David Bennett
Vice President,
Regulatory Affairs & General Counsel

FortisBC Inc.
Suite 100 - 1975 Springfield Road
Kelowna, BC V1Y 7V7
Ph: 250 717 0853
Fax: 866 605 9431
regulatory@fortisbc.com
www.fortisbc.com

August 7, 2008

Via Email
Original via Courier

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: An Application for a CPCN for the 2009-2010 Capital Expenditure Plan Project No. 3698519

Please find enclosed FortisBC Inc.'s responses to Information Request No.1 from the BC Utilities Commission. Twenty copies will be couriered to the Commission.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

1.0 Reference: Capital Plan, p. 5, Executive Summary;
Capital Plan, p. 17, Summary of Expenditures by Category, Table 1.5
Detail of projects

"The 2009-2010 Capital Expenditure Plan ("2009-2010 Capital Plan") of FortisBC Inc. ("FortisBC" or the "Company") consists of expenditures of $178.8 million in 2009 and $181.1 million in 2010. These expenditures are necessary to ensure the ability to provide service, public and employee safety and reliability of supply to the Company's growing customer base."

Q1.1 Please expand Table 1.5 in the Capital Plan and provide a summary of capital additions added to plant in service based on the projected capital expenditures for 2009 and 2010. The summary is to include when the additions will happen by project by year from 2005 to 2015.

A1.1 The information requested is provided in Table A1.1 below. All of the 2009-2010 Capital Expenditure Plan additions are expected to be placed in service by 2012. Projects referenced by an asterisk in the Project Name column of Table A1.1 below involve the replacement of assets.

Table A1.1
Summary of Capital Additions

	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Generation	($000s)							
1	South Slocan Unit 1 Life Extension (replace turbine)*	-	-	-	17,822	39	-	-	**17,861**
2	South Slocan Unit 3 Life Extension (no Turbine)*	-	-	13,061	-	-	-	-	**13,061**
3	Corra Linn Unit 1 Life Extension (replace Turbine)*	-	-	-	-	18,950	-	-	**18,950**
4	Corra Unit 2 Life Extension (replace Turbine)*	-	-	-	-	14,696	7,984	-	**22,681**
5	South Slocan Plant Completion*	-	-	-	3,550	-	-	-	**3,550**
6	Upper Bonnington Old Unit Repowering Ph.1*	131 (2007)	3,060	1,045	1,651	-	-	-	**5,887**
7	South Slocan Unit 1 Head Gate Rebuild*	-	-	-	856	-	-	-	**856**
8	South Slocan Headgate Hoist, Control, Wire Rope Upgrade*	-	-	1,103	-	-	-	-	**1,103**
9	All Plants Upgrade Station Service Supply*	-	-	1,478	1,342	1,309	883	-	**5,010**
10	All Plants Lighting Upgrade*	-	-	365	451	-	-	-	**816**
11	All Plants Spare Unit Transformer	-	-	1,849	-	-	-	-	**1,849**
12	All Plants Fire Safety Upgrade Ph.1	-	-	241	-	-	-	-	**241**
13	All Plants Public Safety & Security Ph.1	-	-	34	-	99	-	-	**133**
14	Lower Bonnington Power House Crane Upgrade*	-	-	174	-	-	-	-	**174**
15	Corra Linn Power House Crane Upgrade*	-	-	172	-	-	-	-	**172**
16	Corra Linn East Wingdam Handrail Upgrade*	-	-	78	-	-	-	-	**78**
17	All Plants Portable Headgate Closing Device	-	-	50	-	-	-	-	**50**
18	All Plants Spare Exciter Transformer	-	-	-	140	-	-	-	**140**
19	South Slocan Domestic Water Supply Ph.3*	-	-	-	97	-	-	-	**97**
20	All Plants 2009 Pump Upgrades*	-	-	233	-	-	-	-	**233**
21	Upper Bonnington & Corra Linn Deluge Valves*	-	-	50	-	-	-	-	**50**
22	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm Sys U/G*	-	-	128	-	-	-	-	**128**

Table A1.1 cont'd

	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Generation cont'd	($000s)							
23	Lower Bonnington and Upper Bonnington Upgrade Spillway Gate Control Ph.1*	-	-	40	-	-	-	-	**40**
24	Upper Bonnington and South Slocan Airwash Tank Rehab*	-	-	108	-	-	-	-	**108**
25	South Slocan Tailrace Gate Corrosion Control*	-	-	-	114	-	-	-	**114**
26	Queen's Bay Level Gauge Building Ph.1*	-	-	67	-	-	-	-	**67**
27	Upper Bonnington Unit 5/Unit 6 Tailrace Gate Corrosion Control*	-	-	-	139	-	-	-	**139**
28	Upper Bonnington Extension Trash Rack Gantry Replacement*	-	-	-	417	-	-	-	**417**
29	Lower Bonnington Intake Area Upgrade Ph.1*	-	-	393	-	-	-	-	**393**
30	Lower Bonnington Intake Area Upgrade Ph.2*	-	-	-	102	-	-	-	**102**
31	Corra Linn Spillway Gate Isolation Study	-	-	-	-	46			**46**
32	South Slocan Dam Rehabilitation Study	-	-	-	-	46			**46**
33	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade*	-	-	-	212	-	-	-	**212**
34	Lower Bonnington and Upper Bonnington Communication Network Comp.*	-	-	-	392	-	-	-	**392**
35	**Sub Total Generation (Note 1)**	**131**	**3,060**	**20,671**	**27,286**	**35,185**	**8,867**	**-**	**95,198**

Note 1 – Total reconciles with the total from Table 2.1 from the Application (Exhibit B-1), page 20, line 15.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Transmission Growth	($000s)							
36	Ellison Distribution Source	-	15,434	1,734	-	-	-	-	**17,168**
37	Black Mountain Distribution Source	-	-	14,430	-	-	-	-	**14,430**
38	Naramata Rehab*	-	-	7,524	-	-	-	-	**7,524**
39	Okanagan Transmission Reinforcement*	-	-	-	137,497	-	-	-	**137,497**
40	Ootischenia Substation	-	7,702	389	-	-	-	-	**8,091**
41	Benvoulin Distribution Source	-	-	-	17,684	-	-	-	**17,684**
42	Recreation Capacity Increase Stage 1,2,3	-	-	-	3,578	-	-	-	**3,579**
43	Kelowna Distribution Capacity Requirements	-	-	-	-	1,035	-	-	**1,035**
44	Tarrys Capacity Increase	-	-	403	-	-	-	-	**403**
45	Huth Split Bus*	-	-	-	-	3,413	-	-	**3,413**
46	Static VAR Compensator (SVC) - Kelowna	-	-	-	-	400	-	-	**400**
	30 Line Conversion	-	-	4,500	-	-	-	-	**4,500**
50	**Sub Total Transmission Growth (Note 2)**	**-**	**23,136**	**28,979**	**158,760**	**4,848**	**-**	**-**	**215,724**
51	**Transmission and Stations Sustaining**								
52	Transmission Line Urgent Repairs*	-	-	288	293	-	-	-	**581**
53	Transmission Right-of-Way Acquisition*	-	-	311	345	-	-	-	**656**
54	Transmission Right-of-Way Reclamation	-	-	550	602	-	-	-	**1,152**
55	Transmission Line Pine Beetle Hazard Allocation	-	-	1,218	821	-	-	-	**2,039**
56	Transmission Line Condition Assessment*	-	-	427	496	-	-	-	**923**
57	Transmission Line Rehabilitation*	-	-	1,639	1,888	-	-	-	**3,527**
58	Castlegar Substation Switch CAS-6 & CAS-26 Upgrade*	-	-	-	132	-	-	-	**132**

Note 2 – Table 3.1 from the Application (Exhibit B-1), page 42, line 14, included $3,911,000 for cost of removal.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Transmission and Stations Sustaining cont'd	**($000s)**							
59	20 Line Rebuild*	-	-	1,943	1,540	-	-	-	**3,483**
61	27 Line Rebuild*	-	-	648	642	-	-	-	**1,289**
62	30 Line Crossing Rehabilitation*	-	-	-	350	-	-	-	**350**
63	Station condition Assessment and Minor Repair*	-	-	620	680	-	-	-	**1,300**
64	Castlegar Substation Ground Grid Upgrade*	-	-	572	-	-	-	-	**572**
65	Station Unforeseen/Urgent Repairs*	-	-	473	448	-	-	-	**921**
66	Kootenay 12 MVA Mobile Breaker Replacement*	-	-	-	292	-	-	-	**292**
67	LTC Oil Filtration for Westminister T2*	-	-	-	32	-	-	-	**32**
68	LTC Oil Filtration for OK Mission T1*	-	-	-	32	-	-	-	**32**
69	LTC Oil Filtration for Summerland T2*	-	-	32	-	-	-	-	**32**
70	Slocan City – Valhalla*	-	-	2,173	-	-	-	-	**2,173**
71	Passmore – 19 Line Breaker	-	-	-	1,987	-	-	-	**1,987**
72	Pine Street Replacement of Distribution Breakers (F-1, F-2, F-3 Breaker Replacement & Protection upgrade)*	-	-	345	-	-	-	-	**345**
73	Princeton old PLP Reclosers with new Breakers*	-	-	-	1,513	-	-	-	**1,513**
74	Joe Rich Breaker Addition*	-	-	-	404	-	-	-	**404**
75	Creston Substation Transformer T1&T2 Circuit Switchers*	-	-	488	-	-	-	-	**488**
76	**Sub Total Transmission and Stations Sustaining (Note 3)**	**-**	**-**	**11,727**	**12,496**	**-**	**-**	**-**	**24,224**

Note 3 – Total reconciles with the total from the Application (Exhibit B-1), page 43, Table 3.1, line 39.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Distribution Growth	($000s)							
77	New Connects System Wide*			9,788	10,670				**20,458**
78	New Glenmore Feeder	-	-	788	-	-	-	-	**788**
79	Airport Way Upgrade (Ellison Feeder - 3)*	-	-	-	1,551	-	-	-	**1,551**
80	Hollywood-3 & Sexsmith-4 Tie	-	-	-	365	-	-	-	**365**
81	Christina Lake Feeder-1 Capacity Upgrade*	-	-	-	1,097	-	-	-	**1,097**
82	Beaver Park Feeder-2 to Fruitvale Feeder-1 Distribution Tie Upgrade*	-	-	-	1,227	-	-	-	**1,227**
83	Oliver Feeder-1 New Regulator	-	-	-	137	-	-	-	**137**
84	Small Capacity Improvements Unplanned	-	-	974	994				**1,968**
85	**Sub Total Distribution Growth (Note 4)**	**-**	**-**	**11,550**	**16,043**	**-**	**-**	**-**	**27,591**

Note 4 – Total reconciles with the total from the Application (Exhibit B-1), page 78, Table 4.1, line 11.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Distribution Sustaining	($000s)							
86	Distribution Line Condition Assessment	-	-	599	667				**1,266**
87	Distribution Line Rehabilitation*	-	-	3,124	3,470				**6,594**
88	Distribution Right-of-Way Reclamation	-	-	621	646				**1,267**
89	Distribution Pine Beetle Hazard Allocation	-	-	722	551				**1,273**
90	Distribution Line Rebuilds*	-	-	1,178	1,167				**2,344**
91	Small Planned Capital*	-	-	668	747				**1,415**
92	2008 FortisBC Forced Upgrades*			1,255	1,461				**2,716**
93	Distribution Urgent Repairs*	-	-	1,911	1,805				**3,716**
94	PCB Testing Program - Distribution	-	-	1,073	1,117				**2,190**
95	Aesthetic & Environmental Upgrades	-	-	100	100				**200**
96	Copper Conductor Replacement Program*	-	-	4,952	6,271				**11,223**
97	**Sub Total Distribution Sustaining (Note 5)**	**-**	**-**	**16,202**	**18,002**	**-**	**-**	**-**	**34,202**

Note 5 – Difference due to 2008 expenditures for Copper Conductor Replacement Project offset by cost of removals.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Telecommunications Growth	($000s)							
98	Distribution Automation*	-	225	2,341	1,953	1,860	-	-	**6,379**
99	**Sub Total Telecommunications Growth (Note 6)**	-	225	**2,341**	**1,953**	**1,860**	-	-	**6,379**
	Telecommunications Sustaining								
100	Harmonic Remediation	-	-	117	119	-	-	-	**236**
101	Protection Upgrades*	-	-	448	508				**956**
102	Communication Upgrades*	-	-	299	111				**410**
103	**Sub Total Telecommunications Sustaining (Note 6)**	**-**	**-**	**864**	**738**	**-**	**-**	**-**	**1,602**
	Demand Side Management								
104	Demand Side Management (net of income tax)	-	-	2,513	2,707				**5,220**
105	**Sub Total Demand Side Management (Note 7)**	**-**	**-**	**2,513**	**2,707**	**-**	**-**	**-**	**5,220**

Note 6 – Totals reconcile with totals from the Application (Exhibit B-1), page 101, Table 5.1, lines 3 and 10.

Note 7 – Total reconciles with total from the Application (Exhibit B-1), page 107, Table 6.1, line 3.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Vehicles	($000s)							
106	Vehicles*			1,326	2,868				**4,195**
107	**Sub Total Vehicles (Note 8)**		**-**	**1,326**	**2,868**	**-**	**-**	**-**	**4,195**
	Metering								
108	Advanced Metering Infrastructure*	-		16,492	20,240	-	-	-	**36,732**
109	Metering Changes to Uninstalled Meter Inventory	-		526	559				**1,085**
110	**Sub Total Metering (Note 8)**	**-**	**-**	**17,019**	**20,799**	**-**	**-**	**-**	**37,817**
	Information Technology								
111	Desktop Infrastructure Upgrades	-		842	847				**1,689**
112	AMFM Systems Enhancements	-		211	423				**634**
113	Customer Systems Enhancements	-		789	794				**1,583**
114	Infrastructure Upgrades	-		789	794				**1,583**
115	SAP Operations Systems Enhancements	-		947	953				**1,900**
116	SCADA Systems Enhancements	-	-	789	688				**1,477**
117	Distribution Design Software	-	-	799	-	-	-	-	**799**
118	**Sub Total Information Technology (Note 8)**	**-**	**-**	**5,167**	**4,499**	**-**	**-**	**-**	**9,666**
	Telecommunications								
119	Telecommunications*			105	106				**211**
120	**Sub Total Telecommunication (Note 8)**		**-**	**105**	**106**	**-**	**-**	**-**	**211**

Note 8 – Totals reconcile with totals from Application (Exhibit B-1), page 116, Table 7.1, lines 1, 2, 3, 4 and 5.

Table A1.1 cont'd

Line No.	Project Name	Pre-2008	2008	Additions to Plant in Service					Total All Years
		Actual	Current Estimate	2009	2010	2011	2012	2013	
	Facilities	($000s)							
121	Construction Projects Requirements	-	-	218	219	-	-	-	**437**
122	Emergency Building Upgrades*	-	-	88	89	-	-	-	**177**
123	Corporate Security System	-	-	305	305	-	-	-	**610**
124	Facility Upgrades*	-	-	2,637	1,368	-	-	-	**4,005**
125	**Sub Total Facilities (Note 9)**	**-**	**-**	**3,248**	**1,981**	**-**	**-**	**-**	**5,229**
	Furniture								
126	Furniture & Fixtures*	-	-	347	393	-	-	-	**740**
127	**Sub Total Furniture (Note 9)**	**-**	**-**	**347**	**393**	**-**	**-**	**-**	**740**
	Tools								
128	Tools and Equipment*			572	575				**1,147**
129	**Sub Total Tools (Note 9)**	**-**	**-**	**572**	**575**	**-**	**-**	**-**	**1,147**
130	**Grand Total**	**131**	**26,421**	**122,631**	**269,249**	**41,890**	**8,867**	**-**	**469,141**

Note 9 – Totals reconcile with totals from the Application (Exhibit B-1), page 116, Table 7.1, lines 6, 7 and 8.

Q1.2 Please indicate which assets are being replaced.

A1.2 Projects referenced by an asterisk in the Project Name column of Table A1.1 above involve the replacement of assets.

Q1.3 Please show in the table what the rate impact is for each of the additions in the Capital Plan.

A1.3 The information requested is provided in Table A1.3 below. A project by project rate impact calculation has not been performed, however plant additions of approximately $25 million result in a rate impact of approximately 1 percent, assuming all other Revenue Requirement components remain equal. The following table is based on using a 1 percent rate increase per $25 million capital plant additions.

Table A1.3
Rate Impact by Project

Line No.	Project Name	Additions to Plant in Service		Total 2009/10	Generic Rate Impact
		2009	2010		
	Generation	$000s			%
1	South Slocan Unit 1 Life Extension (replace turbine)	-	17,822	17,822	0.713
2	South Slocan Unit 3 Life Extension (no Turbine)	13,061	-	13,061	0.522
3	South Slocan Plant Completion	-	3,551	3,551	0.142
4	Upper Bonnington Old Unit Repowering (Ph.1)	1,045	1,651	2,696	0.108
5	South Slocan Unit 1 Head Gate Rebuild	-	856	856	0.034
6	South Slocan Headgate Hoist, Control, Wire Rope Upgrade		-	1,103	0.044
7	All Plants Upgrade Station Service Supply	1,478	1,342	2,820	0.113
8	All Plants Lighting Upgrade	365	451	816	0.033
9	All Plants Spare Unit Transformer	1,849	-	1,849	0.074
10	All Plants Fire Safety Upgrade Ph.1	241	-	241	0.010
11	All Plants Public Safety & Security Ph.1	34	-	34	0.001
12	Lower Bonnington Power House Crane Upgrade	174	-	174	0.007
13	Corra Linn Power House Crane Upgrade	172	-	172	0.007
14	Corra Linn East Wingdam Handrail Upgrade	78	-	78	0.003
15	All Plants Portable Headgate Closing Device	50	-	50	0.002
16	All Plants Spare Exciter Transformer	-	140	140	0.006
17	South Slocan Domestic Water Supply Ph.3	-	97	97	0.004

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Table A1.3 cont'd

Line No.	Project Name	Additions to Plant in Service		Total 2009/10	Generic Rate Impact
		2009	2010		
	Generation cont'd	$000s			%
18	All Plants 2009 Pump Upgrades	233	-	233	0.009
19	Upper Bonnington & Corra Linn Deluge Valves	50	-	50	0.002
20	Lower Bonnington, Upper Bonnington, & Corra Linn Sump Oil Alarm Sys U/G	128	-	128	0.005
21	Lower Bonnington & Upper Bonnington Upgrade Spillway Gate Cntrl Ph.1	40	-	40	0.002
22	Upper Bonnington & South Slocan Airwash Tank Rehab	108	-	108	0.004
23	South Slocan Tailrace Gate Corrosion Control	-	114	114	0.005
24	Queen's Bay Level Gauge Building Ph. 1	67		67	0.003
25	Upper Bonnington Unit 5/Unit 6 Tailrace Gate Corrosion Control		139	139	0.006
26	Upper Bonnington Extension Trash Rack Gantry Replacement	-	417	417	0.017
27	Lower Bonnington Intake Area Upgrade Ph.1	393	-	393	0.016
28	Lower Bonnington Intake Area Upgrade Ph.2	-	102	102	0.004
29	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade	-	212	212	0.008
30	Lower Bonnington & Upper Bonnington Comm. Network Comp.	-	392	392	0.016
	Transmission Growth				
31	Ellison Distribution Source	1,734	-	1,734	0.069
32	Black Mountain Distribution Source	14,430	-	14,430	0.577
33	Naramata Rehab	7,524	-	7,524	0.301
34	Okanagan Transmission Reinforcement	-	137,487	137,487	5.499
35	Ootischenia Substation	389	-	389	0.016
36	Benvoulin Distribution Source	-	17,685	17,685	0.707
37	Recreation Capacity Increase Stage 1,2,3	-	3,578	3,578	0.143
38	Tarrys Capacity Increase	403	-	403	0.016
39	30 Line Conversion	4,500		4,500	0.18
40	Transmission Line Urgent Repairs	288	293	581	0.023
41	Transmission Right of Way Acquisition	311	345	656	0.026
42	Transmission ROW Reclamation	550	602	1,152	0.046
43	Transmission Line Pine Beetle Hazard Allocation	1,217	821	2,038	0.082
44	Transmission Line Condition Assessment	427	496	923	0.037
45	Transmission Line Rehabilitation	1,639	1,888	3,527	0.141
46	Castlegar Substation Switch CAS-6 & CAS-26 Upgrade	-	132	132	0.005
47	20 Line Rebuild	1,943	1,540	3,483	0.139
48	27 Line Rebuild	648	642	1,289	0.052
49	30 Line Crossing Rehabilitation	-	350	350	0.014
50	Station Condition assessment and Minor Repair	620	680	1,300	0.052
51	Castlegar Substation Ground Grid Upgrade	572	-	572	0.023
52	Station Unforeseen /Urgent Repairs	473	448	921	0.037
53	Kootenay 12 MVA Mobile Breaker Replacement	-	292	292	0.012

1 **Table A1.3 cont'd**

Line No.	Project Name	Additions to Plant in Service		Total 2009/10	Generic Rate Impact
		2009	2010		
	Transmission Growth cont'd	$000s			%
54	LTC Oil Filtration for Westminister T2	-	32	32	0.001
55	LTC Oil Filtration for OK Mission T1	-	32	32	0.001
56	LTC Oil Filtration for Summerland T2	32	-	32	0.001
57	Slocan City – Valhalla	2,173	-	2,173	0.087
58	Passmore - 19L Breaker	-	1,987	1,987	0.079
59	Pine Street Replacement of Distribution Breakers (F-1, F-2, F-3 Breaker Replacement & Protection upgrade)	345	-	345	0.014
60	Princeton old PLP Reclosers with new Breakers	-	1,513	1,513	0.061
61	Joe Rich Breaker Addition	-	404	404	0.016
62	Creston Substation Transformer T1&T2 Circuit Switchers	488	-	488	0.020
	Distribution Growth				
63	New Connects System Wide	9,788	10,670	20,458	0.818
64	New Glenmore Feeder	788	-	788	0.032
65	Airport Way Upgrade (Ellison Feeder - 3)	-	1,551	1,551	0.062
66	Hollywood-3 & Sexsmith-4 Tie	-	365	365	0.015
67	Christina Lake Feeder-1 Capacity Upgrade	-	1,098	1,098	0.044
68	Beaver Park Feeder-2 to Fruitvale Feeder-1 Distribution Tie Upgrade	-	1,227	1,227	0.049
69	Oliver Feeder-1 New Regulator	-	137	137	0.005
70	Small Capacity Improvements Unplanned	974	994	1,968	0.079
	Distribution Sustaining				
71	Distribution Line Condition Assessment	599	667	1,267	0.051
72	Distribution Line Rehabilitation	3,124	3,470	6,594	0.264
73	Distribution Right-of-Way Reclamation	621	646	1,267	0.051
74	Distribution Pine Beetle Hazard Allocation	722	551	1,272	0.051
75	Distribution Line Rebuilds	1,178	1,167	2,344	0.094
76	Small Planned Capital	668	747	1,414	0.057
77	2008 FortisBC Forced Upgrades	1,255	1,461	2,716	0.109
78	Distribution Urgent Repairs	1,911	1,805	3,716	0.149
79	PCB Testing Program - Distribution	1,073	1,117	2,189	0.088
80	Aesthetic & Environmental Upgrades	100	100	200	0.008
81	Copper Conductor Replacement Program	4,952	6,271	11,223	0.449
	Telecommunications Growth				
82	Distribution Automation	2,341	1,953	4,294	0.172
	Telecommunications Sustaining				
83	Harmonic Remediation	117	119	236	0.009
84	Protection Upgrades	448	508	956	0.038
85	Communication Upgrades	299	111	410	0.016

Table A1.3 cont'd

Line No.	Project Name	Additions to Plant in Service		Total 2009/10	Generic Rate Impact
		2009	2010		
	Demand Side Management	$000s			%
86	Demand Side Management	2,513	2,707	5,220	0.209
	Vehicles				
87	Vehicles	1,326	2,868	4,195	0.168
	Metering				
88	Advanced Metering Infrastructure	16,492	20,240	36,732	1.469
89	Metering Changes to Uninstalled Meter Inventory	526	559	1,085	0.043
	Information Technology				
90	Desktop Infrastructure Upgrades	842	847	1,689	0.068
91	AM/FM Systems Enhancements	211	423	634	0.025
92	Customer Systems Enhancements	789	794	1,583	0.063
93	Infrastructure Upgrades	789	794	1,583	0.063
94	SAP Operations Systems Enhancements	947	953	1,900	0.076
95	SCADA Systems Enhancements	789	688	1,477	0.059
96	Distribution Design Software	799	-	799	0.032
	Telecommunications				
97	Telecommunications	105	106	211	0.008
	Facilities				
98	Construction Projects Requirements	218	219	437	0.017
99	Emergency Building Upgrades	88	89	177	0.007
100	Corporate Security System	305	305	610	0.024
101	Facility Upgrades	2,637	1,368	4,005	0.160
	Furniture				
102	Furniture & Fixtures	347	393	740	0.030
	Tools				
103	Tools and Equipment	572	575	1,147	0.046

2.0 Reference: 2009-2010 Capital Expenditure Plan
Exhibit No. B-1, Executive Summary, p. 6
Capital Expenditure Plan

Q2.1 Please provide summary tables similar to Table 1.1 with and without the related Copper Conductor Replacement Project costs.

A2.1 Summary tables similar to Table 1.1 from page 6 of the 2009-2010 Capital Plan (Exhibit B-1) are provided below with and without the related Copper Conductor Replacement Project costs.

Table A2.1a
2009/10 Capital Expenditure Plan with Copper Conductor Replacement Costs

		2009	2010	Future
		$millions		
1	Generation	21.9	22.6	24.7
2	Transmission and Stations	96.1	88.7	3.0
3	Distribution	28.2	33.8	
4	Telecom, SCADA, Protection and Control	2.2	2.2	1.6
5	Demand Side Management	2.5	2.7	
6	General Plant	27.8	31.2	
7	**TOTAL Capital**	**178.8**	**181.1**	**29.3**
8	Annual Operating Savings	0.20	0.72	

Note: Differences due to rounding.

Table A2.1b
2009/10 Capital Expenditure Plan without Copper Conductor Replacement Costs

		2009	**2010**	**Future**
			($millions)	
1	Generation	21.9	22.6	24.7
2	Transmission and Stations	96.1	88.7	3.0
3	Distribution	23.4	27.2	
4	Telecom, SCADA, Protection and Control	2.2	2.2	1.6
5	Demand Side Management	2.5	2.7	
6	General Plant	27.8	31.2	
7	**TOTAL Capital**	**174.0**	**174.5**	**29.3**
8	Annual Operating Savings	0.20	0.72	

Note: Differences due to rounding.

Q2.1.1 Please provide the tables with a date range starting in 2005 and extending into the future, beyond 2010, by year.

A2.1.1 Please see Tables A2.1.1a and A2.1.1b below.

Table A2.1.1a
Capital Plan Expenditures with Copper Conductor Replacement Costs

		Pre-2008	2008	2009	2010	2011	2012
		($millions)					
1	Generation	9.9	16.1	21.9	22.6	15.7	9.0
2	Transmission and Stations	5.3	50.8	96.1	88.7	3.0	
3	Distribution		0.3	28.2	33.8	15.6	10.2
4	Telecom, SCADA, Protection and Control	0.05	1.9	2.2	2.2	1.6	
5	Demand Side Management			2.5	2.7		
6	General Plant			27.8	31.2		
7	**TOTAL Capital**	**15.3**	**69.1**	**178.8**	**181.1**	**35.9**	**19.2**
8	Annual Operating Savings			0.20	0.72		

Note: Differences due to rounding.

Table A2.1.1b
Capital Plan Expenditures without Copper Conductor Replacement Costs

		Pre-2008	2008	2009	2010	2011	2012
		($millions)					
1	Generation	9.9	16.1	21.9	22.6	15.7	9.0
2	Transmission and Stations	5.3	50.8	96.1	88.7	3.0	
3	Distribution			23.4	27.2		
4	Telecom, SCADA, Protection and Control	0.05	1.9	2.2	2.2	1.6	
5	Demand Side Management			2.5	2.7		
6	General Plant			27.8	31.2		
7	**TOTAL Capital**	**15.3**	**68.8**	**174.0**	**174.5**	**20.3**	**9.0**
8	Annual Operating Savings			0.2	0.72		

Note: Differences due to rounding.

Q2.1.2 Please provide the annual cash flow curves and cumulative cash flow curves for these tables.

A2.1.2 Please see Figures A2.1.2a and A2.1.2b below.

Figure A2.1.2a
Annual Cash Flow Curve

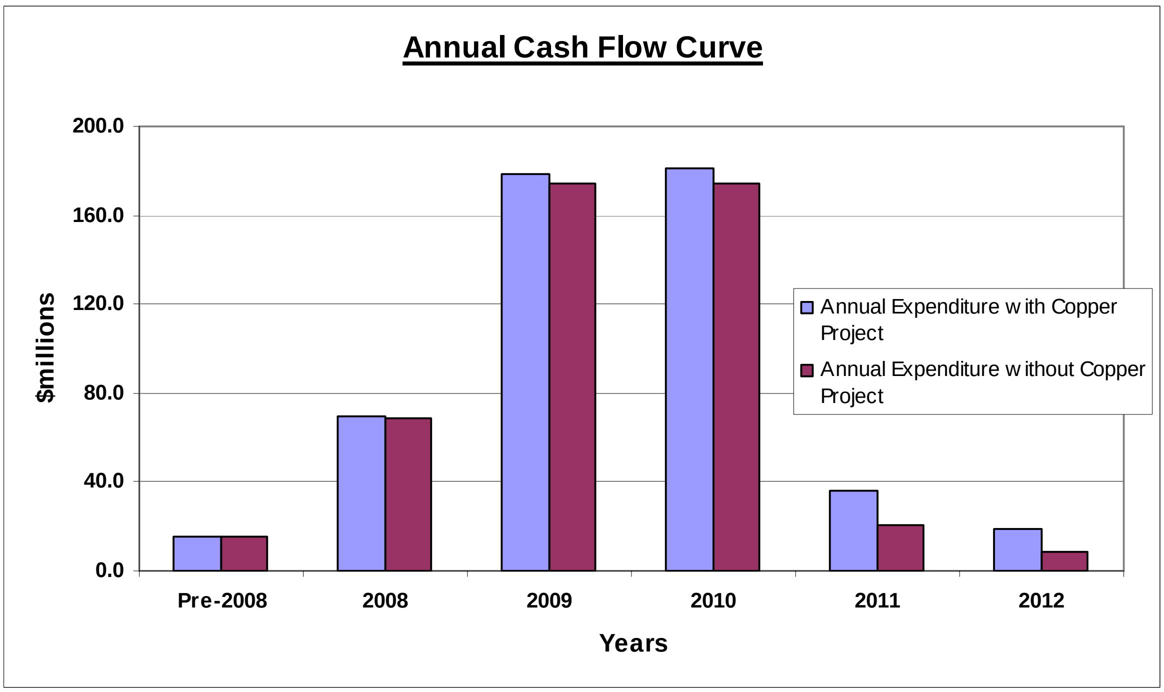
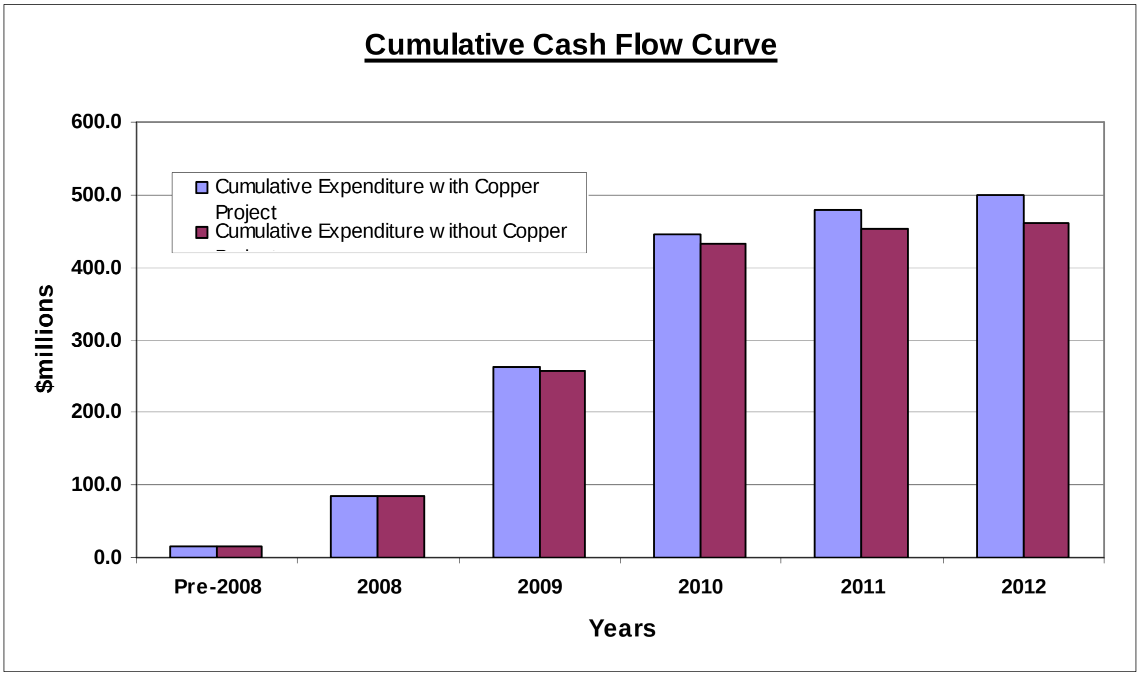


Figure A2.1.2b
Cumulative Cash Flow Curve



3.0 Reference: Capital Plan, pp. 7-8

Transmission Growth

Unanticipated delays

"Transmission Growth – Expenditure increases in this category total $75.2 million and are due to several factors, primarily made up of the following: … (5) Unanticipated delays that shifted the substantial completion date of the Okanagan Transmission Reinforcement ("OTR") Project from 2009 to 2010 and scope refinement associated with the completion of detailed engineering, ($71.6 million)."

Q3.1 Please provide examples of the unanticipated delays of the OTR Project which comprised the expenditure of $71.6 million.

A3.1 The 2007 SDP Update anticipated that the OTR CPCN would be filed in the first quarter of 2007 with construction taking place between the 2007 and 2011 timeframe. Internal delays associated with completion of the detailed design and CPCN application filing has deferred approximately $5.0 million of the anticipated 2007 and 2008 expenditures to 2009 and 2010. Examples of these delays include a longer than anticipated time to confirm and finalize FortisBC's contract with BC Hydro, as well as additional engineering time to assess alternative transmission line corridors and structure types.

4.0 Reference: Capital Plan, p. 8
Transmission Growth
Huth Substation

"These [Transmission Growth] expenditure increases were partially offset by the following factors:
…(7) The Huth Substation rebuild has been deferred from 2010 to 2011 to avoid conflicts with the OTR construction schedule. Only the engineering and planning and some material acquisition is included in 2010, ($5.9 million);…" [brackets added]

Q4.1 Please explain why the engineering and planning and some material acquisition were not deferred along with the deferred Huth Substation rebuild expenditures.

A4.1 Engineering, planning and some material acquisition for the Huth Substation upgrade will be carried out in 2010 so that the Project can commence as soon as practical after the work on the OTR Project allows 76 Line to be returned to service, prior to year end 2010. The completion of noted activities will allow construction on the Huth Substation upgrade to commence in the first quarter of 2011.

5.0 Reference: Capital Plan, p. 8

Transmission Line Sustaining

Fortis BC August 31/06 response to Commission IR#1, Q. 1.1 and Q. 1.2, p. 1,

2007-2008 Capital Plan

Right-of-way expenditures

With regard to the Transmission Line Sustaining and the Right of Way Reclamation Project referred to in the 2007-2008 Capital Plan, FortisBC provided the following response in to IR#1, Q. 1.1 and Q. 1.2:

1.0 Reference: CEP p. 9, 50 Right of Way Reclamation Project

Q1.1 Please explain why no expenditures were included in the original plan for this project.

