
10	48.7	200	200	200	200	200	200	200		200
11	52.8	200	200	200	200	200	200	200	200	
12	77.9	500	500	500	500	200*	500	500		200*
13	57.5	200	200	200	200	200*	200	200	200*	
14	66.4	200*	200*	200*	200*	200*	200*	200*	200*	

Notes:

100* - only towers that would be damaged in a 1 in 100 year event would be reinforced to a 1 in 500 year withstand level.

[3] For example, a 1 in 50 year event has a 50 year return period.

200* - only towers that would be damaged in a 1 in 200 year event would be reinforced to a 1 in 500 year withstand level.

The reinforcement scenarios considered were intended to provide the maximum benefit by eliminating customer outages at the design ice storms considered.

2.2 Impact of Event

For each scenario, the estimated total dollar impact under each ice storm event was calculated based on the probability of structure failure and the cost impact of structure failure:

Event Impact Risk $_{\text{Specified Ice Storm}}$ =
Σ(Probability of structure failure $_{\text{Specified Ice Storm}}$ X Cost of Structure Failure $_{\text{Specified Ice Storm}}$)

The cost impact of structure failure was based on estimates of the cost of damages to the system, including repair costs, crew safety, auxiliary damage and public safety and financial impacts due to load curtailment (Lower Mainland and Vancouver Island), including estimates of customer damage costs.

The probabilities of circuit failure from icing and associated repair costs were determined in a detailed per line and per tower type analysis for a 1 in 50, 1 in 100, 1 in 200 and 1 in 500 year event.

The probability of structure failure in each reinforcement scenario is a factor of the ice accretion level and circuit characteristics (structure type and conductor span).

The determinations of ice accretion levels on steel transmission lines include studies of numerous sources of information. Regular statistical weather data is usually only available for airports and, since transmission lines frequently pass through mountainous terrain far removed from these data collection points, it is difficult to make accurate ice and wind predictions. Generally, field staff observations, old test stations, records of line damage, modeling, etc., were used to augment actual weather station data. In addition, icing information was requested from Atmospheric Environment Canada (now Meteorological Services Canada – MSC) and this helped increase knowledge of potential events. BCTC continues to work closely with MSC to develop and refine weather models for system evaluation and planning.

Results from the ice studies indicated the typical radial ice accretion associated with storms in the Fraser Valley and Pemberton/Howe Sound corridors as follows:

Table 2. Radial Ice Accretion

	Return Period	Radial Ice Accretion (mm)
1	1 in 30 years	25.9
2	1 in 50 years	29.2
3	1 in 100 years	33.7
4	1 in 200 years	38.1
5	1 in 500 years	43.9
6	1 in 1000 years	48.4

A key assumption is that the weight of ice is proportional to the square of the diameter.[4]

Based on the data collected and the expected ice accretion levels, BCTC determined the risk levels for extreme icing events on the identified circuits in the Fraser Valley and Pemberton/Howe Sound corridors (5L30, 5L42, 5L45, 5L82, 2L77, 2L78, 5L40, 5L81, 5L32, and 5L41). For each circuit, ice loading effects on towers and conductors were modeled to determine potential failures under the various loadings experienced in different storm events.

The Present Value results of the total dollar impact analysis, multiplied by the Event Probability, are presented below in Section 2.4.

2.3 Event Probability

The occurrence of ice storm events is considered to be a random distribution, characterized by a Poisson statistical distribution, and therefore not dependent on elapsed time since a prior event. In effect, the events will correspond to the probability of having one or more incidents given by the expression:

$$P(x) = \frac{(vt)^x \cdot e^{-vt}}{x!}$$

Where: "v" is the average rate of occurrence
"t" is the time period being considered

[4] BC Hydro T & D, Transmission System Hazard Risk Assessment, November 1998.

"x" is the number of events being considered

For example, for a 1:50 year ice storm, the probability of having no storm in the next 50 years is:

$$P(0) = \frac{(1/50\ .\ 50)^{0}\ .\ e^{-1/50.50}}{0!} = \sim 0.37 = 37\%$$

For a 1:50 year ice storm, the cumulative probability of having 1 or more ice storms occurring is:

P (1 or more) = 1 – P(0) = 1 – 37 = 63%

In effect, there is a 63% chance that one or more events with a return period of 1:50 will occur in the next 50 years.

2.4 Benefit to Cost Ratio

Using the probability of event occurrence and the impact of event, the annualized risk was calculated for each scenario:

Annualized Risk = Σ(Probability of Specified Ice Storm × Impact of Specified Ice Storm)

For each scenario, a Present Value of the Annualized Risk amounts was then calculated and the benefit/cost ratio was determined using:

$$\text{Benefit/Cost Ratio} = \frac{\text{(Annualized Risk of Scenario – Annualized Risk of Base Scenario)}}{\text{Reinforcement Cost of Scenario}}$$

The results are shown in Table 3.

Table 3. Ice Storm Risk Summary

Scenario	Reinforcement Cost (M$)	20 Years Risk (Net Present Value) Without Customer Damage		With Customer Damage Costs	
		M$	Efficiency	M$	Efficiency
Base	$0.0	$98.0	-	$1,455.6	-
1	$1.4	$95.1	2.1	$1,440.1	11.1
2	$11.3	$68.5	2.6	$1,114.5	30.1
3	$10.7	$69.0	2.7	$1,115.0	31.8
4	$7.2	$70.6	3.8	$1,116.6	47.3
5	$6.6	$71.1	4.1	$1,117.1	51.6
6	$118.9	$43.7	0.5	$43.7	11.9
7	$112.0	$46.8	0.5	$46.8	12.6
8	$10.3	$71.1	2.6	$1,059.6	38.5
9	$63.9	$59.1	0.6	$128.4	20.8
10	$48.7	$67.4	0.6	$371.4	22.2
11	$52.8	$67.0	0.6	$370.9	20.5
12	$77.9	$51.8	0.6	$158.9	16.6
13	$57.5	$60.5	0.7	$295.1	20.2
14	$66.4	$57.7	0.6	$196.6	19.0
All Lines to 1:50	$4.2	$80.3	4.2	$1,345.0	26.3
All Lines to 1:100	$21.9	$70.9	1.2	$1,046.0	18.7
All Lines to 1:200	$68.4	$70.9	0.4	$304.0	16.8
All Lines to 1:500	$167.7	$50.1	0.3	$0.0	8.7

In the 2004 analysis, the efficiency (benefit of cost ratio) was calculated with and without customer damage costs due to the uncertainty of the cost value used for customer damage. In using the results of this report, BCTC considered the efficiency with customer damage costs because it was considered to be reasonable to include some measure of customer damage.

3.0 PREFERRED SOLUTION

The analysis described in Section 2 was a key input into BCTC's decision on a reinforcement program in terms of scope and structure. BCTC's System Planning Withstand Performance Criteria, local knowledge, and construction experience over mountainous terrain were also taken into account.

The System Planning Withstand Performance Criteria were developed for seismic events and indicate that, even though it might not be necessary or even possible for all risk elements to be mitigated such that no damage will occur to the transmission system, customer load supply should be restored within 72 hours for critical system elements. BCTC has applied this criterion as a minimum performance level to be maintained during ice storm events as well.

In Reinforcement Scenario 5, critical circuits are reinforced to a 1 in 100 year withstand for $6 million. While this scenario provides the highest benefit/cost efficiency in terms of risk mitigation per expenditure, it was not selected as the preferred alternative because it does not meet BCTC's performance criteria. To meet BCTC's 72 hour customer restoration criterion, subsequent upgrades of key circuits would be required, costing an estimated $120 million. Similarly, Scenario 4, with the second highest benefit to cost ratio, was also rejected because it would not allow for load supply restoration within 72 hours.

Reinforcement Scenario 8 had the next highest benefit to cost ratio. In Reinforcement Scenario 8, critical circuits are reinforced to a 1 in 100 year withstand for $10 million. This scenario reinforces critical circuits that would be damaged in a 1 in 100 year storm to the 1 in 500 year level. As Scenario 8 had the highest benefit to cost ratio of the scenarios that met BCTC's performance criteria, it was moved forward for further study, definition and implementation.

4.0 DEFINITION AND IMPLEMENTATION

Upon further analysis, BCTC identified that Circuit 5L45 should be reinforced as part of Scenario 8. As shown in Figure 1, 5L45 connects the bulk system transmission lines that are routed through the Fraser Valley corridor, terminating at Meridian Substation, MDN, and the Howe Sound/Pemberton corridor, terminating at Cheekeye Substation, CKY, This connection allows power to flow to the Lower Mainland and Vancouver Island through both corridors.

Figure 1. TLICE 500 kV Circuits (5L30, 5L42, 5L45, 5L82)

Reinforcing 5L45 ensures that this vital connection will withstand ice storm events, thereby further securing supply to the Lower Mainland and Vancouver Island. Additionally, 5L45 provides system flexibility during reinforcement work on 5L82. As a result of these benefits, BCTC included the reinforcement of 5L45 in its implementation plan, which is shown below.

Table 4

Circuit	F2006	F2007	F2008	F2009	F2010	F2011
5L30	D	C				
5L42		D	C			
5L45		D	C			
5L82			D	C		
2L77				D	C	
2L78					D	C

Note:

D = Design Work and includes identification of structures, spans and reinforcement planning

C = Construction work and includes detailed planning and execution of reinforcement work on site

Based on the assumption that a 1 in 100 year event would not affect both the Fraser Valley and Howe Sound/Pemberton corridors, reinforcements were planned such that circuits with the highest potential for impact in the event of failure were addressed first. Project staging is planned so that works on adjacent circuits are not started in the same year. This is to avoid trying to schedule outages on the same corridor and to ensure that one circuit along a corridor is always in service. Additionally, the current method of executing the design and planning work for circuit reinforcements in the fiscal year prior to implementation ensures construction risks are adequately addressed and design issues resolved.

Another essential modification BCTC has made to Scenario 8, as described in Section 2, is to reduce the maximum reinforcement level to a 1 in 200 year withstand. This was done as result of the limited availability of component parts that meet the 1 in 500 year criteria, increasing the cost of the reinforcements and thereby decreasing the benefit to cost ratio of the scenario. This modification still ensures that customer outages, due to a 1 in 100 year storm would be avoided and outage times after a 1 in 500 year event would be reduced.

In order to maximize the benefit of the TLICE program, detailed design and analysis are undertaken on each proposed circuit to determine reinforcement requirements and cost estimates, system reliability concerns during construction, and confirmation of the benefits of the reinforcement prior to implementation.

For instance, the preliminary structural evaluation that was conducted as part of the 2004 analysis was based on structure specific loadings and assumed equal ice on the conductors and towers. Prior to any project implementation, detailed structural analysis is completed for the affected tower types in order to accurately determine the response of the circuits and structures when ice loading occurs. This data enables greater accuracy in the estimates of reinforcement work required and costs.

As another example, through the modelling of the reinforcement for Circuit 5L82, BCTC determined it was more cost effective to add additional conductor to a key span instead of adding a new tower as originally planned.

5.0 PROGRESS TO DATE

The TLICE program started in F2005 with detailed design for 5L30, for which actual construction work started in F2006. So far, 5L30, 5L42, 5L45 and 5L82 have been reinforced, with expenditures to date of $6.4 million. Design for the reinforcement required for 2L77 is underway with reinforcement planned in F2010. The design and construction work for 2L78 will be completed in F2010 and F2011, respectively. BCTC estimates that the cost to implement the remainder of the reinforcements will bring the total cost of the implementation plan for the modified Scenario 8 to approximately $10 million, as planned, even with the added reinforcement of 5L45.

Since the start of the TLICE program, BCTC has continued to study the risk of structure failure due to ice loading.

Utilities historically used deterministic methods in the design of transmission lines, and BCTC, as well as other utilities across Canada, typically construct transmission structures according to CSA Standard C22.3 No. 1-01, 'Overhead Systems'. According to this standard, structures are loaded with 12.5 mm of radial ice under normal loading conditions. Structures were designed with a safety factor of 1.5 to account for design uncertainty resulting from uneven tower loading, ice thicknesses, effects of wind, ambient temperature, steel strength, asset condition, etc.. This safety factor essentially provided reserve capacity to mitigate uncertainties.

Safety factors are commonly used in the designs of other transmission components and reflect the preferred sequence of failure incorporated into these designs.

Components such as conductors, insulators and hardware utilize a 2.0 factor of safety and foundations use a 1.75 safety factor; consequently, these components generally remain intact even in the event of structure failure.

Some structures are located in areas where MSC and historical data have indicated extreme loading conditions are possible. Structures in these areas could experience higher loadings than their original design and these are the portions that this program seeks to reinforce.

More recently, probabilistic methods based on return periods (e.g.., 1 in 50 year event etc.) have been followed in transmission line design. This method allows for increased industry knowledge on the performance of materials and levels of loading expected.

For structural analysis and modelling, BCTC uses Power Line Systems Computer Aided Design (PLS CADD) and PLS Tower. These tools are currently used by most utilities for analysis and design of transmission lines and allow for more dynamic modelling and achievement of greater accuracy. Through this structural analysis, it was determined that structures loaded to 1.2 times the original design capacity were not likely to fail. As a result, the design capacity could safely be increased by 20%, thereby reducing the load factor to 1.5/1.2 = 1.25. This revised load factor translates into the following design criteria:

Load factor LF ≥1.25 → Reinforcement not required

Load factor 1 ≤ LF ≤1.25 → Reinforcement may not be required but further study should be initiated

Load factor LF ≤ 1 → Reinforcement required

Based on the recommendation of structural engineers, structures identified in the PLS CADD models as having a load factor less than or equal to 1 are considered for reinforcement since they are at high risk of failure. This analysis and modelling has allowed for a reduction in expected levels of reinforcement than were initially planned.

BCTC was able to validate the results of the accuracy of the structural models by carrying out actual load tests on a type A lattice structure, the most common configuration of towers on the 230 kV system. The real time performance data were the result of a mechanical test sponsored by BCTC and developed jointly with BCTC, BC Hydro and PowerTech, when a typical tower was being taken out of service in order to construct a new tap circuit. The bridge of the tower was taken off and shipped to the PowerTech labs for testing. The results of the test indicated the precise level and type of reinforcement required, which was of great value in defining the design process. The test of a full size tower bridge was noted across the North American utility industry since these tests and dynamic response model comparisons do not normally occur. The lessons learned from the test indicate that reinforcements planned for the critical 230 kV circuits will be adequate.

Similarly, a test protocol is being developed to investigate the withstand capacity of insulators. When completed, this test is expected to further refine BCTC's reinforcement program.

BCTC is participating in the CEATI Wind & Ice Storm Mitigation Interest Group (WISMIG) to increase organizational response capacity and knowledge about the impacts of extreme events on the transmission system. Data from joint research efforts and information sharing ensures that BCTC is up to date on practices and methods of other utilities. Work on modeling extreme events in collaboration with UBC and MSC is also continuing so that reliable weather data and an increased understanding of the performance of steel towers under extreme ice loads can be achieved.

In addition to the TLICE program, BCTC has an Emergency Response Plan (ERP) in place, which defines the System for Transmission Emergency Repair (STER). STER provides for materials, tools and manpower to be stocked in readiness to rebuild up to 5 km of 500 kV transmission line within weeks. This strategy should ensure that the bulk of the peak winter demand load of 7200 MW for the Lower Mainland and Vancouver Island is served.

