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

February 18, 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 Okanagan Transmission Reinforcement (OTR) Project No. 3698488

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

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

Project No. 3698488: Okanagan Transmission Reinforcement (OTR) Project
Requestor Name: BC Utilities Commission
Information Request No: 1
To: FortisBC Inc.
Request Date: January 22, 2008
Response Date: February 18, 2008

1.0 Load Forecast

Reference: Exhibit B-1-1; Tab 3; Section 3.1

Q1.1 S 3.1.2.1 Load Forecast

Q1.1.1 Please describe the basis of the data used in this section: i.e. are the data used average, high or low forecasts? Please provide data and charts in Figures 3-1-2-1A to 3-1-3-5B showing the high, mean and low forecasts comprising the range of estimates for load growth.

A1.1.1 The forecast values are expected values. High and low forecasts were not developed. Please see the responses to BCUC IR No.1 Q6.2 and Q6.3 for a discussion of the sensitivity of Project timing and scope to load growth

Q1.1.2 Please describe the basis and source of the economic/growth assumptions on which the load growth forecasts are based. i.e. are the forecasts a linear projection of recent load growth experience? To what extent do the load forecasts take into account forward economic forecasts?

A1.1.2 For system planning purposes, load forecasts are determined at the distribution feeder level and are built up to the transformer to station and finally to the terminal station level, using historical coincident factors. The forecasts are generally based on linear projections of recent load growth. Where appropriate, these projections are adjusted to reflect information available through the relevant Official Community Plans and through FortisBC's ongoing discussions with regional or municipal planners and local developers.

2.0 Load Forecast - Components and Variation

Reference: Exhibit B-1-1, Tab 3, Section 3.1, p. 2

Q2.1 Is the "previous forecast" that is referred to on line 23 the 2005 SDP forecast? If not, please identify the forecast, and provide a copy of those forecast figures.

A2.1 Yes, the "previous forecast" that is referred to on line 23 refers to the 2005 SDP forecast.

Q2.2 Please show, by rate class, the variations from the previous forecast in terms of changes in number of accounts and changes in per-customer use-rates.

A2.2 Peak load forecasts (2005 SDP and 2007 SDP Update) are not class-specific. Provided below in Table 2.2 (a) are the forecast and actual percentage changes in total number of Customer Accounts by Rate Class, based on load forecasts for FortisBC's Revenue Requirements applications.

Table: 2.2 (a) Forecast and Actual Customer Growth by Rate Class

Rate Class	2005		2006		2007	
	Forecast	Actual	Forecast	Actual	Forecast	Actual
Residential	2.2%	3.4%	1.8%	2.7%	1.8%	1.9%
General Service	3.8%	1.1%	3.1%	2.7%	4.3%	3.2%
Industrial	0.0%	0.0%	0.0%	0.0%	5.4%	0.0%
Wholesale	0.0%	0.0%	0.0%	0.0%	-12.5%	-12.5%
Other	0.0%	-16.2%	0.0%	17.6%	-2.6%	-1.4%
Total Company	**2.3%**	**2.8%**	**1.9%**	**2.6%**	**1.9%**	**2.0%**

FortisBC utilizes use per customer for forecasting residential and general service classes only. Industrial and wholesale load forecasts are based on individual customer forecasts.

Provided below in Table 2.2 (b) are the forecast and actual energy usage (MWh/customer).

Table: 2.2 (b) Forecast and Actual Per Customer Usage (MW.h) by Rate Class

	2005		2006		2007	
Rate Class	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual**
Residential	12.34	12.59	12.35	12.55	12.14	12.70
General Service	55.83	55.66	55.92	59.02	58.05	59.28
Industrial	8,575.00	9,030.26	9,455.59	8,942.31	9,030.67	8,721.13
Wholesale	120,500.00	114,513.64	116,857.29	119,097.71	118,459.73	108,971.98
Other	18.21	18.68	18.65	18.98	20.74	20.77

Q2.3 Please identify which variations FortisBC expects to be of a single-event nature, and which are indicative of trends that are anticipated to continue into the future.

A2.3 **Residential:** The 2007 residential customer count growth is lower than both recent history and future expectations. (The recent high residential customer count growth has been primarily driven by growth in the Okanagan area.) The residential use per customer has been generally declining and is expected to do so in the future.

General Service: The general service customer count growth has been approximately three percent annually. This growth rate is expected to continue in the foreseeable future. The general service use per customer has been steadily increasing and is expected to do so in the future.

Industrial: The industrial customer count has historically been fairly steady. In 2008 it is expected that industrial customers will decline from 38 to 36 customers due to the slowdown in the forestry industry. Both of these two industrial customers are south of Penticton. Beyond 2008 the number of industrial customers is expected to once again stabilize. The use per industrial customer has been decreasing slightly due in part to the slowdown in the forestry sector and to a plant optimization by a large industrial customer. The slowdown in the forestry sector and the plant optimization both have occurred outside of the Penticton to Kelowna area.

Wholesale: The wholesale customer count has remained at 8 until 2007 when FortisBC converted Princeton Light and Power from one wholesale customer into 3,212 direct customers. It is expected that the number of wholesale customers will remain at seven for the foreseeable future. The wholesale use per customer tends to fluctuate year by year however generally has been increasing at a rate of approximately two percent annually and is expected to continue in the future.

Other (Street Light and Irrigation): The Other customer count tends to fluctuate annually however has been fairly constant over the long term. No change is expected in the future. The use per customer in the Other category has been increasing slightly and is expected to continue.

3.0 Load Forecast - Indirect Customers

Reference: Exhibit B-1-1, Tab 3, Section 3.1, p. 3

Q3.1 Who are the "indirect customers" that are referred to in Table 3-1-2?

A3.1 The indirect customers referred to in Table 3-1-2 are those served by FortisBC's wholesale customers in the region: the City of Penticton, the District of Summerland and the City of Kelowna.

Q3.2 What is the distribution of the indirect customers as to rate classes?

A3.2 The information in Table A3.2 below was provided to FortisBC in February 2007. The relative proportions are not expected to have changed significantly.

Table: A3.2

Indirect Customer Count as of February 28, 2007

	Residential	**General Service**	**Total**
District of Summerland	4,769	472	5,241
City of Kelowna	11,681	1,274	12,955
City of Penticton	14,306	1,664	15,970
Total	**30,756**	**3,410**	**34,166**

4.0 Load Forecast - Components and Constraints

Reference: Exhibit B-1-1, Tab 3, Section 3.1, p. 4

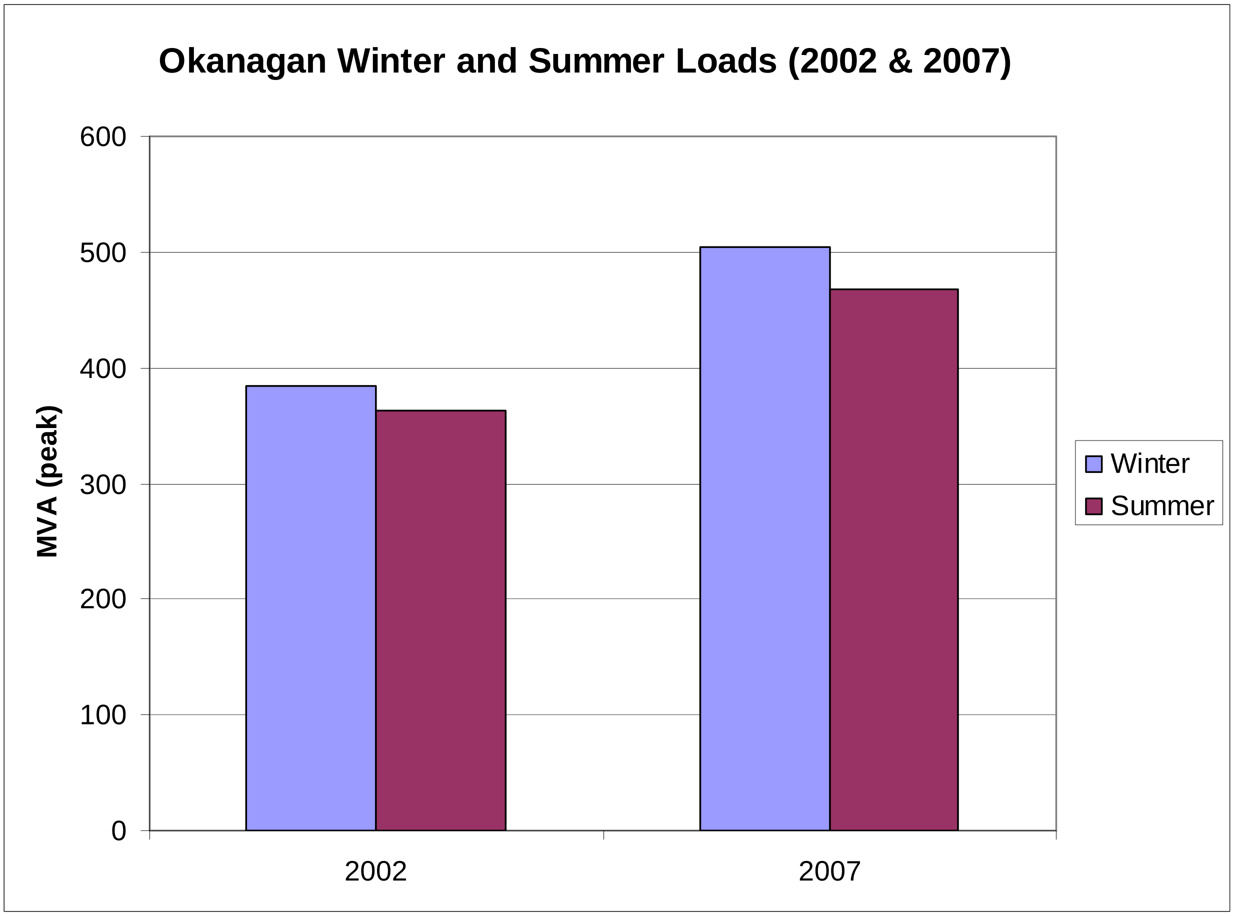
Q4.1 Please show a version of Figure 3-1-2-1A depicting the following series: unconstrained forecast total load (as opposed to load growth); constrained forecast total load with the OTR Project; constrained forecast total load with the existing system.

A4.1 The FortisBC load forecast assumes that load growth will not be constrained by network limitations, therefore, the load forecast in the CPCN Application is the unconstrained forecast.

Q4.2 Please show the monthly peak loads for the Okanagan Region for each of 2002 and 2007.

A4.2 FortisBC does not collate the monthly peak loads since only the winter and summer peak loads are required for load forecasting. These loads for the Okanagan region for 2002 and 2007 are shown in Table A4.2 below.

Table: A4.2



Note: The winter load for 2002 and 2007 are based on the winter of 2001/2002 and the winter of 2006/2007 respectively

Q4.3 Please show, by rate class, the number of accounts in 2002 and 2007.

A4.3 Please see Table A4.3 below.

Table: A4.3

Average Annual Customers		
	2002	**2007**
Residential	79,771	92,761
General Service	9,138	10,842
Wholesale	8	7
Industrial	37	38
Irrigation	990	1,033
Lighting	2,063	2,135
Total	**92,007**	**106,815**

Q4.4 Please show, by rate class, the average annual and peak period use-rates in 2002 and 2007.

A4.4 Please see Table A4.4 below.

Table A4.4: Average Annual and Peak Period Use Rates

	Average Peak Monthly Usage (MWh)		**Average Annual Usage (MWh)**	
	2002	**2007**	**2002**	**2007**
Residential Weather Normalized Sales	121,911 (Feb)	141,140 (Jan)	83,622	98,118
General Service Sales	52,109 (Jan)	66,993 (Jul)	83,622	98,118
Wholesale Weather Normalized Sales	94,236 (Jan)	96,428 (Dec)	43,699	53,561
Industrial Sales	35,954 (May)	40,919 (May)	72,733	72,648
Streetlight Sales	887 (May)	1,447 (Oct)	842	1,048
Irrigation Sales	10,859 (Aug)	10,238 (Aug)	842	1,048

Note: The residential and wholesale classes are sensitive to weather variations and hence the sales in these classes are normalized relative to the normal twenty year historic weather profile.

Q4.5 What population elasticity of demand does FortisBC assume in the forecast?

A4.5 For the purpose of system planning, population elasticity of demand is not a forecast variable. Please see the response to BCUC IR No.1 Q1.1.2 describing the forecast method, and the responses to BCUC IR No.1 Q6.2 and Q6.3 for a discussion of the sensitivity of Project timing and scope to load growth

Q4.6 What price elasticity of demand is assumed in the forecast?

A4.6 For the purpose of system planning, price elasticity of demand is not a forecast variable. Please see the response to BCUC IR No.1 Q1.1.2 describing the forecast method, and the responses to BCUC IR No.1 Q6.2 and Q6.3 for a discussion of the sensitivity of Project timing and scope to load growth

Q4.7 What is the source of the population forecast used in the load estimates, and what date was that forecast issued?

A4.7 For the purpose of system planning, population is not a forecast variable (please see the response to BCUC IR No.1 Q1.1.2 describing the forecast). It is used as a means of validating the load forecast results. The source of the population forecast is BC Stats: http://www.bcstats.gov.bc.ca/

Q4.8 Please describe the socioeconomic factors in addition to population that drive the load forecast and provide the source documents from which these factors were established.

A4.8 Examples of other socioeconomic factors that might influence load growth could include changes in disposable income per capita or per family unit; lifestyle trends such as proportion of dual-earner families or labour force trends resulting in increases or decreases in leisure time. Such factors are complex and not used as forecast variables but will be reflected in use per customer over time.

Q4.9 What are the factors that are expected to result in slower growth beyond 2011/12? Does the reduced rate apply to all rate classes equally?

A4.9 Area load growth in recent years has been higher than the long-term historical growth rates. The load forecast is based on recent history and known developments up to approximately 2011/2012. FortisBC is not aware of any further large development loads beyond this point and hence forecasts a return towards the lower long-term historical growth beyond this point.

Q4.10 The Application indicates expectations of increases in business incorporations. Please describe the expected impact on demand for each of the Commercial and Industrial rate classes. What use rate is assumed for each of those classes?

A4.10 The data on business incorporations provides general support for the rate of overall load growth as forecast. At Tab 3, page 4 of CPCN Application (Exhibit B-1-1), FortisBC stated that strong load growth is forecast for the immediate future (line 3). The statement on lines 5 to 7 of page 4 refers to historical information on business incorporations. FortisBC does not have or use forecast business incorporations in its load forecast.

Q4.11 What is FortisBC's expectation as to how residential demand growth will be distributed between the following types of dwellings: single-family (house), multiple-family (duplex), multiple-family (apartment)?

A4.11 FortisBC has seen a trend towards multiple family dwellings (both duplex and apartments) throughout the Okanagan region. This expectation is supported by recent Canadian Mortgage and Housing Corporation (CMHC) reports for the Kelowna area. According to the CMHC Fourth Quarter 2007 report, apartment condominiums starts climbed to record high in 2007, accounting for almost 50% of new construction activity. Detached home construction is forecast to decline slightly. These trends are expected to continue.

Q4.12 Are there specific development proposals for the affected area, that FortisBC is aware of, which are contingent on the OTR Project? If so, what are they? How much load is expected from each?

A4.12 FortisBC is aware of many development proposals for the affected area. A number of these are listed below, with estimated load when possible. However, none of these proposals are "contingent" on the OTR Project in the sense that FortisBC has an ability to deny service to an applicant in compliance with the Terms and Conditions of Service.

Table: A4.12 South Okanagan Development Proposals

Development	Location	Size	Date
Residential Subdivision (93 lots)	Okanagan Falls		Winter 2007
Resort	Osoyoos	800 kW	Winter 2007
Residential Development	Osoyoos	1.2 MW	Spring 2008
Residential Subdivision (70 lots)	Osoyoos		Spring 2008
Residential Development (50 lots)	Naramata		Spring 2008
92 Unit Residential	Osoyoos	750 kW	Spring 2009
Hotel (up to 150 rooms)	Oliver		Spring 2009
Hotel/Conference Centre/Commercial	Oliver		by 2010
Residential Development (1000+ lots)	Lake Osoyoos		by 2014
Residential Subdivision (700+ lots) electric heat	Osoyoos		by 2017
Commercial Development	Osoyoos	1 MW	by 2017

Q4.13 What foregone gross revenue would be associated with opting for an alternative with a 2012 completion date?

A4.13 FortisBC has not estimated the foregone revenue. System requirements are planned on the basis of peak demand, while a revenue forecast would be based on demand and energy consumption for each development project. FortisBC has not requested that data and does not expect that it is yet available for many of the projects listed in the previous response. Further to the response to BCUC IR No.1 Q4.12, FortisBC has an obligation to provide service, pursuant to its Terms and Conditions, at the time of the customer's choosing and does not have the ability to delay the provision of service.

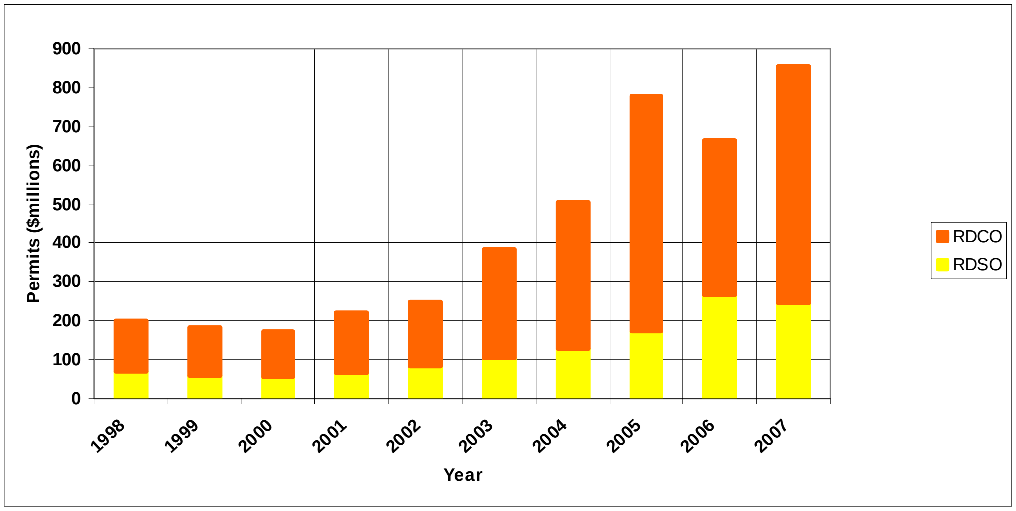
5.0 Load Forecast - Components and Constraints

Reference: Exhibit B-1-1, Tab 3, Section 3.1, p. 5

Q5.1 Figure 3-1-2-1B shows two winter load forecasts for the Penticton area served by RG Anderson ("RGA"): one is from the 2005 System Development Plan; the other is from the 2007-08 Capital Expenditure Plan. The chart shows an upward shift of approximately 80 MW from the 2005 to the 2007/08 series. What does FortisBC attribute the upward shift to?

A5.1 The 2005 load forecast was based on numbers obtained up to 2004 and the primary reason for the upward shift is new load growth. Figure A5.1 below shows the value of building permits approved since 1998 for the Regional Districts of Okanagan-Similkameen (south Okanagan) and Central Okanagan (Kelowna area). The value of approved building permits in the South Okanagan/Similkameen region (served by RG Anderson Terminal station and Oliver Terminal station) increased from $174 million in 2005 to $265 million in 2006 (an increase of 52%) and $246 million in 2007. (BC STATS: http://www.bcstats.gov.bc.ca/data/bus_stat/econ_stat.asp)

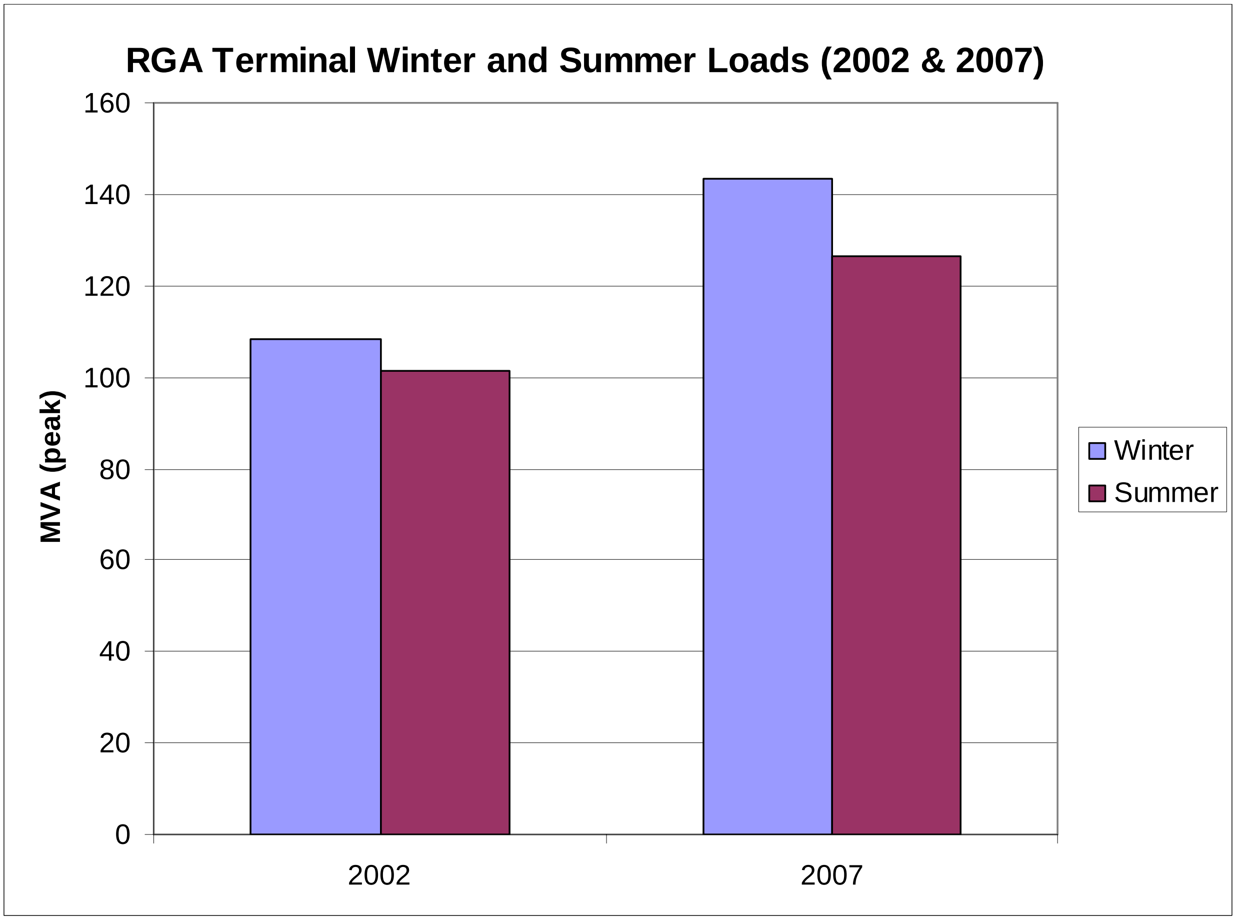
Figure: A5.1 Approved Building Permits



Q5.2 Please show the monthly peak loads for the RGA for each of 2002 and 2007.

A5.2 FortisBC does not collate monthly peak loads since only the winter and summer peak loads are required for load forecasting. These loads for the RG Anderson Terminal station for 2002 and 2007 are shown in Figure A5.2 below.

Figure: A5.2



Note: The winter load for 2002 is based on the winter of 2001/2002 and the winter load for 2007 is based on the winter of 2006/2007 respectively.

Q5.3 FortisBC states:

> **"System winter peak demand in the Kelowna-Penticton area overall is forecast to exceed system capacity, under normal operating conditions, by 2009" (Exhibit B-1-1, p. 5).**

Please clarify whether the term "normal operating conditions" means at average operating conditions, standard atmospheric conditions, or other.

A5.3 The term "normal operating conditions" referred to above indicates a system status of N-0, i.e., all major elements of the power system are in service. The term does not imply specific atmospheric conditions or other factors.

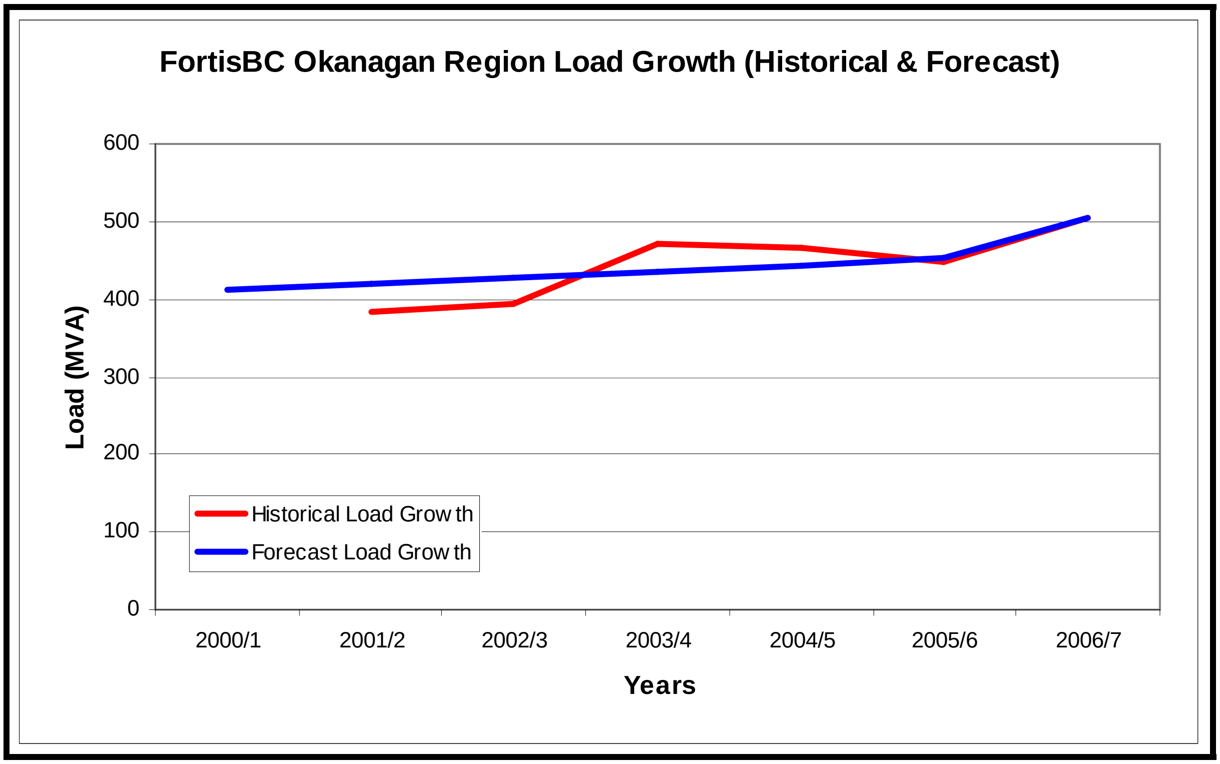
6.0 Load Forecast

Reference: Exhibit B-1-1, Tab 3, Section 3.1.2.1 (Load Forecast), p. 4

Q6.1 Please provide a version of Figure 3-1-2-1A that shows the corresponding historical values from 2000/1 to 2006/7 as well as the forecast values.

A6.1 Please see Figure A6.1 below.

Figure: A6.1



Q6.2 Please describe the sensitivity of the timing of the OTR project to changes in growth rates. In particular, if the growth rate were to drop to 2% immediately as a result of an economic slowdown, would the need for the project or certain portions thereof be pushed out beyond 2010? Please explain.

A6.2 Equipment rating violations are already occurring at peak times in both N-0 and N-1 scenarios (as described in Section 3.1.2.1 and Section 3.1.2.3 of the Application), with an associated risk of equipment damage and increasing customer outages. Thus, load growth would have to become negative to fully alleviate current system constraints.

Please see the response to BCUC IR No.1 Q9.4 for a discussion of the potential to defer portions of the Project.

Q6.3 Please describe how growth projections have influenced the sizing of equipment (transformer ratings, conductor sizes, etc.), and explain whether a lower growth-rate projection would lead FortisBC to install lower-capacity equipment. In particular, if the growth rate were to revert to the values anticipated in the 2005 SDP, would the size of equipment or the timing of the project be affected?

A6.3 Equipment ratings are not selected solely on the basis of load forecasts; standards and engineering requirements are a large part of the selection process.

In the case of the ampacity for 75 Line, 76 Line and 40 Line, the minimum size of the conductor is driven by the requirement to minimize corona discharge from the energized 230 kV conductors. The smallest standard conductor used by FortisBC at 230 kV is 795 kcmil ACSR “Drake” and it is this conductor that is proposed for 40 Line. The proposed conductor for the 75 Line / 76 Line double-circuit is 1193 kcmil ACSR “Bunting”; which is required for line design reasons such as span and sag distances, and radio frequency interference.

In terms of transformer ratings, four new transformers are proposed for the project:

- RG Anderson Transformer 4 (to replace RG Anderson Transformer 2 which will be relocated to Bentley and known as Bentley Transformer 1) - the new transformer will be matched to the existing RGA Transformer 1 (which can be uprated to 180 MVA). The reasons for this are stated in Section 3 Page 28, lines 1 – 4 of the Application (Exhibit B-1-1). RG Anderson Transformer 4 will have a 200 MVA rating, which is the nearest standard FortisBC rating.
- Bentley Transformer 2 – this transformer is sized to match the available transmission capacity rating of 11 Line to Trail thus ensuring that the transformer is not a bottleneck for the transmission path.
- Bentley Transformer 3 – this transformer is sized to match the available transmission capacity rating of 43 Line to Princeton thus ensuring that the transformer is not a bottleneck for the transmission path.
- Oliver Transformer 3 (new distribution transformer) – this transformer is a 12/16/20 MVA unit which is the FortisBC standard rating for communities similar to Oliver.

Bus and circuit breaker ratings for the OTR project are primarily driven by the standard ratings available for equipment of that voltage level. There are no high-rated buses or circuit breakers required for the OTR Project.

Q6.4 Please discuss how the load forecast incorporates the expected benefits of AMI technology (as discussed in FortisBC's current Advanced Metering Infrastructure CPCN application), including the effect of innovative rate structures, load control, and demand-side management programs. Please provide quantitative answers where possible.

A6.4 FortisBC's Advanced Metering Infrastructure ("AMI") Project, if approved, will see the replacement of all direct customer meters in the Company's service territory with AMI-enabled meters. The immediate operational savings and benefits of the AMI Project will result from the capability for remote meter reading, however the meters will have other features such as the ability for readings at more frequent intervals, which will provide a basis for influencing customer usage.

The Company has not attempted to design new rates or load control or additional demand-side management programs prior to the approval of the AMI Project and the collection and analysis of consumption data available through that project. The expected completion date for AMI implementation is 2010, and the impact of these measures on FortisBC's load forecast would not influence the OTR Project.

Also, as indicated in the response to BCUC IR No.1 Q3.2, approximately 34,000 customers in the Okanagan area are indirect customers not included in FortisBC's AMI implementation.

Q6.5 As part of its AMI initiative, has FortisBC considered using the technology to inform customers of when the transmission system is heavily loaded and to encourage them, through pricing or other means, to reduce consumption? Please explain.

A6.5 FortisBC has considered the future implementation of AMI technology for this purpose. However, the costs and benefits of a program such as this have not been evaluated. As indicated in the response to BCUC IR No.1 Q6.4, this potential benefit will only be available to FortisBC's direct customers.

7.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Glossary, p. 3; Tab 3, pp. 11-14

Q7.1 When defining N-1-1 and N-2, FortisBC states these are typically transmission system design criteria used for a major urban centre. For each of N-1-1 and N-1, please provide the basis for the statement, how the transmission planning criteria is stated and applied for the FortisBC system, and the definition of "major urban centre".

A7.1 The stated reliability criteria apply and refer to the bulk transmission system. Currently, the FortisBC bulk transmission system all the way from the Kootenay River generating stations through to Kelowna (and to BCTC at Vernon) is operated meshed. Under NERC/WECC criteria, an outage to any single bulk transmission line shall not result in a load loss or voltage violation.

Most urban areas in FortisBC's service territory (including Kelowna, Penticton, Oliver/ Osoyoos, Princeton, Grand Forks, Trail, Castlegar and Creston) currently have some level of N-1 transmission reliability in that they have at least two sources of transmission or subtransmission supply. In some cases however, a short outage may result while switching occurs to enable the second supply following a loss of the primary source. The N-1 planning criterion is normally the only contingency level specified by NERC/WECC requirements that does not permit the loss of any load (refer also to response to BCUC IR No.1 Q7.2).

FortisBC considers Kelowna to be a "major urban centre" as it has a concentrated population of over 100,000 residents. The next largest city in the FortisBC service area is much smaller with approximately 30,000 residents. The Kelowna area alone represents approximately 1/3 of the FortisBC customer base. On this basis no other area of the FortisBC service area is considered a "major urban centre."

The statement that N-1-1/N-2 reliability is typical for major urban areas is not meant to imply that it is a requirement of the NERC or WECC minimum reliability criteria. Rather it is a de-facto standard that is considered "good utility practice" and applied by many utilities since the consequences of load loss in large urban areas justify exceeding the minimum N-1 reliability requirement.

Q7.2 For each of N-1-1 and N-2, please describe fully the (minimum) transmission planning criteria established by the Western Electricity Coordinating Council ("WECC") and provide a copy of the WECC standards that apply.

A7.2 The WECC transmission planning criteria are adapted from the NERC (North American Electric Reliability Corporation) Planning Standards. The relevant portion of the presently approved WECC/NERC standard is attached as Appendix A7.2.

The following terminology equivalence applies with respect to contingencies:

OTR CPCN Application	NERC/WECC Standards
N-0	Category A
N-1	Category B
N-2 / N-1-1	Category C

For reference, following is the criteria that must be followed for N-0 (NERC/WECC "Category A") planning:

"The interconnected transmission systems shall be planned, designed,

> *and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and projected firm (non-recallable reserved) transmission services, <u>at all demand levels</u>* [emphasis added] *over the range of forecast system demands, under the conditions defined in Category A of Table I"* - (WECC Transmission Standard I.A.S1 - Appendix A7.2)

Following is the NERC/WECC standard for N-1-1/N-2 (NERC/WECC "Category C") contingencies:

> *"The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, <u>at all demand levels</u>* [emphasis added] *over the range of forecast system demands, under the conditions of the contingencies as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard."* - (WECC Transmission Standard I.A.S1 - Appendix A7.2)

NERC/WECC criteria effectively do not discriminate between N-2 and N-1-1 contingencies:

> *"System performance assessments based on system simulation testing shall show that for system conditions where (See Table I Category C)*

> *1. The initiating event results in the loss of two or more elements, or*
>
> *2. Two separate events occur resulting in two or more elements out of service with time for manual system adjustments between events,*
>
> *and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. Planned outages of customer demand or generation (as noted in Table I, footnoted) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed."* - (WECC Transmission Standard I.A.M3.3 - Appendix A7.2)

Q7.3 If FortisBC planning criteria require a higher standard of reliability than WECC, please justify the use of a higher reliability standard for the OTR Project.

A7.3 FortisBC criteria do not require a higher reliability standard than WECC. As shown in Table W-1 of Appendix 7.2, NERC and WECC consider that Category C events are estimated to occur approximately once every 3 to 30 years. However, as shown in Table 3-1-3-4 at page 17 Tab 3 of the Application (Exhibit B-1-1), these N-2 events have historically occurred much more frequently than this guideline, one to two times per year.

As well, while controlled load-shedding is permissible under N-2 contingencies, for a significant portion of the year it would be necessary to shed more than 50% of the Kelowna/Penticton area load. FortisBC considers that this is unacceptable given the historical frequency of events experienced by these customers.

Note that the WECC does have a formal process where a reliability performance category can either be upgraded or downgraded depending on the expected performance of system elements:

> *“For contingencies involving existing or planned facilities, the Table W-1 performance category can be adjusted based on actual or expected performance (e.g. event outage frequency and consideration of impact) after going through the WECC Phase I Probabilistic Based Reliability Criteria (PBRC) Performance Category Evaluation (PCE) Process.”* - (WECC Transmission Standard I.A.WECC-S5 - Appendix A7.2)

Following is a specific example where this process has been applied:

> *“**Existing Facility with Poor Performance** - performance category downgrading scenario*
> *Facility: Malin-Round Mountain lines 1 and 2 sharing the same corridor*
> *Disturbance Outage Class: Two elements*
> *Criteria Category Specified: C*
> *Class Outage Frequency: 0.033-0.33 outages/year*
> *Historical Performance: 0.50 outages/year (Hypothetical)*
> *Recommended Category Adjustment: A* [Single element] *(Downgrade)”*

Source: WECC Reliability Performance Evaluation Work Group - Phase I Probabilistic Based Reliability Criteria Implementation Procedure, June 14, 2001, p. 13

At this time, the WECC formal review process is not applicable to the Lee-Vernon transmission lines as they are not part of a WECC rated path. However, the principle is still valid. Thus, given this criterion, and the historical frequency of outages to the Kelowna area (discussed above), FortisBC considers it reasonable to apply the NERC/WECC Category B (N-1) planning criteria as opposed to the less stringent Category C (N-2) criteria.

Q7.4 Further to quotation from page 59 of the Reasons for Decision regarding Order G-52-05, please note that the Commission issued Letter No. L-48-05 to clarify this portion of the Reasons for Decision, and stated:

"The Commission Panel is concerned that the determination on page 59 of the Decision and a discussion on page 57 of the Decision may be interpreted to mean that the Commission Panel has set increased standards of reliability for the City of Kelowna and, by inference, for other similar load centers. This is not the case. The Commission Panel's determination was that for the particular circumstances the City of Kelowna is facing, i.e., the risk of losing the two lines from Vernon due to various causes (including forest fires) and in consideration of the consequences in losing those lines for the loss of load in Kelowna, the advancement of a 230 kV line from Vaseux Lake to Penticton to alleviate that risk, would be a prudent investment. This would have the result of increasing the level of reliability for Kelowna beyond what is commonly referred to as an N-1 contingency level but this outcome should not be interpreted as meaning the Commission Panel has set increased design standards of reliability for the City of Kelowna or for other similar load centers. Each case involving facilities which improve reliability levels must be evaluated on its own merits. In doing so the Commission Panel is guided by good Utility practice, public safety and the economics of providing service."

Based on this clarification, why does FortisBC believe "Order G-52-05…supported a double contingency reliability planning criteria for Kelowna"?

A7.4 The support is explicitly stated in Order G-52-05: "The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time". Letter L-48-05 states that the proposed 230 kV line "would be a prudent investment. This would have the result of increasing the level of reliability for Kelowna beyond what is commonly referred to as an N-1 contingency level".

Letter L-48-05 further states that "each case involving facilities which improve reliability levels must be evaluated on its own merits. In doing so the Commission Panel is guided by good Utility practice, public safety and the economics of providing service." The Company understands that each case must be evaluated on its own merits and is prepared to do so.

The enhancement of double contingency reliability in the City of Kelowna is consistent with good utility practice, public safety and is economic. Please see the response to BCUC IR No.1 Q7.1 which discusses the application of transmission planning criteria to urban areas.

FortisBC submits that, with regard to the OTR Project CPCN Application, there is no issue arising from the provision of double contingency reliability in the Okanagan area, as there is no incremental cost associated with its provision (please see the response to BCUC IR No.1 Q8.2).

Q7.5 Please confirm that the Resource Plan that was the subject of Order No. G-52-05 was for the advancement of the schedule for a single 230 kV circuit from Vaseux Lake to Penticton, or explain.

A7.5 The reference above should be to the FortisBC 2005-2024 T&D System Development Plan (SDP). FortisBC did not seek an Order approving the SDP but stated that the SDP needed to be considered when evaluating the Company's 2005 Capital Expenditure Plan, which was approved in Order G-52-05. At page 59 of the Reasons for Decision accompanying Order G-52-05, it is stated that "although the Commission has not been requested to approve the System Development Plan, the Commission Panel has several comments".

The timing of the 230 kV circuit(s) from Vaseux Lake to Penticton was the subject of Intervenor submissions in the 2005 proceeding. Section 2.4.2 of the SDP described the requirements to upgrade the transmission system between Vaseux Lake and RG Anderson Terminal to 230 kV operation. The development included what was described as "a 230 kV circuit" to be in service within the 2007/08 timeframe. However, within the same application the ultimate development was to be a double-circuit 230 kV transmission line between Vaseux Lake and Penticton, as described in Section 2.4.4. in Appendix C, and in response to Information Requests regarding the SDP .

For the reasons stated above, FortisBC respectfully submits that no Order regarding the timing or specifics of any project was included in the Reasons for Decision accompanying Order G-52-05. The justification for the OTR Project, timing, and configuration is the subject of this Application.

Q7.6 Further to the responses to the previous questions, please provide a summary of FortisBC's understanding of the need to meet an N-2 standard in the Okanagan region.

A7.6 FortisBC does not hold the view that a double contingency reliability standard is a requirement for the Okanagan region as a whole. However, as stated in BCUC IR No.1 Q7.1 above it is considered "good utility practice" and is applied by many utilities since the consequences of load loss in large urban areas justify exceeding the minimum N-1 reliability requirement. Please also see the response to BCUC IR No.1 Q7.4 above.

8.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.1.1, p. 3; Section 3.1.2.3, p. 7

Q8.1 Please describe fully what is meant by "enhance the double-contingency reliability for the Kelowna area," providing quantitative data (such as expected energy not served, SAIDI, etc.) where available.

A8.1 The Project will enhance the double-contingency reliability for the Kelowna area by reducing the period of vulnerability during which the peak load will exceed system capacity under double contingency (N-1-1 / N-2) scenario and may necessitate shedding of load.

Quantitatively, Figure A8.1 (a) below indicates that under existing conditions the Kelowna-Penticton system is vulnerable for 7,400 hours per year (84% of the year) during 2008 when the system capacity will be exceeded under a double contingency scenario. Without the OTR Project, the level of vulnerability will reach 8,753 hours (99.9%) by 2024, which in all practical terms means total absence of double contingency compatibility. Figure A8.1 (a) also indicates that with completion of the OTR Project (with introduction of SVC by 2012) the Kelowna-Penticton system reliability improves markedly with double contingency vulnerability reduced to zero till 2014 and to 35 hours during 2024.

Figure A8.1 (a)

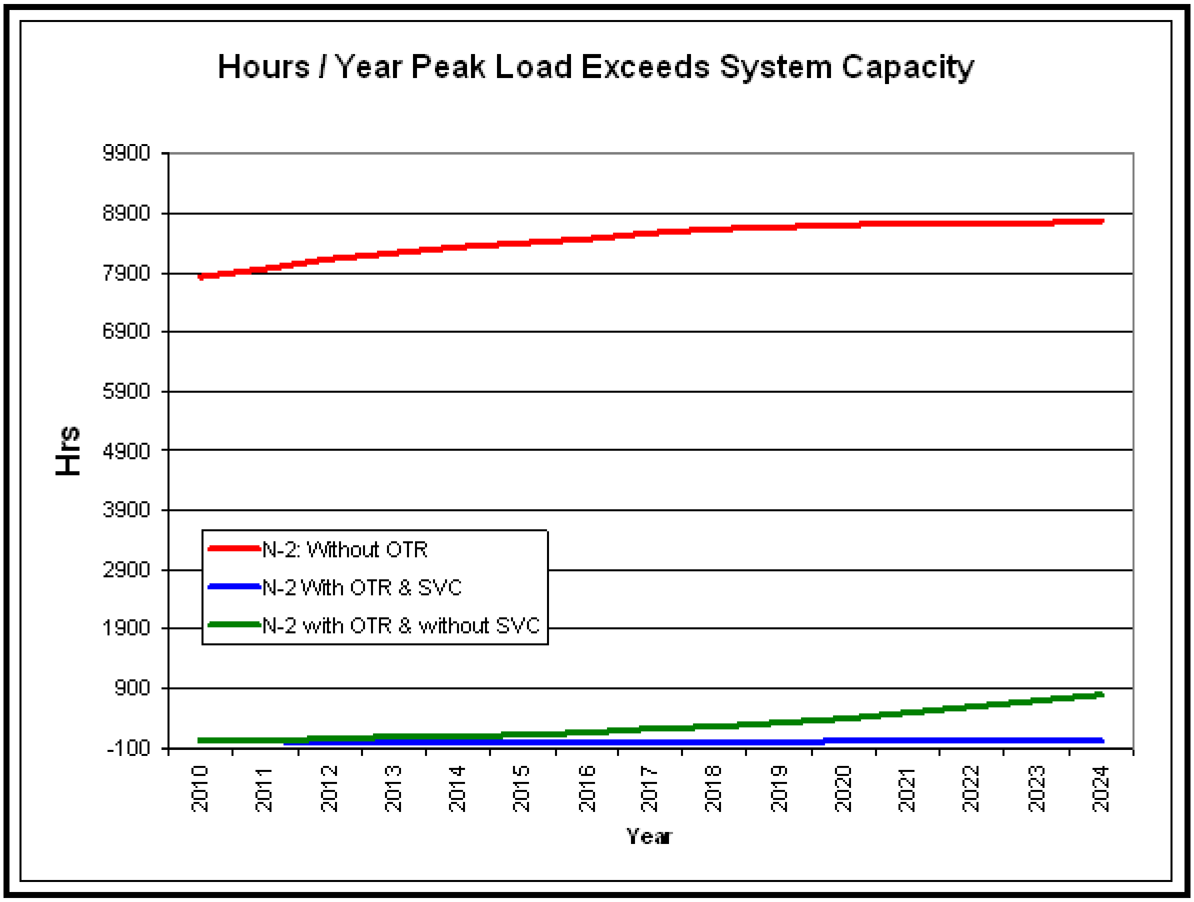
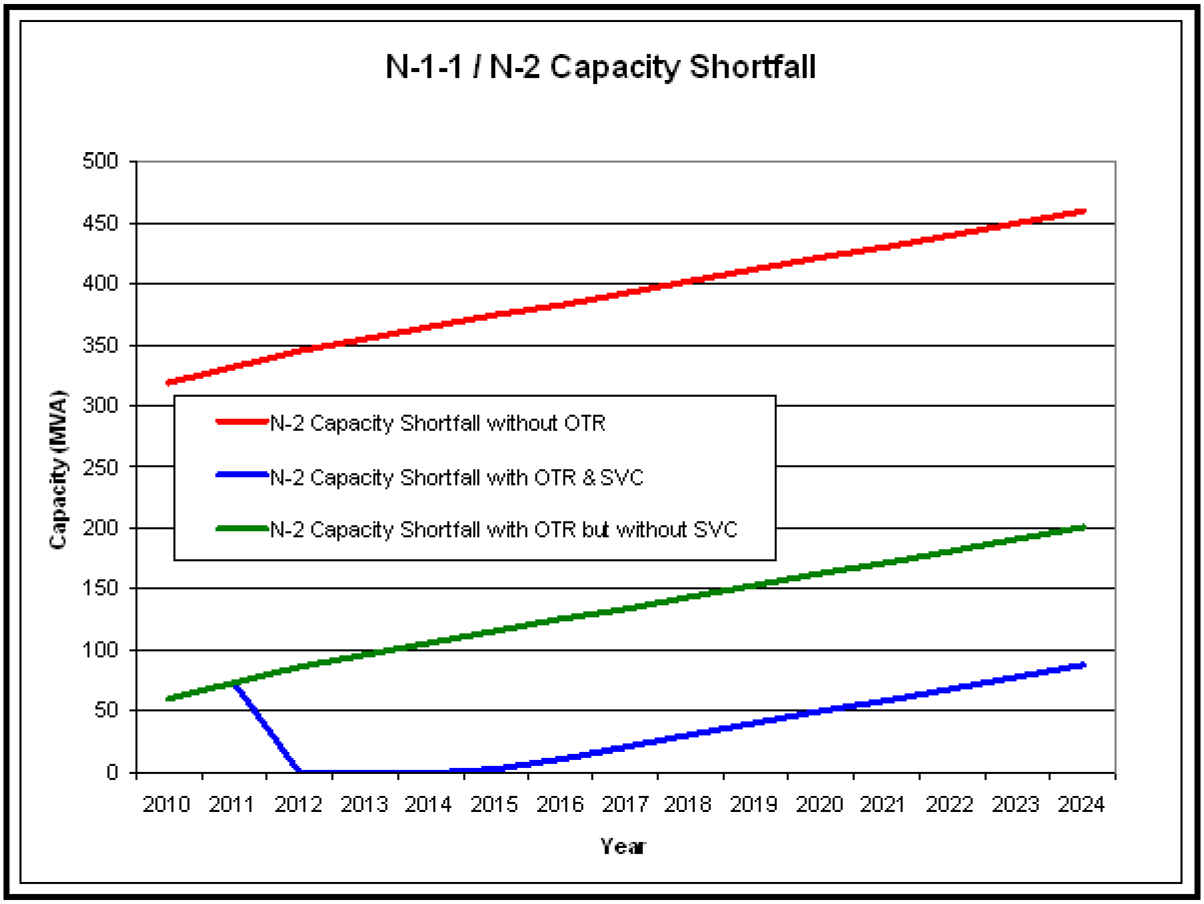


Figure A8.1 (b) below also indicates that with completion of the OTR Project the Kelowna-Penticton capacity shortfall also improves significantly from 2010 to 2024 (both with and without the addition of static Var compensators (SVC)) At Section 3.6 of the Application (Exhibit B-1-1) the likely addition of a 150 MW SVC in 2010/2011 is discussed. The impact of adding SVC at DG Bell Terminal station is not being requested in this Application, however the impact is shown in this and a number of other responses to illustrate conditions following its installation..

Figure A8.1 (b)



Note: Please note that the post OTR capacity shortfall reduces in 2012 due to the proposed introduction of the SVC as indicated.

Q8.2 Please describe which components of the OTR, if any, are required to enhance double-contingency reliability that would not otherwise be required to enhance single-contingency reliability. Please discuss N-1-1 and N-2 separately.

A8.2 All components proposed under the OTR project are sized to provide adequate capability during normal operation (N-0) and during a single contingency (N-1). In addition, they will significantly enhance the double contingency (N-1-1 and N-2) reliability of the system compared to what it is with the present system. Refer also to the response to BCUC IR1 Q6.2.

Q8.3 Please describe which components of the OTR, if any, are sized differently than they would be otherwise to enhance double-contingency reliability. Please discuss N-1-1 and N-2 separately.

A8.3 Please see the response to BCUC IR No.1 Q8.2 above.

Q8.4 Please describe the credible double contingencies that FortisBC has included in its planning scenarios, along with the associated probabilities of occurrence.

A8.4 The double contingencies considered in the planning scenarios are:

- Simultaneous outage of lines 72 Line and 74 Line (Vernon Terminal - FA Lee Terminal).
- Simultaneous outage of lines 75 Line and 76 Line (Vaseux Lake Terminal - RG Anderson Terminal).
- Outage of any one of 72 Line, 74 Line, 75 Line or 76 Line during the prior scheduled outage of any of the other lines.

Double-line outages are considered credible N-2 events as they have occurred and are expected to continue to occur. Double contingency events resulting from station equipment outages (such as circuit breaker failures or multiple transformer failures) occur less frequently and have not been considered.

Historical occurrences of these double contingencies are highlighted in Table 3-1-3-4 of the CPCN Application (Exhibit B-1-1), which is also shown below:

Table 3-1-3-4: Kelowna/Penticton Area Transmission Outages 1997 – July 2007 (Exhibit B-1-1)

	Description of Cause	Element	Down Timestamp	Up Timestamp	Duration	Total Direct & Indirect Cust.	Total Direct & Indirect Cust. Hrs.
1	WIND	72 & 74 LINE	3/9/1997 12:44:49 PM	3/9/1997 6:49:08 PM	06:04:19	46,570	84,589
2	INSULATOR	72 LINE	3/10/1997 12:35:28 PM	3/10/1997 12:35:42 PM	00:00:14	46,570	181
3	INSULATOR	72 LINE	4/1/1997 6:39:00 PM	4/1/1997 6:39:06 PM	00:00:06	0	0
4	LOSS OF SUPPLY	2L255 & 2L256	7/5/1997 5:03:00 PM	7/5/1997 5:05:00 PM	00:02:00	46,767	1,559
5	LIGHTNING	72 & 74 LINE	7/21/1997 2:50:42 PM	7/21/1997 2:52:11 PM	00:01:29	46,767	1,156
6	LIGHTNING	72 & 74 LINE	7/21/1997 3:34:45 PM	7/21/1997 3:44:26 PM	00:09:41	46,767	4,851
7	LIGHTNING	72 & 74 LINE	7/21/1997 4:15:20 PM	7/21/1997 4:15:31 PM	00:00:11	46,767	143
8	LIGHTNING	72 & 74 LINE	9/5/1997 4:10:49 PM	9/5/1997 4:30:03 PM	00:19:14	15,947	5,112
9	LIGHTNING	72 LINE	6/20/1998 4:39:26 PM	6/20/1998 4:39:37 PM	00:00:11	0	0
10	LIGHTNING	72 LINE	6/25/1998 9:54:22 PM	6/25/1998 9:59:26 PM	00:05:04	0	0
11	INSULATOR	74 LINE	1/31/1999 5:36:28 AM	1/31/1999 5:50:41 AM	00:14:13	0	0
12	LIGHTNING	74 LINE	8/19/1999 3:22:04 AM	8/19/1999 3:22:08 AM	00:00:04	567	1,702
13	LOSS OF SUPPLY	72 LINE	5/18/2000 10:37:00 AM	5/18/2000 11:21:00 AM	00:44:00	0	0
14	LOSS OF SUPPLY	2L255 & 2L256	7/8/2000 5:05:49 PM	7/8/2000 5:05:53 PM	00:00:04	47,141	52
15	LOSS OF SUPPLY	2L255 & 2L256	7/20/2000 6:39:12 PM	7/20/2000 6:47:19 PM	00:08:07	47,141	6,377
16	LOSS OF SUPPLY	74 LINE	7/22/2000 7:02:00 PM	7/22/2000 7:08:00 PM	00:06:00	0	0
17	LIGHTNING	72 & 74 LINE	7/25/2000 1:09:25 PM	7/25/2000 1:09:38 PM	00:00:13	47,141	170
18	VEHICLE	73 LINE	8/16/2000 2:10:45 AM	8/16/2000 2:18:25 AM	00:07:40	6,233	796
19	TREE ON LINE	72 LINE	7/2/2001 2:24:05 PM	7/2/2001 8:28:09 PM	06:04:04	0	0
20	LIGHTNING	LEE TERMINAL	8/22/2001 4:01:12 AM	8/22/2001 4:18:38 AM	00:17:26	54,101	8,918
21	UNKNOWN	74 LINE	11/8/2001 2:14:30 AM	11/8/2001 2:14:42 AM	00:00:12	0	0
22	LIGHTNING	73 LINE	6/18/2002 2:26:20 AM	6/18/2002 2:26:28 AM	00:00:08	18,361	41
23	LIGHTNING	74 LINE	8/6/2002 6:26:22 AM	8/6/2002 6:26:37 AM	00:00:15	0	0
24	LIGHTNING	72 & 74 LINE	8/19/2002 7:45:21 PM	8/19/2002 7:45:34 PM	00:00:13	61,544	222
25	CROSSARM	73 LINE	3/24/2003 5:21:34 PM	3/26/2003 5:57:23 PM	48:35:49	35,789	2,185
26	FOREST FIRE	73 LINE	8/19/2003 9:36:14 PM	9/1/2003 8:14:00 PM	310:37:46	0	0
27	STRUCTURE	73 LINE	3/26/2004 2:49:50 AM	3/26/2004 3:28:10 PM	12:38:20	24,741	4,000
28	LIGHTNING	72 & 74 LINE	5/20/2004 7:25:46 PM	5/20/2004 7:25:59 PM	00:00:13	51,741	187
29	UNKNOWN	72 LINE	7/24/2004 8:59:04 AM	7/24/2004 8:59:16 AM	00:00:12	0	0
30	LIGHTNING	RGA TERMINAL	6/21/2005 7:01:18 PM	6/21/2005 7:08:02 PM	00:06:44	24,918	3,222
31	LOSS OF SUPPLY	2L255 & 2L256	3/3/2006 1:38:30 PM	3/3/2006 2:50:37 PM	01:12:07	52,121	24,721
32	LIGHTNING	73 LINE	6/9/2006 4:23:18 PM	6/9/2006 4:23:24 PM	00:00:06	0	0
33	LIGHTNING	73 LINE	7/5/2006 7:24:54 PM	7/5/2006 7:25:00 PM	00:00:06	25,699	43
34	POLE FIRE	73 LINE	8/30/2006 10:53:38 PM	8/30/2006 11:47:00 PM	00:53:22	3,534	3,143
35	LIGHTNING	73 LINE	6/16/2007 4:03:23 PM	6/16/2007 4:03:33 PM	00:00:10	0	0
36	LOSS OF SUPPLY	2L255 & 2L256	6/29/2007 3:56:43 PM	6/29/2007 4:11:18 PM	00:14:35	69,965	28,587
37	LIGHTNING	RGA TERMINAL	7/19/2007 2:56:48 PM	7/19/2007 2:58:25 PM	00:01:37	24,782	668
38	LIGHTNING	73 LINE	7/23/2007 6:39:18 PM	7/23/2007 6:39:25 PM	00:00:07	0	0

Q8.5 What are the negative operational and/or economic consequences of offloading some portion of the Penticton load to 42 Line following the concurrent loss of 72 Line and 74 Line?

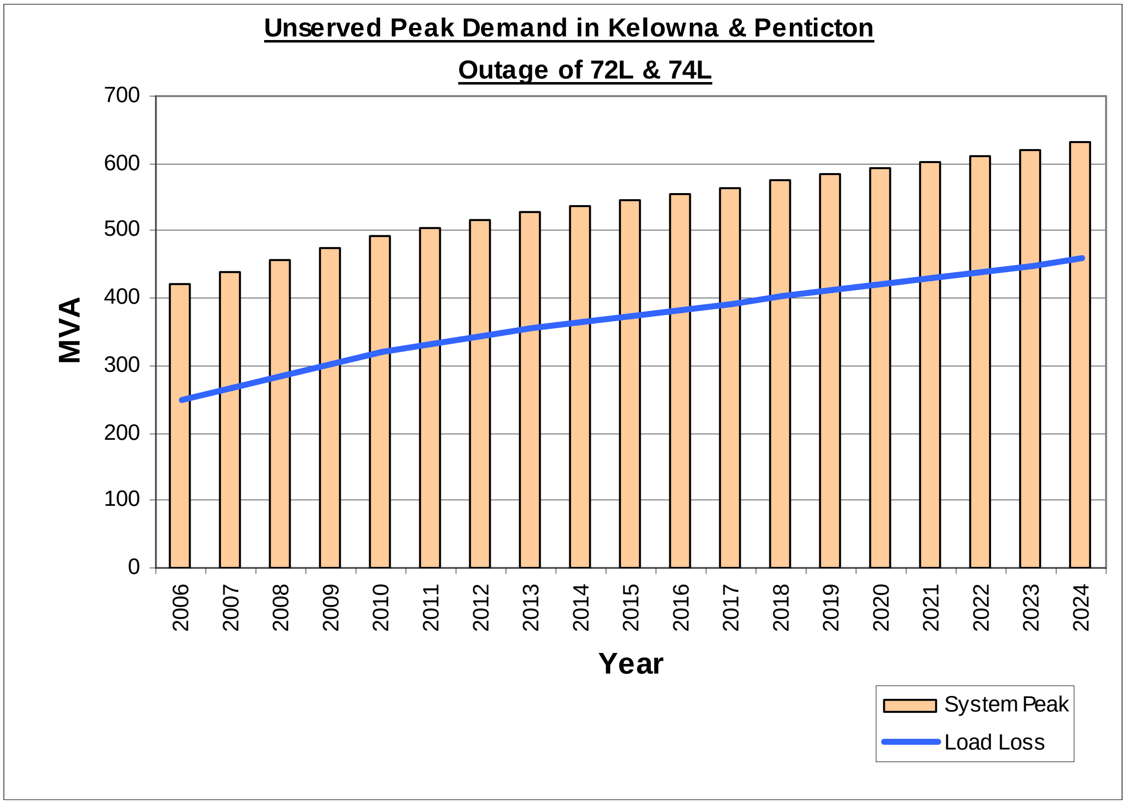
A8.5 It is possible to offload some of the Penticton load onto 42 Line from Oliver, but the amount of load that can be supplied is limited by the available transformation at Oliver. The maximum rating of Oliver Transformer 1 (the normal source for the Oliver 63 kV bus) is 60 MVA. At peak times much of this capacity would be used to supply the Oliver/Osoyoos area; little capacity would remain to supply load north to Penticton (which would also have to include Kaleden and Okanagan Falls substations). Oliver Transformer 2 could be used as a 63 kV source in an emergency situation, however this would require supplying all of the 43 Line load (including Princeton, Terasen, Hedley and Keremeos) from BCHydro via 56 Line (this is because Oliver Transformer 2 cannot be used as both a 138 kV and 63 kV source at the same time due to voltage regulation issues).

Refer also to the response to BCUC IR No.1 Q22.1 for the amount of load that could be offloaded to 42 Line.

Q8.6 What is the expected load loss (unserved demand, unserved energy) given a maintenance outage on 72 Line followed by an outage on 74 Line, and vice versa?

A8.6 The expected loss of load in Kelowna and Penticton for the loss of 72 Line and 74 Line is given in Figure A8.6 below. Refer also to Figure 3-1-3-5B from Section 3, page 20 of the CPCN Application (Exhibit B-1-1), showing existing system capacity and peak forecast load.