A1.1 The Transmission Line Right of Way Reclamation project is required to remove danger trees and expand the tree free zone around the transmission lines. The original plan for this project included funds for 2004 and 2005; however, the plan inadvertently omitted to include funds for subsequent years.

Q1.2 Will the Mountain Pine Beetle problem affect this program? If so, please explain the expected cost impact.

A1.2 Yes, the mountain pine beetle, and the western pine beetle will affect the program. The mountain pine beetle preys on lodge pole pine, and the western pine beetle on ponderosa pine. Both eat into the wood layer under the bark and kill trees in one season. There is also an attack of spruce bugs eating the needles of other species, primarily Douglas Fir in the FortisBC service territory.

The following table defines the areas that will be affected the most by these insects, and the projected 2007 hazard tree removal costs due to the die-off.

Table 1.1

	($000s)
Okanagan (North and South) Primarily Western Pine beetle due to the prevalent species (Ponderosa Pine)	70
Princeton Area (Hedley to Tulameen) Both Spruce bug and Mountain Pine beetle (Lodge Pole Pine and Fir)	40
Boundary Area Mountain Pine beetle (Lodge Pole Pine)	20
Kootenay Area Mountain Pine beetle and Spruce bug (Lodge Pole Pine and Fir)	30
Total	**160**

The 2009-2010 Capital Plan states:

"Transmission Line Sustaining – Forecast expenditures in this category have increased by $6.8 million primarily due to:

(1) The requirement for increased transmission right-of-way expenditures associated with the removal of damaged trees resulting from the Pine Beetle infestation problem, ($2 million):…"

Excerpt of Modified Settlement Agreement, Order No. G-147-07, Appendix A, page 7:

APPENDIX A
to Order No. G-147-07
Page 7 of 40

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ISSUES	ISSUE DESCRIPTION	RESOLUTION	REFERENCE
Tab 7 – Capital Expenditures			
Preliminary Investigative Projects: (Sec. 7.2.8) Duck Lake Substation Property	FortisBC proposes to purchase property adjacent to its Duck Lake Substation in order to secure access and provide for possible future expansion of the substation.	The purchase of the land is not approved at this time. FortisBC may bring forward this item at a future time when a near term or medium term need is established.	Updated Exhibit B-1, Tab 7, p. 17; and attached report; Exhibit B-2, BCUC Q7.2 & Q51.3
Preliminary Investigative Projects: (Sec. 7.2.8) Pine Beetle Kill – Hazard Trees	FortisBC proposes to capitalize the removal of danger trees killed by the pine beetle as additional right of way reclamation expenditures.	Accept budget forecast for 2008 for the purposes of this negotiation. FortisBC is to provide detailed analysis at the next annual review of the extent of the hazard and the future costs. FortisBC and the Participants hold differing views on the treatment of removal costs for Pine Beetle Kill. The Parties agree that the 2008 removal costs will be recorded in a rate-base deferral account, amortized over 10 years, without prejudice to the treatment of future expenditures.	Updated Exhibit B-1, Tab 7, pp. 17-18; and attached report; Exhibit B-2, BCUC Q7.4, p.14; Q27.5.1, p.91, Q27.5.2, p.91, Q27.5.3, p.92, Q41.1, p.123; Exhibit B-2, Appendix Q28.1A, p.31

Q5.1 Are the $2 million transmission right-of-way expenditures included in or separate from the Transmission Line Right of Way Reclamation project?

A5.1 The $2 million referenced is separate from the Transmission Line Right-of-Way Reclamation project. For clarification, as outlined in Table 3.1, page 43, lines

19 and 20 of the 2009-2010 Capital Plan (Exhibit B-1), the Transmission Sustaining category contains two projects: (1) Transmission Line Right of Way Reclamation project ($1.15 million) and (2) Transmission Pine Beetle Hazard Allocation project ($2.04 million) respectively.

Q5.1.1 If included, has the tree removal cost increased from $160,000 in 2007 to $2,000,000 in 2008? Please explain the increase.

If separate, what is the dollar increase/decrease change for the Transmission Line Right of Way Reclamation project from 2007 to 2008?

A5.1.1 As stated in response to BCUC IR No. 1 Q5.1, the Transmission Line Right of Way Reclamation and Transmission Pine Beetle Hazard Allocation are separate projects. The following table from page 58 of the 2009-2010 Capital Plan (Exhibit B-1) shows the actual and forecast expenditure for the Transmission Line Right of Way Reclamation project.

Right-of-Way Reclamation

Year	**2005**	**2006**	**2007**	**2008F**	**2009**	**2010**
Cost ($000s)	443	421	821	359	550	602

Q5.2 On the danger trees mentioned in IR 4.0 and 4.1, is FortisBC putting the removal cost into a deferral account as required by the 2007 Settlement Agreement and Order No.G-147-07, Appendix A, page 7? If not, why not?

A5.2 Yes, the Company is capturing the 2008 costs of the Pine Beetle Kill – Hazard Tree Removal in a deferral account and will amortize those costs over 10 years in accordance with Commission Order G-147-07.

6.0 Reference: Capital Plan, p. 9

Distribution

Capital Plan, Table 4.1, p. 78

Copper conductor

"Distribution – An increase of $16.5 million in expenditures is explained primarily by:…

…(3) An assessment of aged copper conductor which has identified the conductor as a safety and reliability issue, ($11.4 million)."

Q6.1 Please track the Copper Conductor Replacement Program separately from the Capital Plan and provide revised Capital Plan without this expenditure.

A6.1 Please see Revised Table 4.1 below without the Copper Conductor Replacement Program expenditures.

Revised Table 4.1
Distribution Projects Expenditures

		Previously Approved	2009 Total	2010 Total
			($000s)	
1	**GROWTH**			
2	New Connects - System-wide		9,788	10,670
3	**Distribution Growth Projects**			
4	Glenmore -New Feeder		788	
5	Airport Way Upgrade Feeder			1,551
6	Hollywood Feeder 3- Sexsmith Feeder 4 Tie			365
7	Christina Lake Feeder 1 Upgrade		608	489
8	Beaver Park-Fruitvale Tie			1,227
9	Small Growth Projects			137
10	Unplanned Growth Projects		974	994
11	**TOTAL GROWTH**		**12,158**	**15,433**
12	**SUSTAINING**			
13	**Distribution Sustaining Programs and Projects**			
14	Distribution Line Condition Assessment		599	667
15	Distribution Line Rehabilitation		3,124	3,470
16	Distribution Right-of-Way Reclamation		621	646
18	Distribution Pine Beetle Hazard Allocation		722	551
19	Distribution Line Rebuilds		1,178	1,167
20	Small Planned Capital		668	747
21	Forced Upgrades and Line Moves		1,255	1,461
22	Distribution Urgent Repair		1,911	1,805
23	PCB Program	G-52-05	1,073	1,117
24	Aesthetic and Environment Upgrades	G-58-06	100	100
26	**TOTAL SUSTAINING**		**11,251**	**11,731**
27	**TOTAL**		**23,409**	**27,164**

Q6.2 What is the age of the copper conductor and the normal life of copper conductor?

A6.2 All of the copper conductor is in excess of 50 years old. The normal useful life of the copper conductor is generally considered to be between 40-50 years.

Q6.3 Is the safety and reliability issue a recent or ongoing concern? Are there any annual safety checks or inspections currently in place?

A6.3 The safety and reliability issue has been an ongoing concern, however the increased failures since 2004 created an increased awareness of the potential safety hazards associated with such incidents. The Company has an ongoing distribution condition assessment program to help identify potential hazards, however the nature of the failures is such that potential failures cannot always be detected during the condition assessment process.

7.0 Reference: Capital Plan, p. 10
Generation
2007-2008 Capital Plan, pp. 10-11, p. 18
Generating units

Pages 10-11 of the 2007-2008 Capital Plan state:

"Generation – FortisBC has a total of fifteen generating units in its four power plants. Since 1997 a major upgrade and life extension project has been underway and well documented in several forums. To date five units have been totally completed, the sixth will be completed in 2006 and the seventh in 2007."

Page 10 of the Capital Plan states:

"By the end of 2008, seven units will have been completed, with the eighth to be completed in 2009, and the ninth and tenth forecast for completion in 2010."

Page 18 of the Capital Plan states:

"The program has been extended by one year compared to the 2007/08 Capital Plan filing due to extended delivery times being experienced for major components."

Q7.1 Please describe the factors caused the extended delivery times being experienced for major components.

A7.1 The factors causing the extended delivery times for major components are the increased world-wide demand for the component, and the associated availability of raw materials for their manufacture. This is supported by anecdotal information provided by vendors when inquiring as to the availability and placing of orders for these components.

Q7.2 What is the cost attributable to the delay of the seventh unit to be completed in 2008 and not in 2007?

A7.2 The seventh unit, Lower Bonnington Unit 3, is complete with the unit returned to service in July 2007.

8.0 Reference: Capital Plan, p. 12

Appendix 4, MMK Consulting, BC Hydro Construction Cost Trends and Outlook, Exhibit 7a, p. 54

Inflation rate

"A report completed by MMK Consulting in 2007…recommends a cost inflation allowance between four percent and six percent for 2007-2010 and between three percent and four percent for 2011-2015 for all construction projects. FortisBC has adopted an inflation rate of five percent for 2009 and 2010."

Q8.1 On what basis did FortisBC choose an inflation rate of five percent for 2009 and 2010?

A8.1 FortisBC chose an inflation rate of five percent for 2009 and 2010 based on Company experience, and on discussions with BC Hydro which commissioned the MMK report. The inflation rate of five percent is the midway point of the range (four to six percent) recommended in the MMK report.

9.0 Reference: Capital Plan, p. 12

Estimate accuracy

"Project costing within utilities has been very volatile during the past years. Those projects for which a CPCN has been filed or for which FortisBC expects to file a CPCN in 2009, have a cost estimate with a +/- 10 percent level of accuracy. However since detailed engineering has not been completed for many other projects listed in the 2009-2010 Capital Plan, the estimates for these projects are at a +/- 20 percent level of accuracy."

Q9.1 Please explain why detailed engineering has not been completed for many other projects listed in the 2009-2010 Capital Plan in order to increase the level of accuracy of project cost estimates.

A9.1 There are basically two categories of project for which detailed engineering has not been completed. These include planning level projects for which a detailed scope has not been developed and sustaining projects where the planned expenditures are based on historical cost and for which specific items or locations have not been identified.

Detailed engineering has not been undertaken due to the amount of work and cost that would be associated, as well as the fact that the planning level projects will not result in construction costs until the 2011-2012 time frame. Estimates for the construction costs will be +/- 10 percent when submitted for approval as part of the next Capital Expenditure Plan Application.

The planning level projects include such projects as:

- Kelowna Distribution Capacity Requirements;

- Huth Substation Upgrade; and
- Static Var Compensator.

The sustaining projects include such projects as:

- Transmission Urgent Repairs;
- Transmission Rehabilitation;
- Station Urgent Repairs ;
- New Connects – System Wide;
- Unplanned Growth Projects;
- Distribution Line Rehabilitation;
- Small Planned Capital (Sustaining);
- Forced Upgrades and Line Moves; and
- Distribution Urgent Repairs.

10.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, Major Projects, p. 20
Table 2.1

Q10.1 Please add a column to Table 2.1 showing the approved CPCN Budget.

A10.1 Please see Revised Table 2.1 below.

Revised Table 2.1
Generation Projects

		Previously Approved	Expenditures to Dec 31/08[1]	2009	2010	Future [2]	Total	Approved Budget
	Sustaining		**$000s**					
1	South Slocan Unit 1 Life Extension	G-147-06	6,729	7,832	3,261	39	17,861	13,334
2	South Slocan Unit 3 Life Extension	G-147-06	11,010	2,051	-	-	13,061	13,311
3	Corra Linn Unit 1 Life Extension	G-147-06	874	4,487	8,476	5,113	18,950	11,835
4	Corra Linn Unit 2 Life Extension	-	-	104	5,264	17,313	22,681	-
5	South Slocan Plant Completion	G-147-06	1,012	940	1,598	-	3,550	1,935
6	Upper Bonnington Civil / Structural Upgrade and Old Unit Repowering (Phase 1)	G-147-06	4,142	1,094	651	-	5,887	5,490
7	South Slocan Unit 1 Headgate Rebuild	G-147-06	-	577	279	-	856	670
8	South Slocan Headgate Hoist, Control, Wire Rope Upgrade	G-147-06	669	434	-	-	1,103	669
9	Generating Plants Upgrade Station Service Supply	G-147-06	1,144	484	1,191	2,192	5,011	3,785
10	Generating Plants Area Lighting	-	-	478	338	-	816	-
11	All Plants Spare Unit Transformer	-	469	1,380	-	-	1,849	-
12	**Subtotal Major Projects**	-	**26,049**	**19,861**	**21,058**	**24,657**	**91,625**	-
13	**Subtotal Minor Projects from Table 2.2**	-	-	**2,074**	**1,499**	-	**3,573**	-
14	**Total Generation**	-	**26,049**	**21,935**	**22,557**	**24,657**	**95,198**	-

(1) Future expenditures for ongoing sustaining programs have not been included in these tables.

(2) All forecast figures are based on forecasts as of April 30, 2008.

11.0 Reference: Capital Plan, p. 21

South Slocan Unit 1 Life Extension (Replace Turbine)

Document request

"This project is a multi-year project with initial expenditures occurring in 2005/06. A condition assessment of the unit's major components and systems was done to determine the scope of work and cost estimate."

Q11.1 Please provide copies of all supporting documents, assessment reports, studies and standards referred to in the Capital Plan and SDP.

A11.1 The requested documents are attached as Appendix A11.1.

12.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, South Slocan Unit 1 Life Extension, p. 21
Project Cost Overruns

Q12.1 Considering the cost overrun of $4.6 million, does FortisBC have any comments on why there has been a significant delay from 2005 to 2010 in the project?

A12.1 The project as initially approved would have seen final costs and project close-out in 2008, therefore the project delay is two years. The delay is due to the negotiation of the Canal Plant Entitlement Adjustment Agreement (EAA) in 2004, which resulted in a need to re-engineer the replacement turbine to comply with the EAA, and for subsequent approval by BC Hydro. The engineering contributed to one year of delay and the other year can be attributed to major component delivery lead time.

13.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, South Slocan Unit 3 Life Extension, p. 22
Project Scope Change

Q13.1 Considering the original cost was $13.31 million including the blade runner at $1.7 million, the revised cost without the blade runner would be $11.61 million so the project is actually $1.45 million over-budget. Please confirm and comment.

A13.1 FortisBC confirms the numbers quoted. Considering the original costs of $13.31 million stated in the 2007-2008 Capital Plan and the revised cost of $13.06 million as stated in the 2009-2010 Capital Plan, the reduction of $1.7 million due to the removal of the turbine scope of work has been offset by increases due to escalation of materials in other scopes of work. For example, the turbine component refurbishment has increased $0.45 million, main lead cables by $0.34 million, generator step-up transformer by $0.31 million, generator windings by $0.10 million and transformer bay upgrades by $0.13 million.

14.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, Corra Linn Unit 1 Life Extension, pp. 22-23
Project Scope

The original budget was $11.81 million and the current total estimated cost is $18.95 million. The overrun is $7.15 million.

Q14.1 Please confirm that the new turbine runner costs $2.5 million.

A14.1 FortisBC can not confirm that the new runner costs will be $2.5 million, as the tendering process has yet to be completed to obtain a firm price from suppliers. The estimate of $2.5 million is a preliminary +/- 20 percent estimate based on FortisBC's knowledge of current market pricing of similar sized turbines.

15.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, Corra Linn Unit 2 Life Extension, pp. 23-24
Project Scope Change

FortisBC states that the turbine condition assessment has yet to be completed. FortisBC states that the unit upgrade cost is $22.7 million.

Q15.1 Does FortisBC expect to apply for a CPCN after the completion of the turbine condition assessment? Please explain.

A15.1 FortisBC does not expect to file a CPCN application for this project. The Company is of the opinion that the Life Extension and Upgrade Program is well established and that the completed projects have demonstrated that the public interest is well served by continuation of the program. Given the similarity of this project to others in the program, additional information can be adequately garnered as part of the current regulatory process. Further, the cost threshold for the requirement of a CPCN of $20 million was established in 2005, and has remained at that level while project costs have been subject to escalating factors. Accordingly, FortisBC does not believe that a CPCN application is required.

In addition, FortisBC believes that previous Commission Decisions reflect the fact that the ongoing nature of these projects, and the continued demonstration that they are in the public interest make expenditures related to a CPCN process imprudent. In 2005, FortisBC submitted a CPCN Application for the Lower Bonnington ULE Project. Noting that the Application was not required under the CPCN Requirement Criteria proposed at the time, in its Decision on the FortisBC 2005 Revenue Requirement Application (G-52-05), the Commission invited FortisBC to withdraw the CPCN Application.

16.0 Reference: Capital Plan, Appendix 2 – Corra Linn Unit 2 Life Extension, p. 1

Turbine replacement

"The project will follow the same condition assessment of major unit components and systems as previous upgrade and life extension projects. A turbine replacement condition assessment has yet to be completed which will determine if a new turbine or turbine refurbishment is required."

Q16.1 When does FortisBC expect that the turbine replacement condition assessment will be completed?

A16.1 The condition assessment is planned to be completed from September 28, 2008 to October 2, 2008.

Q16.2 Please explain in Appendix 2 as to why there is a $1,113,000 ($2,118,000 - $1,005,000) increase in line 39 Cost of Removal between the "run to failure in 2011 and do not repair" option and the other two options (i.e., "planned life extension" and "run to failure in 2011, then do life extension").

A16.2 There is an increase in cost of removal for the "run to failure in 2011 and do not repair" option due to additional costs to decommission the plant which is not required for the other two options.

17.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, South Slocan Plant Completion, pp. 24-25
Project Scope Delay

The original budget was $1.9 million and the current total estimated cost is $3.55 million. The expected increase in cost is $1.65 million.

Q17.1 Please provide a detailed comparison, in table format, of the original estimate to the current estimate.

A17.1 Please see Table A17.1 below.

Table A17.1
Estimated Cost Comparison

		Original Estimate	**Current Estimate**	**Variance**
		$000s		
1	Unit 2 Completion	1,169	1,283	114
2	Unit Protection and Control	254	944	690
3	Engineering	0	190	190
4	Environment, Health and Safety	41	201	160
5	Structures and Related Facilities	180	448	268
6	Plant Auxiliary Equipment - Electrical	238	217	(21)
7	Plant Auxiliary Equipment - Mechanical	53	270	217
8	**Total**	**1,935**	**3,553**	**1,618**

Q17.2 Please provide justification for the $0.35 million in engineering and environmental.

A17.2 The $0.35 million in “engineering and environmental” are required as they are integral to the project and were overlooked in the original estimate. For example, engineering support is required for Unit Protection and Control, Plant Auxiliary Electrical and Mechanical Equipment. Environmental support is required to develop safe work plans and audit the handling of hazardous materials and other environmentally sensitive work activities.

Q17.3 Please identify where the unaccounted for $0.61 million originate from.

A17.3 As shown in Table A17.1 above, the unaccounted $0.61 million originates from Unit 2 completion at $0.11 million, Structures and Related Facilities at $0.28 million, and Plant Auxiliary Equipment Mechanical at $0.22 million.

Q17.4 Why was there a project delay?

A17.4 All South Slocan Unit Life Extensions must be completed in order to complete this project. As a result this project will now be completed in 2010, following completion of the Unit 1 Life Extension.

Q17.5 Does FortisBC expect to re-apply for a CPCN? Please explain.

A17.5 FortisBC does not intend to apply for a CPCN for this project. The project was approved by Commission Order G-147-06 regarding the 2007-2008 Capital Plan, and FortisBC believes that regulatory process to review the 2009-2010 Capital Plan is sufficient to provide any additional information required by the Commission and intervenors.

18.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, Upper Bonningtion Old Unit Repowering, p. 25
Lack of Construction Resources

The original budget was $5.49 million and the current total estimated cost is $5.89 million. The increase in cost is $0.40 million.

Q18.1 Please confirm that the project delay was solely due to the lack of civil construction resources.

A18.1 The project delay was not solely due to the lack of civil construction resources, but also a lack of engineering resources. As stated in the Capital Plan (Exhibit B-1), page 25, line 5, “Much of the work is seasonally dependent. Availability of civil construction resources has extended the project completion date to 2010”. The reference to “construction resources” also pertains to the engineering aspect of this project. Due to the age and the associated condition of the documentation on the structure, the civil work at Upper Bonnington requires considerable engineering which is also a limited resource.

19.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, South Slocan Unit 1 Headgate Rebuild, pp. 25-26
30% Larger Headgates

The original budget was $0.67 million and the current total estimated cost is $0.86 million. The increase in cost is $0.19 million.

Q19.1 Please explain how the 30% larger factor is directly proportional to the cost increase.

A19.1 The larger size of Unit 1 Headgate resulted in additional materials and labour costs, but the size is not considered to be directly proportional to the cost increase.

Q19.2 Please describe the amended procedures to accommodate the limited access.

A19.2 The amended procedure to accommodate the limited access is the use of a hoisting structure assembled on site which allows gate removal. With normal road access this task would be accomplished with mobile crane equipment.

Q19.3 Please explain why the 30% larger headgates and limited accesses issues were not adequately address in the original estimate.

A19.3 The original estimate was made by using costs from a previously completed rehabilitation project for a smaller gate which did not have access problems.

Q19.4 Why was there a project delay?

A19.4 A unit outage must be taken and the unit dewatered to complete the work on the embedded parts in the water passage. In order to minimize outage costs this project was delayed so as to coordinate with the South Slocan Unit 1 ULE outage.

20.0 Reference: 2. Generation, Major Projects
Exhibit No. B-1, South Slocan Headgate Hoist, Control, Wire Rope Upgrade, p. 26
Project Delay

The original budget was $0.67 million and the current total estimated cost is $1.1 million. The increase in cost is $0.43 million.

Q20.1 Please provide a detailed comparison, in table format, of the original estimate to the current estimate.

A20.1 Please see Table A20.1 below.

Table A20.1
Estimated Cost Comparison

	Original Estimate	Current Estimate	Variance
		$000s	
Hoist	475	672	197
Controls	111	244	133
Wire Rope	83	137	54
Engineering, Procurement and Construction Management	0	50	50
Total	**669**	**1,103**	**434**

Q20.2 Why was there a project delay?

A20.2 The project was rescheduled to align with the Headgate rebuild for the reasons described in response to BCUC IR No. 1 Q19.4.

21.0 Reference: 2. Generation, Small Sustaining Projects
Exhibit No. B-1, All Plants Fire Safety Upgrade Phase 1, pp. 30-31
Phase 1

Q21.1 Are there other phases to this project?

A21.1 Yes, Phase II will be the installation portion of this project. Phase II will be submitted for regulatory approval as part of FortisBC's next Capital Expenditure Plan to be filed in 2010.

Q21.2 Please provide a cost, in table format, for each plant.

A21.2 Please see Table A21.2 below.

Table A21.2
Fire Safety Upgrade Costs by Plant

Plant	2009 - Phase I
	($000s)
Lower Bonnington	60.25
Upper Bonnington	60.25
South Slocan	60.25
Corra Linn	60.25
Total	**241.0**

22.0 Reference: 2. Generation, Small Sustaining Projects
Exhibit No. B-1, All Plants Public Safety and Security Phase 1, p. 31
Phase 1

Q22.1 Are there other phases to this project?

A22.1 The phases are equivalent to those of the Fire Safety Upgrade Project described in the response to BCUC IR No. 1 Q21.1 above.

Q22.2 Please provide a cost, in table format, for each plant.

A22.2 Please see Table A22.2 below.

Table A22.2
Public Safety and Security Costs by Plant

Plant	2009 - Phase I	2010 - Phase II
	($000s)	
Lower Bonnington	20.5	13.0
Upper Bonnington	20.5	13.0
South Slocan	20.5	13.0
Corra Linn	20.5	13.0
Total	**82.0**	**52.0**

23.0 Reference: 2. Generation, Small Sustaining Projects
Exhibit No. B-1, Lower Bonnington Power House Crane Upgrade, p. 31
Capacity

Q23.1 What is the crane lift capacity?

A23.1 The rated crane capacity is 120 tonnes on the main hook and 20 tonnes on the auxiliary hook.

24.0 Reference: 2. Generation, Small Sustaining Projects
Exhibit No. B-1, Corra Linn Power House Crane Upgrade, pp. 31-32
Capacity

Q24.1 What is the crane lift capacity?

A24.1 The rated crane capacity is 120 tonnes on the main hook and 20 tonnes on the auxiliary hook.

25.0 Reference: 2. Generation, Small Sustaining Projects
Exhibit No. B-1, All Plants 2009 Upgrades, p. 33
Dewatering Pumps

Q25.1 Please provide a cost, in table format, for each plant.

A25.1 Please see Table A25.1 below.

Table A25.1
Dewatering Pump Costs by Plant

Plant	2009
	($000s)
Lower Bonnington	116.0
Upper Bonnington	117.0
South Slocan	0.0
Corra Linn	0.0
Total	**233.0**

26.0 Reference: 2. Generation, Small Sustaining Projects Exhibit No. B-1, Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade, pp. 38-39

Solid State Meters

Q26.1 When were the Quad 4 power meters installed?

A26.1 The Quad 4 power meters were installed in 1995 and 1996.

Q26.2 When were the PML-7650 meters first released?

A26.2 The PML-7650 meter was first released in September 2004.

Q26.3 What is the meter accuracy of the Quad 4 versus the PML?

A26.3 The meter accuracy of the Quad 4 and the PML is the same. Both are Class 0.2 Revenue Accuracy.

27.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Naramata Rehabilitation (Naramata Substation), p. 45
Concrete Aesthetic Wall

In Exhibit B-5, page 6 of the Naramata hearing FortisBC outlines the total cost of the Fire Hall site as $7.272M with chain link fencing having privacy slats. Also in the same table, FortisBC outlines the total cost of the Fire Hall site as $7.362M with an aesthetic wall.

In the Naramata Transcript on page 136 Mr. Finke of FortisBC stated "Yeah, the two options that we've allowed for would be a concrete aesthetic wall, or privacy slats and a chain-link fence".

Order No. G-124-07 directs FortisBC to "Consult with local residents on alternatives for substation screening and select an option which is cost effective and sensitive to local concerns. The details of the consultation and substation screening are to be included in the quarterly project reports".

Q27.1 Would FortisBC please explain why the aesthetic issues have now increased the cost to $7.524M and how it would be considered as cost effective?

A27.1 As directed by the Commission, FortisBC engaged in public consultation to determine an acceptable form of aesthetic screening for the substation at the Firehall site. The final cost of the option selected by the community has not been finalized, however the preliminary estimate to complete this work is $0.250 million which (compared to the initial estimate of $0.14 million) would increase the projected project costs from $7.412 million to $7.524 million.

Overall, the Naramata Project cost is estimated to be within 3 percent of budget. FortisBC will continue to work to minimize actual construction costs by competitively bidding the procurement and installation of the fence, and actively managing the installation to maximize potential cost savings.

28.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Benvoulin Substation, p. 47
Siting

Q28.1 Would FortisBC please supply conceptual substation and transmission line siting diagrams including footprints and existing as well as new statutory rights-of-way?

A28.1 FortisBC will be filing a CPCN application for this project in the third quarter of 2008 which will contain the requested information.

Q28.2 Would FortisBC please supply the load demand curve justifying the need for this substation?

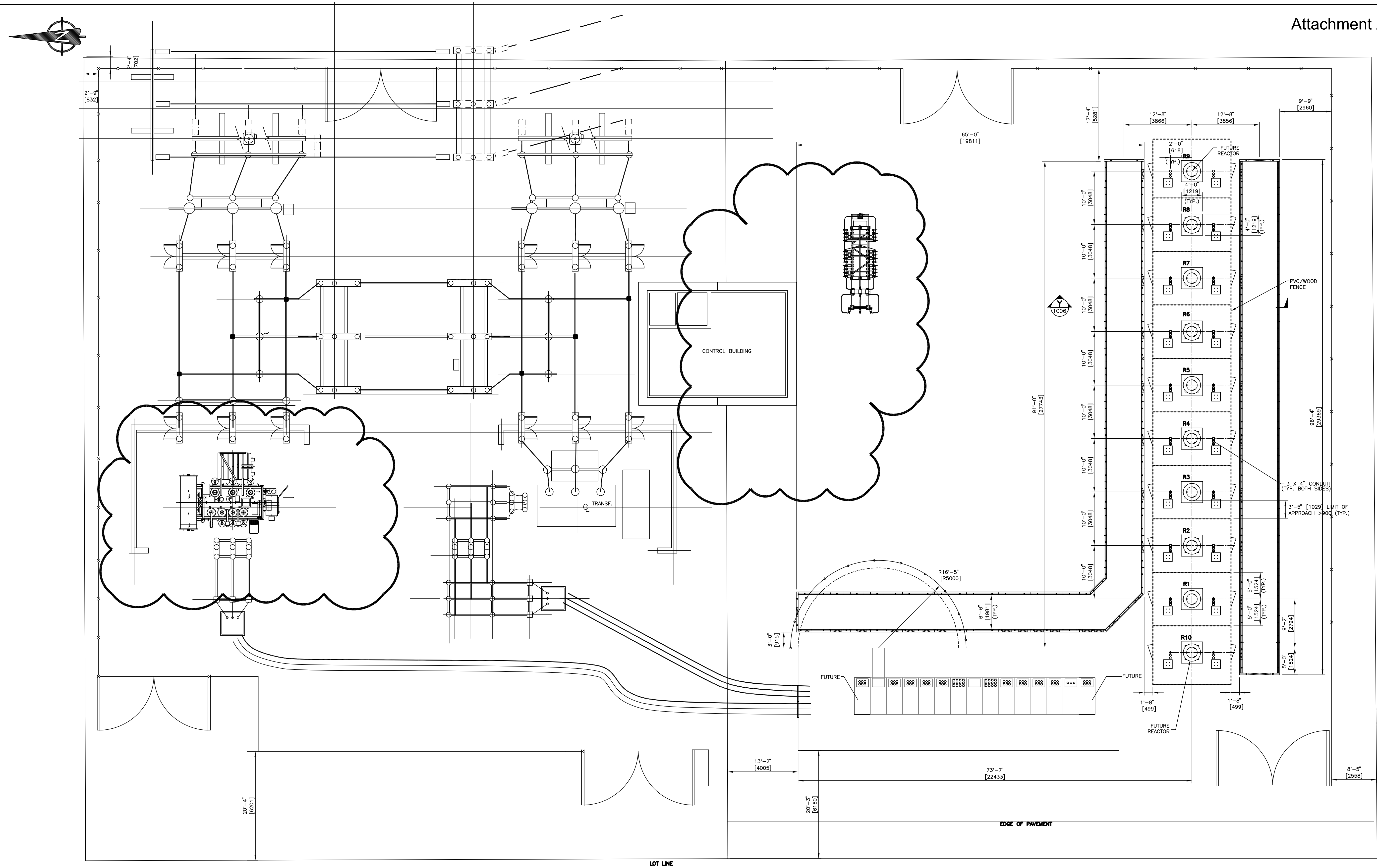
A28.2 FortisBC will be filing a CPCN application for this project in the third quarter of, 2008 which will contain the requested information.

29.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Recreation Substation, p. 49
Siting

Q29.1 Would FortisBC please supply conceptual substation and transmission line siting diagrams including footprints and existing as well as new statutory rights-of-way?

A29.1 Please see Attachment A29.1.

Attachment A29.1



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P2						
1						

DRAWN BY: H.URSAKI NOV/07
DESIGNED BY: HJU
CHECKED BY: HJU

APPROVALS: ELEC | CIVIL | MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: TRANSMISSION-DISTRIBUTION
LOCATION: RECREATION SUBSTATION
TITLE: 2009/2010 GENERAL ARRANGEMENT - T2 ADDITION

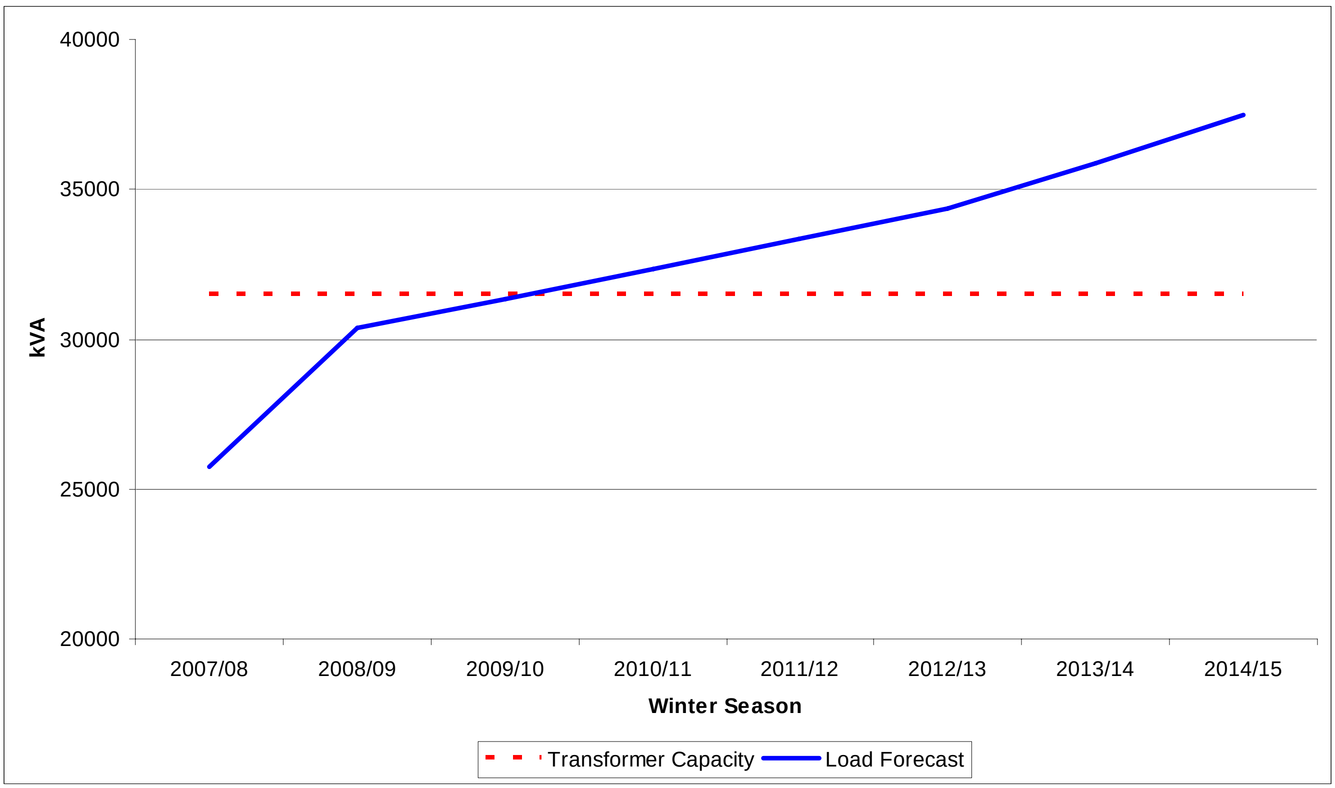
SCALE: 1/8" : 1'-0" SCALE FACTOR: 96

DRAWING NUMBER: C-306-8100 REVISION: P0

Q29.2 Would FortisBC please supply the load demand curve justifying the need for this substation?

A29.2 Please see Figure A29.2 below.

Figure A29.2
Recreation Substation Load Forecast



Q29.3 Does FortisBC expect to file a CPCN for this capital expenditure? Please explain.

A29.3 No, the Project does not meet the CPCN criteria as stated in Commission Order G-52-05 which include:

- the total project cost is $20 million or greater; or
- the project is likely to generate significant public concerns; or

- FortisBC believes for an reason that a CPCN application should proceed; or
- after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

However, FortisBC acknowledges that the Commission reserves the authority to designate any projects it deems necessary for a CPCN application.

The upgrade will be confined to additions within the existing substation fence, mitigating any potential public concerns, and the estimated cost for the project is below the $20 million threshold for a CPCN Application.