6.0 NEXT STEPS

Following completion of the current implementation plan, BCTC will re-assess the transmission system based on the withstand levels expected and identify any further circuits that remain at risk of failing during 1 in 100 year ice storm events. Preliminary analysis has shown that Circuits 5L40, 5L81, 5L32 and 5L41 will likely require mitigation as part of a second stage of reinforcement. Potentially, BCTC would investigate the benefits of further reinforcing system elements to the levels described in Scenario 9, in which critical circuits are reinforced to a 1 in 500 year withstand. This scenario still has a benefit to cost ratio well over 1.0 and would further secure the transmission system supply during ice storm events. As greater knowledge and forecasting is developed about ice storms and loadings, this scenario will be revisited in terms of benefit/cost and compared to other systems risks from natural events.

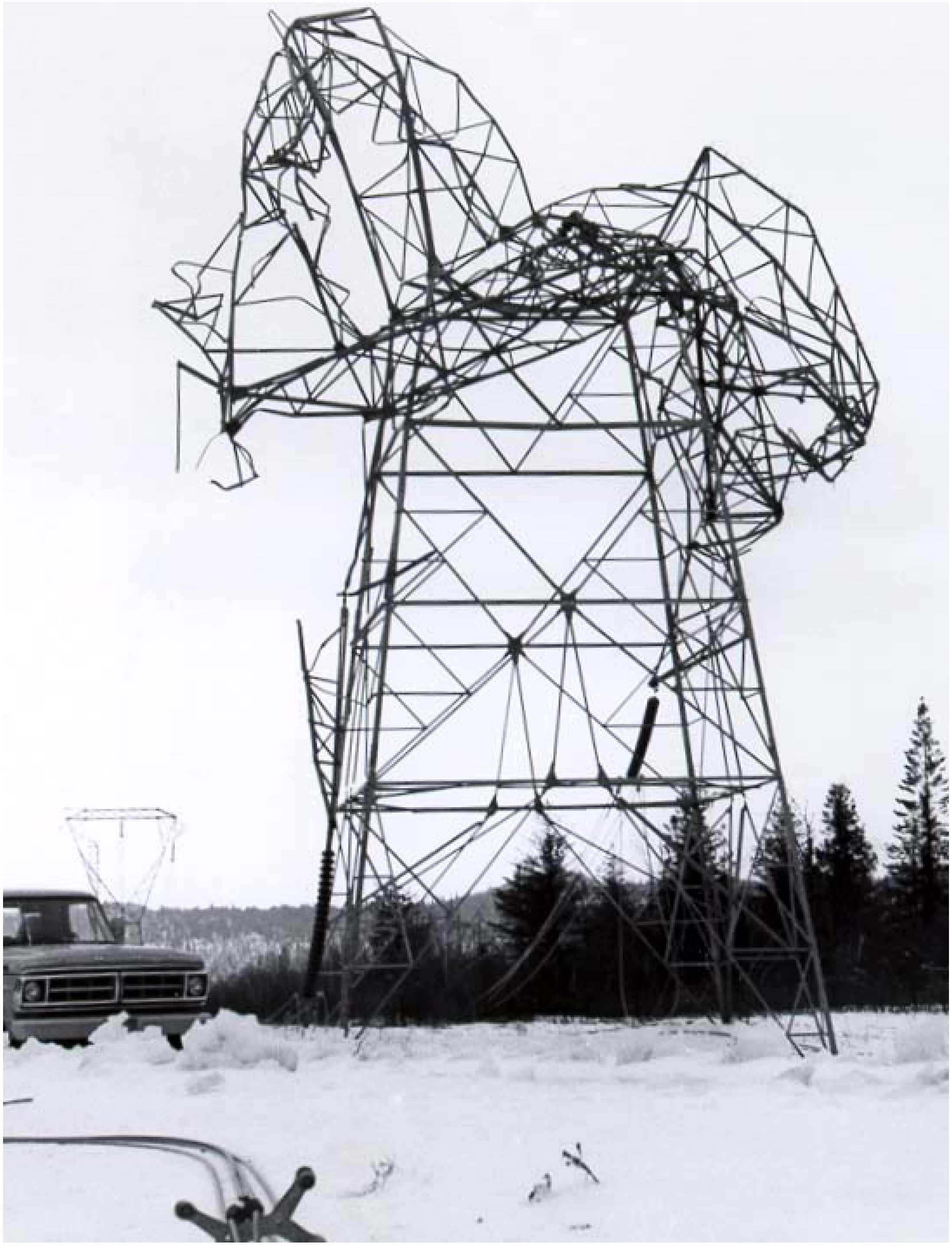
BCTC is also investigating the possibility of incorporating ice risk and expected impacts on transmission circuits in a Geographic Information System (GIS). Work is already underway on representing spatially other system risks, such as seismic, corrosion and wind, on the GIS tool. Inclusion of the ice risk would allow for efficiencies in construction and determining the most vulnerable areas of the transmission system.

As part of the STER initiative, BCTC plans to develop new emergency steel tower types for rapid deployment in the event of unforeseen system failures.

7.0 CONCLUSIONS

Past ice storms in BC and North America have demonstrated the devastating effects an ice storm can have on transmission systems. The 1998 ice storm in Quebec cost Hydro Quebec approximately $1.5 billion in rebuilds and restoration. In BC, historical meteorological data has shown that circuits in the Fraser Valley and Howe Sound/Pemberton corridors are also at risk of failure due to ice loading. A typical example of one of the 26 failed towers resulting from the 1972 Seabird Island ice storm in the Eastern Fraser Valley is shown in the following figure.

Figure 2. Damage from Ice Loading to Structure on 5L41



The BCTC TLICE Program investigates the risks to the transmission system from ice storms, develops alternative solutions for mitigating these risks, and implements the preferred alternatives.

The TLICE Program was originally planned to be put in place over a period of 6 years with total planned expenditures of approximately $10 million. The selected alternative for this program involves reinforcing structures along the identified corridors on Circuits 5L30, 5L42, 5L45, 5L82, 2L77, and 2L78 with a benefit to cost efficiency ratio of the selected reinforcement alternative of about 35.0

BCTC is using the most innovative designs and methods to ensure the reinforcements are adequate for the design storms expected. So far the reinforcement program has been efficient largely due to the improved data from modeling, full scale mechanical tests and industry knowledge as well as the degree of planning undertaken.

With new knowledge and increasing research about the potential impacts of climate change on ice accretion levels and wind speeds, BCTC has adopted a proactive approach to mitigate identified risks. By reinforcing critical circuits, the vision of a robust and reliable transmission system will be achieved. The implementation of the TLICE program will ensure that the province has a more robust system capable of withstanding any expected design events.

8.0 REFERENCES

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Government of British Columbia, 2007 Energy Plan. “A Vision for Clean Energy Leadership”

Appendix E

Canadian Electricity Association Benchmarking Study Results

Canadian Electricity Association Benchmarking Study Results

CEA COPE Priority Key Performance Indicators	F2007		F2006		F2005	
	BCTC	CEA Composite	BCTC	CEA Composite	BCTC	CEA Composite
Direct OM cost per cct length ($/km)	7.28	6.18	7.02	6.27	7.00	6.40
Direct OM cost per GFA (%)	2.7	2.2	2.6	2.2	2.4	2.3
Direct OM cost per Energy Transmitted (GWh) * cct length (km)	0.13	0.06	0.12	0.06	0.13	0.06
Total OMA cost per cct km ($/km)	9.58	9.28	9.86	9.13	9.98	8.83
Total OMA cost per GFA (%)	3.6	3.2	3.6	3.2	3.5	3.1
Total OMA per Energy Transmitted (GWh) * Cct length (km)	0.17	0.09	0.17	0.09	0.18	0.09
Total OMA + Sustaining Maintenance Capital cost per GFA (%)	6.6	5.5	6.0	5.3	5.7	5.0
Total OMA + Sustaining Maintenance Capital cost per energy transmitted * cct length ($/(MWh*km))	0.30	0.16	0.27	0.15	0.29	0.15
Total OMA + Sustaining Maintenance Capital cost per System Peak Capacity ($/MW)	34.4	30.5	32.1	29.2	30.8	26.1
GFA per energy transmitted ($/MWh)	84.1	75.8	83.2	73.7	94.5	75.6
GFA per System Peak Capacity ($000/MW)	524	466	534	466	545	454
Total cost per Energy Transmitted ($/MWh)	10.5	9.5	11.7	10.0	12.0	9.8
Total Cost per System Peak Capacity ($/MW)	65.4	58.6	75.5	63.6	68.9	59.2

COPE NOTES:

The Composite is a Three Year Trend and therefore includes only those utilities that participated in that KPI for the 3 year period

The F2007 CEA COPE study included AltaLink Management, BC Transmission Corporation, Hydro One, TransEnergie, Manitoba Hydro, New Brunswick Power, Newfoundland Power, Nova Scotia Power, and SaskPower although utilities might not participate in every KPI (i.e., the composite might be a subset of the utilities listed)

CEA BES Reliability Results	
TSAIDI (hrs /delivery point)	CEA BES Reliability Results are provided in Section 3 Figures 3-17, 3-20, and 3-21.
TSAIFI (# of sustained interruptions /delivery point)	
TSAIFI - MI (# of momentary interruptions /delivery point)	

BES NOTES:

The C2006 CEA BES Composite includes: AltaLink Management, ATCO, BC Transmission, EPCOR, Hydro One, TransEnergie, Manitoba Hydro, New Brunswick Power, Newfoundaland & Labrador Hydro, and SaskPower

CEA Occupational Health and Safety Report Key Performance Indicators	F2007		F2006		F2005	
	BCTC	CEA Composite	BCTC	CEA Composite	BCTC	CEA Composite
Lost-Time Injury Frequency Rate	0	0.67	0	0.79	0	0.8
Lost-Time Injury Severity Rate	0	13.7	0	17.6	0	17.67
All Injury / Illness Frequency Rate	0.31	2.88	0	2.84	0.34	2.76
Recordable Injury Frequency Rate	0.31	3.09	0	2.95	0.69	2.84
Recordable Injuries / Illnesses	1	1474	0	1322	2	1261
Restricted Days Severity Rate	0	33.84	0	26.65	0	23.74

OHS NOTES:

Due to the nature of the strategic partnerships with service providers, the BCTC values may not be comparable to the CEA Composite because most utilities included in the composite have field staff whereas BCTC is not required to report the contractor safety incidents

Appendix F

International Transmission Operations and Maintenance Study (ITOMS) Benchmarking Results

Overview

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

The ITOMS Consortium

The International Transmission Operations & Maintenance Study (ITOMS) was initiated in 1994 as a consortium of interested international transmission companies as a means of comparing performance and practices within the transmission industry worldwide. The consortium requested that UMS Group facilitate and provide program management and analysis expertise to conduct the study. The program has enabled in-depth comparisons to be made in this area, and has facilitated the exchange of information and ideas on performance improvements and innovative working practices. As a result of these mutually beneficial exchanges, the participants have a developing understanding of the best practices in their field.

Reference: ITOMS 2007 Participation Agreement

Data Revision Date:	1/13/2008		
Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

This Meeting Is One in a Series of Individual and Group Workshops

Decide Objectives, Methods & Timetable

Design Review Meetings April, November 2006

- Confirm scope for 2007 Program
- Review strengths and weaknesses of 2005 program
- Rework 2007 Practices Questionnaire

Learn about Company-specific Strengths & Concerns

Orientation/ Practices Interviews June-Sept 2007

- Review data collection materials
- Discuss practices in place during study year
- Understand organizational designs and industry forces at place

Present Performance Baseline & Comparison

Data Validation Workshop October 2007

- Review preliminary benchmarking data
- Clarify definitional issues
- Work through individual anomalies
- Set direction for Results Materials and Year 2007/08 Workshops

Summarize Program Performance & Best Practice Findings

Practices Workshop May 2008

- Assess strategic implications for 2007 Program
- Create energy and momentum for change
- Learn about best practices implemented by peer group participants

Customize & Focus Results

On-site Results Workshops (Optional) June-October 2008

- Broaden client audience
- Assess internal processes
- Present targeted practices and process recommendations
- Gap analysis (report in local currency)
- Trending comparisons

The ITOMS Program Is Predicated On The Collection And Analysis Of Valid And Defensible Data

• The project was managed by UMS group for the consortium. UMS Group is a management consultancy whose expertise lies in performance measurement of the electric utility industry. UMS has led the ITOMS Program previously in 2005, 2003, 2001, 1999, 1997, 1995 and 1994.

• The ITOMS project was developed by a 4 member Steering Group, made up of employees of organizations representing each of the global regions involved. The Steering Group plays a significant role in creating and approves the final project scope, schedule, and data collection materials. The Steering Group members provided direction and oversight for the program and worked closely with UMS to resolve data validation and collection issues.

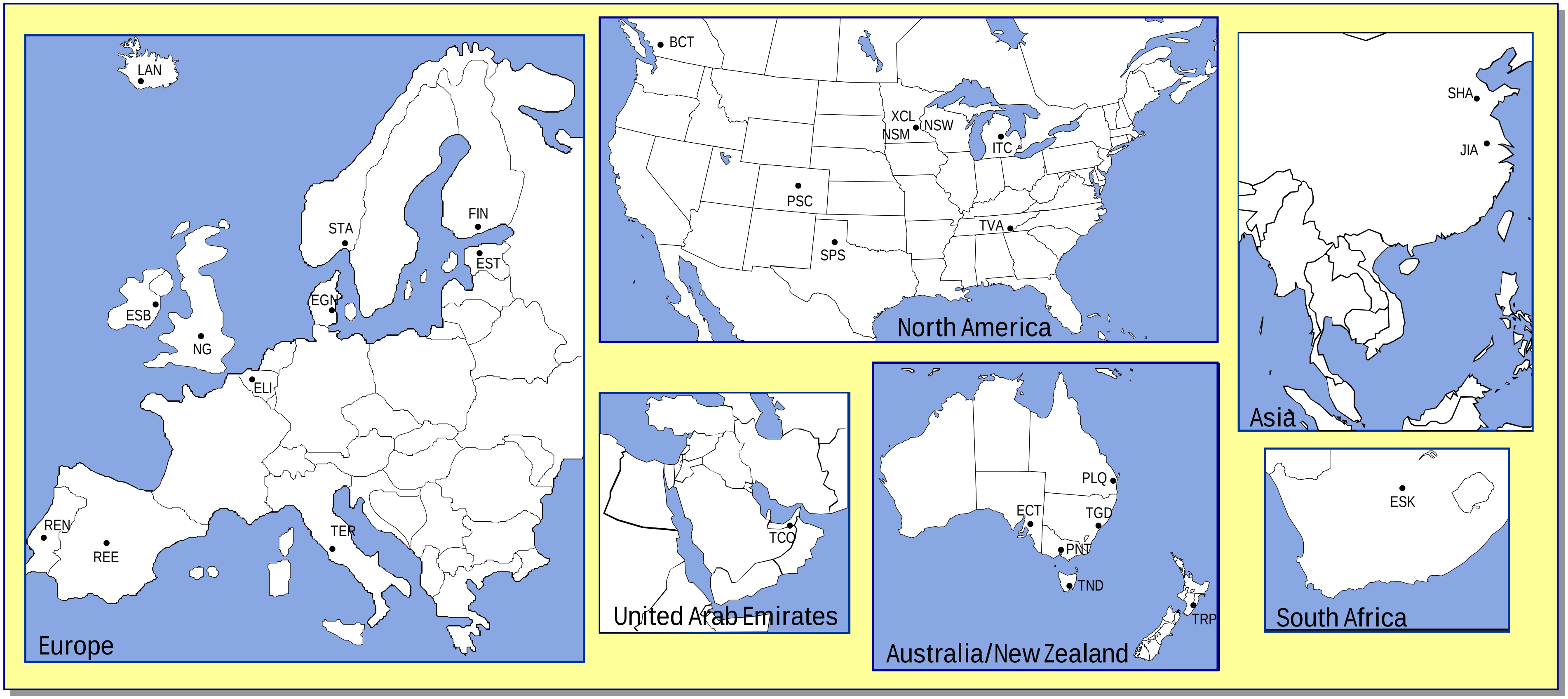
• Performance data was collected via the new UMS Group on-line web tool.