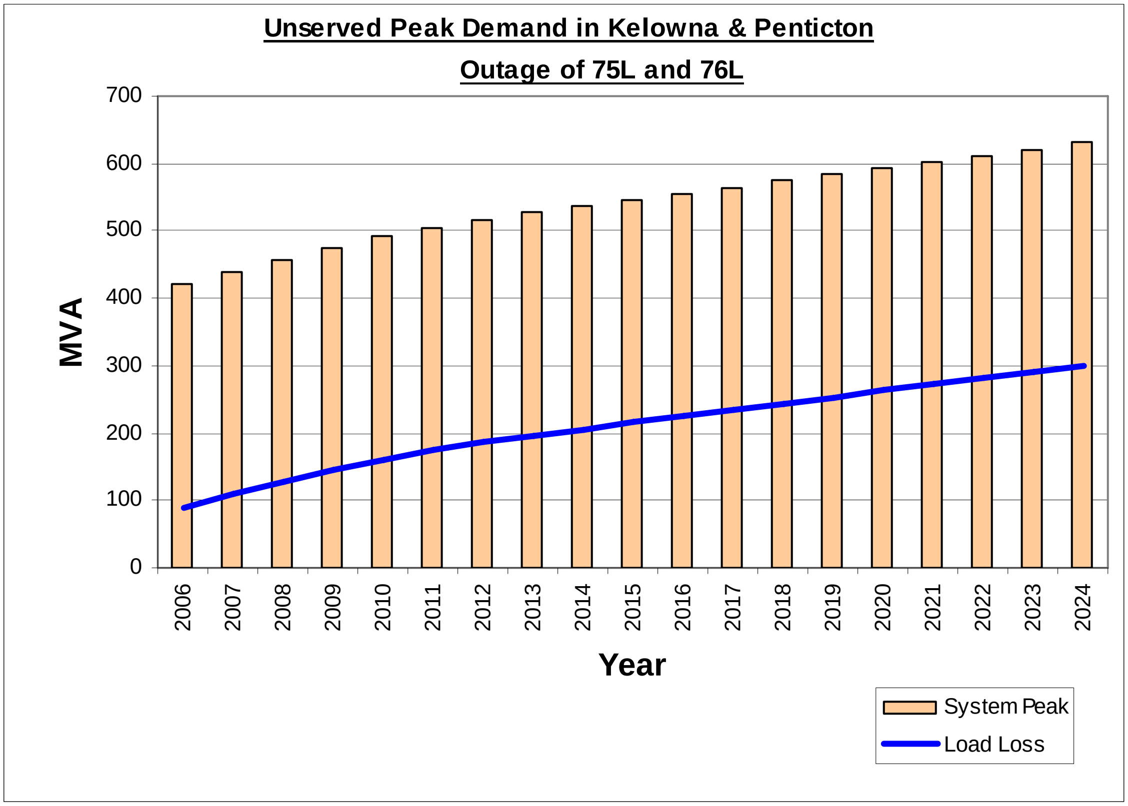
Figure: A8.6



Q8.7 **Please repeat the previous question for 76 Line and the proposed 75 Line between Vaseux Lake and R. G. Anderson.**

A8.7 The expected loss of load in Kelowna and Penticton for the loss of 76 and 75 Line is given in Figure A8.7 below. Refer also to Figure 3-1-3-5B from Section 3, page 20 of the CPCN Application (Exhibit B-1-1).

1 **Figure: A8.7**


Unserved Peak Demand in Kelowna & Penticton
Outage of 75L and 76L
MVA
0
100
200
300
400
500
600
700
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
Year
System Peak
Load Loss

9.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.1.2.3 (System Capacity Limitations), p. 7

Q9.1 For each major segment of the Okanagan transmission system (Vernon to F.A. Lee, F.A. Lee to D.G. Bell, etc.), and for each individual station, as shown in Figure 3-2-1 on page 24, please provide:

Q9.1.1 The existing summer and winter capacity ratings, along with a description of the factor (thermal rating of a particular piece of equipment, voltage stability, etc.) that is responsible for that limit;

A9.1.1 The requested transmission line and transformer ratings are provided in Table A9.1.1 (a) and Table A9.1.1 (b) below:

Table: A9.1.1 (a) Transmission Line Capacity Ratings

Line	Conductor	Rating (MVA)	
		Summer	Winter
72, 74, 73	795 kcmil	339	407
76	477 kcmil	170	204

The above ratings are based on the following:

1. Normal ampacity based on maximum conductor temperature of 100° C;
2. Emergency ampacity based on maximum conductor temperature of 150° C;
3. Summer ambient temperature 30° C;
4. Winter ambient temperature 0° C;
5. Normal MVA rating based on 80% of the normal Ampacity;

6. Emergency MVA rating based on 100% of the emergency Ampacity; and
7. All ampacities based on air velocity of 2 feet per second.

The above line ratings are based on the ampacities of the conductor used. The actual capacity of the line is dependent on other factors like network configuration and load conditions and available reactive resources.

Table: A9.1.1 (b) Transformer Capacity Ratings

Transformer	Rating (MVA)
RG Anderson Transformer 1	110.0
RG Anderson Transformer 2	137.5
Vaseux Lake Terminal Transformer 1 and Transformer 2	250.0

Q9.1.2 Summer and winter path flow duration curves based on hourly power flows for the past year;

A9.1.2 Estimated peak power flow and hourly flow duration curves for summer and winter seasons for various transmission line paths and major substations in 2007 are provided below in Figures 9.1.2 (a) and 9.1.2 (b).

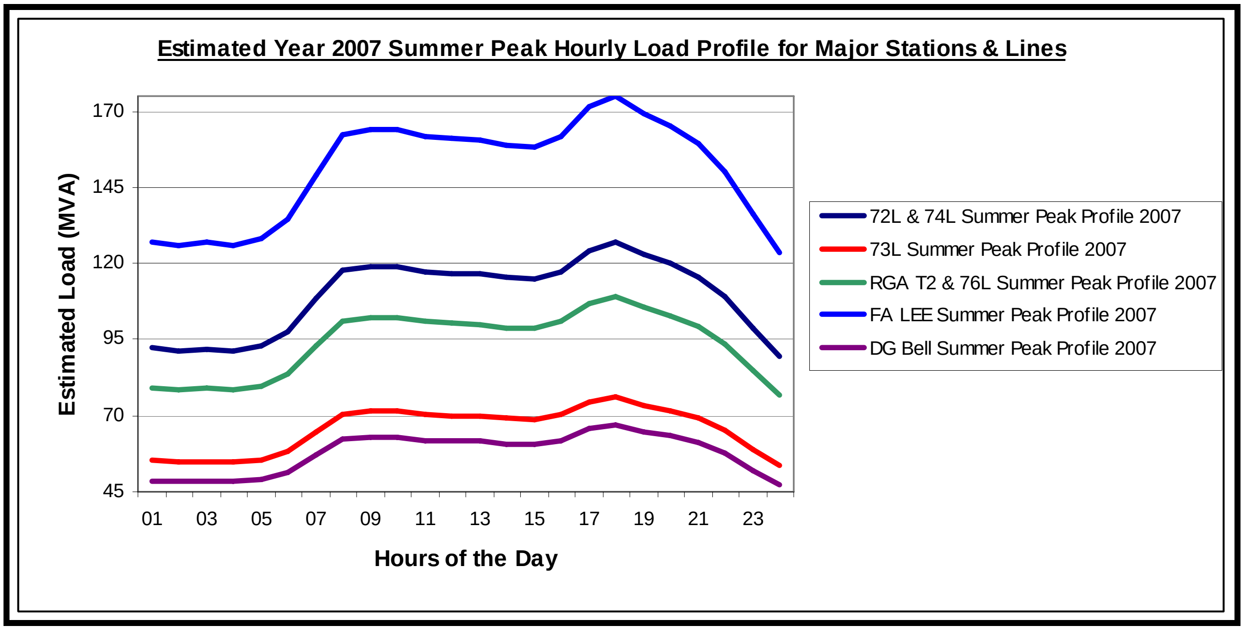
Table 9.1.2 below provides peak loadings for various element components in 2007 under normal operating conditions.

Table: 9.1.2 Peak Power Flows, 2007

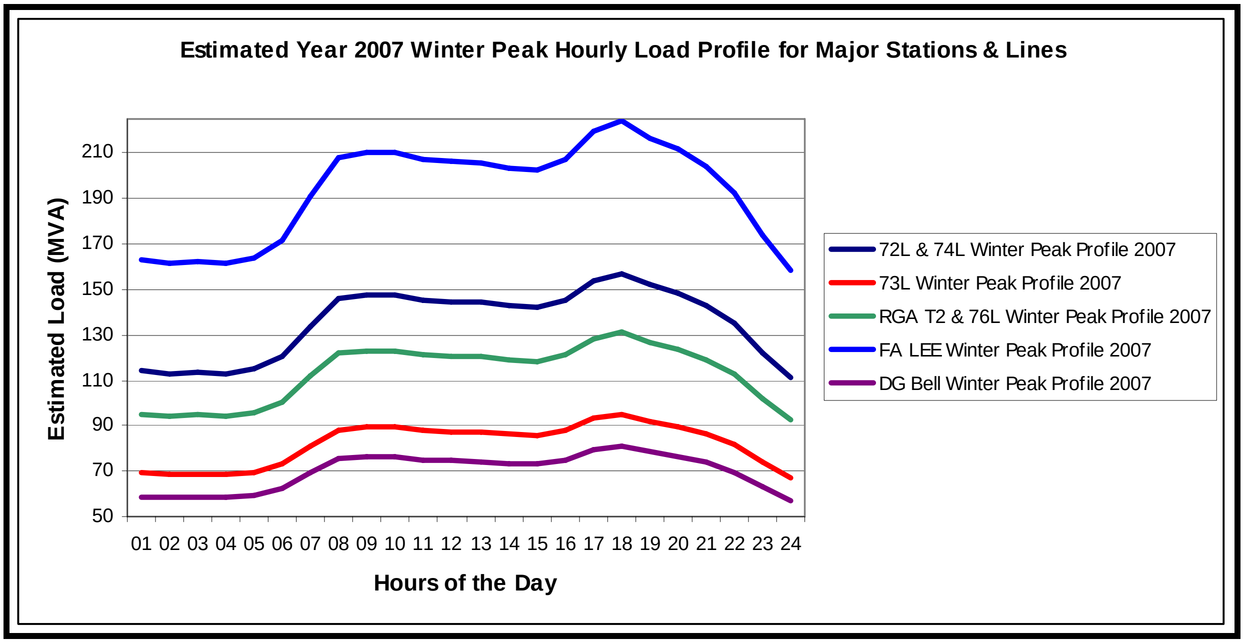
	2007 Peak Flow (MVA)	
Elements	**Summer**	**Winter**
72 Line and 74 Line	127	157
73 Line	76	95
RGA Transformer 2 and 76 Line	109	131
FA Lee	175	224
DG Bell	67	81

Hourly estimated flow duration curves for various Element Components in 2007 are provided below:

Figure: 9.1.2 (a)



1 **Figure: 9.1.2 (b)**



Q9.1.3 Forecast summer and winter path flow duration curves based on projected hourly power flows for 2011, 2016, and 2024; and

A9.1.3 Estimated peak power flow and hourly flow duration curves for summer and winter seasons for various transmission line paths and major substations in 2011 are provided below in Figure 9.1.3 (a) and Figure 9.1.3 (b).

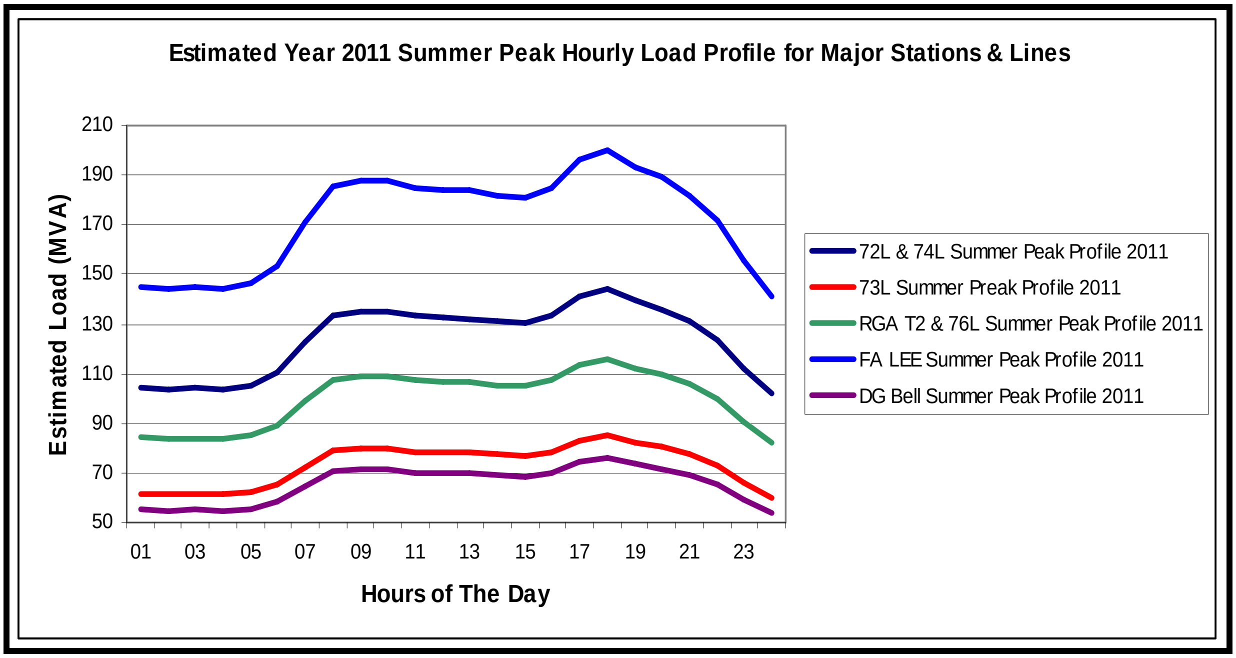
Table A9.1.3 below provides peak loadings for various element components and peak loadings in 2011 (Estimated as per load forecast SDP-2007-2008):

Table: 9.1.3 Forecast Peak Power Flows, 2011

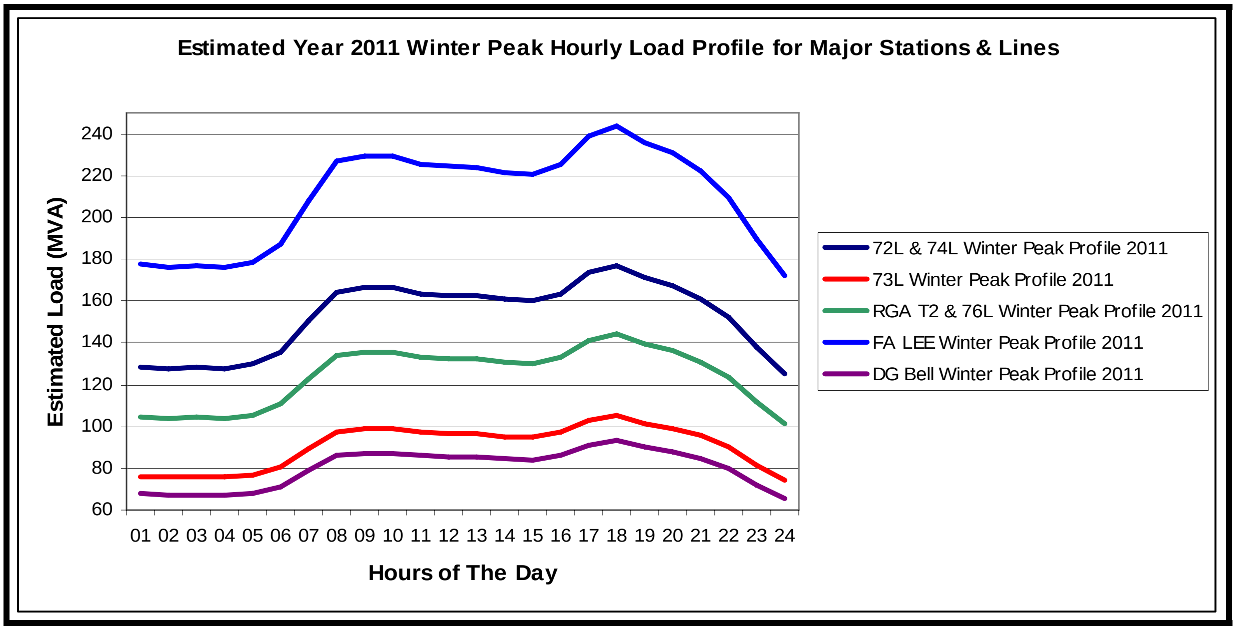
Elements	**2011 Peak Flow (MVA)**	
	Summer	**Winter**
72 Line and 74 Line	144	177
73 Line	85	105
RGA Transformer 2 and 76 Line	116	144
FA Lee	200	244
DG Bell	76	93

Hourly estimated flow duration curves for various element components in 2011 are provided below:

1 **Figure: 9.1.3 (a)**



2 **Figure: 9.1.3 (b)**



Please note that load flow data for the various transmission lines and substation components cannot be realistically derived for years 2016 and 2024, since the network under present configuration will exceed its operational limits.

Q9.1.4 A table showing, for each station and segment, the capacity that will be required to meet N-0, N-1, N-1-1, and N-2 criteria in each of 2011, 2016, and 2024.

A9.1.4 Please find below Table A9.1.4 showing the minimum capacity requirements for major transmission lines and stations to satisfy N-0, N-1, N-1-1 / N-2 contingencies for 2011, 2016 and 2024 under present configuration. There would be an additional component for line / transformer losses in each case, which has not been indicated for simplicity.

Table: A9.1.4 Required Capacity, Single and Double Contingency

Elements	Contingency	Year / Minimum Load Delivery Capacity (MVA) *		
		2011	2016	2024
FA Lee & DG Bell Terminals Combined	N-0	≥ 353	≥ 391	≥ 451
	N-1			
	N-1-1 / N-2			
RG Anderson Terminal Combined	N-0	≥ 155	≥ 164	≥ 180
	N-1			
	N-1-1 / N-2 (Outages excluding 76L)			
RG Anderson T1	N-1-1 / N-2: 72L + 74L Outage	≥ 353	≥ 391	≥ 451
RG Anderson T2		≥ 508	≥ 555	≥ 631
72L, 74L & 76L Combined	N-0	≥ 508	≥ 555	≥ 631
74L & 76L Combined	N-1: 72L Outage	≥ 508	≥ 555	≥ 631
72L & 76L Combined	N-1: 74L Outage	≥ 508	≥ 555	≥ 631
72L & 74L Combined	N-1: 73L Outage	≥ 353	≥ 391	≥ 451
76L		≥ 155	≥ 164	≥ 180
72L & 74L Combined	N-1: 76L Outage	≥ 508	≥ 555	≥ 631
76L	N-1-1 / N-2: 72L + 74L Outage	≥ 508	≥ 555	≥ 631
72L	N-1-1 / N-2: 72L + 76L Outage	≥ 508	≥ 555	≥ 631
76L	N-1-1 / N-2: 74L + 76L Outage	≥ 508	≥ 555	≥ 631

Q9.2 Please discuss FortisBC's use, if any, of probabilistic planning methods. In particular, does FortisBC employ probabilistic measures such as expected energy not served ("EENS") when evaluating whether facility upgrades are to be undertaken?

A9.2 In general, FortisBC does not use probabilistic planning methods. Instead, traditional deterministic planning is used to determine when system reinforcements are required. Probabilistic planning could be difficult to implement at FortisBC given the relatively small size of the transmission system – the required sample set of available reliability data would not necessarily be statistically valid.

As well, probabilistic planning is more suited to evaluating between two or more project alternatives. For example, on two previous occasions, project specific EENS studies have been filed with the Commission:

1. Kelowna Area Upgrade CPCN – a study to determining the preferred site (FA Lee versus DG Bell Terminal) for a third transmission transformer in the Kelowna area.
2. Black Mountain Substation CPCN – a study to compare the improvement in distribution reliability by supplying the load from the FA Lee transformer tertiary windings versus a dedicated distribution transformer.

In the case of the OTR, there are no alternate viable technical alternatives that require evaluation, thus probabilistic methods are not required.

Q9.3 When FortisBC observes that the power flow on a particular transmission path or device is forecasted to exceed the path rating, does it examine opportunities for demand response in particular hours to attempt to defer infrastructure investment? Please explain and, if appropriate, provide specific examples.

A9.3 FortisBC demand-side management is used as a resource management tool to reduce the overall system consumption. In general, it is not applied to reduce the load in a specific area or on a specific path. Given current technology and the level of customer communications (i.e. without the availability of AMI and real-time communications with customers), it would be difficult to provide targeted information that could significantly decrease the transmission path flow on a real-time basis.

Q9.4 Assume for the purposes of this question that FortisBC is only able to upgrade one segment or station of the Okanagan transmission system at a time (with the segments and stations being those set out in response to Part 1 of this question). Please provide a table that shows, in the order in which the segment or station upgrades would be undertaken by FortisBC:

A9.4 Resolution of the capacity constraints in the south Okanagan requires an integrated solution to allow safe and cost effective construction while also minimizing the risk to the system. It is not feasible to separate portions of the project and construct them as independent segments or stations. The project involves upgrades to an existing bulk transmission system that cannot be removed from service for construction purposes. It is not comparable to building a single-site construction project such as a new distribution substation. For example, there is no mobile substation that can be installed to replace the functionality of the R.G. Anderson or Vaseux Lake Terminal stations – the stations must be kept energized at all times with only the minimal equipment removed from service to permit upgrading. Deferring portions of the project will almost certainly increase the overall project costs and/or place a large amount of load at additional risk by removing transmission components from service for extended periods of time.

Some specific examples of the inter-dependent nature of the project can be cited as follows:

- It is not possible to upgrade the R.G. Anderson Terminal to 230-kV operation unless the transmission line from Vaseux Lake is also rebuilt and reinsulated to 230-kV.
- If R.G. Anderson and the transmission line from Vaseux Lake are configured to operate at 230-kV, then Vaseux Lake must be converted to 230-kV as well.
- If Vaseux Lake is converted to 230-kV operation, then it is required to build the Bentley Terminal and up-rate 40 Line as there would no longer be a source of 161-kV supply for Oliver (and there is no space in Oliver for 230/63 kV transformation).
- To allow the connection of the Oliver Station to the 63-kV source at Bentley, then at least one of the Oliver transformers must be removed to allow connection of the incoming 63-kV lines.
- Once Oliver T1 is removed, the Oliver distribution station portion must be constructed to replace the supply source for the Oliver distribution load.

Realistically, the only sub-projects that could be separated or deferred from the overall OTR solution are the capacitor installations at Lee and Bell. However, these are relatively low cost items that reinforce the capacity and thus the reliability of the system at peak times. As well, the capacitors help to reduce system losses at all times by removing the requirement to transport reactive power across the bulk transmission lines.

To reiterate, the Project components are interdependent and several Project segments need to be constructed simultaneously. This is reflected in the Project schedule available in Appendix G (Exhibit B-1-3). For these reasons, FortisBC is unable to provide the table requested.

Q9.4.1 A full description of the upgrade (which the Commission expects would be one of the upgrades proposed in this application, though that is not necessarily the case);

A9.4.1 Descriptions of the upgrades are presented in Section 4 of the Application (Exhibit B-1-1); the references are provided below:

1 - Double-Circuit 230 kV Vaseux Lake to Penticton (75/76 Line)	Page 4, Line 17
2 - Lee Terminal 138 kV Capacitor Upgrade	Page 7, Line 22
3 - Bell Terminal 138 kV Capacitor Upgrade	Page 8, Line 1
4 - RG Anderson Terminal Upgrade	Page 7, Line 10
5 - Vaseux Lake 230 kV Terminal Upgrade	Page 7, Line 1
6 - Vaseux Lake 500 kV Terminal Upgrade	Page 4, Line 17
7 - Single-Circuit 230 kV Vaseux Lake to Bentley (40 Line)	Page 5, Line 5
8 - Bentley to Oliver 63 kV and 138 kV	Page 5, Line 2
9 - New Bentley Terminal	Page 4, Line 24
10 - Oliver Substation Upgrade	Page 7, Line 17

Q9.4.2 The before and after capacities of the segment or station;

A9.4.2 Table A9.4.2 below provides a listing of all transformer and line (winter) ratings associated with the OTR Project. As previously emphasized, the OTR is an integrated solution and that it is not necessarily possible to upgrade specific elements of the transmission system without considering the area transmission system as a whole.

Table: A9.4.2 OTR Project Line and Transformer Ratings

Element	Pre-OTR	Post-OTR	Comments
72/74L	407 MVA	407 MVA	No change
73L	407 MVA	407 MVA	No change
76L	204 MVA	506 MVA	Conversion from 161 kV to 230 kV and conductor change
75L	-	506 MVA	New line
40L	204 MVA	437 MVA	Conversion from 161 kV to 230 kV and conductor change
RGA T1	110 MVA	168 MVA	Currently de-rated to 110 MVA. Can also be up-rated to 180 MVA with additional fans.
RGA T2	138 MVA	-	Relocated to Bentley
RGA T4	-	200 MVA	New transformer to match existing RGA T1
VAS T1	250 MVA	250 MVA	Reconnected to operate at 500/230 kV (presently 500/161 kV)
VAS T2	250 MVA	250 MVA	Reconnected to operate at 500/230 kV (presently 500 / 161 kV)
OLI T1	60	-	Spare – to Grand Forks to backup GFT T1
OLI T2	82	-	To be scrapped
OLI T3	-	20 MVA	New distribution transformer
BEN T1	-	168 MVA	Ex RGA T1 – reconnected to operate at 230 kV
BEN T2	-	150 MVA	New transformer operated at 161 / 63 kV (switchable to 138 / 63 kV)
BEN T3	-	100 MVA	New transformer operated at 138 / 63 kV

Notes:
1. All transformer ratings shown are the nameplate maximum with full cooling.
2. Line ratings shown are thermal only. The actual path rating may be less due to other factors (such as voltage stability following contingencies).

Q9.4.3 The transmission capacity available to feed Penticton and

Kelowna from the north and from the south;

A9.4.3 The response to BCUC IR No.1 Q9.4 above explains that the Project can not be segmented. However, on completion of the Project;:

1. Supply capability available to feed Penticton and Kelowna from the north on completion of the Project in 2010: Technical capacity limit is 499 MVA. Available capacity limit is 330 MVA, subject to agreement between FortisBC and BCTC (see Figure A17.1 in response to BCUC IR NO. 1 Q17.1).
2. Supply capability available to feed Penticton and Kelowna from the south, on completion of the Project in 2010: 430 MVA

Q9.4.4 The improvement in system reliability that would be achieved through the upgrade, assuming that the upgrades listed previously in the table have already taken place. In responding to this part of the question, please describe which of the limitations set out in Section 3.1.2.3 of the Application would be alleviated. Quantitative information (e.g., the reduction in outage hours or the observed change in Figure 3-1-3-5A) should be provided where possible.

A9.4.4 Because, as stated in the response to BCUC IR No.1 Q9.4 above, the Project components must be built concurrently, all of the limitations would be alleviated, as set out in Section 3.1.3.3 of the CPCN Application (Exhibit B-1-1)

Q9.4.5 The contingency level (N-0, N-1, etc.) to which each of the major Okanagan loads would be protected following the upgrade in 2011, 2016, and 2024.

In answering this question, please treat the two 230 kV lines from Vaseux Lake to Penticton (75 Line and 76 Line) as separate projects.

A9.4.5 The table below indicates the system capacity and load hours of vulnerability per year during 2011, 2016 and 2024 at various stages / combinations of system upgrades, with or without: 1) Capacitors, 2) SVC and 3) Double-Circuit Transmission Lines between Vaseux and RG Anderson Terminal Stations.

While approval for the installation of SVC at DG Bell Terminal station is not sought in this Application, the post-OTR contingency compatibilities are included for completeness. The shaded lines refer to the components that are the subject of this Application.

Table A9.4.5: System Capacity and Load Hours not Met

Year	**Stage Definition**		**Contingency Compatibility**					
			N-0		**N-1**		**N-1-1/N-2**	
			System Capacity Limit (MVA)	**Load Cannot be met for (Hrs/Yr.)**	**System Capacity Limit (MVA)**	**Load Cannot be met for (Hrs/Yr.)**	**System Capacity Limit (MVA)**	**Load Cannot be met for (Hrs/Yr.)**
2011	**1.1**	Post OTR without Capacitors & SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	1282	330	1282
	1.2	Post OTR with Capacitor but without SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	1282	330	1282
	1.3	Post OTR without Capacitors & SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	499	2	380	267
	1.4	Post OTR with Capacitor but without SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	562	0	430	42
2016	**2.1**	Post OTR without Capacitors & SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	2.2	Post OTR with Capacitor but without SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	2.3	Post OTR without Capacitors & SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	499	25	380	786
	2.4	Post OTR with Capacitor but without SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	562	0	430	177
	2.5	Post OTR with Capacitors & SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	2.6	Post OTR with Capacitors & SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	658	0	543	3
2024	**3.1**	Post OTR without Capacitors & SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	3.2	Post OTR with Capacitor but without SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	3.3	Post OTR without Capacitors & SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	499	127	380	2112
	3.4	Post OTR with Capacitor but without SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	562	27	430	809
	3.5	Post OTR with Capacitors & SVC and single Tr. Line between VAS-RGA (either 75L or 76L)	830	0	330	2257	330	2257
	3.6	Post OTR with Capacitors & SVC and double Tr. Line between VAS-RGA (75L + 76L)	830	0	658	0	543	35

10.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.1.2.4, pp. 9-10; Section 3.1.3, p. 13; Section 3.4, p. 33

Q10.1 Please provide versions of Figure 3-1-2-4 showing power flows under normal conditions and the most severe N-1 conditions.

A10.1 The requested graph cannot be created since 76 Line cannot be loaded to either its summer (170 MVA) or winter (204 MVA) ratings since it is constrained by the lower capacity ratings of RG Anderson Transformer 2, which are: normal nameplate capacity of 110 MVA and maximum nameplate capacity of 137.5 MVA.

Figure 3-1-2-1C, page 6 of the CPCN Application (Exhibit B-1-1) illustrates that the nameplate capacity of RG Anderson Transformer 2 has already been exceeded.

Q10.2 For each of the years 2010 to 2015, please provide summer and winter flow duration curves for the Vaseux-Penticton transmission path.

A10.2 Please refer to the response to BCUC IR No.1 Q10.1 above.

Also please refer to Figure 3-1-2-1C on page 6, which illustrates that the system network has already hit its limitations due to the peak loading conditions on RG Anderson Transformer 2 which has exceeded both its normal and maximum nameplate capacities during the peak summer and winter load periods of 2006/07.

Q10.3 Please provide an estimate of the EENS if the transmission path from Vaseux to Penticton is built to handle N-1 events rather than N-1-1 or N-2 events. A rough calculation of this value is acceptable if a formal EENS study has not been completed.

A10.3 No EENS study has been undertaken for the OTR Project. However, the transmission path from Vaseux to Penticton cannot be built exclusively N-1 compatible and NOT N-1-1/N-2 compatible. This is because if the OTR Project is constructed with a single Transmission Line between Vaseux and RG Anderson Terminals, i.e., 75 Line or 76 Line, then it will lose both N-1 and N-1-1/N-2 capabilities as indicated in the table below. Please also refer to Table 9.4.5 above. In the following table, the shaded lines refer to the components that are the subject of this Application.

Table: A10.3 Load and Energy Not Met

Year	Stage Definition		Compatibility Status	N-1	N-1- 1 / N-2	Energy that may not be deliverable at N-1 Contingency Scenario (GWh)	Energy that may not be deliverable at N-1-1 / N-2 Contingency Scenario (GWh)
				Load Cannot be met for (Hrs/Yr.)	Load Cannot be met for (Hrs/Yr.)		
2016	**1.1**	Post OTR with Capacitors & SVC and single Tr. Line between VAS-RGA (either 75 or 76L)	N-0	2257	2257	3,662	3,662
	1.2	Post OTR with Capacitors & without SVC and double Tr. Line between VAS-RGA (75+76L)	N-1 & N-1-1 / N-2	0	177	0	158
	1.3	Post OTR with Capacitors & SVC and double Tr. Line between VAS-RGA (75+76L)	N-1 & N-1-1 / N-2	0	3	0	0
2024	**2.1**	Post OTR with Capacitors & SVC and single Tr. Line between VAS-RGA (either 75 or 76L)	N-0	3923	3923	12,652	12,652
	2.2	Post OTR with Capacitors & without SVC and double Tr. Line between VAS-RGA (75+76L)	N-0	27	809	16	1,111
	2.3	Post OTR with Capacitors & SVC and double Tr. Line between VAS-RGA (75+76L)	N-1 & N-1-1 / N-2	0	35	0	36

- **Single Circuit between Vaseux & Penticton:**

1. N-1 / N-2 (2016): Energy may not be deliverable: 3,662 GWh
2. N-1 / N-1-1 & N-2 (2024): Energy may not be deliverable: 12,652 GWh

- **Double Circuit between Vaseux & Penticton without SVC:**

3. N-1 (2016): Energy may not be deliverable: 0 GWh
4. N-1 (2024): Energy may not be deliverable: 16 GWh
5. N-2/N-1-1 (2016): Energy may not be deliverable: 159 GWh
6. N-2/N-1-1 (2024): Energy may not be deliverable: 1,111 GWh

- **Double Circuit between Vaseux & Penticton with SVC:**

7. N-1 (2016 / 2024): Energy may not be deliverable: 0 GWh

8. N-2/N-1-1 (2016): Energy may not be deliverable: 0 GWh
9. N-2/N-1-1 (2024): Energy may not be deliverable: 36 GWh

Q10.4 It appears from Figure 3-1-2-4 that the number of hours in which the Vaseux-Penticton flow will exceed the path rating is likely to be quite small, at least for the first few in-service years for the proposed new line. What efforts, if any, has FortisBC made to address those specific hours through non-wires alternatives such as demand response? Please explain.

A10.4 The Company does not have a demand response program in place to address the specific hours that exceed the path rating, nor is one envisioned at this time.

The Company's existing Demand Side Management initiatives are premised upon resource acquisition, and the primary economic driver is long-term energy savings. Thus Demand Side Management programs are geared to energy conservation measures, although commensurate capacity savings accrue through those measures. Demand Side Management programs are aimed at the distribution level, though there are aggregate effects at the bulk transmission level such capacity savings are not necessarily co-incident to the specific hours in question.

Conservation rate structures, such as Time of Use is a non-wires alternative offered to FortisBC customers (direct and wholesale). Take-up of the Time of Use Rate has been low at best, and again aggregate effects at the transmission level are unlikely to be co-incident with the hours in question.

Q10.5 Please provide a quantitative estimate of the decrement in reliability (preferably in EENS terms) that would result from using the bundled or high-capacity conductor option for the Vaseux Lake to RG Anderson path. This alternative will be defined later in this Information Request as the high capacity single-circuit option that is included in Alternative 1C.

A10.5 To compare the relative reliability of single-circuit versus a double-circuit, the method of "fault tree analysis" has been used. This is a quantitative method to determine the probability of a specified failure event. By combining the unavailability of two or more system elements, an assessment of the unavailability of the overall system can be made. For further details of the method refer to "*Probabilistic Risk Assessment and Management for Engineers and Scientists*", Kumamoto, H., Henley, E.J., 2nd Ed. 1996, IEEE Press, Piscataway, NJ.

To assist in responding to this question, a request was made of BCTC to determine the relative reliability of a double-circuit 230 kV transmission line versus a single-circuit 230 kV transmission lines. BCTC was able to supply forced outage statistics for a 10 year period for a 230 kV double circuit construction very similar to that proposed for the OTR. It was found that, of 15 forced outages involving double-circuit construction, 4 events resulted in an outage to both circuits. In other words, approximately 27% (4/15) of forced events on a double-circuit line will result in the loss of both circuits.

In order to develop the fault tree for the double-circuit failure of both 75L and 76L, the following assumptions have been made:

- each circuit is removed from service for 8 hours on an annual basis for scheduled maintenance,
- a forced outage (typically due to lightning in this area) lasts 2 minutes (this is conservative since in most cases the circuit will successfully auto-reclose after 5 seconds),
- in 27% of the cases a forced outage on one circuit will occur simultaneous with an outage on the adjacent circuit

The probability of a forced outage is based on the WECC 200-300 kV circuit reliability rate of 3.29 outages per 100 miles (2007 WECC Reliability Performance Evaluation Work Group). Thus, for a 28 km circuit an outage rate of 0.572 outages per circuit per year is expected. This closely matches the historical frequency of outages on 76L (one outage every year or two).

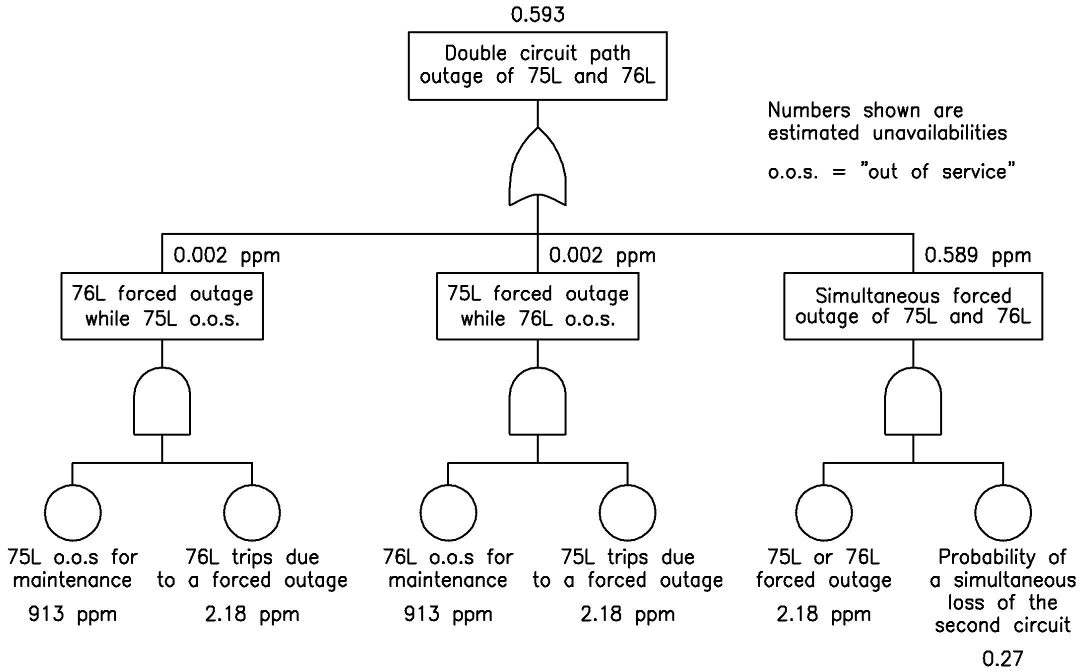
Given the above assumptions, the following annual unavailabilities have been calculated:

Single circuit outage (maintenance): $\dfrac{8\,\text{hrs}}{8{,}760\,\text{hrs}} = 913\,\text{ppm}$

Single circuit outage (forced): $\left(\dfrac{2\,\text{min}}{525{,}600\,\text{min}}\right) \cdot 0.572 = 2.18\,\text{ppm}$

Note: (ppm = parts per million)

From these unavailability estimates, the following fault tree was developed:



From the above fault tree, the unavailability of the top level event (a path outage resulting from the simultaneous loss of 75L and 76L) is 0.593 parts per million. A comparison with the expected unavailability of a single circuit option is summarized in the Table A10.5 below:

Table: A10.5 Estimated Outage Probabilities

Contingency	**Unavailability**
Double-circuit path outage	0.593 ppm
Single-circuit path outage (forced)	2.18 ppm
Single-circuit path outage (maintenance)	913 ppm

Thus, the availability of the double-circuit option proposed in the OTR is 3.7 times greater than a single-circuit option (in terms of forced outages). The double-circuit option is 1540 times more available than a single-circuit (in terms of maintenance outages). Clearly, the double-circuit construction offers a significant improvement over a single-circuit construction, and on this basis it is the proposed configuration in the OTR Application.

Q10.6 Please elaborate on the statement that maintenance outages will be "challenging," providing quantitative answers where applicable.

A10.6 This statement refers to the fact that removing the single high-capacity circuit from service would be the equivalent to removing both the 75 Line and 76 Line circuits (given that the recommended configuration in the Application is a double-circuit). This would place the system in contingency equivalent to an N-2 state (again, as compared to the proposed configuration). If a subsequent forced outage occurred during the maintenance outage, the system would be exposed to load loss.

Thus, the windows during which the high-capacity circuit could be removed from service would be significantly shorter than that for removing only one line of double-circuit transmission line. Since some maintenance operations require a significant amount of time (i.e. replacing broken insulators, maintaining line disconnect switches, etc.), the system would be relatively more exposed to outages compared to the recommended double-circuit configuration.

Q10.7 In the context of the transmission system in the Okanagan, the load duration curve for the area, and the ages of the transmission facilities, please explain the extent to which maintenance outages can be scheduled in low demand periods, so that the N-1-1 criteria is not a material constraint.

A10.7 Planned maintenance outages are scheduled in low demand periods to the extent possible in order to minimize customer interruptions. Unfortunately, some types of maintenance outages are not always able to be scheduled during periods of low load. Two examples that can be cited are insulator replacements or line disconnect-switch maintenance.

Insulators with broken bells or sheds can be encountered and discovered at any time, and if severe enough can require priority replacement (to prevent an insulator string failure).

High-resistance jaw connections in line disconnect switches can also occur without warning and are usually detected by infrared inspection. Again, if severe enough, this type of problem may require advancement of maintenance schedules.

Q10.8 What is the origin of the “close to 100%” target for N-1-1/N-2 security to the Kelowna-Penticton area for 2010, and the “nearly 90% levels” during 2024?

A10.8 The origin of the statement “close to 100%” and “nearly 90% levels may be found in Table A10.8 below. Please note, the statement “nearly 90% levels” should read “approximately 90% levels” in 2024:

Table: A10.8

Year	**Post OTR: Expected N-1-1 / N-2 Contingency without SVC**		
	Yearly Incompatibility	**Yearly Compatibility**	**% Yearly Compatibility**
	Hours per Year	**Hours per Year**	**% Hourly**
2010	32	8728	99.6%
2011	47	8714	99.5%
2012	61	8699	99.3%
2013	87	8674	99.0%
2014	112	8648	98.7%
2015	145	8616	98.4%
2016	177	8583	98.0%
2017	230	8531	97.4%
2018	282	8478	96.8%
2019	341	8420	96.1%
2020	399	8361	95.4%
2021	502	8259	94.3%
2022	604	8156	93.1%
2023	707	8054	91.9%
2024	809	7951	90.8%

11.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.1.3.4, pp. 17-18

Q11.1 Please describe the current lightning protection for 72 Line and 74 Line, and explain whether changes to that protection could reduce the number of simultaneous outages caused by lightning.

A11.1 The only existing lightning protection for 72 Line and 74 Line are short lengths (up to approximately 500 metres) of shield wire installed at the line terminals. This shielding is provided to protect substation equipment from nearby lightning strikes.

Overhead transmission shield wires (earth wires) are rarely used in BC due to problems with high ground resistivity which results in excessive tower-footing ground resistance. This reduces the effectiveness of shield wires against lightning protection. The only way to reduce the tower footing resistance is to bury a continuous counterpoise along the length of the transmission line. This can be very costly depending on the prevailing terrain.

Q11.2 Many of the simultaneous lightning-related outages lasted less than one minute. Please describe the impact on customers of these events.

A11.2 With modern electronic equipment, a short outage (< 1 minute) can be just as disruptive in some cases as a longer duration outage.

An example is the widespread use of high-intensity discharge lighting outdoors for street lighting and indoors for large areas such as arenas, shopping malls, warehouses, etc. These lamps require a cool-down period following a power outage before the lamp can re-strike. This interval can take several minutes. During this time there is little to no light emitted. Compounding matters is the fact that since power has been restored any emergency lighting is automatically extinguished. Thus, even momentary outages can be troublesome during hours of darkness or where natural lighting is not available.

Computer equipment that is not protected with uninterruptible power supplies (UPSs) will also be disrupted and suffer data losses for outages lasting more than a few seconds.

Traffic light controllers can often be reset by momentary outages and revert to four-way flashing mode. If many signals in a large urban area revert to this fault mode, it can be very disruptive to traffic flow until the controllers are manually reset.

Q11.3 Please describe the events leading to the simultaneous loss of 2L255 and 2L256 due to loss of supply.

A11.3 There are five events listed in Table 3-1-3-4 of the CPCN Application (Exhibit B-1-1) attributable to the simultaneous loss of 2L255 and 2L256. Those events are further summarized in Table A11.3 below as follows:

Table A11.3: Simultaneous Outage Events for 2L255 and 2L256

Event Date/Time	Cause
7/5/1997 5:03:00 PM	Teleprotection problem during 500 kV fault (problem subsequently fixed)
7/8/2000 5:05:49 PM	Lightning strike tripped both 2L255/2L256
7/20/2000 6:39:12 PM	Teleprotection problem during 500 kV fault (different than 1997 outage)
3/3/2006 1:38:30 PM	Human error
6/29/2007 3:56:43 PM	Ashton Creek 500/230 kV transformer protection misoperation (initial event was a lightning strike on a BCTC 500 kV line)

Q11.4 Assuming that an OTR-like project completed in 1997 had eliminated all of the simultaneous outages on 72 Line and 74 Line, what level of improvement would have been achieved in end-use customer reliability, as measured by SAIDI, SAIFI, and CAIDI, considering that customers may be affected by generation, transmission, and distribution outages?

A11.4 Assuming that an OTR-like project had been completed in 1997 eliminating outages due to simultaneous failures of 72 Line and 74 Line, then the 13 associated customer outages would not have occurred. A copy of Table 3-1-3-4 from the CPCN Application (Exhibit B-1-1) is provided in the response to Q8.4.

This above hypothetical project would have improved yearly the SAIDI, SAIFI and CAIDI indices for the affected years (as indicated in Table A11.4 below) as follows:

Table: A11.4 Impact on Reliability Statistics of 1997 "OTR" Project

Year	SAIDI	SAIFI	CAIDI
1997	1.157	2.188	0.529
2000	0.075	1.199	0.063
2002	0.002	0.430	0.006
2004	0.002	0.429	0.005
2006	0.265	0.430	0.617
2007	0.306	0.450	0.679

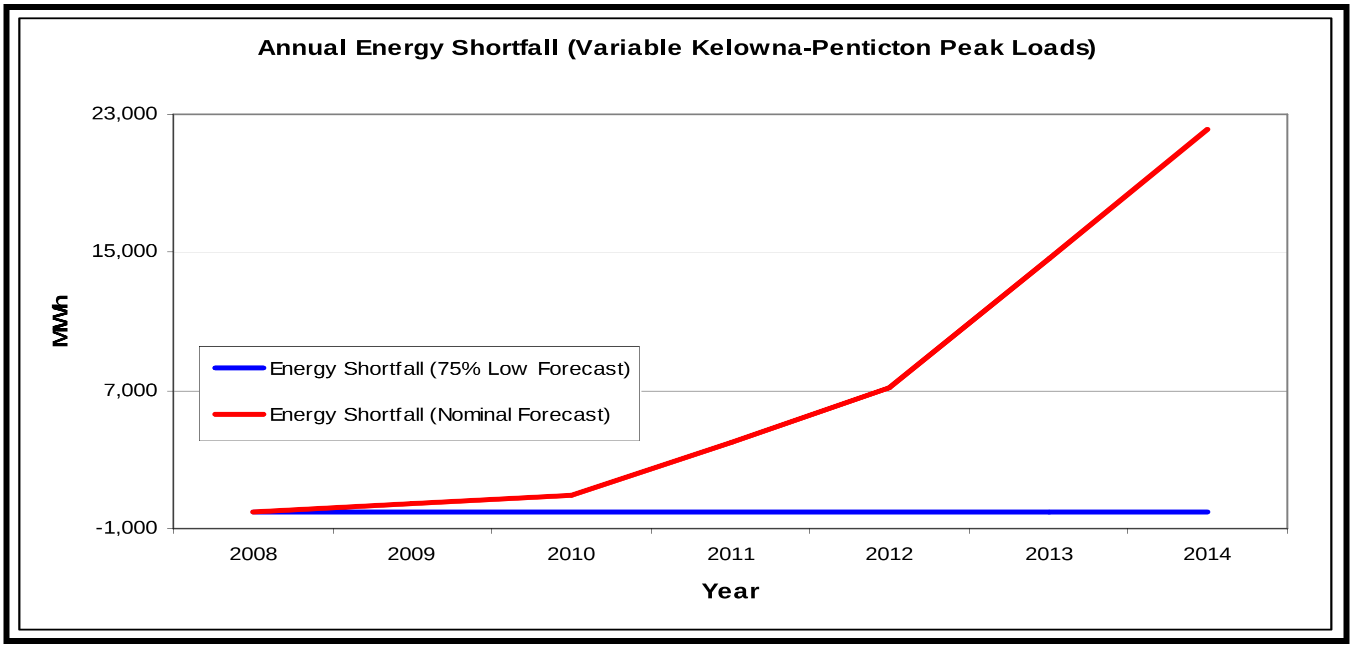
12.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.1.3.5 (Contingency Analysis), p. 19

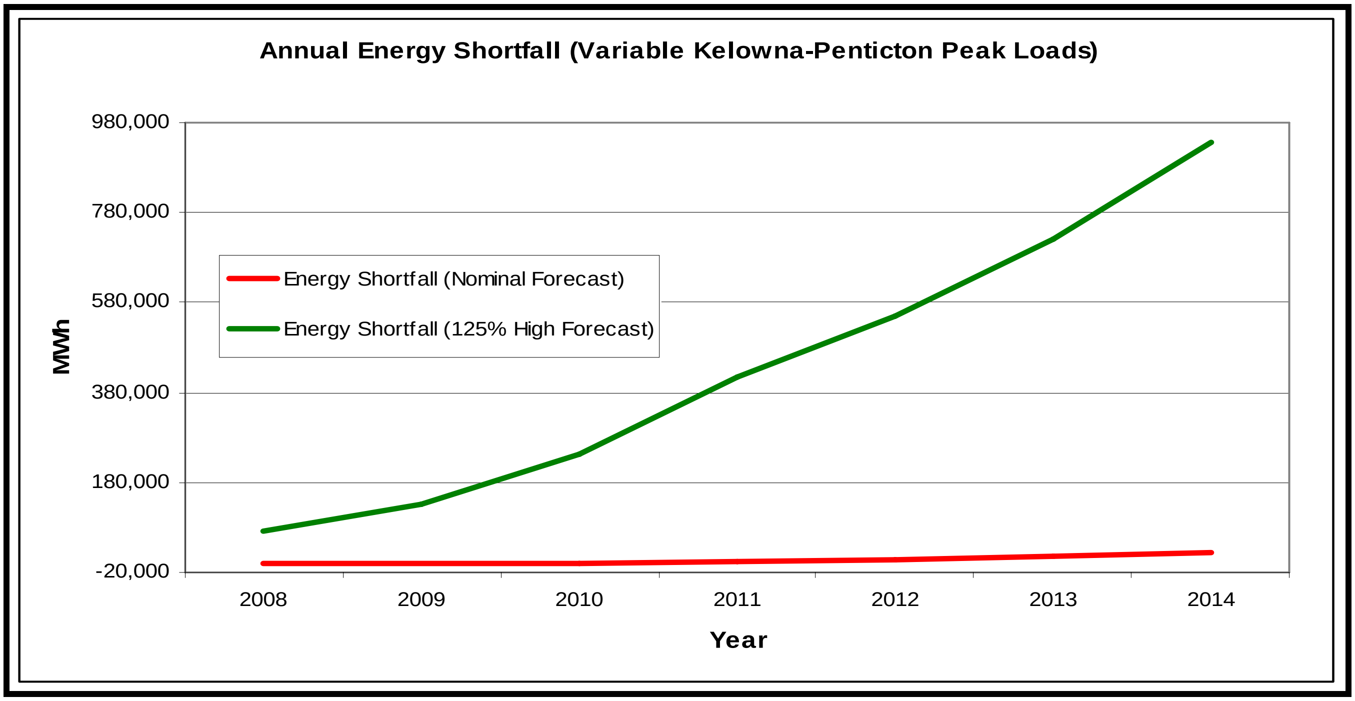
Q12.1 Please provide additional versions of Figure 3-1-3-5A, focused on the years 2008 through 2014, assuming that load growth is 25 percent less than what FortisBC currently expects, and then assuming it is 25 percent more than what FortisBC expects.

A12.1 The relevant figures are provided below:

Figure: A12.0 (a)



1 **Figure: A12.0 (b)**



13.0 Reliability Planning Criteria

Reference: Exhibit B-1-1, Tab 3, Section 3.3 (Project Priority), pp. 31-33

Q13.1 Please describe the events following which it would “not be possible to restore the entire system back to normal,” and provide an assessment of the likelihood of each.

A13.1 This statement is simply referring to the fact that, after a major contingency, there simply would not be enough available transmission capacity to meet all customer load; hence, blackouts and/or rotating outages would result.

The initiating events would generally be the loss of one or more transmission lines or terminal station transformers. In 2007, the WECC Reliability Performance Evaluation Work Group performed a survey to determine the outage reliability for high voltage transmission lines and transformers. This report gives the following outage probabilities as shown in Table A13.1 below. These statistics are supported by FortisBC historical experience.

Table A13.1: Outage Probabilities

Equipment	Outages per year
Transformers (230 / 345 kV)	0.22
Transmission lines* (200 - 300 kV)	3.29 per 100 miles
* - with no overhead ground wires	

Q13.2 How long would it take to complete the necessary corrective actions to RG Anderson T1? What would the cost be, and what would then become the next “bottleneck”?

A13.2 It would require approximately a one month outage to restore RG Anderson Transformer 1 to its full nameplate rating. This would involve: removing the transformer oil, entering the main tank to reconnect and reinsulate the affected connection, and then refilling the transformer with oil. The cost to complete this work is estimated at $150,000.

Even if RG Anderson Transformer 1 is restored to full capacity, the existing bottleneck of RG Anderson Transformer 2 (maximum rating of 137.5 MVA when operated at 161 kV) would remain.

Q13.3 Please provide a detailed explanation of the voltage collapse that will occur by 2010/2011. Will the addition of reactive compensation in the Kelowna area address the potential for voltage collapse?

A13.3 Voltage collapse is generally characterized by the loss of a stable operating point as well as by the deterioration of voltage levels in and around the electrical center of the region undergoing voltage collapse. It commonly occurs as a result of reactive power deficiency. Following a system contingency the Okanagan transmission system is subjected to a sudden increase of reactive power demand. The loading on the remaining lines increases. This increases the reactive power losses in the remaining lines (reactive power absorbed by a line increases rapidly for loads above surge impedance loading), thereby causing a heavy reactive power demand on the system and eventually leads to a voltage collapse due to the unavailability of reactive resources in the area.

Without removing the capacity bottleneck of RG Anderson Transformer 2 provision of just additional reactive compensation in Kelowna will not address the voltage collapse issue.

14.0 Assessment of System Needs

Reference: Exhibit B-1-1, Tab 3, p. 7; Tab 4, p. 34; Exhibit B-1-2, Appendix C, Transmission Line Design, pp. 13, 16; Exhibit B-1-3, Appendix G, Tables G1, G3, G4

Q14.1 The Application at Tab 3, page 7 states that the existing 161 kV line from Vaseux Lake to RG Anderson has a capacity of 170 MVA (summer)/204 MVA (winter). Appendix C at page 13 states that the double circuit conductor will be 604.3 mm^2 45/7 "Bunting" (1192.7 kcmil). What is the capacity in MVA of each of the proposed circuits between Vaseux Lake and RG Anderson?

A14.1 The rating of the proposed circuits between Vaseux Lake Terminal and RG Anderson Terminal is 904 amperes (360.1 MVA) summer and 1,270 amperes (505.9 MVA) winter.

Q14.2 Please explain how FortisBC determined that the capacity of the proposed 230 kV circuits was optimal.

A14.2 The rating of the proposed 230 kV circuits was based on providing adequate capacity during single contingency conditions over the current twenty-year planning horizon. Please also see the response to BCUC IR No.1 Q8.2.

Q14.3 The British Columbia Transmission Corporation Vancouver Island Transmission Reinforcement Project ("VITR") is for a single 230 kV circuit with a capacity of 600 MW. Further to the reference in subsection 3.1.2.4 to a bundled conductor, please describe the design of a single 230 kV circuit between Vaseux Lake and RG Anderson that would have approximately the same capacity as the two proposed circuits. If the high

capacity circuit would not have a capacity of approximately 600 MVA, please explain.

A14.3 The design of the high capacity 230 kV circuit between Vaseux Terminal and RG Anderson Terminal ("Alternative C") is for steel pole H-frame construction with a single 1,590 kcmil 45/7 Lapwing conductor, continuous two wire overhead groundwire and associated buried counterpoise.

For the groundwire to be of benefit for lightning protection, the estimate includes a complete two wire buried ground (counterpoise) system to reduce ground resistance to approximately 10 ohms or less at each site.

A majority of the poles would be direct bury, with only a few long span structures requiring foundations equivalent to those required for the double circuit steel pole structures.

The required conductor rating has been identified as 1,850 A, winter. Lapwing conductor has an ampacity of 1,925 A at 10°C ambient, 100°C conductor temperature. The summer rating with Lapwing will be less, approximately 1,500 A at 40°C ambient, 100°C conductor temperature.

For 230 kV, a 600 MVA capacity at 1.0 power factor results in a conductor current of 1,500 A. Therefore, both under summer and winter operating conditions, the Lapwing conductor provides the necessary capacity.

A similar configuration using a bundled rather than single conductor was also considered. A two bundle 618 kcmil conductor would provide roughly the same ampacity as the single Lapwing. For the same number of structures, the height will be 3 to 5 m less in some but not all instances.

Q14.4 Please identify what FortisBC considers would be the optimal capacity for a high capacity single 230 kV circuit between Vaseux Lake and RG Anderson, and explain why. (In this Information Request, such a circuit will be referred to as a "high capacity single circuit", and the OTR Project incorporating this option will be referred to as "Alternative 1C".)

A14.4 The conductor size that has been studied for this option is 1,590 kcmil ACSR "Lapwing" with a rating of approximately 1850 A. This is based on the revised 2007-08 load forecast which shows the 2026 winter peak load for Kelowna and Penticton is 650 MVA. To supply this load during emergency conditions (the outage of both Lee to Vernon circuits) the flow is 1,665 A. Assuming that the transmission line will be allowed to be loaded to 90% of its winter emergency rating the required rating for the new Vaseux Lake-RG Anderson single circuit line is 1,665/0.9 = approximately 1,850 A.

It should be noted that while this conductor has been selected based on the projected load requirements, FortisBC does not consider this an optimal solution given: a) the import constraints from the BCTC Vernon Terminal (330 MW limit) coupled with b) the inherent unreliability of a single circuit between RG Anderson and Vaseux Terminal stations compared to a double-circuit.

Q14.5 Please provide a cost estimate in the form of Tables G1, G3, and G4 for the OTR Project with a high capacity single circuit between Vaseux Lake and RG Anderson. Please assume that the high capacity single circuit will be built on H-frame structures similar to those shown as Cross Section B on page 34 of Tab 4, similar to the design for the line from Vaseux Lake to Bentley.

A14.5 The cost estimate for Alternative 1C is provided in Tables 14.5(a), 14.5(b), and 14.5(c), at a planning level cost estimates (+35 / -20%).

Estimates include planning, environmental, consultation, properties, engineering, project and construction management, procurement, construction and commissioning for:

Bentley Terminal Station (BEN):

This component requires the construction of a new station at Oliver, BC adjacent to the existing Oliver Terminal station to connect 230 kV from Vaseux Terminal station to 63 kV for the local load, a 161 kV tie line to the FortisBC system at Warfield and a 138 kV line to Keremeos and Princeton.

RG Anderson Terminal Station (RGA):

The existing station is built to 230 kV standards and part of it is operated at 230 kV for a line north from Kelowna. The reminder is operated at 161 kV and requires conversion to 230 kV operation. This conversion involves adding two 230 kV, 2000A dead tank circuit breakers, replacement of the existing Transformer 2 with a new 230/63/25 kV auto power transformer; adding a 63 kV, 2000A dead tank circuit breaker to split 63 kV bus; and two 63 kV , 15 Mvar capacitor banks.

Vaseux Lake Terminal Station (VAS):

The low voltage portion of Vaseux Lake terminal station is operated at 161 kV. This segment requires its complete conversion to 230 kV plus addition of independent transformer switching. In order to make this conversion additional equipment is required which includes: One 230 kV circuit breaker, two 230 kV motor operated disconnect switches, conversion of three 230 kV capacitive voltage transformers (CVTs), five sets of three 230 kV surge arresters and related civil, electrical, protection and control works. One existing 230 kV circuit breaker will be relocated to a new transformer switching position and the new 230 kV circuit breaker, an independent pole operated breaker will be used on

76 line for single-pole-reclose functionality.

On the high voltage portion of the station one new 500 kV circuit breaker and associated motor operated disconnect switches and CVT and will be installed for independent transformer switching.

Oliver Terminal Station (OLI):
Oliver Terminal station presently connects 161 kV to 63 kV and 138 kV plus a small 13 kV distribution station. In this component the major transformation is to be removed, converting to a 63 kV switching station plus a new 63-13 kV distribution station.

FA Lee Terminal Station (LEE):
An addition of a 30 MVAR, 138 kV shunt capacitor bank and related switching equipment.

DG Bell Terminal Station (BELL):
An addition of a 30 MVAR, 138 kV shunt capacitor.

VAS to RGA 230 kV Transmission Line, High Capacity Single Circuit Steel Poles:
The new transmission line to replace the existing 161 kV single circuit will be comprised of a high capacity single circuit H-Frame 230 kV AC transmission lines from Vaseux Lake Terminal station (VAS) near Okanagan Falls to RG Anderson (RGA) Terminal station in Penticton. The existing ROW will be used for this work. The length of the transmission line would be approximately 28 kilometres including reconstruction of the 1.7km section from Vaseux that was pre-built for lower capacity 230 kV operation.

Vaseux Lake Terminal station to New Bentley Terminal station 230 kV Alternative Circuit Transmission Line, Single Circuit Steel Poles:

The new transmission line to replace the existing 161 kV single circuit will be comprised of single circuit 230 kV transmission lines from Vaseux Lake Terminal station to the new Bentley Terminal station. The length of the transmission line would be approximately 11 kilometres, less the 1.7km section of line from Vaseux that was pre-built for 230 kV operation.