30.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects

Exhibit No. B-1, Kelowna Distribution Capacity Increase, p. 50

Detailed Investigation and Recommendation

Q30.1 Would FortisBC please elaborate how the increasing load will place pressure on the distribution infrastructure in the area?

A30.1 The continuing load growth in the greater Kelowna area is forecast to place an additional load of 100 MW on the Kelowna distribution system by 2012.

As load increases on the distribution system, individual feeder conductor segments can exceed their rated capacity and voltage drop across the feeder length can result in line voltage falling below acceptable limits. It also creates operational difficulties through the inability to adequately shift load through normal operation or during emergencies when backing up feeders. Lower life expectation of distribution equipment though overload is also a direct consequence. This results in the need for projects such as the Airport Way Upgrade, the Christina Lake Upgrade and the Beaver Park-Fruitvale Tie Upgrade in FortisBC's service territory.

As load further increases, the capability of individual feeders are exceeded, this results in projects such as the Glenmore New Feeder Project.

As load increases still further, there is a requirement to add additional capacity at the substation as is the case with the Recreation Capacity increase project. Where there is insufficient physical space at a particular substation to add additional capacity, then a new substation is required, as is the case with the Benvoulin Substation Project.

Q30.2 Would FortisBC please provide a listing of the distribution areas perceived to be at risk and rank them by the level of risk by year over the next five years?

A30.2 As noted in response to BCUC IR No. 1 Q30.1, the greater Kelowna area is facing high sustained growth levels. The specific areas of concern are:

- Kelowna north / Sexsmith / Highway 97 commercial area served by the Sexsmith Substation [risk ranking: high]
- Kelowna downtown served by the Saucier Station [risk ranking: high]

Q30.3 Would FortisBC please provide an outline of the engineering work (i.e., scope)?

A30.3 The Project in 2009/10 will develop a long-range plan to assist FortisBC in documenting major additions and reconfiguration changes required to accommodate load growth projections in the greater Kelowna area. While a detailed scope has not been completed, it is anticipated that the project will involve detailed planning and engineering analysis to identify alternative solutions and projects which will be required to maintain system stability and accommodate customer growth.

Q30.4 Would FortisBC please provide a rough estimate of the total project cost?

A30.4 FortisBC is unable to provide estimates as a detailed plan has not been developed.

31.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Tarrys Capacity Increase, pp. 50-51
Cooling Fans

Q31.1 Considering the state of the lumber industry in BC, what would be the load on this transformer if the Kalesnikoff Lumber Mill was to close down?

A31.1 If the Kalesnikoff Lumber Mill closed, the 1.2 MVA of residential load west of Tarrys, which is currently served by Playmor Substation, would be transferred to the Tarrys Substation. At the present time, FortisBC has no expectation of such an event.

Q31.2 As the peak load on this transformer was 2.9MVA in 2007 and fan cooling only provides 2.5MVA capacity, is not the transformer still operating at 16% above its fan cooled rating?

A31.2 Yes, the transformer will operate above the fan cooled rating during peak periods. However, due to the cyclical nature of the mill load, the equivalent load of the transformer is maintained within acceptable limits. The average daily load on the transformer is approximately 70 percent of peak load and the weekend average load is approximately 40 percent of peak load.

Q31.3 What is the age of this transformer?

A31.3 The transformer is 59 years old.

Q31.4 What is the current life expectancy considering the recent overloading of this transformer?

A31.4 The current life expectancy of this transformer has not been determined, however oil samples tested in July 2007 show no signs of any major internal problems.

Q31.5 What is the projected increase in load demand over the next five years for the Tarrys Substation?

A31.5 The current five year forecast does not project any increase in load demand for the Tarrys substation.

Q31.6 What was the cost of the other options? Please discuss the preference for the cooling fans over the other options.

A31.6 Please see Table A31.6 below. Please note that the 2009-2010 Capital Plan (Exhibit B-1) page 51, line 8, indicated that the preferred option involved the installation of 200 amp regulators. This should read 400 amp regulators. Please also refer to Errata No. 1.

Table A31.6
Options Cost

Option No.	Description	Cost ($000s)
1	Rehabilitation an existing 5.6 MVA transformer and installation at Tarrys Substation	922
2	Install three 400 amp regulators and a recloser on the existing Playmor Feeder 1 to provide distribution backup to the mill and salvage the Tarrys substation.	500
3	Install three 400 amp regulators on the existing Playmor Fdr 1 to provide distribution backup to the mill and install cooling fans on the Tarrys transformer.	400

Option 3 was selected in order to maintain the Tarrys substation supply to the mill and to provide distribution backup in the event of a transformer failure at Tarrys. Option 1 was eliminated due to the high capital cost. Option 2 was eliminated because the Company wishes to maintain the Tarrys Substation and not permanently transfer the load to Playmor due to the line interference resulting from the mill operation.

Q31.7 Please explain why the expenditure is $400,000 for the item. Provide details.

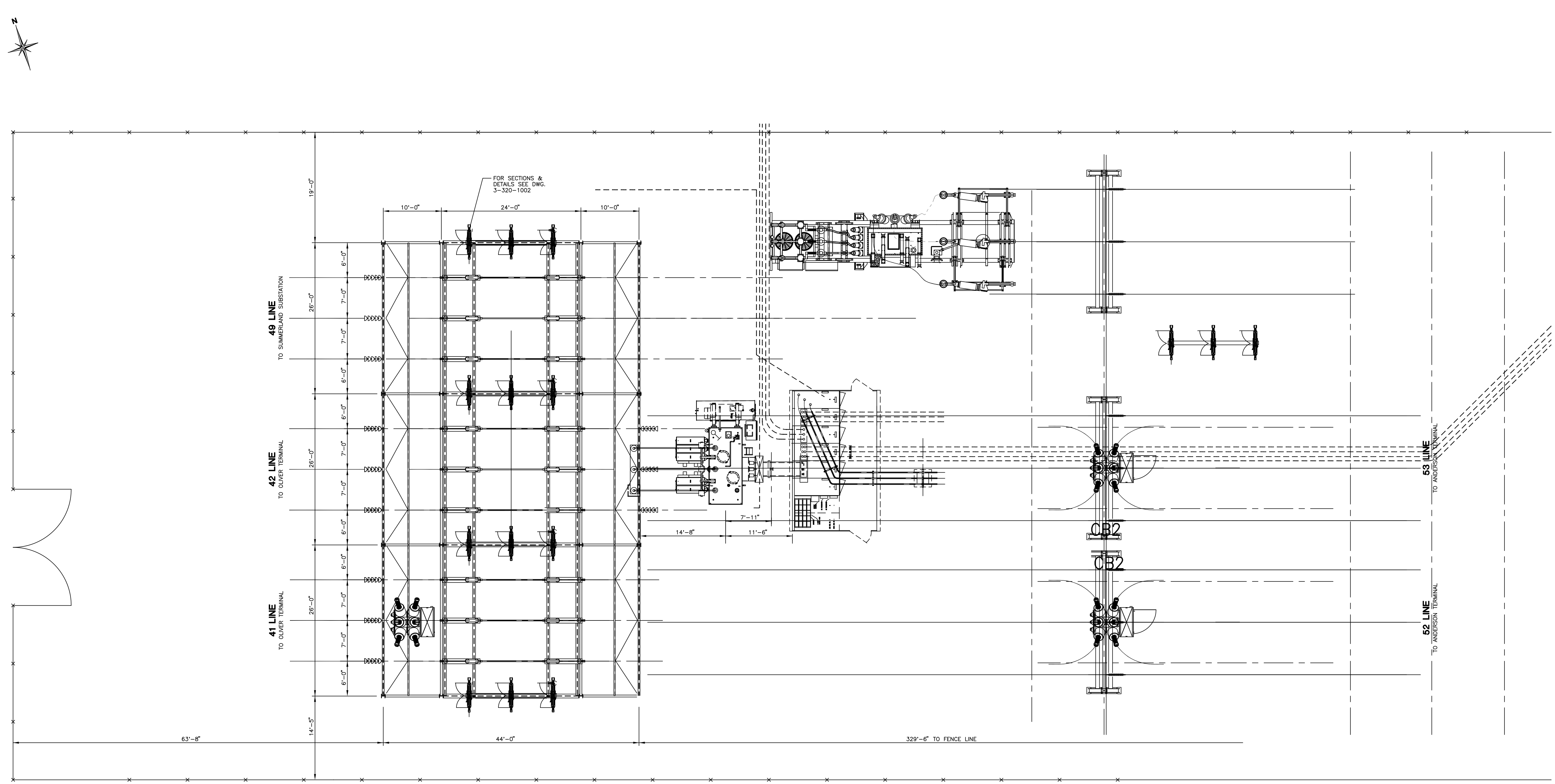
A31.7 The $400,000 estimated in the 2009-2010 Capital Plan includes approximately $0.2 million in material costs (regulators, regulator electronic controllers, regulator platform, transformer cooling fans, A/C panels and associated line construction material), $0.15 million in construction labor costs and $0.05 million in Engineering, Project Management and overhead costs.

32.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Huth Substation Upgrade, pp. 51-52
Bus Arrangement Modification

Q32.1 Would FortisBC please supply conceptual substation and transmission line siting diagrams including footprints and existing as well as new statutory rights-of-way?

A32.1 A conceptual general arrangement of the substation work is attached as Attachment A32.1 below. No new rights-of-way are required for either the substation or transmission line work.

Attachment A32.1



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DRAWN BY: H.URSAKI	JULY/07
DESIGNED BY: HJU	
CHECKED BY:	
APPROVALS	
ELEC / CIVIL / MANAGEMENT	

FORTISBC

DIVISION	OKANAGAN
DEPARTMENT	TRANSMISSION-DISTRIBUTION
LOCATION	HUTH SUBSTATION
TITLE	2009/2010 GENERAL ARRANGEMENT

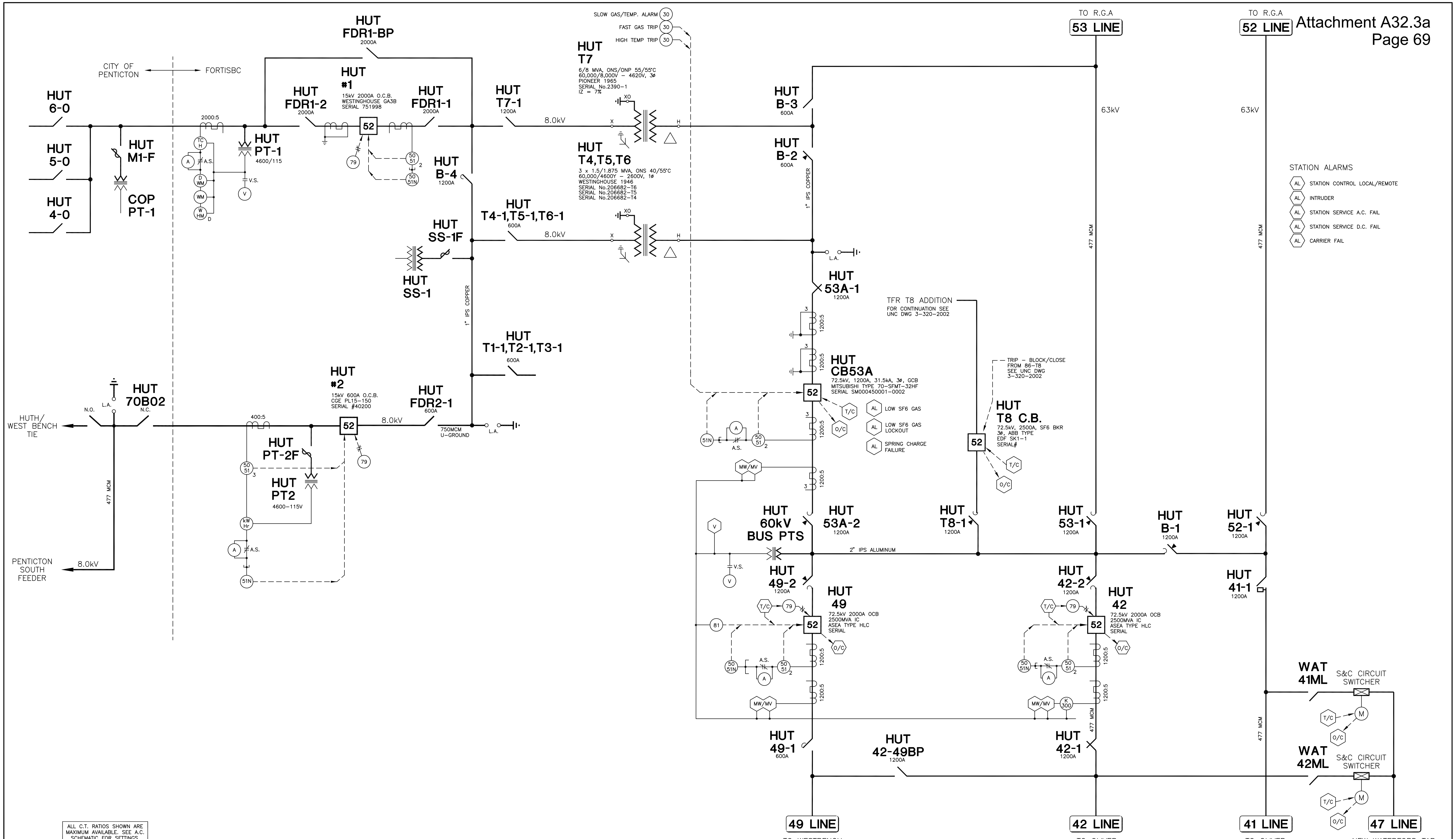
SCALE: 1/8" = 1'-0"	SCALE FACTOR: 96
DRAWING NUMBER	REVISION
C-320-8100	P0

Q32.2 Would FortisBC please identify if there have been any reported safety issues with this substation since 1950?

A32.2 Although the station is a legacy substation and does not necessarily meet current construction standards, no specific safety issues have been identified.

Q32.3 Would FortisBC please provide single line diagrams for the existing, single-us configuration and the ring bus alternative?

A32.3 Please see Attachment A32.3a below depicting the existing configuration, Attachment A32.3b depicting a split bus configuration, and Attachment A32.3c depicting a ring bus configuration.



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1050 Eldorado Street, Suite 202, Trail, BC V1R 3V7
Toronto, Ottawa, Winnipeg, Vancouver

REVISIONS

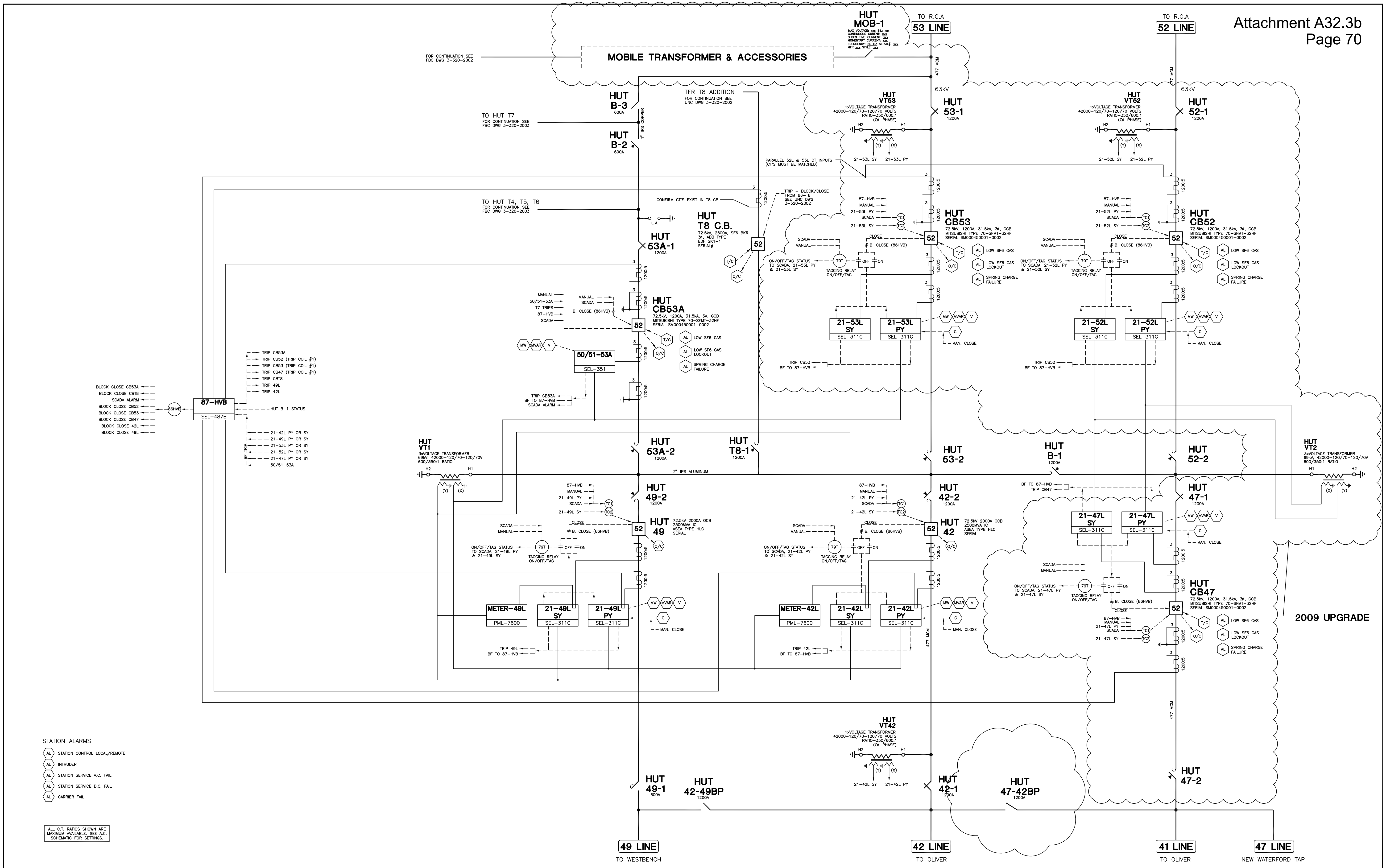
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
17	MAY/06	RY	DK	HUTH 63kV 53A BREAKER REPLACEMENT – ISSUED FOR CONSTRUCTION		
16	OCT/05	PFE		AS PER SCC REVISIONS (D. MOORE)		
15	APR/04	PFE	HJU	REMOVED IN-LINE JUMPERS AS PER SCC	H. URSAKI	APR/04
18	DEC/06	RY	RY	AS BUILT	K. HEDGES	MAY/02

DRAWN BY: K.R. HEDGES OCT/90
DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC | CIVIL | MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: PROTECTION-CONTROL
LOCATION: HUTH SUBSTATION
TITLE: 60 & 8.8 kV SINGLE LINE DIAGRAM

SCALE: NONE
SCALE FACTOR: 1
DRAWING NUMBER: 3-320-2000
REVISION: 18



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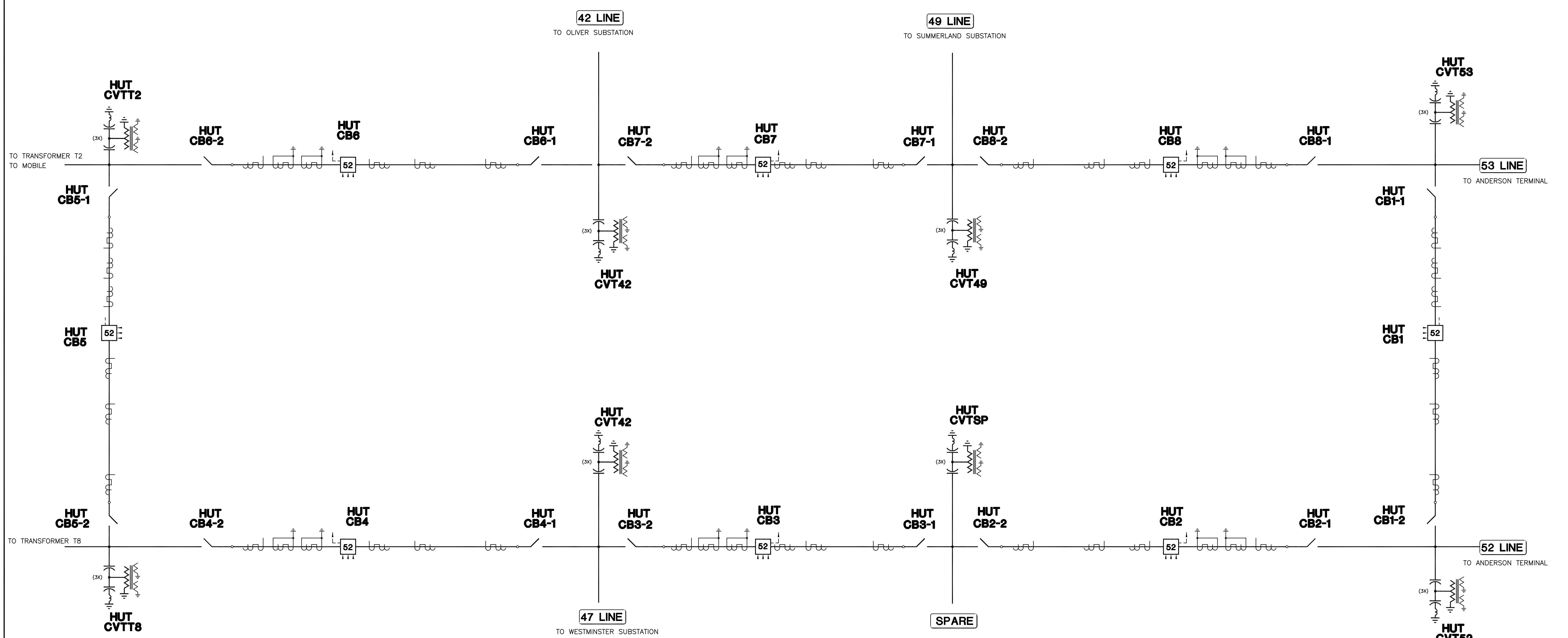
P4						

DRAWN BY: H. URSAKI OCT/07
DESIGNED BY: HJU
CHECKED BY: HJU
APPROVALS: ELEC | CIVIL | MANAGEMENT

FORTISBC

DIVISION: OKANAGAN
DEPARTMENT: PROTECTION-CONTROL
LOCATION: HUTH SUBSTATION
TITLE: 2009/10 SINGLE LINE - SPLIT BUS OPTION 1

SCALE: NONE SCALE FACTOR: 1
DRAWING NUMBER: C-320-8000
REVISION: P0



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FORTISBC

DIVISION	OKANAGAN
DEPARTMENT	PROTECTION-CONTROL
LOCATION	HUTH SUBSTATION
TITLE	69kV SINGLE LINE DIAGRAM - 2009 RING BUS

SCALE: NONE	SCALE FACTOR: 1.25
DRAWING NUMBER	REVISION
3-320-8200	P0

Q32.4 Would FortisBC please supply the cost of the ring bus alternative?

A32.4 The total cost of the ring bus alternative is estimated at $5.7 million.

Q32.5 Does FortisBC expect to file a CPCN for this capital expenditure? Please explain.

A32.5 No, the Project does not meet the CPCN criteria as stated in Commission Order G-52-05 which include:

- the total project cost is $20 million or greater; or
- the project is likely to generate significant public concerns; or
- FortisBC believes for an reason that a CPCN application should proceed; or
- after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

However, FortisBC acknowledges that the Commission reserves the authority to designate any projects it deems necessary for a CPCN application.

The upgrade will be confined to additions within the existing substation fence, mitigating any potential public concerns; and the estimated cost for the project is below the $20 million threshold for a CPCN Application.

33.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, 30 Line Conversion and the Installation of Capacitor at Coffee Creek and Kalso, p. 52-53

Q33.1 What is the current load and power factor at Coffee Creek and Kalso?

A33.1 The peak load and average power factor for the past year are shown in Table A33.1 below.

Table A33.1
Load and Power Factor

Substation	2007/08 Summer Peak (kVA)	Average Estimated Power Factor (%)	2007/08 Winter Peak (kVA)	Average Estimated Power Factor (%)
Coffee Creek	4,399	97	5,615	97
Kaslo	4,860	97	7,395	97

Q33.2 What is the estimated rating of the capacitors proposed to be installed?

A33.2 The proposed capacitor bank ratings are:

- Kaslo Substation: two 2.4 Mvar capacitor banks both operating at 25 kV; and;
- Coffee Creek Substation: one 3.6 Mvar and one 4.8 Mvar bank both operating at 63 kV.

The two capacitor banks are required at each station to minimize the voltage change during capacitor switching as well as to prevent any harmonic resonances which would occur with a single, larger bank.

Q33.3 Are there any large loads that are below 0.95 power factor at these locations?

A33.3 FortisBC has no large loads in this area other than primary services to BC Hydro for the Lardeau area north of Kaslo (about 2.9 MVA peak in 2007/08) and to Nelson Hydro south of Coffee Creek (about 3.9 MVA peak in recent years). The Company has no power factor information available for these loads as FortisBC bills these customers solely on kVA demand, and does not record kW demand.

Q33.4 Would FortisBC please advise why it does not need to replace deteriorated transformers at Coffee Creek and Crawford Bay?

A33.4 The scope of the preferred option will replace all of the 161/63 kV deteriorated power transformers that are no longer required since the high voltage will be reduced to 63 kV. Legacy distribution (63 kV to 12.5 kV) transformers that will remain in service will be replaced when justified by capacity or condition.

Q33.5 What was the cost of the other options? Please discuss its preference over the other options.

A33.5 The cost of the other two options is shown in Table A33.5 below. The Company prefers Option One over Option Two due to the fact that Option Two costs approximately $2.6 million more than Option One and that the extra cost does not justify the small increase in reliability that would be gained. The Company prefers Option One over Option Three due to the significant increase in cost and the Company’s overall plan to remove its 161 kV equipment from service when it is cost effective to do so.

Table A33.5
Option Cost

Options		Cost ($millions)
Option 1	Convert 30L from 161 kV to 63 kV, capacitors for voltage support and eliminating 161 kV equipment.	4.5
Option 2	Convert 30L from 161 kV to 63 kV by installing new 63 kV ring bus, capacitors for voltage support and eliminating 161 kV equipment.	7.1
Option 3	Replace all 161/63 kV transformers and retain 30 Line at 161 kV	10.0[1]

[1] This is the estimated capital cost for replacing the four 161/63 kV transformers over the next five year period. It does not include any necessary substation re-configuration cost. This option has not been explored any further due to the high capital cost.

Q33.6 Does FortisBC expect to file a CPCN for this capital expenditure? Please explain.

A33.6 No, the Project does not meet the CPCN criteria as stated in Commission Order G-52-05 which include:

- the total project cost is $20 million or greater; or
- the project is likely to generate significant public concerns; or
- FortisBC believes for an reason that a CPCN application should proceed; or
- after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

However, FortisBC acknowledges that the Commission reserves the authority to designate any projects it deems necessary for a CPCN application.

The upgrade will be confined to additions within the existing substation fence, mitigating any potential public concerns; and the estimated cost for the project is below the $20 million threshold for a CPCN Application.

34.0 Reference: 3. Transmission and Stations, Transmission and Station Growth Projects
Exhibit No. B-1, Static VAR Compensators (SVC) Kelowna, pp. 54-55
Estimated Expenditures - Engineering

Q34.1 Would FortisBC please confirm that the in-service date for N-1/N-2 is now 2008/2009 and the in-service date for N-1 is now 2013/2014?

A34.1 The above dates are confirmed. Load growth in the Kelowna area will lead to a decline in the contingency level to N-1 in 2013/2014.

Q34.2 Would FortisBC please provide an outline of the engineering work (i.e., scope)?

A34.2 A high-level outline of the Engineering work consists of the following:

- Conduct power system studies to determine the performance and design requirements for the SVC (ratings, type, response time, etc.);
- Preliminary engineering to produce a high-level scope, single-line diagrams and general arrangements; and
- Vendor discussions regarding technology, pricing and schedule.

This $400,000 is not meant to cover the costs of the detailed design. The amount requested is primarily to cover the planning and preliminary engineering stages of the project, prior to Commission approval.

Q34.3 Would FortisBC please provide a rough estimate of the total project cost?

A34.3 At this time, only a conceptual estimate has been completed based on manufacturer quotes for typical SVC installations. The cost of the SVC itself, along with the required substation work is estimated at approximately $30 million.

Q34.4 Will the 150 Mvar SVC fit within the outline of the DG Bell Terminal Station?

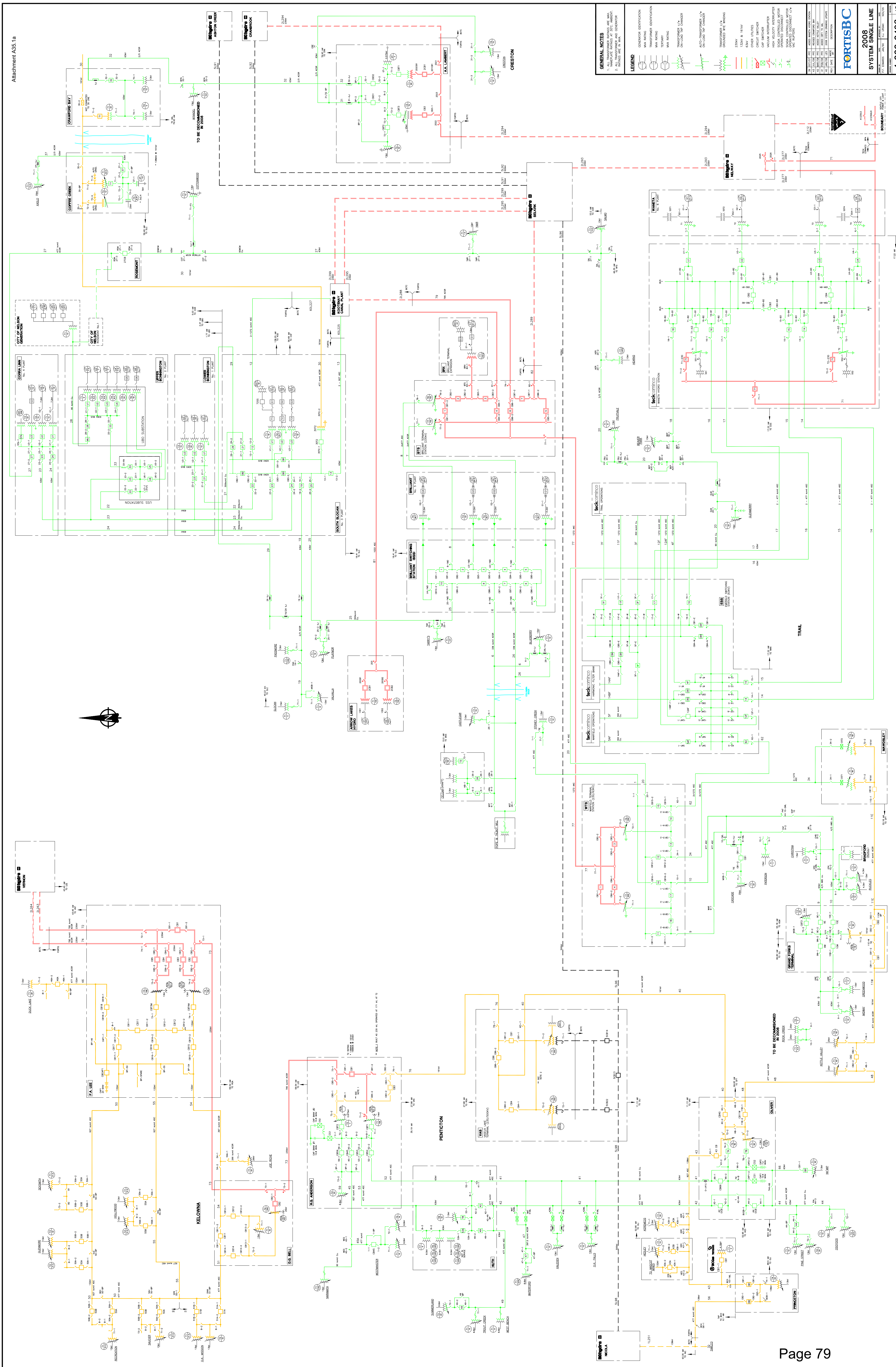
A34.4 No, there is insufficient space within the existing fence-line to accommodate the SVC installation. However, the existing substation only takes up a portion of the property owned by FortisBC at the DG Bell Terminal site. Thus, while expansion of the fence-line will be required, no additional land acquisition should be required.

35.0 Reference: 3. Transmission and Stations, Sustaining Projects Exhibit No. B-1, Transmission Line Sustaining Projects, p. 55 Table 3.2

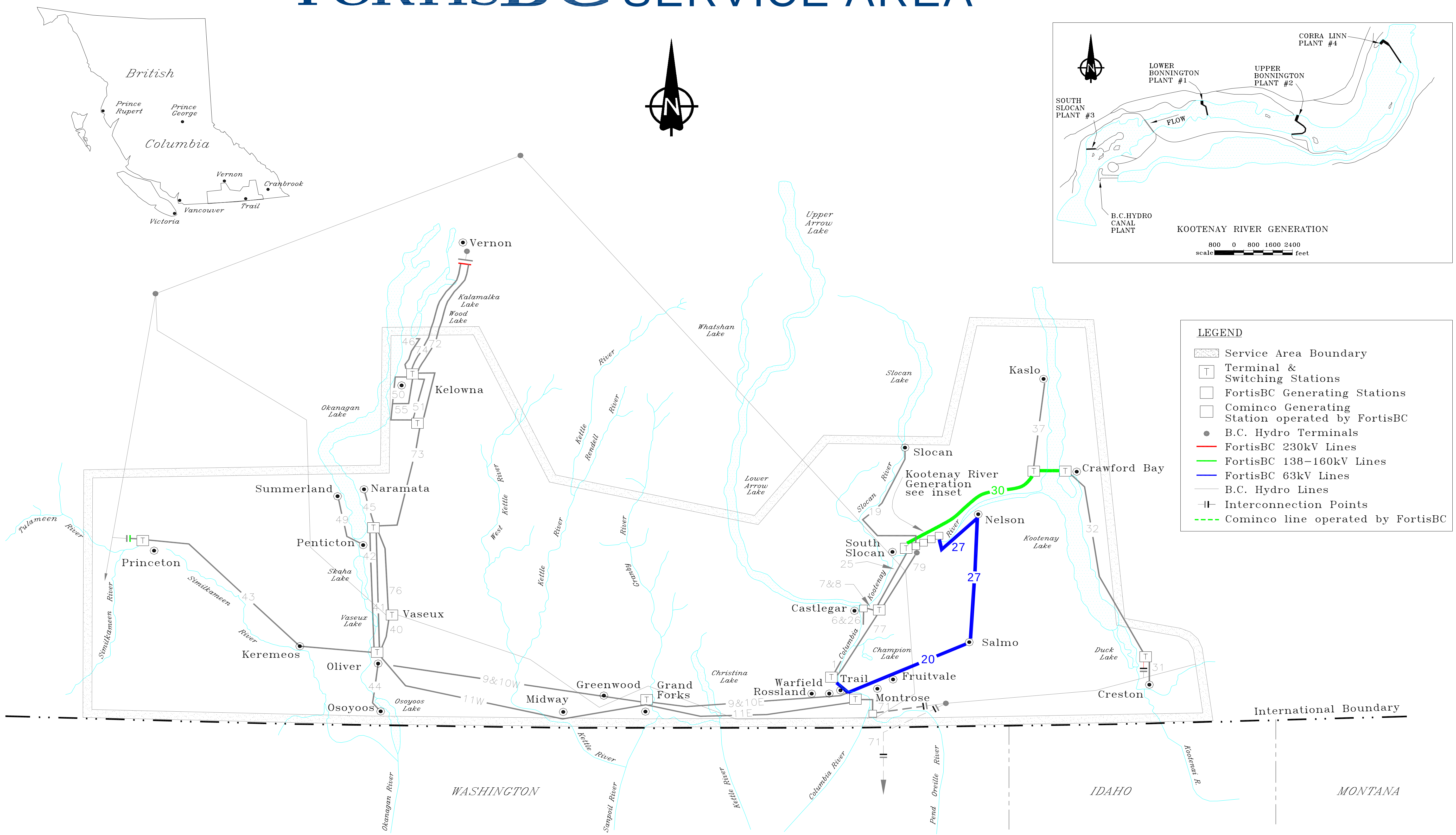
Q35.1 Please provide a one-line diagram of the FortisBC transmission system and a FortisBC service area diagram showing the transmission lines in the table.