•Data collection was scheduled over a 5 month period. Historically, this has allowed participants sufficient time to collect data and, if they preferred, to use the most relevant financial year (as opposed to a strict calendar year).

• The ITOMS 2007 Program continued to employ a stringent QA/QC process developed during the 2001 program year. This process involves the Steering Group and external audits of UMS materials, and documented ITOMS process guides. All data submittals were documented for receipt and data versions were tracked using an automated document control format.

• At the Data Validation Workshop, the Steering Group and UMS assessed the validity of the data submitted during the data collection period. This Workshop involved conference calls with all participants to discuss a prepared list of concerns. Participants addressed all data validation concerns following the Workshop, prior to publishing final results.

Conference Calls Have Been Coordinated With the Participant Group to Communicate Data Validation Issues



North America

BCT	British Columbia Transmission Co.
ITC	International Transmission Co.
TVA	Tennessee Valley Authority
NSM	Northern States Power Minnesota
NSW	Northern States Power Wisconsin
PSC	Public Service Company of Colorado
SPS	Southwestern Public Service Co.
XCL	Xcel Energy

Europe/Scandinavia

ELI	Elia	NG	National Grid
EGN	Energinet dk	REE	Red Eléctrica de España
ESB	ESB National Grid	REN	Rede Eléctrica Nacional, S.A.
EST	Estonia OÜ Põhivõrk	STA	Statnett
FIN	Fingrid Oyj	TER	Terna S.p.A.
LAN	Landsnet		

Australia/New Zealand

ECT	Electranet SA
PLQ	Powerlink Queensland
PNT	SP AusNet
TND	Transend
TGD	TransGrid
TRP	Transpower New Zealand

Other

ESK	ESKOM
JIA	Jiangsu Power
SHA	Shandong Power
TCO	TRANSCO

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

ITOMS Company Characteristics

Company	Market Supply System	Service Territory (km2)
ECT	Independent System Operator – Energy Market	150,000
PLQ	Independent System Operator – Energy Market	313,000
PNT	Independent System Operator – Energy Market	227,600
TGD	Independent System Operator – Energy Market	803,698
TND	THE TASMANIAN ELECTRICITY SYSTEM IS GOVERNMENT OWNED (NATIONALISED GENERATION AND TRANSMISSION) BUT IS REGULATED ACCORDING TO A 'PRIVATISED GENERATION AND TRANSMISSION' MODEL. TRANSEND HAS ENTERED THE NATIONAL ELECTRICITY MARKET, WHICH IS AN 'INDEPENDENT	64,100
TRP	Nationalized Grid with Energy Market Pool	266,171
BCT	Independent System Operator – Energy Market	422,500
ITC	Independent System Operator – Energy Market	19,700
TVA	FEDERAL GOV'T OWNED TRANSMISSION AND GENERATION SYSTEMS	207,199
FIN	Independent System Operator – Energy Market	336,592
STA	TSO - TRANSMISSION SYSTEM OPERATOR + NORDIC ENERGY MARKET.	323,802
LAN	Nationalized Grid with Energy Market Pool	103,000
ESB	Independent System Operator – Energy Market	67,600
NG	PRIVATISED GENERATION, TRANSMISSION AND DISTRIBUTION. SYETEM OWNER AND OPERATOR, WITH ENERGY MARKET.	151,189
ELI	TRANSMISSION BUSINESS AND SYSTEM OPERATION ARE GROUPED IN ONE COMPANY (ELIA S.A.), WHICH IS AN INDEPENDENT COMPANY FROM THE GENERATION AND DISTRIBUTION BUSINESS.	30,527
REE	Independent System Operator – Energy Market	506,000
REN	PRIVATIZED GENERATION WITH TRANSMISSION OWNED BY THE STATE (MAJORITY OF CAPITAL).	89,348
EST	INDEPENDENT SYSTEM OPERATOR	45,227
EGN	IN PRACTICE, THE GRID IS NATIONALIZED AND WE DO OPERATE WITH AN ENERGY MARKET POOL (NORDPOOL COVERING NORWAY, SWEDEN, FINLAND AND DENMARK). HOWEVER THE MAJORITY OF THE PRODUCTION CAPACITY (MORE THAN 75%)IN DENMARK IS OWNED BY TWO COMPANIES: DONG ENERGY -	43,000
TER	PRIVATE TSO WITH ENERGY MARKET POOL	301,338
ESK	Nationalized Grid with Energy Market Pool	1,221,037
TCO	51% GOVERNMENT GENERATION 49% PRIVITIZATION	66,525
NSM	Independent System Operator – Energy Market	0
NSW	Independent System Operator – Energy Market	0
PSC	Privatized Generation and Transmission Systems	0
SPS	Privatized Generation and Transmission Systems	0
JIA	Independent System Operator – Energy Market	Approx. 102,000
SHA	Independent System Operator – Energy Market	Approx. 153,000

Data Revision Date: 1/13/2008

No Data: XCL

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

ITOMS Asset Characteristics

Company	Overhead Line Transmission Structures > 60kV	Overhead Line Transmission Circuit Km > 60kV	Circuit Ends > 60kV	Substations & Switching Stations > 60kV	3 Phase Unit & 3 Phase Eq. Transformers > 60kV
ECT	13,352	5,681	408	76	138
PLQ	21,371	12,115	891	103	188
PNT	13,004	6,360	527	45	184
TGD	36,543	12,725	1,058	90	184
TND	8,031	3,609	315	55	105
TRP	38,402	16,172	1,008	167	338
BCT	68,518	18,953	1,568	363	579
ITC	17,440	4,261	619	89	63
TVA	102,214	25,204	1,797	536	255
FIN	48,101	14,019	1,001	106	75
STA	31,011	11,216	871	125	165
LAN	9,167	1,850	167	33	14
ESB	26,017	6,430	1,082	145	48
NG	22,100	13,955	3,615	409	765
ELI	20,061	8,947	2,464	451	868
REE	70,033	33,058	2,763	383	108
REN	15,679	6,996	922	59	138
EST	18,974	5,171	561	149	250
EGN	3,639	1,818	158	24	46
TER	104,711	38,420	4,194	426	577
ESK	75,285	27,755	2,258	160	456
TCO	4,495	3,843	615	74	231
NSM	68,853	8,231	299	96	100
NSW	33,757	3,564	94	32	41
PSC	34,804	5,971	193	105	58
SPS	63,960	11,395	304	135	120
JIA	106,190	35,937	6,157	1162	1910
SHA	68,270	23,251	3,470	493	872
XCL	201,375	29,161	890	368	319

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

The ITOMS Framework Provides Comprehensive And Understandable Measures Of Performance Across Cost And Service Level In Several Key Sub-Areas Of Your Transmission Business To Give An Accurate And Detailed Assessment Of Performance

Measurement Framework: Transmission Maintenance

Activity	Productivity Measures	Service Level Measure
Overhead Line Maintenance 60-99 kV	• Overhead Line Maintenance Spending 60-99 kV Per Circuit Km • Overhead Line Maintenance Spending 60-99 kV Per Equivalent Circuit Km* • Overhead Line Maintenance Spending 60-99 kV Spending Per Structure • Overhead Line Maintenance Spending 60-99 kV Spending Per Equivalent Structure	• 60-99 kV Overhead Line Forced and Fault Outages Per 60-99 kV Circuit Km* • 60-99 kV Overhead Line Forced and Fault Outages Per 60-99 kV Structure
Overhead Line Maintenance 100-199 kV	• Overhead Line Maintenance Spending 100-199 kV Per Circuit Km • Overhead Line Maintenance Spending 100-199 kV Per Equivalent Circuit Km* • Overhead Line Maintenance Spending 100-199 kV Spending Per Structure • Overhead Line Maintenance Spending 100-199 kV Spending Per Equivalent Structure	• 100-199 kV Overhead Line Forced and Fault Outages Per 100-199 kV Circuit Km* • 100-199 kV Overhead Line Forced and Fault Outages Per 100-199 kV Structure
Overhead Line Maintenance 200+ kV	• Overhead Line Maintenance Spending 200+ kV Per Circuit Km • Overhead Line Maintenance Spending 200+ kV Per Equivalent Circuit Km* • Overhead Line Maintenance Spending 200+ kV Spending Per Structure • Overhead Line Maintenance Spending 200+ kV Spending Per Equivalent Structure	• 200+ kV Overhead Line Forced and Fault Outages Per 200+ kV Circuit Km* • 200+ kV Overhead Line Forced and Fault Outages Per 200+ kV Structure *
Patrol & Inspections 60-99 kV	• Patrol & Inspection 60-99 kV Spending Per Circuit Km • Patrol & Inspection 60-99 kV Spending Per Equivalent Circuit Km* • Patrol & Inspection 60-99kV Spending Per Structure • Patrol & Inspection 60-99kV Spending Per Equivalent Structure	• 60-99 kV Overhead Line Forced and Fault Outages Per 60-99 kV Circuit Km* • 60-99 kV Overhead Line Forced and Fault Outages Per 60-99 kV Structure
Patrol & Inspections 100-199 kV	• Patrol & Inspection 100-199 kV Spending Per Circuit Km • Patrol & Inspection 100-199 kV Spending Per Equivalent Circuit Km* • Patrol & Inspection 100-199kV Spending Per Structure • Patrol & Inspection 100-199kV Spending Per Equivalent Structure	• 100-199 kV Overhead Line Forced and Fault Outages Per 100-199 kV Circuit Km* • 100-199 kV Overhead Line Forced and Fault Outages Per 100-199 kV Structure

Data Revision Date: 1/13/2008

* Indicates that these measures are used for the composite analysis

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Measurement Framework: Transmission Maintenance Continued

Activity	Productivity Measures	Service Level Measure
Patrol & Inspections 200+ kV	• Patrol & Inspection 200+ kV Spending Per Circuit Km • Patrol & Inspection 200+ kV Spending Per Equivalent Circuit Km * • Patrol & Inspection 200+ kV Spending Per Structure • Patrol & Inspection 200+ kV Spending Per Equivalent Structure	• 200+ kV Overhead Line Forced and Fault Outages Per 200+ kV Circuit Km* • 200+ kV Overhead Line Forced and Fault Outages Per 200+ kV Structure
Right-of-Way Maintenance	• Right-of-Way Maintenance Spending Per Vegetation Exposed Right-of-Way Hectare • Right-of-Way Maintenance Spending Per Equivalent Vegetation Exposed Right-of-Way Hectare	• Vegetation Caused Forced and Fault Outages Per Vegetation Exposed Right-of-Way Hectare

Measurement Framework: Substation Operations & Maintenance

Activity	Productivity Measures	Service Level Measure
Relay, SCADA & Communications System Maintenance	• Relay, SCADA & Communications Spending Per Scheme • Relay, SCADA & Communications Spending Per Equivalent Scheme *	• Relay, SCADA & Communications Forced and Fault Outages Per Scheme *
Circuit Breaker Maintenance – 60-99 kV	• Circuit Breaker Maintenance Spending 60-99 kV Per Breaker • Circuit Breaker Maintenance Spending 60-99 kV Per Equivalent Breaker*	• 60-99 kV Breaker Forced And Fault Outages Per 60-99 kV Breaker*
Circuit Breaker Maintenance – 100-199 kV	• Circuit Breaker Maintenance Spending 100-199 kV Per Breaker • Circuit Breaker Maintenance Spending 100-199 kV Per Equivalent Breaker *	• 100-199 kV Breaker Forced And Fault Outages Per 100-199 kV Breaker*
Circuit Breaker Maintenance – 200+ kV	• Circuit Breaker Maintenance Spending 200+ kV Per Breaker • Circuit Breaker Maintenance Spending 200+ kV Per Equivalent Breaker*	• 200+ kV Breaker Forced And Fault Outages Per 200+ kV Breaker*
Transformer Maintenance – 60-99kV	• Transformer Maintenance Spending 60-99 kV Spending Per Transformer • Transformer Maintenance Spending 60-99 kV Spending Per Equivalent Transformer*	• 60-99 kV Transformer Forced And Fault Outages Per 60-99 kV Transformer*

Data Revision Date: 1/13/2008

* Indicates that these measures are used for the composite analysis

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Measurement Framework: Substation Operations & Maintenance Continued

Activity	Productivity Measures	Service Level Measures
Transformer Maintenance – 100-199kV	• Transformer Maintenance Spending 100-199 kV Spending Per Transformer • Transformer Maintenance Spending 100-199 kV Spending Per Equivalent Transformer*	• 100-199 kV Transformer Forced And Fault Outages Per 100-199 kV Transformer*
Transformer Maintenance – 200+ kV	• Transformer Maintenance Spending 200+ kV Spending Per Transformer • Transformer Maintenance Spending 200+ kV Spending Per Equivalent Transformer*	• 200+ kV Transformer Forced And Fault Outages Per 200+ kV Transformer*
Compensation Equipment Maintenance	• Compensation Equipment Maintenance Spending Per Equivalent Compensation Device *	• Compensation Equipment Forced And Fault Outages Outage Per Compensation Device *
Disconnector & Earth Switch Maintenance	• Disconnector & Earth Switch Maintenance Spending Per Switch/ Disconnector • Disconnector & Earth Switch Maintenance Spending Per Equivalent Switch/ Disconnector *	• Disconnector & Earth Switch Maintenance Forced And Fault Outages Per Switch/Disconnector*
Instrument Transformer & Other Circuit End Equipment Maintenance	• Instrument Transformer & Other Circuit End Equipment Maintenance Spending Per Instrument Transformer *	• Instrument Transformer & Other Circuit End Equipment Forced And Fault Outages Per Instrument Transformer
Substation Site & Auxiliary Equipment Maintenance	• Substation Site Maintenance Per Substation & Switching Station* • Auxiliary Equipment Maintenance Per Circuit End *	• Substation Site Forced And Fault Outages Per Circuit End*
Substation Field Operations	• Substation Field Switching Operations Spending Per Circuit End *	• Field Switching Errors Per Switching Operations • Field Switching Errors Per Circuit End*

Data Revision Date:	1/13/2008

* Indicates that these measures are used for the composite analysis

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Description of Outliers

- "Outliers" are data points on a chart that are outside the peer group range. An outlier may be a high or low outlier. Being marked as an outlier does not mean that the data is suspect, but rather that it is either so high or so low that it skews the average.
- The criteria for determining whether a data point is an outlier is if the one data point can significantly alter the average, will extend the chart such that it is difficult to read the majority of the data points which end up squeezed together, or that are more than two standard deviations from the average.

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Composite Benchmark Methodology

Composite Benchmark Methodology

Each company's composite benchmark position is derived by calculating a composite cost score (ranging from 0 to 2, where a 2 is indicative of high cost) and a composite service level score (ranging from 0 to 2, where 2 is indicative of strong service level performance).