63 kV, 138 kV, and 138 kV Re-Termination Work presently into Oliver Terminal station but moving to the new Bentley Terminal station:

The work involves the re-termination of existing transmission lines into the new Bentley Terminal station.

Contingency

Project contingency is at 17% on all engineering, procurement, construction and project and construction management services.

Inflation

Estimates are based on May 2007 dollars. Project Inflation for civil, substation and transmission components will increase at 6% for the remainder of 2007 and 5%, 5%, 4%, 3% and 3% years 2008, 2009, 2010, 2011 and 2012 respectively.

Basis of Pricing

The pricing is based on historical costs, previous purchase orders and installation tenders for other similar projects received from supplier(s) and installation contractors.

Please see Tables A14.5 (a), A14.5 (b), and A14.5 (c) below. Note, costs of components in Tables A14.5 (a), (b), and (c) unaffected by single circuit option will differ from same components in Tables G1, G3, and G4 in Appendix G of the CPCN Application. Please see the response to BCUC IR No.1 Q30.1.

Table: A14.5 (a)

Okanagan Transmission Reinforcement Project
Estimate Summary #1C 2010

	2007	2008	2009	2010	Total
			($ 000s)		
Single Heavy Circuit 230kV Vaseux to Penticton (75/76 Line)		4,402	22,009	17,607	44,018
Single Circuit 230kV Vaseux to Bentley (40 Line)		471	2,353	1,882	4,705
63 & 138kV Circuits Bentley to Oliver		69	347	278	694
New Bentley Terminal		3,205	16,023	12,818	32,046
Oliver Substation Upgrade		588	2,940	2,352	5,881
RG Anderson Terminal Upgrade		1,233	6,164	4,931	12,328
Lee Terminal 138kV Capacitor Upgrade		173	866	693	1,732
Bell Terminal 138kV Capacitor Upgrade		168	839	671	1,677
Vaseux 230kV Terminal Upgrade		209	1,046	837	2,092
Vaseux 500kV Terminal Upgrade		293	1,464	1,171	2,928
Planning & Preliminary Engineering	3,972	1,391			5,363
Project Management, Engineering & Operations Support		347	1,735	1,388	3,470
Sub Total	3,972	12,548	55,785	44,628	116,933
AFUDC		615	2,665	5,677	8,957
Removals & Salvage			1,193	2,783	3,976
TOTAL	3,972	13,163	59,643	53,089	129,866

Table: A14.5 (b)

Transmission Line Estimates #1C 2010
($000s)

	Single Heavy Circuit 230kV Vaseux to Penticton (75/76	Single Circuit 230kV Vaseux to Bentley (40 Line)	63 & 138kV Circuits Bentley to Oliver	Total
		($ 000s)		
Engineering	630	162	75	867
Materials	7,710	1,391	163	9,264
Construction Overhead Transmission	20,267	1,496	235	21,998
Commissioning	32	13	4	49
BCH EPCM Services	4,716	504	79	5,299
Sub Total	33,356	3,565	556	37,477
Contingency	5,480	586	91	6,157
Inflation	5,182	554	47	5,784
Total	44,018	4,705	694	49,418
Removals & Salvage	1,177	400		
Contingency	193	66		
Inflation	183	62		
Total	1,553	528		

Table: A14.5 (c)

Stations & Terminals Estimates #1C 2010
($000s)

	New Bentley Terminal	Oliver Substation Upgrade	RG Anderson Terminal Upgrade	Lee Terminal 138kV Capacitor Upgrade ($ 000s)	Bell Terminal 138kV Capacitor Upgrade	Vaseux 230kV Terminal Upgrade	Vaseux 500kV Terminal Upgrade	Total
Engineering	1,749	562	586	276	276	464	336	4,250
Equipment	7,334	1,210	3,863	301	296	247	797	14,048
Materials	4,740	896	1,511	202	202	189	391	8,131
Construction	6,208	881	1,740	253	221	385	599	10,287
Commissioning	819	278	321	95	95	75	133	1,816
BCTC EPC Services							172	172
BCH EPC Services	3,433	630	1,321	186	180	224		5,974
Sub Total	24,283	4,456	9,341	1,312	1,271	1,585	2,428	44,678
Contingency	3,990	732	1,535	216	209	260	348	7,289
Inflation	3,773	692	1,451	204	197	246	152	6,716
Total	32,046	5,881	12,328	1,732	1,677	2,092	2,928	58,683
Removals & Salvage		1,436						
Contingency		236						
Inflation		223						
Total		1,895						

Q14.6 If future expansion of the system is a concern, please discuss how FortisBC could expand a configuration consisting of a high capacity single 230 kV circuit. In the discussion, please address both the construction in the future of a second circuit on H-frame structures similar to Cross Section D, and the use of single two-circuit poles (Cross Section C) with only one circuit installed at this time.

A14.6 If future expansion were to be necessary, the construction of a future second circuit would require:

- If using the H-Frame single circuit structure option the construction of an additional line in the future would require the widening of the right of way by approximately 10 meters. This is providing placement of the proposed line could accommodate being located as close as possible to one side of the current right of way as shown in cross section D Figure 4-3-1B on Section 4, page 34 of the CPCN Application (Exhibit B-1-1).

- In order to accommodate an additional line in the future using the single pole configuration shown in cross section C Figure 4-3-1B on Section 4, page 34 of the CPCN Application (Exhibit B-1-1).FortisBC would construct the structures as shown and only install one circuit at this time with the additional circuit being installed when needed.

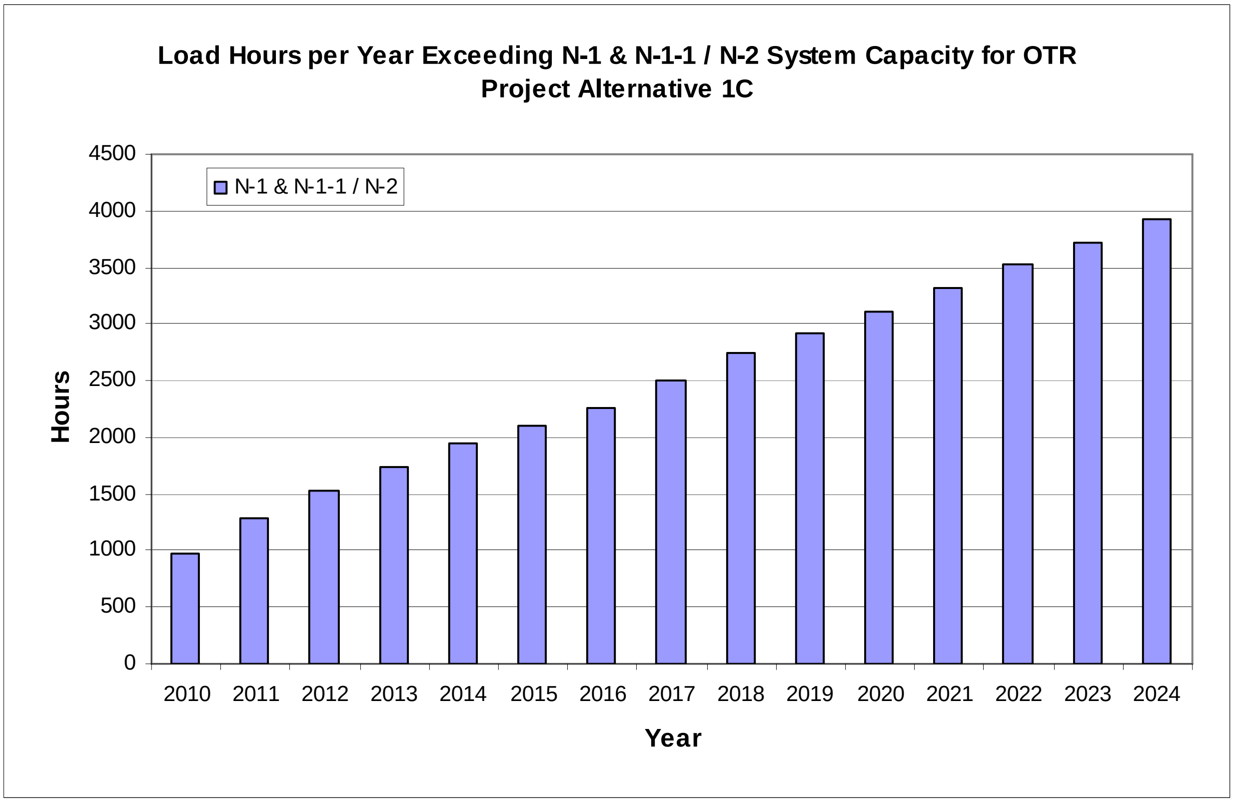
15.0 Assessment of System Needs

Reference: Exhibit B-1-1, Tab 3, p. 7-20

Q15.1 Please reproduce Figure 3-1-2-3 assuming 76L is rebuilt as a high capacity single circuit between Vaseux Lake and RG Anderson, and explain when such a system would need to be expanded to meet N-1 reliability requirements.

A15.1 It is important to note that a single high-capacity circuit would not be N-1 compliant even at the in-service date of the project. This is because an outage of this circuit (an N-1 event) would require supplying the entire Kelowna and Penticton load from the Vernon Terminal supply. Since the peak load for this area already significantly exceeds the import limit at the Vernon point of delivery, there would be a requirement for load shedding following an N-1 outage to avoid exceeding the limit. The load shedding exposure will grow over time as the area load continues to increase. This is shown graphically in Figure A15.1below.

Figure A15.1

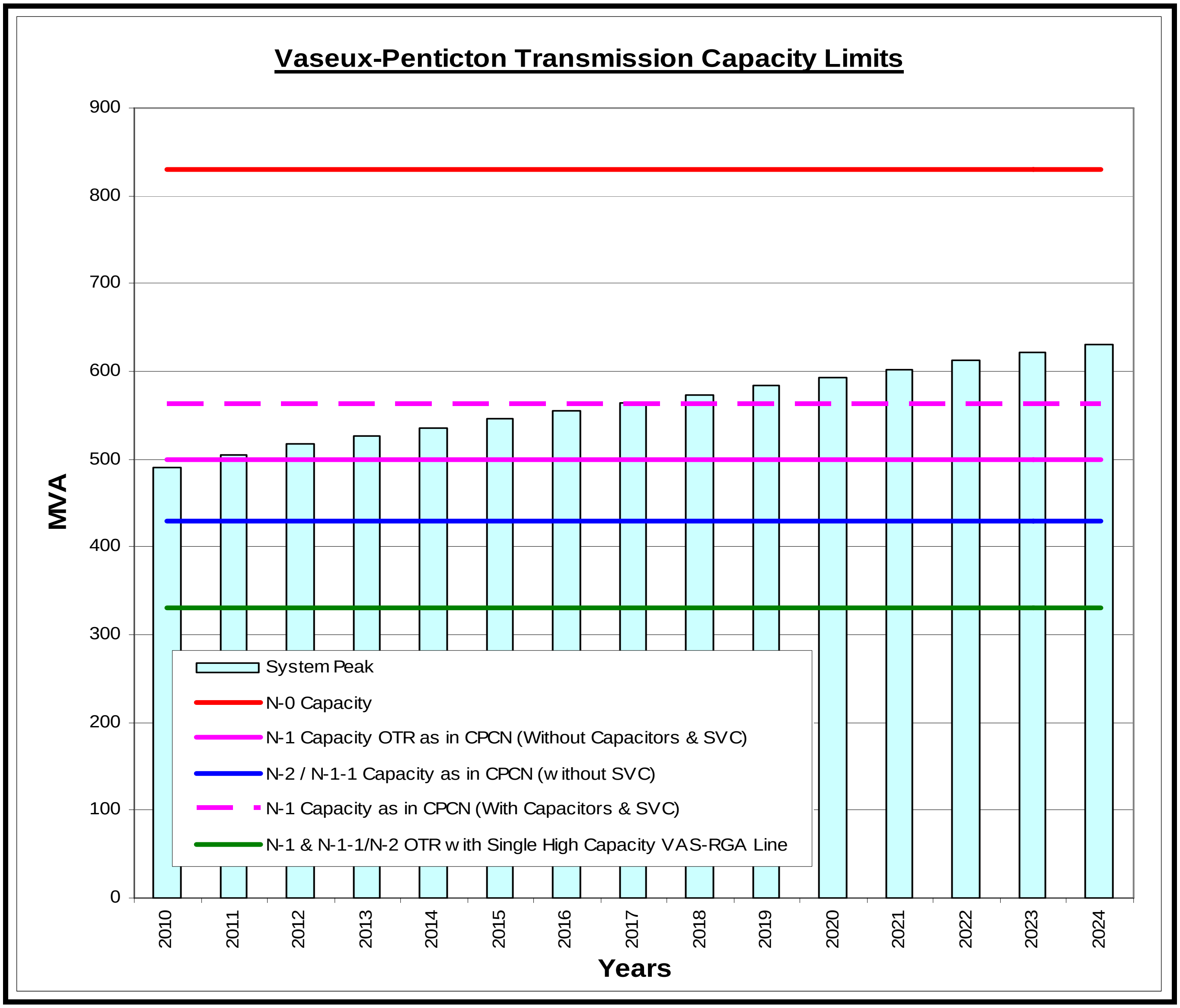


There would be an immediate requirement to add additional transmission capacity to meet N-1 compliance. Hence, a single high-capacity circuit is not considered technically viable.

Q15.2 Please reproduce Figure 3-1-2-4, and explain when a system that included 76L rebuilt as a high capacity single circuit would need to be expanded to meet N-2 criterion.

A15.2 In addition to being non-compliant with the N-2 criterion, a high-capacity single circuit would not even meet N-1 compliance (as discussed in the response to BCUC IR No.1 Q15.1). There would be an immediate requirement to add additional transmission capacity to meet both N-1 and N-2 compliance. A comparison between the proposed OTR solution and a single high-capacity circuit option are shown graphically in Figure A15.2.

Figure A15.2



Q15.3 If the responses to the two previous questions do not assume that the high capacity single circuit has a capacity of approximately 600 MVA, please repeat the questions assuming a capacity of 600 MVA for the high capacity single circuit.

A15.3 The capacity of the high-capacity single circuit is not relevant; when the single circuit is not available the area peak load would still exceed the import capacity limit at the Vernon interconnection. Refer also to the response to BCUC IR No.1 Q15.1

The thermal capacity of a conductor does not necessarily indicate its load delivery capability when placed in an electricity transmission and distribution network. The load delivery capacity of a conductor is a function of the 1) conductor capacity; 2) system load characteristics; and 3) system parameters and configuration at any specific time.

Q15.4 Further to the statement on page 10 that losing a high capacity single circuit line would be equivalent to a double contingency on the proposed Vaseux Lake to RG Anderson configuration, please use the discussion in Section 3.1.3.4 and the information in Table 3-1-3-4 to explain why a double circuit is significantly superior to a high capacity single circuit. Please include a discussion of applicable WECC reliability criteria and actual outage experience on transmission systems in the FortisBC area.

A15.4 A double circuit may not always be superior to a single circuit and each must be assessed on a case by case basis. While double-circuit transmission is not a perfect construction (compared to two single circuits with diverse routes), the process of obtaining additional right of way to install a separate circuit is often prohibitive. In addition to property costs there are also many issues which arise including land use, tenures and environmental impacts which make acquisition of an additional right of way both a costly and extended undertaking.

It is common utility practice to install multiple circuits on the same tower when faced with the need to increase transmission capacity. There are many double-circuit 230 kV transmission lines in the Lower Mainland/Vancouver Island portions of the BCTC system where land issues also place constraints on obtaining additional rights-of-way.

Additionally, although the magnetic fields from both the proposed single-circuit and double-circuit configurations will be within the ICNIRP guidelines, the double-circuit configuration further reduces the magnetic fields over that of a single circuit.

Please see the response to BCUC IR1 Q10.5 for a discussion of the relative reliability of double-circuit versus single-circuit construction.

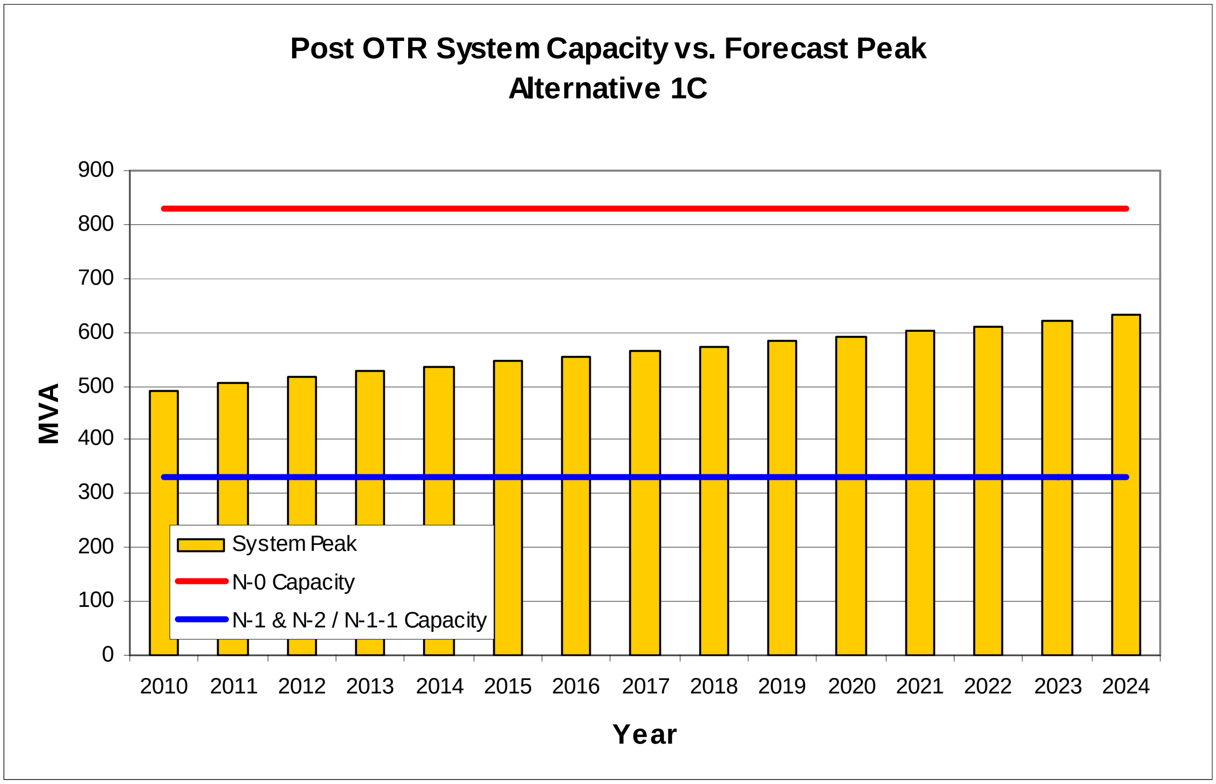
Q15.5 Please provide an update to Figure 3-1-3-5B assuming that the OTR Project goes into service as proposed.

A15.5 This information is provided in Section 3, Figure 3-6B on page 37 of the CPCN Application (Exhibit B-1-1).

Q15.6 Please repeat the previous question, assuming that the OTR Project goes ahead as proposed, but with a high capacity single 230 kV circuit between Vaseux Lake and RG Anderson.

A15.6 Please see Figure A15.6 below. As noted, Alternative 1C is not N-1 compliant.

Figure A15.6



Q15.7 Please confirm that a high capacity single circuit will fulfill the first three "must" requirements on page 33 of Tab 3, and explain why requirement four (N-1-1/N-2 security) is a "must" requirement.

A15.7 A high capacity single circuit would not meet requirement 3 (repeated here for clarity):

> "3. Provide a high level of single contingency (N-1) supply security to the Kelowna-Penticton area for outages on 72 Line, 73 Line, 74 Line, 76 Line, or the proposed 75 Line;"

A high-capacity single circuit would be the same as combining 75 Line and 76 Line into a single circuit. As discussed in Section 3.1.2.4.b of the Application, the loss of this theoretical single high-capacity circuit would be equivalent to an

N-2 scenario in the proposed OTR solution. As shown in Figure A15.6 of the previous response, this N-1 contingency would not meet FortisBC planning criteria or industry-accepted (NERC/WECC) standards at the in-service date of the Project.

The fourth requirement is included on the basis that FortisBC feels that it is unacceptable for an urban area such as Kelowna to continue to be exposed to major outages (which have historically occurred at the rate of one to two per year for the last ten years).

16.0 Assessment of System Needs

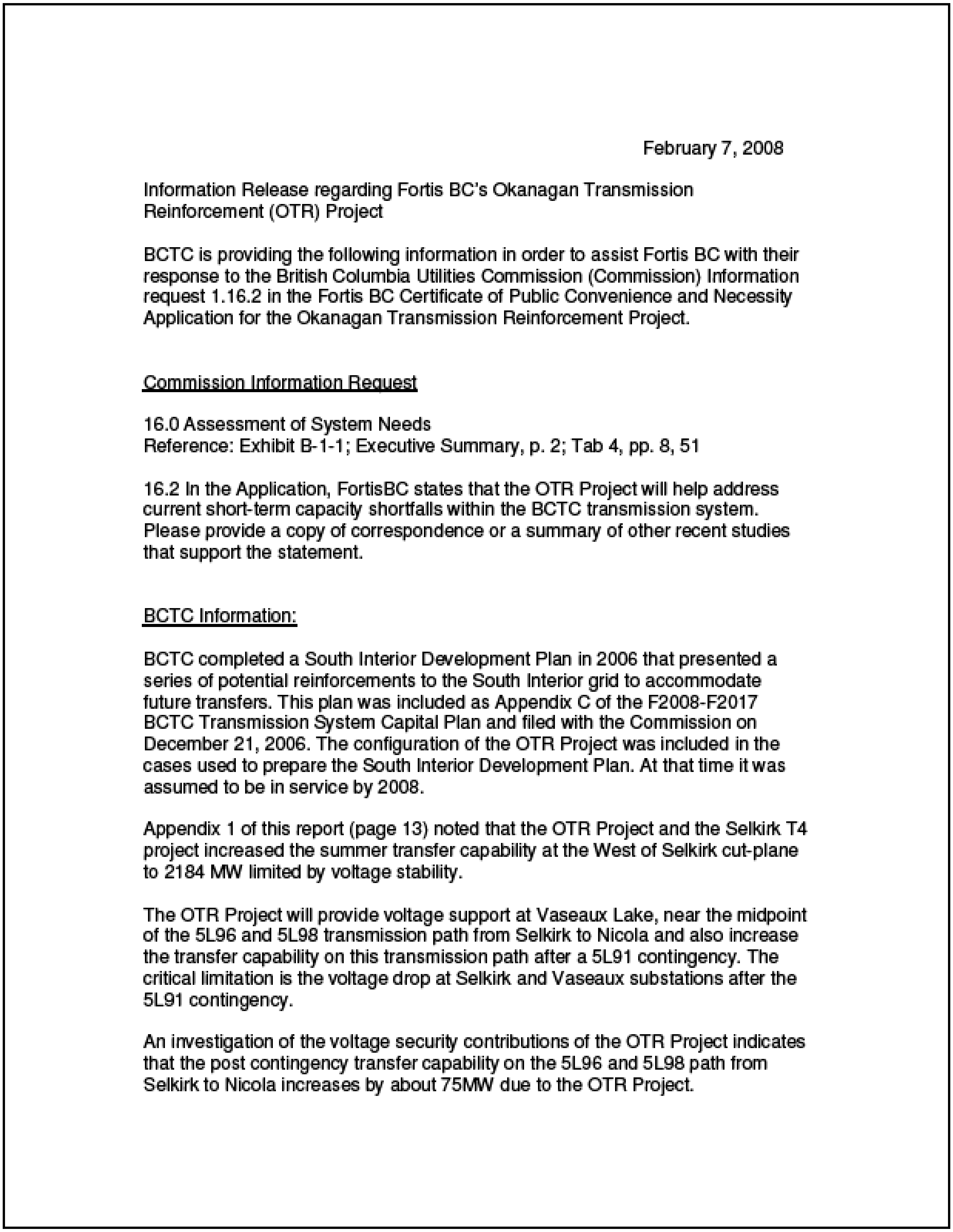
Reference: Exhibit B-1-1; Executive Summary, p. 2; Tab 4, pp. 8, 51

Q16.1 Please provide copies of the Okanagan System Impact Study and BCTC's South Interior Bulk System Development Plan.

A16.1 The requested documents are attached as Appendix 16.1a (Okanagan System Impact Study) and Appendix A16.1b (South Interior Bulk System Development Plan).

Q16.2 In the Application, FortisBC states that the OTR Project will help address current short-term capacity shortfalls within the BCTC transmission system. Please provide a copy of correspondence or a summary of other recent studies that support the statement.

A16.2 The following information release provided by BCTC and posted on their website (http://www.bctc.com/NR/rdonlyres/CBEA01F4-7015-458B-9392-013BC5EAA17F/0/InfoReleaseFortisBCOTRproject.pdf) supports the referenced statement.



February 7, 2008

Information Release regarding Fortis BC's Okanagan Transmission Reinforcement (OTR) Project

BCTC is providing the following information in order to assist Fortis BC with their response to the British Columbia Utilities Commission (Commission) Information request 1.16.2 in the Fortis BC Certificate of Public Convenience and Necessity Application for the Okanagan Transmission Reinforcement Project.

Commission Information Request

16.0 Assessment of System Needs
Reference: Exhibit B-1-1; Executive Summary, p. 2; Tab 4, pp. 8, 51

16.2 In the Application, FortisBC states that the OTR Project will help address current short-term capacity shortfalls within the BCTC transmission system. Please provide a copy of correspondence or a summary of other recent studies that support the statement.

BCTC Information:

BCTC completed a South Interior Development Plan in 2006 that presented a series of potential reinforcements to the South Interior grid to accommodate future transfers. This plan was included as Appendix C of the F2008-F2017 BCTC Transmission System Capital Plan and filed with the Commission on December 21, 2006. The configuration of the OTR Project was included in the cases used to prepare the South Interior Development Plan. At that time it was assumed to be in service by 2008.

Appendix 1 of this report (page 13) noted that the OTR Project and the Selkirk T4 project increased the summer transfer capability at the West of Selkirk cut-plane to 2184 MW limited by voltage stability.

The OTR Project will provide voltage support at Vaseaux Lake, near the midpoint of the 5L96 and 5L98 transmission path from Selkirk to Nicola and also increase the transfer capability on this transmission path after a 5L91 contingency. The critical limitation is the voltage drop at Selkirk and Vaseaux substations after the 5L91 contingency.

An investigation of the voltage security contributions of the OTR Project indicates that the post contingency transfer capability on the 5L96 and 5L98 path from Selkirk to Nicola increases by about 75MW due to the OTR Project.

Q16.3 If a configuration with a single high capacity 230 kV circuit rather than a double 230 kV circuit between Vaseux Lake and RG Anderson would have a materially different impact on the BCTC transmission system, please explain and provide supporting documentation.

A16.3 FortisBC is unable to provide a definitive response as the studies in question have been performed by BCTC. In general, it would be expected that a single transmission line that has the same capacity as the proposed 75 Line and 76 Line should not have any significant impact on the BCTC available transmission capacity.

Q16.4 In the Application at Tab 4, page 8, FortisBC states it has funded stability studies for its interconnection to BCTC, and that these studies indicate that minor modifications to the Remedial Action Schemes ("RAS") will be required. What changes to the RAS would be needed if the Vaseux Lake to RG Anderson connection is a high capacity single 230 kV circuit?

A16.4 It should be clarified that only preliminary joint system studies have been conducted at this time. If construction of a single high capacity circuit was directed by the Commission, then this information would be incorporated in the future operational contingency studies. It is not expected that there would be any significant costs required for remedial action scheme modifications associated with a single high capacity circuit.

17.0 Assessment of System Needs

Reference: Exhibit B-1-1, Tab 3, pp. 38, 39

Q17.1 Please repeat Figure 3-6C and Table 3-6-1 assuming the OTR Project goes ahead with a high capacity single circuit between Vaseux Lake and RG Anderson.

A17.1 Please see Figure A17.1 and Table A17.1 below. Note this design will be inadequate (meet neither N-1 nor N-2) as indicated below. Prior to the OTR project, the N-2 limiting condition is the R.G. Anderson Transformer 2 capacity bottleneck. Following the completion of the OTR Project, the N-2 limiting condition moves to the northern supply (Vernon import capacity limit). Note that two load limit lines are shown. The lower line is the contractual import limit at the Vernon interconnection. The higher, dashed line indicates the technical limit beyond which further load increases will result in voltage or thermal violations. Note that the technical limit may decrease over time as the load in the BCTC system increases (as given by BCTC forecasts). This has the effect of reducing the available supply capacity at Vernon. Both lines' capacity limits are less than the peak load beyond the year 2015.

Figure A17.1

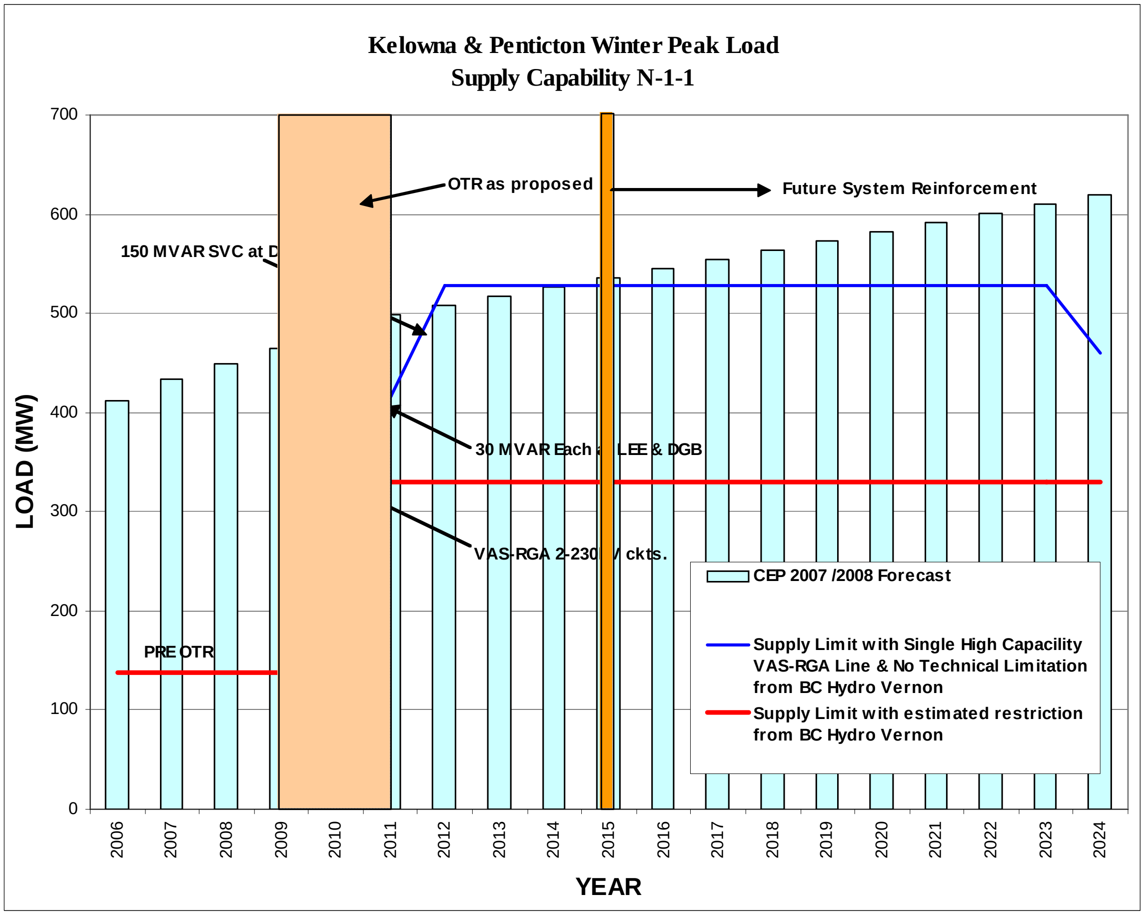


Table: A17.1 Okanagan Area Capacity/Adequacy Timeline, Alternative 1C

Reliability Level	Year
N-0	2024 + (past planning horizon with / without SVC)
N-1	Incompatible
N-1-1 / N-2	Incompatible

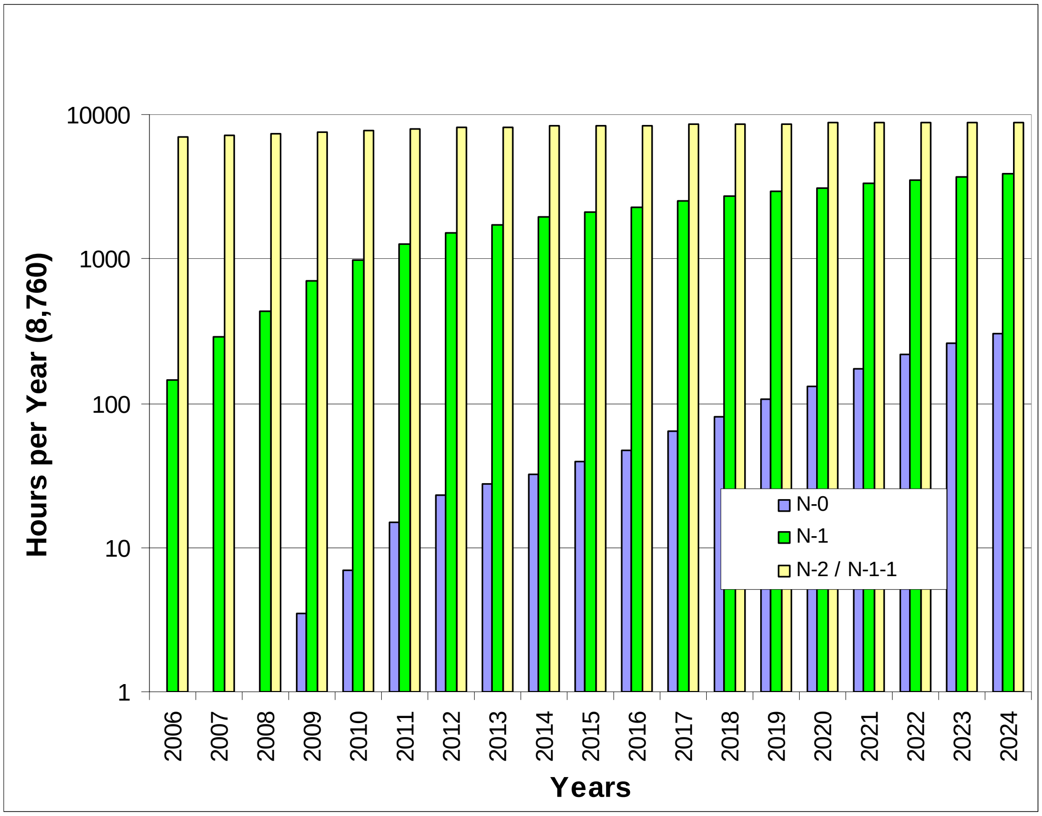
18.0 Assessment of System Needs - Reliability

Reference: Exhibit B-1-1, Tab 1, Section 1.2, p. 2; Tab 3, Figure 3-1-2-3

Q18.1 Please show the estimated impact of the OTR Project on customer outages versus the existing assets, using load data from the most recent available 12-month period.

A18.1 The following sequence of graphs shows the degree of increased reliability (indicated by Load Hours per Year Exceeding System Capacity).

Figure 3-1-2-3 Existing System
(Exhibit B-1-1)



The system improves significantly post-OTR Project as indicated in Figure A18.1 (a) below, and in Figure 18.1 (b) following the expected introduction of SVC, if subsequently approved. At that point the system will be totally N-0 and N-1 compliant. Additionally N-1-1 / N-2 compatibility will reach a very high level (compatibility exceeding 99% of the year) with 35 hours of expected violation per year in 2024.

Note: As indicated in Figure A18.1 (b) below N-1-1/N-2 compatibility improves in 2012 due to the proposed introduction of SVCs (which is not included in this Application).

Figure A18.1 (a)

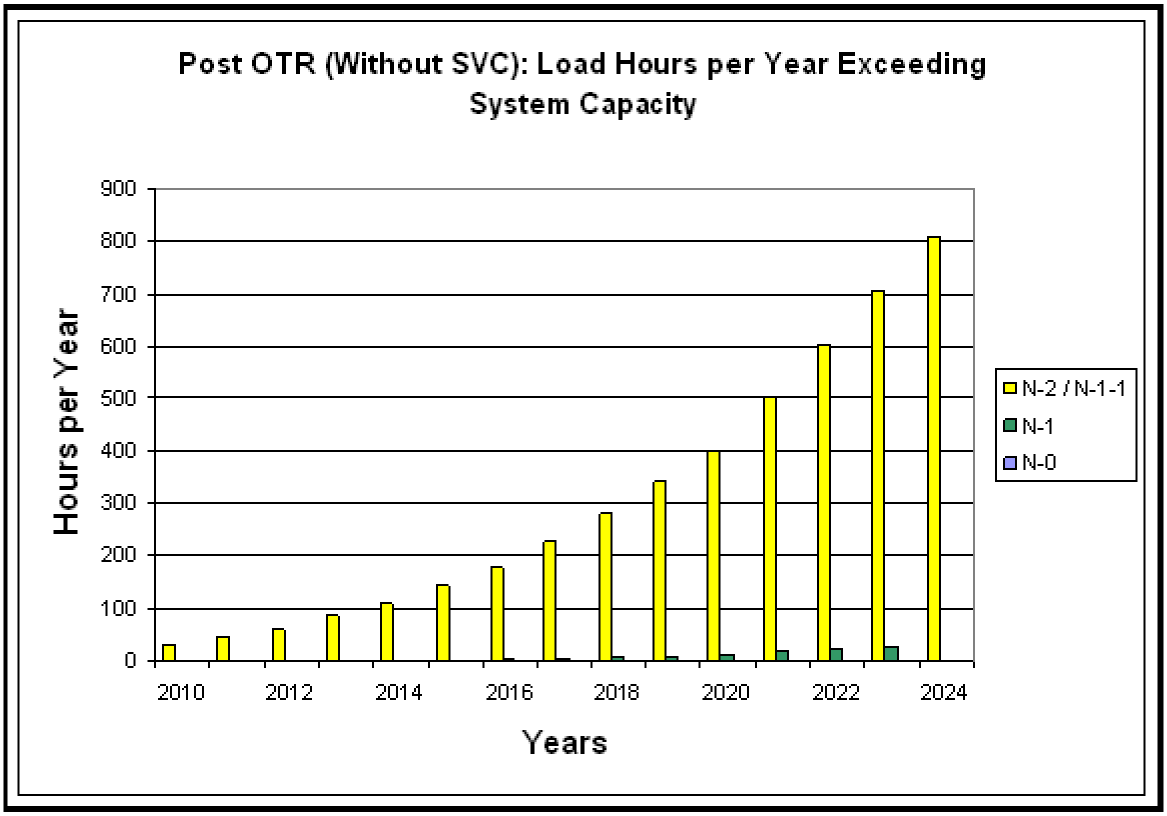
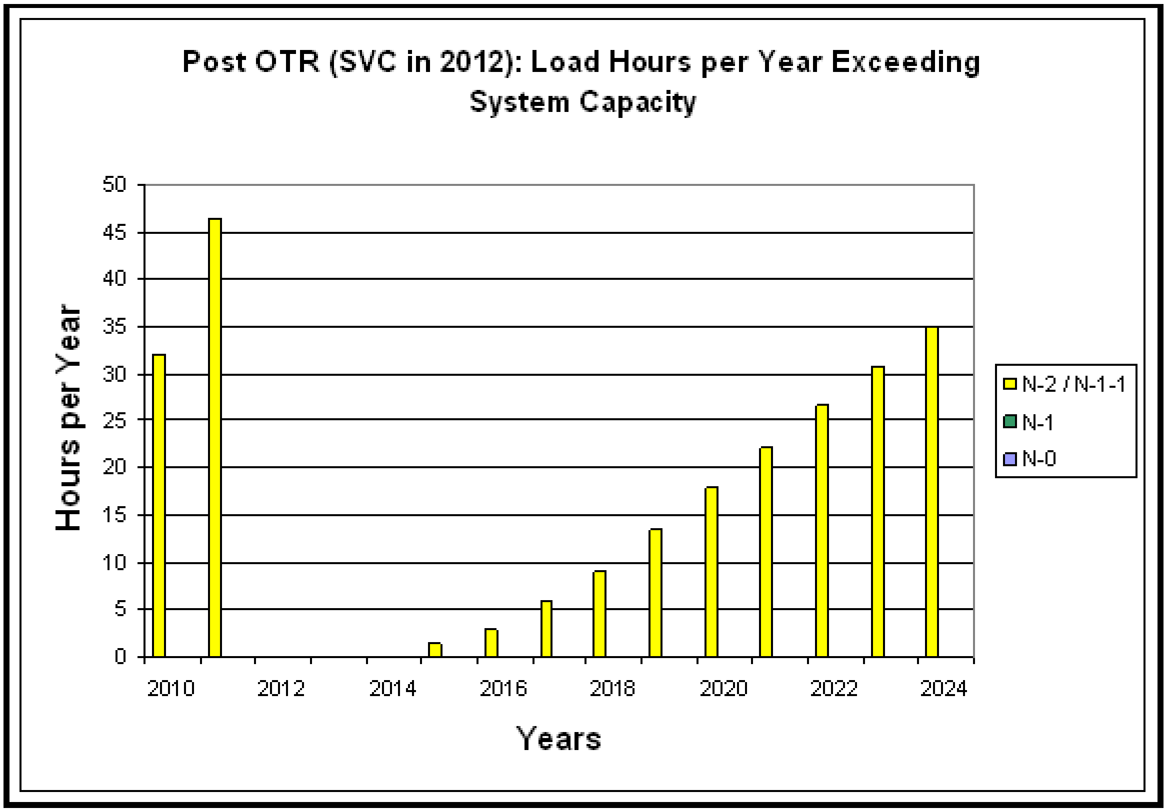


Table: A18.1 (b)



Q18.2 **Please quantify the estimated customer benefits associated with the reduced outages.**

A18.2 Please see the response to BCUC IR No.1 Q18.4.

Q18.3 **Please list and quantify (where possible) system benefits, other than the accommodation of new customers and reduced outages, associated with the Project.**

A18.3 A listing of other system benefits resulting from the OTR Project can be found in the Application (Exhibit B-1-1) in Section 3.4 page 33 under the heading "Additional Consequential Benefits" and is reproduced below. Accommodation of new customers and increased reliability are the primary drivers for the OTR Project (Items 1, 3, 4, and 5). In addition, the OTR Project will reduce system losses (Item 2), and hence, power supply expense, and reduce future capital costs by optimizing equipment usage (Item 6). The OTR Project also has benefits from a provincial perspective by increasing the overall transmission capacity and reducing losses in the provincial grid (Items 7 and 5).

1. Provide separate transformer and bus protection zones for Vaseux Lake Transformer 1 and Transformer 2 to ensure that both transformers are not lost due to a single contingency failure;
2. Reduce system losses (see section 5.2);
3. Increase the area transformation capacity by commissioning the new Bentley Terminal station and rebuilding the Oliver Terminal station as a distribution substation;
4. Facilitate system maintenance and enhance sub-transmission reliability in the Penticton and Oliver areas by adding 63 kV bus coupler circuit breakers at RG Anderson and Oliver Terminal stations;
5. Improve overall reliability in the Oliver area by transferring the distribution load presently supplied by the Oliver Transformer 1 tertiary winding to a dedicated distribution transformer;
6. Optimize equipment usage within the system:
   a. RG Anderson Transformer 2 will be refurbished and relocated to the proposed Bentley Terminal station to provide the 230/63 kV transformation. A new transformer will be installed at RG Anderson to better match the existing Transformer 1.

   b. The redundant Oliver Transformer 1 may be reused for a future capacity/reliability upgrade of the Grand Forks Terminal station or retained as a spare;
   c. Oliver Terminal station will have adequate space for future distribution growth; and
7. Provide increased transmission capacity in the provincial grid. As discussed in the BCTC 2006 South Interior Bulk System Development Plan, the OTR Project, combined with transformer upgrades at BCTC's Selkirk Terminal, will also help address current short-term capacity shortfalls within the BCTC transmission system.

Q18.4 Figure 3-1-2-3 shows the load hours per year exceeding system capacity. From the chart, the change in reliability metrics between 2008 and 2011 appear to be as follows: N-0 from 0 to 70 hours; N-1, from 900 to 2,000; N-2, no change.

What is FortisBC's estimate of the quantified benefit to customers of the reliability benefits associated with the OTR Project?

A18.4 From Figure 3-1-2-3, the change in reliability metrics between 2008 and 2011 for N-0 is 0 to15 hours rather than the 0 to 70 hours as stated in the question. Over the years there have been several studies completed on electric utility customers' valuation of service reliability. One such study, attached as Appendix A18.4a, is described in the article entitled "Cost of Service Disruptions to Electricity Consumers", Chi-Keung Woo and Roger L. Pupp, published in 1992 by the periodical *Energy,* Vol. 17, No. 2, pp. 109-126. The Wacker, Wojezynzki, and Billinton study referenced in Table 2 of the article formed the basis of the customer outage cost calculations that were included in FortisBC's 1998 20 Year Plan. Also attached as Appendix A18.4b is a brief overview of the article that includes, in Table 18.4 (b) below, the costs of interruption previously filed in FortisBC's 1998 20 Year Plan.

The costs shown in the 1998 plan were escalated at 2.2% per annum. to 2007 and are in the table below.

The results from updating the costs shown in the plan to 2007 are shown in Table 18.4 (a) below, however FortisBC is not able to determine the validity of these estimates for its customers, individually or collectively.

Table: A18.4 (a) Unit Cost of Interruptions

Customer Class	Demand	Cost of Interruption (2007)	
		Per Hour	**$/kWh**
Residential	750 kW	$4,237	$1.68
General Service	150 kW	$1,412	$22.09
Small Industrial	100 kW	$553	$10.73

Source: FortisBC 1998 20 Year Plan

Based on the table above, it could be said that the customer costs of interruption for a one hour total loss of 250 MW of service would be estimated at $5.4 million. ($4.6 million for 1 hour interruption and $0.754 million of energy value)

Table: 18.4 (b) Value of Interruptions by Customer Class

	Demand	**Cost of Interruption - 1MW (2007)**		**Demand**	**Cost of Interruption - 250 MW (2007)**			
Customer Class	1 MW	Per Hour	$/kWh	250 MW	1 Hour ($000)	Load Factor	Consumption	Energy Value ($000)
Residential	750 kW	$4,237	$1.68	187,500kW	$1,550	0.53	99,375	$167
General Service	150 kW	$1,412	$22.09	37,500 kW	$754	0.45	16,875	$373
Small Industrial	100 kW	$553	$10.73	25,000 kW	$2,305	0.8	20,000	$215
				Total ($000)	*$4,610*			*$754*

19.0 Assessment of System Needs

Reference: Exhibit B-1-1, Executive Summary, p. 1

Q19.1 Has FortisBC quantified the reliability and security benefits provided by the Vaseux Lake Terminal? If so, please provide the relevant statistics. If not, what is the basis for the statement that reliability and security have been improved?

A19.1 No detailed analysis to quantify the reliability and security benefits has been conducted to determine the direct impact on reliability indices. The difficulty in quantifying this reliability benefit is that there are many external factors that may result in a system outage and affect the duration for restoration. One of the major externalities is weather. For example, in any given year there will be greater or fewer storms than predicted by the past averages which will affect the system performance indicators. Additionally, system improvements / infrastructure upgrades may also result in outages affecting reliability.

The referenced statement from the Executive Summary of the Application was based on the following assertions:

1. Prior to the SOK Project, the Okanagan region was fed from three general directions, i.e., from North (72 Line and 74 Line), East / South East (11 Line and 40 Line) and West (56 Line and 43 Line)
2. Any one of these three general paths are affected due to outage, then the security / reliability of Okanagan supply would be compromised
3. Such outages have taken place regularly at an average rate of 12 failures per year (please refer to Table A19.1 below)
4. Introduction of the Vaseux Lake Terminal Station provided for a second BCTC / BC Hydro source of supply in the Okanagan region consequently

reinforcing the supply security / reliability in the region by reducing relative dependency on the existing supply paths.

Table: A19.1

Year	Failure of Power Supply Lines feeding into Okanagan			
	56 Line + 43 Line (West Path)	11 Line + 40 Line (East / South East Path)	72 Line + 74 Line and BC Hydro Outages (North Path)	TOTAL
1997	9	10	8	**27**
1998	2	3	2	**7**
1999	5	6	2	**13**
2000	2	5	6	**13**
2001	4	5	2	**11**
2002	1	1	3	**5**
2003	4	9	2	**15**
2004	5	2	3	**10**
2005	3	7	0	**10**
2006	2	4	4	**10**
2007	1	3	3	**7**
TOTAL	**38**	**55**	**35**	**128**

20.0 Assessment of System Needs

Reference: Exhibit B-1-1, Executive Summary, p. 6

Q20.1 The Kelowna area has experienced one or two blackouts per year due to a loss of supply from the north. What studies or actions have been undertaken with respect to reducing the frequency of events involving the loss of supply from the north?

A20.1 FortisBC has studied the issue since 2004 and the outcome of those studies is to increase the available transmission capacity as proposed in the OTR Project application.

To date, the majority of the blackouts to Kelowna have resulted from:

- lightning strikes to FortisBC transmission lines;
- lightning strikes to BCTC transmission lines;
- FortisBC protection misoperations; and,
- loss of supply from the BCTC Vernon Terminal.

There is little that can be done to reduce the impact of lightning-caused outages short of installing overhead shield wires on 72 Line / 74 Line and BCTC's 2L255/2L256. This would be very costly and would require rebuilding the lines as taller structures capable of supporting overhead shield wires. The effectiveness of these shield wires is questionable due to the very high soil resistivity in the area which makes achieving low tower footing resistance very difficult.

Protection misoperations in the FortisBC system have been greatly reduced by replacing problematic equipment at the FA Lee Terminal as part of the Kelowna Area Upgrade project. This issue is no longer considered a concern.

A loss of supply from Vernon has resulted from a number of different causes including: lightning (discussed above), human error and protection misoperations. FortisBC has no control over how BCTC operation and maintenance of the BC Hydro transmission system. Beyond stressing the importance of this critical interconnection point with BCTC there is no direct remediation of any of these issues that FortisBC can perform.

Notwithstanding the above, as an interim measure FortisBC has implemented temporary Remedial Action Schemes (RAS) that proactively shed load following the loss of critical transmission elements. This RAS, which is armed and operated by the FortisBC System Control Centre (SCC) dispatchers, will typically shed the majority of the load in the Kelowna area following a loss of supply from the north. This is in an attempt to maintain reasonable voltage levels for the remaining customers. The SCC would then be responsible for instituting rotating outages in an attempt to ensure that customers would at least have power available for some portion of the time.

This RAS is backed up by under-voltage load shedding protection that will force a separation of the Kelowna to Vernon transmission path if a severe, sustained under-voltage condition is detected. Unfortunately, the only possible recovery for this condition is to trip all load in the Kelowna area which results in a complete blackout (which is still preferable to risking equipment damage by delivering extremely low voltages to customers).

21.0 Assessment of System Needs

Reference: Exhibit B-1-1, Tab 3, Section 3.5, pp. 35-39; Exhibit B-1-3, Appendix G, Schedule

Q21.1 The Schedule indicates 30 Mvar capacitor banks to go into service at FA Lee and DG Bell Terminal Stations in September 2010 as part of the OTR Project. Please provide additional detail on the requirement for capacitor banks at both FA Lee and DG Bell.

A21.1 The proposed 30 MVAR capacitor banks at FA Lee and DG Bell are required to provide voltage support during normal and contingency conditions. Please also see the responses to BCUC IR No.1 Q13.3 and Q21.2.

Q21.2 Are the capacitors at D.G. Bell and F.A. Lee intended to support system voltages when the power flow into the Okanagan is predominantly or entirely from south to north as a result of a contingency? If so, why are capacitors not required further south to support predominantly north-to-south flows during system events?

A21.2 Yes, the proposed capacitor banks at DG Bell and FA Lee are intended to support system voltage during contingency conditions. The outage of the north lines (72 Line and 74 Line) resulting in south to north flow is a more critical outage compared to the outage of south lines (75 Line and 76 Line) resulting is north to south flow because of the geographic distribution of load. The capacitor banks have been optimally located to provide the desired reactive support while keeping the reactive power flows to a minimum. Please also see the response to BCUC IR No.1 Q13.3.

Q21.3 Was consideration given to installing a single, perhaps larger, capacitor bank at one of the stations or at a different location on the transmission system? Please explain.

A21.3 Yes. The flow of reactive power in lines causes voltage drop so it is important that reactive requirements be supplied from nearby reactive resources. The reactive losses can be reduced by locating sources of reactive power close to the areas of reactive power loss or loads. Installing a single large capacitor bank will not be as effective and beneficial as compared to distributing the reactive compensation to minimize reactive flows. More over switching a single large capacitor bank will result in a higher step change in voltage (ΔV) which can be detrimental to the operation of voltage sensitive loads and other consumer appliances.

Q21.4 Appendix G of the Application at page 2 refers to 20 Mvar capacitors; what size is included in the $141.4 million cost estimate?

A21.4 The reference at page 2 is incorrect. The capacitors are 30 Mvar which is the size included in the $141.4 million cost estimate.

Q21.5 The Application at Tab 3, page 35 also refers to a project to install a 150 Mvar SVC at D.G. Bell in 2011, which will be the subject of a separate application. When does FortisBC intend to file the separate application for the SVC?

A21.5 A request for Commission approval of the SVC will be contained in the FortisBC 2009-2010 Capital Expenditure Plan and System Development Plan Update Application to be filed in Q3 of 2008.

Q21.6 Please discuss whether the SVC would delay or eliminate the need for the capacitor banks, particularly at D.G. Bell.

A21.6 The capacitor banks are required to provide the required voltage support during normal and contingency conditions. With the forecast growth in the Okanagan load the need for voltage support will increase requiring the subsequent installation of the SVC. Installing the SVC at the beginning of the Project will delay the need for the capacitor banks but will result in a substantial increase of the initial cost.

22.0 Assessment of System Needs

Reference: Exhibit B-1-1, Tab 5, Section 5.7 (Contingency Plan for OTR Project Delays), pp. 8-9

Q22.1 How much Penticton-area load can be supplied via 42 Line?

A22.1 The Penticton area load that can be supplied via line 42 Line depends on the transformation capacity of the source at Oliver and the load supplied from Oliver (Oliver, Osoyoos, and Pine Street). The normal rating of Oliver Transformer 1 is 60 MVA while the normal rating of the 63 kV winding of the four winding transformer Oliver Transformer 2 is 60 MVA. The normal winter rating of line 42 Line is 70.8 MVA. For the Penticton load that can be supplied via line 42 Line please see Table A22.1 below:

Table: A22.1 Available 42 Line Supply to Penticton

COMPONENT	**LOAD (MVA)**				
	2008	**2009**	**2010**	**2011**	**2012**
Oliver	8.3	8.5	8.7	8.9	9.1
Osoyoos	20.2	21.0	21.9	22.8	23.7
Pine Street	18.4	18.7	19	19.2	19.4
Total	46.9	48.2	49.6	50.9	52.2
Capacity (Oliver T1+T2) MVA	120.0	120.0	120.0	120.0	120.0
Penticton load that can be supplied via 42L	73.1	71.8	70.4	69.1	67.8

Please also refer to the response to BCUC IR No.1 Q8.5.

Q22.2 How much load does FortisBC expect could be curtailed through voltage reductions?

A22.2 FortisBC conducted voltage reductions in the Kelowna area a number of years ago in order to reduce system peak demand to avoid exceeding import capacity limits at the Vernon interconnection. A number of tests were carried out and analyzed to determine the effectiveness of voltage reductions. At the time, it was found that a 5% voltage reduction would result in approximately a 3% decrease in demand. An 8% voltage reduction resulted in approximately a 5% decrease in demand.

It should be noted that these tests were conducted in the winter when the system load is predominantly resistive (due to heating and lighting load). It is expected that the demand reduction would be less during summer load peaks due to the predominance of motor loads from air conditioning (motors are generally constant-power loads).

It should also be noted that voltage reductions can cause customer problems. It is difficult to ensure that customers at the end of long distribution feeders still receive voltage within CSA limits.

Finally, the demand reduction only lasted for one to two hours – after that time the load diversity was lost and the system demand rapidly increased back to nearly the previous pre-reduction consumption.

Q22.3 Assuming the two previous actions have already been taken, what are the magnitude, frequency, and duration of likely rotating customer outages if the OTR Project were to be delayed by two years?

A22.3 Table A22.3 below gives an idea of the magnitude of load that will have to be shed in case of the outage of 72 Line and 74 Line.

Table: A22.3 Load Shedding for Outages of 72 Line and 74 Line

COMPONENT	LOAD (MVA)					
		2008	**2009**	**2010**	**2011**	**2012**
Total Penticton load	1	146.3	149.2	152	154.9	157.8
Penticton load served via 42 Line	2	73.1	71.8	70.4	69.1	67.8
Penticton load via RGA T2 (1-2)	3	73.2	77.4	81.6	85.8	90.0
Kelowna Load	4	311.2	324.1	338.9	352.8	360.2
Kelowna & Penticton load via RGA (3+4)	5	384.4	401.5	420.5	438.6	450.2
RGA T2 Emergency Capacity via 76L	6	172.0	172.0	172.0	172.0	172.0
Unserved Load (5-6)		**212.4**	**229.5**	**248.5**	**266.6**	**278.2**

The Kelowna plus Penticton load is expected to be above the emergency capacity of RGA Transformer 2 for approximately 92% of the time in the year, please refer to Figure-3-1-2-3 on page 8. The amount of load that cannot be served and the duration will increase if the OTR Project is delayed by two years. For the frequency of outages please refer to Table 3-1-3-4 on page 17, Tab 3 of the CPCN Application (Exhibit B-1-1).

Q22.4 Please clarify whether opening the 76 Line – 73 Line path between Vaseux Lake and Vernon would leave the system vulnerable to the first unplanned event or the second one.

A22.4 Opening the 76 Line – 73 Line path between Vaseux Lake and Vernon has the effected of “un-meshing” the transmission system. This is highly undesirable for extended periods as it means that the Penticton area would then be vulnerable to a single event causing a complete blackout.

For example, if 73 Line was opened, then all of the Penticton load would be supplied via 76 Line. A failure of 76 Line (or its source supply) would cause a city-wide blackout.

On the other hand, if 76 Line was opened, then all of the Penticton load would be supplied via 73 Line. A failure of 73 Line (or its source supply) would cause a city-wide blackout.

23.0 Power Supply Options

Reference: Exhibit B-1-1, Tab 6

Q23.1 What is the precision of the cost estimate for the other supply options considered in Tab 6? Are these costs in real or nominal dollars?

A23.1 The estimates are conceptual only and the impact of inflation has not been considered.

Q23.2 Option 2 (North-South Transmission Reinforcement) and Option 3 (Westbank 230 kV BCTC Inter-tie) both directly involve the BCTC system. Please confirm that BCTC has verified the technical feasibility of these options and does not take issue with their estimated costs.

A23.2 Early in the screening process, Options 2 and 3 were removed from further consideration due to their very high estimated costs. However, both options were presented to BCTC in December 2006. The discussions were at a high level only and BCTC offered no formal opinion on the viability of either option. As well, no detailed studies have been performed to determine the technical feasibility.

The cost estimates have been performed by FortisBC based on the known system requirements. If additional work was required by BCTC then the estimated costs would have to be increased accordingly.

Q23.3 How is electrical power currently supplied to the BCTC substation at Westbank?

A23.3 The BCTC Westbank Substation is supplied radially via an 80 kilometre 138 kV transmission line from the BCTC Nicola Substation northeast of Merritt. Nicola is a major BCTC transmission station and operates at 138 kV, 230 kV and 500 kV.

Q23.4 When is BCTC likely to reinforce the supply to its Westbank substation to meet its own requirements? If this were to occur, would the existence of a stronger supply at Westbank provide a viable reinforcement option for FortisBC?

A23.4 FortisBC is aware that BCTC is considering reinforcing the Westbank supply via a second transmission source.

BCTC has stated that the 138 kV transmission supply to Westbank is considered adequate from a capacity point of view (reference: “BCTC Transmission System Capital Plan F2009 to F2018, Section 5.5.2.2.18 Westbank 138 kV System Reconfiguration”, lines 11 - 14). Given that fact, it appears unlikely that a 230 kV supply interconnection would be considered. Without a 230 kV source to Westbank, the station would not be strong enough to provide a viable transmission supply for the FortisBC bulk system.

It should be noted that even if a 230 kV source were available at Westbank, there would still be the requirement for an additional 230 kV overhead line through Westbank from the BC Hydro source, a 230 kV submarine cable across Okanagan Lake, and an additional 230 kV overhead line from the lake edge to DG Bell Terminal station in order to interconnect with FortisBC’s system.

24.0 Power Supply Options

Reference: Exhibit B-1-1, Section 6, pp. 2, 11

Q24.1 FortisBC submits that the OTR Project is required to resolve supply deficiencies, and that local generation options were also considered, including natural gas, coal, diesel, wind and biomass. Please describe the local generation options that FortisBC considered, and the reasons for their elimination.

A24.1 FortisBC evaluated five local generation options for further development; natural gas, coal, diesel, wind, and biomass generation. Coal, diesel, and biomass were dismissed for obvious environmental and public concerns and permitting constraints. Wind was dismissed for primarily technical constraints with regards to reliability. Gas generation was deemed to be the only technically viable option for further development considering the above concerns and constraints.