A35.1 Please see Attachment A35.1a and A35.1b below. For convenience, an electronic copy of the requested single line diagram of the FortisBC transmission system has also been included.

Attachment A35.1a



FORTISBC SERVICE AREA



Q35.2 Please complete modified table 3.2 below and indicate if the estimate was based on historical costs.

	Project	2005	2006	2007	2008F	2009	2010
		($000s)					
1	Transmission Line Urgent Repairs					288	293
2	Right-of-Way Easements					311	345
3	Right-of-Way Reclamation					550	602
4	Transmission Pine Beetle Hazard Allocation					1,218	821
5	Transmission Condition Assessment					427	496
6	Transmission Line Rehabilitation					1,639	1,888
7	Switch Additions						132
8	20 Line Rebuild					1,943	1,540
9	27 Line Rebuild					648	642
10	30 Line Lake-Crossing Rehabilitation						350
11	**Total**					**7,024**	**7,109**

A35.2 The requested revised table from the 2009-2010 Capital Plan (Exhibit B-1) page 55, line 13, is provided below. The estimates for Lines 1, 2, 3, 5 and 6 are based on historical cost adjusted for inflation.

Table A35.2
Transmission Line Sustaining Projects

	Project	2005	2006	2007	2008F	2009	2010
		($000s)					
1	Transmission Line Urgent Repairs	268	347	351	312	288	293
2	Right-of-Way Easements	360	223	332	350	311	345
3	Right-of-Way Reclamation	443	421	821	359	550	602
4	Transmission Pine Beetle Hazard Allocation	-	-	-	1,500	1,218	821
5	Transmission Condition Assessment	57	248	152	845	427	496
6	Transmission Line Rehabilitation	3,468	993	336	3,443	1,639	1,888
7	Switch Additions	-	-	-	-	-	132
8	20 Line Rebuild	-	-	-	-	1,943	1,540
9	27 Line Rebuild	-	-	-	-	648	642
10	30 Line Lake-Crossing Rehabilitation	-	-	-	-	-	350
11	**Total**	**4,596**	**2,232**	**1,992**	**6,809**	**7,024**	**7,109**

Q35.3 Please complete modified table 3.3 below and indicate if the estimate was based on historical costs.

	Project	**2005**	**2006**	**2007**	**2008F**	**2009**	**2010**
		($000s)					
1	Station Assessments & Minor Planned Projects					620	680
2	Ground Grid Upgrades					572	
3	Station Urgent Repairs					473	448
4	Bulk Oil Breaker Replacement Program						292
5	Transformer Load Tap Changer Oil Filtration Project					32	64
6	Slocan City-Valhalla Substation Upgrade					2,173	
7	Passmore Substation Upgrade						1,987
8	Pine Street Substation –Distribution Breaker replacement					345	
9	Princeton Substation Distribution Recloser replacement						1,513
10	Joe Rich Transformer Protection Upgrade						404
11	Creston Substation Protection Upgrade					488	
12	**Total**					**4,703**	**5,388**

A35.3 The following revised Table 3.3 provides the information requested. Only Line 3 is based on historical cost adjusted for inflation.

Revised Table 3.3
Station Sustaining Projects and Programs

	Project	2005	2006	2007	2008F	2009	2010
		($000s)					
1	Station Assessments & Minor Planned Projects	871	1,132	2,043	1,603	620	680
2	Ground Grid Upgrades	182	393	160	446	572	-
3	Station Urgent Repairs	279	562	416	393	473	448
4	Bulk Oil Breaker Replacement Program	66	1,412	44	-	-	292
5	Transformer Load Tap Changer Oil Filtration Project		81	191	278	32	64
6	Slocan City-Valhalla Substation Upgrade	-	-	-	-	2,173	-
7	Passmore Substation Upgrade	-	-	-	-		1,987
8	Pine Street Substation –Distribution Breaker replacement	-	-	-	-	345	-
9	Princeton Substation Distribution Recloser replacement	-	-	-	-	-	1,513
10	Joe Rich Transformer Protection Upgrade	-	-	-	-	-	404
11	Creston Substation Protection Upgrade	-	-	-	-	488	
12	**Total**	**1,398**	**3,580**	**2,854**	**2,720**	**4,703**	**5,388**

36.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Transmission Line Repairs, p. 56
Failures

Q36.1 Please provide a table listing the reasons for failure and the duration of outage from 2005 to current.

A36.1 There are over 300 service interruptions to report during the referenced period. Table A36.1 below provides a sample of the outages that have occurred since 2005 including the reason for failure and the duration of outage.

Table A36.1
Transmission Outage Data

Reason for Outage	Line	Date and Time of Outage	Duration
2005			
TREE INTO LINE	32 LINE	1/18/2005 9:09:21 AM	08:45:14
TREE INTO LINE	9 LINE	3/12/2005 7:51:17 AM	64:08:43
TREE INTO LINE	19 LINE	4/27/2005 6:02:39 AM	03:39:00
TREE INTO LINE	30 LINE	5/30/2005 7:29:03 PM	03:41:40
TREE INTO LINE	19 LINE	6/2/2005 9:52:31 AM	02:33:18
POLE FIRE	71 LINE	7/15/2005 10:30:00 PM	17:02:00
TREE INTO LINE	18 LINE	6/13/2005 3:43:20 PM	05:46:40
TREE ON LINE	30 LINE	7/28/2005 12:53:00 PM	02:14:00
TREE INTO LINE	32 LINE	8/12/2005 2:07:02 PM	06:54:50
INSULATOR	30 LINE	8/31/2005 8:08:24 PM	15:51:36
POLE FIRE	41 LINE	6/21/2005 7:37:59 PM	22:22:01
TREE ON LINE	30 LINE	7/13/2005 10:59:00 AM	01:01:00
TREE INTO LINE	30 LINE	10/14/2005 12:22:06 PM	01:04:02
INSULATOR	25 LINE	9/3/2005 11:02:43 PM	00:50:31
VEHICLE	45 LINE	12/4/2005 10:59:00 AM	02:00:00
2006			
SNOW UNLOADING	10 EAST LINE	1/2/2006 1:48:48 PM	02:21:12
TREE INTO LINE	19 LINE	1/10/2006 6:00:17 AM	13:59:43
SNOW UNLOADING	9 WEST LINE	1/7/2006 2:56:30 PM	21:03:15
INSULATOR	6 LINE	1/10/2006 12:41:20 PM	04:31:50
TREE INTO LINE	30 LINE	1/11/2006 5:55:52 AM	53:25:42
INSULATOR	26 LINE	1/13/2006 6:57:00 AM	07:59:00
SNOW UNLOADING	10 EAST LINE	1/28/2006 8:29:51 AM	01:16:00
SNOW UNLOADING	10 EAST LINE	1/29/2006 6:59:18 PM	88:53:42
STRUCTURE	10 LINE	2/2/2006 9:52:33 AM	05:32:27
ANIMAL	33 Line	4/26/2006 7:48:41 AM	01:47:15
TREE INTO LINE	30 LINE	5/22/2006 8:14:09 PM	18:16:16
TREE INTO LINE	30 LINE	7/1/2006 5:18:14 PM	05:30:48
TREE INTO LINE	30 LINE	5/31/2006 11:42:28 AM	07:36:32

Table A36.1 cont'd

Reason for Outage	Line	Date and Time of Outage	Duration
INSULATOR	6 LINE	1/16/2006 8:43:00 AM	06:41:00
POLE FIRE	10 EAST LINE	8/11/2006 4:26:01 PM	24:05:20
ANIMAL	32 LINE	8/9/2006 7:49:31 PM	18:15:31
TREE INTO LINE	30 LINE	1/10/2006 6:02:18 AM	11:41:11
SLIDE	37 LINE	1/11/2006 2:38:08 AM	05:11:52
ANIMAL	33 Line	4/26/2006 7:48:41 AM	01:47:15
SNOW UNLOADING	32 LINE	12/14/2006 11:40:57 PM	02:56:37
SNOW UNLOADING	10 EAST LINE	12/15/2006 3:20:32 AM	05:54:28
TREE INTO LINE	32 LINE	11/27/2006 4:23:34 PM	05:03:02
CONDUCTOR	27 SOUTH	11/27/2006 8:12:56 PM	19:47:04
WIND	32 LINE	10/29/2006 3:39:54 PM	02:49:36
TREE INTO LINE	30 LINE	11/7/2006 1:31:41 AM	02:06:22
TREE INTO LINE	30 LINE	10/29/2006 2:51:20 PM	19:01:12
POLE FIRE	10 EAST LINE	10/27/2006 11:17:00 AM	75:59:00
POLE FIRE	10 EAST LINE	8/11/2006 4:26:01 PM	24:05:20
CROSSARM FAILURE	19 LINE	10/17/2006 10:57:37 AM	01:28:24
SNOW UNLOADING	10 LINE	11/29/2006 7:44:46 PM	17:25:55
2007			
TREE ON LINE	20 LINE	1/2/2007 1:30:00 PM	03:51:00
INSULATOR FAILURE	27 LINE	1/2/2007 6:02:00 PM	02:13:00
POLE FIRE	27 SOUTH	1/12/2007 3:45:00 PM	143:59:00
POLE FIRE	27 SOUTH	1/24/2007 7:37:16 AM	05:52:44
VEHICLE	27 SOUTH	2/14/2007 7:59:00 PM	00:49:00
TREE INTO LINE	37 LINE	3/12/2007 12:34:00 PM	06:21:10
INSULATOR FAILURE	9 EAST LINE	3/14/2007 9:30:00 AM	05:00:00
TREE INTO LINE	37 LINE	3/20/2007 10:39:25 AM	01:59:49
CONDUCTOR FAILURE	32 LINE	4/21/2007 6:59:00 AM	10:19:00
CROSSARM FAILURE	30 LINE	4/22/2007 7:41:00 AM	07:50:00
POLE FIRE	32 LINE	4/24/2007 7:30:00 AM	09:30:00
CROSSARM FAILURE	42 LINE	6/5/2007 9:15:23 AM	05:06:37
TREE INTO LINE	30 LINE	12/19/2007 7:33:44 AM	06:08:11

Table A36.1 cont'd

Reason for Outage	Line	Date and Time of Outage	Duration
TREE INTO LINE	32 LINE	11/10/2007 1:09:06 PM	04:24:21
TREE INTO LINE	19 LINE	11/10/2007 2:16:35 PM	01:27:47
VEHICLE	19 LINE	11/11/2007 10:16:42 AM	03:31:07
POLE FIRE	19 LINE	9/20/2007 3:14:19 PM	04:08:50
INSULATOR	9 LINE	9/28/2007 8:42:39 AM	34:08:21
LIGHTNING	62 LINE	8/31/2007 8:16:02 PM	01:23:11
POLE FIRE	17 LINE	8/10/2007 9:10:26 PM	68:15:16
FOREST FIRE	71 LINE	8/12/2007 8:01:36 PM	01:44:32
FOREST FIRE	71 LINE	8/13/2007 3:01:27 PM	02:43:37
CONDUCTOR FAILURE	41 LINE	7/19/2007 4:34:50 PM	23:27:36
INSULATOR FAILURE	41 LINE	7/20/2007 9:09:36 PM	68:07:43
TREE INTO LINE	30 LINE	7/18/2007 4:58:12 PM	04:52:56
INSULATOR FAILURE	27 LINE	7/17/2007 11:56:00 AM	04:30:00
TREE INTO LINE	27 LINE	6/5/2007 6:27:30 PM	45:32:30
ANIMAL	32 LINE	5/22/2007 7:59:46 AM	04:12:57
TREE INTO LINE	32 LINE	5/24/2007 11:44:50 AM	04:53:59
2008			
CONDUCTOR	27 SOUTH	1/9/2008 10:00:00 AM	01:47:00
TREE INTO LINE	10 EAST LINE	1/11/2008 1:05:06 AM	109:54:54
POLE FIRE	27 SOUTH	2/7/2008 4:22:03 AM	16:49:22
INSULATOR FAILURE	20 LINE	2/7/2008 5:17:05 AM	18:36:39
TREE INTO LINE	27 LINE	4/18/2008 1:33:36 PM	06:27:03
TREE INTO LINE	19 LINE	4/19/2008 5:23:19 AM	03:40:14
POLE FIRE	41 LINE	4/23/2008 1:05:49 PM	06:10:09
TREE INTO LINE	32 LINE	5/26/2008 9:38:00 PM	20:38:20
TREE INTO LINE	19 LINE	6/13/2008 5:01:14 PM	02:22:10
LIGHTNING	73 LINE	6/30/2008 7:02:10 PM	08:15:33

Q36.2 Please provide a level of accuracy on the estimated costs.

A36.2 The level of accuracy of the transmission line urgent repair project is estimated to be +/- 20 percent.

37.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Right of Way Easements, p. 56
ROW & Easements

Q37.1 Please provide a listing of the easements or rights-of-way that are proposed to be obtained as well as any maps of the intended easement or rights-of-way.

A37.1 The proposed expenditure estimates are based on historical cost adjusted for inflation. The expenditures are forecast in anticipation of issues that will arise in 2009 and 2010 based on past experience. Consequently, the information requested is unavailable at this point in time.

Q37.2 Please provide an update of estimated costs.

A37.2 Costs are dependent on location, size and market values. The estimated project cost of \$0.311 million for 2009 and \$0.345 million for 2010 has not been updated since the Application has been filed.

38.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Right of Way Reclaimation, pp. 57-58
Tree Free Zone

Q38.1 Will the tree-free zone be outside the rights-of-way? If so, provide a map highlighting the areas involved.

A38.1 Dependent on right-of-way slope gradient, conductor and tree height, it is possible that in some locations the tree-free zone will be outside of the right-of-way. Maps highlighting possible areas where the tree-free zone is outside of the right-of-way have not been developed.

Q38.2 Will the trees be sold as salvage?

A38.2 Trees are sold as salvage if harvested on Crown land if it is cost effective to do so. When trees are harvested on private, municipal, or Ministry of Transportation and Infrastructure lands, the owner of the tree asset determines the wood disposal.

Q38.3 Will the trees be used for biomass energy generation?

A38.3 FortisBC believes it is unlikely that the trees will be used for biomass energy generation. When trees from Crown land are marketed, the sawmill owner determines the best use. When trees are harvested from private, municipal or Ministry of Transportation and Infrastructure lands, the owner determines the wood disposal.

39.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Right of Way Reclaimation – Pine Beetle Kill Hazard Trees,
pp. 58-59
Pine Beetle Trees

Q39.1 Will the trees be sold as salvage?

A39.1 Please see the response to BCUC IR No. 1 Q38.2.

Q39.2 Will the trees be used for biomass energy generation?

A39.2 Please see the response to BCUC IR No. 1 Q38.3.

40.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Transmission Line Condition Assessment, pp. 59-60
Pole Replacement

Q40.1 Please repeat tables 3.2(a) and 3.2(b) showing the minimum pole age, maximum pole age, average pole age and the most frequent failure mode.

A40.1 The requested tables based on the Company's best efforts is shown below. The company's records does not contain the age of individual poles, consequently the complete data for pole age demographics is not available making the average pole age impossible to calculate. The estimated minimum age is based on the fact that some poles would have been replaced as a result of the last condition assessment.

Table 3.2(a)
Transmission Line Condition Assessment Projects 2009

	Line	Location	Poles	Original Construction	Most Frequent Failure mode (Note 1)	Estimated Maximum age	Estimated Minimum age
1	1	Warfield to Stoney Creek	15	1905 Line was last rebuilt in the mid 1990s	Condition assessment – test and treat program	12	5
2	25	Slocan to Playmor to Tarrys to Brilliant	299	1930 Line was rebuilt in the mid 1950's	Condition assessment – test and treat program	55	5
3	29	Slocan Valley	140	1956	Condition assessment – test and treat program	52	6
4	31	Lambert to Creston	105	1953	Condition assessment – test and treat program	55	7
5	30	Coffee Creek to Crawford Bay	26	1952	Condition assessment – test and treat program	56	7
6	50	FA Lee to Sexsmith to Glenmore to Recreation to Saucier	320	1922 Line was rebuilt in the mid 1960s	Condition assessment – test and treat program	40	6
7	49	Huth to West Bench to Trout Creek to Summerland	310	1949	Condition assessment – test and treat program	59	6

Table 3.2(b)
Transmission Line Condition Assessment Projects 2010

	Line	Location	Poles	Original Construction	Most Frequent Failure mode (Note 1)	Estimated Maximum age	Estimated Minimum age
1	41	Huth to Waterford to Kaleden to OK Falls to Oliver	580	1921 Line rehabilitated in 2002	Condition assessment – test and treat program	55	6
2	42	Huth to Waterford to Kaleden to OK Falls to Oliver	420	1921 Line rebuilt between 1979-81	Condition assessment – test and treat program	28	6
3	45	RG Anderson to Westminster to Naramata	290	1922 Poles replaced in 1960s and mid 80's Line reconfigured in 1998/99	Condition assessment – test and treat program	45	2
4	45A	45 Line to Downtown Penticton	48	Line was rebuilt in mid 1970's and early 1990's	Condition assessment – test and treat program	30	6
5	46	FA Lee to Duck Lake	87	1958	Condition assessment – test and treat program	50	3
6	47	Huth to Waterford	50	Line was rebuilt in the early 1980's	Condition assessment – test and treat program	25	5
7	49	Huth to West Bench to Trout Creek to Summerland	310	1949	Condition assessment – test and treat program	59	6

41.0 Reference: Capital Plan, p. 60

Transmission Line Condition Assessment

Q41.1 Please explain the dramatic increase from $152,000 in 2007 to $845,000 forecasted in 2008 for transmission line condition assessment expenditures [Table 3.2(c)].

A41.1 The proposed budget filed in the 2007-2008 Capital Plan (page 52) for Transmission Line Condition Assessment was $0.616 in 2007 and $0.647 in 2008 for a total of $1.263 million. Due to a variety of reasons including scheduling of other projects and resources, a large amount of the planned work was carried forward from 2007 into 2008. The total value of Transmission Line Condition Assessment work for 2007 and 2008 is now forecast to be $0.997 million over the two years, with the bulk of the spending occurring in 2008.

42.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Transmission Line Rehabilitation, p. 61
Rehabilitation Projects

Q42.1 Please provide a tabular listing of the rehabilitation projects by line, by scope of work, by cost.

A42.1 The work undertaken in the Transmission Line Rehabilitation Project is based on the previous years Transmission Line Condition Assessments. Therefore, the rehabilitation projects for 2009 are those identified on the transmission lines assessed in 2008. Likewise, the rehabilitation projects for 2010 are the lines to be assessed in 2009. Tables A42.1a and A42.1b below identify the transmission lines FortisBC plans to assess in 2008 and 2009. Assessments for 2008 are not yet complete, therefore a list of rehabilitation work for 2009 is not yet available, and the same applies for the 2010 rehabilitation work.

The cost to rehabilitate each line is dependant on the outcome of the assessment. The budget presented on page 61 of the 2009-2010 Capital Plan (Exhibit B-1) is based on a historical costs adjusted for inflation. The scope of work for rehabilitations can also be found on page 61 of the 2009-2010 Capital Plan (Exhibit B-1) and includes stubbing of poles, replacement of cross arms and poles, maintenance of structures, insulator changes and guy wire changes.

Table A42.1a
2008 Transmission Condition Assessments

	Line	Location
1	8	Brilliant Switching Station to Brilliant Terminal
2	12	Kootenay Canal to South Slocan Terminal
3	28	Upper Bonnington to Nelson Blewett
4	34	Warfield to Mawdsley
5	37	Coffee Creek to Kaslo
6	44	Oliver to Pine Street to Osoyoos
7	51	DG Bell to OK Mission (Kelowna)
8	54/54A	FA Lee Terminal through DG Bell Terminal
9	74	FA Lee Terminal to Vernon

Table A42.1b
2009 Transmission Condition Assessments

	Line	Location
1	1	Warfield to Stoney Creek
2	25	Slocan to Playmor to Tarrys to Brilliant
3	29	Slocan Valley
4	31	Lambert to Creston
5	30	Coffee Creek to Crawford Bay
6	50	FA Lee to Sexsmith to Glenmore to Recreation to Saucier
7	49	Huth to Westbench to Trout Creek to Summerland

43.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, Switch Additions, p. 61
Motor Operators and Remote Control

Q43.1 Will these motor operators be tied into the Substation Automation Project 2007?

A43.1 Yes, these motor operators will be connected to the station automation systems to allow their remote operation by the FortisBC System Control Centre.

Q43.2 How many switches are involved for $132,000?

A43.2 There are two switches involved: one for 6 Line and one for 26 Line.

44.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, 20 Line Rebuild, p. 62
Scope of Rebuilt

Q44.1 Please provide a project scope of the rebuild.

A44.1 Project scope includes the following:

- Replace an estimated 194 transmission poles and hardware due to condition and clearance issues between transmission and/or distribution circuits and the ground;
- Replace crossarms, replace insulation and reframe several other structures where pole condition is deemed to be satisfactory; and
- Upgrade deficient anchoring as determined during the pole installation process.

45.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, 27 Line Rebuild, p. 62
Scope of Rebuilt

Q45.1 Please provide a project scope of the rebuild.

A45.1 Project scope includes the following:

- Replace an estimated 111 transmission poles and hardware due to condition and clearance issues;
- Replace crossarms, replace insulation and reframe several other structures where poles condition is deemed to be satisfactory; and
- Upgrade deficient anchoring as determined during the pole installation phase.

Q45.2 Will additional easements or right-of –way be required?

A45.2 Additional easements or rights-of-way may be required for upgraded anchoring and/or access to certain structures.

46.0 Reference: 3. Transmission and Stations, Sustaining Projects
Exhibit No. B-1, 30 Line Lake-Crossing Rehabilitation, pp. 64-65
Alternate

Q46.1 Is there any alternate means for supplying power to these areas?

A46.1 No, there are no alternate means for supplying power to these areas. The 30 Line lake crossing is the only tie between the transmission systems on the east and west sides of Kootenay Lake. With the crossing removed, the communities of Crawford Bay, Coffee Creek and Kaslo would all be served by single radial transmission lines.

47.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Replace DC Protection Systems at Various Substation, pp. 66-67
Battery Replacement

Q47.1 Please explain why battery replacement is a capital expenditure and not an operating and maintenance expenditure.

A47.1 According to the Uniform System Of Accounts ("USOA") Prescribed For Electric Utilities, battery banks are included in the definition of Plant Account 353 "Station Equipment". Also, under the section describing the accounting treatment for "Plant Additions" and more specifically, "Replacements" (USOA, page 12), the guidelines outline the treatment as follows:

> "the ledger value of the original plant unit shall be credited to the appropriate plant account and the cost of the replacement shall be charged to the appropriate plant account."

The Company considers the Battery Replacement project to be the replacement of a major plant unit and not "Minor items of plant" (USOA, page 12) and accordingly has included the project as a capital expenditure.

Q47.2 How many gel type battery banks are older than ten years?

A47.2 There are three gel-type banks older than ten years.

Q47.3 How many battery banks test below 70% of capacity or are older than 20 years?

A47.3 There are two battery banks older than 20 years that test below 70 percent capacity. As, well, there are two additional banks older than 20 years that test below 75 percent capacity (i.e. close to threshold).

48.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Ground Grid Upgrades, p. 68
Step and Touch Potentials

Q48.1 Please provide the current values for the step and touch potential both inside and outside the fence.

A48.1 The following table provides the information requested. The model is based on current substation configuration standards, fault levels and assuming the distribution neutral is connected.

Table A48.1
Model Results

Season	Resistance	Fault	GPR STATION	Step Inside Station	Step Residence Garden	Touch Inside Station	Touch Residence Garden Shed
	(Ohms)	(Amps)	(Volts)				
Summer	2.1	6,198	13,077	2,093	618	4,047	543
Spring	2.14	6,198	13,287	2,194	735	5810	573

Q48.2 Please provide the values required by current standards and identify the standard.

A48.2 Table A48.2 below provides the information requested. (From Institute of Electrical and Electronic Engineers [IEEE] 80)

Table A48.2
Safe Allowable Voltages

	Step Voltage	Touch Voltage	Ground Potential Rise
	(Volts)		
1,678 ohm-meters Native Soil with 10% moisture external to substation	2,315	657	3,000
167.8 ohm-meters Native Soil with 21.7% moisture external to substation	362	160	3,000
Native Sand/Gravel 3,856 ohm-meters	3,915	1,096	3,000
Summer/ Spring 100mm 5,000 ohm-meter gravel	4,757	1,306	3,000
100mm 10,000 ohm-meter asphalt or gravel	8,264	2,183	3,000

Safe step and touch voltages for the residential backyard are based on 500 ohm body resistance, 0.25 sec fault clearing time and 167.8 ohm/meter native soil with a moisture content of 20 percent.

Safe step and touch voltages for the substation are based on 1,000 ohm body resistance, 0.25 seconds fault clearing time and 4 inches of 5,000 ohm/meter gravel.

49.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Station Urgent Repairs, p. 69
Scope

Q49.1 Please provide a historical listing of the stations involved, the scope of the repair and the cost.

A49.1 Table A49.1 below provides the information requested.

1 **Table A49.1**
2 **Station Urgent Repairs**

Line No.	Substation	Scope of work	Cost ($)
	2007		
1	Grand Forks Terminal Station	T3 Equipment Failure	10,968
2	Grand Forks Terminal Station	Roof repair	27,480
3	Mawdsley Terminal Station	T1 and T2 Transformer Radiator sandblast and paint	14,622
4	RG Anderson	Repair of spare breaker used for replacement of RGA 52L breaker	48,448
5	Lambert Station	Equipment Repair	32,918
7	Valhalla	Replace failed PML Meter	9,812
8	Castlegar	Replace tapchanger parts	2,624
9	Passmore	Replace failed regulator	17,006
10	Greenwood	Repair bus damage	15,005
11	Ruckles	Repair flood damage	28,872
12	Hollywood	Repair Roof	1,442
13	Hollywood	Repair Overhead Door	1,878
14	Glenmore	Roof repair	6,425
15	Recreation	Replace LTC contacts	34,482
16	Duck Lake	Repair Regulators	4,851
17	Saucier	Roof repair	5,089
18	Saucier	Replace failed battery bank	11,486
19	Saucier	Replace wooden fence	14,703
20	Osoyoos	Replace failed battery bank	22,520
21	Osoyoos	Replace LTC contacts	12,593
22	Osoyoos	Remove Asbestos found in building walls	28,276
23	Huth	Repair ground grid.	7,475
24	Princeton	Replace failed breaker	50,224

Table A49.1 cont'd

Line No.	Substation	Scope of work	Cost ($)
	2008		
25	Lee Terminal Station	Transformer gassing	7,779
26	Oliver	Replacement of failed gaskets	16,854
27	RG Anderson	Repair of fence due to theft	5,069
28	Lee Terminal Station	Removal of non compliant septic system failed in service	14,273
29	Oliver	Replacement of failed Hydran unit	4,807
30	Christina Lake	Fence slats installed to reduce noise from transformer noticeable after trees knocked down by windstorm.	2,457
31	Ruckles	Fence repair due to vehicle collision	7,817
32	Duck Lake	Replacement of failed battery bank	35,562
33	Glenmore	Repairs required after short circuit caused by rodent	19,862
34	Osoyoos	Replacement of failed LTC components	7,897
35	Keremeos	Replacement of failed relay	6,624
36	Hedley	Repair of damaged cable	277
37	Summerland	Repair of damaged fence caused by theft	2,313
38	Kaleden	Repair of damaged fence caused by theft	500
39	Huth	Repair of damaged fence caused by theft	1,632
40	Pine Street	Repair of damaged fence caused by theft	786
41	OK Falls	Replacement parts for LTC	12,530
42	Recreation	Roof repair	5,217
43	Osoyoos	Replacement of failed Meter	7,135
44	OK Mission	Replacement of reclosers due to lightning strike.	12,796
45	Westminster	LTC failure repair	24,446
46	Fruitvale	Correction to allow parallel connections of substation	12,227
47	Ruckles	Creation of water catchment and pumps to control water ingress	34,332
48	Lambert	Phasing correction to allow parallel connection	21,380
49	Duck Lake	Remediation of oil contaminated soil	17,602

50.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects

Exhibit No. B-1, Bulk Oil Breaker Replacement Program, p. 69

SF6 Breakers

Q50.1 Please provide the cost of a SF6 breaker.

A50.1 The typical cost for a 72.5 kV SF6 circuit breaker is $45,000 to $60,000.

Q50.2 How many bulk oil breakers will be replaced?

A50.2 One bulk oil breaker will be replaced on the 12 MVA mobile substation. In this particular case the new breaker will be a vacuum design, not SF6, in order to avoid gas leakage issues that might arise as a result of frequent movement of the unit. As well, due to the unique nature of this application the design of the breaker installation will have to be customized for the mobile unit.

51.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Transformer Load Tap Changers Oil Filtration Project, p. 69
Maintenance Cycle

Q51.1 Please provide the frequency of maintenance for the transformer load tap changers.

A51.1 In the past, maintenance has been scheduled every four to five years. With the implementation of the CMMS program FortisBC will be transitioning to a condition based maintenance schedule.

Q51.2 Please provide a listing of the load tap changers involved.

A51.2 The following is a list of the load tap changers (LTC) scheduled for the installation of permanent oil filtration systems.

- Summerland Transformer 2-LTC:
- Westminster Transformer 2-LTC:
- OK Mission Transformer 1-LTC:

Q51.3 Please provide installed cost of the individual tap changers.

A51.3 The estimated installed cost for each tap changer is $0.032 million.

52.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Slocan City –Valhalla Substation Upgrade, p. 70
10 MVA Transformer

Q52.1 What is the age of the 10 MVA transformer?

A52.1 The transformer is 35 years old.

Q52.2 What is the remaining life expectancy of the 10 MVA transformer?

A52.2 This transformer will be fully refurbished before being placed in service and will have a life expectancy between 15 and 20 years.

Q52.3 Considering the existing transformer is 4.2 MVA, is there a smaller transformer that could be used?

A52.3 The Company does not have a smaller transformer in the inventory of spare units. The standard for new units in this size range is 6/8/10 MVA. The existing Valhalla transformer is 6/8/10 MVA. The new transformer will act as a replacement for the existing 4.2 MVA at Slocan City Substation as well as a station backup transformer for the Valhalla 6/8/10 MVA unit. Therefore, at 10 MVA, it is sized appropriately for this project.

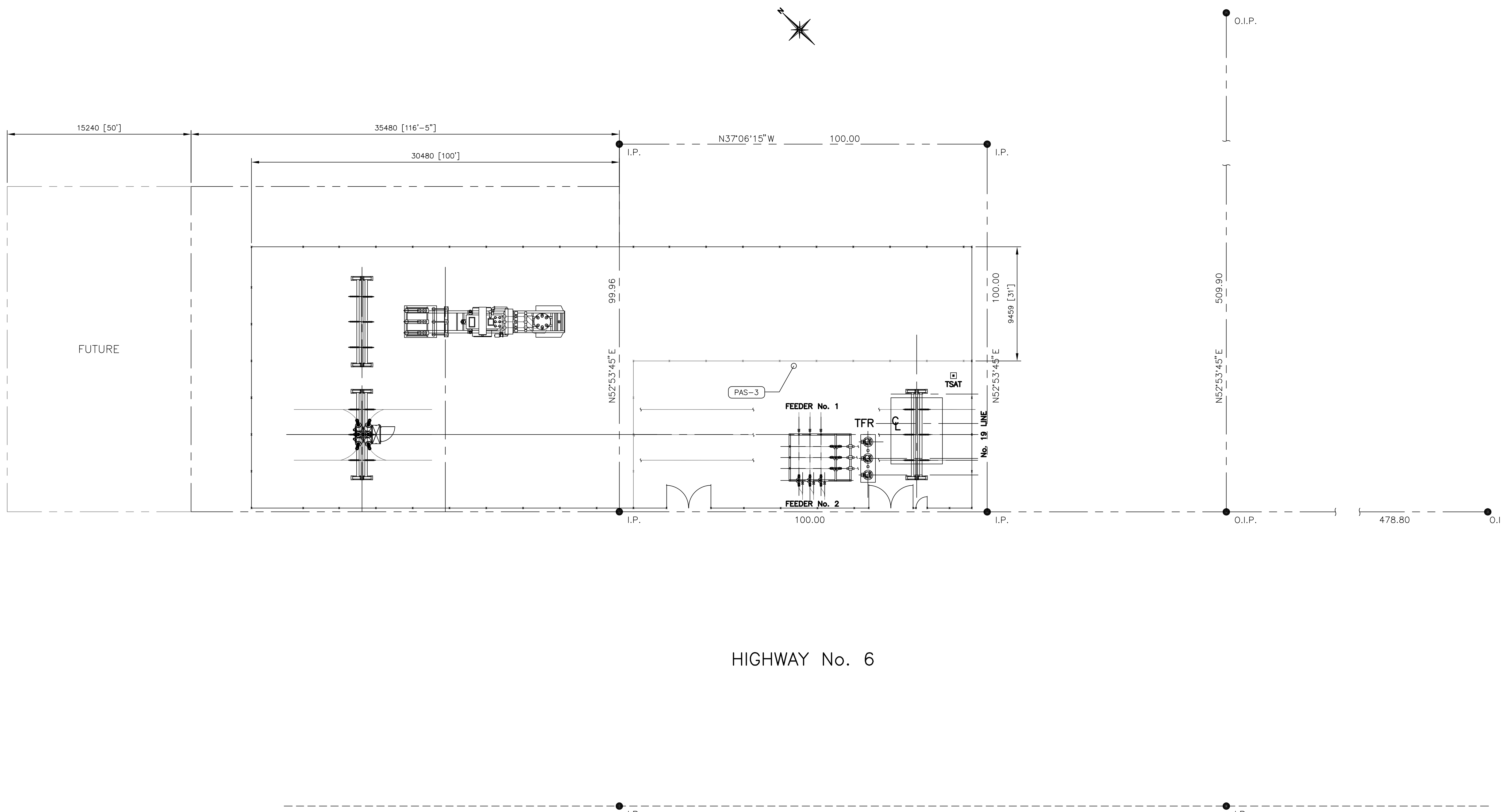
Q52.4 Are there any additional considerations regarding the proposed installation of the 10 MVA transformer such as current ratings?

A52.4 There are no additional considerations regarding the proposed installation of the 10 MVA transformer.

53.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Passmore Substation Upgrade, p. 71
Substation Expansion

Q53.1 Would FortisBC please supply conceptual substation and transmission line siting diagrams including footprints and existing as well as new statutory rights-of-way that may be required?

A53.1 Please see attachment A53.1 below.



REVISIONS						
REV	DATE	BY	CHECKED	DESCRIPTION	REVISION APPROVAL	DATE
P1						
P2						
P3						
P4						

DRAWN BY: H.URSAKI MAR/08
DESIGNED BY:
CHECKED BY:
APPROVALS: ELEC / CIVIL / MANAGEMENT

FORTISBC

DIVISION: KOOTENAY
DEPARTMENT: PROTECTION-CONTROL
LOCATION: PASSMORE SUBSTATION
TITLE: 2009/2010 GENERAL ARRANGEMENT

SCALE: 1:200
SCALE FACTOR: 200
DRAWING NUMBER: C-130-8100
REVISION: P0

54.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Pine Street Substation – Distribution Breaker Replacement,
pp. 71-72
Breaker Replacement

Q54.1 Please provide the cost of a replacement breaker.

A54.1 The estimated cost of a replacement distribution breaker is approximately $0.018 million.

Q54.2 Are these vacuum or SF6 breakers?

A54.2 The breakers referenced above are vacuum breakers.

55.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects

Exhibit No. B-1, Princeton Substation – Distribution Recloser Replacement,

pp. 72-73

Recloser Replacement

Q55.1 Please provide copy of standard.