Calculating the Composite Cost Score for each sub-function:

For each sub-functional area included in the scatter (e.g. the Overhead Transmission Line Maintenance composite benchmark includes Overhead Line Patrol & Inspection 60-99 kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99 kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance), the cost per unit for that sub-function is converted into a 0 to 2 score. The relative 0 to 2 score is calculated by comparing the company's cost per unit metric against the metrics of the rest of the peer group. The highest cost per unit company will receive a 2 score and the lowest cost per unit company will receive a 0 score. All other companies will be spread out on the scale between this 0 and 2 range.

Calculating the Composite Service Level Score for each sub-function:

Similar to the composite cost calculation, a composite service level score is calculated for each sub-functional area included in the composite benchmark scatter (e.g. the Overhead Transmission Line Maintenance composite benchmark includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance). The service level metric for each sub-function is converted into a relative score on a 0 to 2 scale, where 2 indicates strong service level performance. Again, this relative 0 to 2 score is calculated by comparing the company's service level performance for a particular sub-function vs. the performance of the rest of the peer group. The company with the strongest service level performance will receive a 2 score and the company with the worst service level performance will receive a 0 score. All other companies will be spread out on the scale between this 0 and 2 range.

Composite Benchmark Methodology

Calculating the Overall Composite Cost Score for each company:

Once a 0 to 2 cost score is calculated for each sub-function , an overall composite score (again on a 0 to 2 scale) is calculated by weighting each individual cost composite score by that sub-function's relative importance, based on percentage of total cost. (Please note: if a company has some costs for a sub-function, but does not have a cost per unit score (indicating that workload was not reported), this sub-function will not be weighted in the calculation). The 2005 program added a second view of the composite that takes a straight average (non-weighted) of each individual cost composite score.

This is an Overall Relative comparison based upon each company's spend for their assets. There is not a specific dollar value gap between each value, it is a relative position.

There is no linear relationship between values. This is a topographical mapping of a relationship relative to the rankings, not the data.

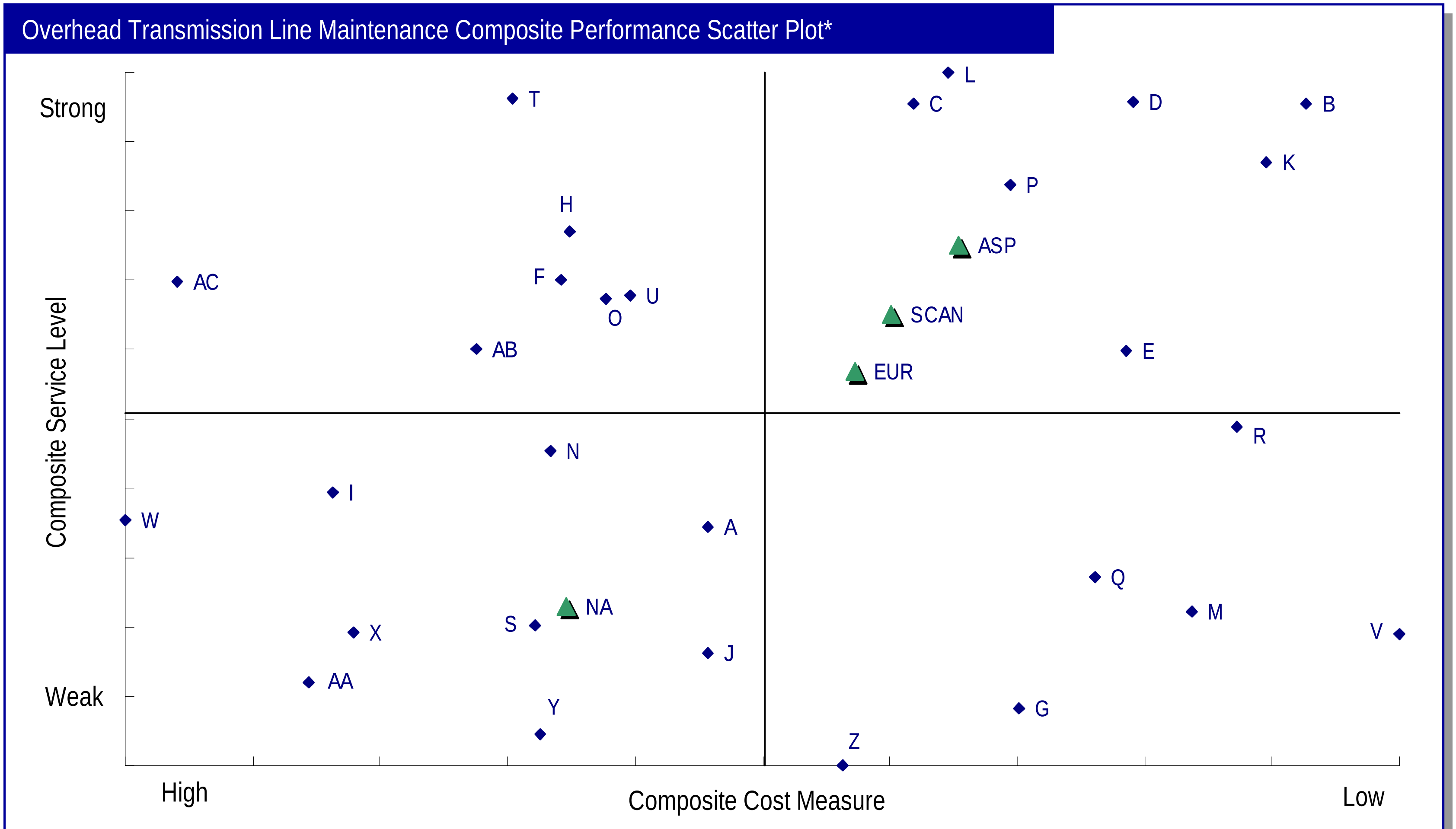
Calculating the Overall Composite Service Level Score for each company:

Once a 0 to 2 service level score is calculated for each sub-function , an overall composite score (again on a 0 to 2 scale) is calculated by weighting each individual service level composite score by that sub-function's relative importance, based on percentage of total cost. (Please note: if a company has some costs for a sub-function, but does not have a service level score (indicating that workload was not reported), this sub-function will not be weighted in the calculation). The 2005 program added a second view of the composite that takes a straight average (non-weighted) of each individual service level composite score.

This is an Overall Relative comparison based upon each company's spend for their assets. There is not a specific dollar value gap between each value, it is a relative position.

There is no linear relationship between values. This is a topographical mapping of a relationship relative to the rankings, not the data.

Transmission Line Maintenance Composite Benchmark – Weighted Average**



**Weighted average indicates that each sub-function component score was weighted by the % spend in that sub-function. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance.

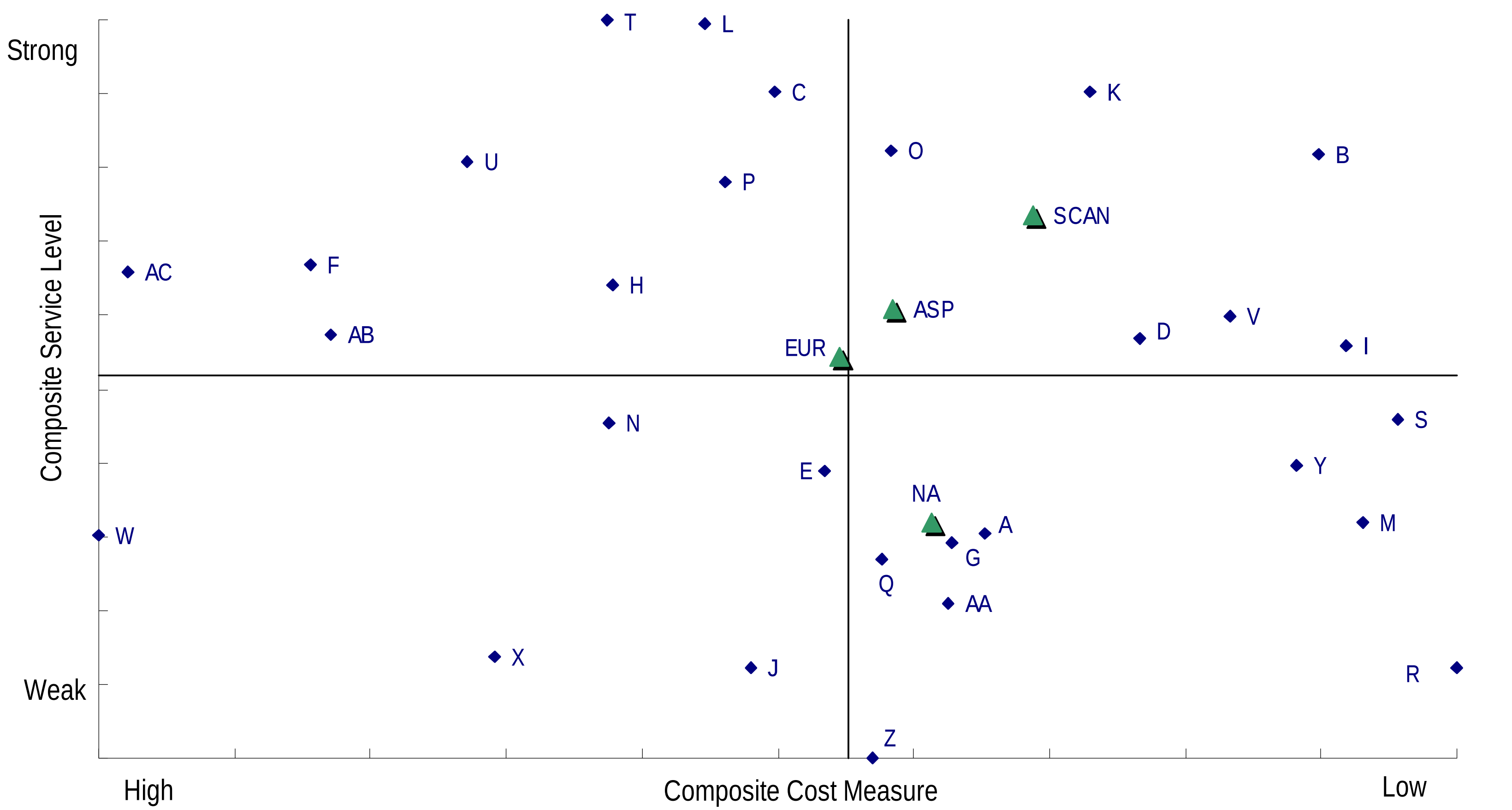
Data Revision Date:	1/13/2008

Average lines indicate the average of the peer group

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Transmission Line Maintenance Composite Benchmark – Non-Weighted Average**

Overhead Transmission Line Maintenance Composite Performance Scatter Plot*



**Non-weighted average indicates that a straight average was taken of each sub-function component score. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance.

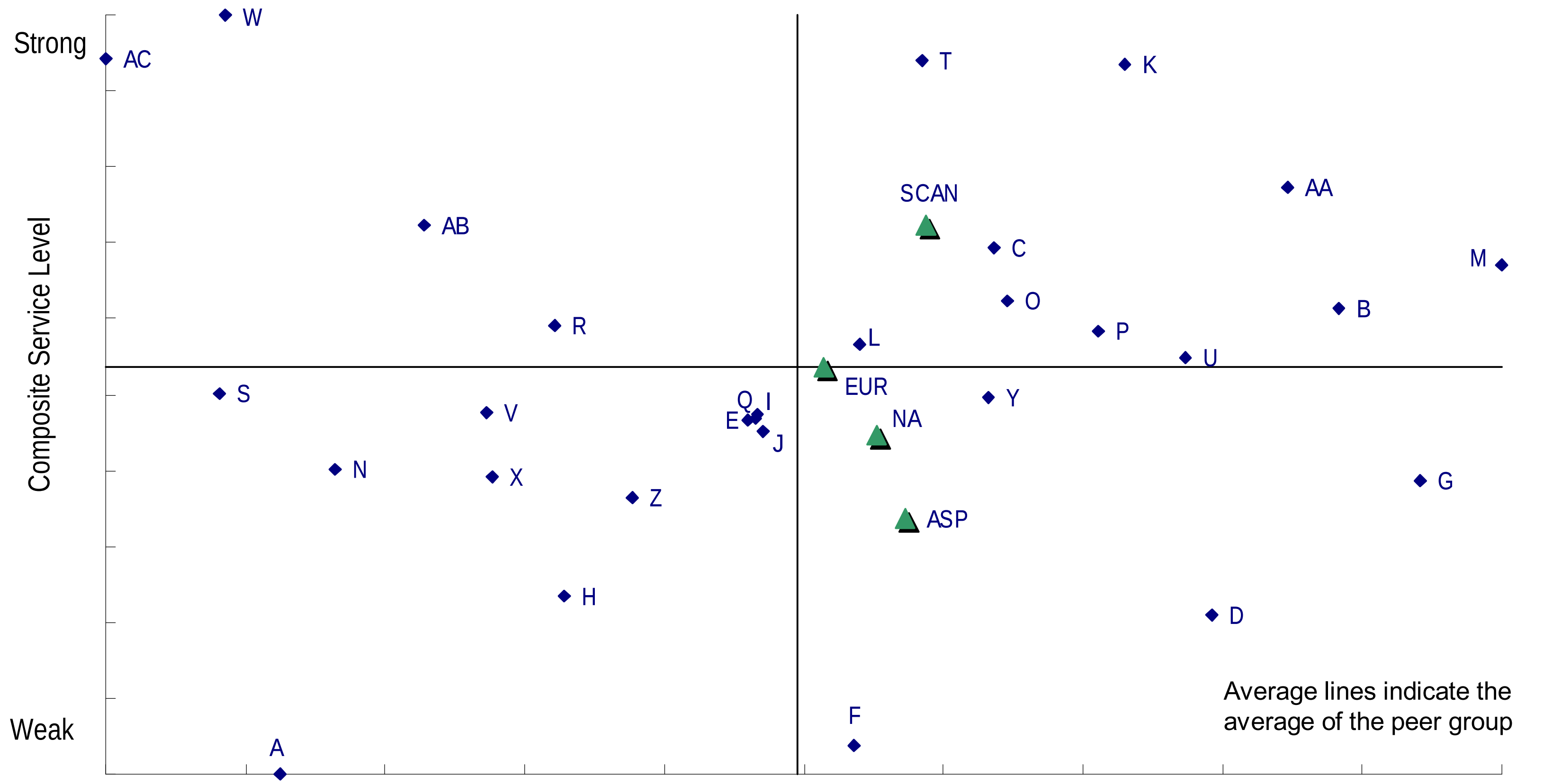
Data Revision Date:	1/13/2008

Average lines indicate the average of the peer group

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Substation Maintenance Composite Benchmark – Weighted Average**

Substation Maintenance Composite Performance Scatter Plot*



**Weighted average indicates that each sub-function component score was weighted by the % spend in that sub-function. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