25.0 Project Description

Reference: Exhibit B-1-1, Tab 4, pp. 11, 18, 30

Q25.1 FortisBC states "All transmission line upgrades and additions contained in the proposed OTR Project can be accomplished within the existing brownfield rights-of-way." FortisBC also states that 40L line and Alternative 1A for 75L and 76L lines will be built on the existing right-of-way ("ROW") established in 1965 which is on average 40 metres wide. What is the minimum width of the ROW between Vaseux Lake and RG Anderson? Please provide a map showing the sections of the ROW where the width is less than 40 metres.

A25.1 The minimum width of the right-of-way between Vaseux Lake and RG Anderson is 40.2 metres.

Q25.2 How many ROW agreements are there between Vaseux and RG Anderson, and between Vaseux and Oliver Substation?

A25.2 There are 25 different charge numbers (different right of way agreements) between Vaseux and RG Anderson that appear as charges against titles on 88 individual properties. There are two right of way agreements between Vaseux Terminal and the Oliver Terminal stations that pertain to Crown land and the Osoyoos Indian Band Reserve.

Q25.3 Please file a copy of a typical ROW agreement between RG Anderson and Oliver Substation. If there are several forms of ROW agreements, please describe the differences between them and provide examples.

A25.3 There are four forms of right of way agreements that pertain to the subject area. They include the agreement from the Crown Figure A25.3(a); the Section 28.2 agreements over the First Nations lands, Figure A25.3(b); the original standard right of way agreement executed in 1965 for all private properties Figure

A25.3(c); and a modification widening agreement, Figure A25.3(d).

50 add C/T

6.40

6.90

225

Form / Z 1 - 172

WILLSON STATIONERS E24102

Attachment A25.3a

No. ....

AUG-20-70 214230 21 ST

20 9 : 13

LAND REGISTRY ACT

FORM C

(Section 127)

Application for Registration of Charge

Date August 17, *19*70

I, WILLIAM GRANT TINDALE, solemnly declare that I am ~~[a Solicitor for or]~~ the duly authorized Agent of West Kootenay Power and Light Company, Limited and that ~~he~~ it is] entitled to a

* Charge by way of Right-of-Way

over the land hereunder described, and hereby make application under the provisions of the "Land Registry Act" and claim registration of a charge accordingly.

The full name, address, and occupation of the person so entitled to be registered as owner of the charge is

West Kootenay Power and Light Company, Limited, Trail, B.C.

Generators and Distributors of Electrical Energy

† Not applicable where the applicant is a corporation. Strike out words not applicable.

I am a British subject.† [*Or*]

I am not a British subject.† [*Or*]

I am informed by ...., and

(Adapt to suit circumstances.)

‡ For use where the application is made by a solicitor or agent.

verily believe, that the person so entitled to be registered as owner of the charge is a British subject [*or*] is not a British subject.†‡

The fee-simple is registered in Vol. , Fol. , of the Register.

DESCRIPTION OF LAND

Municipality or Assessment District	Lot or Section	Admeasurement or Acreage
KETTLE RIVER ASSESSMENT DISTRICT	That part of District Lot 2710, Similkameen, formerly Osoyoos, Division Yale District, lying between Osoyoos Indian Reserve No. 1 and Sublot 28, District Lot 2710, Plan 1189, Similkameen Division Yale District - and - LOTS 1 & 2, PLAN 10521 that part of District Lot 2710, Similkameen, formerly Osoyoos, Division Yale District, lying between Sublots 36 and 41, District Lot 2710, Plan 1189 and Lot 3203, all of Similkameen Division Yale District - and -	✓ 24.40 acres ✓ 23.60 acres ✓ 12.21 acres ✓ 4.16 acres ✓ 64.37 AC TOTAL ✓

LIST OF INSTRUMENTS

Date	Parties	Character of Deed
March 25, 1966	HER MAJESTY THE QUEEN IN RIGHT OF THE PROVINCE OF BRITISH COLUMBIA - and - WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED	SEE OVER ORDER-in-COUNCIL No. 880 IMAGE

Do not write outside the side-line. Space reserved for binding.

And I solemnly declare that I have investigated and ascertained the value of the interest covered by the charge, registration of which is hereby applied for, and that the true value thereof at the date of this application is $1,416.00 dollars: [*In the case of a Solicitor or Agent, add*] and I am duly authorized by the owner to make this application [*In the case of an Agent, add*] and I reside in the Province of British Columbia, and am of the full age of twenty-one years.

And I make this solemn declaration conscientiously believing it to be true, and knowing that it is of the same force and effect as if made under oath and by virtue of the "Canada Evidence Act."

DECLARED before me this 17th day of August, 1970, at Trail, British Columbia.

(Signature) W. G. Tindale

(Full post-office address) West Kootenay Power & Light Co. Ltd., Trail, B.C.

For mailing notices and documents.

GLENN ELDRIDGE MASON

the Province of British Columbia

* NOTE.—Insert here the estate less than the fee-simple, or encumbrance or equitable interest claimed in, over, or upon the land; e.g., mortgage in fee-simple for $500, estate for life, lis pendens (according to circumstances, upon, in, over).

★ o

Application	$ 1	00
Registration of Charge	2	00
Deposit of Deeds	2	00
Deposit of Map		
Documents filed		
¹⁄₁₀ of 1% on $ 1,416.00	1	42
$	~~6~~	~~42~~

Cash

√ **that part of Lots 1 and 2 of District Lot 2710, Similkameen Division Yale District, Plan 10521 - and -**

√ **that part of District Lot 2710, Similkameen Division Yale District, lying between Sublots 38 and 18, District Lot 2710, Plan 1189, all as shown outlined in red on Plan CG2146.**

Roll (16-4)

Attachment A25.3a

880.

I hereby certify that the following is a true copy of a Minute of the Honourable the Executive Council of the Province of British Columbia, approved by His Honour the Lieutenant-Governor on the 25th day of March, A.D. 1966.

E. E. Protheroe

Assistant DEPUTY PROVINCIAL SECRETARY.

To His Honour

The Lieutenant-Governor in Council:

The undersigned has the honour to

report:

THAT an application has been received from West Kootenay Power and Light Company Limited (hereinafter referred to as the Grantee) for a right-of-way over certain Crown lands for all purposes necessary or incidental to the operation of an electrical power transmission line.

AND TO RECOMMEND THAT pursuant to Section 70 of the Land Act, being Chapter 206 of the Revised Statutes of British Columbia, 1960, and all other powers thereunto enabling, Her Majesty the Queen in right of the Province of British Columbia (hereinafter referred to as the Grantor), in consideration of the payment of the sum of one thousand four hundred and sixteen dollars and fourteen cents ($1416.14) (the receipt whereof is hereby acknowledged), doth grant unto the Grantee, its successors and assigns and its and their servants, agents, and licensees the full, free and uninterrupted right and privilege to enter, labour and pass along, over and under those parts of Lots 1 and 2 of Lot 2710, Similkameen, formerly Osoyoos, Division of Yale District, Plan 10521 and those parts of Lot 2710, Similkameen, formerly Osoyoos, Division of Yale District, all as shown on the official plan in the Department of Lands, Forests, and Water Resources and numbered 5 Tube 745 and on Plan C.G. 2146 on file in the Land Registry Office, Kamloops, containing a total of 64.37 acres (hereinafter referred to as the Crown lands), for the purpose of constructing, operatin maintaining, inspecting and safeguarding thereon one or more electric transmission or distribution lines, together with any telephone or other signal lines or apparatus as are necessary for the safe and efficient operation of the transmission or distributi lines, including the right to construct, erect, operate and maintain thereon towers and poles with anchors, guy wires, brackets, cross-arms, insulators, transformers and their several attachments and to string thereover one or more wires for the transmission and distribution of electrical energy and for the telephone or other signal lines or apparatus and to place therein underground conductors (hereinafter collectively referred to as the installations), and to clear the Crown lands and keep them cleared of all or any part of any trees, growth, buildings or obstructions now or hereafter on the Crown lands.

AND TO FURTHER RECOMMEND THAT subject to all the provisions hereinafter contained, the term of the right-of-way herein granted shall be the period during which the right-of-way is required by the Grantee subject, however, to the provisions of Clause 5.

1. That the Grantee shall pay and discharge all taxes, rates, duties and assessments whatsoever, now or hereafter charged upon or payable in respect of the right-of-way and the installations and which the Grantee is liable to pay.
2. That the Crown lands shall be used by the Grantee solely for the purposes aforesaid and for no other purposes.

IMAGE

3. That the Grantee shall, as soon as weather and soil conditions permit and in so far as it is practicable so to do, bury and maintain underground conductors or other underground installations so as not to interfere with the drainage or ordinary cultivation of the Crown lands, and the top of such conductors or other installations shall be not less than thirty (30) inches below the normal ground level; provided, however, that after the underground conductors or other underground installations are in place all excavations shall be carefully back-filled and all surplus materials shall be removed and the Crown lands restored to a condition satisfactory to the Minister of Lands, Forests, and Water Resources (hereinafter referred to as the "Minister"), which restoration may include reseeding with suitable grasses and legumes.

4. That the Grantee shall at all times wholly indemnify the Grantor from and against all loss, damage, injury, and expense to which the Grantor may be put by reason of any damage or injury to persons or property caused by the Grantee's installations as well as against any damage or injury resulting from the imprudence, neglect, or want of skill of the employees or agents of the Grantee in connection with the construction, operation, maintenance, inspection, and safeguarding of the installations or the use thereof.

5. That if the Grantee shall, over any period of two (2) consecutive years or over such extended period as may be granted in writing by the Minister, fail to make diligent use of the Crown lands for the purposes aforesaid, the rights and privileges granted herein shall cease and terminate forthwith, and the Grantee shall, within two (2) years from the date of such termination or within such extended period as may be granted by the Minister, have the right to remove its installations. Any installations of the Grantee not so removed shall become the property of the Grantor; provided, however, that the Grantee shall in any event leave the Crown lands in a safe condition satisfactory to the Minister.

6. That notwithstanding any rule of law or equity but subject to the provisions of clause 5, the installations brought onto, laid, or erected upon or buried under the Crown lands by the Grantee shall remain the property of the Grantee, and the Grantee shall have the right at any time and from time to time to remove in whole or in part any of its installations.

7. That the Grantee performing and observing the conditions and provisions herein contained shall and may peaceably hold and enjoy the rights, liberties, and privileges hereby granted without hindrance, molestation, or interruption on the part of the Grantor, subject, however, to all the provisions herein contained.

8. That nothing herein contained shall be deemed to vest in the Grantee any title to timber, gold, silver or any minerals, coal, petroleum, natural gas, building and construction stone, limestone, marble, shale, clay, sand, gravel, volcanic ash, earth, soil, diatomaceous earth, marl, or peat on or under the Crown lands, except only the parts thereof that are necessary to be dug, carried away, or used in the construction of the installations of the Grantee.

9. That any Crown timber cut or destroyed on the Crown lands shall be paid for at a stumpage rate (inclusive of royalty) to be set by the Minister. Billing will be on the basis of a cruise acceptable to the Minister, but in the event of a subsequent sale of timber exceeding in volume the amount of the cruise, then any excess over the cruise figures will be billed at the full rate of stumpage; provided, however, that notwithstanding the foregoing the Grantor may dispose of timber on the Crown lands under the provisions of the Forest Act.

10. That slash and debris created in connection with clearing the Crown lands shall be disposed of in keeping with the requirements of the Forest Act, as required by the Forest Officer in charge.

11. That the Grantor shall at all times be entitled to the use and possession of the surface of the Crown lands and to dispose of same subject to the rights and restrictions herein contained and subject also to the Grantee's right to prevent the placing of any building, structure, excavation, or obstruction which may in any way interfere with the safe and efficient operation of the installations on the right-of-way.

12. That this grant is and shall be of the same force and effect to all intents and purposes as a covenant running with the land, and these presents, including all the conditions and provisions herein contained, shall extend to and be binding upon and enure to the benefit of the Grantee and the Grantor and their respective heirs, executors, administrators, successors, and assigns.

13. That this grant is made and accepted subject to prior rights existing in favour of third parties, if any.

14. That the right-of-way granted herein does not extend to any highway within the meaning of the Highway Act.

15. That upon breach by the Grantee of any of the provisions herein contained and upon failure of the Grantee to rectify the breach within sixty (60) days from the date of registered notice thereof, mailed by the Minister to the Grantee at its registered office or chief place of business, the Minister may terminate the right-of-way by like notice to the Grantee by registered mail; provided, however, that in the event of such termination the Grantee shall within two (2) years from the date of such termination or within such extended period as may be granted by the Minister have the right to remove its installations. Any installations of the Grantee not so removed shall become the property of the Grantor; provided, however, that the Grantee shall in any event leave the Crown lands in a safe condition satisfactory to the Minister.

16. That the Grantee shall not assign or sublet the rights and privileges granted herein without the written consent of the Minister; provided, however, that such consent shall not be required in the event of the Grantee mortgaging or pledging the rights and privileges granted herein to secure the payment of any bonds or other indebtedness of the Grantee.

17. That the Grantee shall abide by and comply with all lawful by-laws, rules, and regulations of every municipality or other authority which in any manner relate to or affect the Crown lands in so far as the Grantee is subject thereto.

18. That it shall be lawful for the Minister or for any person authorized by him at all reasonable times to enter upon the Crown lands to determine that the provisions herein are being fully complied with by the Grantee.

19. That the Grantor shall not be liable for damages caused by vandalism or for other interference by third parties to the Grantee's installations.

20. That the Grantee shall provide and install at its own expense casings, culverts, or other like fabricated materials required to protect the installations over which any highway or railway crossing may be constructed by any Provincial authority or railway owned or controlled by the Province up to the extent of one hundred (100) lineal feet on each side respectively of the installations crossed in respect to any one crossing. All other costs of constructing any such crossing in accordance with the laws, orders, and regulations applicable to the operations of the Grantee shall be borne by the Provincial authority or Provincially owned or controlled railway constructing the same.

21. That the Grantee, its contractors, agents, or employees, shall be permitted to pass or repass over the Crown lands for the purpose of ingress and egress, including the right to construct, maintain, and use on the Crown lands any access road or roads reasonably required in connection only with the exercise of the rights and privileges granted herein; provided, however, that the Grantee shall not extend to other parties any right to the use of such road or roads and that the Granter reserves the right to grant rights-of-way for any purpose across or along the said road or roads.

22. That this grant shall be subject to all rights of free miners under the mining laws of the Province for the time being, and to the laws of the Province from time to time with respect to the acquisition of minerals, precious or base, including phosphate, coal, petroleum, and any gas or gases.

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E.E.P.

Attachment A25.3a

23. That the Grantee shall observe all and singular the provisions of the land laws for the time being of the Province.

24. That the Grantee shall without cost give and grant to any Provincial authority or railway owned or controlled by the Province requiring the same right of entry in and upon the Crown lands for the purpose of constructing and maintaining highway and railway crossings in accordance with the terms of any valid laws, orders, and regulations in respect to the construction and maintenance of such crossings applicable to the operation of the Grantee.

25. That the British Columbia Forest Service shall have free access to and use of roads and trails constructed by the Grantee on the Crown lands.

26. That the Grantee will co-operate with the Crown in solving any interference problems which might arise should it be necessary for the Grantee to install any equipment or other facilities on the Crown lands which interfere with, or render inoperative, any radio equipment or communication facilities of the Crown which are presently operating and which may hereafter be operated during the term of the right-of-way.

DATED this 25th day of March , A.D. 1966

"Ray Williston"

Minister of Lands, Forests, and Water Resources.

APPROVED this 25th day of March , A.D. 1966

"W.A.C. Bennett"

Presiding Member of the Executive Council.

File: 0255800
ES:rl

IMAGE T

P.E.M.

164/31-3-2-1 (R3) (10)

Permit #4645

THIS AGREEMENT, made in triplicate, this first day of September, in the year of Our Lord, One thousand nine hundred and-sixty-four.

BETWEEN:

HER MAJESTY QUEEN ELIZABETH THE SECOND, in right of Canada, hereinafter called "Her Majesty", represented by the Minister of Citizenship and Immigration, hereinafter called the "Minister",

OF THE FIRST PART,

AND:

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED, a body corporate having its Head Office and chief place of business at the City of Trail, in the Province of British Columbia, hereinafter called the "Permittee",

OF THE SECOND PART.

OKANAGAN
Indian
DEC 30
Agency
VERNON, B. C.

WHEREAS the lands hereafter described are reserve lands within the meaning of the Indian Act, Chapter 149, Revised Statutes of Canada, 1952.

AND WHEREAS the Permittee has applied for certain rights over the lands hereinafter described for the purpose of constructing, operating and maintaining thereon electric power transmission lines and a transformer station.

AND WHEREAS the [redacted] for whose use and benefit the said Reserve has been set apart, has by Resolution dated November 7, 1963, and December 12, 1963, approved the application.

NOW THEREFORE THIS AGREEMENT WITNESSETH that in consideration of the sum of one dollar ($1.00) paid to the Minister by the Permittee (the receipt whereof is hereby acknowledged) and of the covenants and agreements herein reserved and contained on the part of the Permittee to be kept, observed and performed, the Minister under authority of Section 28(2) of the Indian Act, Chapter 149, Revised Statutes of Canada, 1952, as amended doth hereby grant the Permittee, its successors and assigns, the right to construct, operate and maintain electric power transmission lines and a transformer station on the said lands being in Osoyoos Indian Reserve No. 1, in the Province of British Columbia, and more particularly described as follows:

LINES # 11 & 40 RW
PLAN CLSR 51875 - 44. AC 7.55" 0.84 & 0.39
ROLL (18-18)
FILES #11-422 & 423
PLAN CLSR 51876 - 54.56 AC
(ROLL 18-19)
TOTAL 107.34

Firstly: In the province of British Columbia; in Osoyoos Indian Reserve No. 1; all those portions of rights-of-way according to plans 51875 and 51876 in the Canada Lands Surveys Records at Ottawa; said portions containing together by admeasurement 107.34 acres, more or less, subject however, to prior grants of easement dated April 10, 1959 and January 16, 1961, to Inland Natural Gas Co. Ltd., for natural gas pipeline as same are shown on plans 4536 and 4585 in said Records and subject further to a prior grant of lease of certain lands dated January 15, 1962, to Oliver Lakeshore Golf and Resorts Ltd., as said lands are shown on plan 50925 in said Records.

PLAN CLSR 51874 (M658)
2.69 AC
(DRAWING 5-214)

Secondly: In the province of British Columbia, in Osoyoos Indian Reserve No. 1, the whole of lot three according to plan fifty-one thousand eight hundred and seventy-four in the Canada Lands Surveys Records at Ottawa, a copy of which is deposited in the Land Registry Office for the Kamloops Land Registration District at Kamloops under Number M six hundred and fifty-eight; said lot containing by admeasurement two acres and sixty-nine hundredths of an acre, more or less, subject however to a prior grant of easement dated April 19, 1937, to West Kootenay Power and Light Company Limited, for an electric power transmission line as same is shown on Plan IRR 1765 in said Records.

(ROLL 22-8)

IT IS AGREED AND UNDERSTOOD that the aforesaid permission is subject to the following stipulations, provisos and conditions, that is to say;

1. THAT the rights hereby granted may be exercised by the Permittee for such period of time as the said lands are required for the purpose of electric power transmission lines and a transformer station.

2. THAT the Permittee shall, at its own expense, construct operate and maintain an electric power distribution line on the said Osoyoos Indian Reserve No. 1, to supply electric service to Indians on the Reserve who wish such service.

3. THAT for electric power supplied to Indians the Permittee shall charge only the residential 3 or 4 rate as established by the Public Utilities Commission and shall not charge the rural rate.

4. THAT the Permittee shall, at its own expense, construct facilities for the supply of electric power to any Indian owned or occupied building subsequently erected within three hundred (300) feet of the said distribution line when so requested.

5. THAT no change in the rates charged Indian customers on Osoyoos Indian Reserve No. 1, for electric power shall be made without the prior consent of the Public Utilities Commission.

6. THAT the Permittee shall employ members of the Osoyoos Band of Indians to slash and clear the said lands however if no members are available

IMAGE

to do the work non-members may be employed.

7. THAT the Permittee will at all times hereafter indemnify and keep Her Majesty indemnified against all actions, claims and demands that may be lawfully brought or made against Her Majesty by reason of any act or omission by the Permittee in the exercise or purported exercise of the right hereby granted.

8. THAT the Permittee shall not assign or sublet the rights hereunder without the written consent of the Minister.

9. THAT the Permittee will pay and discharge all rates, taxes, duties and assessments whatsoever now charged or hereafter to be charged upon the said permit area or upon the said Permittee or occupier in respect thereof or payable by either in respect thereof.

10. THAT it shall be lawful for the Minister or any person thereunto authorized by him at all reasonable times to enter upon the said lands for the purpose of examining the condition thereof.

11. THAT the said lands shall be used for the purposes aforesaid and for no other purpose.

12. THAT the Permittee, its servants, employees, and workmen shall have and enjoy the right to unload and store material on the said lands for the erection, operation and maintenance of the said electric power transmission lines and transformer station and to unroll wire thereon and to use existing reserve roads and to do all such other acts and things as may be necessary or requisite for the purpose of properly erecting, operating, maintaining and patrolling the said electric power transmission lines and transformer station.

13. THAT the Permittee will not fence the said lands except those occupied by the transformer station and Her Majesty is to be allowed free access to and use of the said lands, except those occupied by the transformer station and except for building purposes and except insofar as it may be necessary for the Permittee to use the same for the purpose of constructing, operating, maintaining and patrolling the electric power transmission lines and transformer station.

14. THAT the Permittee may cut down any trees standing outside the said lands which in its opinion might in falling or otherwise endanger the conductors, wires, structures, equipment or other plant of the Permittee, paying to the Minister reasonable compensation for the value of any trees so cut down.

IT IS FURTHER AGREED that this permit shall be subject to the provisions of the Indian Act and Regulations established thereunder, which may be now in force or which may hereafter be made and established from time to time in that behalf by the Governor in Council.

AND IT IS FURTHER HEREBY STIPULATED AND AGREED that notwithstanding anything to the contrary herein contained, this agreement shall not be deemed to set up a tenancy by implication or otherwise.

IN WITNESS WHEREOF the Deputy Minister of Citizenship and Immigration has hereunto set his hand and the Permittee has hereunto caused to be affixed its corporate seal attested by the signatures of its officers duly authorized in that behalf.

SIGNED, SEALED AND DELIVERED
In the Presence of:

Mackay
As to the signature of the Deputy Minister.

C.M. Isbister
Deputy Minister.

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED.

Anderson
President

Harper
Secretary-Treasurer

EASEMENT

THIS INDENTURE made this 26th day of May , 1965 .

BETWEEN: [redacted]

(hereinafter called "the Grantor")
OF THE FIRST PART

- and -

WEST KOOTENAY POWER AND LIGHT COMPANY, LIMITED

(hereinafter called "the Company")
OF THE SECOND PART

WITNESSETH that in consideration of the sum of Fifteen Hundred Eighteen Dollars ($, 1,518), now paid by the Company to the Grantor, the receipt whereof is hereby acknowledged, the Grantor HEREBY GRANTS AND CONVEYS unto the Company, its agents, servants and workmen, and all other persons acting on its or their behalf, an easement for a right-of-way for full, free and uninterrupted ingress and egress at all times hereafter by day or night with or without equipment and vehicles of any description and with or without animals, to, through, along and over all that certain parcel of land situate, lying and being in the Similkameen Division Yale District in the Province of British Columbia, particularly described as ~~that part~~ those parts of

Firstly: Sub Lot 29 save and except that part shown on Reference Plan [illegible].
Secondly: That part of Sub Lot 29 shown on Reference Plan [illegible].
Thirdly: Sub Lot 49, District Lot 2710, Plan 1189, save and except that part thereof shown on Plan 14107, shown outlined in red on Plan [illegible].

containing by admeasurement 15.18 acres, more or less; AND FURTHER, an easement to construct and maintain thereon electric power transmission, telegraph and telephone lines, with the right to dig up the soil and rock thereof and therein, thereon and thereover, to place poles, towers, wires, posts, cables, guy wires, anchors, equipment and apparatus, and to use, maintain and operate the same and from time to time to inspect, repair, remove, alter, renew and replace the same or any part or parts thereof as may be deemed necessary or expedient by the Company, its agents, servants or workmen, together with the right to cut and clear and keep clear the said right-of-way from any trees and underbrush growing, encroaching, or likely to fall thereon; RESERVING, HOWEVER, UNTO THE GRANTOR THE RIGHT TO CULTIVATE OR OTHERWISE USE THE SAID LAND AND THE RIGHT TO COMPENSATION FOR ANY DAMAGE DONE BY THE COMPANY OR ITS AGENTS, SERVANTS AND WORKMEN WHEN ON THE BUSINESS OF THE COMPANY TO CROPS GROWING THEREON.

The Grantor covenants that it has the right to enter into this Indenture; that it will not at any time hereafter do any act of whatever nature or plant any trees or climbing vines on the said right-of-way that will jeopardize or interfere with the operation or maintenance of the said line or lines or other property of the Company on the said right-of-way; that it will not erect thereon any buildings or structures, and that it will cause no damage to nor interfere with the works or structures of the Company thereon.

The Company may provide gates for vehicles in each and every fence now or hereafter constructed across the said right-of-way and shall furnish each such gate with a good and sufficient lock, a key to which shall be left in the possession of the Grantor.

This Indenture shall enure to the benefit of and be binding upon the parties hereto, their heirs, administrators, successors and assigns.

IMAGE

WITNESS:
Name R.P. Brown
Address Penticton
Occupation BCHS

Consented to by:
[redacted]
[illegible] Canadian Imperial Bank of Commerce

CANADIAN IMPERIAL BANK OF COMMERCE
295 MAIN ST.
PENTICTON, B.C.
MANAGER

WEST KOOTENAY POWER AND
LIGHT COMPANY, LIMITED

and

E A S E M E N T

LEGAL DIVISION
TRAIL, B.C.

AFFIDAVIT OF WITNESS

TO WIT:

[redacted] of the City of Penticton, in the Province of British Columbia,
MAKE OATH AND SAY:

1. I was personally present and did see the within instrument duly signed and executed by William Eric Bomford, the party thereto, for the purpose named therein.
2. The said party executed the said instrument at Okanagan Falls.
3. I know the said party, and that he is of the full age of twenty-one years.
4. I am the subscribing witness to the said instrument and am of the full age of sixteen years.

SWORN before me at Penticton)
in the Province of British Columbia, this)
29th day of June, 1965.)

~~A Notary Public in and for the Province of British Columbia~~
A Commissioner for taking affidavits for British Columbia

ACKNOWLEDGMENT OF OFFICER OF CORPORATION

I HEREBY CERTIFY that, on the day of , 19 , at , in the Province of (whose identity has been proved by the evidence on oath of , who is) personally known to me, appeared before me and acknowledged to me that he is the of , and that he is the person who subscribed his name to the annexed instrument as such officer of the said company and affixed the seal of the said company to the said instrument, that he was first duly authorized to subscribe his name as aforesaid, and affix the said seal to the said instrument, and that such corporation is legally entitled to hold and dispose of land in the Province of British Columbia.

IN TESTIMONY WHEREOF I have hereunto set my hand and seal of office at , this day of , in the year of our Lord one thousand nine hundred and .

A Notary Public in and for the Province of British Columbia
A Commissioner for taking Affidavits for British Columbia

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L 56833
L 56834

L 56833

MODIFICATION OF RIGHT OF WAY

THIS INDENTURE made the 13th day of April 1976.

BETWEEN:

[redacted]

(hereinafter called the "Grantor")

OF THE FIRST PART

AND:

WEST KOOTENAY POWER AND LIGHT COMPANY LIMITED, a body corporate, with an office and place of business at Cedar Avenue, Trail, British Columbia

(hereinafter called the "Grantee")

OF THE SECOND PART

IMAGE

WHEREAS the Grantor is the registered owner of those lands and premises in the Kettle River Assessment District, and more particularly described as;

Firstly:	Sub-Lot 29, EXCEPT that part shown on Plan B4249,
Secondly:	That part of Sub-Lot 29 shown on Plan B4249 EXCEPT those parts included in Plans 21364 and 23475,
Thirdly:	Sub-Lot 45, EXCEPT those parts included in Plans 14107, 17357, 19076 and 21364,

All of District Lot 2710, Similkameen Division Yale District, Plan 1189,

JW

(hereinafter called the "said lands");

AND WHEREAS the Grantee is the owner of a charge by way of Right of Way over those portions of the said lands as shown on Plan "A"2717 and registered in the Kamloops Land Registry Office under No. 118537E (hereinafter called the "said Right of Way");

AND WHEREAS the Grantor has requested that the Grantee release certain other Rights of Way held by the Grantee, and the Grantee has agreed so long as the Grantor extends the said Right of Way as hereinafter provided;

NOW THIS AGREEMENT WITNESSETH that in consideration of the foregoing and of the terms and conditions herein the parties agree that the said Right of Way registered under No. 118537E is extended and modified as follows:

(1) The Grantor grants to the Grantee for the benefit of works constructed or to be constructed on the said Right of Way, the right to cut brush and clear any danger trees on the said lands to the east of and outside the said Right of Way in an area between the easterly boundary of said Right of Way and a line drawn parallel thereto and 16 feet perpendicularly distant therefrom.

(2) The Grantor further covenants with the Grantee for the benefit of the said Right of Way and to the intent that the same shall be construed as a covenant running with the land, not to erect or cause to be erected any buildings within the said 16 foot strip with a height exceeding 20 feet.

(3) This Indenture shall enure to the benefit of and be binding upon the parties hereto, their respective heirs, executors, administrators, successors and assigns.

(4) Wherever the singular or masculine is used throughout this Indenture the same shall be construed as meaning the plural or feminine or body corporate or politic where the context or the parties hereto so require, and where a party is more than one person all covenants shall be deemed to be joint and several.

IN WITNESS WHEREOF the Grantor and Grantee have hereunto set their respective Common Seals in the presence of their proper Officers the day and year first above written.

[redacted]

THE COMMON SEAL of WEST
KOOTENAY POWER AND LIGHT
COMPANY LIMITED was duly
affixed in the presence of:

Vice-President and General Manager

Secretary

Q25.4 Please confirm that the ROW agreements permit FortisBC to replace the lines on the ROW, and to increase the voltage level.

A25.4 FortisBC confirms that the ROW agreements permit the Company to replace the lines on the ROW, and to increase the voltage level.

Q25.5 Please confirm that the ROW agreements permit the proposed Project to upgrade the existing 75L line and to install a second line on the right-of-way.

A25.5 FortisBC confirm that the ROW agreements permit the proposed Project to upgrade the existing 75 Line and to install a second line on the right-of-way.

Q25.6 Are any amendments to existing ROW agreements required for the Project as proposed? If yes, please describe the amendments, the process and timing for achieving them, and any risks to the Project that may result.

A25.6 No amendments are required.

26.0 Project Description - Line 76 and Line 40

Reference: Exhibit B-1-1, Section 4, p. 4

On Section 4, page 4 FortisBC states: "The OTR Project transmission line will be constructed on the existing brownfield line corridor (established 1965) utilizing route Alternative 1A between Oliver and Penticton and is represented geographically in Figure 4-0 above."

Q26.1 When was Line 76 built? What was the expected life expectancy at the time of installation? What is the estimated remaining economic life?

A26.1 76 Line was originally an extension of 40 Line prior to the construction of Vaseux Terminal and was constructed in 1964/65. The assumed life expectancy would have been 40 – 70 years based on FortisBC's current standards, dependent on environment, maintenance and the ability to meet the area's power needs.

Q26.2 When was Line 40 built? What was the expected life expectancy at the time of installation? What is the estimated remaining economic life?

A26.2 Please see the response to BCUC IR No.1 Q26.1.

27.0 Project Description

Reference: Exhibit B-1-1, Tab 4, Section 4.1 (Project Overview), p. 5

Q27.1 Please elaborate on the benefits of steel pole H-frame construction for the Vaseux Lake to Bentley line compared with single-steel-pole construction.

A27.1 The benefit of steel pole H-frame construction compared to single-steel-pole construction over the Vaseux Tap Point to the Bentley Terminal station is itemized below:

All pole installations can be direct bury, (conventional wood pole installation). Direct bury installation is possible due to the resulting lower ground moment from the wide stance of the H-frame type structure. The poles for H-frame construction will be light and lesser diameter than would result with single pole construction.

Single free standing steel pole construction concentrates all of the ground moments on the foundation and thus for the same structure spacing as the H-frame construction, the foundations are usually reinforced concrete which are significantly more expensive than two conventional H-frame pole holes. Alternatively the single steel poles can be guyed in order to reduce the load on the foundation, therefore the costs of two to four anchors and guys, or the span lengths can be reduced to reduce load on the structure and groundline moments.

Road access is available over the length of the Vaseux Tap Point to Bentley section, though much of it can be classified as rough. Even so, smaller bucket trucks can be use to perform much of the line maintenance. H-frame structures are lower and on one level which makes almost all parts of the structure accessible by bucket.

Permanent or removable ladders are required for single steel poles because of their height.

For structure erection and stringing a smaller layout site is required because the H-frame poles are of less length. e.g. 65 foot H-frame steel pole vs. 100 foot for the single steel pole, and a smaller crane can be used to erect the H-frame structures compared to the single steel poles. Activities like sagging and clipping are also simplified because conductors are lower to the ground and on one level, whereas single steel pole construction is on three individual levels.

28.0 Project Description

Reference: Exhibit B-1-1, Tab 4, Section 4.2 (Engineering Design and Capacity), p. 20

Q28.1 Please discuss the difference between using wood poles and using steel poles in the low-fire-risk sections. In your response, please evaluate life-cycle costs based on:

Q28.1.1 current prices;

A28.1.1 It is more desirable from a construction and maintenance perspective to have the same structure types on a transmission line. FortisBC expects to achieve a 40 to 70 year life on transmission structures with relatively little maintenance cost for wood or steel poles for line construction proposed for 40 Line. The primary benefit of steel over wood is fire resistance in this application.

FortisBC has not conducted any specific life cycle costs on wood versus steel pole use in the 4 to 5 kilometre section of low-fire risk on 40 Line. At the time of material tendering for 40 Line current market costs will be sought for both wood and steel poles. An assessment will be made then of what if any premium in net capital cost there may be to have 40 Line constructed using the same steel pole types for its entire 9.3 kilometre distance versus a mix of wood and steel poles.

Q28.1.2 the price of steel rising 25 percent;

A28.1.2 Please see the response to BCUC IR No.1 Q28.1.1

Q28.1.3 the price of steel falling 25 percent.

A28.1.3 Please see the response to BCUC IR No.1 Q28.1.1

29.0 Project Cost Estimate

Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix G, p. 3

Q29.1 Table 5-1 provides a first-level breakdown of the cost estimate for the Project of $141.4 million under Option 1A. Further to Appendix G, page 3, please confirm that this estimate is in real 2007 dollars.

A29.1 No, this cost estimates is in nominal dollars. Please see the response to BCUC IR No.1 Q37.2.

Q29.2 Please provide a table that is similar to Table 5-1 that is expressed in nominal dollars and confirm that the inflation factors used are those on page 3 of Appendix G.

A29.2 Table 5-1 is in nominal dollars, using the inflation factors referred to in the Application on page 3 in Appendix G.

Q29.3 What was the estimated cost of the OTR Project that was in the 2005 Resource Plan that was generally accepted by Order No. G-52-05, and what dollars was the estimated cost expressed in?

A29.3 The reference above should be “the 2005 – 2024 System Development Plan”. The OTR Project components were included in the 2005 – 2024 System Development Plan at an estimated cost of $57.0 million (real dollars, $2005).

Q29.4 The FortisBC 2007-2008 Capital Expenditure Plan at pages 39 to 41 identified a cost for the OTR Project of $75.0 million. Please provide a table that compares the breakdown of the 2005 Resource Plan estimate and this cost estimate to the estimate in Table 5-1. If the dollar bases for the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate are not the same as the basis as Table 5-1, please include columns that show the 2005 Resource Plan estimate and the 2007-2008 Capital Plan estimate on the same basis as Table 5-1. Please show the difference in estimated cost for each item.

A29.4 The reference above should be “the 2005 – 2024 System Development Plan”. Please see Table A29.4 below.

Table: A29.4 OTR Capital Cost Summary Comparisons

Project Component	**2005 SDP**	**2007-08 Capital Plan**	**Table 5-1 OTR CPCN**
Double Circuit 230kV Vaseux to RGA Penticton (75/76 Line)	29,500	36,300	55,527
Single Circuit 230kV Vaseux to Bentley (40 Line)	5,000	6,150	4,550
63 & 138kV Circuits Bentley to Oliver			672
New Bentley Terminal	20,500	25,200	30,990
Oliver Substation Upgrade		4,900	5,687
RG Anderson Terminal Upgrade			10,498
Lee & Bell Terminals 138kV Capacitor Upgrade (formerly Kelowna Shunt Capacitors)	2,000	2,450	3,297
Vaseux 230kV Terminal Upgrade			4,440
Vaseux 500kV Terminal Upgrade			2,928
Planning & Preliminary Engineering			5,363
Project Management, Engineering & Operations Support			3,807
Sub Total	**57,000**	**75,000**	**127,760**
AFUDC			9,736
Removals & Salvage		3,050	3,912
TOTAL	**57,000**	**78,050**	**141,408**

Q29.5 Further to the response to the previous question, for each item where there is a material difference between the estimates, please provide a detailed explanation of the causes for the difference. Where the scope of the project has changed, please justify why the change to scope is necessary. Where the change to the estimate for an item has several significant causes, please identify the portion of the increase that is due to each. Please specifically address the double circuit for the connection from Vaseux Lake to RG Anderson, and the separation of the transformers at Vaseux Lake.

A29.5 The estimates included in the 2005 SDP and 2007/08 Capital Plan were at a conceptual level only for planning purposes only and not for rate setting purposes. The original 2005 estimate of $57.0 million was in $2005 dollars excluding overheads, and was adjusted to $75.0 million for the Capital Plan based on inflation and required overheads. The $75.0 million did not include $3.05 million in removals and salvage budgeted at the time. Detailed scope refinement and preliminary engineering had not taken place in the development of these estimates.

The conceptual scope for the development of the 2005 SDP included the double circuit 230kV from Vaseux to RGA, a single circuit 230kV from Vaseux to Oliver, the Bentley Terminal, and Shunt Capacitors in the Kelowna region.

Detailed engineering, planning and estimating in 2007/08 for inclusion in the CPCN had refined the conceptual scope to meet the primary requirements of the project. The main conceptual scope elements had not changed from the 2005 SDP and 2007/08 Capital Plan with the exception of:

- The replacement of one transformer at RGA and its subsequent relocation to Bentley to provide additional capacity and to reduce operational complexity at RGA (with no net change in the number of transformers purchased for the project); and

- The inclusion of additional 230 kV and 500 kV breakers at Vaseux Terminal to further improve the reliability of the station.

Subsequent scope refinement of all project elements coupled with un-anticipated inflation in the labour and commodity's markets further increased the costs to $141.4 million as detailed in Table 5-21 (Exhibit B-1-1) and Appendix G (Exhibit B-1-3).

30.0 Project Cost Estimate

Reference: Exhibit B-1-3, Appendix G, pp. 4, 8

Q30.1 A comparison of Tables G1 and G5 indicates several smaller differences in the cost estimates for components of the project that would not appear likely to be affected by the type of structures between Vaseux Lake and RG Anderson (e.g., the estimate for Bentley Terminal). Please explain and justify the differences, and confirm the total cost estimates for the project alternatives.

A30.1 Some project common services costs were estimated and set into a budget category that will be managed to during the project. Most of these are "semi-fixed" costs such as project support services, project management, procurement and construction management, project insurance, property services, environmental monitoring etc that remained the same or varied slightly with the Alternatives estimates. To reflect these common costs in the project elements and they were allocated to the Project elements in the Tables based on their relative percentage of the project. As the Alternatives for the double circuit varied the relative cost proportion of the double circuit in the project total cost, it caused minor shifts in the common costs among the other project elements.

31.0 Project Cost Estimate

Reference: Exhibit B-1-1, Tab 5, Section 5.1, p. 2

Q31.1 Please explain the cost estimating technique used to develop this estimate.

A31.1 The cost estimate was developed using a technique known as a 'Bottom-up Estimating'. This is defined in the Max's Wideman Comparative Glossary of Project Management Terms v3.1as follows:

> *The preparation of detailed estimates for every task in the work breakdown structure and summing them up to provide a total project cost estimate or cost plan.*
>
> *The approach to making a cost estimate or plan in which detailed estimates are made for every task shown in the work breakdown structure and then summed to provide a total cost estimate or plan for the project.*

Q31.2 Please supply an electronic copy of the complete estimate.

A31.2 An electronic version of the requested estimate is being filed concurrently with these responses.

Q31.3 Please identify the exclusions and assumptions made to perform this estimate.

A31.3 Refer to Appendix G 1.0 Cost Estimates (Exhibit B-1-3).

Exclusions:

The project cost estimate does not include allowances for events outside of the control of FortisBC which would include at least the following: changes in legislation related to aspects of the project; changes in escalation due to market forces; taxation or duties; accidents or catastrophes; abnormal weather; civil disobedience; and strikes or other labour disruption and other force majeure related events.

Assumptions:

- The construction and labour markets do not change significantly from the time of the estimates, that is, markets can provide competitive bids for a project of this size;
- Productivity rates will not fall outside the range the estimates were prepared upon;
- The project schedule does not change significantly from that laid out in the Application;
- The final design is essentially the same as the preliminary level design;
- Preliminary level line design work done to date is sufficiently accurate using existing line drawings and digital elevation model terrain data;
- Preliminary access and clearing design is sufficiently accurate based on ortho-photography assuming average 29 meter trees, that recent hazard tree management on existing route has been done by FortisBC, and with no consideration of possible mountain pine beetle attack in area; and
- Detailed engineering for key long lead material and equipment items starts in Q2 2008, and the Project is in service by November 2010 for Alternative 1A;

Q31.4 What are the FortisBC and BC Hydro Corporate Overhead rates applied for this project?

A31.4 A FortisBC Capital Overhead rate charged at 7% is applied to all Project costs with the exception of AFUDC.

Pursuant to the OTR EPC Agreement, BC Hydro recovers a margin through its loading which is applied to labour and other related expenses. There is no loading applied to construction or supply subcontracts. It is FortisBC's understanding, based on discussions with BC Hydro, that this margin is for the cost recovery of unallocated BC Hydro corporate costs.

Q31.5 If Monte Carlo methods were employed for this estimate, please discuss.

A31.5 Monte Carlo simulation methods were not used.

Q31.6 Based on the five cost estimate classifications by Association for the Advancement of Cost Engineering (“AACE”), Recommended Practice for Classifying Cost Estimates, what would be FortisBC’s classification of this estimate?

A31.6 This would be classified as a Class 3 estimate as preliminary design has been completed and definition is estimated at 20%. An AACE Class 3 estimate falls within a 10%-40% definition.

Q31.7 Did FortisBC conduct an internal review of this cost estimate and was there input from an independent third party other than BC Hydro? Was the review subjective (informal, less-structured) or objective (formal, structured, checklist reviews) in nature?

A31.7 Yes, FortisBC conducted a subjective internal review with no input from third parties.

Q31.8 Did FortisBC conduct an external review of this cost estimates and project scope using an independent third party other than BC Hydro? If not, why not?

A31.8 No, FortisBC did not conduct an external review using an independent third party. Based on the subjective internal review of the cost estimate and a detailed review with BC Hydro’s staff throughout the development stage FortisBC did not deem it necessary.

Q31.9 Please provide an OTR Project Capital Cost Summary table in the format shown for the project cost estimate in Table 5-1.

Item	2007	2008	2009	2010	Total
Direct Costs					
Indirect Costs					
BC Hydro Corporate Overhead Costs					
FortisBC OTR Project Support Team Costs					
FortisBC OTR Project Management Costs					
BC Hydro Corporate Overhead Costs					
AFUDC					
Total Costs					
Escalation (includes Inflation)					
Performance Measurement Baseline (“PMB”)					
Management Reserves					
Total Allocated Budget (“TAB”)					
BC Hydro Profit/Fees					
Contract Price					
Other Non-Contract Costs					
First Nation Consultation & Accommodation					
Regulatory Cost					
Contingency					
Total Project Cost (“TPC”)					

Item	Definition
AFUDC	Allowable Funds Used During Construction

Direct Costs	Any costs that may be identified specifically with a particular cost objective.
Indirect Costs	Costs, which because of their incurrence for common or joint objectives, are not readily subject to treatment as direct costs.
Total Costs – Direct & Indirect	Total of direct and indirect costs.
Escalation (including inflation)	Escalation is the provision in a cost estimate for increases in the cost of equipment, material, labor, etc., due to continuing price changes over time. Escalation is used to estimate the future cost of a project or to bring historical costs to the present (Inflation).
Performance Measurement Baseline ("PMB")	The Performance Measurement Baseline is the baseline that summarizes all the budgets assigned to scheduled work and planning packages (listed in the Work Breakdown Structure) and provides a measure against which actual performance can be compared.
Management Reserves	An amount of the total allocated budget withheld for management control purposes by the contractor. Management Reserve is part of the Performance Baseline.
Total Allocated Budget ("TAB")	Sum all budgets for work on contract. The total allocated budget is all scope authorized under the contract included negotiated and also includes unpriced efforts.
Contract Price	The contract budget does not include profit or fees because progress and performance is never measured based on the amount of profit or fee earned because profit or fee are not used to perform work scope
Other Non-Contract Costs	Project costs outside the scope of the contract. The total allocated budget is simply the budget allocated to the contract because there often is budget allocated to non-contract requirements such as payment in lieu of taxes.
Regulatory Cost	The costs for regulatory approvals.
Contingency	Contingency is the portion of project budget that is available for uncertainty within the project scope but outside the scope of the contract. That is, contingency is budget that is

	not place on contract.
Total Project Cost ("TPC")	Total cost for the project including all cost regardless of sources or type of funds.
Performance Baseline ("PB")	The collected key performance, scope, cost, and schedule parameters, which are defined for all projects. The Performance Baseline defines the threshold and boundary conditions for a project and is a top-down tally of the entire project budget (total cost of the project) including such items as management reserve and profit or fee.
S-curve (spending curve; funding profile)	Graphic display of cumulative costs, labor hours, or other quantities plotted against time.
Earned Value	(1) A method for measuring project performance. It compares the value of work performed with the value of work scheduled and the cost of performing the work for the reporting period and/or cumulative to date. (2) The budgeted cost of work performed for an activity or group of activities.

A31.9 The capital cost summary in a format similar to that requested is provided in Table A31.9 below.

Table A31.9: OTR Project Capital Cost Summary

Item	2007	2008	2009	2010	Total
Direct Costs FBC		7,937	40,035	32,565	80,537
Indirect Costs	3,437	535			3,972
EPC		1,127	5,636	4,509	11,272
FortisBC OTR Project Support Team Costs		181	1,603	1,223	3,007
FortisBC OTR Project Management Costs		200	300	300	800
BC Hydro Corporate Overhead Costs (1)					
AFUDC		647	2,892	6,197	9,736
Total Costs	3,437	10,627	50,467	44,794	109,324
Contingency (2)		1,375	6,704	5,102	13,181
Escalation (includes Inflation)		1,420	6,920	5,261	13,600
Baseline Capital Budget	3,437	13,422	64,091	55,156	136,105
Management Reserves (2)					
Removals & Salvage			823	1,921	2,745
Contingency (2)			171	398	569
Escalation (includes Inflation)			179	419	598
Total Capital + Salvage Budget	3,437	13,422	65,264	57,894	140,017
BC Hydro Profit/Fees (1)					
Regulatory Costs	214	856			1,070
Public Consultation	321				321
Total Project Budget	3,972	14,278	65,264	57,894	141,408

(1) BC Hydro Corporate Overheads. Profits and Fees are embedded into Direct Costs to FortisBC under the EPC.

(2) FortisBC does not have a Management Reserve component in the budget. Contingency is managed by the OTR Project Manager and reported on to FortisBC Senior Management.

Q31.10 Please provide the project summary S-curve for the project cost estimate in Table 5-1 as set out in the response to the previous question, using PMB cost over time and showing any management reserve as a shaded bar across the top. Please refer to http://www.oecm.energy.gov/Portals/2/DOE%20EVM%20Gold%20Card%2020060621.pdf for a typical format.

A31.10 FortisBC does not use earned value methodology in its quality, schedule and cost (QSC) monitoring and reporting process. Once the project is approved and detailed construction and spending schedules have been refined FortisBC will update the cost curve supplied below to reflect any project budget or schedule changes. This cost curve is similar to the ones supplied in previous Commission progress report for FortisBC major projects and is at a Planning level only.

Variances between budget, actual and forecast would be further expounded in quarterly progress reports, if they are a requirement of the CPCN approval. Key project component budget costs will be compared to actual costs to date, percentage of budget spent, percentage of component compete and key component stage and as shown in Table A31.10 below. This format presented along with progress report content could be further developed to meet the Commission's additional needs.

1 **Figure A31.10**

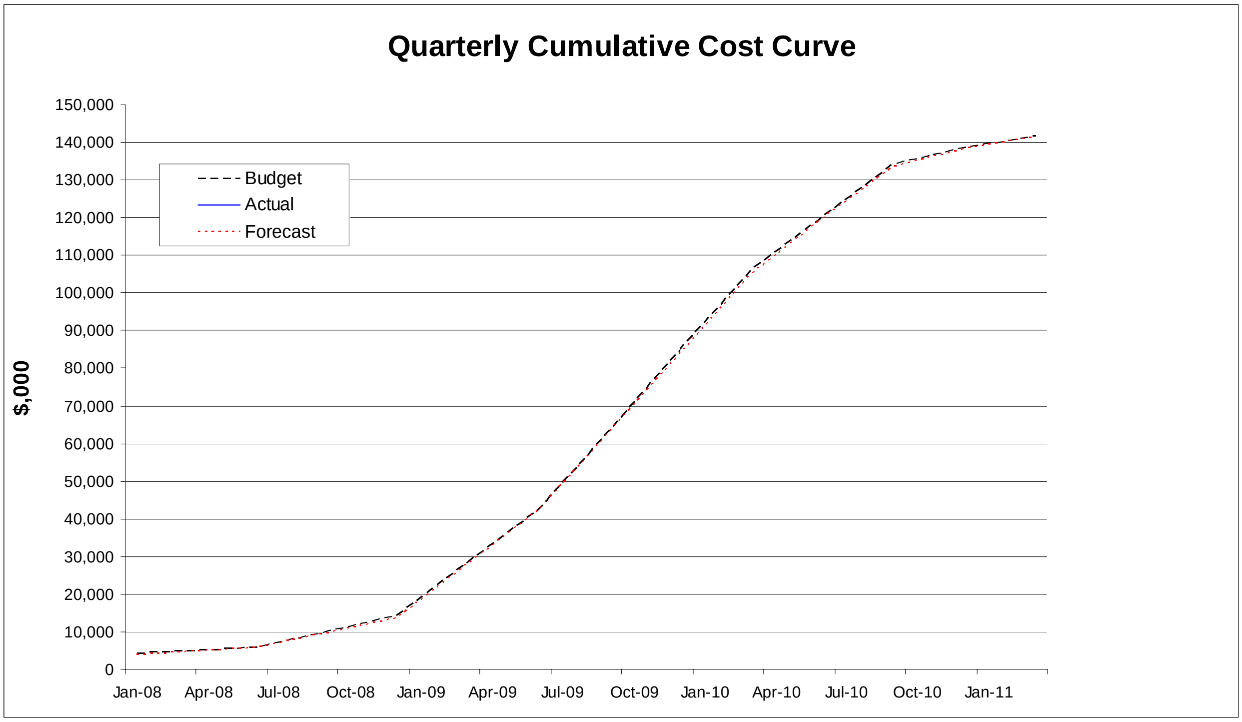


Table A31.10: Key Project Component vs. Cost Tracking

Key Project Component	Budget ($000)	Actuals ($000)	% Budget Spent	% Complete	Current Stage
Double Circuit 230kV Vaseux to Penticton (75/76 Line)	55,527	0	0%	0%	Engineering, Construction or Commissioning
Single Circuit 230kV Vaseux to Bentley (40 Line)	4,550	0	0%	0%	
63 & 138kV Circuits Bentley to Oliver	672	0	0%	0%	
New Bentley Terminal	30,990	0	0%	0%	
Oliver Substation Upgrade	5,687	0	0%	0%	
RG Anderson Terminal Upgrade	10,498	0	0%	0%	
Lee Terminal 138kV Capacitor Upgrade	1,675	0	0%	0%	
Bell Terminal 138kV Capacitor Upgrade	1,622	0	0%	0%	
Vaseux 230kV Terminal Upgrade	4,440	0	0%	0%	
Vaseux 500kV Terminal Upgrade	2,928	0	0%	0%	
Planning & Preliminary Engineering (includes Regulatory)	5,363	3,972	74%		
Project Management, Engineering & Operations Support	3,807	0	0%		
AFUDC	9,736	0	0%		
Removals & Salvage	3,912	0	0%		
TOTAL	**141,408**	**3,972**	**3%**		

Note: Engineering includes contract major equipment procurement.

32.0 Project Cost Estimate

Reference: Exhibit B-1-1, Tab 4, p. 18; Tab 5, p. 2

Q32.1 Please provide a circuit cost per kilometer for the new lines in the Vaseux-Penticton Zone (L75 and L76 lines).

A32.1 The circuit cost for the 28 kilometres of double circuit lines Vaseux to RG Anderson with reference to Table 5-1 is $55.52 million or $1.98 million per kilometre.

Q32.2 Please confirm that Line 40 from Vaseux Lake to Bentley Terminal will be re-built as an 11 km single circuit 230 kV line on H-frame structures, at an estimated cost of $4.55 million or $414,000 per kilometer.

A32.2 The 1.7 kilometre section of 40 Line east from Vaseux was pre-built as part of the South Okanagan Reinforcement Project at 230 kV and interim operated at 161 kV. The remaining 9.3 kilometres of 40 Line will be re-built as single circuit 230 kV for the estimated cost of $4.55 million or $489,000 per kilometre.

Q32.3 What would be the cost per kilometer of a high capacity single circuit 230 kV line on H-frame structures (Cross Section B) from Vaseux Lake to RG Anderson (Alternative 1C)?

A32.3 The circuit cost for the 28 kilometres of a high capacity single circuit line from Vaseux to RG Anderson is $44.02 million or $1.47 million per kilometre.

Please see the response to BCUC IR No.1 Q14.5

Q32.4 If there is a significant difference between the estimated unit costs for Line 40 and the Alternative 1C line, please provide a detailed comparison of the cost estimates for the two lines and explain the reasons for significant differences.

A32.4 Please refer to the response to BCUC IR No.1 Q14.3 for an updated summary of the costs for the existing options and the added Alternative 1C.

Yes, there is a significant difference between the estimated unit cost for 40 Line and the Alternative 1C. These differences are in the materials and construction costs of the Alternative 1C due to the heavier, higher ampacity conductor needed.

The 40 Line is designed with 795 kcmil Drake conductor, whereas the 76 Line Alternative 1C is with 1,590 kcmil Lapwing, which is roughly twice the size of the Drake conductor and will have much higher install tensions. The conductor size and line tensions impact structure design details such as increased height, pole mass, and foundation requirements. The more robust structures require additional assembly/erection labour and equipment to install. The larger 1,590 kcmil conductor will result in shorter pull lengths and more effort and heavier equipment during stringing.

To offset some of the reliability lost by the single circuit Alternative 1C versus the security of double circuit Alternatives, Alternative 1C includes continuous overhead ground wire and associated continuous buried counterpoise, while the 40 Line does not. The ground wire and counterpoise would improve lightning protection of the 76 Line.

33.0 Project Cost Estimate

Reference: Exhibit B-1-1; Tab 4, p. 10

Q33.1 S 4.2.1: Reference is made to 'preliminary designs', and 'These designs will be refined as part of detailed design after OTR Project approval.' Table 4-1-2 indicates a total cost for the OTR Project of $141.408 million.

Q33.1.1 What level of confidence does FortisBC have in its current cost estimates?

A33.1.1 Based on a subjective internal review and experience working with BC Hydro on the South Okanagan Reinforcement Project FortisBC has a +20/-10% level of confidence in the cost estimates.

Q33.1.2 What is FortisBC's range of accuracy for cost estimates based on the preliminary designs?

A33.1.2 As outlined in Appendix G Route Alternatives 1A 2010, 1B 2010 and 2B 2012 are at the +20/-10% level. Alternatives 2A 2012 and 2B 2012 are at the +35/-15% level.

Q33.1.3 Will FortisBC be able to provide more firm cost estimates for the Commission to consider in the course of this proceeding?

A33.1.3 No, FortisBC does not intend to issue any Requests for Quotes for major equipment and resource pricing prior to Commission approval of the Project.

34.0 Project Cost Estimate- Contingency

Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix G, Section 1.0, p. 3

Q34.1 Please explain the basis for FortisBC using 15 percent for the project contingency estimate.

A34.1 At this stage of the project, with approximately 20% of the engineering complete, 15% contingency is appropriate and typical for a cost estimate with this level of definition.

Q34.2 Please provide a risk and contingency analysis for the cost estimate in Table 5-1 that is based on at least these five risk factors: technical issues, design completion and maturity, equipment/vendor, construction cost, and construction schedule. Please provide a impact magnitude cost for each item listed and include in the risk matrix requested below.

A34.2 Please see the response to BCUC IR No.1 Q34.3 below.

Q34.3 Please provide a risk matrix that is a five by five matrix that allows assigning a risk to one of 25 blocks based on a qualitative assessment of its relative impact and the likelihood of its occurrence and include the magnitude cost of each item?

A34.3 To prepare the requested qualitative risk and contingency analysis, the three tables further below were adapted for the OTR project:

Table 1 - Impact Rating to Project
Table 2 - Likelihood of Risk to Occur During the Project
Table 3 - Net Classification of the Risk to the Project

The five risk factors were included in the inventory of eight relevant and significant project risk factors (Table 4) which includes a relative assessment of impact and likelihood of the risk, its contingency or risk mitigation, and the re-assessment after application of the contingency mitigation.

When the resulting or net risks are reviewed against the five by five matrix the risks are summarized as follows:

3 High Risks
3 Moderate Risks
1 Guarded
1 Low Risk

Table A34.3 (a) - Impact Rating to the OTR Project

Description	Criteria
Insignificant	The consequence would not threaten the scope or schedule of any aspect of the project and would be dealt with on a routine basis. Event results in a financial impact to the project of less than $50,000.
Minor	The consequences would threaten the scope and/or schedule of some aspect of the project but would be dealt with internally. Event results in a financial impact to the project of less than $0.5 million.
Moderate	The consequences would not threaten the success of the project but could affect scope and/or schedule. Event results in a financial impact to the project of greater than $0.5 million.
Major	The consequences would have a significant impact on the project's scope, cost and/or schedule. Event results in a financial impact to the project greater than $2.0 million. (>1.5% <10% of project cost)
Catastrophic	The consequences would threaten the overall success of the project's quality, scope cost and/or schedule. Event results in a financial impact to the project greater than $14.0 million (>10% of project cost).

Table A34.3 (b) - Likelihood of Risk to Occur During the OTR Project

Description	Criteria
Rare	May occur only in exceptional circumstances.
Unlikely	Could occur at some time/the event has not yet occurred but could occur at some time.
Possible	Might occur at some time/the event could occur once in your career or could occur at any time.
Likely	Will probably occur in most circumstances/the event has occurred several times or more in your career.
Almost Certain	Is expected to occur in most circumstances/will occur on an annual basis or more frequently.

Table A34.3 (c) - Net Classification of the Risk to the OTR Project

Net risk – Likelihood Vs. impact Ratings					
LIKELIHOOD	**IMPACT**				
	Insignificant	**Minor**	**Moderate**	**Major**	**Catastrophic**
Almost Certain	Moderate	Moderate	High	Extreme	Extreme
Likely	Guarded	Moderate	High	High	Extreme
Possible	Guarded	Moderate	Moderate	High	High
Unlikely	Low	Guarded	Moderate	Moderate	Moderate
Rare	Low	Low	Guarded	Guarded	Moderate

Table: A34.3 (d) - FortisBC OTR Project – Risk Inventory

		Inherent Risk				Residual Risk			
Risk Description	**Risk Category**	**Impact**	**Likelihood**	**Rating**	**Risk Response**	**Impact**	**Likelihood**	**Rating**	**Comments**
1. Active construction industry limits competitive bidding for construction of lines and stations, increasing costs above estimate. Compounded by shortage of skilled workers.	Cost Quality	Catastrophic	Likely	Extreme	• Inflate construction cost estimate based on review of market conditions and forecast. • Procurement strategy to bundle contracts as appropriate to attract most number of contractors to bid. • Inflate line construction labour cost estimate with 20% labour productivity factor • Quality assurance tasks in place to monitor that quality is delivered as specified by contractors	Major	Possible	High	Immediate & Contingent
2. Active construction industry has limited skilled resources for construction of lines and stations, delaying or slowing work progress .	Schedule	Moderate	Likely	High	• Procurement strategy to assess contractor availability locally & regionally to determine extent of tender solicitation needed to get contractors. • Schedule buffers	Moderate	Likely	High	Immediate & Contingent
3. Equipment/Materials (transformers, poles, breakers etc) prices differ from estimate period, impacting costs.	Cost	Major	Likely	High	• Assess equipment & material cost trends and include in project cost escalation estimate. • Procurement strategy to tender with adequate lead times, and where beneficial make use of Alliance agreements with suppliers e.g. transformers	Moderate	Likely	High	Immediate & Contingent
4. Technical issues with transmission or station design that are not addressed in project scope or estimates that require extra unplanned costs to resolve.	Cost Scope Schedule	Major	Likely	High	• Retain experienced engineering firm - BCH has done significant and recent 230 kV work in BC and in the Okanagan and combine team with local FortisBC expertise. • Identify & address issues in Definition Phase of Project. • Use of contingency funds • Use of Professional Errors and Omissions Insurance	Minor	Possible	Moderate	Immediate & Contingent
5. Design completion and maturity is not adequate and gaps that are not addressed in project scope or estimates that require extra unplanned costs to resolve.	Cost Scope Schedule	Major	Likely	High	As above plus: • Conduct appropriate level of preliminary planning, engineering on project to reduce unknowns. • Use proven recent designs and equipment in project.	Moderate	Possible	Moderate	Immediate & Contingent
6. Loss during construction due to fire/flood/theft or other loss risks.	Cost Schedule	Major	Possible	High	• Construction Insurance with appropriate deductibles. • Schedule buffers • Site security review	Minor	Rare	Low	Immediate & Contingent
7. Long delivery equipment (transformers, steel double circuit poles).	Schedule	Moderate	Likely	High	▪ Schedule ordering of long lead items to match delivery requirements. ▪ Schedule buffer.	Minor	Possible	Moderate	Immediate & Contingent
8. Environmental impacts of construction activities.	Environment	Moderate	Possible	Moderate	▪ Completed comprehensive ESIA ▪ Environmental Management System to be used. ▪ Incorporate EMP in contracts.	Minor	Unlikely	Guarded	Immediate & Contingent

35.0 Project Cost Estimate- Inflation

Reference: Exhibit B-1-3, Appendix G, Section 1.0, p. 7

Q35.1 Please detail how the figures for inflation for the Vaseux 230kV, and Vaseux 500kV, Terminal Upgrades were arrived at.