A55.1 There is no formal copy of the standard available. FortisBC's present practice is to ensure that the maximum expected fault current is no greater than 80 percent of the interrupting rating of the equipment. The guideline was first applied in the development of the 1998 Master Plan and has been followed as a de facto standard in all succeeding plans.

Q55.2 Is the 12 kA unit acceptable?

A55.2 No, the 80 percent criterion discussed in the response to BCUC IR No. 1 Q55.1 is exceeded for this unit as well.

Q55.3 If only three units will be retained for future use, which three are retained and why and what happens to the other two?

A55.3 The three newest units (manufactured after 1990) will be retained as they only require refurbishment and are still in serviceable condition. The other two units are in poor condition and will be disposed of.

56.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Joe Rich Protection Upgrades, pp. 74-75
HV Fuse Replacement

Q56.1 How long has the 20 MVA transformer at Joe Rich been protected by fuses?

A56.1 This transformer has been protected by fuses since the substation was first constructed in 1993.

Q56.2 Is this a FortisBC standard as well? Please submit FortisBC standard.

A56.2 There is no formal copy of the standard available. Other than Joe Rich, all 138 kV transformers in the FortisBC system are protected by high-side circuit breakers. Circuit breaker protection is typical for transformers of this size and voltage and this practice is consistent with other utilities.

Q56.3 In the Black Mountain or Big White projects, is there a breaker in the Black Mountain Substation that currently protects the Joe Rich Substation?

A56.3 As part of the Black Mountain Substation Project, a node in the 138 kV ring bus will be installed for terminating 57 Line. This node will be equipped with transmission line relaying for 57 Line. This protection equipment will provide some level of protection for the downstream Joe Rich transformer, but it will not coordinate with the existing fuses located there (refer also to the response to BCUC IR No. 1 Q56.4 below).

Q56.4 As Joe Rich is a radial substation, what is the risk to the loads in the area if the HV fuses remain in service?

A56.4 The primary risk relates to the load that will be supplied from the new Big White Substation. Once Big White is energized there will be two substations connected to the radial 57 Line: Joe Rich and Big White. Over 80 percent of this load will be supplied via the Big White Substation. The HV fuses on the Joe Rich transformer do not coordinate with the 57 Line transmission protection; if a fault occurs in the Joe Rich transformer, the fuses are unlikely to blow before the line protection operates. The result will be that a transformer problem at Joe Rich (which could have been cleared by local protection if a circuit breaker was installed), will also result in an extended outage to the much larger load supplied from the Big White Substation. The installation of a local circuit breaker at Joe Rich will ensure that a fault at that location will only affect the customers supplied by the Joe Rich transformer.

57.0 Reference: 3. Transmission and Stations, Station Sustaining Programs and Projects
Exhibit No. B-1, Creston Substation Protection Upgrade, pp. 75-76
Circuit Switchers

Q57.1 Why are circuit breakers not recommended as per the FortisBC standard?

A57.1 Circuit breakers were not recommended for this project because of space restrictions at the Creston Substation. For further detail regarding the decision to install circuit switchers instead of breakers, please see the responses to BCUC IR No. 1 Q57.2 and Q57.3.

Q57.2 What is the cost and complications of adding circuit breakers?

A57.2 Physically there is no room in the existing station to accommodate circuit breakers for transformer protection. A circuit breaker was not considered an option due to the extensive modifications and capital expenditures that would be required at the Creston Substation to accommodate circuit breakers.

Q57.3 Please provide a full comparison of circuit switchers and circuit breakers when considered for used in this substation. Please take into account safety, outage frequency and duration, and costs.

A57.3 FortisBC's standard practice is to use circuit breakers for all applications requiring a fault interrupting device, including transformer HV protection. Circuit breakers generally have higher interrupting-current ratings and duty cycles compared to circuit switchers, however they do cost somewhat more. Circuit breakers also require the installation of HV disconnect switches to allow the breaker to be safely isolated for maintenance and repairs.

Circuit switchers are often used for transformer protection applications as they typically have an integrated disconnect switch which removes the need for a separate disconnect. The lower ratings and duty cycles are generally acceptable for transformer protection as this type of application is less severe than other uses such as transmission line protection (where faults are much more frequent). As well, newer circuit switchers can be equipped with integrated current measuring devices which remove the need for external current transformers. This is advantageous in retrofit locations where there are no existing current transformers installed in the power transformer. There is no significant difference in safety between either device.

In the case of the Creston Substation, the preference would be to use circuit breakers if possible, as per FortisBC standards. However, due to the very limited amount of space in this legacy substation there is insufficient space to install both a circuit breaker and disconnect switch for each transformer. The Creston power transformers are also not equipped with current transformers, so using circuit switchers with integrated current measuring devices removes the need to retrofit new bushing current transformers. It is on this basis that FortisBC has selected circuit switchers for the Creston Substation transformer protection.

58.0 Reference: 4. Distribution
Exhibit No. B-1, New Connects System Wide, pp. 78-79
Growth

Q58.1 What are the estimated number of new connects?

A58.1 The estimated number of Net Customer Additions and New Connects is shown in Table A58.1 below.

Table A58.1
Estimated New Connects

		2004	**2005**	**2006**	**2007**	**2008F**	**2009F**	**2010F**
1	Net Customer Additions	2,304	2,735	2,668	1,818	2,858	2,974	2,845
2	New Connects	3,625	3,970	3,999	3,766	4,195	4365	4176
		($000s)						
3	Average New Connect Unit Cost	1.55	1.80	2.30	2.36	2.23	2.24	2.56
4	Average CIAC Cost per New Connect	1.49	1.55	1.99	2.94	2.94	3.16	3.68
5	Total Unit Cost Per New Connect (Includes New connects cost + CIAC)	3.05	3.35	4.29	5.30	5.17	5.40	6.24
6	Average Forced Upgrade Cost Per New Connect	1.03	1.30	1.71	1.25	1.25	1.34	1.57

Q58.2 What is the basis for this projected growth? Please explain.

A58.2 Net customer additions are the difference in the Company's customer count from one year to the next. The Company forecast its customer count and net customer additions based on past trends, incorporating the population growth numbers from BC Statistics, as well as other factors including city and regional activity and forecast housing starts.

New connects is based on the Company's construction activity. The Company did not forecast new connects as part of its 2009-2010 Capital Expenditure Plan. The numbers shown in Table A58.2 below have been calculated for this response based on the historical ratio between net customer additions and new connects, which has averaged approximately 1:1.45 for the past five years. This means that FortisBC has net customer growth of one customer for every 1.45 new connects constructed. The difference is based on several reasons. In some instances new connects are upgrades to an existing customer premise and do not result in a net addition. In other instances, customer connects are permanently removed when premises are no longer utilized, resulting in a net decrease in customer count.

As noted above, the Company did not forecast the new connects – capital expenditures for 2009 and 2010 based on projected customer growth. The statement in the 2009-2010 Capital Plan (Exhibit B-1) page 79 line 10-11 is in error (see Errata No. 1 Item 8). The expenditure forecast for new connects for 2009 and 2010 was based on historical expenditures. This is a change from the 2007 and 2008 expenditure forecast methodology which was based on projected customer growth, average CIAC and historical forced upgrade costs. The change was made in reaction to the significant variance between the 2007 and 2008 forecast and actual expenditures, which are shown in the Table A58.2 below.

Table A58.2

Year	Original Forecast	Current Actual or Forecast	Variance amount	Variance Percent
	($000s)			%
2007	7,245	8,900	1,655	23
2008	7,977	9,366	1,389	17

Q58.3 What are the unit costs of new connects, the average CIAC, and the forced upgrade costs?

A58.3 The estimated unit cost per new connects, the average CIAC, and the average forced upgrade cost for 2008 - 2010 is shown in Table A58.1 in response to BCUC IR No. 1 Q58.1.

Q58.4 Please provide the historical costs for the unit cost of new connects, the average CIAC, and the forced upgrade costs?

A58.4 The historical unit cost per new connects, the average CIAC, and the average forced upgrade cost for the period 2004 - 2007 is shown in Table A58.1 in response BCUC IR No. 1 Q58.1.

59.0 Reference: 4. Distribution, Distribution Growth Capacity Projects
Exhibit No. B-1, Glenmore - New Feeder, p. 81
Underground Feeder

Q59.1 What is the voltage level for this feeder?

A59.1 The voltage level for this feeder is 12.5 kV.

Q59.2 Why is this feeder an underground feeder when FortisBC's standard of service is overhead?

A59.2 FortisBC's policy is to construct lines overhead. It will construct new feeders with a provision for an additional circuit to be underbuilt on the same structure. However, in this instance all overhead lines along the planned route already contain two circuits.

Q59.3 Could this feeder be replaced with an overhead line?

A59.3 No, all overhead feeders running along the proposed route already have two circuits.

60.0 Reference: 4. Distribution, Distribution Growth Capacity Projects
Exhibit No. B-1, Airport Way Capacity Upgrade, p. 82
Underground Feeder

Q60.1 What is the voltage level for this feeder?

A60.1 The voltage level for this feeder is 12.5 kV.

Q60.2 Why is this feeder an underground feeder when FortisBC's standard of service is overhead?

A60.2 This feeder is an existing underground system and the project calls for an upgrade of capacity from 200 amps to 600 amps to accommodate the large growth at Kelowna airport.

Q60.3 Could this feeder be replaced with an overhead line?

A60.3 No. This is a well established commercial/industrial corridor where the feeder was originally installed underground. Construction of an overhead system will make it difficult to maintain safe limits of approach. Please also refer to the response to BCUC IR No. 1 Q60.2.

61.0 Reference: 4. Distribution, Distribution Growth Capacity Projects Exhibit No. B-1, Hollywood Feeder 3- Sexsmith Feeder 4 Tie, pp. 82-83 Underground Feeder

Q61.1 What is the voltage level for this feeder?

A61.1 The voltage level for this feeder is 12.5 kV.

Q61.2 Why is this feeder an underground feeder when FortisBC's standard of service is overhead?

A61.2 When the civil work was done on the Highway 33 extension (between Highway 97 and Enterprise Way), FortisBC installed conduit for future use. This project will utilize this conduit system along this section of Highway 33 (approximately 350 meters) while the rest of the proposed feeder tie will be overhead.

Q61.3 Could this feeder be replaced with an overhead line?

A61.3 Yes. Alternative options (both overhead and underground) were investigated but having this small section of the project underground was determined to be the most cost effective solution.

62.0 Reference: 4. Distribution, Distribution Growth Capacity Projects
Exhibit No. B-1, Christina Lake Feeder 1 Capacity Upgrade, p. 83
Re-conductoring

Q62.1 Please provide the reference for the standard voltage level criteria.

A62.1 The reference for the standard voltage level criteria is per the FortisBC Distribution Planning Criteria and is based on the Canadian Standards Association (CSA Standard CAN3-C235-83: "Preferred Voltage Levels for AC systems 1 to 50 000 V").

Q62.2 What is the frequency and duration of these voltage sags?

A62.2 According to the results of FortisBC's distribution models, sections of the Christina Lake Feeder 1 experience voltages below the Planning Criteria during peak periods in both summer and winter. Specifically, the peak periods occur in the morning and late afternoons from June to August and December to February.

63.0 Reference: 4. Distribution, Distribution Growth Capacity Projects Exhibit No. B-1, Beaver Park Feeder 1 – Fruitvale Feeder 2 Tie Upgrade, pp. 83-84

Substation Upgrade

Q63.1 Can this project be delayed two years if the tie between the substations is upgraded?

A63.1 Any anticipated substation upgrade project can be delayed more than two years if the proposed project to upgrade the tie between the substations is completed.

Q63.2 What is the cost of upgrading the tie line only?

A63.2 As outlined in the Application (Exhibit B-1) page 84, Line 15, the estimated cost of upgrading the tie line is $1.23 million.

Q63.3 Please explain the planning criteria for station backup and why it is not met?

A63.3 The planning criterion for single transformer substations is that the substation has adequate capacity available to meet 80 percent of peak load at the neighboring substation. The planning criteria for station backup are not met in this situation due to the size of the transformers and the capacity available for backup in the Beaver Park and Fruitvale areas. Currently, the station transformers and the distribution system in the area do not have adequate capacity available to meet 80 percent of peak load at the neighboring substation.

Q63.4 Please provide an estimate of the cost for meeting the planning criteria for station backup?

A63.4 To meet station backup planning criteria for Fruitvale would involve transformer capacity upgrades at Beaver Park and upgrades to the distribution system in the Beaver Park and Fruitvale areas. The overall scope and estimate of the station upgrades has not been completed at this time. However, based on past experience, the cost to upgrade the substations and the distribution system to accommodate the load transfer would likely be in the vicinity of $10.0 million.

64.0 Reference: 4. Distribution, Distribution Growth Capacity Projects
Exhibit No. B-1, Small Growth Projects, pp. 84-85
Voltage Regulators

Q64.1 How many customers are served by the Oliver 1 Feeder?

A64.1 611 customers are served by the Oliver 1 Feeder.

Q64.2 Can the installation of this voltage regulator be delayed by two years?

A64.2 No, continued load growth on the feeder would cause the under-voltage to fall even further below the acceptable voltage limits and affect more customers at the extremes of the feeder.

Q64.3 What is the frequency and duration of these voltage sags?

A64.3 This project does not relate to intermittent voltage sags, but rather prolonged under-voltage caused by voltage drop over a long feeder.

65.0 Reference: 4. Distribution, Distribution Growth Capacity Projects
Exhibit No. B-1, Unplanned Growth Projects, p. 85
Unplanned Load

Q65.1 Please provide historical and project unplanned growth data on line two of the Unplanned Growth Projects for the years 2005 to 2010.

A65.1 The Unplanned Growth projects are necessary to serve unforeseen load emergence that require capacity upgrades and voltage correction. These involve minor additions to plant and are not tracked on an individual basis, consequently the requested information is unavailable.

66.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Distribution Sustaining Programs and Projects, p. 85
Modified Table 4.3

Q66.1 Please complete the following table and indicate if the estimate was based on historical costs.

	Project	**2005**	**2006**	**2007**	**2008F**	**2009**	**2010**
		($000s)					
1	Distribution Line Condition Assessment					599	667
2	Distribution Line Rehabilitation					3,124	3,470
3	Distribution Right-of-Way Reclamation					621	646
4	Distribution Pine Beetle Hazard Allocation					722	551
5	Distribution Line Rebuilds [1]					1,178	1,167
6	Small Planned Capital					668	747
7	Forced Upgrades and Line Moves					1,255	1,461
8	Distribution Urgent Repairs [2]					1,911	1,805
9	PCB Program					1,073	1,117
10	Aesthetics and Environmental Upgrades					100	100
11	Copper Conductor Replacement Program					4,798	6,586
12	**Total**					**16,049**	**18,317**

Notes:
1. $1 million reduction as a result of the CCR Project
2. $50,000 reduction as a result of the CCR Project

A66.1 The following revised Table 4.3 provides the requested information. Lines 1, 2, 3, 6, 7, and 8 are based on historical costs adjusted for inflation.

Table A66.1
Distribution Line Sustaining Programs and Project Costs

	Project	2005	2006	2007	2008F	2009	2010
		($000s)					
1	Distribution Line Condition Assessment	575	431	928	386	599	667
2	Distribution Line Rehabilitation	569	1,961	1,231	2,582	3,124	3,470
3	Distribution Right-of-Way Reclamation	478	572	641	593	621	646
4	Distribution Pine Beetle Hazard Allocation	-	-	-	1,000	722	551
5	Distribution Line Rebuilds [1]	1,230	3,847	1,470	1,972	1,178	1,167
6	Small Planned Capital	305	515	1,030	435	668	747
7	Forced Upgrades and Line Moves	1,418	716	1,564	1,370	1,255	1,461
8	Distribution Urgent Repairs [2]	1,001	2,123	2,030	1,411	1,911	1,805
9	PCB Program	691	1,560	961	239	1,073	1,117
10	Aesthetics and Environmental Upgrades					100	100
11	Copper Conductor Replacement Program	-	-	-	-	4,798	6,586
12	**Total**					**16,049**	**18,317**

[1] $1.0 million reduction as a result of the Copper Conductor Replacement Project
[2] $0.050 million reduction as a result of the Copper Conductor Replacement Project

67.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Distribution Line Rehabilitation, pp. 88-90
Hot Tap Connections

Q67.1 Please explain why all of these funds are not included in the Copper Conductor Replacement Project.

A67.1 The funds associated with the hot tap connectors are not included in the Copper Conductor Replacement Project because the majority of the connectors are associated with aluminum conductor and can be replaced more efficiently within the Rehabilitation Project. This results from the fact that some of the connector replacements will occur in conjunction with other identified rehabilitation work including pole, crossarm, insulator, and guy wires replacement.

Q67.2 Please identify the six years referred to and show the amounts for one full eight year cycle.

A67.2 The six years referred to are 2011 to 2016 inclusive. The amounts for one full eight year cycle included in the Rehabilitation Project for Hot Tap Connector Replacements are shown in the following table.

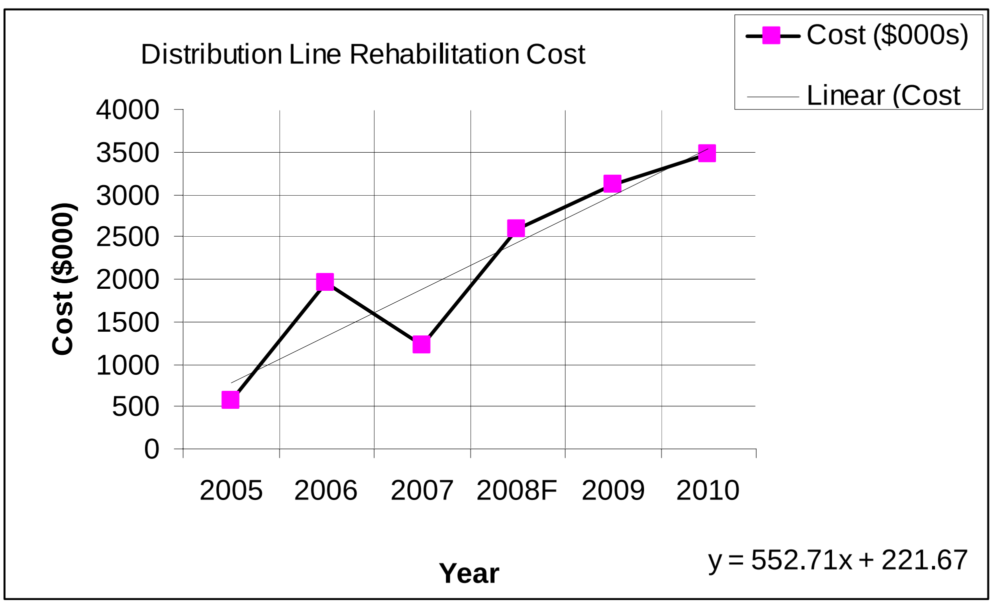
Table A67.2
Hot Tap Connector Replacements Costs

	2009	2010	2011	2012	2013	2014	2015	2016	Total
$000s	750	750	500	500	500	500	500	500	4,500

Q67.3 Would FortisBC consider adding these funds to the Copper Conductor Replacement Project and removing this item from the 2009-2010 Capital Expenditure Plan?

A67.3 FortisBC believes there are more efficiencies associated with the existing Rehabilitation Project and the Hot Tap Connector Replacements than there are between the Copper Conductor Replacement Project and the Hot Tap Connector Replacements. The Company sees no benefit to customers by adding these funds to the Copper Conductor Replacement Project and removing them from the 2009-2010 Capital Plan.

Q67.4 As these estimates are based on historical information, please explain the <u>additional</u> annual growth in the annual estimated funds required of $500,000/year. See Chart.



A67.4 As noted in the 2009-2010 Capital Plan (Exhibit B-1), page 89, line 28 and 29, the historical average has been increased by $750,000 per year for 2009 and 2010 to accommodate Hot Tap Connector replacements.

68.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Distribution Right-of-Way Reclamation, pp. 90-91
Tree-Free Zones

Q68.1 Will the tree-free zone be outside the rights-of-way? If so, provide a map highlighting the areas involved.

A68.1 As stated in the response to BCUC IR No. 1 Q38.1, it is possible (dependent on right-of-way slope gradient, conductor and tree height) that in some locations the tree-free zone will be outside of the right-of-way. Maps highlighting possible areas where the tree-free zone is outside of the right-of-way have not been developed.

Q68.2 Will the trees be sold as salvage?

A68.2 As stated in the response to BCUC IR No. 1 Q38.2, trees are sold as salvage if harvested on Crown land if it is cost effective to do so. When trees are harvested on private, municipal, or Ministry of Transportation and Infrastructure lands, the owner of the tree asset determines the wood disposal.

Q68.3 Will the trees be used for biomass energy generation?

A68.3 As stated in the response to BCUC IR No. 1 Q38.3, FortisBC believes it is unlikely that the trees will be used for biomass energy generation. When trees from Crown land are marketed, the sawmill owner determines the best use. When trees are harvested from private, municipal or Ministry of Transportation and Infrastructure lands, the owner determines the wood disposal.

69.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Right-of-Way Reclamation – Pine Beetle Kill Hazard Trees,
pp. 90-91
Pine Beetles

Q69.1 Will the trees be sold as salvage?

A69.1 As stated in the response to BCUC IR No. 1 Q38.2, trees are sold as salvage if harvested on Crown land if it is cost effective to do so. When trees are harvested on private, municipal, or Ministry of Transportation and Infrastructure lands, the owner of the tree asset determines the wood disposal.

Q69.2 Will the trees be used for biomass energy generation?

A69.2 As stated in the response to BCUC IR No. 1 Q38.3, FortisBC believes it is unlikely that the trees will be used for biomass energy generation. When trees from Crown land are marketed, the sawmill owner determines the best use. When trees are harvested from private, municipal or Ministry of Transportation and Infrastructure lands, the owner determines the wood disposal.

70.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Distribution Line Rebuilds, p. 93
Copper Conductor Replacement Project

Q70.1 Please explain why all of these funds are not included in the Copper Conductor Replacement Project.

A70.1 The funds associated with the Distribution Line Rebuilds Project are not included in the Copper Conductor Replacement Project due to the fact that the proposed Rebuild projects involve assets other than copper conductor and have been initiated by other drivers in addition to safety. The Distribution Line Rebuild Project has been decreased by $1.0 million in both 2009 and 2010 to reflect the fact that in previous years a number of rebuild projects involved copper conductor replacement.

Q70.2 Please identify the six years referred to and show the amounts for one full eight year cycle.

A70.2 FortisBC can not locate the information in the document to which this question refers.

Q70.3 Would FortisBC consider adding these funds to the Copper Conductor Replacement Project and removing this item from the 2009-2010 Capital Expenditure Plan?

A70.3 The Distribution Line Rebuilds Project has been an integral part of FortisBC's capital expenditure plans for a number of years and is anticipated to be an ongoing requirement to maintain the integrity of Company distribution assets. The Copper Conductor Replacement Project is a specific initiative, scheduled to be completed within a ten year period. FortisBC believes there are no efficiencies to be gained by combining the Copper Conductor Replacement and the Distribution Line Rebuilds Project. The Company sees no benefit to customers by adding these funds to the Copper Conductor Replacement Project and removing them from the 2009-2010 Capital Plan.

71.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects

Exhibit No. B-1, Distribution Urgent Repairs, p. 97

Copper Conductor Replacement Project

Q71.1 Please explain why all of these funds are not included in the Copper Conductor Replacement Project.

A71.1 The funds associated with the Distribution Urgent Repair Project are not included in the Copper Conductor Replacement Project due to the fact that the proposed Urgent Repair Projects involve assets other than copper conductor and are initiated by other drivers in addition to safety. The Distribution Urgent Repair Project has been decreased by $50,000 in 2010 to reflect the fact that in previous years a number of Urgent Repair Projects involved copper conductor failures.

Q71.2 Would FortisBC consider adding these funds to the Copper Conductor Replacement Project and removing this item from the 2009-2010 Capital Expenditure Plan?

A71.2 The Distribution Urgent Repair Project has been an integral part of FortisBC's capital expenditure plans for a number of years and is anticipated to be an ongoing requirement to maintain the integrity of Company distribution assets. The Copper Conductor Replacement Project is a specific initiative, scheduled to be completed within a ten year period. FortisBC believes there are no efficiencies to be gained by combining the Copper Conductor Replacement and the Distribution Urgent Repair Project. The Company sees no benefit to customers by adding these funds to the copper Replacement Project and removing them from the 2009-2010 Capital Plan.

72.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects

Exhibit No. B-1, PCB Program, p. 97

Status of Affected Units

Of the 31,000 units how many units have been assessed?

Of the 31,000 units, how many units have been found to have levels above 50 ppm?

A72.0 The Company has completed the assessment of 21,807 units. To date, 935 of the units assessed have been found to have PCB levels above 50 ppm.

73.0 Reference: 4. Distribution, Distribution Sustaining Programs and Projects
Exhibit No. B-1, Copper Conductor Replacement Program, pp. 98-99
Related Projects

Q73.1 Would FortisBC please expand the table "Copper Conductor Replacement Program" to include the years 2009 through to 2018?

A73.1 Please see the requested table below.

Year	Copper Replacement ($000)
2008	300
2009	4,728
2010	6,492
2011	15,569
2012	10,242
2013	10,446
2014	10,656
2015	10,867
2016	11,085
2017	11,308
2018	11,547
Total	**103,241**

Q73.2 Would FortisBC please add the costs for all related projects to this expanded table?

A73.2 Table A73.2 below includes projects that are suggested by BCUC IR No. 1

Q67.0, Q70.0, and Q71.0 as related projects. The expenditures for the period 2011 to 2018 are based on the previous years' expenditures inflated by 5 percent annually, with the exception of the Hot-Tap Connector Replacement program which has been reduced to $0.5 million in 2011 and then inflated annually as per the other projects. The Company cautions that over the long term, this simplistic estimating approach may result in significant variances based on the age demographics of in service assets. A more advanced estimating method may result in step increases in the rebuild projects. This will be addressed as part of FortisBC's next long term System Development Plan.

Table A73.2
Combined Project Costs

Year	Copper Conductor Replacement	Hot Tap Connector Replacement	Distribution Rebuilds	Distribution Urgent Repair	Total
	$000s				
2008	300				**300**
2009	4,728	750	1,178	1,911	**8,567**
2010	6,492	750	1,167	1,805	**10,214**
2011	15,569	500	1,225	1,895	**19,189**
2012	10,242	525	1,287	1,990	**14,044**
2013	10,446	551	1,351	2,090	**14,438**
2014	10,656	579	1,418	2,194	**14,847**
2015	10,867	608	1,489	2,304	**15,268**
2016	11,085	638	1,564	2,419	**15,706**
2017	11,308		1,642	2,540	**15,490**
2018	11,547		1,724	2,667	**15,938**
Total	**103,241**	**4,901**	**14,046**	**21,814**	**144,002**

Q73.3 Would FortisBC consider adding these related funds to the Copper Conductor Replacement Project and removing them from the 2009-2010 Capital Expenditure Plan?

A73.3 As stated in the responses to BCUC IR No. 1 Q67.3, Q70.3, and Q71.2, FortisBC believes there are more efficiencies associated with the existing Rehabilitation Project and the Hot Tap Connector Replacements than there are between the Copper Conductor Replacement Project and the Hot Tap Connector Replacements.

The Distribution Line Rebuilds Project and the Distribution Urgent Repair Project have been integral parts of FortisBC's capital expenditure plans for a number of years and are anticipated to be an ongoing requirement to maintain the integrity of Company distribution assets. The Copper Conductor Replacement Project is a specific initiative, scheduled to be completed within a ten year period.

FortisBC believes there are no efficiencies to be gained by combining the Distribution Line Rebuilds, the Distribution Urgent Repair, or the Hot Tap Connector Replacement Project with the Copper Conductor Replacement Project. The Company sees no benefit to customers by adding these funds to the Copper Conductor Replacement Project and removing them from the 2009-2010 Capital Plan.

74.0 Reference: 5. Telecommunications, SCADA, and Projection and Control Projects, Sustaining Projects
Exhibit No. B-1, Harmonic Remediation, p. 102
Scope

Q74.1 Please identify the cost for investigating and resolving the harmonic issues as separate amounts.

A74.1 It is not possible to provide these costs separately in advance as they depend on a numbers of factors including:

- the location of the harmonic problem;
- whether existing monitoring equipment is installed in the vicinity;
- the extent of any studies necessary to analyze the problem; and
- the cost of any equipment required to mitigate the problem.

Q74.2 Will the customer be required to bear the cost of resolving the harmonic issue emanating from his load?

A74.2 If a customer load is found to be significantly contributing to a harmonic distortion issue, then FortisBC will require the customer to install corrective equipment at the customer's cost.

75.0 Reference: 5. Telecommunications, SCADA, and Projection and Control Projects, Sustaining Projects
Exhibit No. B-1, Protection Upgrades, pp. 102-103
Transformer Differential Relays

Q75.1 What are the risks to safety and reliability if the transformer differential relays are not included as part of this 2009-2010 Capital Expenditure Plan?

A75.1 The risks related to not replacing these relays are related to the fact that these are electromechanical devices. It is difficult to maintain/test this equipment and to ensure that it is functional at all times. As well, spare parts and replacements are no longer available. If a differential relay fails to operate when required, a much more costly asset (the substation transformer) is placed at risk of a catastrophic failure. It should be emphasized that with the completion of the Transmission Protection Upgrades program and the Distribution Substation Automation program, these devices will be the only remaining electromechanical relays in service at FortisBC.

Q75.2 Why were these relays not included in the Distribution Substation Automation Project?

A75.2 The replacement of this equipment was not specifically required to meet the objectives of the Distribution Substation Automation program.

Q75.3 What is the cost of a transformer differential relay?

A75.3 The budgetary price for a FortisBC standard transformer differential relay (SEL-387) is approximately $10,000.

76.0 Reference: 5. Telecommunications, SCADA, and Projection and Control Projects, Sustaining Projects

Exhibit No. B-1, Communication Upgrades, pp. 102-103

Costs

Q76.1 Would FortisBC please provide a breakout of the costs for Kootenay region, the Kelowna RTU's, the FA Lee Terminal teleprotection, and the leased-line modem replacement?

A76.1 Please see Table A76.1 below for a breakdown of the requested costs.

Table A76.1
Communication Upgrade Costs

Description	Estimated Cost ($000s)
JungleMux Laser Replacement (Kootenay Region)	75
Kelowna RTU Upgrades	150
72 Line / 74 Line Teleprotection Upgrade	75
Leased-line Modem Replacement	10

Q76.2 What is the saving on using digital celluar modems?

A76.2 The monthly charge for a CDMA (cellular) data modem is approximately $65. For comparison, the cost of a typical telephone leased-line circuit ranges from $650 to over $2,000 per month. The initial capital costs are also lower for cellular modems.

Q76.3 What is the failure rate in the Kootenay region?

A76.3 No specific failures have occurred with the JungleMux laser equipment. However, the manufacturer has indicated that based on their mean-time-between-failure (MTBF) statistics the new lasers are more reliable.

77.0 Reference: 6. Demand Side Management,
Exhibit No. B-1, Overview, pp. 107-108
Costs

Q77.1 As the program has been in operation since 1989, please provide the DSM cost for MWh saved.

A77.1 The DSM program cost approximately $33.4 million and saved approximately 301,200 MWh during the 19 years between 1989 and 2007. First year costs (per MWh) are not directly compared to power purchase costs, as the benefits of DSM measures continue for the lifespan of the measures.

Q77.2 Please provide the planned and actual energy savings in MWh and the planned and actual costs since 1989 to 2010.

A77.2 The information requested is provided in Table A77.2a and A77.2b below.

1 **Table A77.2a**
2 **Cumulative Energy Savings to December 31, 2007**

Year	Plan	Actual	% of Plan Achieved
	(GWh)		(%)
1989	0.7	0.2	29
1990	4.3	1.0	23
1991	13.3	7.9	59
1992	15.6	16.3	104
1993	26.1	24.1	92
1994	14.2	12.9	91
1995	18.3	15.6	85
1996	16.3	17.0	104
1997	14.4	14.2	99
1998	13.6	13.1	96
1999	11.6	13.5	116
2000	12.0	17.5	146
2001	12.5	16.9	135
2002	14.1	16.3	116
2003	15.6	18.5	119
2004	14.7	21.3	145
2005	19.0	23.9	126
2006	20.4	23.1	113
2007	21.8	27.9	128
2008	19.5		
2009	25.3		
2010	27.5		
Cumulative Savings[1]	**278.5**	**301.2**	

[1] Cumulative savings are for the years 1989-2007.

Table A77.2b
Cumulative FortisBC Costs to December 31, 2007

Year	Plan	Actual	% of Plan Expenditures
	($000s)		(%)
1989	348	395	114
1990	1,453	758	52
1991	2,163	1,241	57
1992	2,084	1,895	91
1993	2,259	3,822	169
1994	1,947	1,660	85
1995	2,705	1,511	56
1996	1,782	1,944	109
1997	1,670	1,567	94
1998	1,637	1,585	97
1999	1,608	1,468	91
2000	1,543	1,697	110
2001	1,522	1,425	94
2002	1,661	1,555	94
2003	1,840	1,706	93
2004	1,814	1,989	110
2005	1,835	2,350	128
2006	2,234	2,241	100
2007	2,474	2,549	103
2008	2,355		
2009	3,668		
2010	3,952		
Cumulative Costs[1]	**34,579**	**33,358**	

[1] Cumulative costs are for the years 1989-2007.

78.0 Reference: 6. Demand Side Management,
Exhibit No. B-1, 2009-2010 Programming, p. 109
Additional Staff

Q78.1 How many additional staff will be added to the DSM program?

A78.1 The Company plans to add 2.5 Full Time Equivalent position comprised of:

- Operations Supervisor (1.0);
- Program delivery representative (1.0); and
- Communications co-ordinator (0.5).

Q78.2 What is the expect costs for the additional staff?

A78.1 The additional staff is estimated to cost approximately $310,000 including benefits and other loadings.

Q78.3 Could this additional staff requirement be met through contract employees?

A78.3 The Company is adding DSM staff in response to the provincial Energy Plan and to meet increased customer demand for DSM offerings. In the Company's opinion these business needs are best met through full-time permanent staff which benefits customers by providing a higher degree of continuity.

79.0 Reference: 6. Demand Side Management, 2009-2010 Programming Exhibit No. B-1, Residential Sector, p. 110 CFLs

Q79.1 Are there disposal issues with CFL lamps?

A79.1 The small amount of mercury in a fluorescent lamp requires that used lamps be disposed of properly. The responsibility rests with the Regional Districts' solid waste departments. The Company's role is to inform customers of the appropriate disposal locations where such facilities exist. This information is available from PowerSense representatives, FortisBC's Contact Centre, as well as the FortisBC website at www.fortisbc.com.

80.0 Reference: 6. Demand Side Management, 2009-2010 Programming Exhibit No. B-1, New Residential Programs, p. 110 Net Metering

Q80.1 Will Net Metering programs be included in the DSM programs?

A80.1 An application for a Net Metering program will be filed by FortisBC in August of 2008. The Net Metering program will be separate from those programs included within the scope of the DSM initiatives, however, the DSM Strategic Plan will address the issue of Customer-owned Generation. It will recommend whether the Company should offer incentives to customers to install Customer-owned Generation in the future.

81.0 Reference: 6. Demand Side Management, 2009-2010 Programming Exhibit No. B-1, New General Service Programs, p. 111
Cool Shops

Q81.1 What is the expected FortisBC cost for energy saved for the Cool Shops pilot project?

A81.1 The Company has budgeted $150,000 in each of the plan fiscal years to continue and expand the Cool Shops program, which will target 0.5 GWh per annum. As with the Kelowna pilot, the Company will seek co-funders to reduce the cost to ratepayers.

82.0 Reference: 6. Demand Side Management, 2009-2010 Programming Exhibit No. B-1, New Industrial Sector Programs, pp. 112-113 EnablingWorkshops

Q82.1 Please discuss the objectives of these enabling workshops, the FortisBC expected cost for MWh saved.