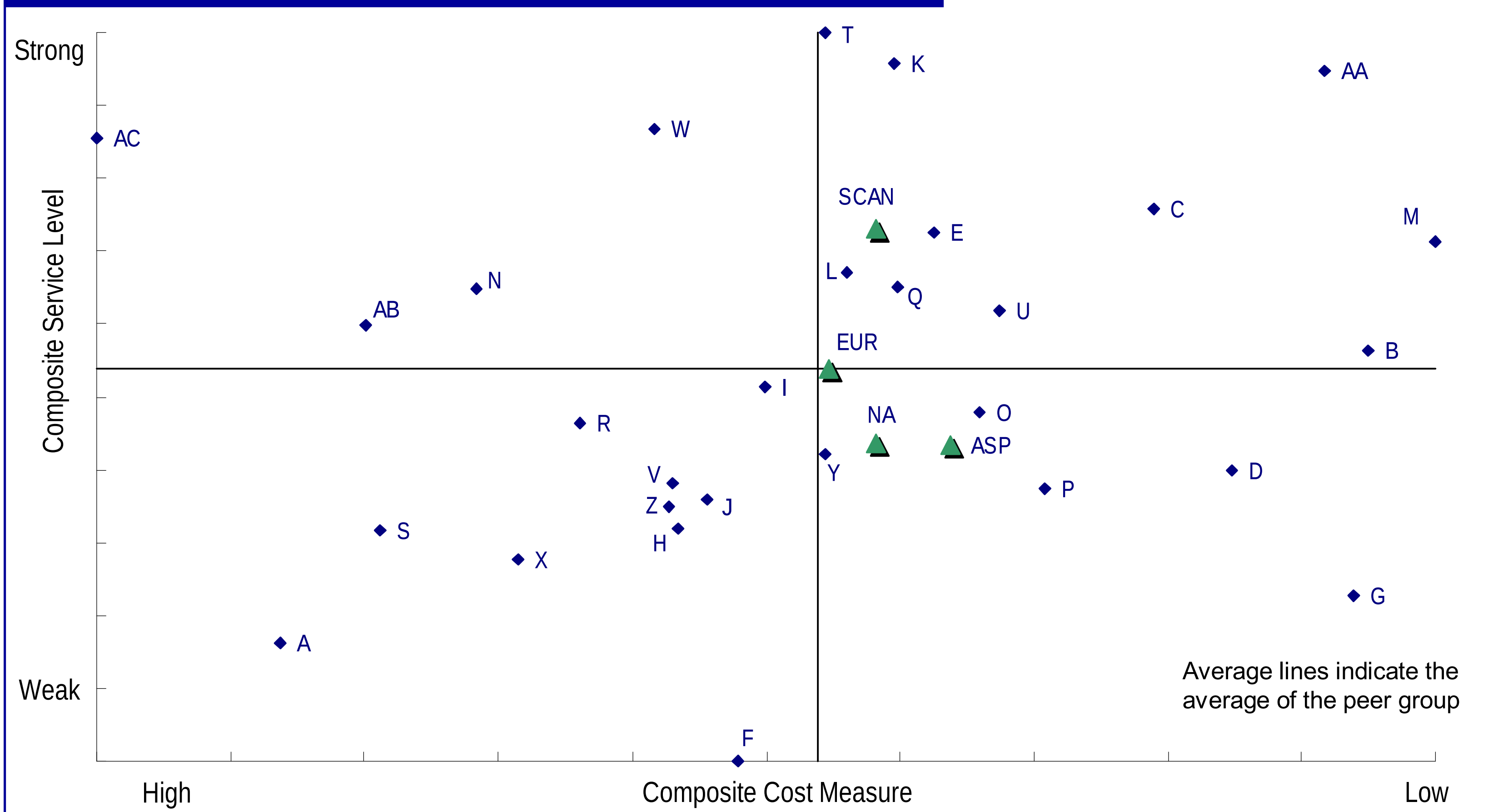
Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Substation Maintenance Composite Benchmark – Non-Weighted Average**

Substation Maintenance Composite Performance Scatter Plot*



**Non-weighted average indicates that a straight average was taken of each sub-function component score. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

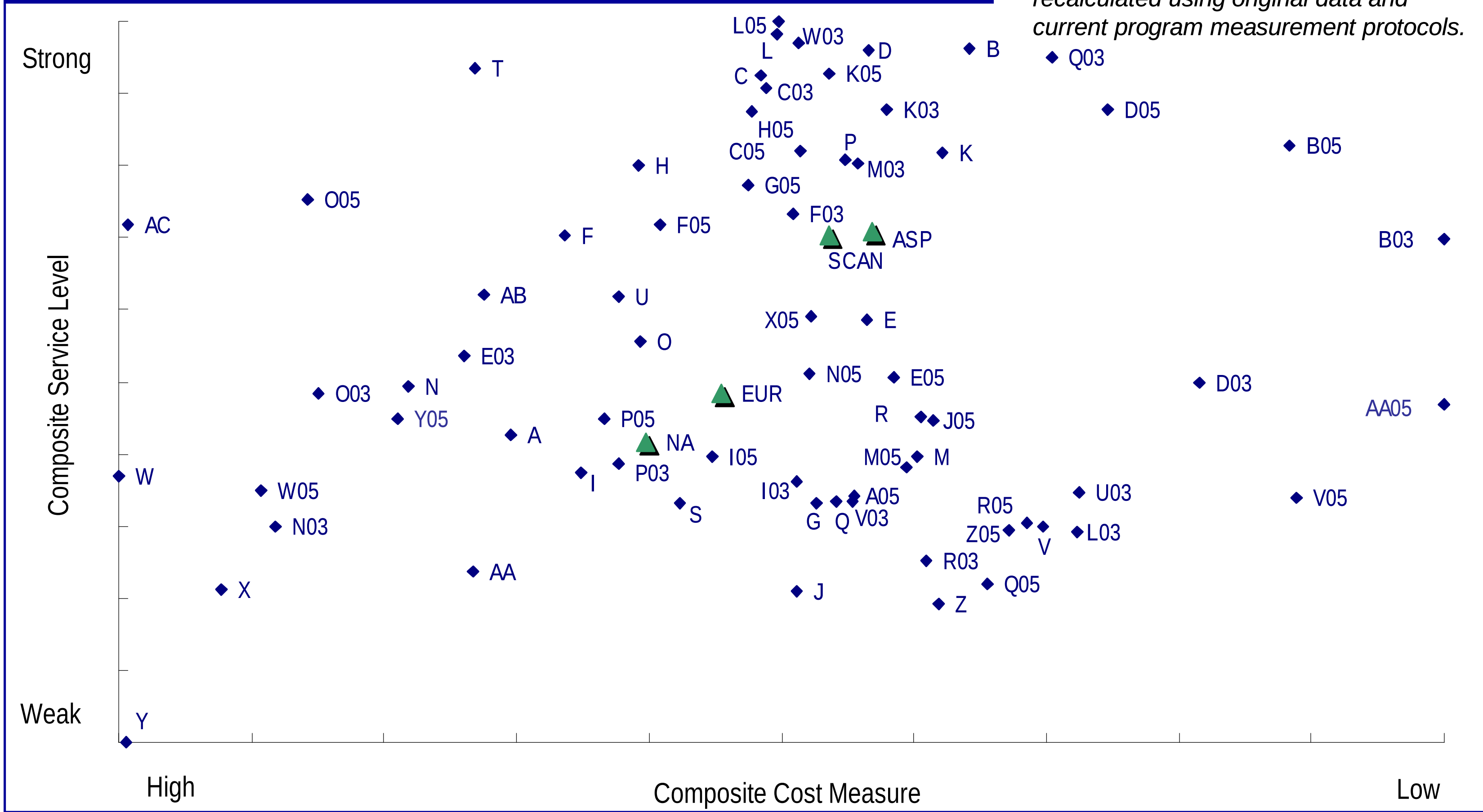
Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Transmission Trend – Weighted Average**

Data points labeled with three letter code represent current study year

Overhead Transmission Line Maintenance Trend Composite Performance Scatter Plot*

Note: Relative performance for each year recalculated using original data and current program measurement protocols.



**Weighted average indicates that each sub-function component score was weighted by the % spend in that sub-function. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Overhead Line Patrol & Inspection 100-199 kV and 200+ kV, Overhead Line Maintenance 100-199 kV and 200+ kV, and Right-of-Way Maintenance.

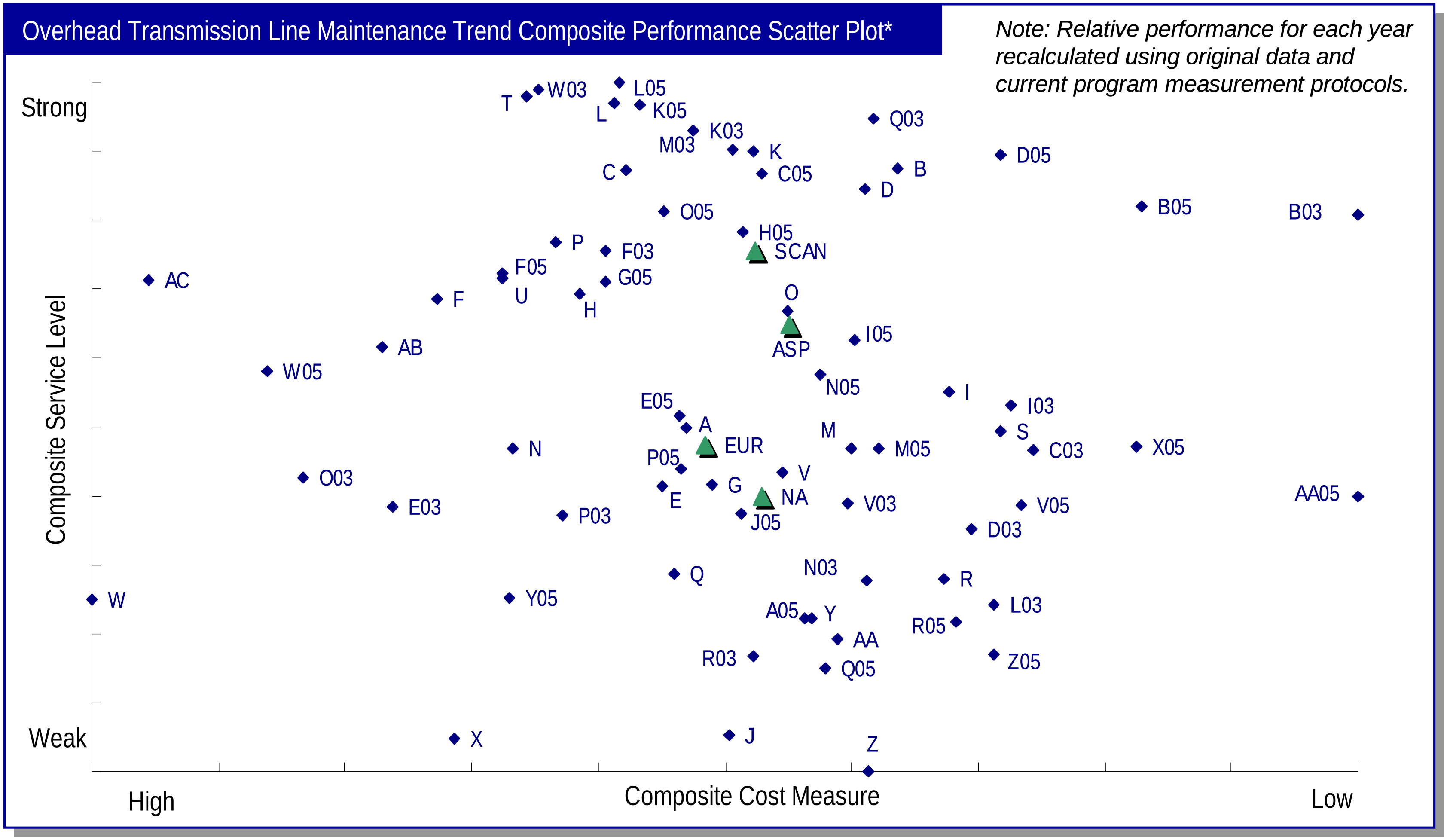
Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Transmission Trend – Non-weighted Average**

Data points labeled with three letter code represent current study year



**Non-weighted average indicates that a straight average was taken of each sub-function component score. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Overhead Line Patrol & Inspection 100-199 kV and 200+ kV, Overhead Line Maintenance 100-199 kV and 200+ kV, and Right-of-Way Maintenance.

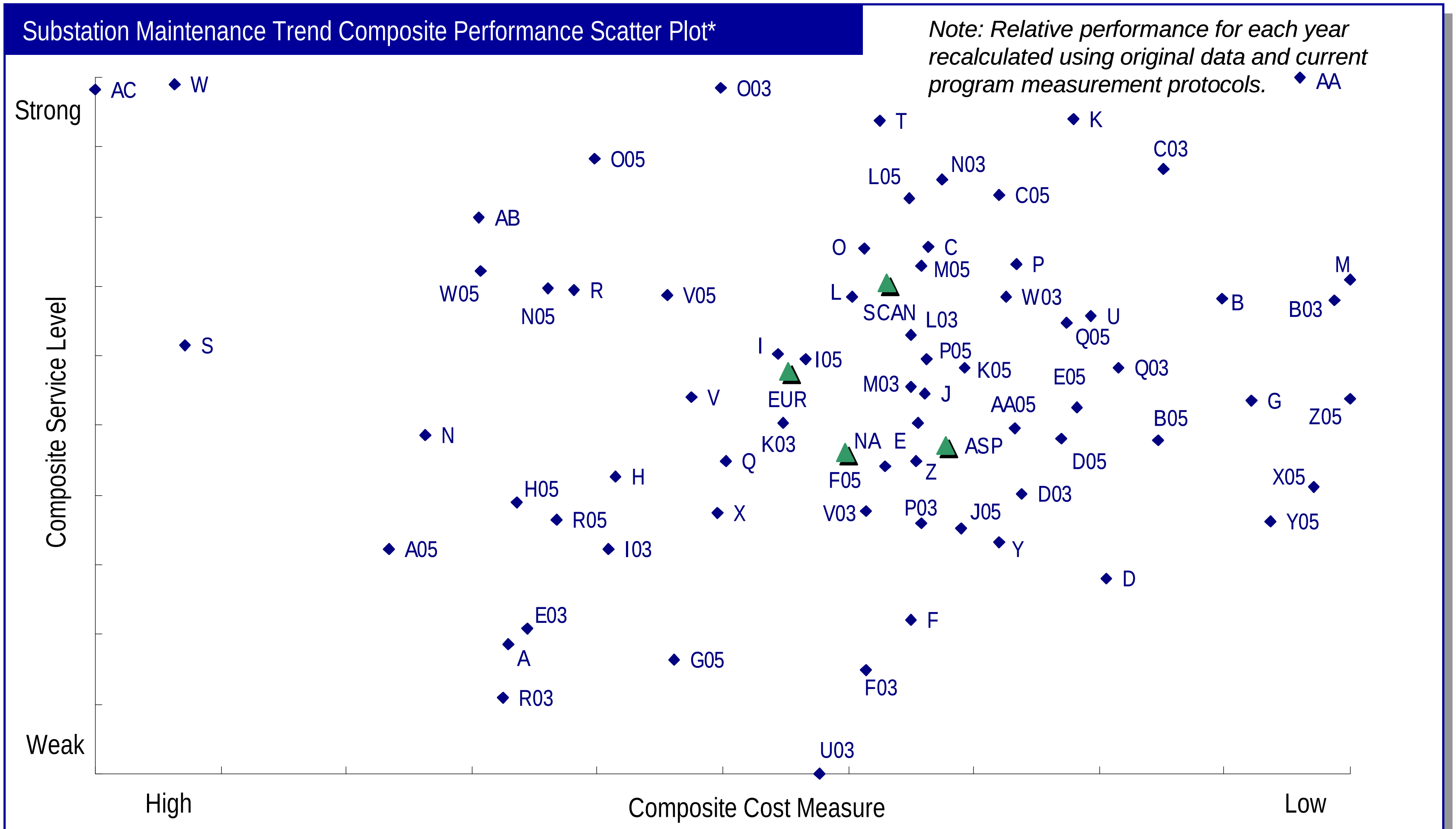
Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Substation Trend – Weighted Average**