A35.1 For the Vaseux 230 kV the approach taken was based on two key variables:

- Annual cash flow.
- Inflation rates as provided in response to BCUC IR No.1 Q37.2

Inflation rates were prorated for the partial years, 2007 and the last year when monies are to be spent. The calculation would be on an annual basis to the mid-point of the year when the monies were spent (based on a straight-line expenditure). The inflation rates used are listed in Appendix G, page 3 of the CPCN Application (Exhibit B-1-3).

For the Vaseux 500 kV Terminal upgrade the BCTC estimate and inflation calculation was prepared in May 2007 using the same technique as above. However at that time the recommended project inflation rates applied the higher escalation rates, noted in the response to BCUC IR No.1 Q37.2, only to the civil construction portion of the estimate, with a lower 2.1% inflation rate for the remainder of the upgrade costs. The civil portion of the Vaseux 500 kV upgrade is a small portion of the costs.

36.0 Project Cost Estimate - Inflation

Reference: Exhibit B-1-3, Appendix G, MMK Report, p. 3

Q36.1 Please list and quantify the elements of the OTR Project that are expected to be priced in US dollars.

A36.1 All prices used in the cost estimate were in Canadian dollars as of November 2007. It is difficult to say at this point what is expected to be purchased from the US as procurement will be via tendering and source of supply is not limited to the North American market. Tenders will be issued for pricing in Canadian dollars.

Q36.2 Please explain how FortisBC escalated the costs of these elements to calculate the Canadian dollar costs for the Project, considering both inflation and exchange rate.

A36.2 All prices used in the cost estimate were based on recent purchases and escalated to November 2007 Canadian dollars. Therefore no US exchange rates were used. The inflation rates used are listed in Appendix G, page 3 of the CPCN Application (Exhibit B-1-3).

37.0 Project Cost Estimate - Inflation

Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix G, MMK Report, p. 4

“The recommended allowances are also based on the assumption that BC Hydro takes appropriate cost mitigation measures to dampen the impact of construction cost inflation, through procurement strategies, value engineering and other cost mitigation initiatives” (B-1-3, Appendix G, p. 14).

Q37.1 Please describe the cost mitigation measures that FortisBC plans to take for the OTR Project.

A37.1 Cost mitigation measures will focus on procurement strategies to obtain competitive pricing in an active equipment supply and construction market. For example for significant purchases such as power transformers FortisBC may bundle these purchases with other orders of FortisBC to maximize the company’s “bulk” buying power.

For transmission line and substation construction work the project will be discussed with the BC contractors to assess capacity and other constraints that may limit competitive tenders. Depending on those assessments the construction work may be let in smaller separate contracts or bundled in larger packages to be attractive to the most number of firms capable of doing the work. The Company may also consider a national or international tender.

Q37.2 Please provide an escalation (including inflation) analysis for the cost estimate in Table 5-1.

A37.2 Total cost escalation (includes inflation CPI) for the project is estimated at $14.346 million. Cost escalation in the estimate was applied to engineering, construction and materials. They are imbedded into each component in the estimate. As the estimate was completed in May 2007 in May 2007 dollars, 6% was used for the remainder of 2007; 5% for 2008; 5% for 2009; and 4% for 2010.

Please see Appendix G, 1.0 Cost Estimates and the MMK Report from the CPCN Application (Exhibit B-1-3), and the response to BCUC IR No.1 Q31.9.

38.0 Project Cost Estimate – Inflation

Reference: Exhibit B-1-1, Tab 3, p. 7; Exhibit B-1-3, Appendix G, MMK Report, pp. 2, 8

BC Stats, Current Statistics Report, August 2007

BC Stats, Current Statistics Report, November 2007

"On balance, we expect that the Canadian electric utility transmission/distribution construction price indices for 2007, when they become available in 2008, will show significantly higher increases than for 2006 and prior years (MMK Report, p. 2)."

"The general non-residential construction industry in BC continues to experience strong levels of building activity, led by commercial construction. While the value of industrial building permits in BC in the first six months of 2007 is down from the same period in 2006, strong markets in Alberta and Ontario continue to put pressure on industrial construction in BC."

"Price indices continue to increase sharply for non-residential construction in BC. Industrial construction price levels in Vancouver rose 6.3% between the fourth quarter of 2006 and second quarter of 2007. This rate of increase was down from the previous six months, but up from the same period in the preceding year. (B-1-3, MMK Report, p.8)"

"Data released by Statistics Canada in September 2007 indicate a short-term decline in new building permits in British Columbia between June 2007 and July 2007. However, it is premature to conclude whether this indicates a shift in medium-term trends (MMK Report, p. 47, footnote)."

"The value of building permits issued by BC municipalities retreated (-2.9%, seasonally adjusted) in June after surging in the previous month. Residential permits declined (-12.6%), while increases in the industrial (+93.3%), institutional (+22.2%) and commercial (+12.7%) sectors pushed planned spending on non-residential projects up 18.5%."

"In Kelowna, permits soared 32.3%, while Victoria (+7.7%) experienced a more moderate increase. On the other hand, Vancouver (-4.8%) and Abbotsford (-43.8%) saw the value of permits slip. Nationally, permits inched down 0.4% (BC Stats, Aug. 2007)."

"The value of building permits issued by BC municipalities fell 19.2% (seasonally adjusted) in September. The decline reflects a significant drop in non-residential building projects (-38.7%) coupled with a 9.8% decline in residential permits. Among census metropolitan areas in BC, Victoria (+32.4%) and Kelowna (+10.4%) showed growth, while building intentions in both Abbotsford (-14.8%) and Vancouver (-31.3%) were substantially lower than in August. Canadian permits were down 1.7% (BC Stats, Nov. 2007)."

The MMK Report is dated September 2007, and the citation from page 2 of the Report refers to data to the end of 2007-Q2 (June 2007). The BC Stats reports indicate a non-trivial slowing of non-residential building activity between their August 2007 Report (which incorporates data to June 2007) and the November 2007 Report (which incorporates data to September 2007).

Q38.1 Given the recent trend in building permits indicated by the BC Stats Reports, please explain whether FortisBC agrees with MMK's view that it remains premature to opt for deferring project commencement and

potentially realizing cost advantages (as suggested by the recent trend reported by BC Stats), versus the advantages of making project commitments early to avoid inflation (as per the MMK Report forecast of continuing increases in costs).

A38.1 FortisBC agrees with the MMK Report that it remains premature to opt for deferring project commencement and potentially realizing cost advantages. The building permits discussed in the BC Stat's reports are not related to electrical infrastructure projects. Considering current capital plans going forward in British Columbia by FortisBC, BC Hydro and BCTC, the potential for any cost advantages by deferral is extremely volatile. Making project commitments early are important to secure resources and long delivery material items considering the risks associated with inflation, resource availability and commodity pricing in the utility industry sector.

Q38.2 FortisBC states: "FortisBC has not identified any options or measures that could significantly impact the scope or timing of the OTR project" (Exhibit B-1-1, Tab 3, p. 7). Please explain whether FortisBC considers that OTR Project costs could be reduced by initiating the project after the majority of the Olympic construction is completed, and what the cost impact would be.

A38.2 FortisBC does not believe the OTR Project costs can be reduced by initiating the Project after the Olympics. Olympic projects are related to venues and transportation while the OTR Project is a major electrical infrastructure project using a different resource and materials set.

39.0 Project Schedule

Reference: Exhibit B-1-3, Appendix G, Section 2.0, p. 14

"If significant load changes occur versus forecast or other system conditions changes or equipment failures occur that reduce the planning construction periods, the OTR Project schedule could be delayed" (B-1-3, Appendix G, p. 14).

Q39.1 What is the minimum load change that would cause the OTR project schedule delay?

A39.1 The construction window of the OTR Project would be between early spring and late fall. Planned outages, (i.e. outage of 76 Line) will be required during construction. The context of the above statement was to indicate that under situations of unexpected weather conditions, (i.e. extreme summer temperatures/prolonged or early winter weather conditions) may create a significant load change within the system that may force the construction window to shrink so as to ensure operational flexibility. Also, an N-1 situation such as the loss of 72 Line and 74 Line or BC Hydro outage from Vernon Terminal for an extended period may force placing 76 Line back into service thus affecting the construction schedule, which could delay the OTR Project completion date.

While such a scenario will depend on several variables as indicated above, it is difficult to quantify any specific limiting condition.

Q39.2 FortisBC states "The OTR Project schedule also assumes that qualified contractors will be available in the time periods needed." In the event that qualified contractors are not readily available, does FortisBC intend to delay the project, or offer a premium to contractors as an incentive to agree to undertake the project immediately? If delayed, what delay does FortisBC anticipate? If a premium, what impact would FortisBC expect that to have on project costs?

A39.2 It is difficult to pre-determine the response and impacts as it will in part be dependant on which work and what type of contractors are not available and its impact on the overall project. Please refer to the response to BCUC IR No. 1 Q37.1 which discusses FortisBC's intent to assess contractor availability and contracting strategy nearer to but prior to tendering of the work. The project estimate contains cost escalation and contingency allowances to address some cost premiums if needed and work re-scheduling within the project plan would also be assessed at the time if the issue arises to minimize project cost.

40.0 Alternatives, Vaseux to Anderson

Reference: Exhibit B-1-1, Tab 4, pp. 11-18, 34

Q40.1 FortisBC proposes to build 75L and 76L as a double circuit on single poles consistent with Cross Section C on page 34 (Alternative 1A). As the structures shown as Cross Section E would result in a considerable reduction in project cost (Alternative 1B), please discuss in detail each of the reasons why FortisBC proposes single pole construction.

A40.1 The key concerns expressed at the open houses in 2007 that FortisBC could address with the use of the existing right of way as proposed were visual impact, EMF and environmental impact.

The single pole double circuit structure proposed was found to be more aesthetically pleasing, has lower EMFs and has a softer environmental footprint than the more imposing double circuit H-Frame structures.

Please refer to BCUC IR No. 1 Q42.1 and Figure 4-2-1A-G renderings from the CPCN Application (Exhibit B-1-1) with regards to visual impact;

Refer to BCUC IR No. 1 Q57.1 – Q57.12 and Figure 4-6A and B from the CPCN Application (Exhibit B-1-1) with regards to EMF.

Refer to Appendix I Table 6-2 from the CPCN Application (Exhibit B-1-3) with regards to environmental impact.

Q40.2 Assuming that the reasons for single pole construction relate primarily to the impact on local residents and hence that these impacts would largely be concentrated in a few areas, would it be possible to largely build the lines using H-frame structures and use single poles only for the more populated areas?

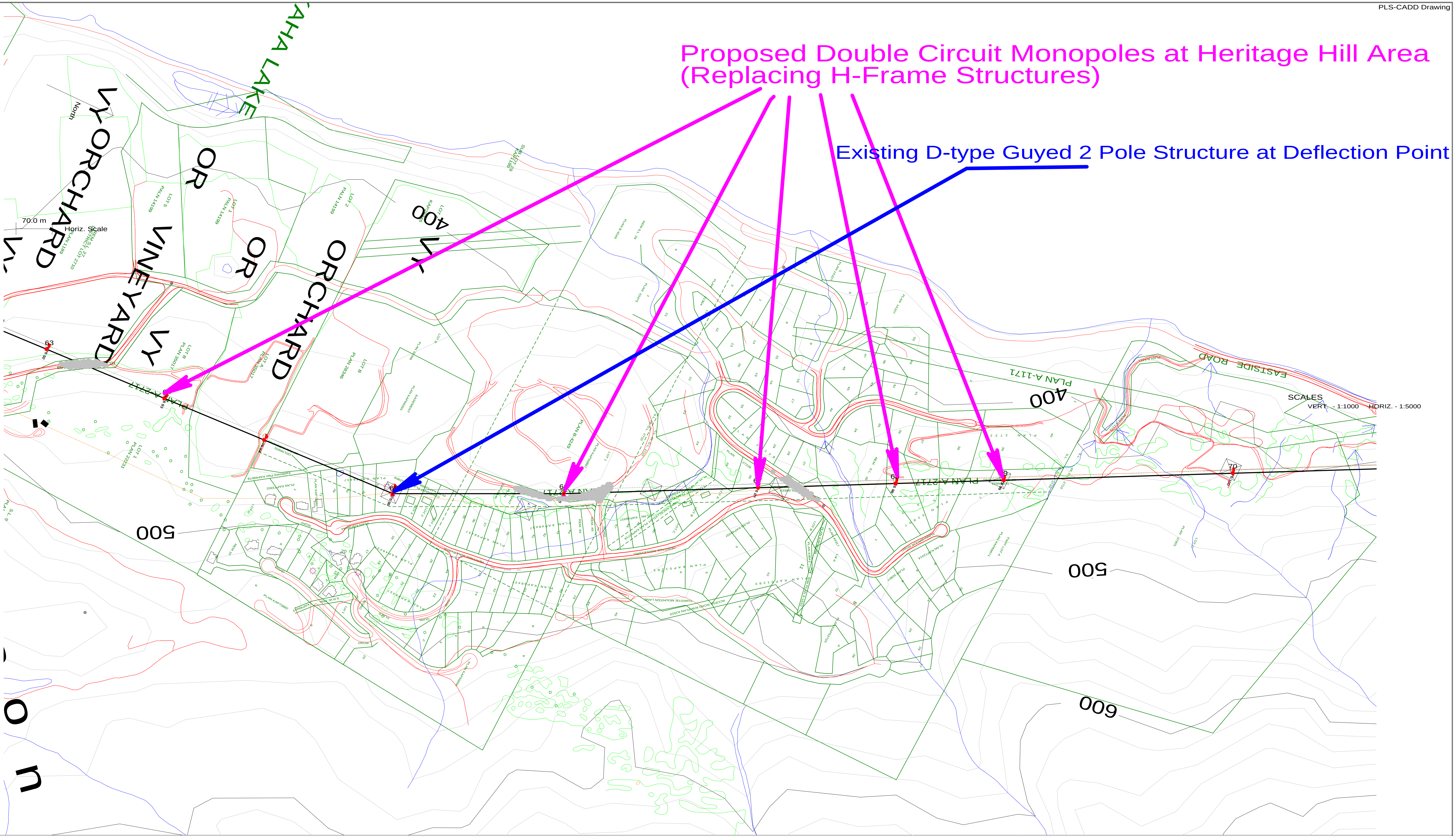
A40.2 Yes, it would be possible to build the line from Vaseux to RG Anderson using primarily the H-frame structures and the single pole type construction in the more populated areas. However this is less desirable from a maintenance perspective as the line would require a wider variety of materials and techniques for maintenance on the different structure types and the transitions between them.

Q40.3 Specifically, what would be the cost impact on Alternative 1B of using single poles through the Heritage Hills section? Please include a sketch that identifies where single poles would be used in this scenario.

A40.3 The Heritage Hills line section is about 2.1 km long. The cost impact to Alternative 1B for applying the single poles as opposed to the double-circuit H-frame structures would be an increase of $735,000 in direct costs before application of inflation, contingency and overhead. Please see attachment A40.3 below depicting pole placement for the contemplated scenario.

FILE ALT_DEM_VAS_RGA_DRAKE_OPTION5B_FEB07_08.xyz PLOTTED 2008-02-08

PLS-CADD Drawing



Proposed Double Circuit Monopoles at Heritage Hill Area (Replacing H-Frame Structures)

Existing D-type Guyed 2 Pole Structure at Deflection Point

REF# | DRAWING NUMBER | TITLE | REF# | DRAWING NUMBER | TITLE

REFERENCE DRAWINGS | REFERENCE DRAWINGS

| NO | REMARKS | DATE | DESIGNED | INDEP CHKD | DFTG | DFTG CHKD | INSPD | REV | ACPT

REVISIONS

DSGN
INDEP CHKD
DFTG
DFTG CHKD
INSPD
REV
ACPT

BC hydro ENGINEERING

FORTIS BC
OKANAGAN TRANSMISSION REINFOR.

VAS TO RGA - 230 kV DCSP "Existing Rt."
(Double Circuit Monopole At Heritage Hill)
PLAN

DATE 2008-02-08
DISTR µ
DWG NO
CAD
SH 1 OF 1
R R1

Q40.4 Further to the statement on Tab 4, page 32 that H-frame structures have features that minimize construction costs, please confirm that the H-frame structures would include steel uprights, and explain what the "features" are that reduce costs.

A40.4 The H-frame structures proposed for Alternative 1B and shown by Cross Section E on Figure 4-3-1B contained in Exhibit B-1-1 include steel poles or uprights.

The features that these double circuit H-frame have to reduce costs include reduced foundation requirements, smaller diameter, shorter and lighter poles.

41.0 Alternatives, Vaseux to Anderson

Reference: Exhibit B-1-1, Tab 4, pp. 41, 44, 47

Q41.1 Table 4-3-2B indicates an $11.5 million higher cost for Alternative 1A, while Table 4-3-3D indicates a 20 point or 5 percent higher Non-Financial ranking. Please discuss how FortisBC balanced these two opposing considerations in reaching the conclusion that Alternative 1A is preferred.

A41.1 As outlined in Table 4-3-3D FortisBC believes that the proposed single pole double circuit configuration would be more aesthetically pleasing and less imposing than the double circuit H-Frame structures through the corridor between Vaseux Terminal and Penticton considering current and proposed development in the area. The environmental factor was reduced on alternative 1A due to increased disruption on the right-of-way as a result of the construction of larger H-Frame Alternative 1B structures and the single pole design takes up considerable less space on the current right-of-way. EMF Levels are less for Alternative 1A than 1B.

Please refer to the following responses to BCUC IR No.1 :

- BCUC IR No. 1 Q40.1;
- BCUC IR No. 1 Q42.1 and Figures 4-2-1A through 4-2-1G from Section 4 pages 13 – 17 from the CPCN Application (Exhibit B-1-1) with regards to visual impact;
- BCUC IR No. 1 Q57.1 through Q57.12 and Figure 4-6A and Figure 4-6B from Section 4, pages 55 – 56 from the CPCN Application (Exhibit B-1-1) with regards to EMF; and
- Appendix I Table 6-2 (pages 53 – 57) from the CPCN Application (Exhibit B-1-3) with regards to environmental impact.

Q41.2 Please expand Tables 4-3-2B and 4-3-3D to include Alternative 1C that includes a high capacity single 230 kV circuit between Vaseux Lake and RG Anderson.

A41.2 Please see revised Table 4-3-2B and Table 4-3-3D below.

Table 4-3-2B: Route Alternatives 1A & 1B 2010 in-service Cost & NPV Analysis

Alternative	1A	1B	1C	2A	2B	3
	($000s)					
TOTAL CAPITAL COST	141,408	129,915	129,866	No costs are presented for these Alternatives due to time frame associated with acquiring a new right-of-way for the upland route.		
Net Present Value of Revenue Requirements	69,659	62,077	62,001			
One-Time Equivalent Rate Impact	2.29%	2.04%	2.04%			

Alternatives 1A & 1B have been revised. Please see the response to BCUC IR No. 1 Q47.2. Note, the Net Present Value and Rate Impact differ from information supplied in Table 4-3-2B in Section 4 of the CPCN Application (Exhibit B-1-1), please see the response to BCUC IR No.1 Q44.4.

Table 4-3-3D: Non-Financial Comparison of Route Alternatives

Criterion	Weighting Factors	Alternative 1A Existing Corridor Single Pole Double Circuit		Alternative 1B Existing Corridor H-Frame structure Double Circuit		Alternative 1C Existing Corridor H-Frame structure Single High Capacity Circuit		Alternative 2A Upland Single Pole Double Circuit		Alternative 2B Upland Two Single Circuits		Alternative 3 Two Single Circuits One Existing, One Upland	
		Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank	Rank	Weighted Rank
Reliability	**15**	4	60	4	60	1	15	2	30	3	45	5	75
Operations and Safety	**15**	3	45	3	45	4	60	1	15	3	45	4	60
Public Health	**10**	5	50	5	50	5	50	5	50	5	50	5	50
Risk of Delay	**15**	5	75	5	75	4	60	1	15	1	15	2	30
First Nations	**10**	4	40	4	40	4	40	2	20	2	20	2	20
Environmental	**10**	5	50	4	40	4	40	3	30	2	20	1	10
Parks and Recreation	**5**	4	20	4	20	4	20	4	20	4	20	2	10
Aesthetics	**5**	2	10	1	5	2	10	4	20	3	15	2	10
Property Values	**5**	5	25	5	25	5	25	5	25	5	25	5	25
EMF	**5**	4	20	3	15	2	10	5	25	5	25	3	15
Effects during Construction	**5**	1	5	1	5	1	5	3	15	3	15	1	5
Totals	**100**		**400**		**380**		**335**		**265**		**295**		**310**

Notes on Non-Financial Comparison of Alternative 1C to previous alternatives;

1. Reliability: Alternative 1C (1C) has the lowest reliability ranking as a single circuit is inherently less reliable than two circuits.
2. Operations and Safety: 1C has less operational safety concerns as there is not a parallel circuit with induction risks to maintainers and it is on the more accessible lower elevation route.
3. Public Health: No difference versus other alternatives.
4. Risk of Delay: Almost equivalent to Alternatives 1A, 1B as on existing right of way except for additional environmental permitting required for buried counterpoise.
5. First Nations: Same as Alternatives 1A and 1B as on existing right of way.
6. Environmental: Same as Alternative 1B with wider footprint of H-frame structures.
7. Parks and Recreation: Same as Alternatives 1A and 1B as on existing right of way.
8. Aesthetics: H-frame structure on existing right of way, shorter than 1B and 1A, but wider than 1A.
9. Property Values: No difference versus other alternatives.
10. EMF: 1C ranks lower on EMF performance than 1A and 1B, but still well within guidelines.
11. Effects during construction: Equivalent to Alternatives 1A, 1B as on existing right of way.

Q41.3 Further to the discussion regarding impact on property values on page 47 of Tab 4, please confirm that the Vancouver Island Transmission Reinforcement Project involved upgrading two transmission circuits on an existing right-of-way.

A41.3 Confirmed. The following is from the VITR CPCN Application, Section 1.1, page 2:

> *In general terms, the VITR Project consists of replacing one of the existing 138 kV transmission lines between South Delta and North Cowichan with a new, 67 km 230 kV transmission line. BCTC proposes building the Project* ***entirely within the existing 138 kV right-of-way (ROW).*** *BCTC also proposes to upgrade the second existing 138 kV line, where prudent, to facilitate the installation of a second 230 kV line in the future, when this is necessary.*

Q41.4 Please explain the reasons why FortisBC believes that adding a second circuit on the right-of-way, as well as increasing the voltage level, is unlikely to reduce the value of adjacent properties.

A41.4 FortisBC is unaware of any studies, previous regulatory proceedings, or Canadian compensation cases that have concluded that there is an impact on property values related to the specific number of circuits or voltage. This remains true when considering tower type or conductor height.

FortisBC believes that, generally speaking, members of the public are not aware of the specific voltage of overhead transmission lines, or of changes.

A specific circuitry or voltage is not specified in the existing right of way agreements and a change in the right of way agreement to add to or replace the existing structures and conductors is not required. The actual agreements provide for an easement to construct and maintain electric transmission and communication lines.

In the case of residential development properties, FortisBC recognizes and pays compensation for rights of way on the basis of the full anticipated impact on the use of the land within the right of way as well as the contiguous lands of each owner at the time of initial construction. Such compensation recognizes the impact on usage within the right of way, possible increases in development costs, and possible impacts on encumbered or adjoining lots developed.

42.0 Alternatives, Vaseux to Anderson

Reference: Exhibit B-1-1, Tab 4, p. 17; Exhibit B-1-3, Appendix H

Q42.1 Please provide a rendering of a high capacity single circuit line on H-frame structures (Cross section B) at Heritage Boulevard in Heritage Hills, similar to Figure 4-2-1G.

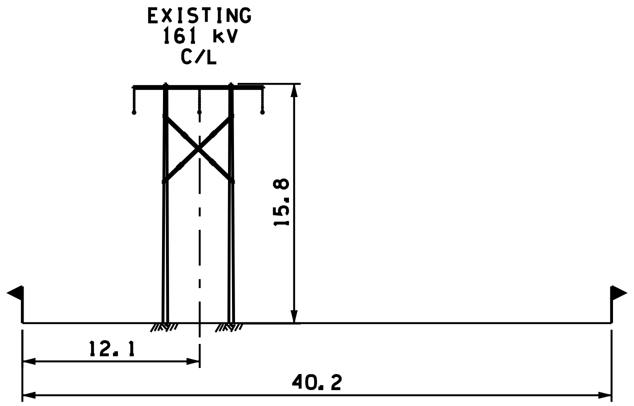
A42.1 Please see the revised rendering below depicting the requested updated rendering of Figure 4-2-1G showing structures for high capacity single circuit for Alternative 1C. The circuit cross section is similar to, but not the same as referenced Cross Section B from Figure 4-3-1B page 34 of Tab 4 of the Application. For clarity an updated Figure 4-3-1B is also attached as Attachment A42.1 below including new Cross Section F which portrays a typical Alternative 1C cross section.

Figure 4-2-1G Revised: Rendering of High Capacity Single Circuit Alternative 1C, Heritage Boulevard, Heritage Hills

Attachment A42.1b

PRELIMINARY

FOR DISCUSSION PURPOSES ONLY

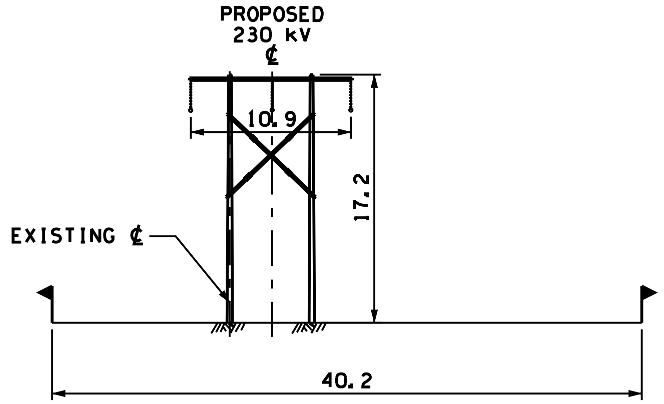


CROSS SECTION A

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) EXISTING 40 LINE
VASEUX LAKE TO OLIVER

2) EXISTING 76 LINE
VASEUX LAKE TO RG ANDERSON



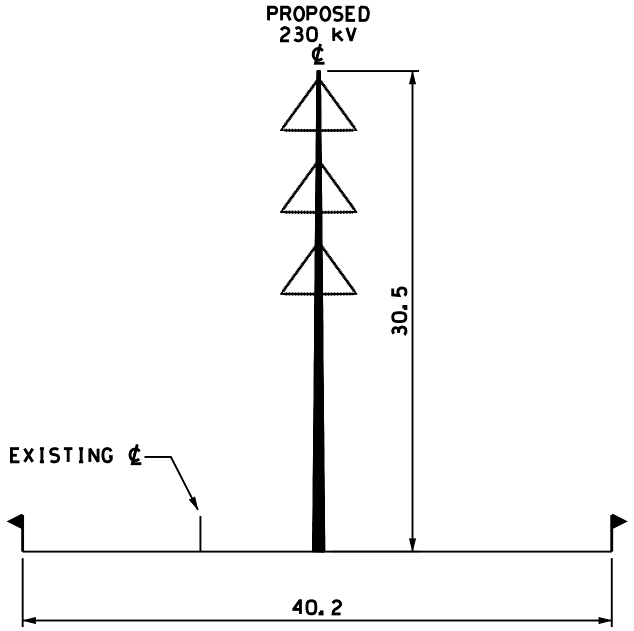
CROSS SECTION B

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) PROPOSED 40 LINE
VASEUX LAKE TO BENTLEY

2) ALTERNATIVE #3
SHUTTLEWORTH CREEK TO
RG ANDERSON FOR:

a) 76 LINE ON EXISTING ROUTE
b) 75 LINE ON NEW UPLAND ROUTE

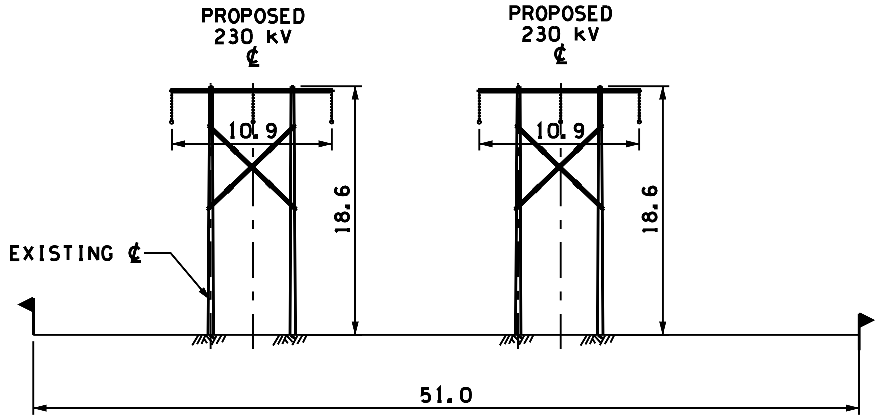


CROSS SECTION C

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) ALTERNATIVE #1A ON EXISTING RIGHT OF WAY
FOR 75 AND 76 LINE

2) ALTERNATIVE #2A ON NEW UPLAND ROUTE FROM
VASEUX LAKE TO RG ANDERSON FOR 75 AND
76 LINE



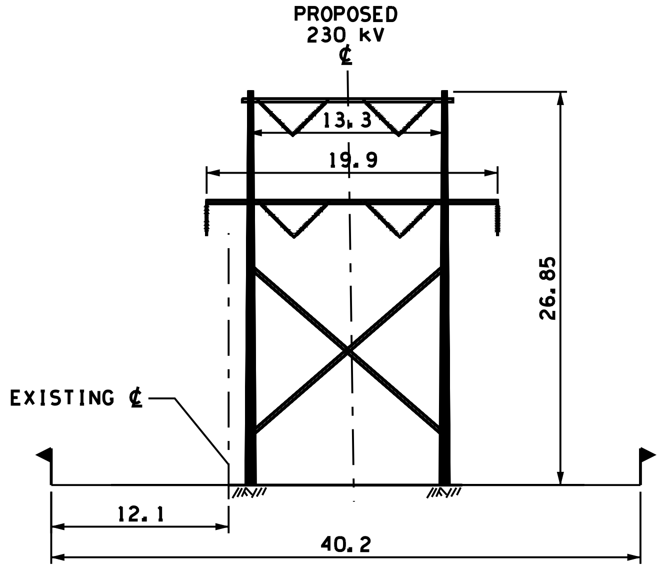
CROSS SECTION D

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) ALTERNATIVE #2B ON NEW UPLAND ROUTE FROM
SHUTTLEWORTH CREEK TO RG ANDERSON FOR
75 AND 76 LINE

NOTE:

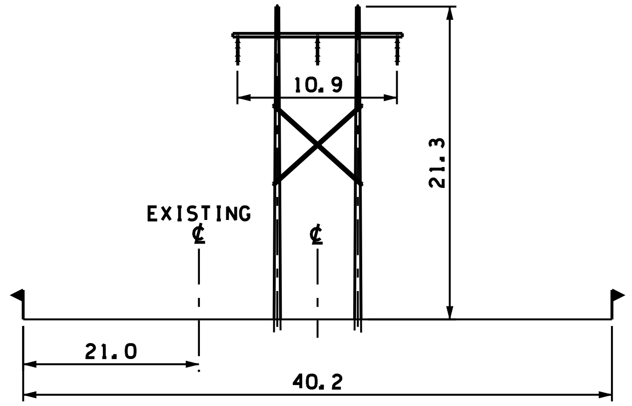
ALTERNATIVE #2B USES TYPICAL CROSS SECTION C
FOR VASEUX LAKE TO SHUTTLEWORTH CREEK.



CROSS SECTION E

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) ALTERNATIVE #1B ON
EXISTING RIGHT OF WAY
FOR 75 AND 76 LINE



CROSS SECTION F

TYPICAL RIGHT OF WAY CROSS SECTION FOR:

1) ALTERNATIVE 1C ON EXISTING RIGHT OF WAY
WITH HIGH CAPACITY SINGLE CIRCUIT LINE

NOTE:

ALL DIMENSIONS ARE IN METRES UNLESS OTHERWISE SPECIFIED.

REVISIONS

REV	DATE	BY	CHECKED	DESCRIPTION	REV. APPR	DATE

DRAWN BY
DESIGNED BY
CHECKED BY
APPROVED BY

FORTISBC

TYPICAL
RIGHT OF WAY
CROSS SECTIONS

DRAWING NUMBER	REV
SKETCH ROW X-SECTIONS	07/11/8

Q42.2 Please provide a revenue requirements spreadsheet similar to those in Appendix H, for Alternative 1C, the high capacity single circuit alternative.

A42.2 Please refer to the response to BCUC IR No. 1 Q47.2 where the requested information is provided.

Q42.3 Starting with a premise that N-2 is not a mandatory reliability criteria for the OTR Project, please compare Alternatives 1A and 1C on the basis of financial and non-financial considerations, identify the project alternative that FortisBC would recommend in this circumstances, and explain why this alternative would be recommended.

A42.3 As stated in the response to BCUC IR No. 1 Q7.6, FortisBC does not consider N-2 to be a mandatory reliability criterion for the Okanagan region as a whole. A financial comparison of Alternate 1A and 1C 2010 in service shows Alternative 1C as $11.5 million cheaper (total capital cost) than Alternative 1A. A non-financial comparison shows Alternative 1A to have a higher ranking than Alternative 1C specifically in the reliability, environmental impact and EMF areas.

Please see the response to BCUC IR No. 1 Q14.5 and Q41.2.

FortisBC continues to recommend Alternative 1A, not for reasons of the above financial comparison but because Alternative 1C would only support N-1 reliability to 2012 for the region due to the capacity limitations at Vernon Terminal in the event of the loss of 76 Line.

43.0 Alternatives at Bentley/Oliver

Reference: Exhibit B-1-1, Tab 4, pp. 21-24, 29

Q43.1 Please provide a copy of the most recent study or business case that FortisBC carried out to evaluate options for the rebuilding of the Oliver Substation, including construction of the Bentley Terminal.

A43.1 Early in the initial scoping of the OTR project, it became clear that there was insufficient space for incorporating the required 230/161/138 kV transformation within the existing Oliver yard. A process was then initiated to acquire additional property which resulted in the acquisition of an approximately 8 acre parcel on Osoyoos Indian Band land for use as the Bentley Terminal. The OTR Application forms the business case for the construction of the Bentley Terminal. Note that the existing 63 kV portion of the Oliver Terminal will essentially be retained as-is.

Q43.2 Figure 4-2-1J indicates a gross area for the Bentley Terminal of 8.0 acres. What is the fenced area of the proposed station?

A43.2 The fenced area of the proposed station is approximately 3.7 acres.

Q43.3 FortisBC proposes to relocate a 230/63 kV transformer to Bentley Terminal station from RG Anderson, and to install a new 161/63 kV transformer at Bentley that will be re-connectable to 138/63 kV. Please explain why the 168 MVA transformer from RG Anderson is suitable, considering the capacity of the proposed 40L line, and the forecast loads on Bentley Terminal.

A43.3 The 168 MVA Bentley Transformer 1 (relocated from RG Anderson T2) would be appropriately sized for the expected peak loads. The maximum load that would be expected on this transformer would be in contingency situations where all 43 Line load (Princeton, BC Gas, Keremeos, and Hedley), all 44 Line / 66 Line load (Pine St., Osoyoos, Nk'Mip) and 48 Line load (Kettle Valley) would be carried simultaneously. The forecast total load for all of the above is approximately 147 MVA in 2026.

Q43.4 Please confirm that the proposed Bentley configuration will be able to supply power at all the voltage levels of 161, 138 and 63 kV.

A43.4 Confirmed.

Q43.5 Please explain whether consideration was given to reducing the number of transmission voltages (230 kV, 161 kV, 138 kV) in the Oliver area. What conclusions resulted from this consideration?

A43.5 While it would be desirable to reduce the number of operating voltages in the area, the logistics and costs of doing so make it unfeasible for the near future.

<u>230 kV</u>

The 230 kV voltage cannot be eliminated as it will be the only transmission source voltage from Vaseux Lake following the voltage conversion at that station.

138 kV

If the 138 kV voltage was eliminated (either up-rated or down-rated) it would require the replacement of the distribution substation transformers at Princeton, Terasen Gas, Hedley and Keremeos. It should also be noted that 43 Line was up-rated from 63 kV in the early 1990's for capacity reasons; thus, only a conversion to 161-kV or higher would be viable. Additionally, the BCTC interconnection at Princeton is 138 kV. Thus, eliminating the 138 kV voltage would require rebuilding of 43 Line, replacement of four distribution transformers and the installation of a suitable transmission step-down transformer at Princeton.

161 kV

The remaining candidate voltage for elimination is 161-kV. Provisions have been made in the proposed Bentley Terminal design to allow for relatively straightforward conversion of the station to future 230/138/63 kV operation. To do so the following steps would be carried out at Bentley:

- T2 would be reconnected to operate on the 138/63 kV tap;
- Two additional 138 kV breakers would be installed to complete a four breaker ring bus; and
- T3 would be relocated to the Trail end of 11 Line to act as a 63/138 kV step-up.

The two distribution transformers at the Kettle Valley substation (currently under construction) were specified to be switchable for 161 or 138-kV operation so there would be minimal work required at that location.

Finally, the existing Grand Forks T1 161/63 kV transformer would need to be replaced with a new 138/63 kV unit (with a second unit for backup).

This future voltage conversion will likely be driven by the ongoing condition assessments of the A.S. Mawdsley 161/63 kV transformers. If there are indications that one or both of the transformers require replacement, then the voltage conversion would be considered at that time.

Q43.6 The Application at Tab 4, page 24 refers to a future conversion of the 161 kV line (Line 11) to Grand Forks/Warfield to 138 kV. Please confirm that this conversion would eliminate the need for 161 kV at Bentley, discuss the conversion in terms of power supply to Kettle Valley Substation and Grand Forks, and explain when it is expected to take place.

A43.6 Please see the response to BCUC IR No.1 Q43.5.

Q43.7 What would be the reductions to the cost of the OTR Project and to the land requirements at Bentley if the need to provide 161 kV service was not included in the design of the Terminal?

A43.7 In terms of the land requirements, it is likely there would be little change to the site size. The 161 kV equipment would essentially be replaced with 138 kV equipment that would occupy substantially the same footprint.

In terms of costs, as described in the response to Q43.5, there would be the additional requirement to purchase and install two 138/63 kV transformers for the Grand Forks Terminal. As well, work would be required at Trail to remove the existing A.S. Mawdsley 161/63 kV transformers from service and to replace them with the 138/63 kV transformer presently proposed to be Bentley Transformer 3.

Thus, the overall OTR project costs would be increased, with no significant offsetting benefit.

Q43.8 Please provide a list that summarizes the components of the existing Oliver substation that will continue in service without significant upgrading after completion of the OTR Project.

A43.8 Oliver Terminal Equipment remaining in service after the OTR project includes:

63 kV Circuit Breakers;
- TA
- TB
- 41 OCB
- 42 OCB
- 44 OCB

63 kV Capacitor Banks;
- CAP 1 10.6 Mvar together with circuit switcher CS1
- CAP 2 7.2 Mvar together with circuit switcher CS2

Bus Potential transformers;
- Bus A PT
- Bus B OT

63 kV Isolating Disconnects;
- Tie A-B
- 41-60
- 42-44
- TA-1
- TB-1
- 42-1,2
- 41-1,2
- 44-1,2
- CAP1-2
- CAP2-2

63 kV Bus work and transmission line entry towers;

Control Building;

Station protection and control ancillaries associated with the above equipment;

Station Battery and Charger; and

Station ground grid and fencing.

Q43.9 Could the new Bentley Terminal be sized and designed to include the planned distribution sub-station functionality of the Oliver facility (300 metres distant) and thus facilitate decommissioning the existing Oliver site? What are the advantages/disadvantages of such an approach? Please include the apparent operational advantages of consolidating the transformation at one location instead of two.

A43.9 Yes, the Bentley Terminal has sufficient yard space to accommodate the 63 kV and distribution functionality of the Oliver station.

The advantages of doing so include:

- Consolidation of all station equipment in one location; and
- Removal of the need for the short 63 kV tie lines between the two sites

The disadvantages include:

- The 63 kV lines presently terminating at Oliver would have to be extended to Bentley Terminal;
- The distribution feeders presently terminating at Oliver would have to be extended to Bentley Terminal;
- The existing Oliver 63 kV equipment would be stranded assets as they could not be relocated to the new Bentley Terminal (due to the need to still supply the area load while constructing Bentley);
- Yard cleanup and possible soil decontamination would be required; and
- The property would be encumbered by FortisBC rights-of-way.

Note that the Oliver substation yard is surrounded on all four sides (golf course to north and east, trailer park to the south, FortisBC business office to the west) and thus the property would have no direct access.

The costs of relocating the Oliver equipment to Bentley would far exceed the value of the vacant property. Refer also to the response to BCUC IR No. 1 Q43.10.

Q43.10 Please provide a cost estimate for relocating the 63 to 13 kV function from Oliver Substation to Bentley, and decommissioning the existing Oliver site.

A43.10 The planning level cost estimate (+35/-20%) to relocate the 63 to 13 kV function from Oliver to Bentley is $36.20 million cost. This is compared to the $30.99 million preliminary level direct cost estimate for the proposed project. This cost is excluding AFUDC.

The planning level cost estimate (+35/-20) to decommission Oliver is $3.05 million direct cost. This is compared to the $5.69 million preliminary level cost estimate for the proposed project upgrade at Oliver. This cost is excluding AFUDC.

Both estimates assume that the existing capacitor bank equipment at Oliver can be re-used at Bentley. All other decommissioned equipment is removed and transported to storage/salvage locations in the Okanagan.

The estimates do not include the additional costs for:

- extending the distribution feeders to Bentley;
- any costs to subdivide or provide property access in preparation for Oliver Terminal property sale;
- any costs for site environmental remediation if needed for property sale; or
- any additional costs or credits for decommissioned material and equipment disposal/salvage.

Q43.11 How many acres of land in total does FortisBC hold at the location of the Oliver Substation? Is this land held in fee simple? If not, please explain the nature of FortisBC's tenure for the land at the Substation site.

A43.11 FortisBC's Oliver office/line room and the Oliver Terminal station are located on 3.27 acres of land held in fee simple. The Oliver Terminal station occupies about 1.69 acres of the property.

Q43.12 Please discuss whether, if the 63 to 13 kV function was located at Bentley, some or all of the FortisBC property at the Oliver Substation site could be sold. What value could be obtained, and could this money be used to offset part of the cost of the OTR Project?

A43.12 If FortisBC were to decommission and dispose of the Oliver Terminal portion of the property, the sale may recover \$0.4 - \$0.5 million for the 1.69 acres of industrial/commercial property. The property would remain encumbered with some statutory right of ways that would cross it from the Bentley Terminal for Lines 42, 43 and 44 as well as two existing and two planned future distribution feeders. The above sale does not take into account costs to decommission the site and dispose of still usable equipment, nor costs for property subdivision. FortisBC's position is that it would not dispose of the property but use it for other service requirements.

Q43.13 Alternatively, would the available area at the Oliver Substation be adequate for the Bentley Terminal function as well as the 63 to 13 kV function, particularly if Line 11 were converted to 138 kV? If not, please explain why not.

A43.13 The Oliver Terminal site is 1.69 acres and is too small to contain the fenced footprint of a combined Bentley/Oliver functionality that would occupy some 3.94 acres. As per the response to BCUC IR No. 1 Q43.7, if 11 Line was converted to 138 kV there is only a marginal reduction of space required for Bentley.

Q43.14 What would be the cost of constructing one terminal/substation at the Oliver Substation site that would provide the functionality that is planned for the Bentley and Oliver facilities?

A43.14 Please see response to BCUC IR No. 1 Q43.13. The Oliver site is too small to construct the combined Bentley/Oliver functionality using conventional switchyard construction.

44.0 Splitting of Vaseux Transformers

Reference: Exhibit B-1-1, Tab 3, pp. 28, 29; Tab 4, p. 27; Tab 5, p. 2

Q44.1 Table 5-1 shows a cost of $4.44 million for the Vaseux 230 kV Terminal Upgrade, and $2.928 million for the 500 kV Terminal Upgrade. Further to the statement in Tab 4, page 27 that the station was designed for conversion from 161 kV to 230 kV "by reconnecting existing pre-equipped transformers, along with minor equipment change outs", please provide a description of the changes required and an estimate of the costs associated only for the conversion from 161 kV to 230 kV.

A44.1 The Vaseux Lake Terminal Station was designed for conversion from 161 kV to 230 kV.

The Vaseux Terminal station work required for the conversion is as follows:

- Convert the main power transformers by reconnecting the secondary winding from 161 to 230 kV using internal link boards provided for this purpose;
- Convert three sets of capacitive voltage transformers (B2-CVT, 40-CVT, 76-CVT) from 161 to 230 kV by reconnection using the provided connection point;
- Replace four sets of 161 kV surge arresters (T1-SA2, T2-SA2, B5-SA, B6-SA) with units rated at 230 kV; and
- Modifications to and change of protective relay settings to reflect power system operation at 230 kV.

The planning level cost estimate (+35/-20) for only the voltage conversion at Vaseux Lake 230 kV Terminal is $515,000. This cost is excluding AFUDC.

For only the voltage conversion work there are no costs at the 500 kV Vaseux

Lake Terminal.

Q44.2 Please elaborate on the requirement for independent switching of the transformers at Vaseux Lake on both the BCTC and FortisBC sides.

A44.2 At the present time both the 230 kV and 500 kV buses at Vaseux Lake are equipped with only three circuit breakers. This arrangement means that both transformers share the same high voltage and low voltage buses. Each transformer can be individually isolated by motor-operated disconnects (MODs), but this can only take place while both transformers are de-energized (the MODs are not fault-break or load-break devices).

Thus, to remove one transformer from service (whether planned or forced), it is necessary to open two breakers in the 230 kV ring bus and two breakers in the 500 kV ring bus. Once both transformers are de-energized, the desired transformer can then be isolated via its MODs. Finally, the four circuit breakers can then be closed to restore the other transformer to service.

In the case of transformer faults the above sequence happens automatically. For planned outages, the System Control Centre dispatchers perform the switching by remote control.

By installing one additional circuit breaker in 230 kV ring bus and an additional breaker in the 500 kV ring bus, each transformer would have completely separate protection zones.

Q44.3 Further to the discussion on pages 23 and 29 of Tab 3, please explain why a station that was energized as recently as 2005 would now require major modifications to place circuit breakers between the two transformers. What would it have cost to include this feature in the design of the station when it was originally constructed?

A44.3 As discussed in the response to BCUC IR No. 1 Q44.2, the installation of only three breakers was undertaken to reduce the overall cost of the substation. There was no significant impact on reliability as the contingency studies at the time showed that the system could support the simultaneous loss of both transformers. However, as the system load continues to grow this is no longer the case.

The cost to include this work in the original project would have been approximately $3.4 million.

Q44.4 In Appendix C of Exhibit B-1-3, page 6 of 57 of the Station Preliminary Design Scope states:

"It is the desire of FortisBC to split the switching for T1 and T2 into separate zones as they are presently a single zone. This requires the addition of CB3. It will also require the addition of a 500 kV CB and reconfiguration of the 500 kV bus connections. This latter work is within BC Hydro ownership and BCTC's management responsibility. FortisBC will have to work out an agreement for this work so this entire portion of the project is optional pending a FortisBC agreement with BCTC. Failure of CB3 is a common mode event that will take out both transformers. The other supply lines will support the system at this stage so it is not considered necessary to configure the station to avoid ever losing both transformers as it is expected to be a very low probability event but in order to permit the transformers to go back into service, motor operators are to be provided for CB3 isolating disconnects to allow the isolation of CB3. Remote control and indication is required for these switches."

Considering the statement that losing both transformers is expected to be "a very low probability event", please explain why the additional expenditure is justified.

A44.4 The statement is meant to imply that <u>after</u> the two transformers are provided with separate protection zones the likelihood of losing both transformers would be a very unlikely event. It is not meant to imply that the likelihood of losing both transformers is a low probability event today.

Q44.5 If BCTC planning criteria were applied to the Vaseux Station, would splitting of the two transformers be required?

A44.5 FortisBC is unable to speak for BCTC and how they would apply their planning criteria to the Vaseux Lake Terminal. BCTC would likely conduct a contingency analysis to determine whether the system could survive the loss of both transformers.

It should be noted however, that a review of a number of BCTC substation single-lines with 500/230 kV transformers shows that they are typically provided with independent protection zones (as proposed by the OTR Project).

45.0 Losses and Other Operating Expenses

Reference: Exhibit B-1-1, Tab 5, pp. 1, 2

Q45.1 Further to Section 5.2 of the Application, please provide a table having similar item descriptors as Table 5-1 showing the existing operating and maintenance ("O&M") cost and the forecast O&M costs with the OTR Project, and the resulting increase of $24,000 per year outcome.

A45.1 Please see Table A45.1 below.

Table: A45.1 Operating and Maintenance ("O&M") Expense

Pre OTR	**Assumptions**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Oliver	Labour & materials (20%)		140,158					170,524					207,469		
	5 Yr. Cycle. Future: (2% + CPI) / Yr		28,032					34,105					41,494		
RGA	Labour & materials (20%)			168,190					204,629					248,962	
	5 Yr. Cycle. Future: (2% + CPI) / Yr			33,638					40,926					49,792	
Lee	Labour & materials (20%)				168,190					204,629					248,962
	5 Yr. Cycle. Future: (2% + CPI) / Yr				33,638					40,926					49,792
Bell	Labour & materials (20%)					168,190					204,629				
	5 Yr. Cycle. Future: (2% + CPI) / Yr					33,638					40,926				
TOTAL		**-**	**168,190**	**201,828**	**201,828**	**201,828**	**-**	**204,629**	**245,555**	**245,555**	**245,555**	**-**	**248,962**	**298,755**	**298,755**
Post OTR	**Assumptions**														
Oliver	Labour & materials (20%); reduced by 30% after conversion in 2010		98,111					119,367					145,228		
	5 Yr. Cycle. Future: (2% + CPI) / Yr		19,622					23,873					29,046		
RGA	Labour & materials (20%)			168,190					204,629					248,962	
	5 Yr. Cycle. Future: (2% + CPI) / Yr			33,638					40,926					49,792	
Lee	Labour & materials (20%)				168,190					204,629					248,962
	5 Yr. Cycle. Future: (2% + CPI) / Yr				33,638					40,926					49,792
	5% increase in Maintenance after installation of Cap. Banks				10,091					12,278					14,938
Bell	Labour & materials (20%)					168,190					204,629				
	5 Yr. Cycle. Future: (2% + CPI) / Yr					33,638					40,926				
	5% increase in maintenance after installation of Cap. Banks					10,091					12,278				
Bentley	Labour & materials (20%)						174,918					212,814			
	5 Yr. Cycle. Future: (2% + CPI) / Yr						34,984					42,563			
TOTAL		**-**	**117,733**	**201,828**	**211,920**	**211,920**	**209,901**	**143,240**	**245,555**	**257,833**	**257,833**	**255,377**	**174,274**	**298,755**	**313,693**
Post OTR	**Incremental Maintenance Cost**	**-**	**(50,457)**	**-**	**10,091**	**10,091**	**209,901**	**(61,389)**	**-**	**12,278**	**12,278**	**255,377**	**(74,689)**	**-**	**14,938**

24,173 Average from 2011 (1st year OTR in-service) to 2024 (end of current SDP)

Q45.2 Please confirm that the O&M for the additional new facilities will more than offset the effect on O&M expense of replacing old facilities, especially wooden poles.

A45.2 O&M expense costs outlined in the application are for Stations and Terminals work only. FortisBC does not typically expense costs for transmission line infrastructure, program structure or apparatus replacements. This capitalization of new transmission line infrastructure would be equal to or lower than the existing line.

Q45.3 What inflation rate has FortisBC applied to the net O&M costs?

A45.3 FortisBC has applied inflation at two percent per year.

Q45.4 Please confirm that the net O&M impact of $24,000 per year is included in the Financial Analyses in Appendix H, and identify where it is shown.

A45.4 The net O&M impact was not included in the Financial Analysis. The revised financial analyses are attached below. Please also see below for updated versions of Tables 4-3-2A and 4-3-2B from Section 4 of the CPCN Application (Exhibit B-1-1).