A82.1 The provincial Industrial Efficiency working group has identified a lack of awareness of energy efficiency opportunities, and a lack of a consistent organizational structure to manage energy use as general issues within the industrial sector. The objective of the workshops is to attract a cross-section of customers' functional managers and assist them to jointly prepare their own energy efficiency plan. The energy efficiency plans will include a list of energy efficient projects and will identify their implementation team. FortisBC estimates energy savings of approximately 700 MWh per year from the Enabling Workshops initiative.

83.0 Reference: 6. Demand Side Management, 2009-2010 Programming
Exhibit No. B-1, Conservation Culture, p. 113
Bright Ideas

Q83.1 As no specific energy savings have been attributed to this expenditure, would FortisBC agree to establish a target for the program going forward?

A83.1 The Conservation Culture expenditures are intended to shift customer behaviors towards using less energy, and to condition the market to increase take-up in DSM programming. As it would be difficult to quantify the effects of the Conservation Culture messaging, the Company has not set a target in the plan filed. The DSM Strategic Plan will address whether targets should be set for subsequent years.

Q83.2 If so, what would be the targeted amount in MWh?

A83.2 Please see the response to BCUC IR No.1 Q83.1

84.0 Reference: 6. Demand Side Management, 2009-2010 Programming Exhibit No. B-1, Planning and Evaluation, pp. 113-114

M&E Plan

Q84.1 In what month in 2008 does FortisBC expect to file its M&E Report?

A84.1 FortisBC expects to file the Monitoring and Evaluation Report in December 2008.

Q84.2 What is the cost of the Management and technical and reporting staff?

A84.2 The cost of the Management, technical and reporting staff contained in the Planning and Evaluation budget is $338,000 in 2009 and $349,000 in 2010.

Q84.3 What is the cost of external expertise?

A84.3 The estimate for external consulting is $145,000 in 2009 and $150,000 in 2010.

Q84.4 What is the cost of the DSM Advisory Committee?

A84.4 The estimated cost of the DSM committee is $20,000 per annum, including facilitation and meeting costs.

Q84.5 Please confirm that the DSM Strategy Report will be available by the end of 2008.

A84.5 FortisBC confirms its intention to file the DSM Strategy Report by year end 2008.

85.0 Reference: 7. General Plant,
Exhibit No. B-1, Vehicles, pp. 116-117
Fleet Additions

Q85.1 What is the cost per kM of a FortisBC vehicle and a leased vehicle?

A85.1 The Company does not track the overall cost per kilometre of vehicles based on ownership. However the Company's experience indicates that the ongoing operating and maintenance cost per kilometre of a leased vehicle is comparable to that of an owned vehicle. The Commission recognized that there is a net benefit to customers by FortisBC owning versus leasing vehicles in Order G-58-06 (Appendix 1, page 6). Since then, when the lease period of a leased vehicle expires, the Company generally purchases a replacement unit.

86.0 Reference: 7. General Plant,
Exhibit No. B-1, Replace Vehicles, pp. 117-118
Vehicle Description

Q86.1 Please provide an expanded vehicle description of the categories 1 through 4 and a unit price for each category.

A86.1 For budget purposes the following guideline applies and includes all applicable taxes, levies, accessories and commissioning. Because of the time lapse between budgeting and placing an order, actual expenditures may vary by class.

Table A86.1
Vehicle Replacement Cost / Trigger by Class

	Description	Average Cost	Trigger
1	Passenger Vehicles	$34,000	5 years/160,000 km
2	3/4 Tons & Smaller	$40,000	5 years/160,000 km
3	Service Vehicles (3/4 and 1 Tons) 2 Wheel Drive	$60,000	5 years/160,000 km
4	Service Vehicles (3/4 and 1 Tons) 4 Wheel Drive	$70,000	5 years/160,000 km
5	Single Axle Line Truck (Digger or Aerial) 2 Wheel Drive	$280,000	10 years/160,000 km
6	Single Axle Line Truck (Digger or Aerial) 4 Wheel Drive	$310,000	10 years/160,000 km
7	Specialty and Small Horsepower (Forklifts, Snowmobiles, ATV's, etc.)	$12,000 - $65,000	Individual Review
8	Trailers	$15,000	20 years
9	Tandem Axle Line Truck (Digger or Aerial)	$320,000	10 years/160,000 km

Q86.2 Please explain the 10 year/160,000 km life on the heavy vehicles when compared to the 5 year/160,000 km life on the lighter vehicles?

A86.2 The target age and odometer readings that trigger a review for continued service versus replacement is different for different classes of vehicles due to the fact that the utilization of each vehicle class is different. The lighter vehicles are generally used for the transportation of line staff and light tools to complete miscellaneous service work. The heavy vehicles have significant equipment attached to them with a primary purpose of constructing and maintaining power lines, substations and generation facilities. The lighter vehicles generally travel more kilometers in a shorter period of time. Additionally, the heavy units are designed and manufactured with an anticipated longer lifespan due to the complexity of the equipment that is added to it. The utilization, type of service and operating conditions that a unit experiences (light or heavy) will have an effect on the actual lifespan of the vehicle.

87.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Infrastructure Upgrade, pp. 121-122
Hardware and Software Life

Q87.1 In light of AMI, please confirm that hardware life is five years and software is upgraded every two years.

A87.1 Office-based computer hardware has an expected life of five years. This does not include industrial grade hardware.

Software upgrades depend on the system. Larger enterprise solutions can go as long as three to four years between upgrades. Smaller specialized solutions, such as AutoCAD server, are upgraded on an annual basis to maintain compatibility with the business community that FortisBC works with.

88.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Desktop Infrastructure Upgrade, pp. 122-123
Unit Cost

Q88.1 What is the unit cost of replacing a desktop system?

A88.1 The unit cost to acquire desktop systems is approximately $1,200 for a desktop workstation with a monitor and $1,700 for a notebook workstation with a docking station and monitor. This does not include the cost to configure and place the equipment in service, which depends on the location of the equipment. On average the internal cost to configure and place the equipment in service cost approximately $400 per unit.

89.0 Reference: 7. General Plant, Information Systems Exhibit No. B-1, SAP and Operations Based Application Enhancements, pp. 123-124 Costsgf

Q89.1 Why is the cost decreasing from 2007?

A89.1 This cost has decreased as a result of the significant work done on these systems over the past few years. There are fewer major enhancements and upgrades to be completed on these systems over the next two years.

90.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, AM/FM Enhancements, pp. 124-125
Costs

Q90.1 Please explain the cost number for 2008, 2009 and 2010 if the estimate is based on historical requirements.

A90.1 The estimate is derived from FortisBC's past experience with annual enhancement and upgrade requirements for other enterprise solutions, taking into account the level of work that can reasonably be expected to be completed in a year with the resources available.

91.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Customer Service System Enhancements, pp. 125-126
Costs

Q91.1 Please explain the cost number for 2008, 2009 and 2010 if the estimate is based on historical requirements.

A91.1 Please see the response to BCUC IR No. 1 Q90.1.

Q91.2 Please provide the expected number of customers served for each of the years 2008, 2009 and 2010.

A91.2 The number of direct customers billed through the CIS billing system is currently 108,864. The forecast growth for 2009 and 2010 is 2,974 customers and 2,845 customers respectively.

92.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, System Control Centre SCADA Enhancements, pp. 126-127
Costs

Q92.1 Please explain the cost number for 2008, 2009 and 2010 if the estimate is based on historical requirements.

A92.1 Please see the response to BCUC IR No. 1 Q90.1.

93.0 Reference: 7. General Plant, Information Systems

Exhibit No. B-1, System Control Centre SCADA Enhancements, pp. 126-127

Costs

Would FortisBC consider approval of this option at a net cost of $799,000 less $323,000 (cost savings) or $476,000?

A93.0 The heading for this question refers to the "System Control Centre SCADA Enhancements" however, the numbers indicate that it actually refers to the "Distribution Design Software Solution". If that is the case, please refer to Errata 1, Item No. 16 filing for Appendix 3, which corrects the capital cost savings for 2009 to $0. The capital savings of $323,000 will not be realized until 2011, after the solution is fully implemented.

94.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Buildings, pp. 128-129
Costs

Q94.1 What is the building space and building cost per employee for office space?

A94.1 The building space is approximately 140,000 square feet. The operating cost per employee is approximately $3,975 per year.

Q94.2 Please explain the scope and cost amounts for building upgrades in buildings that are older than 50 years.

A94.2 Please see the response to BCUC IR No. 1 Q94.3.

Q94.3 Please provide a complete breakdown by building, age, upgrade required and costs for item 1 in Table 7.6.

A94.3 The following is a list of the buildings, age, upgrade required and costs for item 1 in Table 7.6. The costs indicated are the total for 2009-2010.

Table A94.3
Building Upgrades

	Building Location	Age	Upgrade Required	Cost ($000s)
1	Castlegar	circa 35 years	Complete generator installation, install locked storage, roofing upgrades to eliminate icing	150
2	Creston	33 years	Correct structural deficiencies, replace carpet with resilient flooring; improve drainage between upper and lower yards	120
3	Grand Forks	circa 30 years	Upgrade perimeter fencing, renovate bathroom	45
4	Kelowna Benvoulin	7 years	Convert warehouse to workshop and storage for Line Services group, install overhead covers at side entrances to eliminate icing conditions, install additional circulation duct and fans in warehouse and fleet areas, upgrade office for Planning group needs, increase plotter room exhaust	230
5	Kelowna Enterprise	Leased (2 years at site)	Install mezzanine complete with stairs and railing, washroom upgrades	75
6	Keremeos	circa 35 years	Replace fencing, minor paving	38
7	Oliver	circa 40 years	Replace roof, additional covered storage, completion of generator installation, upgrade locker room; upgrades to open areas & meeting rooms	320
8	Princeton Operations	circa 35 years	Provision for covered storage, general upgrades	100
9	South Slocan (Generation)	Circa 50 – 75 years, some shops 20+ years	Access road upgrade & fencing – public safety issue, Generation office structural upgrades, Generation office exterior fire escape platforms, Generation office electrical upgrades, Shops electrical upgrades, Garage concrete repair, handrails, roof, install lunchroom stairs	720
10	Trail	15 years	Recoat exterior stucco (Phase 1); IT computer room expansion; Contact Centre Lighting; improvements; recoat exterior stucco (Phase 2); IT Computer room expansion; carpet replacement 4th floor offices	400

1 **Table A94.3 cont'd**

	Building Location	Age	Upgrade Required	Cost ($000s)
11	Kelowna Springfield	Leased (1 year at site)	Develop mezzanine for office area; wheelchair accessibility in front entrance; general upgrades to accommodate staffing requirements	260
12	Warfield Fleet	29 years	Improve lighting in shop; replace bay exhaust fan; oil storage containment shed.	75
13	Warfield Operations	29 years	Completion of generator installation; improve yard lighting; drainage project phases III & IV; security upgrades – card access/fence upgrades; additional paving required; fascia replacement	700
14	Warfield SCC	25 years	Completion of generator installation; pavement; hot water heater; portable addition; convert front office to meeting room; remove/fill septic tank	150
15	All Sites – Environmental/Energy Efficiency Upgrades		Environmental audits will be carried out at designated sites and upgrades unique to the site will be carried out. Example of upgrades: recycle systems, window replacement, alternate energy projects, lighting upgrades, insulation upgrades, etc.	622

95.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Furniture and Fixtures, pp. 129-130
Costs

Q95.1 Please provide the unit cost of a chair and workstation.

A95.1 The unit cost of a chair is approximately $650. The cost of a workstation including installation of walls, shelving, cabinets, keyboard tray, chair mat, garbage can and recycle bin is approximately $5,350.

96.0 Reference: 7. General Plant, Information Systems
Exhibit No. B-1, Tools, pp. 130-131
Costs

Q96.1 Would FortisBC please provide a listing of tools expected to be purchased and their costs?

A96.1 Please see Table A96.1 below.

Table A96.1
Expected Tool Purchase Costs

Line No.	Department	Description	2009	2010
			$000s	
1	**Kelowna Line Ops**	25 kW multi-tap generator set	28,700	
2		6 ton Stick type Cembre press		2,800
3		Battery Hydraulic Cable Cutter	3,200	
4		Cable thumper / TDR	46,000	
5		Cembre Hydraulic Guy Steel Cutters		1,600
6		ERP Room Monitor		9,200
7		Lighting Stands		3,500
8		Voltage Analyzer		28,700
9		Misc	3,000	3,200
10	**Kelowna Line Ops Total**		**80,900**	**49,000**
11	**Kootenay Line Ops**	25 kV URD Ground Set 1/0 6'	1,000	
12		25 kV URD Grounds Set		1,000
13		40' Lineman Stick	4,500	5,000
14		Automated External Defibrillator		5,200
15		Battery Drills	1,700	2,000
16		Battery Press		1,900
17		Battery Press	1,800	
18		Cembre Guy Cutters Cat.No.HT-TC026Y		7,400
19		Chain Jacks B-B Kito #KTOL5B015-10		1,800
20		Chainsaw Drills	3,000	3,000

Table A96.1 cont'd

Line No.	Department	Description	2009	2010
			$000s	
21	**Kootenay Line Ops cont'd**	Chainsaws	1,700	1,800
22		Circle Cutters Greenlee 705	500	
23		DC High Pot Phasing Sticks	3,800	4,000
24		Ground Resistance Tester	5,500	
25		Ladders	1,700	1,600
26		Modiewalks	2,000	1,900
27		Recording Volt Meter Power Monitors	4,000	3,000
28		Sawzall	2,200	
29		Tools for New Trucks		24,600
30		URD Locators	12,300	
31		URD Secondary Covers		1,000
32		Web Jacks	1,500	
33		Misc	2,000	2,100
34	**Kootenay Line Ops Total**		**49,200**	**67,300**
35	**Kootenay C&M**	ASE 2000-PCM-RS communication test set		4,600
36		Cat #T403-2261 25kV Phasing kit (AB Chance)	3,200	3,400
37		Cat. #BMM80 1000volt hand held meggar		2,300
38		High voltage Amprobe Ammeter		5,900
39		Fluke 43B wattmeter/power analyzers	4,200	4,200
40		Burndy 6 ton In line crimper #PATMD6-14V	2,500	2,500
41		Greenlee Gator model#E12CCX11 w/ acc		10,000
42		Micron infrared camera M7640	57,800	
43		Misc. unforeseen tool purchase (<$500)	6,200	12,300
44		Powermate 330 power quality test set		33,200
45	**Kootenay C&M Total**		**73,900**	**78,400**
46	**Okanagan C&M**	Battery impedance tester		15,000
47		Breaker analyzer	50,000	
48		Kelman portable DGA tester		50,000
49		Mikron 7600pro IR camera	45,000	
50		SFRA test set		20,000
51		Misc	3,000	3,200
52	**Okanagan C&M Total**		**98,000**	**88,200**

1 **Table A96.1 cont'd**

Line No.	Department	Description	2009	2010
			$000s	
53	**Okanagan Construction**	15 ton press		5,700
54		6 ton Stick type Cembre press		16,600
55		Digital voltage indicator	1,200	
56		Hydraulic impact tool	1,400	
57		Insulated web jacks	4,100	
58		link sticks	3,700	
59		Misc. rubber products	3,500	
60		Pre-app tools		3,500
61		Range finders	1,700	
62		Self Dumping Dual Axle Gravel hauling trailer with Gravel Chute		23,000
63		Splice tent c/w ac	5,700	
64		UEI Rated voltmeter	600	
65		Misc.	3,000	3,200
66	**Okanagan Construction Total**		**24,900**	**52,000**
67	**South Okanagan Line Ops**	Cembre ACSR/Guy Cutters Hydraulic	2,900	
68		Cembre Presses Stick Type B54Y	5,000	
69		Hastings HV-240 Triangle Shape Telepole 40 foot testing	1,500	
70		Hilti Drill	5,000	
71		Sensorlink Amcorder Recording Ammeter Kit 6-920-3	6,500	
72		Single phase PMI unit		14,700
73		Three phase PMI unit		10,500
74		Misc.	1,000	1,100
75	**South Okanagan Line Ops Total**		**21,900**	**26,300**
76	**Kootenay Construction**	Grounding sets	2,500	
77		Collapsible Reel for Puller/Tensioner	5,000	
78		Ground Resistance Meter	6,000	
79		Hydraulic cutters for Guy Steel CAT. NO. HT-TC026Y	5,600	

1

Table A96.1 cont'd

Line No.	Department	Description	2009	2010
			$000s	
80		Husky Battery Cutters REC-T33	5,600	
81	**Kootenay Construction cont'd**	Chance Ins. Wiresholders M48057	1,500	
82		Salisbury guards	3,600	
83		Cembre Stick Type Presses B54Y-CDD6-8	3,600	
84		Chance Tele pole #C405-1021 40'	1,500	
85		URD Striping Tools	1,500	
86		Modiew Okanagan Salisbury #4744	1,300	
87		Chance 2 ton chain Jacks	1,500	
88		Cembre Pistol Type Press Cat. No. B55-YB-KV		9,600
89		Kito Chain Jack BB Style Cat. No. KTO5LB15-10		2,000
90		Salisbury Guards 36.6 KV Cat. No.1686		1,800
91		Replace Rope Pole Boss. 3/8 Tenex		4,800
92		Chance Web Hoists Cat No. C309-0451		3,000
93		Cembre Guy Cutters Cat No. HT-TCO26Y		3,000
94		URD locator		7,500
95		Salisbury Pole Guards 6' #2466		1,100
96		Cembre ACSR/Guy cutters Hydraulic		4,800
97		Misc	3,000	3,200
98	**Kootenay Construction Total**		**42,200**	**40,800**
99	**Fleet**	Upgrade Snap-On Can tool Kelowna	9,500	
100		Headlight Alignment Machine	2,500	
101		Hytorc Hydraulic Torque Wrench	23,900	
102		Small Tool Purchases	10,000	
103		Upgrade Snap-On Can tool Oliver		9,500
104		14,000 lb Hoist		19,500
105		Small Tool Purchases		12,000
106	**Fleet Total**		**45,900**	**41,000**
107	**Generation Electrical**	Video camera and film equipment - video tape specific job procedures to be used as training videos for safety and inspections	1,000	

2

1 **Table A96.1 cont'd**

Line No.	Department	Description	2009	2010
			$000s	
108	**Generation Electrical cont'd**	Bore scope with light and camera - to be used for stator inspections, ISO bus inspections, and equipment checks and repairs	1,500	
109		Portable asbestos vacuum (backpack style) X 2 - for asbestos removal	4,000	
110		Battery operated cable cutters - safety and employee ergonomics	1,000	
111		Battery operated crimper - safety and employee ergonomics	1,000	
112		24VDC battery operated 200 ft lb impact wrench X 2	1,500	
113		Fluke Multi-meters - update existing meters	8,000	
114		Grounding truck for Raffin switchgear - station service equipment	25,000	
115		Safety ground tester - update and replace existing equipment	5,000	
116		Phase 2 - Generator Protection and Control Training Simulator - Governor, excitation and vibration simulations and stator protection		50,000
117		Portable air movers for confined space entry X 4	4,000	
118		24v portable hammer drill - replacement	1,000	
119		Cordless drill kits X 2	1,500	
120		Step ladders and extension ladders for trucks - update required	3,000	
121		Infrared temperature scanner - old units require updating	1,500	
122		Grounding truck for COR 15 kV switchgear	25,000	
123		Small parts cleaner for electrical equipment	5,000	
124		Test and calibration station for gas detector maintenance	10,000	
125		Wet cell battery tester	6,000	
126		Battery bank load test - Load Cell	10,000	
127		Grounding truck for COR 15 kV switchgear		25,000
128		Small parts cleaner for electrical equipment		5,000
129		Test and calibration station for gas detector maintenance		10,000

1 **Table A96.1 cont'd**

Line No.	Department	Description	2009	2010
			$000s	
130	**Generation Electrical cont'd**	Wet cell battery tester		6,000
131		Battery bank load test - Load Cell		10,000
132		Misc.	1,000	1,000
133	**Generation Electrical Total**		**116,000**	**107,000**
134	**Generation Mechanical**	Submersible camera with attachments	5,000	
135		Portable kidney loop filtration system	10,000	
136		Drum lifter and tilter	1,500	
137		Poly-dolly mobile dispensing stations	2,600	
138		Hydraulic test/troubleshoot kit		20,000
139		Plasma cutting machine		5,000
140	**Generation Mechanical Total**		**19,100**	**25,000**
141	**Total**		**572,000**	**575,000**

97.0 Reference: 1. 2009 System Development Plan Update
Exhibit No. B-1, Executive Summary, p. 3
Appendix 3

Using the following table, please resubmit the costs and schedule for the various projects in Appendix 3.

Project	In Service Date		CPCN Amount or Budget	Actual (Spent to Date)	Estimate at Completion	Variance
	Planned	Actual				
Total						

A97.0 The requested table is attached as Appendix A97.0.

98.0 Reference: SDP, p. 3

Executive Summary

Cost increases by categories

"Expenditures in the 2009-2010 timeframe increased from $150.3 million as originally scheduled to $251.1 million in the 2009 SDP Update."

Q98.1 Please provide a table that allocates the overall cost increase of $100.8 million into the following categories (as well as any other categories that FortisBC considers appropriate):

- **Inflation**
- **AFUDC or other approved rate changes**
- **Project scope changes**
- **Refined (more accurate) estimates**
- **Schedule changes**
- **Added projects**
- **Cancelled projects**

A98.1 Table A98.1 below provides FortisBC's best efforts at assigning the overall 2009-2010 cost increase of $100.8 million into the various categories requested.

Table A98.1
Cost Increase Allocation

Category	($million)
Inflation	30.1
AFUDC	4.9
Project Scope Changes	32.1
More Accurate Estimates	11.8
Schedule changes	(4.2)
Added Projects	33.1
Cancelled Projects	(7.0)
Total	**100.8**

99.0 Reference: SDP, p. 30

New Connects – System Wide

"This project includes installation of new services requiring additions to FortisBC overhead and underground facilities in all regions of its service territory. These capital expenditures allow FortisBC to meet its obligations to serve. The number of customers connected directly affects increases or decreases to this account."

Q99.1 Please provide the number of new connections by year and region for 2006, 2007 and 2008.

A99.1 Table A99.1 below provides the requested information, except for 2008 which is not available at this time.

Table A99.1
New Connects

	2006	**2007**
Castlegar	271	235
Creston	200	219
Grand Fork	142	162
Kelowna	2,166	2,269
Oliver	504	476
Penticton	226	131
Trail	490	274
Total New Installs	3,999	3,766

memorandum

west kootenay power

To R. Dunsmore

From W. Friml

Subject P3 - G1 Runner Cracking

Date November 15, 1985

File No.

Ref.

Our inspection of the Unit #1 runner at Plant #3 during the Ten Year Overhaul revealed several surface cracks in the runner vanes and on the inside of the runner crown. The crown cracking at the runner cone mounting flange prompted us to request a thorough inspection of the entire runner by Cominco Engineering Services technicians. They quickly identified in the order of 46 cracks ranging from one inch to over a foot in length.

The cracks in the runner crown thought to be the most immediate problem proved to be relatively small. We were able to repair them without undue difficulty using standard low hydrogen repair techniques.

Two large cracks gouged out as representative samples of runner skirt and bucket cracking were another matter. They quickly showed that the elimination of these defects is clearly outside the scope of a five week shutdown. The welding procedure used in the crown did not work on these large cracks. In fact, this technique created further cracking in the parent metal adjacent to the repair. We were able to develop a procedure using stainless steel electrodes that appears to work on this runner but it is very time consuming. The complete removal of the cracks would require a major effort. Welding deposits of this size carry a definite risk of further cracking and the distortion of the casting.

Cracking in steel castings is a serious and unpredictable problem. From the information on hand, it is impossible to draw any conclusions regarding the life expectancy of the runner and more data will have to be collected before any decision can be made. For now, this runner will receive special attention. All the major cracks have been bracketed with stainless steel welds to assist in monitoring any propagation.

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Signed

FORM 45? R.P.

MEMO: To R. Dunsmore
P3 - G1 Runner Cracking
November 15, 1985

The next annual inspection will give us a good indication of the urgency of the problem. After the results of that inspection have been compared to the data on hand, we will be able to make a fairly accurate assessment of the cracking problem.

On a more positive note; several of the vane cracks had been repaired previously, some more than once and although they had re-cracked, none had propagated outside of the repair areas. Six crown cracks had been identified in 1973 and these had not grown significantly since then. With the exception of the large crack in the skirt which was repaired during this Overhaul, the major cracks are in the heavy fillets of the castings where working stresses should be relatively low. These defects are likely rooted in flaws present since the runner was cast.

The magnetic particle inspection carried out in the service bay under ideal conditions undoubtedly revealed defects that would not be found in our routine in situ inspections. It is probable that we have lived with these cracks for a while.

W. Friml

WF:sb

WEST KOOTENAY POWER

PLANT #3 UNIT #1

INSPECTION OF RUNNER DURING 10 YEAR OVERHAUL

OCTOBER 1985

The following list outlines cracking in the cast steel runner as seen from the "outside". For a description of cracking in the runner crown and inside the runner, see separate report following.

VANE #1	Clean
VANE #2	Crack in fillet at runner skirt: Two cracks; top one starting 10" down from lip of runner band and is 3½" long. There is a 2" break and then the second crack, a total of 8" long, follows the center of the gusset. The last 3" of this crack are intermittent.
VANE #3	No cracks
VANE #4	Long series of small cracks in the fillet at the runner crown starting 14" back from leading edge and terminating in a casting imperfection 34" from leading edge. (Page 8 of photo section).
VANE #5	Vertical cracks in upper runner skirt (similar to bucket #9). The cracks are located 12" from the bottom gusset and are intermittent and offset from each other for a total length of 10". They start 2" from the runner skirt lip. (Page 10 of photo section).
VANE #6	Small cracks in runner skirt and two cracks in top fillet. (Page 8 & 10 of photo section).
VANE #7	Small crack in bottom fillet.
VANE #8	Large cracks in crown fillet 7" and 5" long. (Page 9 of photo section).

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<u>VANE #9</u>	Large cracks inside runner skirt. The crack is 9½" long at the surface and completely through the top 4" of the runner band. (See Pages 11 12 & 13 of photo section).
<u>VANE #10</u>	No cracks
<u>VANE #11</u>	No cracks
<u>VANE #12</u>	Crack in fillet at crown. We opened the crack to a depth of 1½" over a length of 14" and it still appeared for the full length of the groove. It was decided to back weld this cavity as repairs of this size were beyond the scope of this overhaul. (The state of this repair will be monitored during the next shutdown).
<u>VANE #13</u>	No cracks
<u>VANE #14</u>	No cracks
<u>VANE #15</u>	Vertical crack in gusset at runner skirt. (See Page 10 of photo section).

For ease of future inspection, all major cracks listed above have a single bead of stainless weld at each end of the crack and at right angle to the defect.

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The following list outlines cracking on the inside of the runner and under the crown at the runner cone mounting flange.

RUNNER CONE MOUNTING FLANGE - RUNNER CROWN

(Pages 1 through 4 of photo section)

The cracking of the flange at the trailing edge of the runner vanes has not entered the heavy casting of the runner crown. The cracks are essentially the same at each point with depths ranging from two to four and one half inches.

VANE #	CRACK DEPTH	COMMENT
1	-	Clean.
2	-	Clean.
3	3"	Repaired 1985 - Noted in 1973 as 3" long at surface - No change in 1985.
4	4½"	Repaired 1985 - Noted in 1973 as 2" long at surface - This crack has grown to 3" at the surface and has split into three cracks.
5	4"	Repaired 1985 - Noted in 1973 as 3" long at surface - No change in 1985.
6	3"	Repaired 1985.
7	-	Not repaired in 1985 - 3" long at surface.
8	3"	Repaired 1985.
9	3"	Repaired 1985.
10	3"	Repaired 1985.
11	3½"	Repaired 1985 - Old repair re-cracked.
12	-	Not repaired in 1985 - 2½" long at surface.
13	-	Not repaired in 1985 - 3" long at surface - No change since 1973.
14	4"	Repaired 1985 - Noted in 1973.
15	1½"	Repaired 1985.

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VANE #2 (Pages 5,6&7 of photo section)	Large crack through the trailing edge of the bucket above an old repair.
VANE #3 (Pages 5,6&7 of photo section)	Has a 10" crack through the runner vane trailing edge and another crack slightly further back on the suction side of the bucket. The crack that penetrated the full thickness did not start at the edge of the casting but has propagated from the inside towards the edge. There remains a short bridge of sound metal between the end of the crack and the trailing edge of the bucket. The second crack further back was gauged as far as we could reach. We did not dig this particular crack out completely as the shape of the runner would have prevented us from welding it back up.

* See Section "CESL" for further detail.

WEST KOOTENAY POWER

WELDING REPAIR UNIT #1 PLANT #3 RUNNER

12 November 1985

DAILY LOG

October 16

- Gouged out a large crack in the top fillet of bucket #12. Although we cut a groove 14" x 2" x 1½" deep, we did not eliminate the crack.
- Gouged out a large vertical crack in the runner skirt at bucket #9. Eliminated the crack on the inside of the skirt.

October 17

Mr. Irwin Tenta of Cominco Engineering Services Ltd. was asked to consult on a procedure for filling the large repairs and to comment on the cracking in general. He indicated that the cracks in the top and bottom gussets of the buckets and in the runner skirt should be mapped for future comparison. He did not consider them an immediate problem. We explained the procedure that we intended to utilize to fill the two defects gouged to date.

1. Preheat to 200°F
2. Block weld using 7018 electrodes.
3. Peen all passes except the root.
4. Back gouge to sound metal.
5. Back weld using the same procedure.

He concurred that this would be an acceptable starting procedure. Mr. Tenta indicated that he considered the cracking in the trailing edge of the bucket at the runner crown the more serious problem.

It was decided at this stage that we would not open up any more of the large cracks in the buckets and that we would concentrate on the defects in the crown. The welding procedure would be as above (with the exception of block welding which would not be required).

October 18

- Gouged runner crown cracks all shift. Most cracks eliminated at 3" depth.
- Prepared for welding all shift.
- Repaired air hammers for peening.
- Cut electrodes in half for welding in confined areas.
- Inspected all runner cracks and commenced logging them for future reference.

. . . 2

DAILY LOG

October 19

It has become apparent that the cracks in the crown are pretty well confined to the runner cone mounting flange and have not propagated into the heavy casting of the runner crown.

- Commenced welding the top fillet at bucket #12. Large cavity is essentially full by end of shift.
- Commenced welding runner skirt at bucket #9.
- Commenced welding runner crown cracks.

Have decided to open up only three or four cracks at a time to ensure that we do not get too far ahead and run into scheduling problem.

Two cracks welded by end of shift, three gouged.

October 20

- Continued welding top fillet at bucket #12.
- Continued welding runner skirt at bucket #9 - inside completed.
- Continued welding & gouging cracks in crown.

Step 3 Page 5 — Back gouged crack at bucket #9. Crack is visible for the full length of the repair.

Step 4 Page 5 — Decided to gouge half of the repair thickness - back weld to half of groove depth and repeat the procedure until the crack is eliminated.

Continued block welding procedure.

The outside weld is near completion by the end of the shift.

October 21

Returned to the inside (original repair) and commenced gouging toward the crack. We were about ½" into the repair when the crack appeared. It was approx. 7" long.

Step 5 & 6 Page 5 — At this time, another crack became visible in the undisturbed metal adjacent to the repair.

Suspended work and called Mr. Irwin Tenta for further consultation.

After discussing the problem and inspecting the work, Mr. Tenta made the following recommendation:

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DAILY LOG

October 21 (cont'd)

1. Abandon the block welding.
2. Change from 7018 to stainless electrodes.
3. Use S.S. 309 to cover the parent metal.
4. Use S.S. 308 as filler material.
5. Use vertical stringer beads for all weld metal deposits.
6. Peening and pre-heating as before.

Mr. Tenta suggests that the 7018 metal deposits are stronger than the parent metal and that the weld shrinkage forces are tearing the parent metal adjacent to the repair. The stainless electrodes are more ductile and will hopefully share the shrinkage stress with our steel casting.

It is decided to complete the original repair before we attempt anything with the new crack.

October 22

Steps 7 & 8 Page 5

During our preparation for further welding, it became apparent that the new crack had propagated into our repair. It therefore became necessary to treat the problem as one large crack. Cleaning up the new crack uncovered a large casting flaw which is the likely cause of our problem. The repair was now over a foot long up to three inches deep and two and one half inches wide. Further to this, a hairline crack was now visible at the bottom of the gap. A 5/16" dia. hole was drilled into the crack to hopefully relieve the stresses and backwelding was started.

- Completed welding the runner crown cracks gouged out to date.
- Completed welding cracks at Vanes 2 and 3.

October 23

- Grinding welding repairs under the runner all shift.
- Commenced final welding of the runner skirt repair at bucket #9.

Step 9 Page 5

Both sides of the gap are built up and ground to a symmetrical shape with a minimum gap before bridging. Two welders alternating inside and outside to minimize distortion.

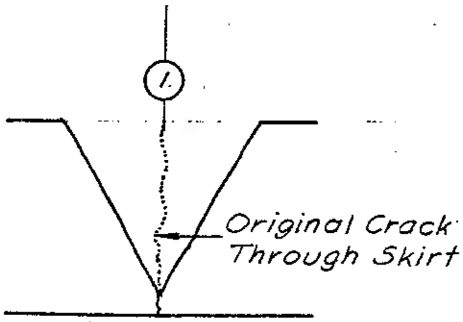
DAILY LOG

October 23 (cont'd)

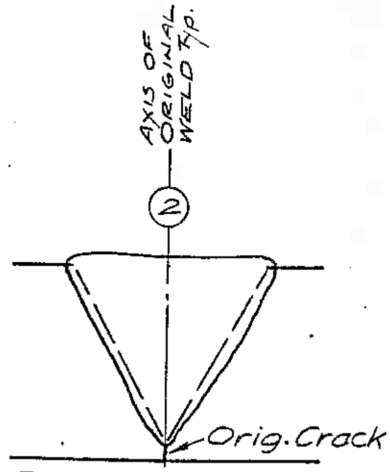
Progress is very soon due to stringer bead welding and allowing time for cooling. The runner skirt deflection is monitored by measuring the gap between the runner and a steel block giraffed out from bucket #9, well away from the area subject to weld deformation. Deflection during cooling is monitored on each side of the crack using dial indicators also mounted well away from the weld area. There are also a series of punch marks on each side of the weld and the distance between them is monitored during the welding.

October 24

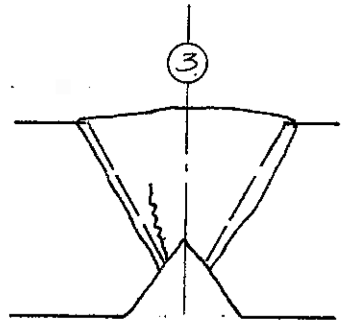
- Final cleaning up of welds by grinding. The large repair has cooled overnight and we are relieved that magnafluxing of the area shows no cracking.



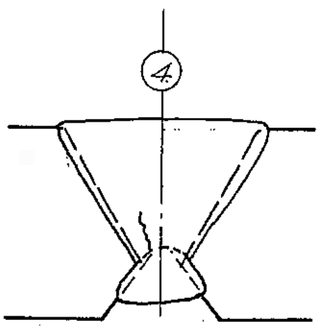
Crack Gouged out. Ready for Welding.