Data points labeled with three letter code represent current study year

Comparison using > 100 kV data



**Weighted average indicates that each sub-function component score was weighted by the % spend in that sub-function. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

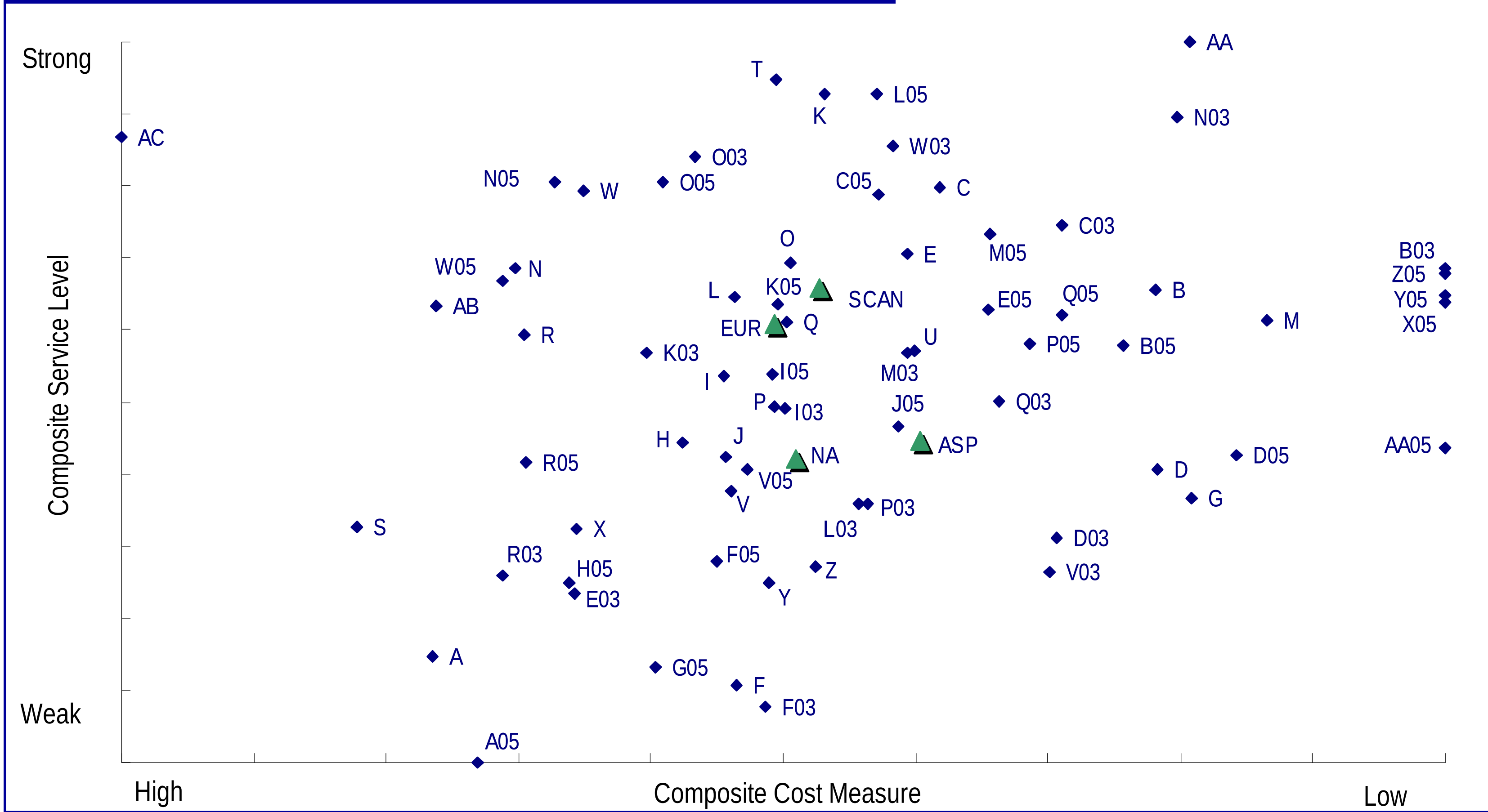
Substation Trend – Non-weighted Average**

Note: Relative performance for each year recalculated using original data and current program measurement protocols.

Data points labeled with three letter code represent current study year

Substation Maintenance Trend Composite Performance Scatter Plot*

Comparison using > 100 kV data



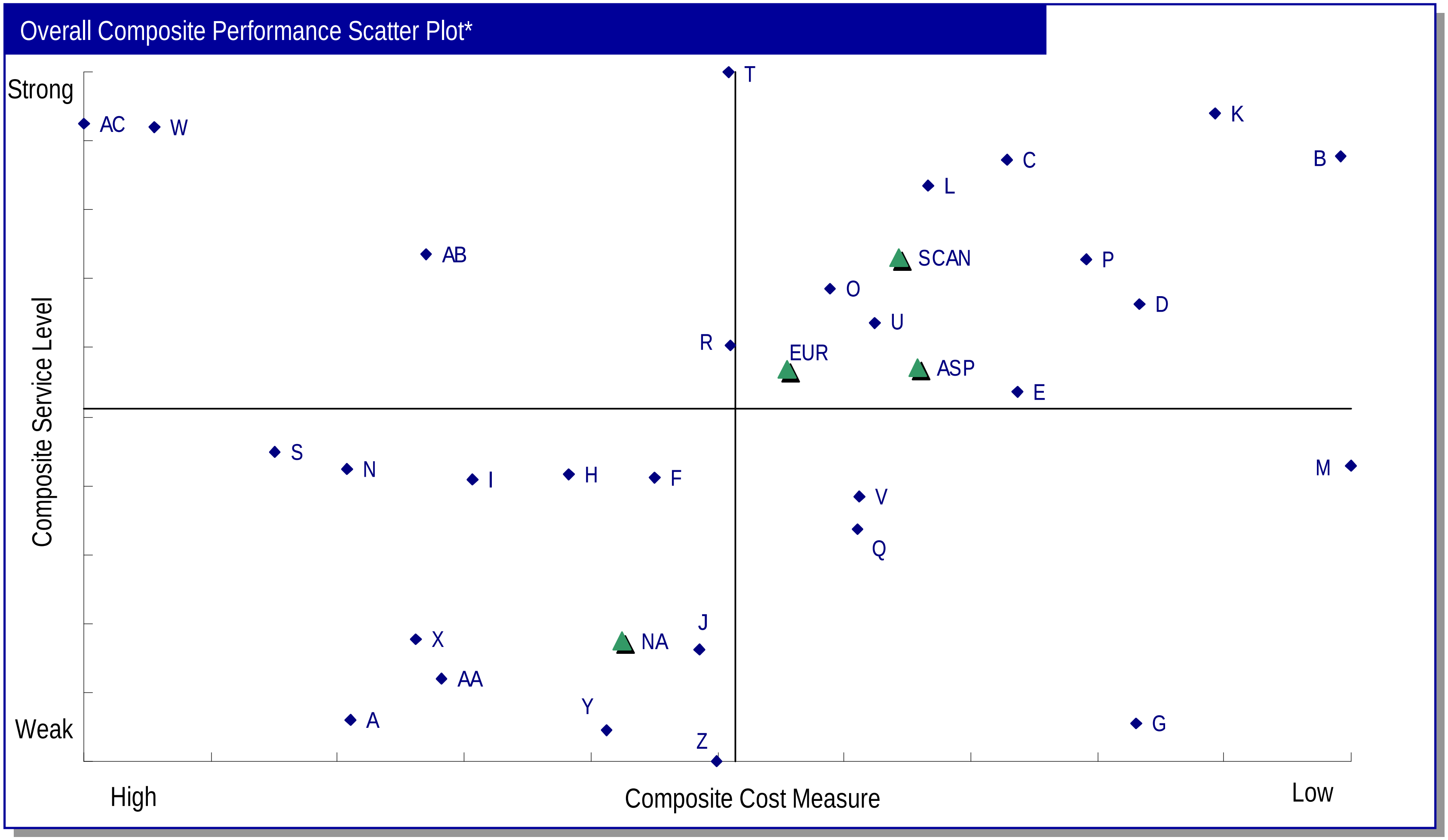
**Non-weighted average indicates that a straight average was taken of each sub-function component score. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Overall Composite Benchmark – Weighted Average**



**Weighted average indicates that each sub-function component score was weighted by the % spend in that sub-function. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

Average lines indicate the average of the peer group

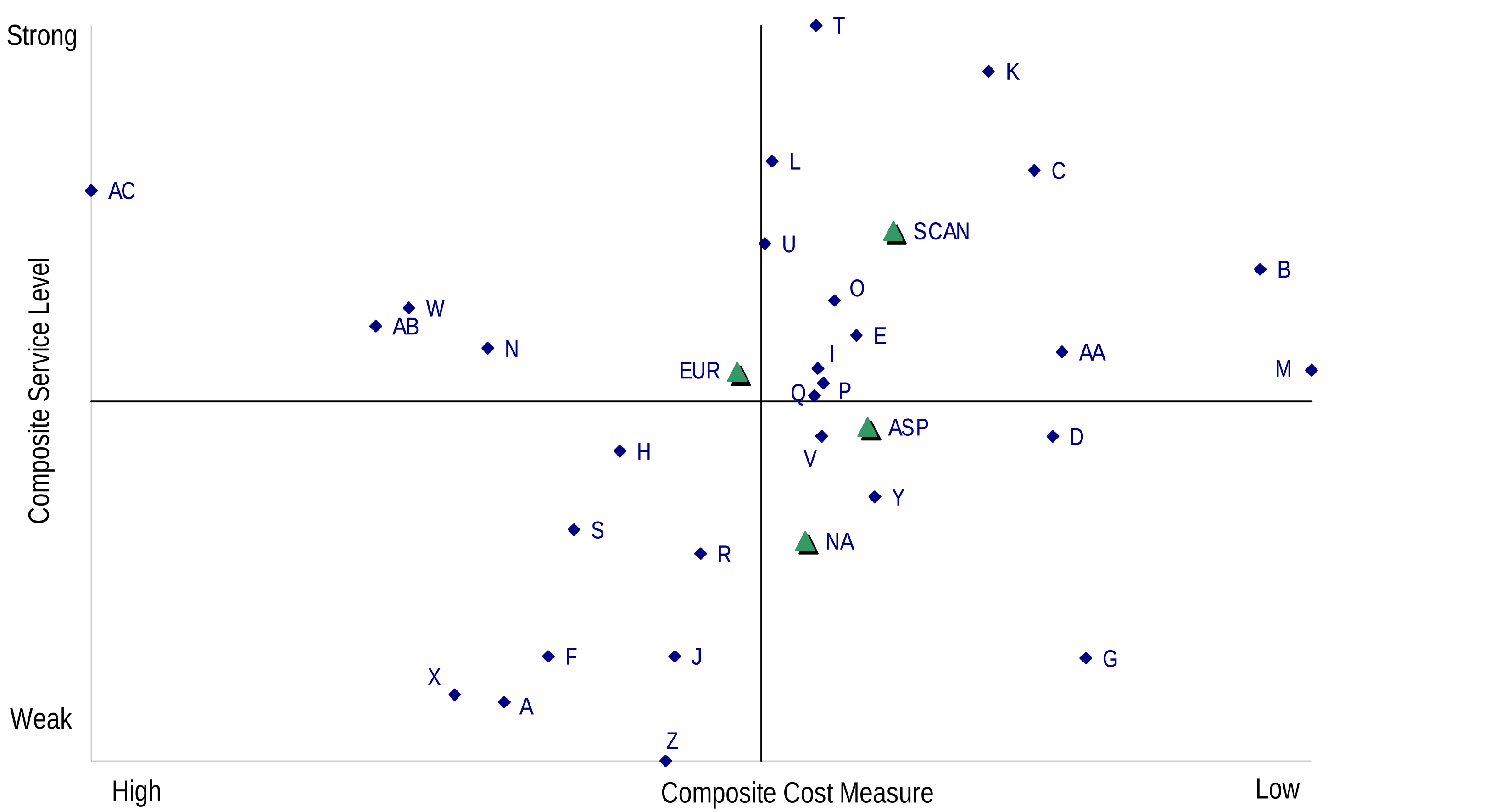
* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance, Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Overall Composite Benchmark – Non-weighted Average**

Overall Composite Performance Scatter Plot*



**Non-weighted average indicates that a straight average was taken of each sub-function component score. See methodology in Overview pages 12-13 and sample calculation in Appendix page 11.

Average lines indicate the average of the peer group

* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, and Right-of-Way Maintenance, Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008
Composite Scatter Analysis Revision Date:	1/10/2008
Overall Charting Revision Date:	2/1/2008

Transmission Top Performing Companies

Overall Transmission Lines Top Performing Companies

Powerlink Queensland (PLQ), Fingrid (FIN), and Transgrid (TGD)

Patrol & Inspect Top Performers

200+KV

Transgrid (TGD)

Tennessee Valley Authority (TVA)

Estonia OÜ Põhivõrk (EST)

100 to 199 KV

Tennessee Valley Authority (TVA)

Fingrid (FIN)

Transgrid (TGD)

60 to 99 KV

ESKOM (ESK)

Elia (ELI)

ROW Maintenance Top Performers

Elia (ELI)

Powerlink Queensland (PLQ)

Fingrid (FIN)

Transgrid (TGD)

ESB (ESB)

Line Maintenance Top Performers

200+ KV

Fingrid (FIN)

Powerlink Queensland (PLQ)

Statnett (STA)

100 to 199 KV

Fingrid (FIN)

Transgrid (TGD)

Tennessee Valley Authority (TVA)

60 to 99 KV

ESKOM (ESK)

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Substation Top Performing Companies

Overall Substation Top Performing Companies

Terna S.p.A (TER) , Landsnet (LAN), Fingrid (FIN), and Powerlink Queensland (PLQ)

Circuit Breaker Top Performers

200+ KV
TRANSCO (TCO) Transend (TND)
Fingrid (FIN)
Red Electricia De Espania (REE)

100 to 199 KV
Energinet dk (EGN) Statnett (STA)
Fingrid (FIN)
Transend (TND)

60 to 99 KV
Terna S.p.A (TER) Statnett (STA)
Tennessee Valley Authority (TVA)

Substation Field Operations Top Performers

S P Ausnet (PNT)
Landsnet (LAN)
National Grid Company (NG)
Terna S.p.A (TER)

Protective Relay Maintenance Top Performers

Energinet (EGN) National Grid (NG)
Fingrid (FIN)

Instrument Transformer Top Performers

Elia (ELI) SP Ausnet (PNT)
Fingrid (FIN) Landsnet (LAN)

Disconnector & Earth Switch Top Performers

Transgrid (TGD) National Grid Company (NG)
Landsnet (LAN) Fingrid (FIN)

Auxiliary Equipment Top Performers

Estonia OÜ Põhivõrk (EST) ESB (ESB)
Powerlink Queensland (PLQ) Elia (ELI)

Power Transformer Top Performers

200+ KV
Landsnet (LAN)
Terna S.p.A (TER) S P Ausnet (PNT)

100 to 199 KV
Landsnet (LAN) Terna S.p.A (TER)
Powerlink Queensland (PLQ)