Table 4-3-2A: Route Alternatives (2012) - Cost & NPV Analysis

Alternative	1A	1B	2A	2B	3
	($000s)				
TOTAL CAPITAL COST	147,977	135,584	167,883	153,391	159,852
Net Present Value of Revenue Requirements	63,375	53,604	68,966	61,047	64,591
One-Time Equivalent Rate Impact	1.98%	1.76%	2.27%	2.01%	2.12%

Table 4-3-2B: Route Alternatives 1A & 1B 2010 in-service Cost & NPV Analysis

Alternative	1A	1B	2A	2B	3
	($000s)				
TOTAL CAPITAL COST	141,408	129,915	No costs are presented for these Alternatives due to time frame associated with acquiring a new right-of-way for the upland route.		
Net Present Value of Revenue Requirements	69,659	62,077			
One-Time Equivalent Rate Impact	2.29%	2.04%			

Table 5.4: Preferred Alternative 1A - Financial Summary

EXPENDITURE / IMPACTS	2007	2008	2009	2010	2015
	($000s)				
Cumulative Capital Expenditure	3,972	18,250	83,514	141,408	41,408
Reduction in Annual System Losses	0	0	0	0	0
Annual Operating Expense	0	0	0	0	(1,104)
Financing and Income Tax	0	0	0	0	321
Total Revenue Requirement	0	0	0	0	12,210
Maximum Annual Incremental Rate Impact Over Previous Year	3.48%				
Net Present Value of Revenue Requirement	69,659				
One-Time Equivalent Rate Impact	2.29%				

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

break after

Alternative 1A - 2010 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary																			
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 26	0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
2	Depreciation Expense	Line 32	0	0	0	0	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	0	0	0
3	Carrying Costs	Line 39	0	0	0	5,133	10,112	9,805	9,499	9,192	8,886	8,579	7,046	5,512	3,979	2,446	913	0	0	0
4	Income Tax	Line 60	0	0	0	(1,284)	(606)	(306)	(75)	134	321	489	1,089	1,391	1,497	1,473	1,363	(228)	(210)	(193)
5	Total Revenue Requirement for Project		0	0	0	4,149	13,059	12,886	12,732	12,500	12,220	12,102	9,963	7,308	3,744	(1,002)	(7,387)	(20,018)	(21,014)	(23,475)
6	**Net Present Value of Revenue Requirement @**	**10.0%**	**69,659**	0	0	2,834	8,109	7,274	6,534	5,831	5,182	4,666	2,385	1,086	346	(57)	(263)	(487)	(464)	(472)
					0	2,834	10,943	18,217	24,750	30,582	35,764	40,430	56,187							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	1.67%	5.14%	4.97%	4.82%	4.64%	4.44%	4.31%	3.22%	2.14%	0.99%	-0.24%	-1.61%	-4.02%	-4.14%	-4.53%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	1.67%	3.48%	-0.17%	-0.16%	-0.18%	-0.19%	-0.13%	-0.16%	-0.14%	-0.14%	-0.15%	-0.17%	-0.80%	-0.12%	-0.39%
9	**NPV of Project / Total Revenue Requirements**		**2.29%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
13	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
14	Capital Costs		3,972	13,631	61,199	48,959														
15	AFUDC			647	2,892	6,197														
16	Total Cash Outlay in Year		**3,972**	**14,278**	**64,091**	**55,156**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Cumulative Cash Outlay		3,972	18,250	82,340	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
18			0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Cumulative Project Cost		3,972	18,250	82,340	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
20	Additions to Plant		0	0	0	137,496	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Cummulative Additions to Plant		0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
22	CWIP		3,972	18,250	82,340	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Line Losses						(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
24	Maintenance						0	(50)	0	10	10	210	255	311	378	460	560	33	681	
25	Property Taxes					300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
26	Total Incremental Operating Costs (Savings)		0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																			
27	Land					589														
	Depreciation Expense																			
28	Opening Cash Outlay		0	0	0	0	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908
29	Additions in Year	Line 20 less Line27	0	0	0	136,908	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Cumulative Total		0	0	0	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908	136,908
31	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
32	Depreciation Expense		0	0	0	0	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	0	0	0
	Net Book Value																			
33	Gross Property	Line 21	0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
34	Accumulated Depreciation		0	0	0	0	(4,107)	(8,214)	(12,322)	(16,429)	(20,536)	(24,643)	(45,179)	(65,716)	(86,252)	(106,788)	(127,324)	(137,496)	(137,496)	(137,496)
35	Net Book Value		0	0	0	137,496	133,389	129,282	125,174	121,067	116,960	112,853	92,317	71,780	51,244	30,708	10,172	0	0	0
	Carrying Costs on Average NBV																			
36	Return on Equity		0	0	0	2,480	4,887	4,739	4,590	4,442	4,294	4,146	3,405	2,664	1,923	1,182	441	0	0	0
37	Interest Expense		0	0	0	2,652	5,225	5,067	4,908	4,750	4,592	4,433	3,641	2,849	2,056	1,264	472	0	0	0
38	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Total Carrying Costs**		0	0	0	5,133	10,112	9,805	9,499	9,192	8,886	8,579	7,046	5,512	3,979	2,446	913	0	0	0
	Income Tax Expense																			
40	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
41	Return on Equity	Line 36	0	0	0	2,480	4,887	4,739	4,590	4,442	4,294	4,146	3,405	2,664	1,923	1,182	441	0	0	0
42	Gross up for revenue (Return / (1- tax rate)		0	0	0	3,543	6,835	6,491	6,288	6,085	5,882	5,679	4,664	3,649	2,634	1,619	604	0	0	0
43	Less: Income tax on Equity Return		0	0	0	1,063	1,948	1,753	1,698	1,643	1,588	1,533	1,259	985	711	437	163	0	0	0
44	Net Income (equal return on equity)		0	0	0	2,480	4,887	4,739	4,590	4,442	4,294	4,146	3,405	2,664	1,923	1,182	441	0	0	0
	Income Tax on Timing Differences																			
45	Depreciation Expense		0	0	0	0	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	4,107	0	0	0
46	Less: Capital Cost Allowance	Line 67	0	0	0	5,476	10,514	9,673	8,899	8,188	7,533	6,930	4,567	3,010	1,984	1,308	862	617	568	523
47	Total Timing Differences		0	0	0	(5,476)	(6,407)	(5,566)	(4,792)	(4,080)	(3,425)	(2,823)	(460)	1,097	2,123	2,800	3,245	(617)	(568)	(523)
48	Income Tax on Timing Differences		0	0	0	(1,643)	(1,826)	(1,503)	(1,294)	(1,102)	(925)	(762)	(124)	296	573	756	876	(167)	(153)	(141)
49	Before Tax Revenue Requirement [=Line48/(1-tax)		0	0	0	(2,347)	(2,554)	(2,059)	(1,772)	(1,509)	(1,267)	(1,044)	(170)	406	785	1,035	1,200	(228)	(210)	(193)
60	**Total Income Tax**	Lines 43 + 49	0	0	0	(1,284)	(606)	(306)	(75)	134	321	489	1,089	1,391	1,497	1,473	1,363	(228)	(210)	(193)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	131,431	120,917	111,243	102,344	94,156	86,624	57,092	37,628	24,800	16,345	10,773	7,718	7,100	6,532
62	Additions in Year		0	0	0	136,908	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	136,908	131,431	120,917	111,243	102,344	94,156	86,624	57,092	37,628	24,800	16,345	10,773	7,718	7,100	6,532
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	10,514	9,673	8,899	8,188	7,533	6,930	4,567	3,010	1,984	1,308	862	617	568	523
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	5,476	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	5,476	10,514	9,673	8,899	8,188	7,533	6,930	4,567	3,010	1,984	1,308	862	617	568	523
68	Ending Balance UCC		0	0	0	131,431	120,917	111,243	102,344	94,156	86,624	79,694	52,525	34,618	22,816	15,038	9,911	7,100	6,532	6,010

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

break after

Alternative 1A - 2012 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary																				
	Revenue Requirements																				
1	Operating Expense (Incremental)	Line 26	0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
2	Depreciation Expense	Line 32	0	0	0	0	0	0	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	2,062	0
3	Carrying Costs	Line 39	0	0	0	0	0	5,524	10,883	10,553	10,223	9,893	8,242	6,591	4,941	3,290	1,640	319	77	0
4	Income Tax	Line 60	0	0	0	0	0	(1,193)	(606)	(330)	(81)	144	960	1,397	1,585	1,608	1,523	1,402	509	(246)
5	Total Revenue Requirement for Project		0	0	0	0	0	4,331	13,899	13,711	13,469	13,384	11,344	8,707	5,108	292	(6,186)	(13,648)	(18,156)	(23,528)
6	**Net Present Value of Revenue Requirement @** **10.0%**		**60,375**	0	0	0	0	2,445	7,133	6,396	5,712	5,160	2,716	1,294	471	17	(220)	(332)	(401)	(473)
					0	0	0	2,445	9,577	15,973	21,685	26,845	44,570							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	0.00%	0.00%	1.67%	5.26%	5.09%	4.90%	4.77%	3.66%	2.55%	1.35%	0.07%	-1.34%	-2.74%	-3.57%	-4.54%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	0.00%	0.00%	1.67%	3.59%	-0.17%	-0.19%	-0.13%	-0.16%	-0.14%	-0.15%	-0.16%	-0.18%	-0.33%	-0.83%	-0.97%
9	**NPV of Project / Total Revenue Requirements**		**1.98%**																	
	Regulatory Assumptions																				
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
13	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
14	Capital Costs		3,972	1,445	107	13,235	65,638	52,510												
15	AFUDC			282	328	728	3,095	6,639												
16	Total Cash Outlay in Year		**3,972**	**1,726**	**435**	**13,963**	68,732	59,149	0	0	0	0	0	0	0	0	0	0	0	0
17	Cumulative Cash Outlay		3,972	5,698	6,133	20,096	88,828	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
18			0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0
19	Cumulative Project Cost		3,972	5,698	6,133	20,096	88,828	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
20	Additions to Plant		0	0	0	0	0	147,977	0	0	0	0	0	0	0	0	0	0	0	0
21	Cummulative Additions to Plant		0	0	0	0	0	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
22	CWIP		3,972	5,698	6,133	20,096	88,828	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Line Losses								(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
24	Maintenance						0		0	10	10	210	255	311	378	460	560	33	681	
25	Property Taxes								676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
26	Total Incremental Operating Costs (Savings)		0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																			
27	Land							589												
	Depreciation Expense																			
28	Opening Cash Outlay		0	0	0	0	0	0	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389
29	Additions in Year	Line 20 less Line27	0	0	0	0	0	147,389	0	0	0	0	0	0	0	0	0	0	0	0
30	Cumulative Total		0	0	0	0	0	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389
31	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
32	Depreciation Expense		0	0	0	0	0	0	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	2,062	0
	Net Book Value																			
33	Gross Property	Line 21	0	0	0	0	0	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
34	Accumulated Depreciation		0	0	0	0	0	0	(4,422)	(8,843)	(13,265)	(17,687)	(39,795)	(61,903)	(84,012)	(106,120)	(128,228)	(145,915)	(147,977)	(147,977)
35	Net Book Value		0	0	0	0	0	147,977	143,556	139,134	134,712	130,291	108,182	86,074	63,966	41,857	19,749	2,062	0	0
	Carrying Costs on Average NBV																			
36	Return on Equity		0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
37	Interest Expense		0	0	0	0	0	2,854	5,624	5,453	5,283	5,112	4,259	3,406	2,553	1,700	847	165	40	0
38	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Total Carrying Costs**		0	0	0	0	0	5,524	10,883	10,553	10,223	9,893	8,242	6,591	4,941	3,290	1,640	319	77	0
	Income Tax Expense																			
40	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
41	Return on Equity	Line 36	0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
42	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0	3,657	7,204	6,986	6,767	6,549	5,456	4,363	3,271	2,178	1,085	211	51	0
43	Less: Income tax on Equity Return		0	0	0	0	0	987	1,945	1,886	1,827	1,768	1,473	1,178	883	588	293	57	14	0
44	Net Income (equal return on equity)		0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
	Income Tax on Timing Differences																			
45	Depreciation Expense		0	0	0	0	0	0	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	2,062	0
46	Less: Capital Cost Allowance	Line 67	0	0	0	0	0	5,896	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
47	Total Timing Differences		0	0	0	0	0	(5,896)	(6,898)	(5,992)	(5,159)	(4,393)	(1,388)	593	1,898	2,758	3,325	3,636	1,340	(665)
48	Income Tax on Timing Differences		0	0	0	0	0	(1,592)	(1,862)	(1,618)	(1,393)	(1,186)	(375)	160	512	745	898	982	362	(179)
49	Before Tax Revenue Requirement [=Line48/(1-tax)		0	0	0	0	0	(2,181)	(2,551)	(2,216)	(1,908)	(1,625)	(513)	219	702	1,020	1,230	1,345	496	(246)
60	**Total Income Tax**	Lines 43 + 49	0	0	0	0	0	(1,193)	(606)	(330)	(81)	144	960	1,397	1,585	1,608	1,523	1,402	509	(246)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	0	0	141,493	130,174	119,760	110,179	72,617	47,861	31,544	20,790	13,702	9,816	9,031	8,308
62	Additions in Year		0	0	0	0	0	147,389	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0	147,389	141,493	130,174	119,760	110,179	72,617	47,861	31,544	20,790	13,702	9,816	9,031	8,308
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	0	0	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0	5,896	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	0	0	5,896	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
68	Ending Balance UCC		0	0	0	0	0	141,493	130,174	119,760	110,179	101,365	66,808	44,032	29,021	19,127	12,606	9,031	8,308	7,644

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

break after

Alternative 2A - 2012 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary																			
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 25	0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
2	Depreciation Expense	Line 31	0	0	0	0	0	0	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	58
3	Carrying Costs	Line 38	0	0	0	0	0	6,104	12,029	11,670	11,311	10,952	9,157	7,362	5,568	3,773	1,978	543	184	2
4	Income Tax	Line 60	0	0	0	0	0	(1,280)	(624)	(324)	(53)	191	1,079	1,554	1,759	1,784	1,691	1,559	1,520	(245)
5	Total Revenue Requirement for Project		0	0	0	0	0	4,824	15,413	15,220	14,971	14,876	12,764	10,021	6,295	1,336	(5,294)	(12,881)	(14,293)	(23,467)
6	**Net Present Value of Revenue Requirement @** 10.0%		**68,966**	0	0	0	0	2,723	7,909	7,100	6,349	5,735	3,056	1,490	581	77	(188)	(313)	(316)	(471)
					0	0	0	2,723	10,632	17,733	24,082	29,817	49,668							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	0.00%	0.00%	1.86%	5.83%	5.65%	5.44%	5.30%	4.12%	2.93%	1.67%	0.32%	-1.15%	-2.59%	-2.81%	-4.53%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	0.00%	0.00%	1.86%	3.97%	-0.19%	-0.20%	-0.14%	-0.18%	-0.16%	-0.17%	-0.17%	-0.19%	-0.34%	-0.23%	-1.71%
9	**NPV of Project / Total Revenue Requirements**		**2.27%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
12	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
13	Capital Costs		3,972	1,605	2,033	15,451	71,100	56,880												
14	AFUDC			286	396	920	3,517	7,356												
15	Total Cash Outlay in Year		**3,972**	**1,891**	**2,429**	**16,371**	74,617	64,236	0	0	0	0	0	0	0	0	0	0	0	0
16	Cumulative Cash Outlay		3,972	5,863	8,292	24,663	99,279	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
17			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Cumulative Project Cost		3,972	5,863	8,292	24,663	99,279	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
19	Additions to Plant		0	0	0	0	0	163,516	0	0	0	0	0	0	0	0	0	0	0	0
20	Cummulative Additions to Plant		0	0	0	0	0	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
21	CWIP		3,972	5,863	8,292	24,663	99,279	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Line Losses								(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
23	Maintenance						0		0	10	10	210	255	311	378	460	560	33	681	
24	Property Taxes								676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
25	Total Incremental Operating Costs (Savings)		0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																			
26	Land							3,264												
	Depreciation Expense																			
27	Opening Cash Outlay		0	0	0	0	0	0	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252
28	Additions in Year	Line 19 less Line26	0	0	0	0	0	160,252	0	0	0	0	0	0	0	0	0	0	0	0
29	Cumulative Total		0	0	0	0	0	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252
30	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
31	Depreciation Expense		0	0	0	0	0	0	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	58
	Net Book Value																			
32	Gross Property	Line 20	0	0	0	0	0	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
33	Accumulated Depreciation		0	0	0	0	0	0	(4,808)	(9,615)	(14,423)	(19,230)	(43,268)	(67,306)	(91,344)	(115,382)	(139,419)	(158,650)	(163,457)	(163,516)
34	Net Book Value		0	0	0	0	0	163,516	158,708	153,900	149,093	144,285	120,248	96,210	72,172	48,134	24,096	4,866	58	0
	Carrying Costs on Average NBV																			
35	Return on Equity		0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
36	Interest Expense		0	0	0	0	0	3,154	6,216	6,030	5,845	5,659	4,732	3,805	2,877	1,950	1,022	280	95	1
37	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	**Total Carrying Costs**		0	0	0	0	0	6,104	12,029	11,670	11,311	10,952	9,157	7,362	5,568	3,773	1,978	543	184	2
	Income Tax Expense																			
39	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
40	Return on Equity	Line 35	0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
41	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0	4,041	7,963	7,725	7,488	7,250	6,062	4,874	3,686	2,498	1,310	359	122	1
42	Less: Income tax on Equity Return		0	0	0	0	0	1,091	2,150	2,086	2,022	1,958	1,637	1,316	995	674	354	97	33	0
43	Net Income (equal return on equity)		0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
	Income Tax on Timing Differences																			
44	Depreciation Expense		0	0	0	0	0	0	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	58
45	Less: Capital Cost Allowance	Line 67	0	0	0	0	0	6,410	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
46	Total Timing Differences		0	0	0	0	0	(6,410)	(7,500)	(6,515)	(5,609)	(4,776)	(1,509)	645	2,064	2,999	3,616	3,954	4,022	(664)
47	Income Tax on Timing Differences		0	0	0	0	0	(1,731)	(2,025)	(1,759)	(1,515)	(1,290)	(407)	174	557	810	976	1,068	1,086	(179)
48	Before Tax Revenue Requirement [=Line47/(1-tax)		0	0	0	0	0	(2,371)	(2,774)	(2,410)	(2,075)	(1,766)	(558)	238	763	1,109	1,337	1,462	1,488	(246)
60	**Total Income Tax**	Lines 42 + 48	0	0	0	0	0	(1,280)	(624)	(324)	(53)	191	1,079	1,554	1,759	1,784	1,691	1,559	1,520	(245)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	0	0	153,842	141,535	130,212	119,795	78,955	52,038	34,297	22,605	14,898	10,673	9,819	9,034
62	Additions in Year		0	0	0	0	0	160,252	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0	160,252	153,842	141,535	130,212	119,795	78,955	52,038	34,297	22,605	14,898	10,673	9,819	9,034
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	0	0	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0	6,410	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	0	0	6,410	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
68	Ending Balance UCC		0	0	0	0	0	153,842	141,535	130,212	119,795	110,211	72,638	47,875	31,553	20,796	13,706	9,819	9,034	8,311

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

break after

Alternative 2B - 2012 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary		9.02%																	
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 25	0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
2	Depreciation Expense	Line 31	0	0	0	0	0	0	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	348
3	Carrying Costs	Line 38	0	0	0	0	0	5,563	10,963	10,636	10,310	9,983	8,351	6,719	5,086	3,454	1,822	516	189	13
4	Income Tax	Line 60	0	0	0	0	0	(1,162)	(564)	(291)	(44)	178	985	1,418	1,603	1,626	1,542	1,422	1,387	(112)
5	Total Revenue Requirement for Project		0	0	0	0	0	4,401	13,973	13,785	13,544	13,460	11,429	8,806	5,223	425	(6,034)	(13,480)	(14,856)	(23,033)
6	**Net Present Value of Revenue Requirement @** **10.0%**		**61,047**	0	0	0	0	2,484	7,170	6,431	5,744	5,189	2,736	1,309	482	24	(215)	(328)	(328)	(463)
					0	0	0	2,484	9,654	16,085	21,829	27,018	44,861							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	0.00%	0.00%	1.70%	5.29%	5.11%	4.92%	4.80%	3.69%	2.58%	1.38%	0.10%	-1.31%	-2.71%	-2.92%	-4.44%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	0.00%	0.00%	1.70%	3.59%	-0.17%	-0.19%	-0.13%	-0.16%	-0.14%	-0.15%	-0.16%	-0.18%	-0.33%	-0.22%	-1.52%
9	**NPV of Project / Total Revenue Requirements**		**2.01%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
12	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
13	Capital Costs	137520	3,972	1,605	2,033	14,098	64,340	51,472												
14	AFUDC	11501		286	396	880	3,233	6,707												
15	Total Cash Outlay in Year	149021	**3,972**	**1,891**	**2,429**	**14,978**	67,573	58,179	0	0	0	0	0	0	0	0	0	0	0	0
16	Cumulative Cash Outlay		3,972	5,863	8,292	23,270	90,843	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
17			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Cumulative Project Cost		3,972	5,863	8,292	23,270	90,843	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
19	Additions to Plant		0	0	0	0	0	149,022	0	0	0	0	0	0	0	0	0	0	0	0
20	Cummulative Additions to Plant		0	0	0	0	0	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
21	CWIP		3,972	5,863	8,292	23,270	90,843	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Line Losses								(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
23	Maintenance						0		0	10	10	210	255	311	378	460	560	33	681	
24	Property Taxes								676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
25	Total Incremental Operating Costs (Savings)		0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																			
26	Land							3,264												
	Depreciation Expense																			
27	Opening Cash Outlay		0	0	0	0	0	0	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758
28	Additions in Year	Line 19 less Line26	0	0	0	0	0	145,758	0	0	0	0	0	0	0	0	0	0	0	0
29	Cumulative Total		0	0	0	0	0	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758
30	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
31	Depreciation Expense		0	0	0	0	0	0	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	348
	Net Book Value																			
32	Gross Property	Line 20	0	0	0	0	0	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
33	Accumulated Depreciation		0	0	0	0	0	0	(4,373)	(8,745)	(13,118)	(17,491)	(39,355)	(61,218)	(83,082)	(104,946)	(126,810)	(144,300)	(148,673)	(149,022)
34	Net Book Value		0	0	0	0	0	149,022	144,649	140,276	135,903	131,531	109,667	87,803	65,939	44,076	22,212	4,721	348	0
	Carrying Costs on Average NBV																			
35	Return on Equity		0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
36	Interest Expense		0	0	0	0	0	2,875	5,665	5,496	5,328	5,159	4,315	3,472	2,628	1,785	941	266	98	7
37	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	**Total Carrying Costs**		0	0	0	0	0	5,563	10,963	10,636	10,310	9,983	8,351	6,719	5,086	3,454	1,822	516	189	13
	Income Tax Expense																			
39	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
40	Return on Equity	Line 35	0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
41	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0	3,683	7,257	7,041	6,825	6,609	5,528	4,448	3,367	2,286	1,206	341	125	9
42	Less: Income tax on Equity Return		0	0	0	0	0	994	1,959	1,901	1,843	1,784	1,493	1,201	909	617	326	92	34	2
43	Net Income (equal return on equity)		0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
	Income Tax on Timing Differences																			
44	Depreciation Expense		0	0	0	0	0	0	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	348
45	Less: Capital Cost Allowance	Line 67	0	0	0	0	0	5,830	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
46	Total Timing Differences		0	0	0	0	0	(5,830)	(6,821)	(5,926)	(5,102)	(4,344)	(1,372)	586	1,877	2,728	3,289	3,596	3,658	(309)
47	Income Tax on Timing Differences		0	0	0	0	0	(1,574)	(1,842)	(1,600)	(1,378)	(1,173)	(371)	158	507	737	888	971	988	(83)
48	Before Tax Revenue Requirement [=Line47/(1-tax)		0	0	0	0	0	(2,156)	(2,523)	(2,192)	(1,887)	(1,607)	(508)	217	694	1,009	1,216	1,330	1,353	(114)
60	**Total Income Tax**	Lines 42 + 48	0	0	0	0	0	(1,162)	(564)	(291)	(44)	178	985	1,418	1,603	1,626	1,542	1,422	1,387	(112)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	0	0	139,928	128,734	118,435	108,960	71,814	47,331	31,195	20,560	13,551	9,708	8,931	8,217
62	Additions in Year		0	0	0	0	0	145,758	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0	145,758	139,928	128,734	118,435	108,960	71,814	47,331	31,195	20,560	13,551	9,708	8,931	8,217
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	0	0	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0	5,830	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	0	0	5,830	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
68	Ending Balance UCC		0	0	0	0	0	139,928	128,734	118,435	108,960	100,243	66,068	43,545	28,699	18,915	12,467	8,931	8,217	7,559

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

break after

Alternative 3 - 2012 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary																			
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 26	0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
2	Depreciation Expense	Line 32	0	0	0	0	0	0	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	219
3	Carrying Costs	Line 39	0	0	0	0	0	5,804	11,438	11,097	10,756	10,415	8,711	7,006	5,301	3,596	1,892	528	187	8
4	Income Tax	Line 60	0	0	0	0	0	(1,215)	(590)	(306)	(48)	184	1,027	1,479	1,673	1,697	1,608	1,483	1,446	(171)
5	Total Revenue Requirement for Project		0	0	0	0	0	4,590	14,615	14,425	14,180	14,092	12,025	9,348	5,701	832	(5,704)	(13,213)	(14,605)	(23,227)
6	**Net Present Value of Revenue Requirement @** **10.0%**		**64,581**	0	0	0	0	2,591	7,500	6,729	6,014	5,433	2,879	1,390	526	48	(203)	(321)	(323)	(467)
					0	0	0	2,591	10,091	16,820	22,834	28,267	47,006							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	0.00%	0.00%	1.77%	5.53%	5.35%	5.16%	5.02%	3.88%	2.73%	1.51%	0.20%	-1.24%	-2.65%	-2.87%	-4.48%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	0.00%	0.00%	1.77%	3.76%	-0.18%	-0.19%	-0.13%	-0.17%	-0.15%	-0.16%	-0.17%	-0.19%	-0.34%	-0.22%	-1.61%
9	**NPV of Project / Total Revenue Requirements**		**2.12%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
13	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
14	Capital Costs		3,972	1,605	2,033	14,702	67,356	53,885												
15	AFUDC			286	396	898	3,359	6,997												
16	Total Cash Outlay in Year		**3,972**	**1,891**	**2,429**	**15,599**	70,716	60,882	0	0	0	0	0	0	0	0	0	0	0	0
17	Cumulative Cash Outlay		3,972	5,863	8,292	23,891	94,607	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
18			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Cumulative Project Cost		3,972	5,863	8,292	23,891	94,607	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
20	Additions to Plant		0	0	0	0	0	155,489	0	0	0	0	0	0	0	0	0	0	0	0
21	Cummulative Additions to Plant		0	0	0	0	0	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
22	CWIP		3,972	5,863	8,292	23,891	94,607	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Line Losses								(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
24	Maintenance						0		0	10	10	210	255	311	378	460	560	33	681	
25	Property Taxes								676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
26	Total Incremental Operating Costs (Savings)		0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																			
27	Land							3,264												
	Depreciation Expense																			
28	Opening Cash Outlay		0	0	0	0	0	0	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225
29	Additions in Year	Line 20 less Line27	0	0	0	0	0	152,225	0	0	0	0	0	0	0	0	0	0	0	0
30	Cumulative Total		0	0	0	0	0	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225
31	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
32	Depreciation Expense		0	0	0	0	0	0	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	219
	Net Book Value																			
33	Gross Property	Line 21	0	0	0	0	0	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
34	Accumulated Depreciation		0	0	0	0	0	0	(4,567)	(9,134)	(13,700)	(18,267)	(41,101)	(63,935)	(86,768)	(109,602)	(132,436)	(150,703)	(155,270)	(155,489)
35	Net Book Value		0	0	0	0	0	155,489	150,922	146,355	141,788	137,222	114,388	91,554	68,720	45,887	23,053	4,786	219	0
	Carrying Costs on Average NBV																			
36	Return on Equity		0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
37	Interest Expense		0	0	0	0	0	2,999	5,911	5,734	5,558	5,382	4,501	3,620	2,739	1,858	977	273	97	4
38	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Total Carrying Costs**		0	0	0	0	0	5,804	11,438	11,097	10,756	10,415	8,711	7,006	5,301	3,596	1,892	528	187	8
	Income Tax Expense																			
40	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
41	Return on Equity	Line 36	0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
42	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0	3,842	7,572	7,346	7,121	6,895	5,766	4,638	3,509	2,381	1,252	349	124	5
43	Less: Income tax on Equity Return		0	0	0	0	0	1,037	2,044	1,984	1,923	1,862	1,557	1,252	948	643	338	94	33	1
44	Net Income (equal return on equity)		0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
	Income Tax on Timing Differences																			
45	Depreciation Expense		0	0	0	0	0	0	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	219
46	Less: Capital Cost Allowance	Line 67	0	0	0	0	0	6,089	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
47	Total Timing Differences		0	0	0	0	0	(6,089)	(7,124)	(6,189)	(5,328)	(4,537)	(1,433)	612	1,960	2,849	3,435	3,756	3,821	(467)
48	Income Tax on Timing Differences		0	0	0	0	0	(1,644)	(1,924)	(1,671)	(1,439)	(1,225)	(387)	165	529	769	927	1,014	1,032	(126)
49	Before Tax Revenue Requirement [=Line48/(1-tax)		0	0	0	0	0	(2,252)	(2,635)	(2,289)	(1,971)	(1,678)	(530)	226	725	1,054	1,270	1,389	1,413	(173)
60	**Total Income Tax**	Lines 43 + 49	0	0	0	0	0	(1,215)	(590)	(306)	(48)	184	1,027	1,479	1,673	1,697	1,608	1,483	1,446	(171)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	0	0	146,136	134,445	123,690	113,794	75,000	49,431	32,579	21,472	14,152	10,138	9,327	8,581
62	Additions in Year		0	0	0	0	0	152,225	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0	152,225	146,136	134,445	123,690	113,794	75,000	49,431	32,579	21,472	14,152	10,138	9,327	8,581
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	0	0	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0	6,089	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	0	0	6,089	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
68	Ending Balance UCC		0	0	0	0	0	146,136	134,445	123,690	113,794	104,691	69,000	45,476	29,973	19,754	13,020	9,327	8,581	7,895

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break after

Alternative 1B - 2010 in service

Line No.		Year: Reference	1 Dec-07	2 Dec-08	3 Dec-09	4 Dec-10	5 Dec-11	6 Dec-12	7 Dec-13	8 Dec-14	9 Dec-15	10 Dec-16	15 Dec-21	20 Dec-26	25 Dec-31	30 Dec-36	35 Dec-41	39 Dec-45	40 Dec-46	41 Dec-47
	Summary																			
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 26	0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
2	Depreciation Expense	Line 32	0	0	0	0	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	0	0	0
3	Carrying Costs	Line 39	0	0	0	4,704	9,267	8,986	8,705	8,424	8,143	7,863	6,458	5,053	3,649	2,244	840	0	0	0
4	Income Tax	Line 60	0	0	0	(1,176)	(554)	(280)	(68)	123	295	449	998	1,275	1,372	1,350	1,250	(209)	(192)	(177)
5	Total Revenue Requirement for Project		0	0	0	3,828	11,921	11,749	11,601	11,377	11,107	11,000	8,940	6,388	2,944	(1,671)	(7,918)	(19,999)	(20,997)	(23,459)
6	**Net Present Value of Revenue Requirement @**	**10.0%**	**62,077**	0	0	2,615	7,402	6,632	5,953	5,307	4,710	4,241	2,140	950	272	(96)	(282)	(486)	(464)	(471)
					0	2,615	10,017	16,649	22,602	27,909	32,620	36,861	51,069							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	1.54%	4.69%	4.53%	4.39%	4.22%	4.04%	3.92%	2.89%	1.87%	0.78%	-0.40%	-1.72%	-4.01%	-4.13%	-4.53%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	1.54%	3.16%	-0.16%	-0.15%	-0.17%	-0.18%	-0.12%	-0.14%	-0.12%	-0.13%	-0.14%	-0.16%	-0.76%	-0.12%	-0.39%
9	**NPV of Project / Total Revenue Requirements**		**2.04%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
11		31.50%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
12	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
13	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
14	Capital Costs		3,972	12,559	55,839	44,671														
15	AFUDC			615	2,667	5,682														
16	Total Cash Outlay in Year		**3,972**	**13,174**	**58,506**	**50,354**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Cumulative Cash Outlay		3,972	17,146	75,652	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
18			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Cumulative Project Cost		3,972	17,146	75,652	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
20	Additions to Plant		0	0	0	126,006	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Cummulative Additions to Plant		0	0	0	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
22	CWIP		3,972	17,146	75,652	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Line Losses						(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
24	Maintenance						0	(50)	0	10	10	210	255	311	378	460	560	33	681	
25	Property Taxes					300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
26	Total Incremental Operating Costs (Savings)		0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																			
27	Land					589														
	Depreciation Expense																			
28	Opening Cash Outlay		0	0	0	0	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417
29	Additions in Year	Line 20 less Line27	0	0	0	125,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Cumulative Total		0	0	0	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417
31	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
32	Depreciation Expense		0	0	0	0	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	0	0	0
	Net Book Value																			
33	Gross Property	Line 21	0	0	0	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
34	Accumulated Depreciation		0	0	0	0	(3,763)	(7,525)	(11,288)	(15,050)	(18,813)	(22,575)	(41,388)	(60,200)	(79,013)	(97,825)	(116,638)	(126,006)	(126,006)	(126,006)
35	Net Book Value		0	0	0	126,006	122,243	118,481	114,718	110,956	107,193	103,431	84,618	65,805	46,993	28,180	9,368	0	0	0
	Carrying Costs on Average NBV																			
36	Return on Equity		0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
37	Interest Expense		0	0	0	2,431	4,789	4,644	4,498	4,353	4,208	4,063	3,337	2,611	1,886	1,160	434	0	0	0
38	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
39	**Total Carrying Costs**		0	0	0	4,704	9,267	8,986	8,705	8,424	8,143	7,863	6,458	5,053	3,649	2,244	840	0	0	0
	Income Tax Expense																			
40	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
41	Return on Equity	Line 36	0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
42	Gross up for revenue (Return / (1- tax rate)		0	0	0	3,247	6,264	5,949	5,763	5,577	5,391	5,205	4,275	3,345	2,416	1,486	556	0	0	0
43	Less: Income tax on Equity Return		0	0	0	974	1,785	1,606	1,556	1,506	1,456	1,405	1,154	903	652	401	150	0	0	0
44	Net Income (equal return on equity)		0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
	Income Tax on Timing Differences																			
45	Depreciation Expense		0	0	0	0	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	0	0	0
46	Less: Capital Cost Allowance	Line 67	0	0	0	5,017	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
47	Total Timing Differences		0	0	0	(5,017)	(5,870)	(5,099)	(4,390)	(3,738)	(3,138)	(2,586)	(422)	1,005	1,945	2,565	2,973	(566)	(520)	(479)
48	Income Tax on Timing Differences		0	0	0	(1,505)	(1,673)	(1,377)	(1,185)	(1,009)	(847)	(698)	(114)	271	525	692	803	(153)	(140)	(129)
49	Before Tax Revenue Requirement [=Line48/(1-tax)		0	0	0	(2,150)	(2,340)	(1,886)	(1,624)	(1,382)	(1,161)	(956)	(156)	372	719	949	1,100	(209)	(192)	(177)
60	**Total Income Tax**	Lines 43 + 49	0	0	0	(1,176)	(554)	(280)	(68)	123	295	449	998	1,275	1,372	1,350	1,250	(209)	(192)	(177)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	120,400	110,768	101,907	93,754	86,254	79,354	52,301	34,470	22,719	14,974	9,869	7,070	6,504	5,984
62	Additions in Year		0	0	0	125,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	125,417	120,400	110,768	101,907	93,754	86,254	79,354	52,301	34,470	22,719	14,974	9,869	7,070	6,504	5,984
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	5,017	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	5,017	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
68	Ending Balance UCC		0	0	0	120,400	110,768	101,907	93,754	86,254	79,354	73,005	48,117	31,713	20,901	13,776	9,079	6,504	5,984	5,505

FortisBC
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break after

Alternative 1B - 2012 in service

Line		Year:	1	2	3	4	5	6	7	8	9	10	15	20	25	30	35	39	40	41
No.		**Reference**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																			
	Revenue Requirements																			
1	Operating Expense (Incremental)	Line 25	0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
2	Depreciation Expense	Line 31	0	0	0	0	0	0	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	1,938	0
3	Carrying Costs	Line 38	0	0	0	0	0	5,061	9,972	9,669	9,367	9,064	7,553	6,041	4,529	3,017	1,505	296	72	0
4	Income Tax	Line 60	0	0	0	0	0	(1,093)	(554)	(302)	(74)	132	880	1,281	1,453	1,474	1,396	1,285	485	(225)
5	Total Revenue Requirement for Project		0	0	0	0	0	3,969	12,668	12,484	12,249	12,172	10,203	7,668	4,192	(487)	(6,820)	(14,160)	(18,309)	(23,508)
6	**Net Present Value of Revenue Requirement @** **10.0%**		**53,604**	0	0	0	0	2,240	6,501	5,824	5,195	4,693	2,442	1,140	387	(28)	(243)	(344)	(405)	(472)
					0	0	0	2,240	8,741	14,565	19,759	24,452	40,459							
	Rate Impact																			
7	**Forecast Revenue Requirements**		209,300	226,200	244,100	249,000	254,000	259,100	264,300	269,600	275,000	280,500	309,700	341,900	377,500	416,900	460,200	498,200	508,200	518,400
8	Rate Impact		0.00%	0.00%	0.00%	0.00%	0.00%	1.53%	4.79%	4.63%	4.45%	4.34%	3.29%	2.24%	1.11%	-0.12%	-1.48%	-2.84%	-3.60%	-4.53%
	Annual Incremental Rate Impact over previous year		**0.00%**	0.00%	0.00%	0.00%	0.00%	1.53%	3.26%	-0.16%	-0.18%	-0.11%	-0.15%	-0.13%	-0.14%	-0.15%	-0.17%	-0.33%	-0.76%	-0.93%
9	**NPV of Project / Total Revenue Requirements**		**1.76%**																	
	Regulatory Assumptions																			
10	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
12	Debt Return		6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																			
13	Capital Costs		3,972	1,445	107	12,078	59,857	47,886												
14	AFUDC			282	328	694	2,852	6,084												
15	Total Cash Outlay in Year		**3,972**	**1,726**	**435**	**12,772**	62,709	53,970	0	0	0	0	0	0	0	0	0	0	0	0
16	Cumulative Cash Outlay		3,972	5,698	6,133	18,905	81,614	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
17			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Cumulative Project Cost		3,972	5,698	6,133	18,905	81,614	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
19	Additions to Plant		0	0	0	0	0	135,584	0	0	0	0	0	0	0	0	0	0	0	0
20	Cummulative Additions to Plant		0	0	0	0	0	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
21	CWIP		3,972	5,698	6,133	18,905	81,614	0	0	0	0	0	0	0	0	0	0	0	0	0
										1.107	1.107	1.107	1.107							
22	Line Losses								(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
23	Maintenance						0		0	10	10	210	255	311	378	460	560	33	681	
24	Property Taxes								676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
25	Total Incremental Operating Costs (Savings)		0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																			
26	Land							589												
	Depreciation Expense																			
27	Opening Cash Outlay		0	0	0	0	0	0	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995
28	Additions in Year	Line 19 less Line26	0	0	0	0	0	134,995	0	0	0	0	0	0	0	0	0	0	0	0
29	Cumulative Total		0	0	0	0	0	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995
30	Depreciation Rate - composite average		3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
31	Depreciation Expense		0	0	0	0	0	0	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	1,938	0
	Net Book Value																			
32	Gross Property	Line 20	0	0	0	0	0	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
33	Accumulated Depreciation		0	0	0	0	0	0	(4,050)	(8,100)	(12,150)	(16,199)	(36,449)	(56,698)	(76,947)	(97,197)	(117,446)	(133,645)	(135,584)	(135,584)
34	Net Book Value		0	0	0	0	0	135,584	131,534	127,484	123,434	119,384	99,135	78,886	58,637	38,387	18,138	1,938	0	0
	Carrying Costs on Average NBV																			
35	Return on Equity		0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
36	Interest Expense		0	0	0	0	0	2,615	5,153	4,996	4,840	4,684	3,903	3,122	2,340	1,559	778	153	37	0
37	AFUDC		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
38	**Total Carrying Costs**		0	0	0	0	0	5,061	9,972	9,669	9,367	9,064	7,553	6,041	4,529	3,017	1,505	296	72	0
	Income Tax Expense																			
39	Combined Income Tax Rate		34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																			
40	Return on Equity	Line 35	0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
41	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0	3,351	6,601	6,401	6,201	6,001	5,000	3,999	2,998	1,997	997	196	48	0
42	Less: Income tax on Equity Return		0	0	0	0	0	905	1,782	1,728	1,674	1,620	1,350	1,080	810	539	269	53	13	0
43	Net Income (equal return on equity)		0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
	Income Tax on Timing Differences																			
44	Depreciation Expense		0	0	0	0	0	0	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	1,938	0
45	Less: Capital Cost Allowance	Line 67	0	0	0	0	0	5,400	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
46	Total Timing Differences		0	0	0	0	0	(5,400)	(6,318)	(5,488)	(4,725)	(4,023)	(1,271)	543	1,739	2,527	3,046	3,331	1,277	(609)
47	Income Tax on Timing Differences		0	0	0	0	0	(1,458)	(1,706)	(1,482)	(1,276)	(1,086)	(343)	147	469	682	822	899	345	(164)
48	Before Tax Revenue Requirement [=Line47/(1-tax)		0	0	0	0	0	(1,997)	(2,337)	(2,030)	(1,748)	(1,488)	(470)	201	643	934	1,127	1,232	472	(225)
60	**Total Income Tax**	Lines 42 + 48	0	0	0	0	0	(1,093)	(554)	(302)	(74)	132	880	1,281	1,453	1,474	1,396	1,285	485	(225)
	Capital Cost Allowance																			
61	Opening Balance - UCC		0	0	0	0	0	0	129,596	119,228	109,690	100,915	66,511	43,836	28,892	19,042	12,550	8,991	8,272	7,610
62	Additions in Year		0	0	0	0	0	134,995	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0	134,995	129,596	119,228	109,690	100,915	66,511	43,836	28,892	19,042	12,550	8,991	8,272	7,610
64	Capital Cost Allowance Rate		8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance		0	0	0	0	0	0	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0	5,400	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA		0	0	0	0	0	5,400	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
68	Ending Balance UCC		0	0	0	0	0	129,596	119,228	109,690	100,915	92,841	61,190	40,329	26,580	17,519	11,546	8,272	7,610	7,001

46.0 Losses and Other Operating Expenses

Reference: Exhibit B-1-1, Tab 5, pp. 3, 4; Exhibit B-1-3, Appendix H

Section 5, page 3 states: "For calculating the system loss, the existing (pre OTR Project) and proposed (post OTR Project) network configuration was compared for year 2010 peak system losses. Then, depending on the system load duration curve and system growth, approximate system losses were calculated for future years. The differential system loss constitutes the differential savings in system losses."

Appendix H line 23 (or 22) Line Losses shows the annual savings for each scenario.

Q46.1 Please provide the calculation of Loss Reduction for 2010, showing the existing and post-OTR peak system losses, how each peak loss was converted to an annual number and the value or price applied to the net loss amount.

A46.1 The basic procedure that was followed for the Loss Reduction Calculation is provided below:

1. Peak Losses for Pre OTR scenario for Year 2010 were assessed from the Load Flow Analysis;
2. Average load for Kelowna Penticton area is then assessed from assessed daily load profiles;
3. Load Factor (LF) of the Kelowna Penticton Area is then calculated using the Peak Load & Average Loads;
4. Loss Load Factor (LLF) is then calculated using the Load Factor value
5. Average Loss is calculated which is a function of LLF;

6. Average loss over the year is used to calculate the yearly energy loss;
7. A yearly peak loss growth of 8% is assumed as a representative approximation. This is since the average load growth in Kelowna is approximately 2.75% in the 20 year horizon and peak load is proportional to peak current, whereas peak loss is proportional to square of the peak current;
8. Future year peak losses and average energy losses were then calculated;
9. Estimated $/MW & $/MWh were assigned to calculate the net loss values for Pre OTR scenario for future years;
10. Steps 1 to 10 is repeated to calculate net loss values for Post OTR scenario for future years; and
11. The difference between the yearly amounts calculated in Steps 10 and 9 provides the Loss Reduction Data.

Q46.2 Please describe in some detail how system losses were calculated for future years, and how the value of this loss was inflated.

A46.2 Please refer to the response to BCUC IR No.1 Q46.1 Item 7.

Q46.3 It appears that the line losses savings are the same for the various route alternatives. Please confirm that the line loss savings are the same for all alternatives beyond 2012.

A46.3 Confirmed. Line loss savings are the same for all alternatives beyond 2012.

Q46.4 From the spreadsheet in Appendix H for alternative 1A, it appears that the line loss savings increase at a rate of 10.7% up to year 15 and then increases at a rate of 8.0% from year 16. Why do the line loss savings initially increase at 10.7%? Why is there a rate change between year 15 and 16? Why do the line loss savings increase at 8.0% in year 16 and beyond?

A46.4 Please note that the yearly peak loss growth is assumed at 8% as a representative approximation (refer response to BCUC IR No.1 Q46.1, Item 7). Additionally, the Demand and the Energy costs are also assumed to rise concurrently at approximately 2.5%. This makes the loss savings approximately grow at 10.7%. However, the Capacity & Energy escalation factors were not applied beyond 2021 (year 15) to keep the calculation and projected savings at a conservative level due to future uncertainties as:

1. Uncertainties in long term energy and capacity rates;
2. New energy and capacity rates may be negotiated in future; and
3. Future system reinforcements may have implications for loss savings that is not known at present.

Q46.5 For the Alternative 1A scenario in Appendix H, please provide the following supporting line loss savings schedule and filed the updated spreadsheet.

	Year 1	Year 2	…	Year 41
Energy Losses				
Losses prior to investment (GW.h/yr)				
Losses after investment (GW.h/yr)				
Net Losses (GW.h/yr)				
Value of Energy ($/MW.h)				
Value of Annual Energy Losses				

A46.5 The requested information is attached as Table A46.5 below

Table: A46.5 Line Loss Savings

PARAMETERS	Years 1,2,3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 15	Year 20	Year 25	Year 30	Year 35	Year 39	Year 40	Year 41
	2007/08/09	2010	2011	2012	2013	2014	2015	2016	2021	2026	2031	2036	2041	2045	2046	2047
Pre OTR Energy Losses (Losses after investment) (GWh / Yr.)		69.32	74.86	80.85	87.32	94.31	101.85	110.00	161.62	237.48						
Post OTR Energy Losses (Losses prior to investment) (GWh / Yr.)		85.34	92.16	99.54	107.50	116.10	125.39	135.42	198.97	292.35						
Net Energy Loss Reduction (GWh / Yr.)		16.02	17.30	18.68	20.18	21.79	23.54	25.42	37.35	54.88						
Estimated value of Energy ($/MWh)		$42	$43	$44	$45	$46	$48	$49	$55	$55						
Value of Energy Loss Reduced		$673,141	$745,167	$824,900	$913,164	$1,010,873	$1,119,036	$1,238,773	$2,059,348	$3,025,858	$4,445,978	$6,532,601	$9,598,534	$13,058,699	$14,103,395	$15,231,667
											Cost escalated @ 8% (Please refer to response A46.1)					

Q46.6 Please add current flow in the Vaseux-Penticton Zone) ("I") and I^2 based on projected load growth up to the circuit capacity proposed for the OTR Project to Figure 5-3, System Loss Reduction.

A46.6 Table A46.6 below provides:

1. The current flow (I) in the Vaseux-Penticton Zone from 2010 (post OTR) based on the projected load growth;
2. The square of the current flow (I^2) in the Vaseux-Penticton Zone from 2010 (post OTR) based on the projected load growth; and
3. The data provided up to 2026 is in line with the load forecast in the 2007/2008 SDP and the CPCN Application.

Table: A46.6 (a) Projected Current Flow, 2010-2017

Parameters / Year	2010	2011	2012	2013	2014	2015	2016	2017
Current Flow in VAS-RGA under proposed scenario (Amps) = I	496	512	520	530	538	548	556	564
Current Square in VAS-RGA under proposed scenario (Ampere)^2 = I^2	246,016	262,144	270,400	280,900	289,444	300,304	309,136	318,096

Table: A46.6 (b) Projected Current Flow, 2018 - 2026

Parameters / Year	2018	2019	2020	2021	2022	2023	2024	2025	2026
Current Flow in VAS-RGA under proposed scenario (Amps) = I	576	586	596	604	614	622	632	640	652
Current Square in VAS-RGA under proposed scenario (Ampere)^2 = I^2	331,776	343,396	355,216	364,816	376,996	386,884	399,424	409,600	425,104

The current (I) and the Current Square (I^2) are shown in Figures 46.6 (a) and 46.6 (b) below. They are not merged with the Loss Curve in Figure 3 due to the difference in scale and units.

1 **Figure 46.6 (a)**

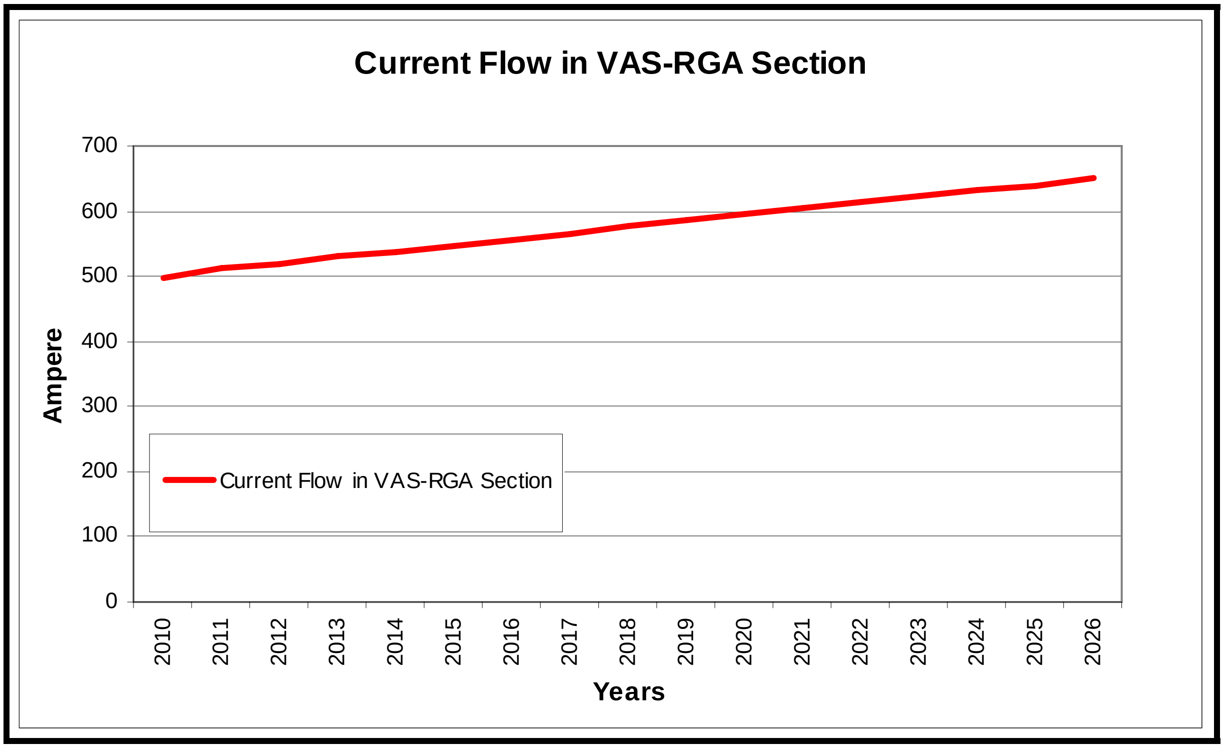
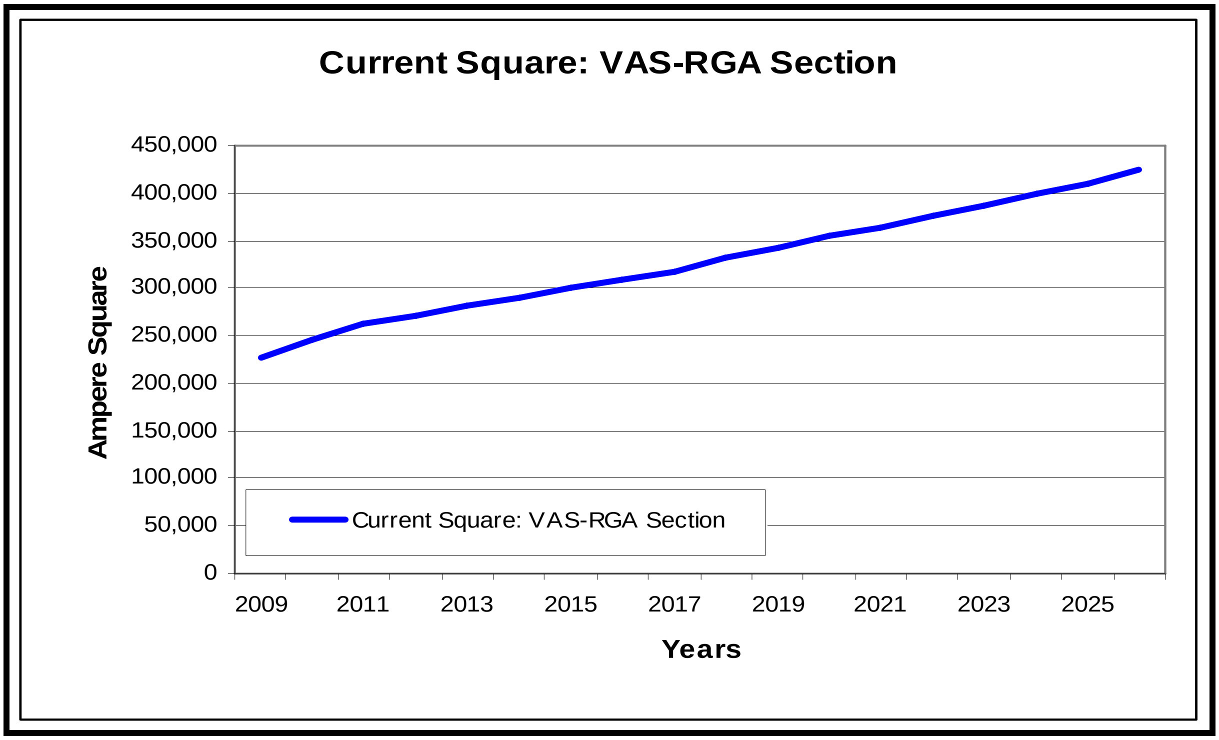


Figure 46.6 (b)



Q46.7 Assuming FortisBC considers that the existing system cannot handle customer loads until 2030, please explain why a loss reduction calculation that shows increasing loss reduction for many years into the future is realistic. Further to Section 6.1 of the Application, does FortisBC believe that a "Do Nothing" scenario is sustainable beyond perhaps 2015, for example?

A46.7 The assumption is more theoretical and conservative. It assumes a virtual scenario that continues to remain stable under additional loading conditions generating losses. In real scenario the losses are likely to grow faster when the existing system continues to load beyond its limits and will generate higher losses with time. Under the circumstances a stable scenario was considered to indicate the scale of savings in losses, which as indicated above remains simplistic and conservative.

FortisBC does not believe that a “Do Nothing” Option is sustainable and hence has not proposed the same. The CPCN is explicit about this (please refer to Section 6.1, Page 2, lines 11-13).

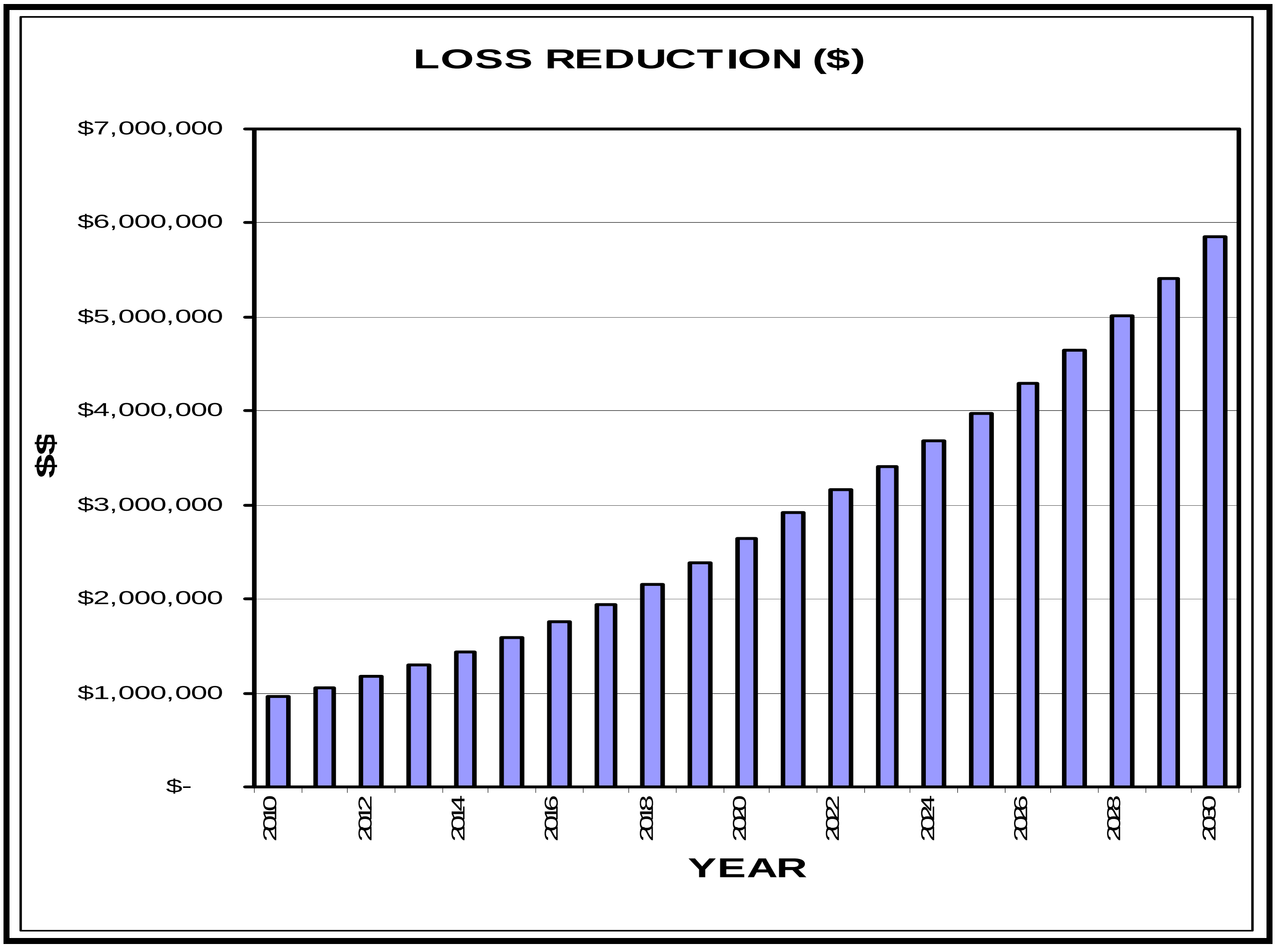
Q46.8 Further to Section 5.3 and Figure 5-3, please provide a comparable line loss calculation that is based on the assumption that the OTR Project includes one 230 kV line with a capacity of approximately 600 MW between Vaseux Lake Terminal and Penticton Zone, rather than two lower capacity 230 kV lines.

A46.8 Please note that the proposed high capacity line is expected to have the same conductor resistance as that of the CPCN proposed configuration with two lines between Vaseux & RG Anderson Terminal stations. Since line losses are a function of the line resistance, there will be no appreciable difference in line loss calculations from that provided in the CPCN Application.

Q46.9 Please provide a version of Figure 5-3 based on having only one of the proposed 230 kV circuits from Vaseux Lake to R. G. Anderson.

A46.9 Please see Figure A46.9 below:

1 **Figure A46.9 Value of Line Losses, Single 230 kV Circuit**



47.0 Losses and Other Operating Expenses -Towers and Substation
Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix H

Q47.1 In Appendix H Alternative 1A - 2010 in service lines 23 to 27 shows the Total Incremental Operating Costs (Savings). Line 24 shows Maintenance with no incremental costs. There is no line for additional operating costs. The Application at Tab 5, page 2 states the O&M expenses are expected to increase by $24,000 as a result of the OTR Project.

Q47.1.1 Please explain where the $24,000 per year is shown on the spreadsheets in Appendix H.

A47.1.1 The O&M costs were omitted in error. Please refer to the response to BCUC IR No. 1 Q45.4.

Q47.2 If the Appendix H spreadsheets do not include the incremental O&M, please refile the spreadsheets to separately show the incremental O&M.

A47.2 Please refer to the response to BCUC IR No.1 Q45.4

Q47.3 Please Columbia Transmission Corporation ("BCTC") in its Interior Lower Mainland ("ILM") CPCN Project includes 1) O&M annual rate for steel towers at 0.10% and 2) O&M annual rate for substations at 1.01%. Are these estimates appropriate for FortisBC? Please explain.

A47.3 No. Please refer to the response to BCUC IR No. 1 Q45.2.

Q47.4 Exhibit B-1-1, Section 7, page 2 states: "New construction related to the OTR Project Proposed Solution is located entirely within existing rights-of-way and FortisBC's property with the exception of the proposed Bentley Terminal station in Oliver. The proposed station site is on Osoyoos Indian Band land and is subject to lease agreement approval by

Osoyoos Indian Band and Indian and Northern Affairs Canada in accordance with the subject Memorandum of Understanding."

Q47.4.1 Should the incremental lease costs be included in the financial analysis? If so, please identify where the lease costs are included in the spreadsheet. If needed, please update the spreadsheet as required.

A47.4.1 Yes, these costs are a one time lease payment specifically for the Bentley Terminal station site. The lease costs are in total capital costs shown on the spreadsheet.

Table: A46.6 (a) Projected Current Flow, 2010-2017

Parameters / Year	2010	2011	2012	2013	2014	2015	2016	2017
Current Flow in VAS-RGA under proposed scenario (Amps) = I	496	512	520	530	538	548	556	564
Current Square in VAS-RGA under proposed scenario $(\text{Ampere})^2 = I^2$	246,016	262,144	270,400	280,900	289,444	300,304	309,136	318,096

Table: A46.6 (b) Projected Current Flow, 2018 - 2026

Parameters / Year	2018	2019	2020	2021	2022	2023	2024	2025	2026
Current Flow in VAS-RGA under proposed scenario (Amps) = I	576	586	596	604	614	622	632	640	652
Current Square in VAS-RGA under proposed scenario $(\text{Ampere})^2 = I^2$	331,776	343,396	355,216	364,816	376,996	386,884	399,424	409,600	425,104

The current (I) and the Current Square (I^2) are shown in Figures 46.6 (a) and 46.6 (b) below. They are not merged with the Loss Curve in Figure 3 due to the difference in scale and units.

1 **Figure 46.6 (a)**

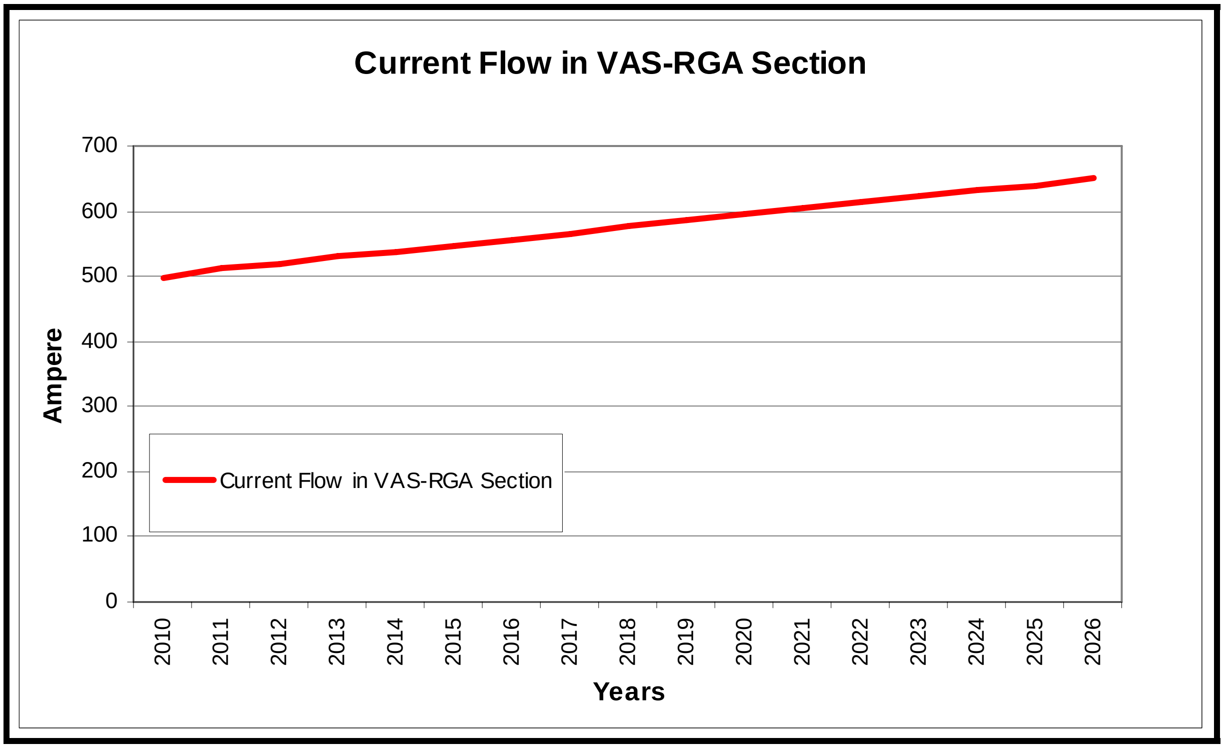
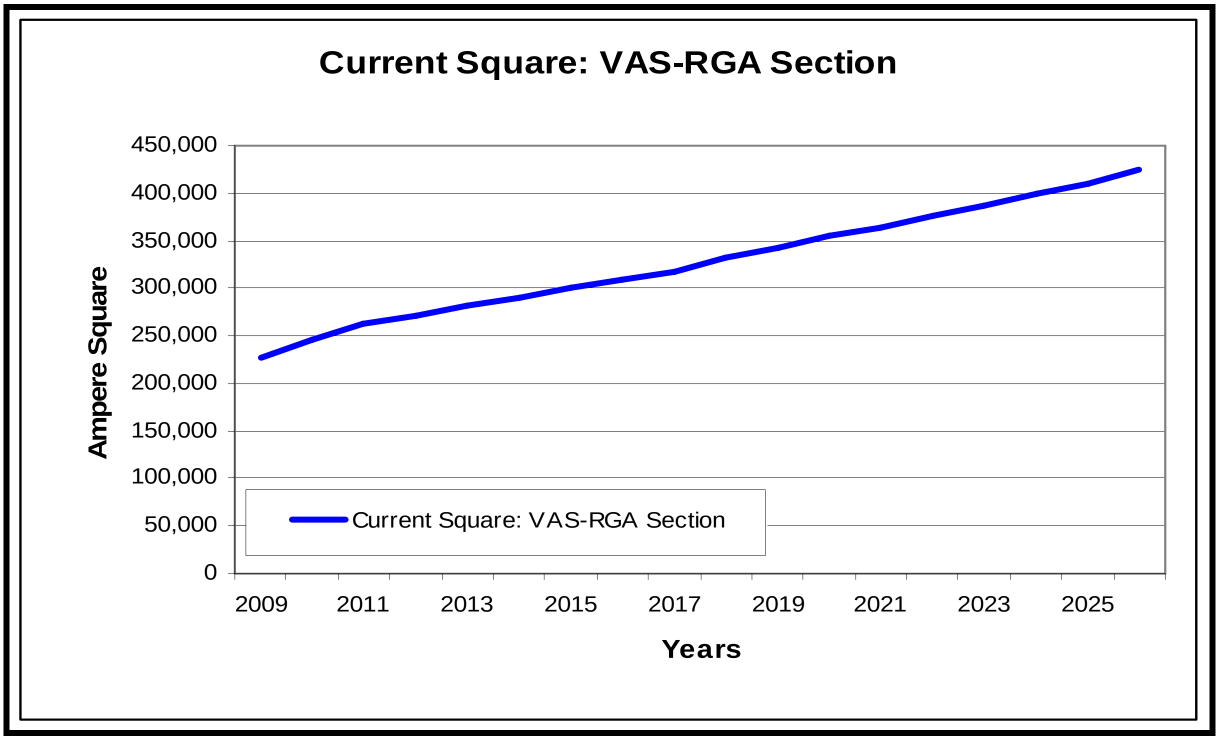


Figure 46.6 (b)



Q46.7 **Assuming FortisBC considers that the existing system cannot handle customer loads until 2030, please explain why a loss reduction calculation that shows increasing loss reduction for many years into the future is realistic. Further to Section 6.1 of the Application, does FortisBC believe that a "Do Nothing" scenario is sustainable beyond perhaps 2015, for example?**

A46.7 The assumption is more theoretical and conservative. It assumes a virtual scenario that continues to remain stable under additional loading conditions generating losses. In real scenario the losses are likely to grow faster when the existing system continues to load beyond its limits and will generate higher losses with time. Under the circumstances a stable scenario was considered to indicate the scale of savings in losses, which as indicated above remains simplistic and conservative.

FortisBC does not believe that a “Do Nothing” Option is sustainable and hence has not proposed the same. The CPCN is explicit about this (please refer to Section 6.1, Page 2, lines 11-13).