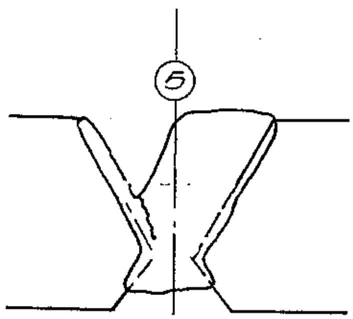
Filled from inside



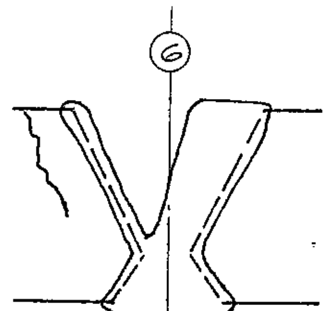
BACK GOUGED.
New crack visible in repair



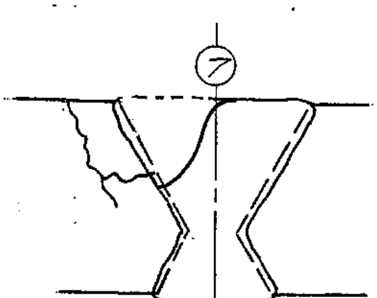
Back welded half of groove depth from the outside



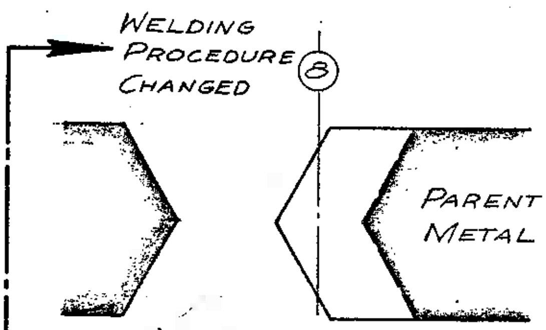
Gouged from Inside



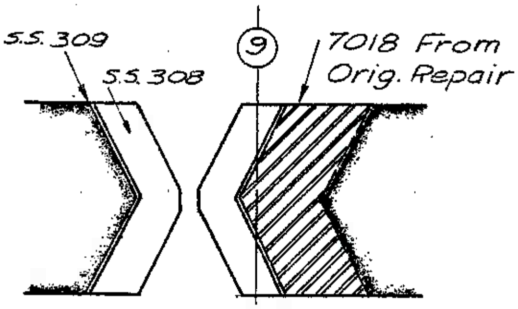
Crack eliminated. New crack appears during Magnafluxing of repair in preparation for backwelding.



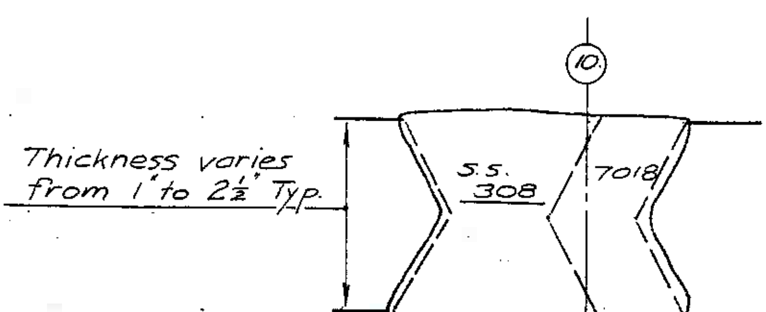
New crack propagates into weld area as we attempt to complete the original repair



New Crack Removed
Block welding abandoned.
7018 Superseded by S.S. 308 and 309 Electrodes.



Closed up gap and ground edge to "V" Groove shape before bridging weld gap. S.S. 309 used between mild Steel and S.S. 308 filler metal



Completed Weld - Ground flush and Magnafluxed after cooling

WEST KOOTENAY POWER
PLANT #3 TURBINE #1

10 YEAR OVERHAUL 1985

ILLUSTRATION OF REPAIR OF LARGE CRACK IN RUNNER SKIRT AT BUCKET #9.

CESL

Memorandum

Cominco Engineering Services Ltd.

To	Asst. Supt., P.G.O., W.K.P.L., South Slocan (Use Title if Possible)	Date	October 24, 1985
From	Technicians, Eng. Testing (R.Dunsmore) (M.D.Saunders/ R.J.Dunsmore) (Use Title if Possible)	File No.	694.40
Subject	#1 GENERATOR COMPONENTS #3 PLANT SOUTH SLOCAN	Reference	

The following components were examined using the appropriate non-destructive testing methods.

SUMMARY OF DEFECTS

A magnetic particle inspection of the turbine runner revealed numerous cracks. See attached sketch for actual locations.

DETAILS

Item	Type of Inspection	Condition
Rotor Shaft	Ultrasonics	Acceptable
Turbine Shaft	"	"
Thrust Bearing Collar	Magnetic Particle	Original casting defects were noted. No recent crack propagation was apparent.
Thrust Bearing Runner Plate	Magnetic Particle	Acceptable
Thrust Bearing Key Assembly	Magnetic Particle	Acceptable
Sixteen Coupling Bolts	Ultrasonics	Acceptable
Governor Ring	Magnetic Particle	Acceptable

Attachment
MDS:RJD/bh
cc: B.Friml
J.W.Farrier
A.J.Dube
File

Signed M Saunders R J Dunsmore

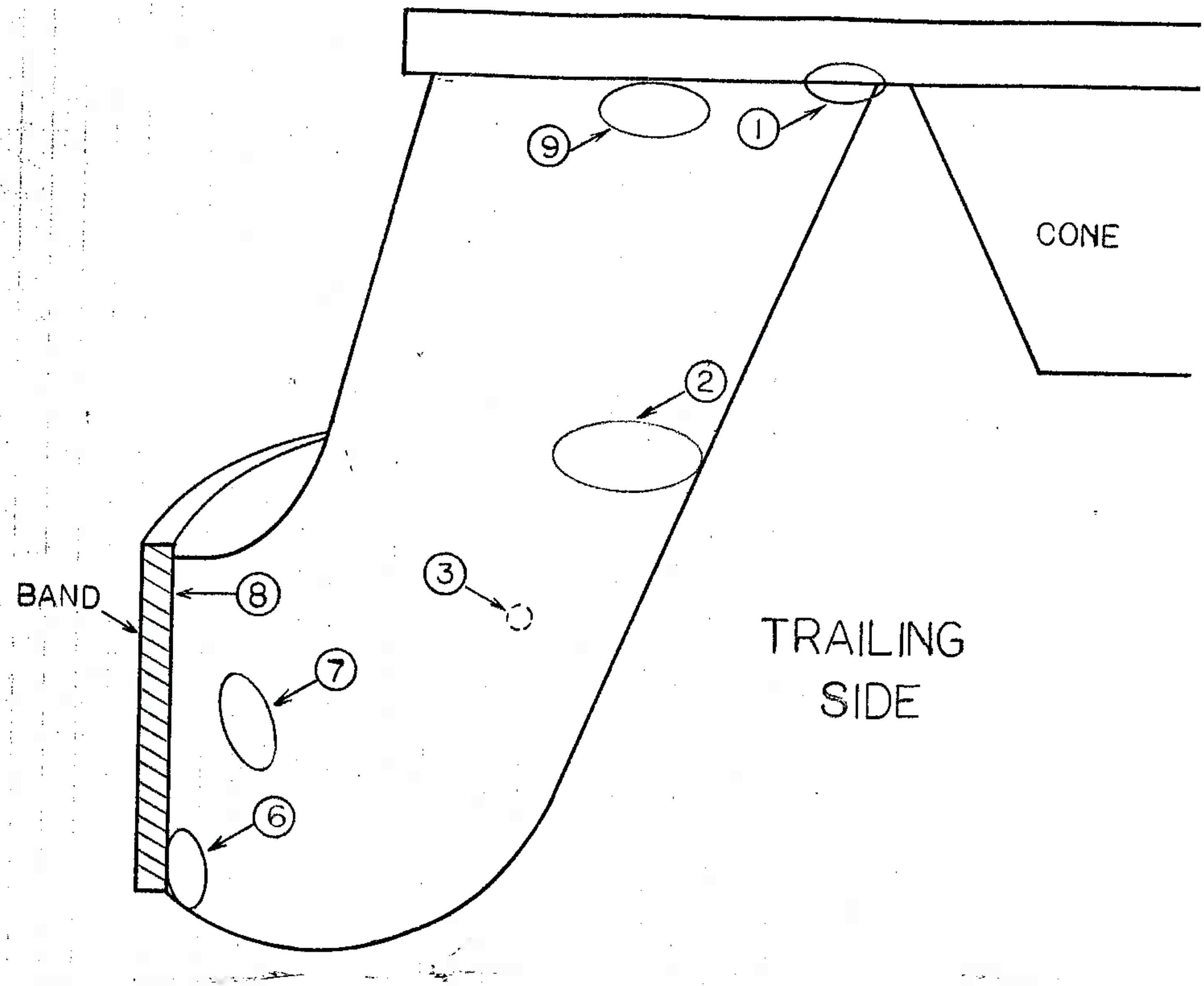
W.K.P. RUNNER INSPECTION NO. 3 PLANT NO. 1 UNIT

Vane Number	Defect Location as Numbered on Sketches		NOTED CRACKING IN CROWN –
	Leading Side	Trailing Side	APRIL 1973
1		3,6	
2	2	6,8	
3	1,2,5	1,2,3	1
4	1	1,9	1
5	3	1,8	1
6	1	1,8,9	
7	1,4	1,7	
8	1,3	1,8,9	
9	1,3	1,3,8	1
10	1,3	1	
11	1	1,3	1, *
12	1	9	1, 9 *
13	1	1	1
14	1	1,3	1
15	1	1,8	

* REPAIRED IN 1973

Shop Sketch

Cominco



b Description	Originator	Materials and specifications		
W.K.P. Runner Inspection	R.J. Dunsmore			
nits and tolerance unless specified will be	Fractional + 1/64 −	Decimal + .005 −	Angular +½° −	Specified	Scale

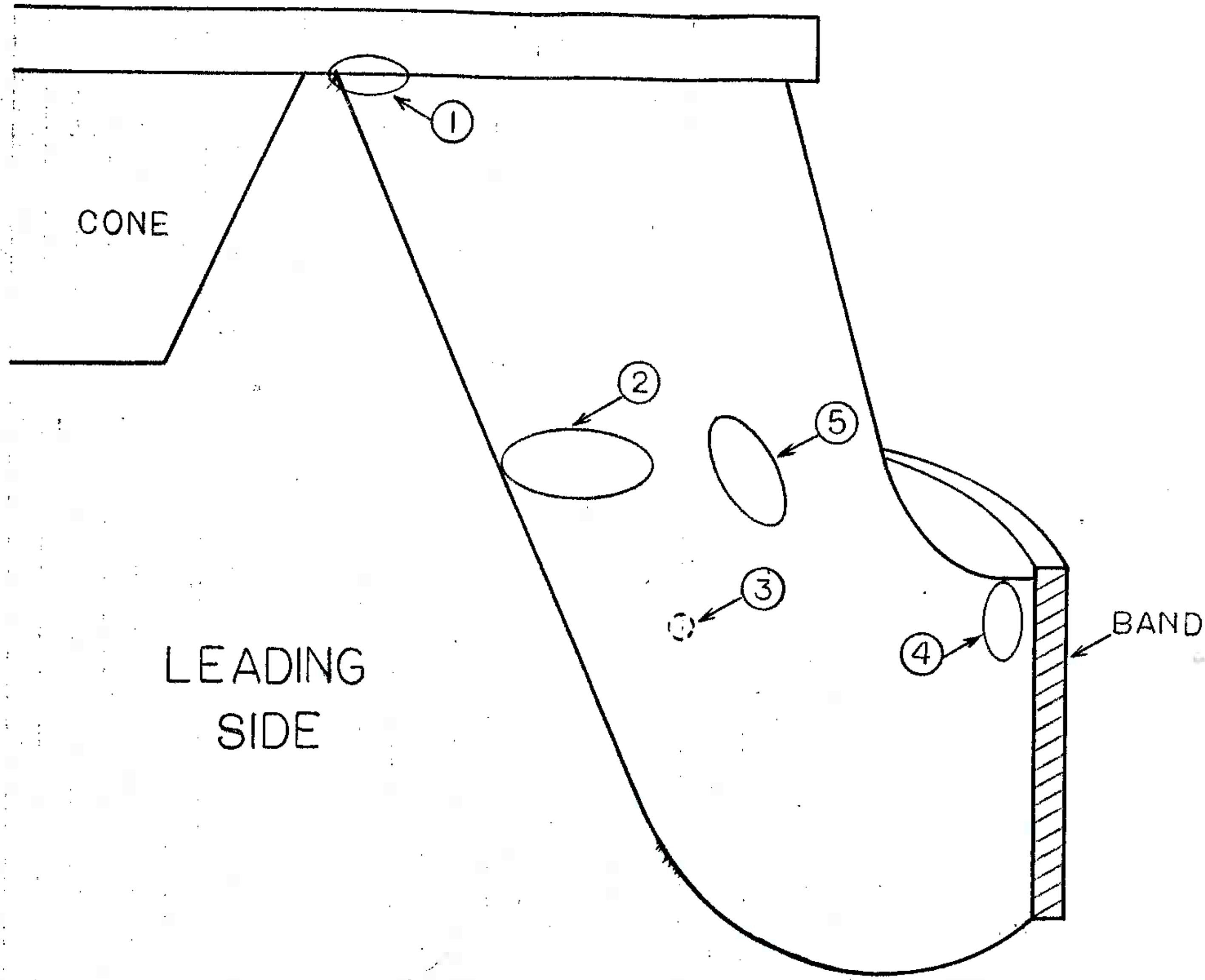
chine finish required	As cast:	Rough	Medium	Fine	Other

narks:

e ______________, 19

Name (please print)

Shop Sketch



Description	Originator		Materials and specifications		
J.K.P. RUNNER INSPECTION	R.J. DUNSMORE				
its and tolerance unless specified will be	Fractional ± 1/64	Decimal ± .005	Angular ± ½°	Specified	Scale

hine finish required	As cast:	Rough	Medium	Fine	Other

arks:

e ______________, 19

Name (please print)

NO. 1 RUNNER - NO. 3 PLANT

WEST KOOTENAY POWER INSPECTION OF April 19, 1973

Hooks welded to draft tube liner (6).

Steps already in scroll case.

Arcaired out behind stay bars.

All Vanes were filled with 308 Stainless. Area about 10" x 10".

Some holes in the Stay Bars capped and ends of the bars welded or rewelded as required.

Vanes 1, 2, 3, 4, 5, 7, 12, and 15 were welded up with 308, approximately 22" up from the discharge end of Vane and 4" out from the band. Area - 10" long by 6" wide. (approximately)

Vane 12 -

2 cracks: (1) 8" long x 1-1/4" deep x 1-1/2" wide, (2) 8" long x 1" deep x 1-1/4" wide

on top of Vane next to Crown edge of the old weld.

Vane 9 -

Crack - 6" long x 3/4" wide x 3/4" deep running vertical into Crown. Removed with arcair and welded with 7018 rod.

Vane 13 -

Crack - on the end of Vane and running in to Crown; 3" long.

Vane 11 -

Crack - on the end of Vane and running next to Crown; 7" long. (old weld is 3" below this crack.)

Vane 14 -

Crack - on the end of Vane and running in to Crown; 3" long.

Vane 3 -

Crack - on the end of Vane and running in to Crown; 3" long.

Vane 4 -

Crack - on the end of Vane and running parallel to Crown; 2" long.

Vane 5 -

Crack - on the end of Vane and running in to Crown; 3" long.

The above cracks were marked for future inspections.

Pictures are attached as to the approximate location of the above cracks.

CESL

Memorandum

Cominco Engineering Services Ltd.

To	W.K.P.L. Assistant Supt., P.G.O., South Slocan (Use Title if Possible)	(R. Dunsmore)	Date	October 28, 1985
From	Materials Engineer (Use Title if Possible)	(E. Tenta)	File No.	E8-10
Subject	#1 GENERATOR TURBINE RUNNER, #3 PLANT		Reference	

Cracking of the 1928-vintage runner as revealed by magnetic particle inspection appears to be due mainly to fatigue, particularly at the junction of the cone mounting flange and the bucket trailing edges. The cyclic stresses causing fatigue cracking are thought to be from a flexing action imposed on the turbine buckets by hydraulic effects during normal operation. The presence of material flaws in the cast steel runner assists in the initiation and propagation of fatigue cracks.

Two metal samples from the runner were examined in the laboratory with a view to assessing weldability, and to identifying a cause for cracking which occurred alongside a repair weld in the stay ring during the present shutdown.

The first sample was taken from the runner cone mounting flange adjacent to the trailing edge of bucket 4; this sample included part of a fatigue crack. Microscopic examination showed a heavy oxide layer to be present on the crack surface, indicating that the crack was an old one. The microstructure of this sample was that of a carbon steel weld metal deposit; the location where the sample was taken had thus been welded at some time in the past.

The second sample was taken from the upper inside surface of the stay ring at bucket position No. 9. Weld repair of a crack there had resulted in re-cracking alongside the weld. The metal sample from here showed a bright, faceted fracture at the re-cracking site, as well as subsurface casting porosity. The microstructure of the sample was that of low carbon cast Bessemer steel, with iron nitride needles precipitated in a ferrite matrix. The presence of nitride needles is indicative of low toughness and is consistent with the observed brittle appearance of the crack surface. Weldability is relatively poor because of low tolerance for thermal shrinkage stresses.

Comments & Recommendations

Not all of the cracks which were seen could be explained in terms of fatigue crack propagation, particularly those cracks which were not at a free edge and which were not at high stress locations. Such cracks probably originated at casting defects and spread through the localized weak area of casting; some of the observed "cracks" may be original casting defects in their entirety.

Signed

CESL

Memorandum

Cominco Engineering Services Ltd.

To	(R. Dunsmore) (Use Title if Possible)	Date	Oct. 28/85
From	(E. Tenta) (Use Title if Possible)	File No.	E8-10
Subject	#1 GENERATOR TURBINE RUNNER, #3 PLANT	Reference	Page 2

Comments & Recommendations

The recommended course of action for dealing with such cracks now is to document them for comparison at subsequent inspections. The first subsequent inspection should be performed after no more than 1 year of further operation.

Locations which have been weld repaired during the present shutdown should be re-inspected after no more than 2 years of further operation.

We recommend that steps be taken towards obtaining a replacement runner for #1 Unit for the following reasons:

1) Expect that fatigue cracking will recur.

2) Embrittlement of the steel by aging (nitride precipitation) results in notch-sensitive fracture characteristics. Cracks which reach a critical size become unstable and capable of very rapid propagation under load.

:kb

cc: W. Friml (S. Slocan)

Signed E. Tenta

PLANT #3 UNIT #1
1985 OVERHAUL
RUNNER REPAIRS

The cracks at the juncture of the trailing edge of the turbine buckets and the runner cone mounting flange initially appeared to be our most serious problem. We could not see the full extent of the cracking till the runner cone was removed. Close inspection after the cone was lowered showed that thirteen of the fifteen buckets had near identical cracks in this area. Due to time constraints, we were able to repair only ten of these defects. Of the three cracks left unrepaired, one (Vane 13) had been noted in 1973 and had not propagated. Another (Vane 12) had been repaired in 1973 and had re-cracked, While the third (Vane 7) had not been noted before. These three cracks provide a good base for monitoring the runner crown cracking in the future. The welding procedure for the work was as follows:

1) Preheat 250°F.
2) 7018 low hydrogen electrodes
3) Peen all passes except the root (the cap was brought high, peened and ground flush)
4) Interpass temp. maintained at 250°F.


6
3" deep


3" deep
8


9

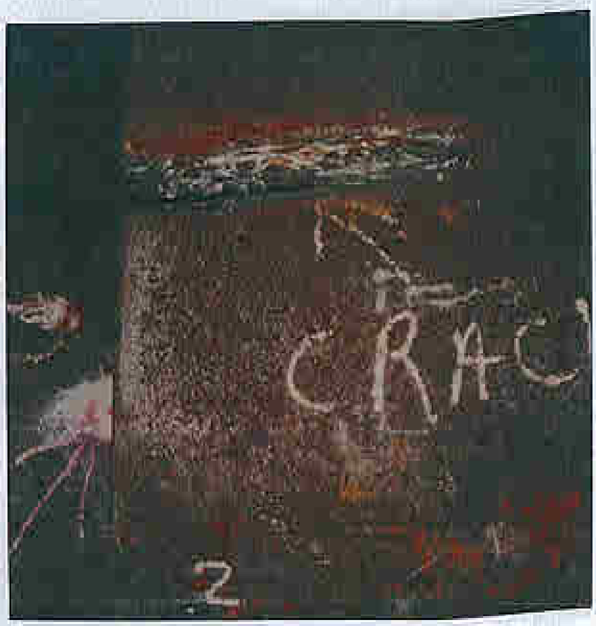

9


3" deep


3½" deep

Crack at edge of No 14 vane
App. runs off into crown cone
mounting hole. Oct 8/85

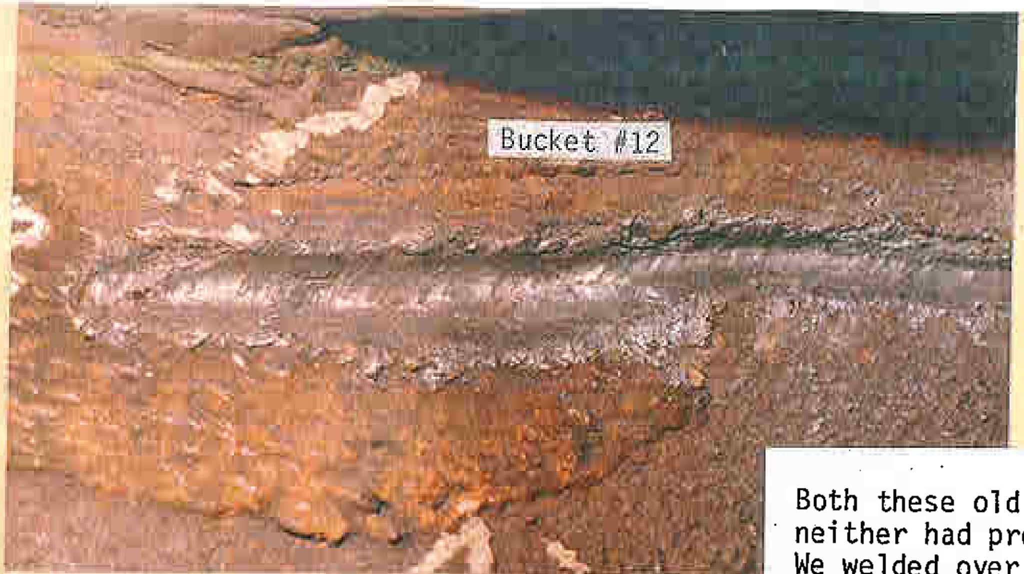
P3-U1 No 3 vane - crack on edge of vane - app. 6" long visible to naked eye oct 8/85



The No.2 vane crack was the initial crack found after the runner had dried out. It and the crack found in No.3 vane were near old repairs but not near enough to indicate a procedure problem in those repairs. Additional stay ~~vanes~~ bars were installed between the cracked vanes and the adjacent sound buckets. The outline of the old repair can be clearly seen in the picture immediately above.

The crack in No.2 vane appears to be the normal fatigue crack starting from the edge, probably at a small notch and propagating inward. The two cracks in No.3 vane however have not done the expected and are locked in the bucket indicating that they started at imperfections present in the metal when the runner was cast. The long crack shown in the bottom picture meanders over the surface of the bucket for 14". We gauged the crack to a depth of ¼" over its full length and it remained visible in the groove. A test section approx. 3" long at the d/s end of the crack was gouged to ½" deep and again the defect remained. As this area is virtually inaccessible for welding it was decided that we would weld over the crack and monitor it in the future. Further digging in this area would have resulted in a massive repair over which we would have serious quality control problems. It is likely that proceding further would have built in as big a problem as we were attempting to remove.

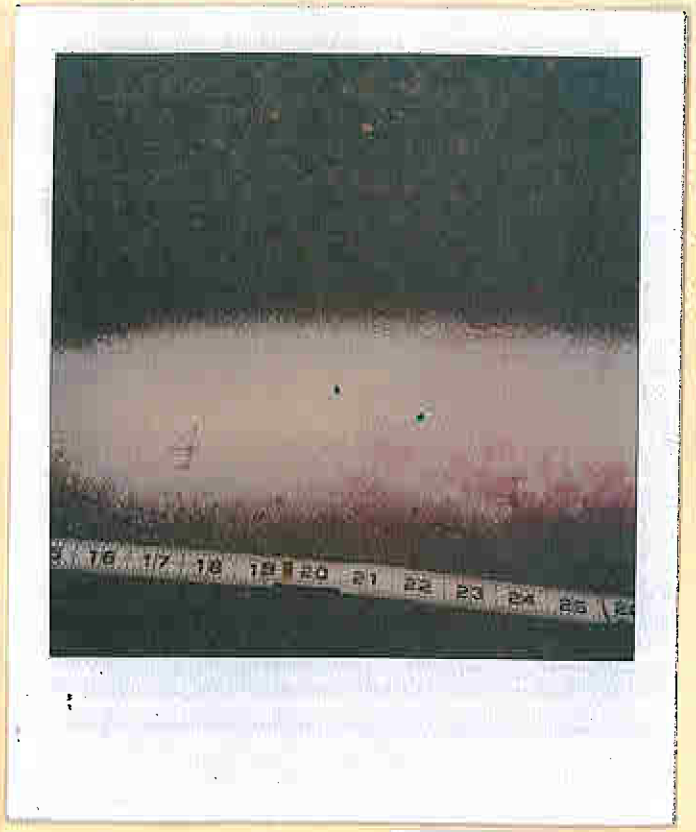
Additional stay bars were welded between Buckets #1-2, #2-3, #3-4, to give additional support to these vanes.



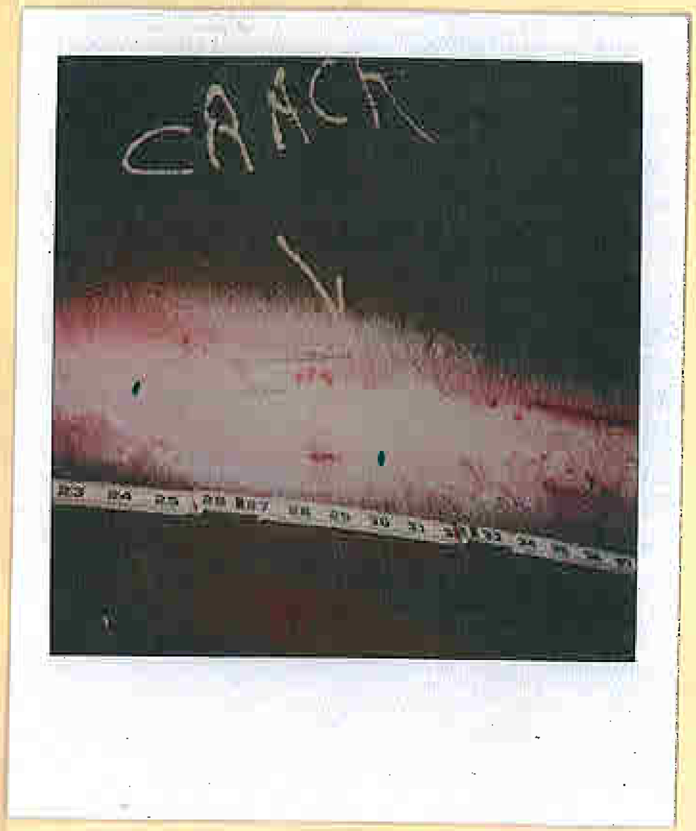
Both these old repairs were cracked but neither had propagated out of the repair. We welded over them and they will likely be back at the surface for the next inspection. A proper fix at this time would have been impossible within the allotted time and its very unlikely they constitute a short term problem.

Repairs at Vanes #2 and #3 before final pass. The repair weld consisted of a S.S. 309 "butter" pass and S.S. 308 filler metal. All passes except the root were peened. The new weld was back gauged to the root and backwelded using the same procedure. Preheat and interpass heat was maintained at 200^{0}F+. The weld was finished high and ground

CRACKING IN TOP GUSSET OF RUNNER BUCKETS ON PRESSURE SIDE



Bucket #4 - Intermittent cracks



Bucket #6 - Two large cracks

Bucket #8 - One foot of cracks in 14"

CRACKING IN RUNNER SKIRT & BOTTOM GUSSET

Bucket #5 - Two cracks - Total length of 10"

Bucket #6

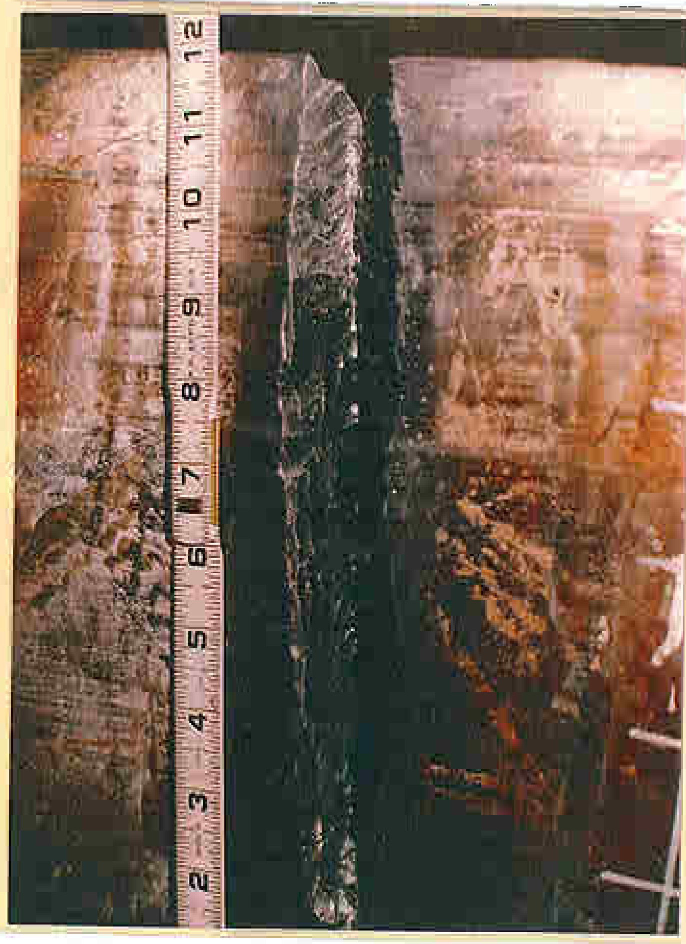
Bucket #15

BUCKET #9 - REPAIR OF LARGE CRACK IN RUNNER SKIRT

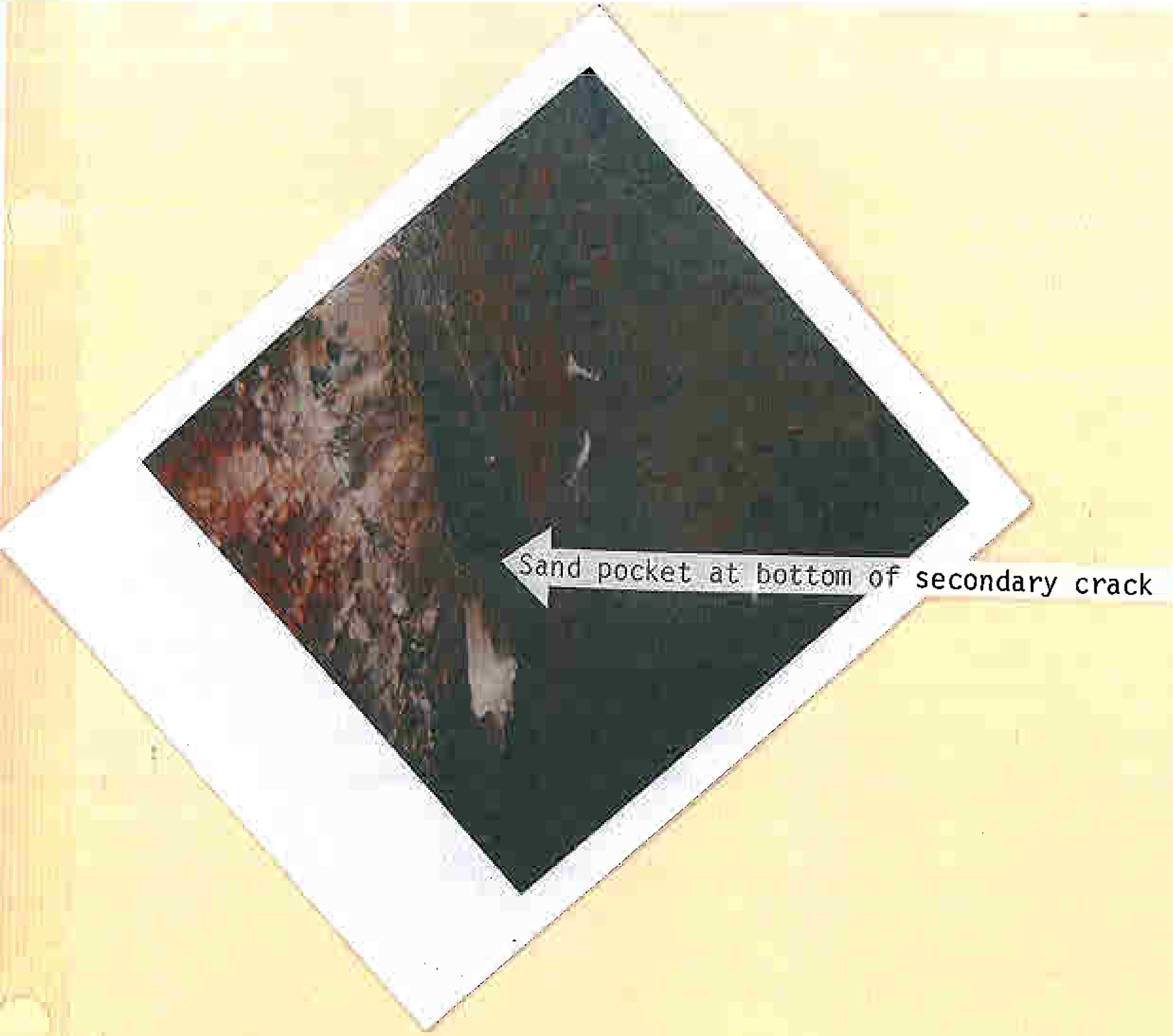
Crack at Bucket #9 inside view after gouging

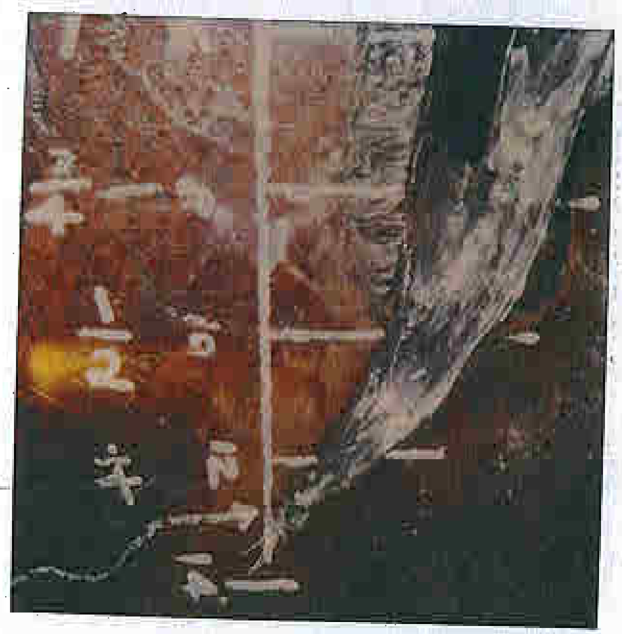
Crack at Bucket #9 outside view before gouging

Block welding on inside



Outside view after backgauging - we had to go right through the new weld to eliminate the crack. At this stage, a magnetic particle check for cracks in the base of the opening revealed a crack adjacent to our weld. We decided to complete the repair on the initial crack and to treat the new crack as a separate problem.