60 to 99 KV
SP Ausnet (PNT)

Compensation Equipment Top Performers

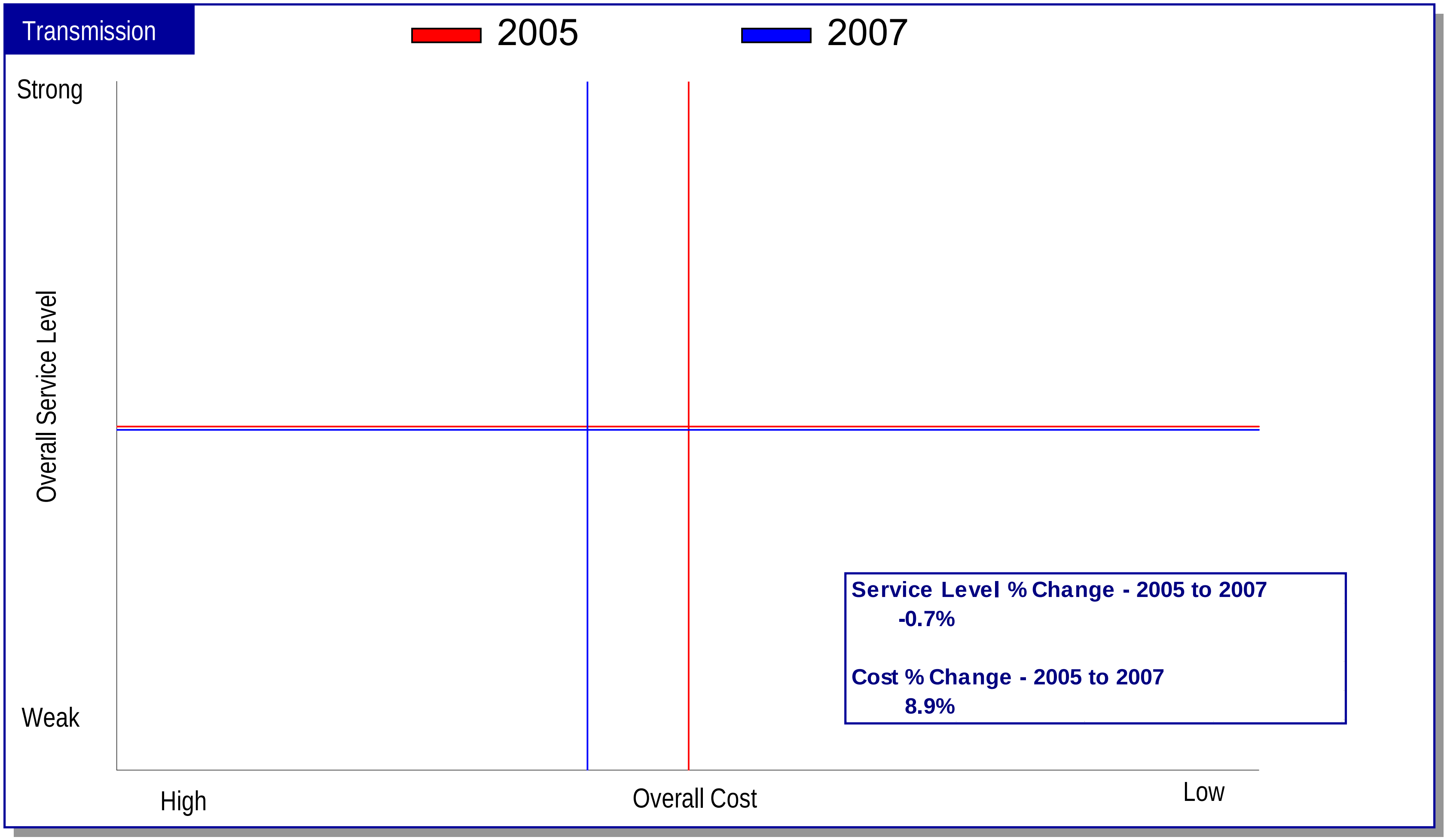
Tennessee Valley Authority (TVA)
Transgrid (TGD)
Powerlink Queensland (PLQ)

Substation Site Top Performers

Powelink Queensland (PLQ)
Elia (ELI)
Red Electricia De Espania (REE)
Landsnet (LAN)

Data Revision Date:	1/13/2008
Composite Scatter Analysis Revision Date:	1/10/2008
Overall Charting Revision Date:	2/1/2008

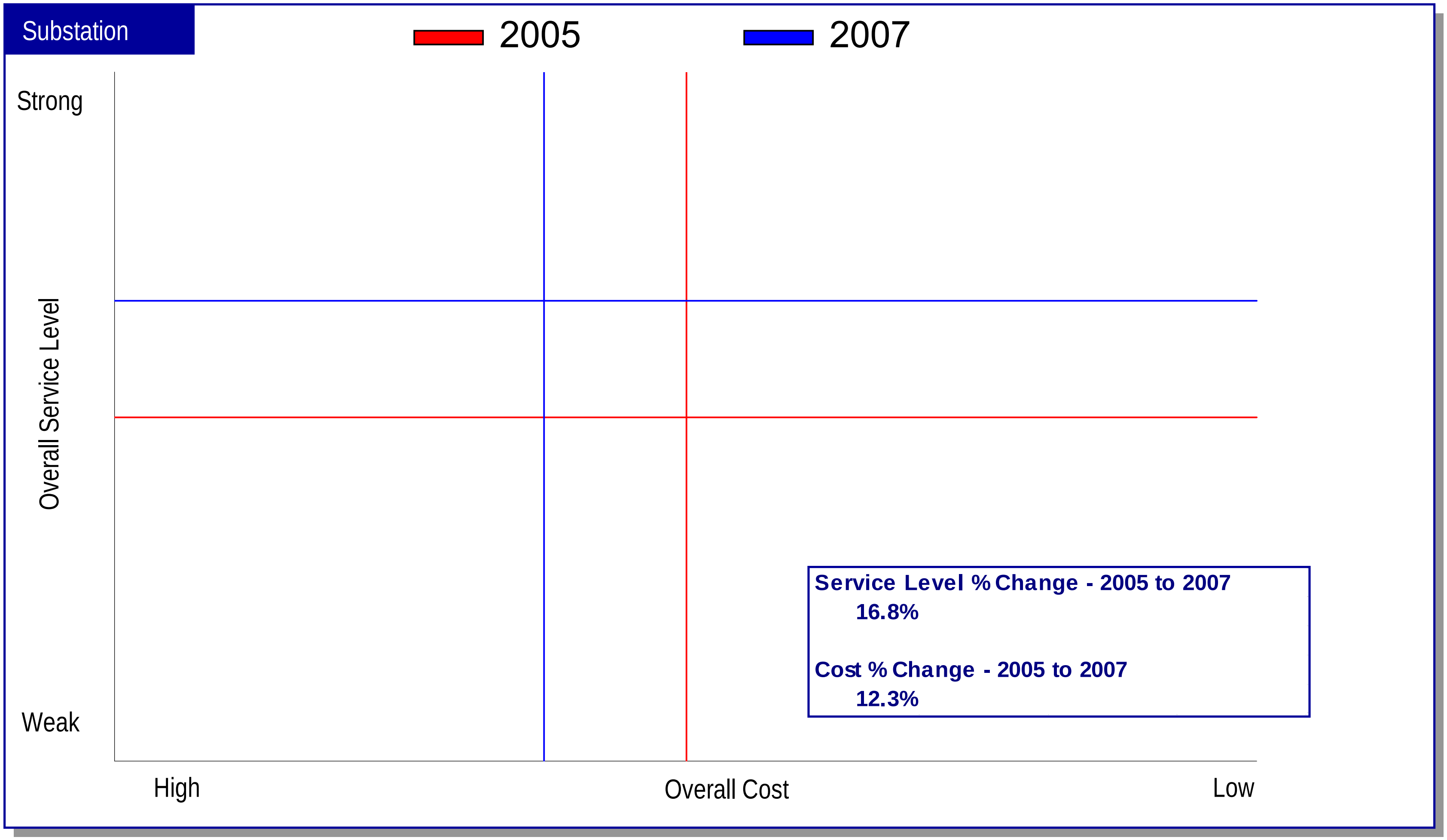
Average Comparisons – 2005 vs. 2007



Calculated with companies participating in both 2005 and 2007 studies, excluding outliers:
Cost: REE, ELI; Service Level: XCL

Data Revision Date:	1/13/2008
Composite Scatter Analysis Revision Date:	1/10/2008
Overall Charting Revision Date:	2/1/2008

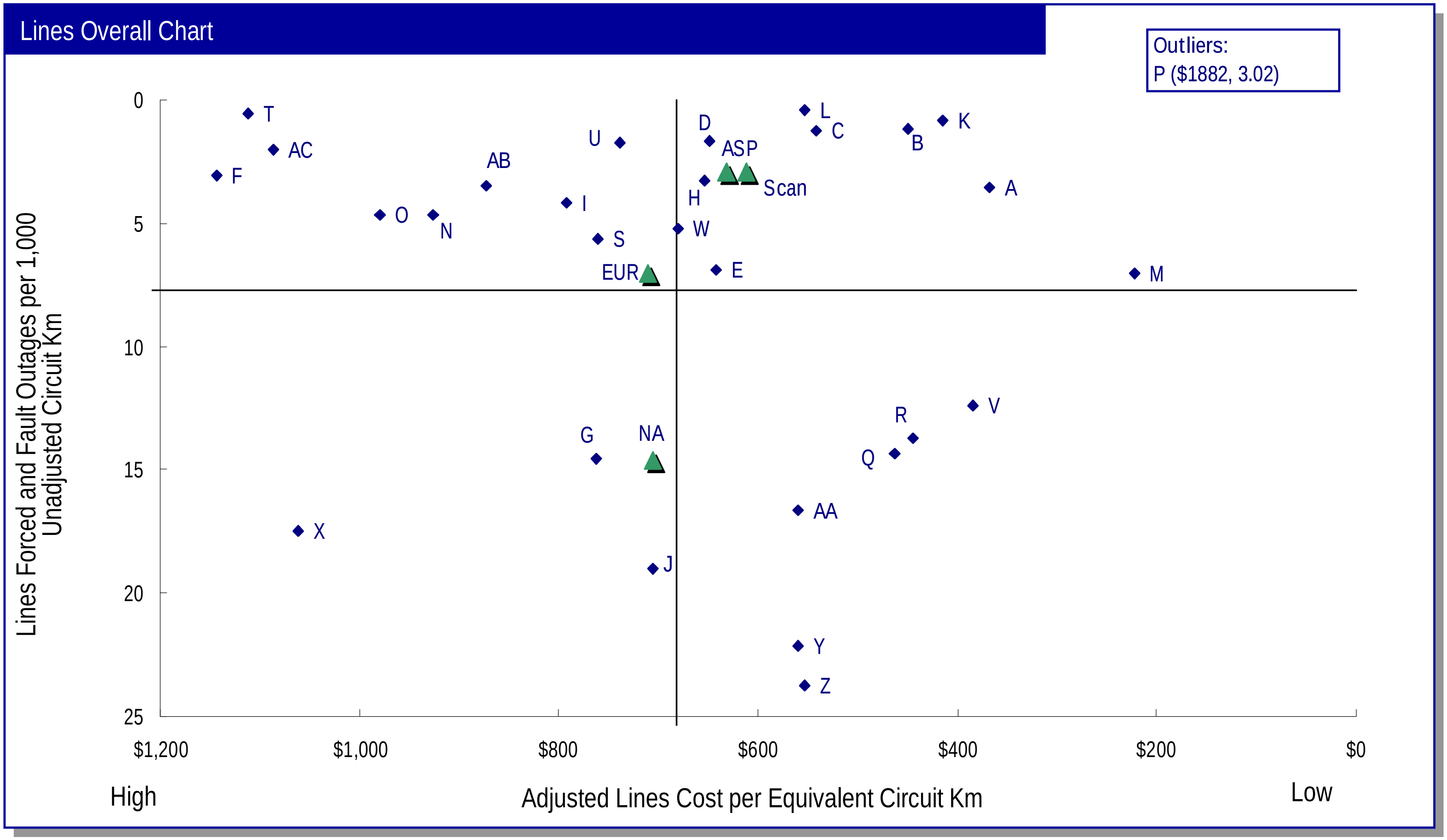
Average Comparisons – 2005 vs. 2007



Calculated with companies participating in both 2005 and 2007 studies, excluding outliers:
Cost: NG, REE, ELI, TCO; Service Level: STA, XCL

Data Revision Date:	1/13/2008
Composite Scatter Analysis Revision Date:	1/10/2008
Overall Charting Revision Date:	2/1/2008

Overall Cost and Faults Comparison – Lines

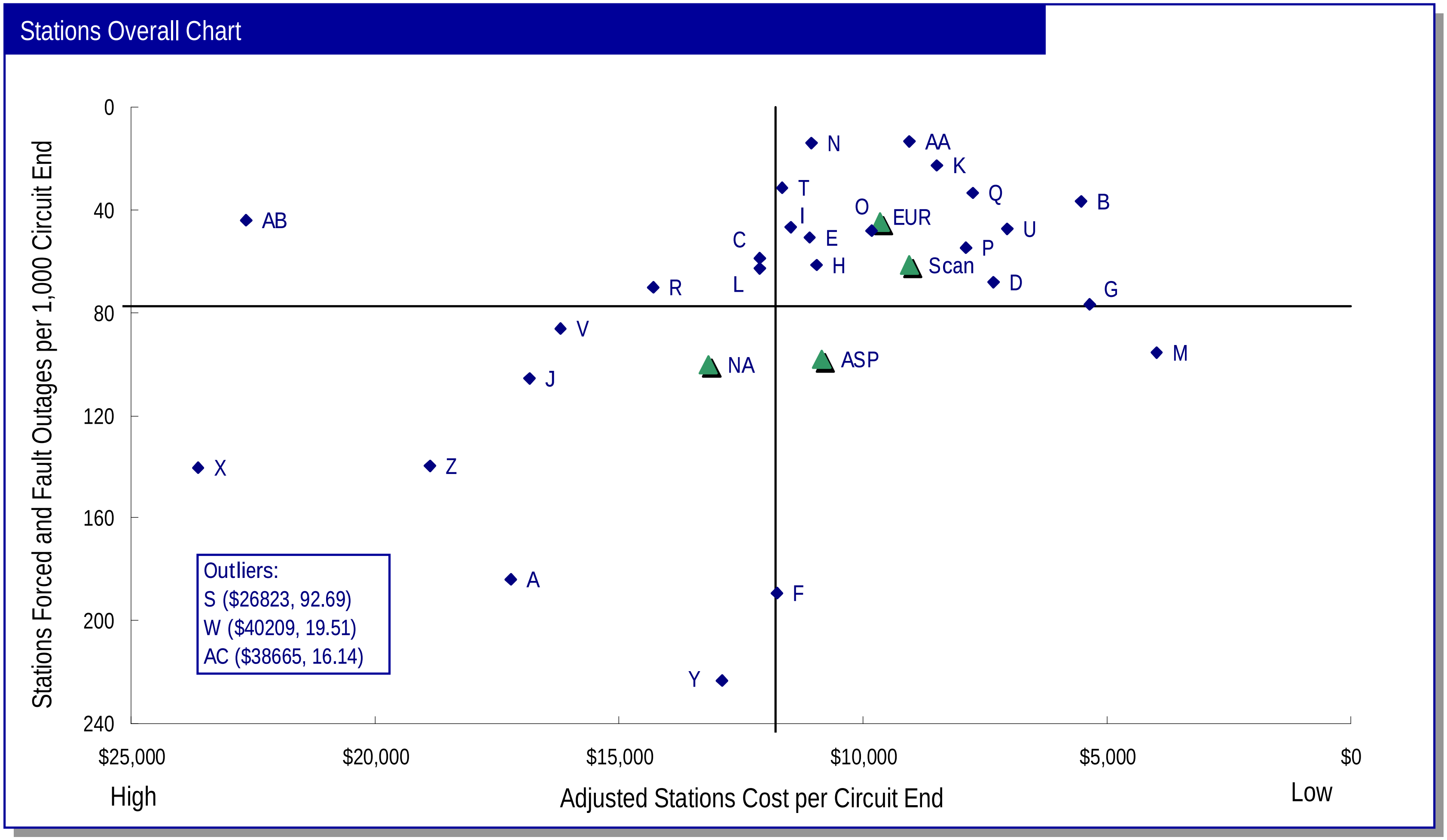


* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, Tower Painting and Right-of-Way Maintenance.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Overall Cost and Faults Comparison – Stations