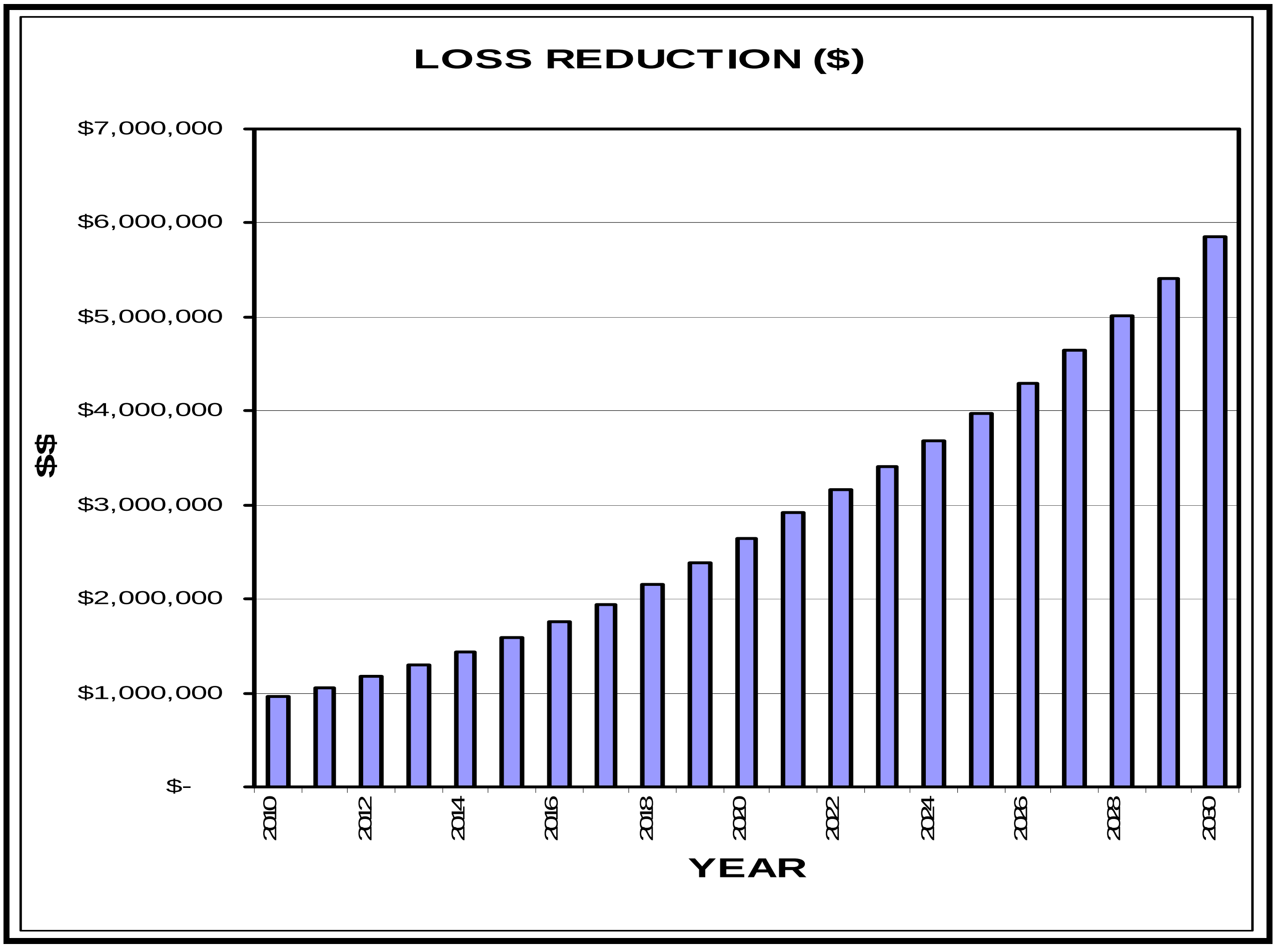
Q46.8 Further to Section 5.3 and Figure 5-3, please provide a comparable line loss calculation that is based on the assumption that the OTR Project includes one 230 kV line with a capacity of approximately 600 MW between Vaseux Lake Terminal and Penticton Zone, rather than two lower capacity 230 kV lines.

A46.8 Please note that the proposed high capacity line is expected to have the same conductor resistance as that of the CPCN proposed configuration with two lines between Vaseux & RG Anderson Terminal stations. Since line losses are a function of the line resistance, there will be no appreciable difference in line loss calculations from that provided in the CPCN Application.

Q46.9 Please provide a version of Figure 5-3 based on having only one of the proposed 230 kV circuits from Vaseux Lake to R. G. Anderson.

A46.9 Please see Figure A46.9 below:

1 **Figure A46.9 Value of Line Losses, Single 230 kV Circuit**



47.0 Losses and Other Operating Expenses -Towers and Substation

Reference: Exhibit B-1-1, Tab 5, p. 2; Exhibit B-1-3, Appendix H

Q47.1 In Appendix H Alternative 1A - 2010 in service lines 23 to 27 shows the Total Incremental Operating Costs (Savings). Line 24 shows Maintenance with no incremental costs. There is no line for additional operating costs. The Application at Tab 5, page 2 states the O&M expenses are expected to increase by $24,000 as a result of the OTR Project.

Q47.1.1 Please explain where the $24,000 per year is shown on the spreadsheets in Appendix H.

A47.1.1 The O&M costs were omitted in error. Please refer to the response to BCUC IR No. 1 Q45.4.

Q47.2 If the Appendix H spreadsheets do not include the incremental O&M, please refile the spreadsheets to separately show the incremental O&M.

A47.2 Please refer to the response to BCUC IR No.1 Q45.4

Q47.3 Please Columbia Transmission Corporation (“BCTC”) in its Interior Lower Mainland (“ILM”) CPCN Project includes 1) O&M annual rate for steel towers at 0.10% and 2) O&M annual rate for substations at 1.01%. Are these estimates appropriate for FortisBC? Please explain.

A47.3 No. Please refer to the response to BCUC IR No. 1 Q45.2.

Q47.4 Exhibit B-1-1, Section 7, page 2 states: “New construction related to the OTR Project Proposed Solution is located entirely within existing rights-of-way and FortisBC’s property with the exception of the proposed Bentley Terminal station in Oliver. The proposed station site is on Osoyoos Indian Band land and is subject to lease agreement approval by

Osoyoos Indian Band and Indian and Northern Affairs Canada in accordance with the subject Memorandum of Understanding."

Q47.4.1 Should the incremental lease costs be included in the financial analysis? If so, please identify where the lease costs are included in the spreadsheet. If needed, please update the spreadsheet as required.

A47.4.1 Yes, these costs are a one time lease payment specifically for the Bentley Terminal station site. The lease costs are in total capital costs shown on the spreadsheet.

48.0 Financial Analyses and Parameters - Removals and Salvage

Reference: Exhibit B-1-1, Section 4, pp. 18, 29; Section 5, p. 2

Table 5-1 OTR Project Capital Cost Summary on Section 5, page 2 includes 'Removals & Salvage' totaling $3.912 million.

Section 4, page 18 states: "The 45 existing 161 kV 16 metre high, H-frame wood pole structures will be salvaged."

Section 4, page 29 states: "Removing the existing 161 kV equipment, including circuit breakers and two transformers for salvage."

Q48.1 With regard to existing assets that are to be retired, please provide an estimate of the expected salvage value and explain where this value is shown on the spreadsheets in Appendix H.

A48.1 FortisBC did not estimate or show in Appendix H, any salvage value for the existing 161 kV transmission lines and equipment as this infrastructure is in excess of 40 years old. Any salvage value for the line is deemed to be minimal and will be applied to the OTR Project. FortisBC will assess equipment value either for retention as spares or salvage once taken out of service.

Q48.2 With regard to the retired assets was there any provision for negative salvage? If so, what were the provisions?

A48.2 There is no provision for negative salvage for the retired assets.

Q48.3 With regard to the existing Line 76, what is the percentage of accumulated depreciation to gross plant and what is the remaining net book value of the line?

A48.3 As noted in Table A48.3 below, the percentage of accumulated depreciation to gross plant for 76 Line is 6.0% and the remaining net book value is $1.0 million.

Table A48.3 Book and Net Values, 76 Line and 40 Line

76 Line	**$000s**	
Gross Book Value	1,087.7	
Accumulated Depreciation	(64.9)	6.0%
Net Book Value	1,022.8	
40 Line		
Gross Book Value	2,991.0	
Accumulated Depreciation	(807.5)	27.0%
Net Book Value	2,183.5	
Combined Total		
Gross Book Value	4,078.7	
Accumulated Depreciation	(872.4)	21.4%
Net Book Value	3,206.3	

Q48.4 With regard to the existing Line 40, what is the percentage of accumulated depreciation to gross plant and what is the remaining net book value of the line?

A48.4 As noted in Table A48.3 above, the percentage of accumulated depreciation to gross plant for 40 Line is 27.0% and the remaining net book value is $2.2 million.

Q48.5 Please describe the accounting treatment that FortisBC proposes for the remaining net book value of the assets that will be replaced by the OTR Project.

A48.5 The Company will be accounting for the assets replaced by the OTR Project in accordance with the BCUC Uniform System of Accounts guidelines for the replacement of assets as noted below:

> “*Replacements - 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.*”

49.0 Financial Analyses and Parameters - Discount Rate

Reference: Exhibit B-1-1, Appendix H

In Appendix H line 6 Net Present Value of Revenue Requirements shows a discount rate of 10%.

Q49.1 Please explain the rationale why the discount rate of 10% was chosen.

A49.1 The discount rate is based on a real discount rate of 8 percent plus inflation of 2 percent. FortisBC has used a real discount rate of 8 percent as a base case in evaluating its capital expenditures for a number of years.

Q49.2 For the purpose of a sensitivity analysis, please provide a summary comparison of the NPV of Revenue Requirement for the proposed Alternative 1A scenario using discount rates of 6% and 12% along with the initial 10% discount rate.

A49.2 Please see Table A49.2 below.

Table: A49.2 Sensitivity of Revenue Requirements to Discount Rate

Alternative 1A - 2010 in service			
Discount Rate (%)	6.0	10.0	12.0
Net Present Value of Revenue Requirement ($000s)	90,107	69,421	60,273

50.0 Financial Analyses and Parameters - Property Taxes

Reference: Exhibit B-1-1, Appendix H

In Appendix H, Alternative 1A, line 25, Property Taxes, FortisBC calculates property tax of $650,000 in year 5 growing at a rate of 2% per year thereafter.

Q50.1 Please show the calculation of the $650,000 in costs for property tax.

A50.1 Please see Table A50.1 below detailing the property tax calculation.

Table: A50.1

Okanagan Transmission Reinforcement Project
Property Taxation Estimate
Based on information available as of July 27, 2007

Transmission:	Description	Assessment Class	Rate / km	Assessment		Tax Estimate
Double Circuit 230kV Vaseux to Penticton (75/76 Line)	28 km Steel Pole	Class 4	445,144	**12,464,032**		
Singlie Circuit 230kV Vaseux to Bentley (40 Line)	10.8 km H-frame steel	Class 6	319,149	**3,446,809**		
63 & 138kV Circuits Bentley to Oliver	0.3 km wood	Class 2	47,343	**14,202**	**15,925,043**	$346,546
Substations:	**Description**	**Size or Rating (MVA etc)**	**Assess Rate**	**Assessment**		
New Bentley Terminal	T1 - 230/63	90/120/168	1,385,000	**1,385,000**		
Built to Utility Class of construction (BCH Standards)	T1 Foundation		464,000	**464,000**		
	T2 - 160/63	90/120/150	1,350,000	**1,350,000**		
	T2 Foundation		464,000	**464,000**		
	T3 - 138/63	60/80/100	900,000	**900,000**		
	T3 Foundation		333,000	**333,000**		
	CB 72.5 kV	2000A	391,000	**391,000**		
	CB 145 kV	2000A	391,000	**391,000**		
	CB 253 kV	2000A	605,000	**605,000**		
	Dead Ends	3	83,000	**249,000**		
	Land	8.65 Ac	Estimate	**750,000**		
	Fence	1,600 ft	$20 / ft	**32,000**		
	Grounding	3.67 Ac	Estimate	**30,000**		
	Gravel	160,000 Sq Ft	0.93	**148,800**		
	Bldg	2,150 Sq ft	$50 / ft	**107,500**	**7,600,300**	$153,693
Oliver Substation Upgrade	T3 - 63/13	12/16/20	307,900	**307,900**		
	T3 Foundation		56,000	**56,000**		
	CB 15 kV	2	228,000	**456,000**		
	CB 72.5 kV	1	228,000	**228,000**	**1,047,900**	$21,191
RG Anderson Terminal Upgrade	T2 - 25/69/236	120/160/200	374,000	**374,000**		
	T2 Foundation	Existing	-	-	**374,000**	$6,776
Lee Terminal 138kV Capacitor Upgrade	CB2 145kV	2000A	391,000	**391,000**		
	CAP2 - 30MVAR	1200A	485,000	**485,000**	**876,000**	$16,806
Bell Terminal 138kV Capacitor Upgrade	CB1 145kV	2000A	391,000	**391,000**		
	CAP1 - 30MVAR	1200A	485,000	**485,000**	**876,000**	$21,212
Vaseux 230kV Terminal Upgrade	CB3 230kV	2000A	525,000	**525,000**		
	CB5 230kV	2000A	525,000	**525,000**		
	CB Line Positions	2	171,000	**342,000**	**1,392,000**	$40,489
Vaseux 500kV Terminal Upgrade	5CB12	4000A	422,000	**422,000**	**422,000**	$12,275
					28,513,243	
			Tax Estimate 2007 Mil Rates			**$618,988**
			Escalated to 2010 (rounded)			**$650,000**

Q50.2 BCTC in its ILM CPCN Project includes 1) Annual taxes for 500 kV transmission lines at $4,056/km and 2) Annual tax rate on physical plant at 1.47%. Are these estimates appropriate for FortisBC? Please explain.

A50.2 No, the estimates are not appropriate for FortisBC for the following reasons:

1. BCTC and BC Hydro pay only school taxes and grants in lieu of property taxes so the property tax liabilities for each entity differs, and
2. The estimates are for 500 kV transmission lines whereas the OTR Project is primarily 230 kV.

51.0 Financial Analyses and Parameters - Depreciation Rate

Reference: Exhibit B-1-1, Appendix H

Appendix H, Alternative 1A, line 31, Depreciation Rate – composite average contains a 3.00% figure.

Q51.1 Please show the details of the computation of this figure by including the types of depreciable assets and its individual rates.

A51.1 All of the depreciable assets included in the Project will fall into one of three plant accounts as shown below per the BCUC Uniform System of Accounts. The depreciation rates for each of the accounts were not computed, but were set at 3.0% as per the terms of the 2005 Negotiated Settlement Agreement approved by BCUC Order G-58-06. Please see Table A51.1 below.

Table A51.1 Depreciation Rates

BCUC Account	Asset Description	Depreciation Rate	Estimated Service Life
353.0	Substation Equipment	3.0%	50 Years
355.0	Poles, Towers and Fixtures	3.0%	45 Years
356.0	Conductors and Devices	3.0%	50 Years

Q51.2 What is the estimated life of each of the asset types to be placed into service under the OTR Project?

A51.2 Please see the response to BCUC IR No. 1 Q51.1 above.

52.0 Financial Analyses and Parameters - Capital Cost Allowance
Reference: Exhibit B-1-1, Appendix H

Appendix H, Alternative 1A, line 64, Capital Cost Allowance Rate contains an 8.00% figure.

Q52.1 Please provide the information in the form of the table below.

A52.1 All of the depreciable assets will be classified as Class 47 property as defined by the Income Tax Act and be allowed a Capital Cost Allowance of 8 percent on the Undepreciated Capital Cost (subject to the half-year rule in the first year the property is placed in service).

	CCA Rate %	**UCC Addition**
Capital Cost Allowance Rate Class 47	8.0	$136,908,000

53.0 Financial Analyses and Parameters – Capital Cost

Reference: Exhibit B-1-1, Appendix H

In Appendix H, Alternative 1A -2010 in service for line 19 shows a cumulative Project Cost of $137,496 million including AFUDC.

Q53.1 In a schedule for each scenario please provide the total costs segmented by asset account. Include identified costs for land, rights-of-way, capitalized tree/brush clearing, towers, conductors, etc.

A53.1 Please see Table A53.1 below.

Table: A53.1 Capital Costs by Asset Class

Option	**1A 2010**	**1A 2012**	**1B 2010**	**1B 2012**	**2A 2012**	**2B 2012**	**3 2012**
Land & ROW ($000s)	679	682	682	684	3,822	3,922	3,831
Structures and Conductor ($000s)	70,086	75,390	57,156	61,458	84,118	65,878	74,936
Stations & Equipment ($000s)	66,731	71,906	68,168	73,442	75,575	79,222	76,722
Total	137,496	147,977	126,006	135,584	163,516	149,022	155,489

Q53.2 Alternative 1A 2010 in service includes land of $589,000 in year 4 (2010). Please identify the land purchased and its purpose, or the other Land costs that are referred to.

A53.2 This $589,000 is for the lease of the Bentley Terminal site from the Osoyoos Indian Band. This includes:

- $482,500 for rent payable under the Bentley Terminal Lease Memorandum of Understanding (MOU) (See Appendix F, Exhibit B-1-3);
- $22,000 penalty fee as a result of not executing the lease prior to March 15 2007 as outlined in the MOU; and
- $85,500 of other associated legal, management and survey costs and fees.

Q53.3 Alternative 2A 2012 in service includes land of $3,264,000 in year 6 (2012). Please identify the land purchased and its purpose, or the other Land costs that are referred to.

A53.3 This $3,264 million includes:

- $589,000 is for the lease of the Bentley Terminal site from the Osoyoos Indian Band as detailed in the response to BCUC IR No. 1 Q53.2;

- $2.675 million allowance for all upland route associated new right of way costs including:
  - Provincial lease payment;
  - Compensation for current lease and tenure holders along the route;
  - First Nations compensation if necessary; and
  - All other associated legal, management and survey costs and fees.
- A detailed determination of the above costs would not take place until negotiations and acquisition of the right of way commences.

54.0 Financial Analyses and Parameters - Economic Analysis

Reference: Exhibit B-1-1, Appendix H

The May 11, 2007 Decision for BC Hydro's 2006 Integrated Electricity Plan and 2006 Long Term Acquisition Plan ("BC Hydro IEP") on pages 200-201 stated:

> **"The Commission Panel accepts BC Hydro's argument that two tests may be considered for use in project evaluation. The first, and the more important, is an economic analysis of a project, which should only use the incremental cash flows disbursed by BC Hydro as its key input. The second, and less material test is a ratepayer impact analysis which examines how BC Hydro will recover a project's costs from its ratepayers and which may include items typically not found in a conventional economic analysis such as sunk costs, interest during construction and costs allocated from other departments of BC Hydro."**

Q54.1 Please provide the OTR Project economic analyses for the various scenarios shown in Tables 4-3-2A and 4-3-2B and for alternative 1C, using a traditional discounted cash flow methodology. Please include a schedule, and identify all material assumptions.

A54.1 The following are the material assumptions made in the analyses.

Discount Rate:	10.0%
General Inflation Rate:	2.0%
Composite Depreciation Rate:	3.0%
Composite CCA Rate:	8.0%

Combined Income Tax Rates:

2008	31.5%
2009	31.0%
2010	30.0%
2011	28.5%
2012 onwards	27.0%

The requested analyses are attached below:

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 1A - 2010 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(103,724)**	(3,972)	(13,631)	(61,199)	(48,959)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**21,094**	0	0	0	(300)	554	720	799	933	1,094	1,074	2,279	3,703	5,839	9,028	13,770	19,790	20,804	23,282
3	Income Tax		**(3,325)**	0	0	0	1,294	617	315	83	(127)	(315)	(484)	(1,086)	(1,389)	(1,495)	(1,471)	(1,361)	229	211	194
4	Net Cash Flow		**(85,955)**	(3,972)	(13,631)	(61,199)	(47,965)	1,171	1,035	882	807	779	590	1,193	2,314	4,344	7,556	12,409	20,019	21,015	23,476
5	**Discounted Cash Flow**		**(85,955)**	(3,972)	(12,392)	(50,577)	(36,037)	800	643	498	414	364	250	314	378	441	476	486	535	511	519
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	13,631	61,199	48,959														
11	AFUDC				647	2,892	6,197														
12	Total Cash Outlay in Year			**3,972**	**14,278**	**64,091**	**55,156**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	18,250	82,340	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
14				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	18,250	82,340	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
16	Additions to Plant			0	0	0	137,496	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
18	CWIP			3,972	18,250	82,340	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses							(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance							0	(50)	0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes						300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
22	Total Incremental Operating Costs (Savings)			0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land																				
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
25	Additions in Year	Line 16 less Line23		0	0	0	137,496	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	0	0	0
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496	137,496
30	Accumulated Depreciation			0	0	0	0	(4,125)	(8,250)	(12,375)	(16,500)	(20,624)	(24,749)	(45,374)	(65,998)	(86,622)	(107,247)	(127,871)	(137,496)	(137,496)	(137,496)
31	Net Book Value			0	0	0	137,496	133,371	129,246	125,121	120,996	116,872	112,747	92,122	71,498	50,874	30,249	9,625	0	0	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	2,480	4,886	4,738	4,589	4,440	4,291	4,142	3,398	2,654	1,910	1,166	422	0	0	0
33	Interest Expense			0	0	0	2,652	5,225	5,066	4,907	4,748	4,588	4,429	3,634	2,838	2,042	1,247	451	0	0	0
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	5,133	10,111	9,804	9,496	9,188	8,880	8,572	7,032	5,492	3,952	2,412	873	0	0	0
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	2,480	4,886	4,738	4,589	4,440	4,291	4,142	3,398	2,654	1,910	1,166	422	0	0	0
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	3,543	6,834	6,490	6,286	6,082	5,878	5,674	4,655	3,636	2,616	1,597	578	0	0	0
39	Less: Income tax on Equity Return			0	0	0	1,063	1,948	1,752	1,697	1,642	1,587	1,532	1,257	982	706	431	156	0	0	0
40	Net Income (equal return on equity)			0	0	0	2,480	4,886	4,738	4,589	4,440	4,291	4,142	3,398	2,654	1,910	1,166	422	0	0	0
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	4,125	0	0	0
42	Less: Capital Cost Allowance	Line 67		0	0	0	5,500	10,560	9,715	8,938	8,223	7,565	6,960	4,587	3,023	1,993	1,313	866	620	570	525
43	Total Timing Differences			0	0	0	(5,500)	(6,435)	(5,590)	(4,813)	(4,098)	(3,440)	(2,835)	(462)	1,102	2,132	2,812	3,259	(620)	(570)	(525)
44	Income Tax on Timing Differences			0	0	0	(1,650)	(1,834)	(1,509)	(1,299)	(1,106)	(929)	(765)	(125)	297	576	759	880	(167)	(154)	(142)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	(2,357)	(2,565)	(2,068)	(1,780)	(1,516)	(1,272)	(1,048)	(171)	407	789	1,040	1,206	(229)	(211)	(194)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	(1,294)	(617)	(315)	(83)	127	315	484	1,086	1,389	1,495	1,471	1,361	(229)	(211)	(194)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	131,996	121,436	111,722	102,784	94,561	86,996	57,338	37,790	24,907	16,416	10,819	7,751	7,131	6,560
62	Additions in Year			0	0	0	137,496	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	137,496	131,996	121,436	111,722	102,784	94,561	86,996	57,338	37,790	24,907	16,416	10,819	7,751	7,131	6,560
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	10,560	9,715	8,938	8,223	7,565	6,960	4,587	3,023	1,993	1,313	866	620	570	525
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	5,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	5,500	10,560	9,715	8,938	8,223	7,565	6,960	4,587	3,023	1,993	1,313	866	620	570	525
68	Ending Balance UCC			0	0	0	131,996	121,436	111,722	102,784	94,561	86,996	80,037	52,751	34,767	22,914	15,102	9,954	7,131	6,560	6,035

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 1A - 2012 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(92,753)**	(3,972)	(1,445)	(107)	(13,235)	(65,638)	(52,510)	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**21,063**	0	0	0	(300)	554	670	799	933	1,094	1,074	2,279	3,703	5,839	9,028	13,770	19,790	20,804	23,282
3	Income Tax		**(3,154)**	0	0	0	0	0	1,193	606	330	81	(144)	(960)	(1,397)	(1,585)	(1,608)	(1,523)	(1,402)	(509)	246
4	Net Cash Flow		**(74,844)**	(3,972)	(1,445)	(107)	(13,535)	(65,084)	(50,647)	1,405	1,263	1,175	930	1,319	2,306	4,254	7,419	12,247	18,388	20,295	23,528
5	**Discounted Cash Flow**		**(74,844)**	(3,972)	(1,313)	(88)	(10,169)	(44,453)	(31,448)	793	648	548	395	347	377	432	468	479	492	493	520
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	1,445	107	13,235	65,638	52,510												
11	AFUDC				282	328	728	3,095	6,639												
12	Total Cash Outlay in Year			**3,972**	**1,726**	**435**	**13,963**	**68,732**	**59,149**	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	5,698	6,133	20,096	88,828	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	5,698	6,133	20,096	88,828	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
16	Additions to Plant			0	0	0	0	0	147,977	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	0	0	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
18	CWIP			3,972	5,698	6,133	20,096	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses							(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance									0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes						300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
22	Total Incremental Operating Costs (Savings)			0	0	0	300	(554)	(670)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land								589												
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	0	0	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389
25	Additions in Year	Line 16 less Line23		0	0	0	0	0	147,389	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	0	0	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389	147,389
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	0	0	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	2,062	0
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	0	0	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977	147,977
30	Accumulated Depreciation			0	0	0	0	0	0	(4,422)	(8,843)	(13,265)	(17,687)	(39,795)	(61,903)	(84,012)	(106,120)	(128,228)	(145,915)	(147,977)	(147,977)
31	Net Book Value			0	0	0	0	0	147,977	143,556	139,134	134,712	130,291	108,182	86,074	63,966	41,857	19,749	2,062	0	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
33	Interest Expense			0	0	0	0	0	2,854	5,624	5,453	5,283	5,112	4,259	3,406	2,553	1,700	847	165	40	0
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	0	0	5,524	10,883	10,553	10,223	9,893	8,242	6,591	4,941	3,290	1,640	319	77	0
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	0	0	3,657	7,204	6,986	6,767	6,549	5,456	4,363	3,271	2,178	1,085	211	51	0
39	Less: Income tax on Equity Return			0	0	0	0	0	987	1,945	1,886	1,827	1,768	1,473	1,178	883	588	293	57	14	0
40	Net Income (equal return on equity)			0	0	0	0	0	2,670	5,259	5,100	4,940	4,781	3,983	3,185	2,388	1,590	792	154	37	0
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	0	0	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	4,422	2,062	0
42	Less: Capital Cost Allowance	Line 67		0	0	0	0	0	5,896	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
43	Total Timing Differences			0	0	0	0	0	(5,896)	(6,898)	(5,992)	(5,159)	(4,393)	(1,388)	593	1,898	2,758	3,325	3,636	1,340	(665)
44	Income Tax on Timing Differences			0	0	0	0	0	(1,592)	(1,862)	(1,618)	(1,393)	(1,186)	(375)	160	512	745	898	982	362	(179)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	0	0	(2,181)	(2,551)	(2,216)	(1,908)	(1,625)	(513)	219	702	1,020	1,230	1,345	496	(246)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	0	0	(1,193)	(606)	(330)	(81)	144	960	1,397	1,585	1,608	1,523	1,402	509	(246)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	0	0	141,493	130,174	119,760	110,179	72,617	47,861	31,544	20,790	13,702	9,816	9,031	8,308
62	Additions in Year			0	0	0	0	0	147,389	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	0	0	147,389	141,493	130,174	119,760	110,179	72,617	47,861	31,544	20,790	13,702	9,816	9,031	8,308
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	0	0	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	0	0	5,896	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	0	0	5,896	11,319	10,414	9,581	8,814	5,809	3,829	2,524	1,663	1,096	785	722	665
68	Ending Balance UCC			0	0	0	0	0	141,493	130,174	119,760	110,179	101,365	66,808	44,032	29,021	19,127	12,606	9,031	8,308	7,644

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 1B - 2010 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	Reference		10.0%	Dec-07	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-21	Dec-26	Dec-31	Dec-36	Dec-41	Dec-45	Dec-46	Dec-47
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(95,099)**	(3,972)	(12,559)	(55,839)	(44,671)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**21,094**	0	0	0	(300)	554	720	799	933	1,094	1,074	2,279	3,703	5,839	9,028	13,770	19,790	20,804	23,282
3	Income Tax		**(3,100)**	0	0	0	1,176	554	280	68	(123)	(295)	(449)	(998)	(1,275)	(1,372)	(1,350)	(1,250)	209	192	177
4	Net Cash Flow		**(77,105)**	(3,972)	(12,559)	(55,839)	(43,796)	1,108	1,000	867	810	799	625	1,281	2,428	4,467	7,678	12,520	19,999	20,997	23,459
5	**Discounted Cash Flow**		**(77,105)**	(3,972)	(11,417)	(46,148)	(32,904)	757	621	489	416	373	265	337	397	454	484	490	535	510	518
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	12,559	55,839	44,671														
11	AFUDC				615	2,667	5,682														
12	Total Cash Outlay in Year			**3,972**	**13,174**	**58,506**	**50,354**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	17,146	75,652	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	17,146	75,652	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
16	Additions to Plant			0	0	0	126,006	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
18	CWIP			3,972	17,146	75,652	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses							(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance							0	(50)	0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes						300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
22	Total Incremental Operating Costs (Savings)			0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land						589														
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417
25	Additions in Year	Line 16 less Line23		0	0	0	125,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417	125,417
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	0	0	0
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006	126,006
30	Accumulated Depreciation			0	0	0	0	(3,763)	(7,525)	(11,288)	(15,050)	(18,813)	(22,575)	(41,388)	(60,200)	(79,013)	(97,825)	(116,638)	(126,006)	(126,006)	(126,006)
31	Net Book Value			0	0	0	126,006	122,243	118,481	114,718	110,956	107,193	103,431	84,618	65,805	46,993	28,180	9,368	0	0	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
33	Interest Expense			0	0	0	2,431	4,789	4,644	4,498	4,353	4,208	4,063	3,337	2,611	1,886	1,160	434	0	0	0
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	4,704	9,267	8,986	8,705	8,424	8,143	7,863	6,458	5,053	3,649	2,244	840	0	0	0
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	3,247	6,264	5,949	5,763	5,577	5,391	5,205	4,275	3,345	2,416	1,486	556	0	0	0
39	Less: Income tax on Equity Return			0	0	0	974	1,785	1,606	1,556	1,506	1,456	1,405	1,154	903	652	401	150	0	0	0
40	Net Income (equal return on equity)			0	0	0	2,273	4,478	4,343	4,207	4,071	3,935	3,800	3,121	2,442	1,763	1,085	406	0	0	0
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	3,763	0	0	0
42	Less: Capital Cost Allowance	Line 67		0	0	0	5,017	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
43	Total Timing Differences			0	0	0	(5,017)	(5,870)	(5,099)	(4,390)	(3,738)	(3,138)	(2,586)	(422)	1,005	1,945	2,565	2,973	(566)	(520)	(479)
44	Income Tax on Timing Differences			0	0	0	(1,505)	(1,673)	(1,377)	(1,185)	(1,009)	(847)	(698)	(114)	271	525	692	803	(153)	(140)	(129)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	(2,150)	(2,340)	(1,886)	(1,624)	(1,382)	(1,161)	(956)	(156)	372	719	949	1,100	(209)	(192)	(177)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	(1,176)	(554)	(280)	(68)	123	295	449	998	1,275	1,372	1,350	1,250	(209)	(192)	(177)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	120,400	110,768	101,907	93,754	86,254	79,354	52,301	34,470	22,719	14,974	9,869	7,070	6,504	5,984
62	Additions in Year			0	0	0	125,417	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	125,417	120,400	110,768	101,907	93,754	86,254	79,354	52,301	34,470	22,719	14,974	9,869	7,070	6,504	5,984
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	5,017	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	5,017	9,632	8,861	8,153	7,500	6,900	6,348	4,184	2,758	1,818	1,198	790	566	520	479
68	Ending Balance UCC			0	0	0	120,400	110,768	101,907	93,754	86,254	79,354	73,005	48,117	31,713	20,901	13,776	9,079	6,504	5,984	5,505

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 1B - 2012 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(85,065)**	(3,972)	(1,445)	(107)	(12,078)	(59,857)	(47,886)	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**20,496**	0	0	0	0	0	0	799	934	1,094	1,074	2,280	3,703	5,839	9,028	13,771	19,791	20,805	23,282
3	Income Tax		**(2,893)**	0	0	0	0	0	1,093	554	302	74	(132)	(880)	(1,281)	(1,453)	(1,474)	(1,396)	(1,285)	(485)	225
4	Net Cash Flow		**(67,462)**	(3,972)	(1,445)	(107)	(12,078)	(59,857)	(46,793)	1,354	1,235	1,168	942	1,400	2,423	4,387	7,554	12,375	18,506	20,320	23,508
5	**Discounted Cash Flow**		**(67,462)**	(3,972)	(1,313)	(88)	(9,075)	(40,883)	(29,055)	764	634	545	399	369	396	445	476	484	495	494	519
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	1,445	107	12,078	59,857	47,886												
11	AFUDC				282	328	694	2,852	6,084												
12	Total Cash Outlay in Year			**3,972**	**1,726**	**435**	**12,772**	**62,709**	**53,970**	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	5,698	6,133	18,905	81,614	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	5,698	6,133	18,905	81,614	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
16	Additions to Plant			0	0	0	0	0	135,584	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	0	0	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
18	CWIP			3,972	5,698	6,133	18,905	81,614	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses									(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance									0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes									676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
22	Total Incremental Operating Costs (Savings)			0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land								589												
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	0	0	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995
25	Additions in Year	Line 16 less Line23		0	0	0	0	0	134,995	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	0	0	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995	134,995
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	0	0	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	1,938	0
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	0	0	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584	135,584
30	Accumulated Depreciation			0	0	0	0	0	0	(4,050)	(8,100)	(12,150)	(16,199)	(36,449)	(56,698)	(76,947)	(97,197)	(117,446)	(133,645)	(135,584)	(135,584)
31	Net Book Value			0	0	0	0	0	135,584	131,534	127,484	123,434	119,384	99,135	78,886	58,637	38,387	18,138	1,938	0	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
33	Interest Expense			0	0	0	0	0	2,615	5,153	4,996	4,840	4,684	3,903	3,122	2,340	1,559	778	153	37	0
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	0	0	5,061	9,972	9,669	9,367	9,064	7,553	6,041	4,529	3,017	1,505	296	72	0
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	0	0	3,351	6,601	6,401	6,201	6,001	5,000	3,999	2,998	1,997	997	196	48	0
39	Less: Income tax on Equity Return			0	0	0	0	0	905	1,782	1,728	1,674	1,620	1,350	1,080	810	539	269	53	13	0
40	Net Income (equal return on equity)			0	0	0	0	0	2,446	4,819	4,673	4,527	4,380	3,650	2,919	2,189	1,458	727	143	35	0
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	0	0	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	4,050	1,938	0
42	Less: Capital Cost Allowance	Line 67		0	0	0	0	0	5,400	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
43	Total Timing Differences			0	0	0	0	0	(5,400)	(6,318)	(5,488)	(4,725)	(4,023)	(1,271)	543	1,739	2,527	3,046	3,331	1,277	(609)
44	Income Tax on Timing Differences			0	0	0	0	0	(1,458)	(1,706)	(1,482)	(1,276)	(1,086)	(343)	147	469	682	822	899	345	(164)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	0	0	(1,997)	(2,337)	(2,030)	(1,748)	(1,488)	(470)	201	643	934	1,127	1,232	472	(225)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	0	0	(1,093)	(554)	(302)	(74)	132	880	1,281	1,453	1,474	1,396	1,285	485	(225)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	0	0	129,596	119,228	109,690	100,915	66,511	43,836	28,892	19,042	12,550	8,991	8,272	7,610
62	Additions in Year			0	0	0	0	0	134,995	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	0	0	134,995	129,596	119,228	109,690	100,915	66,511	43,836	28,892	19,042	12,550	8,991	8,272	7,610
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	0	0	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	0	0	5,400	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	0	0	5,400	10,368	9,538	8,775	8,073	5,321	3,507	2,311	1,523	1,004	719	662	609
68	Ending Balance UCC			0	0	0	0	0	129,596	119,228	109,690	100,915	92,841	61,190	40,329	26,580	17,519	11,546	8,272	7,610	7,001

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 1C - 2010 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(95,013)**	(3,972)	(12,548)	(55,785)	(44,628)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**21,094**	0	0	0	(300)	554	720	799	933	1,094	1,074	2,279	3,703	5,839	9,028	13,770	19,790	20,804	23,282
3	Income Tax		**(3,097)**	0	0	0	1,175	554	279	68	(123)	(295)	(449)	(997)	(1,274)	(1,370)	(1,348)	(1,249)	209	192	177
4	Net Cash Flow		**(77,016)**	(3,972)	(12,548)	(55,785)	(43,754)	1,108	1,000	867	810	799	625	1,282	2,429	4,469	7,679	12,522	19,999	20,997	23,459
5	**Discounted Cash Flow**		**(77,016)**	(3,972)	(11,407)	(46,104)	(32,873)	757	621	489	416	373	265	338	397	454	484	490	535	510	518
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	12,548	55,785	44,628														
11	AFUDC				615	2,665	5,677														
12	Total Cash Outlay in Year			**3,972**	**13,163**	**58,450**	**50,305**	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	17,135	75,585	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890
14				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	17,135	75,585	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890
16	Additions to Plant			0	0	0	125,890	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890
18	CWIP			3,972	17,135	75,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses							(1,204)	(1,333)	(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance							0	(50)	0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes						300	650	663	676	690	704	718	792	875	966	1,066	1,177	1,274	1,300	1,326
22	Total Incremental Operating Costs (Savings)			0	0	0	300	(554)	(720)	(799)	(933)	(1,094)	(1,074)	(2,279)	(3,703)	(5,839)	(9,028)	(13,770)	(19,790)	(20,804)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land						589														
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302
25	Additions in Year	Line 16 less Line23		0	0	0	125,302	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302	125,302
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	0	0	0
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890	125,890
30	Accumulated Depreciation			0	0	0	0	(3,759)	(7,518)	(11,277)	(15,036)	(18,795)	(22,554)	(41,350)	(60,145)	(78,940)	(97,735)	(116,530)	(125,890)	(125,890)	(125,890)
31	Net Book Value			0	0	0	125,890	122,131	118,372	114,613	110,854	107,095	103,336	84,541	65,745	46,950	28,155	9,360	0	0	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	2,271	4,474	4,339	4,203	4,067	3,932	3,796	3,118	2,440	1,762	1,084	406	0	0	0
33	Interest Expense			0	0	0	2,428	4,784	4,639	4,494	4,349	4,204	4,059	3,334	2,609	1,884	1,159	434	0	0	0
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	4,699	9,259	8,978	8,697	8,417	8,136	7,855	6,452	5,049	3,646	2,242	839	0	0	0
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	2,271	4,474	4,339	4,203	4,067	3,932	3,796	3,118	2,440	1,762	1,084	406	0	0	0
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	3,244	6,258	5,943	5,758	5,572	5,386	5,200	4,271	3,342	2,413	1,484	555	0	0	0
39	Less: Income tax on Equity Return			0	0	0	973	1,783	1,605	1,555	1,504	1,454	1,404	1,153	902	652	401	150	0	0	0
40	Net Income (equal return on equity)			0	0	0	2,271	4,474	4,339	4,203	4,067	3,932	3,796	3,118	2,440	1,762	1,084	406	0	0	0
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	3,759	0	0	0
42	Less: Capital Cost Allowance	Line 67		0	0	0	5,012	9,623	8,853	8,145	7,493	6,894	6,342	4,180	2,755	1,816	1,197	789	565	520	478
43	Total Timing Differences			0	0	0	(5,012)	(5,864)	(5,094)	(4,386)	(3,734)	(3,135)	(2,583)	(421)	1,004	1,943	2,562	2,970	(565)	(520)	(478)
44	Income Tax on Timing Differences			0	0	0	(1,504)	(1,671)	(1,375)	(1,184)	(1,008)	(846)	(698)	(114)	271	525	692	802	(153)	(140)	(129)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	(2,148)	(2,337)	(1,884)	(1,622)	(1,381)	(1,159)	(956)	(156)	371	719	948	1,099	(209)	(192)	(177)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	(1,175)	(554)	(279)	(68)	123	295	449	997	1,274	1,370	1,348	1,249	(209)	(192)	(177)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	120,290	110,666	101,813	93,668	86,175	79,281	52,252	34,439	22,698	14,960	9,860	7,063	6,498	5,978
62	Additions in Year			0	0	0	125,302	0	0	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	125,302	120,290	110,666	101,813	93,668	86,175	79,281	52,252	34,439	22,698	14,960	9,860	7,063	6,498	5,978
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	9,623	8,853	8,145	7,493	6,894	6,342	4,180	2,755	1,816	1,197	789	565	520	478
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	5,012	0	0	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	5,012	9,623	8,853	8,145	7,493	6,894	6,342	4,180	2,755	1,816	1,197	789	565	520	478
68	Ending Balance UCC			0	0	0	120,290	110,666	101,813	93,668	86,175	79,281	72,938	48,072	31,683	20,882	13,763	9,071	6,498	5,978	5,500

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 2A - 2012 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(102,600)**	(3,972)	(1,605)	(2,033)	(15,451)	(71,100)	(56,880)	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**20,496**	0	0	0	0	0	0	799	934	1,094	1,074	2,280	3,703	5,839	9,028	13,771	19,791	20,805	23,282
3	Income Tax		**(3,672)**	0	0	0	0	0	1,280	624	324	53	(191)	(1,079)	(1,554)	(1,759)	(1,784)	(1,691)	(1,559)	(1,520)	245
4	Net Cash Flow		**(85,776)**	(3,972)	(1,605)	(2,033)	(15,451)	(71,100)	(55,600)	1,423	1,257	1,148	883	1,201	2,149	4,081	7,244	12,080	18,231	19,284	23,528
5	**Discounted Cash Flow**		**(85,776)**	(3,972)	(1,459)	(1,680)	(11,608)	(48,562)	(34,523)	803	645	535	374	316	351	414	457	473	487	469	520
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	1,605	2,033	15,451	71,100	56,880												
11	AFUDC				286	396	920	3,517	7,356												
12	Total Cash Outlay in Year			**3,972**	**1,891**	**2,429**	**16,371**	**74,617**	**64,236**	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	5,863	8,292	24,663	99,279	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	5,863	8,292	24,663	99,279	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
16	Additions to Plant			0	0	0	0	0	163,516	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	0	0	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
18	CWIP			3,972	5,863	8,292	24,663	99,279	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses									(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance									0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes									676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
22	Total Incremental Operating Costs (Savings)			0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land								3,264												
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	0	0	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252
25	Additions in Year	Line 16 less Line23		0	0	0	0	0	160,252	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	0	0	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252	160,252
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	0	0	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	58
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	0	0	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516	163,516
30	Accumulated Depreciation			0	0	0	0	0	0	(4,808)	(9,615)	(14,423)	(19,230)	(43,268)	(67,306)	(91,344)	(115,382)	(139,419)	(158,650)	(163,457)	(163,516)
31	Net Book Value			0	0	0	0	0	163,516	158,708	153,900	149,093	144,285	120,248	96,210	72,172	48,134	24,096	4,866	58	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
33	Interest Expense			0	0	0	0	0	3,154	6,216	6,030	5,845	5,659	4,732	3,805	2,877	1,950	1,022	280	95	1
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	0	0	6,104	12,029	11,670	11,311	10,952	9,157	7,362	5,568	3,773	1,978	543	184	2
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	0	0	4,041	7,963	7,725	7,488	7,250	6,062	4,874	3,686	2,498	1,310	359	122	1
39	Less: Income tax on Equity Return			0	0	0	0	0	1,091	2,150	2,086	2,022	1,958	1,637	1,316	995	674	354	97	33	0
40	Net Income (equal return on equity)			0	0	0	0	0	2,950	5,813	5,639	5,466	5,293	4,425	3,558	2,691	1,823	956	262	89	1
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	0	0	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	4,808	58
42	Less: Capital Cost Allowance	Line 67		0	0	0	0	0	6,410	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
43	Total Timing Differences			0	0	0	0	0	(6,410)	(7,500)	(6,515)	(5,609)	(4,776)	(1,509)	645	2,064	2,999	3,616	3,954	4,022	(664)
44	Income Tax on Timing Differences			0	0	0	0	0	(1,731)	(2,025)	(1,759)	(1,515)	(1,290)	(407)	174	557	810	976	1,068	1,086	(179)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	0	0	(2,371)	(2,774)	(2,410)	(2,075)	(1,766)	(558)	238	763	1,109	1,337	1,462	1,488	(246)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	0	0	(1,280)	(624)	(324)	(53)	191	1,079	1,554	1,759	1,784	1,691	1,559	1,520	(245)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	0	0	153,842	141,535	130,212	119,795	78,955	52,038	34,297	22,605	14,898	10,673	9,819	9,034
62	Additions in Year			0	0	0	0	0	160,252	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	0	0	160,252	153,842	141,535	130,212	119,795	78,955	52,038	34,297	22,605	14,898	10,673	9,819	9,034
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	0	0	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	0	0	6,410	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	0	0	6,410	12,307	11,323	10,417	9,584	6,316	4,163	2,744	1,808	1,192	854	786	723
68	Ending Balance UCC			0	0	0	0	0	153,842	141,535	130,212	119,795	110,211	72,638	47,875	31,553	20,796	13,706	9,819	9,034	8,311

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 2B - 2012 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(93,609)**	(3,972)	(1,605)	(2,033)	(14,098)	(64,340)	(51,472)	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**20,496**	0	0	0	0	0	0	799	934	1,094	1,074	2,280	3,703	5,839	9,028	13,771	19,791	20,805	23,282
3	Income Tax		**(3,367)**	0	0	0	0	0	1,162	564	291	44	(178)	(985)	(1,418)	(1,603)	(1,626)	(1,542)	(1,422)	(1,387)	112
4	Net Cash Flow		**(76,480)**	(3,972)	(1,605)	(2,033)	(14,098)	(64,340)	(50,310)	1,363	1,224	1,139	896	1,295	2,286	4,236	7,402	12,229	18,368	19,418	23,394
5	**Discounted Cash Flow**		**(76,480)**	(3,972)	(1,459)	(1,680)	(10,592)	(43,945)	(31,238)	769	628	531	380	341	374	430	467	479	491	472	517
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	1,605	2,033	14,098	64,340	51,472												
11	AFUDC				286	396	880	3,233	6,707												
12	Total Cash Outlay in Year			**3,972**	**1,891**	**2,429**	**14,978**	**67,573**	**58,179**	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	5,863	8,292	23,270	90,843	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	5,863	8,292	23,270	90,843	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
16	Additions to Plant			0	0	0	0	0	149,022	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	0	0	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
18	CWIP			3,972	5,863	8,292	23,270	90,843	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses									(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance									0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes									676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
22	Total Incremental Operating Costs (Savings)			0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land								3,264												
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	0	0	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758
25	Additions in Year	Line 16 less Line23		0	0	0	0	0	145,758	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	0	0	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758	145,758
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	0	0	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	348
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	0	0	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022	149,022
30	Accumulated Depreciation			0	0	0	0	0	0	(4,373)	(8,745)	(13,118)	(17,491)	(39,355)	(61,218)	(83,082)	(104,946)	(126,810)	(144,300)	(148,673)	(149,022)
31	Net Book Value			0	0	0	0	0	149,022	144,649	140,276	135,903	131,531	109,667	87,803	65,939	44,076	22,212	4,721	348	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
33	Interest Expense			0	0	0	0	0	2,875	5,665	5,496	5,328	5,159	4,315	3,472	2,628	1,785	941	266	98	7
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	0	0	5,563	10,963	10,636	10,310	9,983	8,351	6,719	5,086	3,454	1,822	516	189	13
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	0	0	3,683	7,257	7,041	6,825	6,609	5,528	4,448	3,367	2,286	1,206	341	125	9
39	Less: Income tax on Equity Return			0	0	0	0	0	994	1,959	1,901	1,843	1,784	1,493	1,201	909	617	326	92	34	2
40	Net Income (equal return on equity)			0	0	0	0	0	2,688	5,298	5,140	4,982	4,825	4,036	3,247	2,458	1,669	880	249	91	6
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	0	0	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	4,373	348
42	Less: Capital Cost Allowance	Line 67		0	0	0	0	0	5,830	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
43	Total Timing Differences			0	0	0	0	0	(5,830)	(6,821)	(5,926)	(5,102)	(4,344)	(1,372)	586	1,877	2,728	3,289	3,596	3,658	(309)
44	Income Tax on Timing Differences			0	0	0	0	0	(1,574)	(1,842)	(1,600)	(1,378)	(1,173)	(371)	158	507	737	888	971	988	(83)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	0	0	(2,156)	(2,523)	(2,192)	(1,887)	(1,607)	(508)	217	694	1,009	1,216	1,330	1,353	(114)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	0	0	(1,162)	(564)	(291)	(44)	178	985	1,418	1,603	1,626	1,542	1,422	1,387	(112)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	0	0	139,928	128,734	118,435	108,960	71,814	47,331	31,195	20,560	13,551	9,708	8,931	8,217
62	Additions in Year			0	0	0	0	0	145,758	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	0	0	145,758	139,928	128,734	118,435	108,960	71,814	47,331	31,195	20,560	13,551	9,708	8,931	8,217
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	0	0	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	0	0	5,830	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	0	0	5,830	11,194	10,299	9,475	8,717	5,745	3,786	2,496	1,645	1,084	777	714	657
68	Ending Balance UCC			0	0	0	0	0	139,928	128,734	118,435	108,960	100,243	66,068	43,545	28,699	18,915	12,467	8,931	8,217	7,559

FortisBC
Capital Project Analysis
OTR - Okanagan Transmission Reinforcement

Discounted Cash Flow
Alternative 3 - 2012 in service

Line	Year:		NPV @	0	1	2	3	4	5	6	7	8	9	14	19	24	29	34	38	39	40
No.	**Reference**		**10.0%**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Dec-13**	**Dec-14**	**Dec-15**	**Dec-16**	**Dec-21**	**Dec-26**	**Dec-31**	**Dec-36**	**Dec-41**	**Dec-45**	**Dec-46**	**Dec-47**
	Summary																				
	Cash Flow																				
1	Capital Cost (Net of AFUDC)		**(97,620)**	(3,972)	(1,605)	(2,033)	(14,702)	(67,356)	(53,885)	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating Expense (Incremental)		**20,496**	0	0	0	0	0	0	799	934	1,094	1,074	2,280	3,703	5,839	9,028	13,771	19,791	20,805	23,282
3	Income Tax		**(3,503)**	0	0	0	0	0	1,215	590	306	48	(184)	(1,027)	(1,479)	(1,673)	(1,697)	(1,608)	(1,483)	(1,446)	171
4	Net Cash Flow		**(80,627)**	(3,972)	(1,605)	(2,033)	(14,702)	(67,356)	(52,670)	1,390	1,239	1,143	890	1,253	2,225	4,167	7,331	12,162	18,307	19,358	23,454
5	**Discounted Cash Flow**		**(80,627)**	(3,972)	(1,459)	(1,680)	(11,046)	(46,005)	(32,704)	784	636	533	378	330	364	423	462	476	489	470	518
	Regulatory Assumptions																				
6	Equity Component			40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
7	Debt Component			60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%	60.00%
8	Equity Return			8.77%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%	9.02%
9	Debt Return			6.40%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%	6.43%
	Capital Cost																				
10	Capital Costs			3,972	1,605	2,033	14,702	67,356	53,885												
11	AFUDC				286	396	898	3,359	6,997												
12	Total Cash Outlay in Year			**3,972**	**1,891**	**2,429**	**15,599**	**70,716**	**60,882**	0	0	0	0	0	0	0	0	0	0	0	0
13	Cumulative Cash Outlay			3,972	5,863	8,292	23,891	94,607	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
14				0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Cumulative Project Cost			3,972	5,863	8,292	23,891	94,607	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
16	Additions to Plant			0	0	0	0	0	155,489	0	0	0	0	0	0	0	0	0	0	0	0
17	Cummulative Additions to Plant			0	0	0	0	0	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
18	CWIP			3,972	5,863	8,292	23,891	94,607	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Line Losses									(1,475)	(1,633)	(1,808)	(2,001)	(3,327)	(4,888)	(7,183)	(10,554)	(15,507)	(21,097)	(22,785)	(24,608)
20	Maintenance									0	10	10	210	255	311	378	460	560	33	681	
21	Property Taxes									676	690	703	717	792	874	965	1,066	1,177	1,274	1,299	1,325
22	Total Incremental Operating Costs (Savings)			0	0	0	0	0	0	(799)	(934)	(1,094)	(1,074)	(2,280)	(3,703)	(5,839)	(9,028)	(13,771)	(19,791)	(20,805)	(23,282)
	(Forecast inflation rate 2%)																				
23	Land								3,264												
	Depreciation Expense																				
24	Opening Cash Outlay			0	0	0	0	0	0	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225
25	Additions in Year	Line 16 less Line23		0	0	0	0	0	152,225	0	0	0	0	0	0	0	0	0	0	0	0
26	Cumulative Total			0	0	0	0	0	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225	152,225
27	Depreciation Rate - composite average			3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%	3.00%
28	Depreciation Expense			0	0	0	0	0	0	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	219
	Net Book Value																				
29	Gross Property	Line 17		0	0	0	0	0	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489	155,489
30	Accumulated Depreciation			0	0	0	0	0	0	(4,567)	(9,134)	(13,700)	(18,267)	(41,101)	(63,935)	(86,768)	(109,602)	(132,436)	(150,703)	(155,270)	(155,489)
31	Net Book Value			0	0	0	0	0	155,489	150,922	146,355	141,788	137,222	114,388	91,554	68,720	45,887	23,053	4,786	219	0
	Carrying Costs on Average NBV																				
32	Return on Equity			0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
33	Interest Expense			0	0	0	0	0	2,999	5,911	5,734	5,558	5,382	4,501	3,620	2,739	1,858	977	273	97	4
34	AFUDC			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	**Total Carrying Costs**			0	0	0	0	0	5,804	11,438	11,097	10,756	10,415	8,711	7,006	5,301	3,596	1,892	528	187	8
	Income Tax Expense																				
36	Combined Income Tax Rate			34.12%	31.50%	31.00%	30.00%	28.50%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%	27.00%
	Income Tax on Equity Return																				
37	Return on Equity	Line 32		0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
38	Gross up for revenue (Return / (1- tax rate)			0	0	0	0	0	3,842	7,572	7,346	7,121	6,895	5,766	4,638	3,509	2,381	1,252	349	124	5
39	Less: Income tax on Equity Return			0	0	0	0	0	1,037	2,044	1,984	1,923	1,862	1,557	1,252	948	643	338	94	33	1
40	Net Income (equal return on equity)			0	0	0	0	0	2,805	5,528	5,363	5,198	5,033	4,209	3,386	2,562	1,738	914	255	90	4
	Income Tax on Timing Differences																				
41	Depreciation Expense			0	0	0	0	0	0	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	4,567	219
42	Less: Capital Cost Allowance	Line 67		0	0	0	0	0	6,089	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
43	Total Timing Differences			0	0	0	0	0	(6,089)	(7,124)	(6,189)	(5,328)	(4,537)	(1,433)	612	1,960	2,849	3,435	3,756	3,821	(467)
44	Income Tax on Timing Differences			0	0	0	0	0	(1,644)	(1,924)	(1,671)	(1,439)	(1,225)	(387)	165	529	769	927	1,014	1,032	(126)
45	Before Tax Revenue Requirement [=Line44/(1-tax)			0	0	0	0	0	(2,252)	(2,635)	(2,289)	(1,971)	(1,678)	(530)	226	725	1,054	1,270	1,389	1,413	(173)
60	**Total Income Tax**	Lines 39 + 45		0	0	0	0	0	(1,215)	(590)	(306)	(48)	184	1,027	1,479	1,673	1,697	1,608	1,483	1,446	(171)
	Capital Cost Allowance																				
61	Opening Balance - UCC			0	0	0	0	0	0	146,136	134,445	123,690	113,794	75,000	49,431	32,579	21,472	14,152	10,138	9,327	8,581
62	Additions in Year			0	0	0	0	0	152,225	0	0	0	0	0	0	0	0	0	0	0	0
63	Subtotal UCC			0	0	0	0	0	152,225	146,136	134,445	123,690	113,794	75,000	49,431	32,579	21,472	14,152	10,138	9,327	8,581
64	Capital Cost Allowance Rate			8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
65	CCA on Opening Balance			0	0	0	0	0	0	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
66	CCA on Capital Expenditures (1/2 yr rule)			0	0	0	0	0	6,089	0	0	0	0	0	0	0	0	0	0	0	0
67	Total CCA			0	0	0	0	0	6,089	11,691	10,756	9,895	9,104	6,000	3,954	2,606	1,718	1,132	811	746	686
68	Ending Balance UCC			0	0	0	0	0	146,136	134,445	123,690	113,794	104,691	69,000	45,476	29,973	19,754	13,020	9,327	8,581	7,895

Q54.2 Please also file the economic analyses in electronic spreadsheet format.

A54.2 The requested documents are being filed concurrently with these responses.

Q54.3 Provide a summary of the results using the economic analyses.

A54.3 Please see Table A54.3 below.

Table A54.3: OTR Discounted Cash Flow Summary

Alternative	**1A**	**1A**	**1B**	**1B**	**1C**	**2A**	**2B**	**3**
In Service Date	**2010**	**2012**	**2010**	**2012**	**2010**	**2012**	**2012**	**2012**
	($000s)							
Total Capital Cost	137,496	147,977	126,006	135,584	125,890	163,516	149,022	155,489
Net Present Value of Discounted Cash Flow	(85,955)	(74,844)	(77,105)	(67,462)	(77,016)	(85,776)	(76,480)	(80,627)

55.0 Non-Financial Comparison

Reference: Exhibit B-1-1, Tab 4, pp. 45-48

Q55.1 What is the FortisBC db limit for audible noise levels at the edge of the proposed ROW during foul weather?

A55.1 FortisBC has not established a limit for audible noise levels (in decibels [db]) at the edge of the proposed right-of-way under any weather conditions. Please see responses to BCUC IR No. 1 Q55.2 and Q55.3.

Q55.2 What measures has FortisBC taken to mitigate audible noise levels at the edge of the proposed ROW during foul weather?

A55.2 The audible noise on transmission lines is typically due to corona discharge that generates both radio frequency and audible noise. In general, audible noise associated with corona discharge is not a problem for transmission lines operating at voltages below 345 kV. By ensuring compliance on radio interference limits, audible noise is also reduced. Please see response to BCUC IR No. 1 Q55.3.

Q55.3 What are the FortisBC acceptable levels of electromagnetic interference for radio and television interference and does the OTR project fall within these levels? Please explain.

A55.3 FortisBC has not established acceptable levels of electromagnetic interference for radio and television interference. In general, electromagnetic interference associated with corona discharge is not a problem for transmission lines operating at voltages below 345 kV.

The preliminary line designs were reviewed versus radio interference parameters to ensure they are within Industry Canada Standards which were the Department of Communications regulations published in the 20 August 1988 edition of the Canada Gazette Part 1. Refinements to the line preliminary design for the double circuit lines Vaseux to RG Anderson were made to achieve compliance by increasing the conductor size from “Drake”(795 kcmil) to “Bunting” (1,192 kcmil).

56.0 Non-Financial Comparison

Reference: Exhibit B-1-1, Section 4, p. 44, Table 4-3-3D

Q56.1 Please explain why the proposed Alternative 1A has a ranking of 3 for Operations and Safety.

A56.1 Alternative 1A, as with Alternatives 1B and 2A includes the use of taller structures that generally preclude the use of bucket trucks. Maintenance is conducted using special ladders on the poles. The structures with double circuits (Alternatives 1A, 1B, 2A) also require more complicated and costly work procedures to ensure safety while working on one circuit while the other is in service due to proximity and/or parallel induction. Alternative 1A is located on the existing right-of-way and does not have the higher mountain side access issues present with Alternatives 2A and 2B and part of 3.

Alternative 3 ranked highest overall as the structures are lower, allowing bucket truck access and the line routing offers segregation of the double circuits reducing proximity and induction risks. It also has less access issues as it has one line at the existing right-of-way at the lower mountain side elevation.

57.0 Electric and Magnetic Fields

Reference: Exhibit B-1-1, Tab 1, pp. 4, 5; Tab 4, pp. 55-57

Q57.1 In Tab 1, FortisBC refers to the Commission's conclusion on page 70 of its July 7, 2006 VITR Decision and, on page 5 of Tab 1, states that the OTR Project as proposed will be compliant with International Commission on Non-Ionizing Radiation Protection ("ICNIRP"), World Health Organization ("WHO") and Health Canada exposure guidelines. On page 43 of Tab 4, FortisBC states that all alternatives will be compliant with ICNIRP reference levels for public exposure. For clarity, please provide a summary of the Electric and Magnetic Fields ("EMF") standards, guidelines and reference levels that FortisBC is referring to.

A57.1 FortisBC understands that the guidelines to which the VITR Decision refers at page 71, and which is quoted on page 5 of Tab 1, refer to guidelines published by the International Commission on Non-ionizing Radiation Protection (1998), the recommendation by the World Health Organization to use the ICNIRP guideline (e.g., WHO, 2007a), and guidance on EMF published by Health Canada. These documents can be read in their entirety by consulting the references and Internet links below. Each reference or link is followed by a brief summary:

ICNIRP

International Commission on Non-Ionizing Radiation Protection (ICNIRP). Guidelines for limiting exposure to time-varying electric, magnetic, and electromagnetic fields (up to 300 GHz). Health Phys. 74:494-522, 1998.
http://www.icnirp.de/

ICNIRP specifies a basic restriction for head and torso, which contains the central nervous system, for exposures of the general public (2 mA/m^2) and exposures of workers in occupational environments (10 mA/m^2). These levels provide for presumed safety factors of 50 and 10, respectively to account "for acute changes in central nervous system excitability and other acute [neural] effects," which ICNIRP estimates to occur at a threshold of 100 mA/m^2. A value of 2 mA/m^2 is an internal level and can only be computed, so ICNIRP published "reference values", which can be measured or readily calculated, are used as screening levels. Measured or calculated exposures below 4.2 kilovolts/metre for the electric field or 833.3 milligauss for the magnetic field are assumed not to exceed a basic restriction on public exposure of 2 mA/m^2.