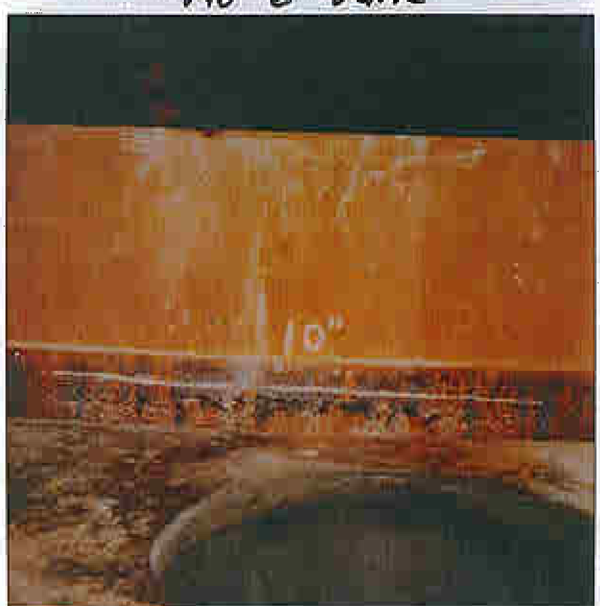

Sand pocket at bottom of secondary crack



Gouging complete - note relief hole

Instrumentation to monitor distortion during welding

No 6 Vane



P3 - U1 TURB RUNNER Oct8/85
Cavitation on BAND Seal
5/8 WIDE 1/4 Deep 10" LONG
Shows at base of each vane

Appendix A11.1

RUNNER INSPECTION

Date: Nov 29/05

Plant: Unit:

JOB PLAN: 300

Repetitive Job # ______

Job Order # ______

Runner report

Bucket #1 as per last inspection + 2 bar cracked 1" deep cavitation

Bucket #2 as per last inspection

Bucket #3 2 bars both cracked (SAME AS LAST YEAR)

Bucket # 4 2 bars both cracked " "

Bucket #5 stay bar cracked " "

Bucket #6 as per last inspection " "

Bucket #7 stay bar cracked " "

Bucket # 8 stay bar cracked " "

Bucket #9 Stay bar cracked " "

Bucket#10 Stay bar missing 1/4" "

Bucket #11 + stay bar cracked " "

Bucket #12 stay bar about to fall off

Bucket #13 stay bar cracked " "

Bucket #14 as per last inspection

Bucket #15 Stay bar cracked 1" deep cavitation

Bucket #16 as per last inspection

TABLE A97.0
PROJECT SCHEDULE AND ESTIMATE

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
1	**TRANSMISSION PROJECT DESCRIPTION**							
2								
3	**TRANSMISSION GROWTH**							
4	**BULK SYSTEM**							
5	DOUBLE CIRCUIT 230 KV VASEUX TO RG ANDERSON	2009						
6	230/161/138 KV BENTLEY TERMINAL	2009						
7	230 KV VASEUX TO BENTLEY	2009						
8	KELOWNA SHUNTS & SVC	2011+						
9	VASEUX TRANSFORMER 3 (500/230 KV)	2011+						
10	CONVERT EXISTING OLIVER TO 138/63/13 KV DISTRIBUTION SOURCE STATION	2009						
11	RG ANDERSON TERMINAL UPGRADE	2009						
12	LEE TERMINAL AND BELL TERMINAL 138 KV UPGRADE	2008						
13	63 KV AND 138 KV CIRCUITS BENTLEY TO OLIVER	2009						
14	**TOTAL OTR (CPCN FILED DEC 14, 2007)**	2010F		141,408	4,828	141,408	0	0
15								
16	**KELOWNA AREA**							
17	BIG WHITE 138 KV LINE AND SUBSTATION	2007	2008	20,318	15,670	20,318	0	0
18	ELLISON DISTRIBUTION SOURCE	2009	2009F	17,168	5,458	17,168	0	0
19	ELLISON TRANSMISSION LOOP	2010	2011+					
20	BLACK MOUNTAIIN DISTRIBUTION SOURCE	2008	2009F	14,430	1,778	14,430	0	0
21	FAULT LEVEL REDUCTION	2006	2007	2,500	920	920	(1,580)	-63
22	CLOSE 138 KV LOOPS KELOWNA	2009	2011+					
23	RECREATION CAPACITY INCREASE	2008	2010F	3,579		3,579	0	0
24	HOLLYWOOD (BENVOULIN DISTRIBUTION SOURCE) CAPACITY INCREASE	2008	CANCELLED					
25	BRAELOCH (SW) DISTRIBUTION SOURCE	2011+	2011+					
26	OK MISSION CAPACITY INCREASE	2011+	CANCELLED					

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TRANSMISSION GROWTH CONT'D							
27	NORTH KELOWNA TRANSFORMER ADDITION	2011+	2011+					
28	KELOWNA DISTRIBUTION CAPACITY REQUIREMENTS	2011+	2011+	1,035		1,035	0	0
29	STATIC VAR COMPENSATOR KELOWNA	2011+	2011+	400		400	0	0
30	DUCK LAKE REGULATOR BANK	2007	2006	294		0	(294)	-100
31	GLENMORE NEW FEEER	2007	2007	392	560	560	168	43
32	**PENTICTON/SUMMERLAND AREA**							
33	NARAMATA REHABILITATION	2006	2009	7,270	3,025	7,524	254	3
34	HUTH REBUILD AS 63 KV RING BUS	2010	2010F	413		413	0	0
35	SUMMERLAND 63 KV BACKUP	2011+	2011+					
36	WEST BENCH SUBSTATION REGULATOR BANK	2006	2007	294	275	275	(19)	-6
37								
38	**OSOYOOS/OLIVER AREA**							
39	NEW EAST OSOYOOS SOURCE	2006	2008	17,980	19,870	19,980	2,000	11
40								
41	**PRINCETON/KEREMEOS AREA**							
42	PRINCETON TRANSFORMER 1 REPLACEMENT	2006	2007	4,504	5,131	5131	627	14
43	PRINCETON TRANSFORMER 2 REPLACEMENT							
44	HEDLEY STEP UP 5 MVA TRANSFORMER	2007	2007	391	470	470	79	20
45								
46	**BOUNDARY/GRAND FORKS AREA**							
47	KETTLE VALLEY DISTRIBUTION SOURCE	2006	2008					
48	KETTLE VALLEY VOLTAGE CONVERSION	2008	2008					
49	BOUNDARY AREA STATION CONVERSIONS	2007	2008					
50	TOTAL KETTLE VALLEY	2007	2008	21,480	22,560	28,310	6,830	32
51	GRAND FORKS AREA VOLTAGE CONVERSIONS	2010	2011+					

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TRANSMISSION GROWTH CONT'D							
52	GRAND FORKS DISTRIBUTION SOURCE	2010	2011+					
53								
54	**CASTLEGAR AREA**							
55	TARRYS SUBSTATION UPGRADE	2009	2009F	403		403	0	0
56	CASTLEGAR CAPACITY INCREASE (OOTISCHENIA SUBSTATION)	2006	2009F	8,160	1,641	8,091	(69)	-1
57								
58	**COFFEE CREEK - KASLO AREA**							
59	COFFEE CREEK TRANSFORMER 3 REPLACEMENT	2008	2011+					
60	30 LINE CONVERT TO 63 KV	2009	2009F	4,500		4,500	0	0
61	COFFEE CREEK AND KASLO CAPACITORS	2007	CANCELLED					
62	**CRAWFORD BAY AREA**							
63	CRAWFORD BAY CAPACITY INCREASE	2006	2007	1,714	2,188	2188	474	28
64								
65	**CRESTON/WYNDELL AREA**							
66	NEW LAMBERT 230\63 KV TRANSFORMER	2006	2007	4,290	6,457	6457	2,167	51
67	NEW LAMBERT 230 KV RING BUS	2006	2011+					
68								
69	**SOUTH SLOCAN AREA**							
70	SLOCAN - NEW DENVER 63 KV LOOP	2011+	CANCELLED					
71								
72	**TRAIL/SALMO AREA**							
73	YMIR FEEDER CONVERSION	2011+	2011+					
74	NEW 18 LINE BREAKER AT WANETA	2006	2007	1,800	306	1997	197	11
75	YMIR/ WHITEWATER (COTTONWOOD) UPGRADE	2006	2007	2,531	4,682	4682	2,151	85
76	**SUBTOTAL - TRANSMISSION GROWTH**			**277,254**	**95,820**	**290,239**	**12,985**	**5**
77								

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
78	**TRANSMISSION LINE SUSTAINING (2005)**							
79	TRANSMISSION LINE URGENT REPAIRS	2005	2005	327	268	268	(59)	-18
80	RIGHT-OF-WAY ENHANCEMENTS	2005	2005	272.5	360	360	88	32
81	RIGHT-OF-WAY RECLAMATIONS	2005	2005	76	443	443	367	483
82	TRANSMISSION CONDITION ASSESSMENTS	2005	2005	763	57	57	(706)	-93
83	SWITCH ADDITIONS	2005	2005	436	70	70	(366)	-84
84	REHABILITATION	2005	2005	3706	3,468	3,468	(238)	-6
85	32 LINE REBUILD	2005	2005	3815	1,958	1,958	(1,857)	-49
86	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2005**			**9395.5**	**6,624**	**6,624**	**(2,771)**	**-29**
87								
88	**TRANSMISSION LINE SUSTAINING (2006)**							
89	TRANSMISSION LINE URGENT REPAIRS	2006	2006	168	347	347	179	107
90	RIGHT-OF-WAY ENHANCEMENTS	2006	2006	307	223	223	(84)	-27
91	RIGHT-OF-WAY RECLAMATIONS	2006	2006	226	421	421	195	86
92	TRANSMISSION CONDITION ASSESSMENTS	2006	2006	562	248	248	(314)	-56
93	REHABILITATION	2006	2006	600	993	993	393	66
94	SWITCH ADDITIONS	2006	2006	335	378	378	43	13
95	32 LINE REHABILITATION	2006	2007	3,437	3,587	3,587	150	4
96	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2006**			**5,635**	**6,197**	**6,197**	**562**	**10**
97								
98	**TRANSMISSION LINE SUSTAINING (2007)**							
99	TRANSMISSION LINE URGENT REPAIRS	2007	2007	257	351	351	94	37
100	RIGHT-OF-WAY ENHANCEMENTS	2007	2007	334	332	332	(2)	-1
101	RIGHT-OF-WAY RECLAMATIONS	2007	2007	339	821	821	482	142
102	TRANSMISSION CONDITION ASSESSMENTS	2007	2007	616	152	152	(464)	-75
103	SWITCH ADDITIONS	2007	2007	362	182	182	(180)	-50
104	REHABILITATION	2007	2007	1,763	336	336	(1,427)	-81

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TRANSMISSION LINE SUSTAINING (2007) CONT'D							
105	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2007**			**3,671**	**2,174**	**2174**	**(1,497)**	**-41**
106								
107	**TRANSMISSION LINE SUSTAINING (2008)**							
108	TRANSMISSION LINE URGENT REPAIRS	2008	2008	308	60	312	4	1
109	RIGHT-OF-WAY ENHANCEMENTS	2008	2008	350		350	0	0
110	RIGHT-OF-WAY RECLAMATIONS	2008	2008	359	223	359	0	0
111	TRANSMISSION CONDITION ASSESSMENTS	2008	2008	647	15	845	198	31
112	SWITCH ADDITIONS	2008	2008	190	162	534	344	181
113	REHABILITATION	2008	2008	1,884	4	3,443	1,559	83
114	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2008**			**3,738**	**464**	**5,843**	**2,105**	**56**
115								
116	**TRANSMISSION LINE SUSTAINING (2009)**							
117	TRANSMISSION LINE URGENT REPAIRS	2009	2009F	288		288	0	0
118	RIGHT-OF-WAY ENHANCEMENTS	2009	2009F	311		311	0	0
119	PINE BEETLE KILL HAZARD TREES	2009	2009F	1,218		1,218	0	0
120	RIGHT-OF-WAY RECLAMATIONS	2009	2009F	550		550	0	0
121	TRANSMISSION CONDITION ASSESSMENTS	2009	2009F	427		427	0	0
122	REHABILITATION	2009	2009F	1,639		1,639	0	0
123	20 LINE REBUILD	2009	2009F	1,943		1,943	0	0
124	27 LINE REBUILD	2009	2009F	648		648	0	0
125	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2009**			**7,024**		**7,024**	**0**	**0**
126								
127	**TRANSMISSION LINE SUSTAINING (2010)**							
128	TRANSMISSION LINE URGENT REPAIRS	2010	2010F	293		293	0	0
129	RIGHT-OF-WAY ENHANCEMENTS	2010	2010F	345		345	0	0
130	PINE BEETLE KILL HAZARD TREES	2010	2010F	821		821	0	0

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TRANSMISSION LINE SUSTAINING (2010) CONT'D							
131	RIGHT-OF-WAY RECLAMATIONS	2010	2010F	602		602	0	0
132	TRANSMISSION CONDITION ASSESSMENTS	2010	2010F	496		496	0	0
133	SWITCH ADDITIONS	2010	2010F	132		132	0	0
134	REHABILITATION	2010	2010F	1,888		1,888	0	0
135	20 LINE REBUILD	2010	2010F	1,540		1,540	0	0
136	27 LINE REBUILD	2010	2010F	642		642	0	0
137	30 LINE REHABILTATION	2010	2010F	350		350	0	0
138	**SUBTOTAL - TRANSMISSION LINE SUSTAINING 2010**			**7,109**		**7,109**	**0**	**0**
139								
140	**STATION SUSTAINING (2005)**							
141	STATION ASSESSMENT AND MINOR PROJECTS	2005	2005	1,036	871	871	(165)	-16
142	STATION UNFORESEEN REPAIRS	2005	2005	327	279	279	(48)	-15
143	CMMS	2005	2008	1,343	1,309	1,487	144	11
144	BULK OIL BREAKER REPLACEMENT	2005	2005	545	66	66	(479)	-88
145	10/12 MVA MOBILE UPGRADE	2005	2005	327	16	16	(311)	-95
146	GROUND GRID UPGRADES	2005	2005	273	182	182	(91)	-33
147	TRANSFORMER OIL FILTRATION/REPLACEMENT	2005	2005	273	119	119	(154)	-56
148	LTC OIL FILTRATION	2005	2005	164	119	119	(45)	-27
149	WEST OSOYOOS TRANSFORMER REHABILITATION	2005	2007	2,150	2,527	2,527	377	18
150	GRAND FORKS NOISE REDUCTION	2005	2005	164	131	131	(33)	-20
151	LOAD TAPCHANGER UPGRADES	2005	2007	654	405	405	(249)	-38
152	KOOTENAY MOBILE SUBSTATION	2005	2008F	2,180	1,305	1,854	(326)	-15
153	**SUBTOTAL - STATIONS SUSTAINING 2005**			**9,434**	**7,329**	**8,056**	**(1,378)**	**-15**
154								
155	**STATION SUSTAINING (2006)**							
156	STATION ASSESSMENT AND MINOR PROJECTS	2006	2006	1,508	1,132	1,132	(376)	-25

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	STATION SUSTAINING (2006) CONT'D							
157	STATION UNFORESEEN REPAIRS	2006	2006	501	562	562	61	12
158	BULK OIL BREAKER REPLACEMENT	2006	2007	1,023	1,464	1,464	441	43
159	GROUND GRID UPGRADES	2006	2006	276	393	393	117	42
160	TRANSFORMER OIL FILTRATION/REPLACEMENT	2006	2006	502	379	379	(123)	-25
161	LTC OIL FILTRATION	2006	2006	218	81	81	(137)	-63
162	WESTMINSTER TRANSFORMER 1 REPLACMENT	2006	2007	324	372	372	48	15
163	PINE STREET TRANSFORMER REPLACEMNENT	2006	2007	1,104	1,628	1,628	524	47
164	**SUBTOTAL - STATIONS SUSTAINING 2006**			**5,456**	**6,011**	**6,011**	**555**	**10**
165								
166	**STATION SUSTAINING (2007)**							
167	STATION ASSESSMENT AND MINOR PROJECTS	2007	2007	1,145	2,043	2,043	898	78
168	STATION UNFORESEEN REPAIRS	2007	2007	353	416	416	63	18
169	WARFIELD TERMINAL CONNECTOR REPLACMENT AND DEFICIENCY CORRECTION	2007	2008F	869	146	926	57	7
170	GROUND GRID UPGRADES	2007	2007	284	160	160	(124)	-44
171	LTC OIL FILTRATION	2007	2007	226	191	191	-35	-15
172	TROUT CREEK TRANSFORMER 1 REHABILITATION	2007	2008	342	238	238	(104)	-30
173	**SUBTOTAL - STATIONS SUSTAINING 2007**			**3,219**	**3,194**	**3,974**	**755**	**23**
174								
175	**STATION SUSTAINING (2008)**							
176	STATION ASSESSMENT AND MINOR PROJECTS	2008	2008F	1,186	1,603	1,603	417	35
177	STATION UNFORESEEN REPAIRS	2008	2008F	401	393	393	(8)	-2
178	WARFIELD TERMINAL CONNECTOR REPLACMENT AND DEFICIENCY CORRECTION	2008	2008F	399	20	399	0	0
179	GROUND GRID UPGRADES	2008	2008F	299	446	446	147	49
180	LTC OIL FILTRATION	2008	2008F	234	278	278	44	19
181	**SUBTOTAL - STATIONS SUSTAINING 2008**			**2,519**	**2,740**	**3,119**	**600**	**24**
182								

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
183	**STATION SUSTAINING (2009)**							
184	STATION ASSESSMENT AND MINOR PROJECTS	2009	2009F	620		620	0	0
185	STATION UNFORESEEN REPAIRS	2009	2009F	473		473	0	0
186	GROUND GRID UPGRADES	2009	2009F	572		572	0	0
187	LTC OIL FILTRATION	2009	2009F	32		32	0	0
188	SLOCAN CITY - VALHALLA SUBSTATION UPGRADE	2009	2009F	2,173		2,173	0	0
189	PINE STREET BREAKER REPLACEMENT	2009	2009F	345		345	0	0
190	CRESTON SUBSTATION PROTECTION	2009	2009F	488		488	0	0
191	**SUBTOTAL - STATIONS SUSTAINING 2009**			**4,703**		**4,703**	**0**	**0**
192								
193	**STATION SUSTAINING (2010)**							
194	STATION ASSESSMENT AND MINOR PROJECTS	2010	2010F	680		680	0	0
195	STATION UNFORESEEN REPAIRS	2010	2010F	448		448	0	0
196	BULK OIL BREAKER REPLACEMENT	2010	2010F	392		392	0	0
197	LTC OIL FILTRATION	2010	2010F	64		64	0	0
198	PASSMORE SUBSTATION UPGRADE	2010	2010F	1,987		1,987	0	0
199	PRINCETON RECLOSER REPLACEMENT	2010	2010F	1,513		1,513	0	0
200	JOE RICH BREAKER	2010	2010F	404		404	0	0
201	**SUBTOTAL - STATIONS SUSTAINING 2010**			**5,488**		**5,488**	**0**	**0**
202								
203	**TOTAL - TRANSMISSION**			**344,645**	**130,553**	**356,561**	**11,916**	**3**
204								
205	**DISTRIBUTION PROJECT DESCRIPTION**							
206								
207	**DISTRIBUTION GROWTH**							
208	NEW CONNECTS SYSTEM-WIDE-2005	2005	2005	4,973	7,147	7,147	2,174	**44**
209	NEW CONNECTS SYSTEM-WIDE-2006	2006	2006	6,082	9,209	9,209	3,127	**51**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION GROWTH CONT'D							
210	NEW CONNECTS SYSTEM-WIDE-2007	2007	2007	7,245	8,900	8,900	1,655	**23**
211	NEW CONNECTS SYSTEM-WIDE-2008	2008	2008F	7,977	3,428	9,366	1,389	**17**
212	NEW CONNECTS SYSTEM-WIDE-2009	2009	2009F	9,788		9,788	0	**0**
213	NEW CONNECTS SYSTEM-WIDE-2010	2010	2010F	10,670		10,670	0	**0**
214	**KELOWNA AREA**							
215	DUCK LAKE - SEXSMITH TIE	2005	2006	491	1,336	1,336	846	**172**
216	QUAIL DEVELOPMENT LOOP FEED	2005	2006	218	141	141	(77)	**-35**
217	DILLWORTH DEVELOPMENT LOOP FEED	2005	2008F	218	562	597	379	**174**
218	OK MISSION 5 – OK MISSION 4	2005	2006	654	978	978	324	**50**
219	DG BELL 2 – OK MISSION 3	2006	2007	1,111	1,265	1,265	154	**14**
220	GLENMORE 5 – SEXSMITH 2	2005	2007	93	44	44	(49)	**-53**
221	KELOWNA GENERAL FEEDER PROTECTION	2005	2005	164	25	25	(139)	**-85**
222	MCKINLEY LANDING CAPACITY UPGRADE(#2 TO #477) FED SEXSMITH 3	2008	2008F	359	404	534	175	**49**
223	GLENMORE FEEDER (50 LINE UNDERBUILD HIGH RD-CLIFTON)	2008	2008	1,371	1,620	1,620	249	**18**
224	HOLLYWOOD 1 - DG BELL 3 / FA LEE 2 TIE	2007	2011+					
225	HOLLYWOOD 1 - OK MISSION 1 TIE ALONG KLO RD	2008	2008F	349		349	0	**0**
226	MCKINLEY TO CLIFTON TIE	2008	2011+					
227	FA LEE 2 - HOLLYWOOD 5 TIE, ADD N.O.	2008	2008F	419	5	419	0	**0**
228	RETERMINATE LEE FEEDER	2008	2009F	545			(545)	**-100**
229	NEW FEEDER N KELOWNA SUBSTATION	2011+	2009F	1,635			(1,635)	**-100**
230	FA LEE 2 REGULATOR	2007	2008F	157	38	38	(119)	**-76**
231	NEW GLENMORE FEEDER	2009	2009F	788		788	0	**0**
232	HOLLYWOOD 3 - SEXSMITH 4 TIE	2010	2010F	365		365	0	**0**
233	AIRPORT WAY UPGRADE	2010	2010F	1,551		1,551	0	**0**
234								
235								

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION GROWTH CONT'D							
	PENTICTON							
236	PRINCETON 4 CAPACITY UPGRADE	2007	2008F	881	103	1310	429	**49**
237	OK FALLS 3 CAPACITY UPGRADE	2008	2008F	594	170	215	(379)	**-64**
238	WEST BENCH 1 VOLTAGE REGULATOR	2005	2007	93	110	110	17	**19**
239	**OSOYOOS/OLIVER**							
240	25 KV TIE TO ANARCHIST/BRIDESVILLE	2009	2011+				0	
241	OLIVER 01 REGULATOR	2010	2010F	137		137	0	**0**
242	NEW FEEDER ACROSS CAUSEWAY	2005	2007				0	
243	3 PHASE OSOYOOS 2	2005	2006	368	857	857	490	**133**
244	**SIMILKAMEEN**							
245	KEREMEOS FEEDER	2006		654			(654)	**-100**
246	KEREMEOS 2 CAPACITY UPGRADE	2007	2007	196	247	247	51	**26**
247	KEREMEOS 1 CAPACITY UPGRADE	2007	2007	353	424	424	71	**20**
248	**BOUNDARY/GRAND FORKS AREA**							
249	CHRISTINA LAKE FEEDER 1 CAPACITY UPGRADE	2010	2010F	1,097		1097	0	**0**
250	FEED BALDY FROM ROCK CREEK	2005	2007	709	1,329	1329	621	**88**
251								
252								
253	**TRAIL/ROSSLAND AREA**							
254	W. TRAIL VOLTAGE CONVERSION	2005	2005	327	297	297	(30)	**-9**
255	PATERSON 25 KV FEED	2006	2007	327	991	991	664	**203**
256	BEAVER PARK FEEDER 2 TO FRUITVALE FEEDER 1 TIE\UPGRADE	2010	2010F	1,227		1,227	0	**0**
257								
258	**SOUTH SLOCAN**							
259	VALHALLA 1 CAPACITY UPGRADE	2008	2008F	897	17	897	0	**0**
260	PASSMORE FEEDER2 UPGRADE	2005	2006	1,036	1,134	1,134	99	**10**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION GROWTH CONT'D							
261	PLAYMORE TARRYS FEEDER UPGRADE	2006	2007	836	1,501	1,501	665	**80**
262	**CRESTON AREA**							
263	CRESTON FEEDER UPGRADE	2006	2006	1,170	1,191	1191	21	**2**
264	CRAWFORD BAY 2 CAPACITY UPGRADE	2007	2007	372	385	385	13	**3**
265	**GENERAL**							
266	SMALL CAPACITY IMPROVEMENTS, 2005	2005	2005	542	961	961	419	**77**
267	SMALL CAPACITY IMPROVEMENTS, 2006	2006	2006	1,618	1,885	1,885	267	**17**
268	SMALL CAPACITY IMPROVEMENTS, 2007	2007	2007	1,167	1,063	1,063	(104)	**-9**
269	SMALL CAPACITY IMPROVEMENTS, 2008	2008	2008F	923	13	763	(160)	**-17**
270	SMALL CAPACITY IMPROVEMENTS, 2009	2009	2009F	974		974	0	**0**
271	SMALL CAPACITY IMPROVEMENTS, 2010	2010	2010F	1131		1,131	0	**0**
272	**SUBTOTAL - DISTRIBUTION GROWTH**			**74,848**	**48,832**	**85,256**	**10,408**	**14**
273								
274	**DISTRIBUTION SUSTAINING (2005)**							
275	DISTRIBUTION CONDITION ASSESSMENTS	2005	2005	491		575	84	**17**
276	DISTRIBUTION REHABILITATION	2005	2005	1,635		569	(1,066)	**-65**
277	RIGHT-OF-WAY RECLAMATION	2005	2005	616		478	(138)	**-22**
278	DISTRIBUTION LINE REBUILDS	2005	2005	818		1,230	413	**50**
279	SMALL PLANNED CAPITAL	2005	2005	583		305	(278)	**-48**
280	PCB PROGRAM	2005	2005	818		691	(127)	**-15**
281	FORCED UPGRADES AND LINE MOVES	2005	2005	545		1,418	873	**160**
282	DISTRIBUTION URGENT REPAIRS	2005	2005	1,090		1,001	(89)	**-8**
283	**SUBTOTAL - DISTRIBUTION SUSTAINING 2005**			**6,595**		**6,267**	**(328)**	**-5**
284								
285	**DISTRIBUTION SUSTAINING (2006)**							
286	DISTRIBUTION CONDITION ASSESSMENT & REHAB	2006	2006	4,707		2,392	(2,315)	**-49**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION SUSTAINING (2006) CONT'D							
287	RIGHT-OF-WAY RECLAMATION	2006	2006	624		572	(52)	**-8**
288	DISTRIBUTION LINE REBUILDS	2006	2006	869		3,847	2,978	**343**
289	SMALL PLANNED CAPITAL	2006	2006	651		515	(136)	**-21**
290	PCB PROGRAM	2006	2006	870		1,560	690	**79**
291	FORCED UPGRADES AND LINE MOVES	2006	2006	708		716	8	**1**
292	DISTRIBUTION URGENT REPAIRS	2006	2006	1,416		2,123	707	**50**
293	**SUBTOTAL - DISTRIBUTION SUSTAINING 2006**			**9,845**		**11,725**	**1,880**	**19**
294								
295	**DISTRIBUTION SUSTAINING (2007)**							
296	DISTRIBUTION CONDITION ASSESSMENTS	2007	2007	637		928	291	**46**
297	DISTRIBUTION REHABILITATION	2007	2007	1,606		1,231	(375)	**-23**
298	RIGHT-OF-WAY RECLAMATION	2007	2007	609		641	32	**5**
299	DISTRIBUTION LINE REBUILDS	2007	2007	1,576		1,470	(106)	**-7**
300	SMALL PLANNED CAPITAL	2007	2007	339		1,030	691	**204**
301	PCB PROGRAM	2007	2007	852		961	109	**13**
302	FORCED UPGRADES AND LINE MOVES	2007	2007	1,168		1,564	396	**34**
303	DISTRIBUTION URGENT REPAIRS	2007	2007	1,228		2,030	802	**65**
304	AESTHETIC AND ENVIRONMENTAL UPGRADES	2007	2007	100		0	(100)	**-100**
305	**SUBTOTAL - DISTRIBUTION SUSTAINING 2007**			**8,115**		**9,855**	**1,740**	**21**
306								
307	**DISTRIBUTION SUSTAINING (2008)**							
308	DISTRIBUTION CONDITION ASSESSMENTS	2008	2008F	678		386	(292)	**-43**
309	DISTRIBUTION REHABILITATION	2008	2008F	1,645		2,582	937	**57**
310	RIGHT-OF-WAY RECLAMATION	2008	2008F	593		593	0	**0**
311	DISTRIBUTION LINE REBUILDS	2008	2008F	1,945		1,972	27	**1**
312	SMALL PLANNED CAPITAL	2008	2008F	378		435	57	**15**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION SUSTAINING (2008) CONT'D							
313	PCB PROGRAM	2008	2008F	868		239	(629)	**-72**
314	FORCED UPGRADES AND LINE MOVES	2008	2008F	1,400		1,370	(30)	**-2**
315	DISTRIBUTION URGENT REPAIRS	2008	2008F	1,414		1,411	(3)	**0**
316	AESTHETIC AND ENVIRONMENTAL UPGRADES	2008	2008F	100		67	(33)	**-33**
317	**SUBTOTAL - DISTRIBUTION SUSTAINING 2008**			**9,021**		**9,055**	**34**	**11**
318								
319	**DISTRIBUTION SUSTAINING (2009)**							
320	DISTRIBUTION CONDITION ASSESSMENTS	2009	2009F	559		559	0	**0**
321	DISTRIBUTION REHABILITATION	2009	2009F	3,124		3,124	0	**0**
322	PINE BEETLE KILL HAZARD TREES	2009	2009F	722		722	0	**0**
323	RIGHT-OF-WAY RECLAMATION	2009	2009F	621		621	0	**0**
324	DISTRIBUTION LINE REBUILDS	2009	2009F	1,178		1,178	0	**0**
325	SMALL PLANNED CAPITAL	2009	2009F	668		668	0	**0**
326	PCB PROGRAM	2009	2009F	1,073		1,073	0	**0**
327	FORCED UPGRADES AND LINE MOVES	2009	2009F	1,255		1,255	0	**0**
328	DISTRIBUTION URGENT REPAIRS	2009	2009F	1,911		1,911	0	**0**
329	AESTHETIC AND ENVIRONMENTAL UPGRADES	2009	2009F	100		100	0	**0**
330	COPPER CONDUCTOR REPLACEMENT	2009	2009F	4,798		4,798	0	**0**
331	**SUBTOTAL - DISTRIBUTION SUSTAINING 2009**			**16,009**		**16,009**	**0**	**0**
332								
333	**DISTRIBUTION SUSTAINING (2010)**							
334	DISTRIBUTION CONDITION ASSESSMENTS	2010	2010F	667		667	0	**0**
335	DISTRIBUTION REHABILITATION	2010	2010F	3,470		3,470	0	**0**
336	PINE BEETLE KILL HAZARD TREES	2010	2010F	722		722	0	**0**
337	RIGHT-OF-WAY RECLAMATION	2010	2010F	646		646	0	**0**
338	DISTRIBUTION LINE REBUILDS	2010	2010F	1,167		1,167	0	**0**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	DISTRIBUTION SUSTAINING (2010) CONT'D							
339	SMALL PLANNED CAPITAL	2010	2010F	747		747	0	**0**
340	PCB PROGRAM	2010	2010F	1,117		1,117	0	**0**
341	FORCED UPGRADES AND LINE MOVES	2010	2010F	1,461		1,461	0	**0**
342	DISTRIBUTION URGENT REPAIRS	2010	2010F	1,805		1,805	0	**0**
343	AESTHETIC AND ENVIRONMENTAL UPGRADES	2010	2010F	100		100	0	**0**
344	COPPER CONDUCTOR REPLACEMENT	2010	2010F	6,566		6,566	0	**0**
345	**SUBTOTAL - DISTRIBUTION SUSTAINING 2010**			**18,468**		**18,468**	**0**	**0**
346								
347	**TOTAL - DISTRIBUTION**			**142,901**	**48,832**	**156,635**	**13,734**	**10**
348								
349	**TELECOM, SCADA, P&C PROJECT DESCRIPTION**							
350								
351								
352	**TELECOM, SCADA, P&C GROWTH**							
353	DISTRIBUTION SUBSTATION AUTOMATION, METERING AND COMMUNICATIONS	2009	2011F	6,379	205	6,379	0	**0**
354	TRAIL-OLIVER PHASE 1 HIGH CAPACITY COMMUNICATIONS	2008	2008				0	
355	TRAIL-OLIVER PHASE 2 HIGH CAPACITY COMMUNICATIONS	2011+	2011+				0	
356	TELECOMMUNCIATIONS BACKBONE LOOP CLOSE	2011+	2011+				0	
357	TELECOMMUNICATIONS FOR BUSINESS SYSTEMS	2011+	2011+				0	
358								
359	**SUBTOTAL - TELECOM, SCADA, P&C GROWTH**			**6,379**	**205**	**6,379**	**0**	**0**
360								
361	**TELECOM, SCADA, P&C SUSTAINING (2005)**							
362	NARROW SPECTRUM CONVERSION	2005	2005	218			(218)	-100
363	HARMONIC REMEDIATION	2005	2005	109			(109)	-100
364	RELAY TEST/MAINTENANCE PROCESS	2005	2005	164			(164)	-100

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TELECOM, SCADA, P&C SUSTAINING (2005) CONT'D							
365	COMM EQUIPMENT TEST/MAINTENANCE PROCESS	2005	2005	164			(164)	-100
366	PROTECTION UPGRADES	2005	2005	460			(460)	-100
367	FAULT LOCATING INACCESSIBLE LINES	2005	2005	164			(164)	-100
368	COMMUNICATIONS UPGRADES	2005	2005	196			(196)	-100
369								
370	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2005**			**1,474**			**(1,474)**	**-100**
371								
372	**TELECOM, SCADA, P&C SUSTAINING (2006)**							
373	NARROW SPECTRUM CONVERSION	2006	2006	299	298	298	(1)	**0**
374	HARMONIC REMEDIATION	2006	2006	103	195	195	92	**89**
375	PROTECTION UPGRADES	2006	2006	448	576	576	128	**29**
376	COMMUNICATIONS UPGRADES	2006	2006	235	516	516	281	**120**
377		2006	2006					
378	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2006**			**1,085**	**1,585**	**1,585**	**500**	**46**
379								
380	**TELECOM, SCADA, P&C SUSTAINING (2007)**							
381	HARMONIC REMEDIATION	2007	2007	97	143	143	46	**47**
382	PROTECTION UPGRADES	2007	2007	1,082	614	801	(281)	**-26**
383	COMMUNICATIONS UPGRADES	2007	2008F	304	187	325	21	**7**
384								
385	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2007**			**1,483**	**945**	**1,269**	**(214)**	**-14**
386								
387	**TELECOM, SCADA, P&C SUSTAINING (2008)**							
388	HARMONIC REMEDIATION	2008	2008F	101		101	0	**0**
389	PROTECTION UPGRADES	2008	2008F	877	210	895	18	**2**
390	COMMUNICATIONS UPGRADES	2008	2008F	110	78	99	(11)	**-10**

TABLE A97.0 CONT'D

	PROJECT	IN SERVICE DATE		CPCN AMOUNT OR BUDGET	ACTUAL (SPENT TO DATE)	ESTIMATE AT COMPLETION	VARIANCE	
		PLANNED	ACTUAL	($000s)				(%)
	TELECOM, SCADA, P&C SUSTAINING (2008) CONT'D							
391								
392	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2008**			**1,088**	**288**	**1,095**	**7**	**1**
393								
394	**TELECOM, SCADA, P&C SUSTAINING (2009)**							
395	HARMONIC REMEDIATION	2009	2009F	117		117	0	**0**
396	PROTECTION UPGRADES	2009	2009F	448		448	0	**0**
397	COMMUNICATIONS UPGRADES	2009	2009F	229		229	0	**0**
398								
399	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2009**			**794**		**794**	**0**	**0**
400								
401	**TELECOM, SCADA, P&C SUSTAINING (2010)**							
402	HARMONIC REMEDIATION	2010	2010F	119		119	0	**0**
403	PROTECTION UPGRADES	2010	2010F	508		508	0	**0**
404	COMMUNICATIONS UPGRADES	2010	2010F	111		111	0	**0**
405								
406	**SUBTOTAL - TELECOM, SCADA, P&C SUSTAINING 2010**			**738**		**738**	**0**	**0**
407								
408	**TOTAL - TELECOM, SCADA, P&C**			**13,041**	**3,023**	**11,860**	**(1,181)**	**-9**
409								
410	**TOTAL**			**500,587**	**182,408**	**525,056**	**24,469**	**5**