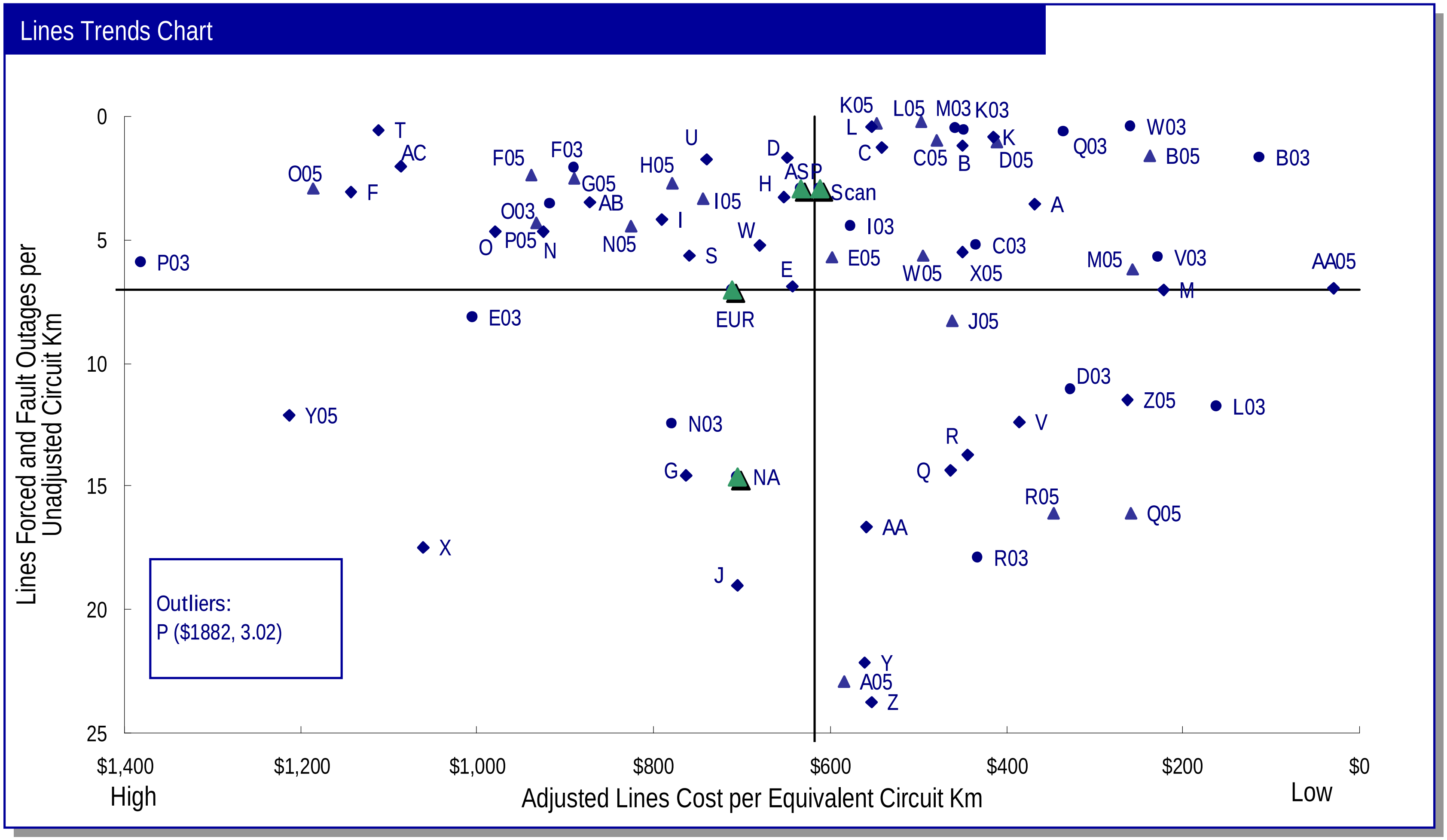


* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Overall Cost and Faults Comparison – Lines (Trend)



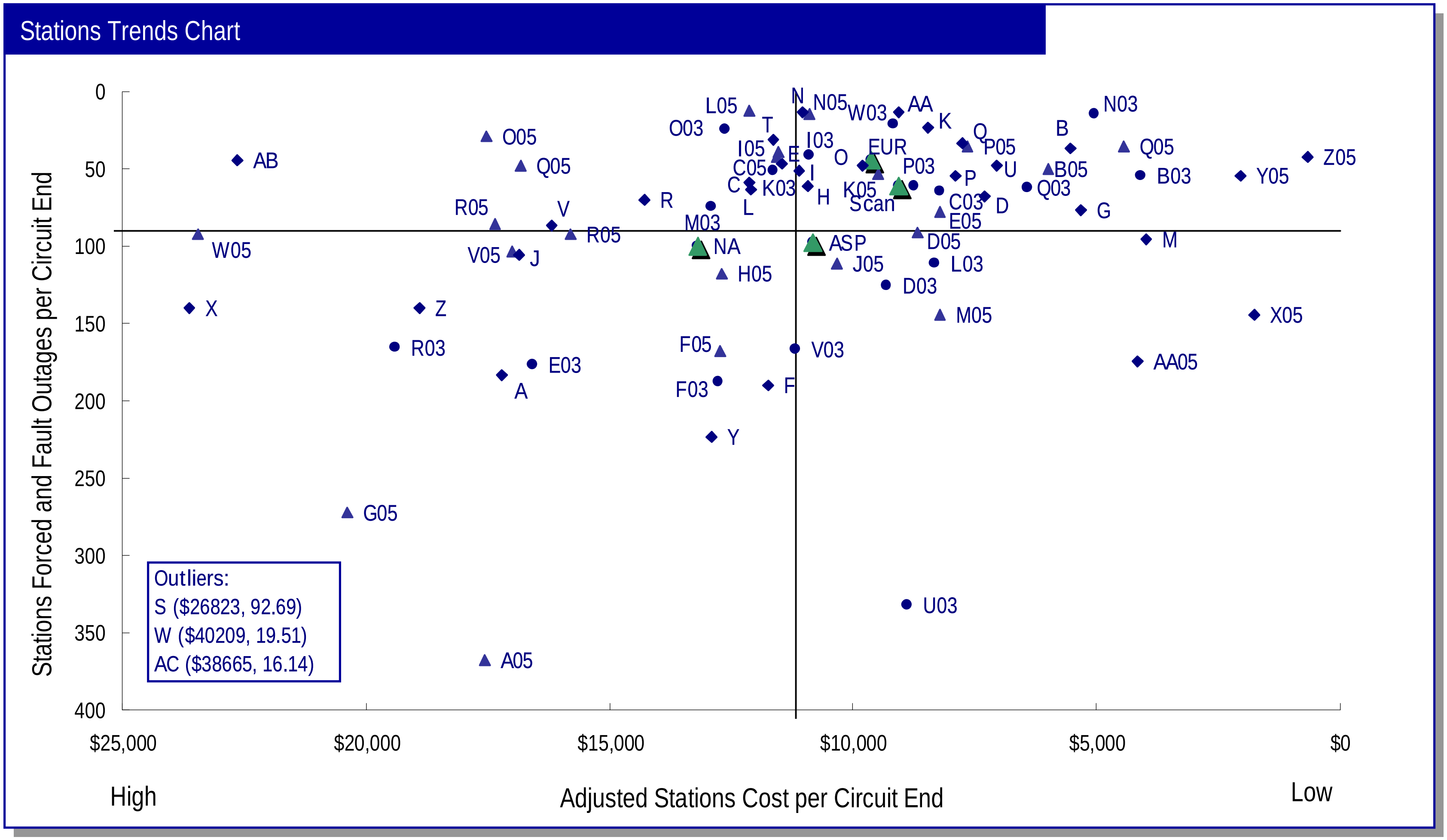
Data points labeled with three letter code represent current study year

* Includes Overhead Line Patrol & Inspection 60-99kV, 100-199 kV and 200+ kV, Overhead Line Maintenance 60-99kV, 100-199 kV and 200+ kV, Tower Painting and Right-of-Way Maintenance.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Overall Cost and Faults Comparison – Stations (Trend)



Data points labeled with three letter code represent current study year

* Includes Breaker Maintenance, Transformer Maintenance, Relay, SCADA & Communications System Maintenance, Compensation Equipment Maintenance, Disconnector & Earth Switch Maintenance, Instrument Transformer & Other Circuit End Equipment Maintenance, Substation Site & Auxiliary Plant Equipment Maintenance, Substation Field Operations.

Data Revision Date:	1/13/2008

Composite Scatter Analysis Revision Date:	1/10/2008	Overall Charting Revision Date:	2/1/2008

Model Version Control – Charting Sheets

Model Name	Charting Sheet Revision Date
OHL Maintenance	1/15/2008
OHL Patrol & Inspection	1/15/2008
Tower Painting	1/16/2008
ROW Management	1/19/2008
Circuit Breakers	1/19/2008
Transformers	1/20/2008
Site	1/16/2008
Disconnectors	1/9/2008
Compensation Equipment	1/9/2008
Relays, SCADA, and Communications	1/19/2008
Instrument Transformers	1/17/2008
Operations	1/17/2008
Support Services	1/10/2008

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Model Version Control – Analysis Sheets

Model Name	Analysis Sheet Revision Date
OHL Maintenance	1/20/2008
OHL Patrol & Inspection	1/15/2008
Tower Painting	1/16/2008
ROW Management	1/19/2008
Circuit Breakers	1/19/2008
Transformers	1/22/2008
Site	1/16/2008
Disconnectors	1/4/2008
Compensation Equipment	1/4/2008
Relays, SCADA, and Communications	1/19/2008
Instrument Transformers	1/17/2008
Operations	1/17/2008
Support Services	1/10/2008

Data Revision Date:	1/13/2008
Composite Scatter Analysis Revision Date:	1/10/2008
Overall Charting Revision Date:	2/1/2008

Revision Number	Revision Date	Revision Description	Revision made by
1	1 Feb 2006	Addition of 2 new trend charts (cost/unit vs F&F outages/unit, general clean-up, definitions of weighted and unweighted averages	K. Kinslow
2	3 Feb 2006	Revise map of participants page, add analysis sheet link, format scatter pages	K. Kinslow
3	7 Feb 2006	Add page on outliers description, add overall lines and substation charts for 1 year (cost v F&F outages), minor text clean-up and clarification, update links	K. Kinslow`
4	7 Mar 2006	Move symbol for ITC, adjust measurement summary to include forced outages (table page 8)	K. Kinslow
5	10 Mar 2006	Added per "1,000" to Service Level labels	J. Lewis
6	1 May 2006	Update all data, add Best Practice company list	K. Kinslow
7	10 Jan 2008	Updated data, outliers, tables	J. Lewis
8	14 Jan 2008	Updated data	J. Wilson
9	20 Jan 2008	Update data	K. Kinslow
10	21 Jan 2008	Update data, scatter labels	J. Wilson
11	22 Jan 2008	Added 60-99kV to text to tables, updated map, asset table	J. Wilson
12	23 Jan 2008	Formatting, map, best performers	J. Wilson
13	28 Jan 2008	Updated map, Asset Characteristics (table pg 7)	J. Wilson
14	30 Jan 2008	Updated notes	J. Wilson
15	1 Feb 2008	Updated charts, pg 26, 27	J. Lewis
16	13 Feb 2008	Blinded data	J. Wilson
17	19 Mar 2008	Update trend charts	J. Wilson

Data Revision Date: 1/13/2008

Composite Scatter Analysis Revision Date: 1/10/2008

Overall Charting Revision Date: 2/1/2008

Appendix G

Draft Order

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

and

An Application by British Columbia Transmission Corporation
for Approval of a
Transmission System Capital Plan F2010 to F2019

BEFORE: [Panel members] [day] [Month] 2008

O R D E R

WHEREAS:

A. Commission Order No. G-107-08 dated 26 June 2008 responded to the British Columbia Transmission Corporation (BCTC) F2009 to F2018 Transmission System Capital Plan; and

B. BCTC filed its F2010 and F2011 Transmission System Capital Plan (F2010 Capital Plan) dated 21 November 2008 pursuant to Sections 44.2 and 45(6) of the *Utilities Commission Act* (Act); and

C. BCTC in the filing applies for an Order which states that the Commission accepts the expenditure schedules identified in the F2010 Capital Plan pursuant to Section 44.2(3) of the Act, that the F2010 Capital Plan meets the requirements of Section 45(6) of the Act, and that BCTC is exempted from certain Commission Directives identified in the F2010 Capital Plan or these Directives are modified; and

D. By Order No. G-[#]-08, the Commission established a Procedural Conference on xx Month 2008 regarding the regulatory process for the review of the F2010 Capital Plan; and

E. The Commission, by Order No. G-[#]-08, established a written public hearing process and Regulatory Timetable for the review of the F2010 Capital Plan; and

F. On [day] [Month] 2008, the Commission issued Information Request No. 1 to BCTC; and

G. The Commission received responses to Information Request No. 1 on [day] [Month] 2009; and

H. The evidentiary phase of the proceeding closed on [day] [Month] 2009; and

I. The Written Argument phase of the proceeding was completed when BCTC filed its Reply Submission on [day] [Month] 2009; and

J. The Commission Panel has considered the F2010 Capital Plan, evidence, and submissions of intervenors and the Applicant;

NOW THEREFORE the Commission Orders as follows:

1. Pursuant to section 44.2(3) of the Act, the following expenditure schedules provided in the F2010 Capital Plan are accepted:

    (a) the Growth Capital Projects for Approval listed in Table 5-1;

    (b) the total Sustaining Capital expenditures of $119,045,000 for F2010 and $122,271,000 for 2011 listed in Table 6-1;

    (c) the BCTC Capital Expenditures for Approval listed in Table 7-1; and

    (d) the emergency capital expenditures for F2008 and F2009 listed in line 27 of Table 6-2.

2. The F2010 Capital Plan meets the requirements of section 45(6) of the Act;

3. Pursuant to sections 88(2) and/or 99 of the Act, BCTC is relieved from the Commission Directives indicated in Sections 5.3, 7.5 and 9.2.13.

DATED at the City of Vancouver, in the Province of British Columbia, this ________ day of [month] 2009.

BY ORDER

Panel Chair