World Health Organization (WHO). Electromagnetic fields and public health: Exposure to extremely low frequency fields, Fact sheet N°322, June 2007a. http://www.who.int/mediacentre/factsheets/fs322/en/index.html
The WHO (2007a) states:

"International exposure guidelines
Health effects related to short-term, high-level exposure have been established and form the basis of two international exposure limit guidelines (ICNIRP, 1998; IEEE, 2002). At present, these bodies consider the scientific evidence related to possible health effects from long-term, low-level exposure to ELF fields insufficient to justify lowering these quantitative exposure limits.
WHO's guidance

For high-level short-term exposures to EMF, adverse health effects have been scientifically established (ICNIRP, 2003). International exposure guidelines designed to protect workers and the public from these effects should be adopted by policy makers. EMF protection programs should include exposure measurements from sources where exposures might be expected to exceed limit values."

Health Canada. Electric and Magnetic Fields at Extremely Low Frequencies:

http://www.hc-sc.gc.ca/iyh-vsv/environ/magnet_e.html

Health Canada states:

"Typical Exposures Present No Known Health Risks
Research has shown that EMFs from electrical devices and power lines can induce weak electric currents to flow through the human body. However, these currents are much smaller than those produced naturally by your brain, nerves and heart, and are not associated with any known health risks.

Health Canada, along with the World Health Organization, monitors scientific research on EMFs and human health as part of its mission to help Canadians maintain and improve their health. At present, there are no Canadian government guidelines for exposure to EMFs at ELF. Health Canada does not consider guidelines necessary because the scientific evidence is not strong enough to conclude that typical exposures cause health problems."

Q57.2 Please also list any recognized and applicable EMF standards that FortisBC and the OTR Project will not comply with.

A57.2 FortisBC is not aware of any recognized and applicable EMF standard with which the OTR Project would not be in compliance.

Q57.3 Please confirm that the response to the foregoing question sets out the current guidelines from each of the organizations, and discuss any changes since the VITR Decision.

A57.3 To FortisBC's knowledge, the guidance provided by the organizations discussed in the response to BCUC IR No. 1 Q57.1 are current and have not changed since the VITR Decision was issued by the BCUC on July 7, 2006.

The VITR Decision directed BCTC to file a public report with the Commission at least every two years, summarizing the latest results of EMF risk assessments and any changes in guidelines developed by the WHO, ICNIRP, Health Canada, and others. Appendix R of BCTC's application for a CPCN for the Interior to Lower Mainland Transmission Project, filed on November 5, 2007, contains expert evidence (Exponent) in compliance with this directive.

Q57.4 In the Naramata Substation proceeding, FortisBC filed a letter dated July 16, 2007 that had enclosed WHO Fact Sheet No. 322 and referred to WHO Monograph No. 238, and which discussed the impact of these new guidelines on substation site comparisons in that proceeding. Please file a copy of the July 16, 2007 letter and WHO enclosure.

A57.4 The requested filing is attached as Appendix A57.4.

Q57.5 Please discuss the impact, if any, of the new WHO guidelines on the OTR Project with respect to substation siting and rebuilding, and with respect to transmission line routing and design.

A57.5 Because the OTR Project meets the ICNIRP reference level guidelines as described in the response to 57.1, it also meets the WHO guidance summarized in response to 57.2.

Other recommendations to address public concerns about potential long term health effects are also discussed by WHO (2007a) and include actions to monitor science and promote research programs, establish effective communication programs, and "when constructing new facilities and designing new equipment, including appliances, low-cost ways of reducing exposures may be explored. Appropriate exposure reduction measures will vary from one country to another. However, policies based on the adoption of arbitrary low exposure limits are not warranted."

FortisBC believes that to the extent that the recommendations of the WHO have been, or are being addressed, by FortisBC, the BCUC, and Health Canada, the WHO 2007a guidance would not impact the substation siting and rebuilding, or the routing and design of the transmission line.

Q57.6 Further to Figure 4-6A for 40 Line, please provide a form of the figure that uses a Magnetic Field scale of up to approximately 200 milliGauss ("mG"). Please also provide a table of the values at maximum and each edge of the right-of-way for each scenario. Further to the statement on page 43 of Tab 4, please confirm that all the load cases for this line scenario comply with the ICNIRP, WHO and Health Canada exposure guidelines.

A57.6 Please see Figure A57.6 and Table A57.6 below showing the before (161 kV) and the after (230 kV) construction magnetic field levels.

Table A57.6 includes for ease of comparison, the Magnetic Field values for BCUC IR No.1 Q57.6, Q57.7, Q57.8, Q57.9, Q57.10 and Q57.11.

It is confirmed that the magnetic field associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also response to BCUC IR No. 1 Q57.1.

Figure A57.6: 40 Line - Magnetic Field Vs Distance from Centre of Right of Way (161 kV Cross Section A, 230 kV Cross Section B)

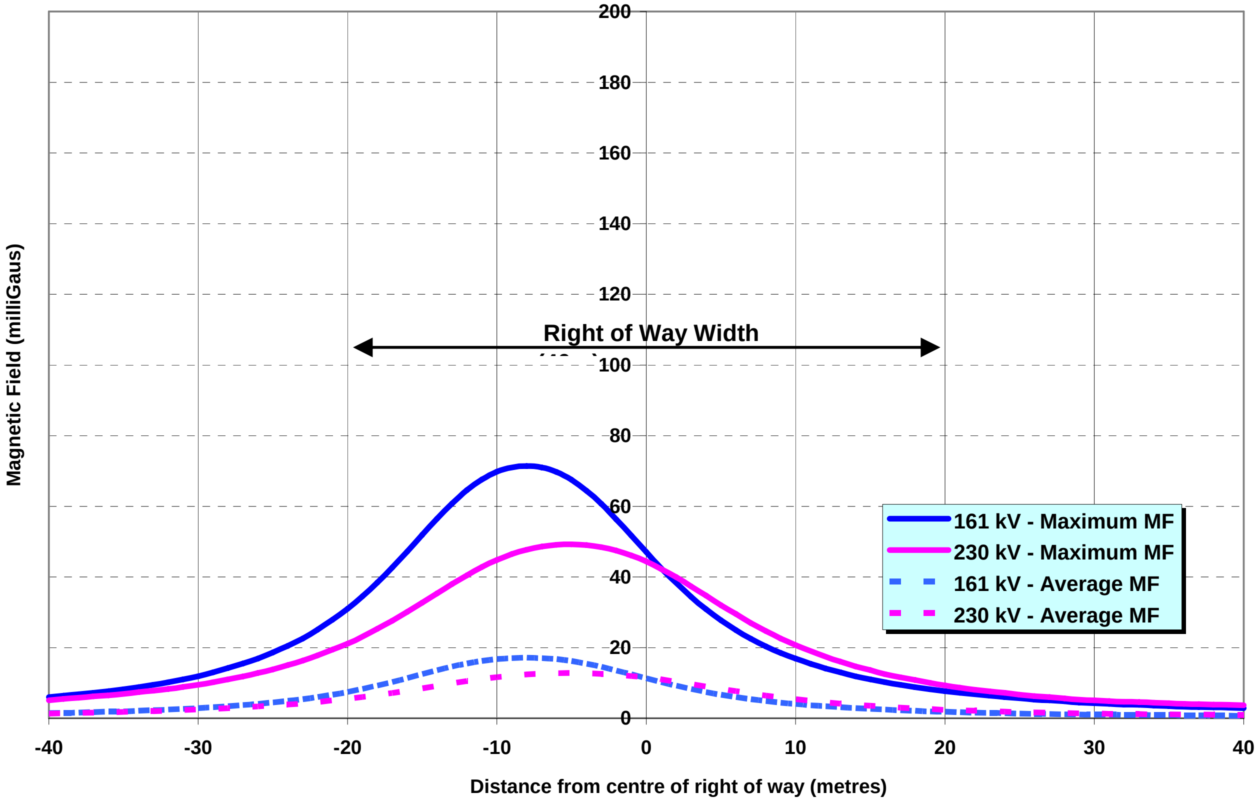


Table A57.6: Magnetic Field Values

		Average Case Magnetic Field (mG)			Maximum Case Magnetic Field (mG)		
IR #	**Configuration**	**Maximum On Right-of-Way**	**Edge of Right-of-Way (side)**		**Maximum On Right-of-Way**	**Edge of Right-of-Way (side)**	
			East	**West**		**East**	**West**
	40 Line - Cross Section A at 161 kV (Existing)	17	2	7	71	10	31
	76 Line - Cross Section A at 161 kV (Existing)	37	4	16	109	11	47
57.6	40 Line - Cross Section B at 230 KV (Post OTR)	13	3	6	49	9	21
57.7	75 Line and 76 Line - Cross Section C at 230 kV (Post OTR)	11	2	2	54	11	11
57.8	75 Line and 76 Line - Cross Section E, at 230kV (Post OTR)	9	4	4	46	21	21
57.9	75 Line and 76 Line - Cross Section D, at 230 kV (Post OTR)	15	11	11	74	54	54
57.10	76 Line High Capacity - Cross Section F, at 230 kV (Post OTR)	27	10	10	136	48	48
57.11	76 Line High Capacity - Cross Section C, at 230 kV (Post OTR)	20	7	9	101	33	44

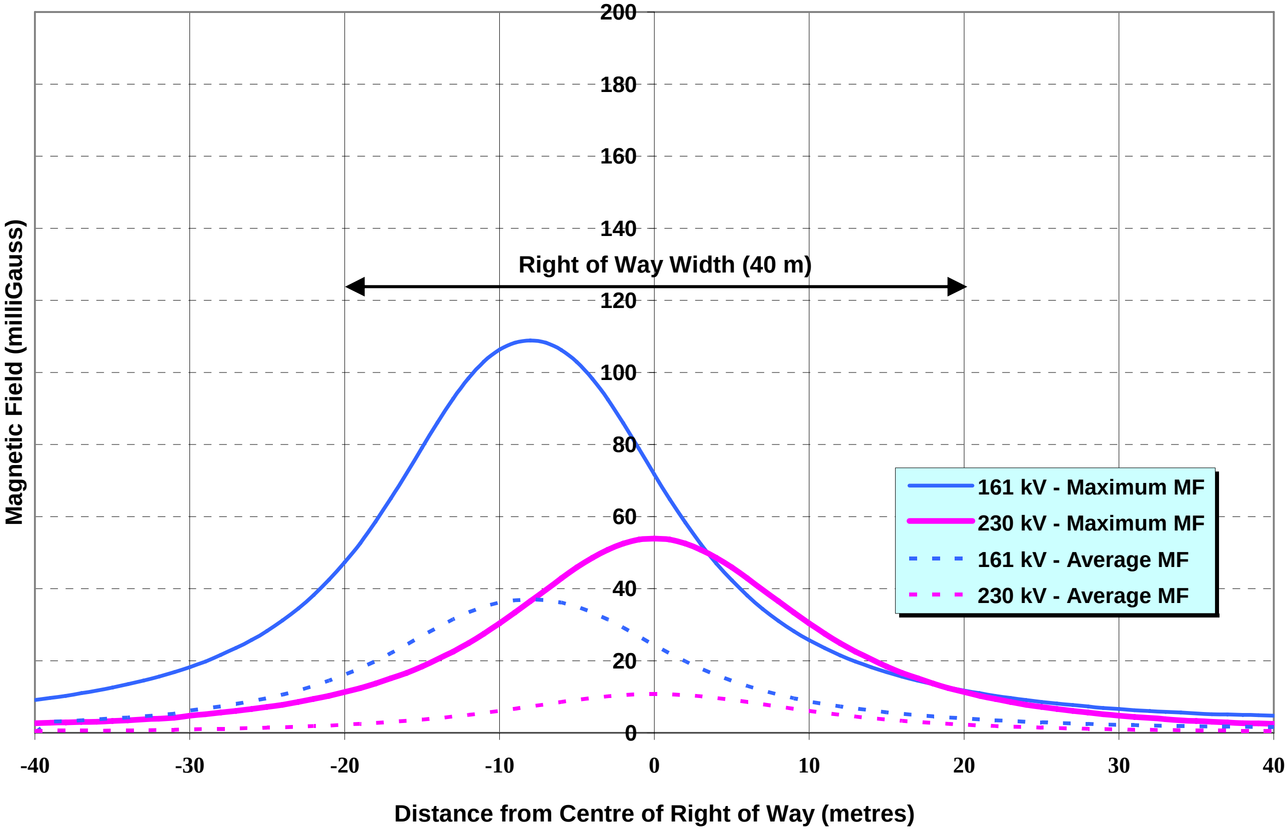
Note: ICNIRP reference level exposure guideline is 830 mG

Q57.7 Please repeat the previous question for Figure 4-6B for 75L and 76L lines.

A57.7 Please see Figure A57.7 below and Table A57.6 shown above in response to BCUC IR No. 2 Q57.6 showing the before (161 kV) and the after (230kV) construction magnetic field levels.

It is confirmed that the magnetic fields associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also the response to BCUC IR No. 1 Q57.1.

Figure A57.7: 75 Line and 76 Line Magnetic Field Vs Distance from Centre of Right of Way
(161 kV Cross Section A, 230 kV Cross Section C)



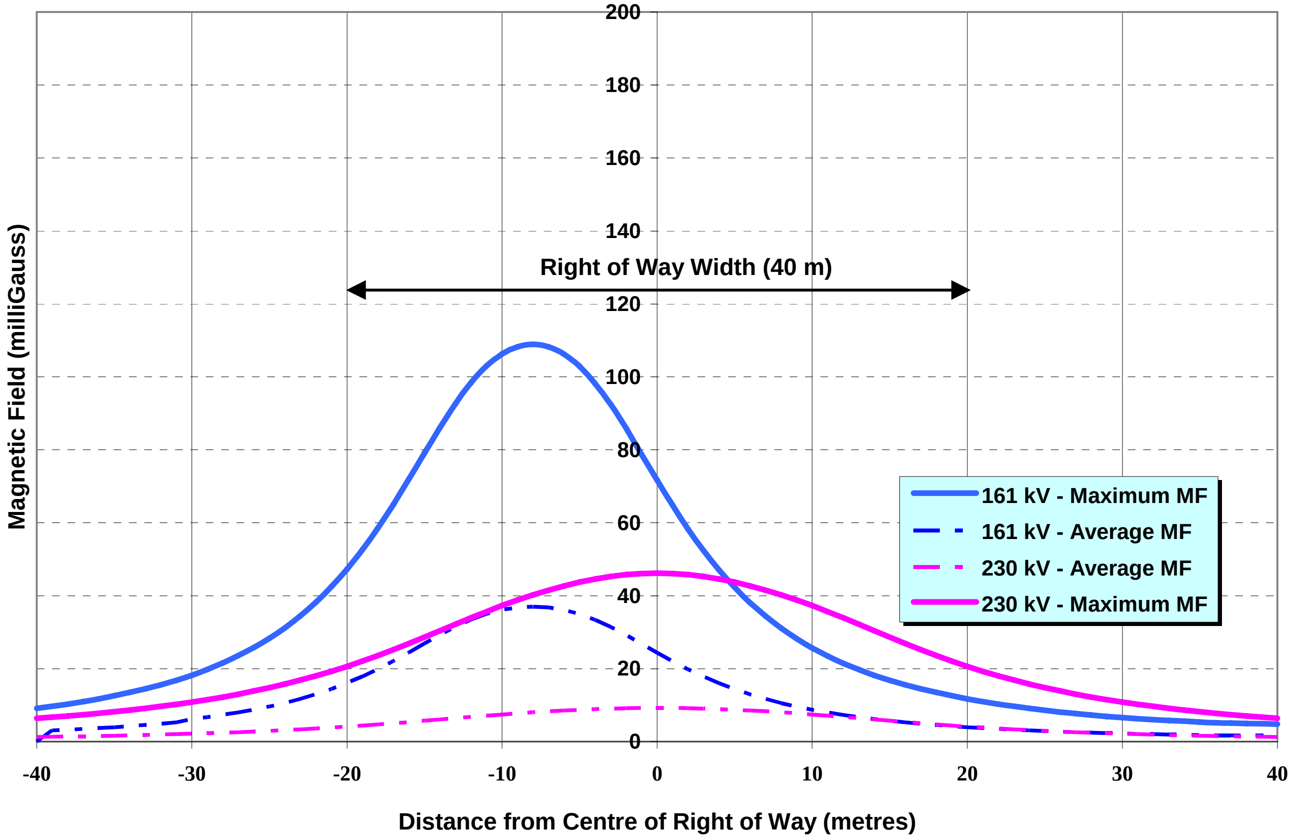
Q57.8 Please repeat the previous question for 75L and 76L, assuming the two circuits are installed on double H-frame structures (Cross Section E on page 34).

A57.8 Please see Figure A57.8 below and Table A57.6 in response to BCUC IR No.1 Q57.6 showing the before (161 kV) and the after (230kV) construction magnetic field levels.

It is confirmed that the magnetic fields associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath

Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also the response to BCUC IR No. 1 Q57.1.

Figure A57.8: 75 Line and 76 Line Magnetic Field Vs Distance from Centre of Right of Way (161 kV Cross Section A, 230 kV Cross Section E)



Q57.9 **Please repeat the previous question for 75L and 76L, assuming the two circuits are installed on single H-frame structures (Cross Section D).**

A57.9 Please see Figure A57.9 below and Table A57.6 in response to BCUC IR No.1 Q57.6 showing the before (161 kV) and the after (230 kV) construction magnetic field levels.

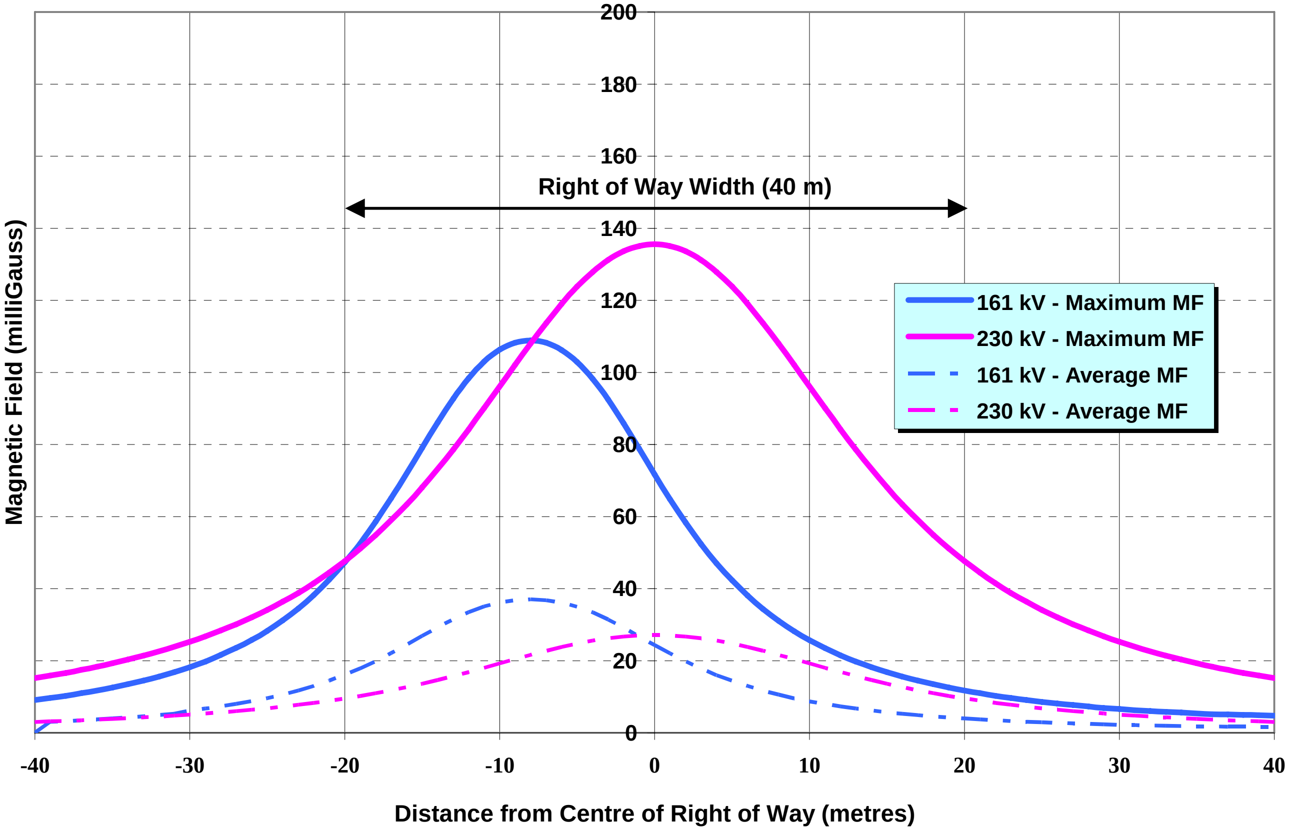
It is confirmed that the magnetic fields associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also the response to BCUC IR No. 1 Q57.1.

Q57.10 Please provide a similar figure and table for the transmission line section between Vaseux Lake and RG Anderson, assuming a high capacity single circuit built on H-frame structures similar to those for 40L (Cross Section B).

A57.10 Please see Figure A57.10 below and Table A57.6 in response to BCUC IR No. 1 Q57.6 showing the before (161 kV) and the after (230 kV) construction magnetic field levels. The cross section used here is the new Cross Section F for a single high capacity single circuit, which is a similar H-frame structure to those for 40 Line (Cross Section B). Refer to updated Cross Section drawing provided in the response to BCUC IR No.1 Q42.1.

It is confirmed that the magnetic fields associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also the response to BCUC IR No. 1 Q57.1.

Figure A57.10: 76 Line(Single High Capacity) Magnetic Field Vs Distance from Centre of Right of Way (161 kV Cross Section A, 230 kV Cross Section F)



Q57.11 Please repeat the previous question, assuming the high capacity single 230 kV circuit is built on dual circuit single poles (Cross Section C), using optimal line location for EMF reduction.

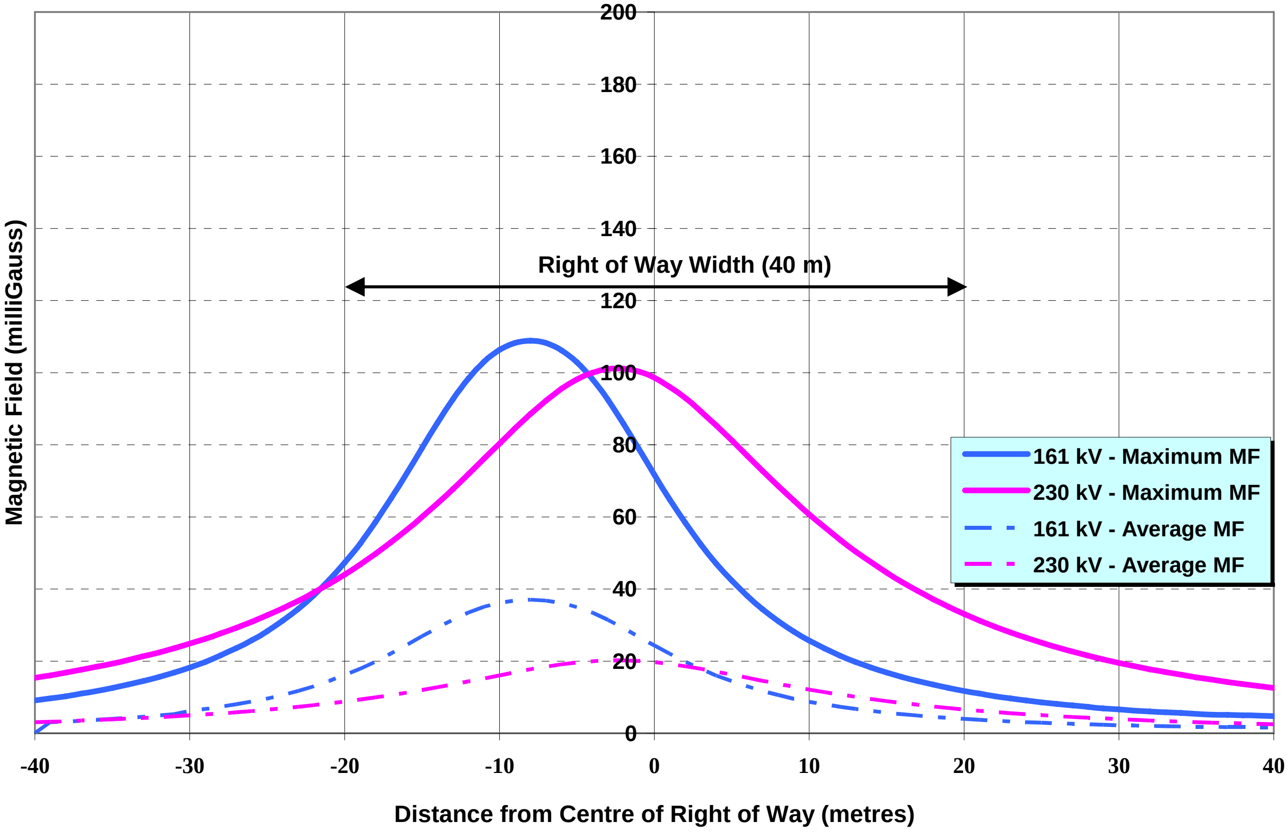
A57.11 Please see Figure A57.11 below and Table A57.6 in response to BCUC IR No. 1 Q57.6 showing the before (161 kV) and the after (230kV) construction magnetic field levels.

FortisBC has interpreted this as request to show the magnetic field for a single high capacity circuit on a single pole structure capable of a future upgrade to a double circuit. The line location to optimize EMF reduction considering a future second circuit was therefore left on the right of way centre line.

The magnetic field calculations were prepared using the structure geometry of Cross Section C and the results are reflected in Figure A57.11 and Table A57.6. However FortisBC has not undertaken any preliminary engineering on that configuration to confirm that the geometry of Cross Section C can be maintained with the application of the heavier conductor for a high capacity circuit. The magnetic field calculations would need to be re-run on a confirmed structure design if this alternative is to be investigated further.

Based on the structure geometry of Cross Section C but with the caveat noted above, it is confirmed that the magnetic fields associated with all load cases for these line scenarios comply with the ICNIRP reference level exposure guidelines for the general public. The WHO recommends the ICNIRP guidelines. Heath Canada has not recommended any quantitative guidelines to limit magnetic field exposure but has provided information for the public. See also the response to BCUC IR No. 1 Q57.1.

Figure A57.11: 76 Line- Single High Capacity Circuit on Double Circuit Monopole
Magnetic Field Vs Distance from Centre of Right of Way
(161 kV Cross Section A, 230 kV Cross Section C)



Q57.12 Please expand Table 4-6 of Electric Field values, to include each of the forgoing scenarios.

A57.12 Please refer to Table A57.12 below and Cross Section Drawing in the response to BCUC IR No. 1 Q42.1

Table: A57.12 Electric Field (EF), kV/m

Configuration	Maximum EF on Right-of-Way	EF at edge of Right-of-Way	ICNIRP Guideline
40 Line and 76 Line - Cross Section A at 161 kV (Existing)	1.70	1.05	4.17 kV/m
40 Line - Cross Section B at 230 KV (Post OTR)	2.15	1.30	
75 Line and 76 Line - Cross Section C at 230 kV (Post OTR)	1.64	0.20	
75 Line and 76 Line - Cross Section E, at 230kV (Post OTR)	1.39	0.85	
75 Line and 76 Line - Cross Section D, at 230 kV (Post OTR)	1.66	1.40	
76 Line High Capacity - Cross Section F, at 230 kV (Post OTR)	1.37	0.69	
76 Line High Capacity - Cross Section C, at 230 kV (Post OTR)	1.80	0.08	

58.0 Electric and Magnetic Fields

Reference: Exhibit B-1-1, Tab 1, Section 1.4.2, pp. 4-5

Q58.1 What is the FortisBC recommended setback limits to buildings and property lines near the edge of the new proposed ROW? Are any buildings or properties affected by this setback? If so, please identify them.

A58.1 FortisBC does not have a setback beyond the edge of the right-of-way.

59.0 Electric and Magnetic Fields

Reference: Exhibit B-1-1, Tab 1, Section 1.4.2, pp. 4-5

Q59.1 Please provide the FortisBC design limits for public exposure to the electric and magnetic fields used for the OTR project.

A59.1 FortisBC does not have specific design limits based upon electric and magnetic fields, but in general the fields from its facilities on and outside rights-of-way are below the recommended guideline reference levels of the International Commission on Non-ionizing Radiation Protection (ICNIRP) listed below.

ICNIRP Guidelines for EMF Exposure at 60 Hz

Magnetic Field Exposure	Electric Field Exposure
Occupational - 4.2 G (4,170 mG)	Occupational - 8.33 kV/m
General Public - 0.833 G (833 mG)	General Public - 4.17 kV/m

Q59.2 What low-cost or no-cost EMF/Electric and Magnetic Interference ("EMI") mitigation measures have been employed in the design of the OTR project and what was the reduction at the edge of the ROW?

A59.2 The low-cost or no-cost EMF/Electric and Magnetic Interference ("EMI") mitigation measures include line design with opposing phasing. Double circuit compact construction also mitigates EMF/Electric and Magnetic Interference ("EMI") but at a higher cost. Please refer to the responses to BCUC IR No. 1 Q57.7, Q57.8 and Q57.9 for relative performance of the designs for edge of right-of-way EMI values.

Q59.3 What precautionary principles had been applied in the EMF/EMI planning of the OTR project that exceeds the normal standards of design? If none, please explain why.

A59.3 FortisBC recognizes that some members of the public have concerns about

EMF and therefore has proposed several precautionary mitigation methods in its planning and design of the OTR Project

These include compact transmission line construction, the double-circuiting of lines, phase orientation to maximize field cancellation, the use of existing infrastructure and rights-of-way, and the distance separation between the Bentley Terminal station and nearby residences.

Q59.4 What is the FortisBC limit for electric fields at the tower centerlines and edge of the ROWs?

A59.4. Please see the response to BCUC IR No. 1 Q59.1

Q59.5 What is the FortisBC proposed minimum distance from the tower centerlines to the edge of ROW?

A59.5 The existing right-of-way between Vaseux Tap Point and RG Anderson and south towards Bentley is 40.2 metres in width. For double circuit steel pole construction configuration of Alternative 1A, the centre of the pole or poles is expected to be located in the centre of the right-of-way, or about 20 metres side to side. Through Heritage Hills the option of locating the line off-set toward the west boundary of the right-of-way to increase the distance the nearest conductors from existing homes was described to some of the residents along the right-of-way.

Q59.6 In the instance of public exposure to the electric and magnetic fields, what is the recommended distance between the OTR power lines and any buildings along the route?

A59.6 FortisBC is not aware of any such recommendations.

Q59.7 In the instance of wildlife/livestock exposure to the electric and magnetic fields or stray voltages, what is the recommended distance between the

OTR power lines and any farm buildings or equipment (farm fences, electric or otherwise) along the route?

A59.7 FortisBC is not aware of any such recommendations.

60.0 Project Management and Oversight

Reference: Exhibit B-1-2, Appendix B, pp. 2, 5

Q60.1 Appendix B at page 2 states that FortisBC has entered into an Engineering, Procurement, and Construction Management (“EPC”) contract for the OTR Project with BCHydro Engineering. Please describe the other project management structures that FortisBC could have used, and explain why it believes this contract with BCHydro is the most cost-effective.

A60.1 Other project management structures FortisBC could have used include:

- Complete all engineering, procurement, construction and management components using internal resources; and
- Complete all engineering, procurement and management internally while contracting out construction resources.

FortisBC believes the BC Hydro contract is the most cost effective as this project is a natural extension of the South Okanagan Reinforcement Project of which BC Hydro played an integral part. BC Hydro is familiar with FortisBC’s issues and standards and has a large project team capable of providing the depth of resources needed to ensure success. FortisBC also recognizes BC Hydro’s increased buying power thus reducing costs of equipment and materials and improving delivery times.

Q60.2 Did FortisBC competitively tender the EPC work? If no, please explain why not. If yes, please explain how many bids were received and why BCHydro Engineering was selected.

A60.2 No, FortisBC did not tender the work. In 2005 FortisBC entered into discussions with BC Hydro and another third party consulting firm. After reviewing each consultant's capabilities for the reasons outlined in the response to BCUC IR No.1 Q60.1 above, it was determined that BC Hydro's Engineering would best meet the needs of the OTR Project.

Q60.3 Please explain the system of project completion schedule, cost and quality milestones that are included in the EPC contract, particularly the incentive/penalty provisions.

A60.3 The EPC Agreement provides that a project schedule is to be prepared jointly by FortisBC and BC Hydro. The project schedule includes timelines for the work to be completed, target in-service dates, milestones and key deliverables. In addition, the agreement requires BC Hydro to make a number of submissions to, and to receive approvals from, FortisBC on key deliverables from BC Hydro (e.g., design and report submissions, progress and forecast reporting, change order controls, contract management recommendations).

The system used for the project schedule is based on the system used in the Vaseux EPC Agreement, as between FortisBC and BC Hydro, and was found to be effective for both parties. As note in the response to BCUC IR No.1 Q61.1, this previous agreement was for the design and construction of the Vaseux Terminal station under the South Okanagan Supply Reinforcement Project energized in late 2005.

With respect to incentive / penalty provisions, the agreement does provide fee incentives to BC Hydro for achieving certain milestones.

Q60.4 Please explain the statement at the bottom of page 5 of Appendix B that OTR Project budgets and schedules will be base-lined when Commission approval is received. Please explain the circumstances that could cause a revision to the cost estimate and schedule in the Application.

A60.4 FortisBC will be monitoring BC Hydro produced Recommended Project Inflation Rate updates expected in March and September 2008. If changes in recommendations are material, FortisBC may prepare updates on project inflation estimates. Updates may also be required if the Commission orders any material changes to the Project that need to be addressed in the Project budget.

The Project schedule has a number of constraints due to environmental and system load related outage windows for upgrade work. With the timing of the Commission approval, the Project schedule must be reviewed as to whether there is any impact to preparing work to be accomplished during those periods and if any adjustments are needed to the schedule.

Q60.5 Further to Appendix G, please identify the components of the costs estimates in Tables G2, G3 and G4 that were made by each of BCHydro and FortisBC.

A60.5 Table G3 cost estimates were provided by FortisBC. Table G4 cost estimates were provided by BC Hydro, FortisBC then added the appropriate internal capitalized overheads. Table G4 cost estimates were provided by BC Hydro with the exception of the Vaseux 500 kV work which was estimated by BCTC, FortisBC then added the appropriate internal capitalized overheads.

Q60.6 As the Application does not propose a cost control or capping mechanism, please explain how the Commission can ensure that, if approved, the OTR Project will be constructed in a timely and cost-effective manner.

A60.6 FortisBC uses the following Internal Project Management tools and functions to effectively manage Quality, Cost and Schedule (QSC) on all FortisBC capital projects:

- Regularly scheduled project meetings;
- Monthly project forecasting and variance reporting;
- Monthly resource planning;
- Cost and scope change management ;
- Procurement management processes with focus on safety, risk, quality, schedule and cost; and
- Quarterly QSC management reporting.

These internal tools and functions ensure that all projects are constructed in a timely cost effective manner and are reviewed and adjusted regularly so as to ensure continuous focus on quality, cost and schedule.

FortisBC expects that periodic progress reports to the Commission will be a requirement of the CPCN for this Project, and that, at an appropriate level of detail to be determined jointly by FortisBC and Commission staff, believes that such reports provide an effective and timely means of monitoring quality, cost and schedule.

Please see response to BCUC IR No.1 Q31.10.

Q60.7 With regard to Alternative 1A as proposed and an estimated cost of $141.4 million, would it be appropriate to establish a cost control

mechanism whereby, for example, FortisBC shareholders would receive an incentive of 50 percent of any reduction in Project costs below 90 percent of the estimate (i.e., $127.3 million), and would pay a penalty of 50 percent of any over-run above 100 percent of the estimate (i.e., $155.5 million)?

A60.7 FortisBC believes that a cost control mechanism, such as the one set out above, is not appropriate for the OTR Project. It is the position of FortisBC that all costs prudently incurred in the construction of the OTR Project should be recovered in rates and that FortisBC's approach to cost containment through active project management and competitive bidding, where appropriate, is the best and most appropriate means of ensuring cost control for the OTR Project. Additionally, as it has done in the past, the Commission may order periodic progress reports, in conjunction with a Commission review, if the Commission deems it necessary.

FortisBC submits that generally there are two aspects relative to the imposition of a cost collar, an incentive/penalty aspect that encourages efficient management with respect to project expenditures related to events that are within the control of the Company, and the other related to the allocations of risks associated with the project that are beyond the reasonable control of the company. Volatility in labour and commodity markets, costs which are competitively bid and force majeure events are examples of risks beyond the control of the Company. A cost collar, if deemed appropriate for a specific project, should encourage efficient management of the project and therefore be based upon controllable costs within a range consistent with the confidence level of the project estimates (in this case +20/-10 percent) and include equal sharing with customers of variances outside of the cost collar. FortisBC respectfully submits that a cost collar should not be used to allocate risks beyond the control of the Company such as those identified above. Imposition of substantial risks beyond the control of the Company may result in an increase to the Company's overall risk profile resulting in a necessary adjustment to the risk premium relating to its return on equity.

The Company does not believe a cost collar is appropriate for the OTR Project. If the Commission were to order a cost collar as a condition of granting a CPCN, the Company respectfully reserves the right to determine whether or not it would be willing to proceed with the Project at that time.

Q60.8 If the forgoing cost control mechanism does not appear appropriate to FortisBC, please describe a cost control mechanism that FortisBC views as reasonable.

A60.8 Please see the response to BCUC IR No.1 Q60.7

61.0 Project Management and Oversight

Reference: Exhibit B-1-1, Tab 1, Section 1.6, pp. 7-8

Q61.1 Please provide a summary of the FortisBC EPC agreement with BCHydro.

A61.1 The OTR EPC Agreement as between FortisBC and BC Hydro is a commercial arrangement as between the two utilities for the planning, management, design, engineering, procurement, construction and construction management of the OTR Project. A summary of the Agreement is provided below.

BC Hydro, as the contractor, will provide services to FortisBC as follows:

- Project management services for engineering and construction,
- Engineering services,
- Procurement and construction management services,
- Construction and supply subcontracts (if requested by FortisBC); and
- Support services for environmental assessments, properties, public consultation and the CPCN application process

FortisBC, as owner and operator, will review key project deliverables for approval and will retain direct responsibility for:

- Project management,
- Transmission system planning,
- First Nations consultation,
- Public communications/consultation,
- Regulatory processes, such as the CPCN application; and
- Properties and lands management

Similar to other commercial arrangements for EPC services, the agreement covers fundamental issues such as Project schedule, compensation, security, change orders, liabilities and indemnities, insurance requirements, warranties, environment/safety, dispute resolution, confidentiality, term and termination, suspension of work, default and delay extensions, intellectual property, and force majeure.

The OTR EPC Agreement is based on the general principles of another previous agreement, as between FortisBC and BC Hydro, which proved to be a successful project from the perspective of both parties. This previous agreement was for the design and construction of the Vaseux substation under the South Okanagan Supply Reinforcement Project energized in late 2005.

Q61.2 Please provide an estimate of the cost of the agreement to FortisBC.

A61.2 The estimate for the BC Hydro services (excluding any construction and supply subcontracts) under the agreement is $19.4M before inflation and contingency. The OTR EPC Agreement provides the flexibility, at the discretion of FortisBC, for either FortisBC to directly contract for construction and supply services or for BC Hydro to subcontract these services as part of the OTR EPC Agreement. If BC Hydro were to obtain such subcontracts, then the cost of the OTR EPC Agreement would correspondingly increase with the cost of each subcontract. As noted in the response to BCUC IR No.1 Q31.4, there is no BC Hydro loading applied to construction or supply subcontracts.

Q61.3 What cost exposure does BCHydro have if claims are pursued against FortisBC for the EPC work done under this agreement?

A61.3 FortisBC does not know what cost exposure BC Hydro has under the OTR EPC Agreement. However, the OTR EPC Agreement does have insurance requirements and liability / indemnity provisions to mitigate and address potential risk exposures to the parties. Please see response to BCUC IR No.1 Q61.4 and Q61.5.

Q61.4 What type of bonds and insurance will be provided by BCHydro to perform this EPC agreement?

A61.4 The OTR EPC Agreement provides that:

1) Project specific "errors and omissions" (professional) liability insurance will be placed by BC Hydro;
2) Construction wrap-up liability insurance will be obtained by FortisBC for the work performed pursuant to the agreement;
3) "Course of construction" (builder's all-risk) insurance will be obtained by FortisBC for the substations and terminal stations work; and
4) BC Hydro and FortisBC, as appropriate, will require their respective contractors to obtain automobile/property damage insurance, own equipment insurance and bonding and surety.

Q61.5 What exposure does FortisBC have under this agreement?

A61.5 Pursuant to the terms of the OTR EPC Agreement, FortisBC is required to indemnify BC Hydro against all direct losses or damages suffered by BC Hydro as a result of any of the following by FortisBC: a breach of the Agreement, negligence or intentional wrongdoing, the failure of the lands required for the facilities to comply with any applicable laws, and inaccurate information provided by FortisBC to BC Hydro in relation to system planning.

FortisBC is not liable for any indirect or consequential losses suffered by BC Hydro.

Please see also the response to BCUC IR No.1 Q61.5.

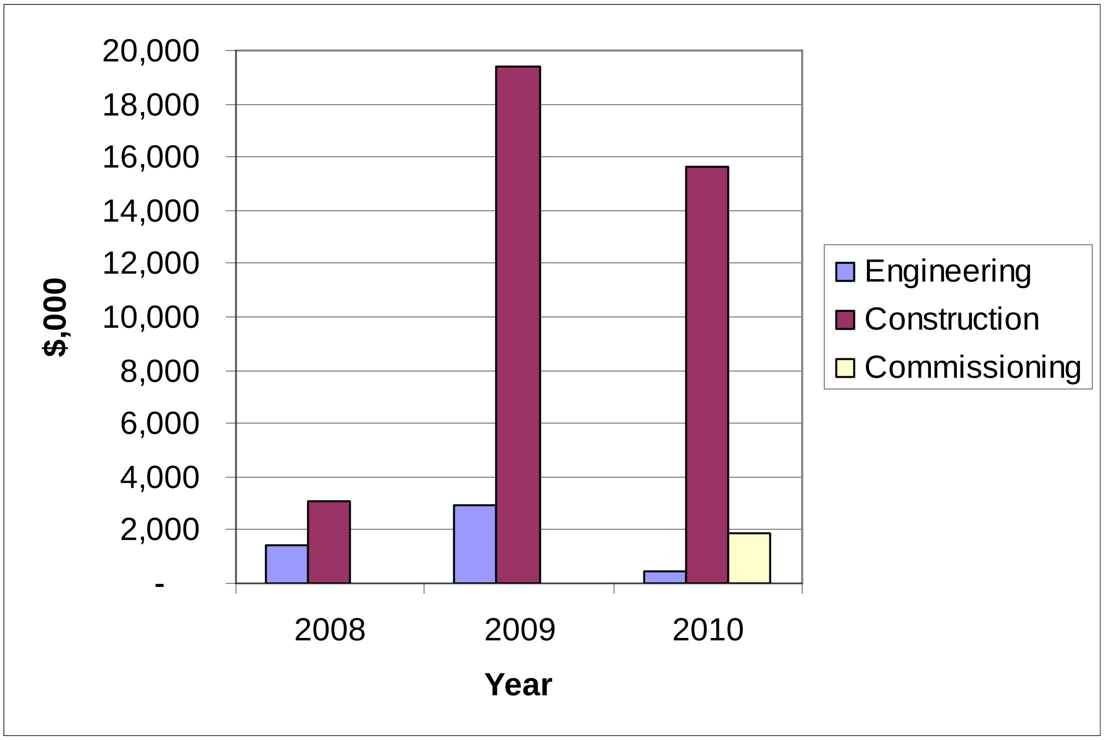
62.0 Project Management and Oversight

Reference: Exhibit B-2-2, Appendix G, Section 1.0, pp. 1-14

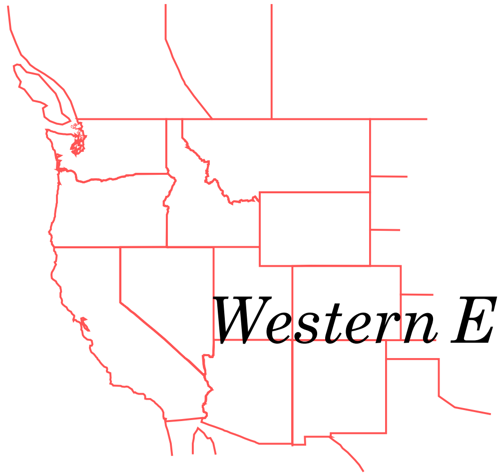
Q62.1 Please provide the project non-cumulative cash flow curve, Engineering Resource manpower and cost curve, and Construction Resource manpower and cost curve.

A62.1 Please see Figure A62.1 below.

Figure: A62.1



Appendix 7.2



Western Electricity Coordinating Council

WESTERN ELECTRICITY COORDINATING COUNCIL

NERC/WECC PLANNING STANDARDS

Revised April 10, 2003

NERC/WECC Planning Standards

Contents

NERC/WECC Planning Standards

Preface and Foreword

Preface

*This document merges the WECC Planning Standards into the **NERC Planning Standards**. The WECC Planning Standards are indicated in italic and are preceded by headings WECC-S, WECC-M, or WECC-G, depending upon whether the differences are Standards, Measures or Guides. Certain aspects of the WECC standards are either more stringent or more specific than the NERC standards.*

The NERC standards and associated Table I are applicable to all systems, without distinction between internal and external systems. Unless otherwise stated, WECC standards and the associated WECC Disturbance-Performance Table of Allowable Effects on Other Systems are not applicable to internal systems.

It is intended that the WECC standards be periodically reviewed by the Reliability Subcommittee as experience indicates, in accordance with WECC's Process for Developing and Approving WECC Standards.

Foreword

This **NERC Planning Standards** report is the result of the NERC Engineering Committee's efforts to address how NERC will carry out its reliability mission by establishing, measuring performance relative to, and ensuring compliance with **NERC Policies**, **Standards**, **Principles**, and **Guides**. From the planning or assessment perspective, this report establishes **Standards** and defines in terms of **Measurements** the required actions or system performance necessary to comply with the **Standards**. This report also provides **Guides** that describe good planning practices for consideration by all electric industry participants.

Mandatory compliance with the **NERC Planning Standards** is required of the NERC Regional Councils (Regions) and their members as well as all other electric industry participants if the reliability of the interconnected bulk electric systems is to be maintained in the competitive electricity environment. This report, however, does not address issues of implementation, compliance, and enforcement of the **Standards**. The timing and manner in which implementation and enforcement of and compliance with the **NERC Planning Standards** will be achieved has yet to be defined.

Background

At its September 1996 meeting, the NERC Board of Trustees unanimously accepted the report, *Future Course of NERC*, of its Future Role of NERC Task Force - II. This report outlines several findings and recommendations on NERC's future role and responsibilities in the light of the rapidly changing electric industry environment.

Foreword

The report also concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In accepting the Task Force's report, the Board also directed the NERC Engineering Committee and Operating Committee to develop appropriate implementation plans to address the recommendations in the *Future Course of NERC* report and to present these plans to the Board at its January 1997 meeting. The primary focus of the action plans and the initiatives from the Engineering Committee perspective was the development of **Planning Standards and Guides**. At its January 1997 meeting, the NERC Board of Trustees accepted the Engineering Committee's November 1996 "Proposed Action Plan to Establish Revised and New NERC Planning Standards and Guides" report. This action plan formed the basis for the development of **NERC's Planning Standards**.

Standards Development

The Engineering Committee assigned the overall responsibility for the development and coordination of the **NERC Planning Standards** to its Reliability Criteria Subcommittee (RCS). The Engineering Committee's other subgroups were also called upon to provide major inputs to RCS in its **Planning Standards** development effort. These other subgroups included: the Reliability Assessment Subcommittee, the Interconnections Dynamics Working Group, the Multiregional Modeling Working Group, the System Dynamics Database Working Group, the Load Forecasting Working Group, and the Available Transfer Capability Implementation Working Group.

In the development of the **NERC Planning Standards**, all proposed **Standards, Measurements, and Guides** were distributed for Regional and electric industry review prior to their submittal to the Engineering Committee and Board for approval. The Engineering Committee recognized that the **NERC Planning Standards** would have to be more specific than in the past, and that differences among the Regions would still need to be considered. It also recognizes that the development of **Planning Standards** will be an evolutionary process with continual additions, changes, and deletions.

The Engineering Committee extends its appreciation to the members of its subgroups and the members of the Regions and electric industry sectors that commented on the proposed drafts of the **NERC Planning Standards** in their development phases. A substantial effort was expended to develop the **NERC Planning Standards** in a very short time frame.

NERC/WECC Planning Standards

Foreword

The **NERC Planning Standards** continue to define the reliability of the interconnected bulk electric systems using the following two terms:

- **Adequacy** - The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- **Security** - The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

The Engineering Committee recognizes that this **NERC Planning Standards** report is the first such industry effort to establish industry **Planning Standards** requiring mandatory compliance by the Regions, their members, and all other electric industry participants. This report also defines the specific actions or system performance that must be met to ensure compliance with the **Planning Standards**.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and their capability to support a wide variety of transfers.

The future challenge to the reliability of the electric systems will be to plan and operate transmission systems so as to provide requested electric power transfers while maintaining overall system reliability.

NERC/WECC Planning Standards

Introduction

Electric system reliability begins with planning. The **NERC Planning Standards** state the fundamental requirements for planning reliable interconnected bulk electric systems. The **Measurements** define the required actions or system performance necessary to comply with the **Standards**. The **Guides** describe good planning practices and considerations.

With open access to the transmission systems in connection with the new competitive electricity market, all electric industry participants must accept the responsibility to observe and comply with the **NERC Planning Standards** and to contribute to their development and continued improvement. That is, compliance with the **NERC Planning Standards** by the Regional Councils (Regions) and their members as well as all other electric industry participants is mandatory.

The Regions and their members along with all other electric industry participants are encouraged to consider and follow the **Guides**, which are based on the **NERC Planning Standards**. The application of **Guides** is expected to vary to match load conditions and individual system requirements and characteristics.

Background

In January 1996, the NERC Board of Trustees formed a task force to reassess NERC's future role, responsibilities, and organizational structure in light of the rapidly changing electric industry environment. The task force's report, *Future Course of NERC*, accepted by the Board at its September 1996 meeting, concluded that NERC will carry out its reliability mission by:

- Establishing Reliability Policies, Standards, Principles, and Guides,
- Measuring Performance Relative to NERC Policies, Standards, Principles, and Guides, and
- Ensuring Conformance to and Compliance with NERC Policies, Standards, Principles, and Guides.

In January 1997, the Board voted unanimously to obligate its Regional and Affiliate Councils and their members to promote, support, and comply with all NERC Planning and Operating Policies.

Regional Planning Criteria and Guides

The Regions, subregions, power pools, and their members have the primary responsibility for the reliability of bulk electric supply in their respective areas. These entities also have the responsibility to develop their own appropriate or more detailed planning and operating reliability criteria and guides that are based on the **Planning Standards** and which reflect the diversity of individual electric system characteristics, geography, and demographics for their areas.

Therefore, all electric industry participants must also adhere to applicable Regional, subregional, power pool, and individual member planning criteria and guides. In those cases where Regional, subregional, power pool, and individual member planning criteria and guides are more restrictive than the **NERC Planning Standards**, the more restrictive reliability criteria and guides must be observed.

Responsibilities for Planning Standards, Measurements, and Guides

The NERC Board of Trustees approves the **NERC Planning Standards, Measurements, and Guides** to ensure that the interconnected bulk electric systems are planned reliably.

To assist the Board, the NERC Engineering Committee:

- Develops the **NERC Planning Standards, Measurements, and Guides** for the Board's approval, and
- Coordinates the **NERC Planning Standards, Measurements, and Guides**, as appropriate, with corresponding Operating Policies, Standards, Measurements, and Guides developed by the NERC Operating Committee.

The Regions, subregions, power pools, and their members:

- Develop planning criteria and guides that are applicable to their respective areas and which are in compliance with the **NERC Planning Standards,**
- Coordinate their planning criteria and guides with neighboring Regions and areas, and
- Agree on planning criteria and guides to be used by intra- and interregional groups in their planning and assessment activities.

Format of the NERC Planning Standards

The presentation of the **Planning Standards** in this report is based on the following general format:

- **Introduction** - Background and reason(s) for the **Standard(s)**.
- **Standard** - Statement of the specifics requiring compliance.
- **Measurement** - Measure(s) of performance relative to the **Standard**.
- **Guides** - Good planning practices and considerations that may vary for local conditions.
- **Compliance and Enforcement** - Not addressed in this report.

Introduction

The **NERC Planning Standards** are in bold face type to distinguish them from the other sections of the report. In some cases, the **Measurements** of a Standard are multifaceted and address several characteristics of the bulk electric systems or system components.

Definition of Bulk Electric System

The **NERC Planning Standards, Measurements, and Guides** in this report are intended to apply primarily to the bulk electric systems, also referred to as the interconnected transmission systems or networks. Because of the individual character of each of the Regions, it is recommended that each Region define those facilities that are to be included as its bulk electric systems or interconnected transmission systems for which application of the **Planning Standards** will be required. Any differences from the following Board definition of bulk electric system shall be documented and reported to the NERC Engineering Committee prior to the application or implementation of the **Planning Standards** in this report.

The NERC Board of Trustees at its April 1995 meeting approved a definition for the bulk electric system as follows:

> **"The bulk electric system is a term commonly applied to that portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher."**

This definition is included in the May 1995 NERC brochure on "Planning of the Bulk Electric Systems" prepared by a task force of the Engineering Committee.

A system facility, element, or component has been defined as any generating unit, transmission line, transformer, or piece of electrical equipment comprising an electric system. This definition is included in the May 1995 NERC *Transmission Transfer Capability* reference document.

Compliance With NERC Planning Standards

The interconnected bulk electric systems in the United States, Canada, and the northern portion of Baja California, Mexico are comprised of many individual systems, each with its own electrical characteristics, set of customers, and geographic, weather, and economic conditions, and regulatory and political climates. By their very nature, the bulk electric systems involve multiple parties. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the reliability of the other systems. Therefore, to maintain the reliability of the bulk electric systems or interconnected transmission systems or networks, the Regions and their members and all electric industry participants must comply with the **NERC Planning Standards**.

The interconnected transmission systems are the principal media for achieving reliable electric supply. They tie together the major electric system facilities, generation resources, and customer demand centers. These systems must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits while achieving their major purposes. These purposes are to:

- **Deliver Electric Power to Areas of Customer Demand -** Transmission systems provide for the integration of electric generation resources and electric system facilities to ensure the reliable delivery of electric power to continuously changing customer demands under a wide variety of system operating conditions.

- **Provide Flexibility for Changing System Conditions -** Transmission capacity must be available on the interconnected transmission systems to provide flexibility to handle the shift in facility loadings caused by the maintenance of generation and transmission equipment, the forced outages of such equipment, and a wide range of other system variable conditions, such as construction delays, higher than expected customer demands, and generating unit fuel shortages.

- **Reduce Installed Generating Capacity -** Transmission interconnections with neighboring electric systems allow for the sharing of generating capacity through diversity in customer demands and generator availability, thereby reducing investment in generation facilities.

- **Allow Economic Exchange of Electric Power Among Systems -** Transmission interconnections between systems, coupled with internal system transmission facilities, allow for the economic exchange of electric power among all systems and industry participants. Such economy transfers help to reduce the cost of electric supply to customers.

Electric power transfers have a significant effect on the reliability of the interconnected transmission systems, and must be evaluated in the context of the other functions performed by these interconnected systems. In some areas, portions of the transmission systems are being loaded to their reliability limits as the uses of the transmission systems change relative to those for which they were planned, and as opposition to new transmission prevents facilities from being constructed as planned. Efforts by all industry participants to minimize costs will also continue to encourage, within safety and reliability limits, maximum loadings on the existing transmission systems.

The new competitive electricity environment is fostering an increasing demand for transmission services. With this focus on transmission and its ability to support competitive electric power transfers, all users of the interconnected transmission systems must understand the electrical limitations of the transmission systems and the capability of these systems to reliably support a wide variety of transfers. The future challenge will be to plan and operate transmission systems that provide the requested electric power transfers while maintaining overall system reliability.

I. System Adequacy and Security

Discussion

All electric utilities, transmission providers, electricity suppliers, purchasers, marketers, brokers, and society at large benefit from having reliable interconnected bulk electric systems. To ensure that these benefits continue, all industry participants must recognize the importance of planning these systems in a manner that promotes reliability.

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Adequacy and Security (I.) are provided in the following sections:

A. Transmission Systems
B. Reliability Assessment
C. Facility Connection Requirements
D. Voltage Support and Reactive Power
E. Transfer Capability
F. Disturbance Monitoring

Introduction

The fundamental purpose of the interconnected transmission systems is to move electric power from areas of generation to areas of customer demand (load). These systems should be capable of performing this function under a wide variety of expected system conditions (e.g., forced and planned equipment outages, continuously varying customer demands) while continuing to operate reliably within equipment and electric system thermal, voltage, and stability limits.

Electric systems must be planned to withstand the more probable forced and planned outage system contingencies at projected customer demand and projected electricity transfer levels.

Extreme but less probable contingencies measure the robustness of the electric systems and should be evaluated for risks and consequences. The risks and consequences of these contingencies should be reviewed by the entities responsible for the reliability of the interconnected transmission systems. Actions to mitigate or eliminate the risks and consequences are at the discretion of those entities.

The ability of the interconnected transmission systems to withstand probable and extreme contingencies must be determined by simulated testing of the systems as prescribed in these I.A. Standards on Transmission Systems.

System simulations and associated assessments are needed periodically to ensure that reliable systems are developed with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future system needs.

Standards

S1. The interconnected transmission systems shall be planned, designed, and constructed such that with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the network can deliver generator unit output to meet projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

S2. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels, under the conditions of the contingencies as defined in Category B of Table I (attached).

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the contingency conditions as defined in Category B of Table I (attached).

S3. The interconnected transmission systems shall be planned, designed, and constructed such that the network can be operated to supply projected customer demands and projected firm (non-recallable reserved) transmission services, at all demand levels over the range of forecast system demands, under the conditions of the contingencies as defined in Category C of Table I (attached). The controlled interruption of customer demand, the planned removal of generators, or the curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard.

Transmission system capability and configuration, reactive power resources, protection systems, and control devices shall be adequate to ensure the system performance prescribed in Table I.

The transmission systems also shall be capable of accommodating planned bulk electric equipment outages and continuing to operate within thermal, voltage, and stability limits under the conditions of the contingencies as defined in Category C of Table I (attached).

S4. The interconnected transmission systems shall be evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I (attached).

WECC-S1 ***In addition to NERC Table I, WECC Member Systems shall comply with the WECC Disturbance-Performance Table of Allowable Effects on Other Systems contained in this section when planning the Western Interconnection. The WECC Disturbance-Performance Table does not apply internal to a WECC Member System.***

WECC-S2 ***The NERC Category C.5 initiating event of a non-three phase fault with normal clearing shall also apply to the common mode contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.***

WECC-S3 ***The common mode simultaneous outage of two generator units connected to the same switchyard, not addressed by the initiating events in NERC Category C, shall not result in cascading.***

WECC-S4 ***The loss of multiple bus sections as a result of a failure or delayed clearing of a bus tie or bus sectionalizing breaker shall meet the performance specified for Category D of the WECC Disturbance-Performance Table.***

WECC-S5 ***For contingencies involving existing or planned facilities, the Table W-1 performance category can be adjusted based on actual or expected performance (e.g. event outage frequency and consideration of impact) after going through the WECC Phase I Probabilistic Based Reliability Criteria (PBRC) Performance Category Evaluation (PCE) Process.***

WECC-S6 ***Any contingency adjusted to Category D must not result in a cascading outage unless the MTBF is greater than 300 years (frequency less than 0.0033 outages/year) or the initiating disturbances and corresponding impacts are confined to either a radial system or a local network.***

WECC-S7 ***For any event that has actually resulted in cascading, action must be taken so that future occurrences of the event will not result in cascading, or it must go through the PBRC process and demonstrate that the MTBF is greater than 300 years (frequency less than 0.0033 outages/year).***

WECC-S8 ***The WECC Planning Standards require systems to meet the same performance category for unsuccessful reclosing as that required for the initiating disturbance without reclosing.***

WECC-S9 ***To the extent permitted by NERC Planning Standards, individual systems or a group of systems may apply standards that differ from the WECC specific standards in Table W-1 for internal impacts. If the individual standards are less stringent, other systems are permitted to have the same impact on that part of the individual system for the same category of disturbance. If these standards are more stringent, these standards may not be imposed on other systems. This does not relieve the system or group of systems from WECC standards for impacts on other systems.***

WECC DISTURBANCE-PERFORMANCE TABLE OF ALLOWABLE EFFECTS ON OTHER SYSTEMS

NERC and WECC Categories	Outage Frequency Associated with the Performance Category (outage/year)	Transient Voltage Dip Standard	Minimum Transient Frequency Standard	Post Transient Voltage Deviation Standard (See Note 2)
A	Not Applicable	Nothing in addition to NERC		
B	≥ 0.33	Not to exceed **25%** at load buses or **30%** at non-load buses. Not to exceed **20% for more than 20 cycles** at load buses.	Not below **59.6** Hz for 6 cycles or more at a load bus.	Not to exceed **5%** at any bus.
C	0.033 – 0.33	Not to exceed **30%** at any bus. Not to exceed **20% for more than 40 cycles** at load buses.	Not below **59.0** Hz for 6 cycles or more at a load bus.	Not to exceed **10%** at any bus.
D	< 0.033	Nothing in addition to NERC		

Notes:

1. *The WECC Disturbance-Performance Table applies equally to either a system with all elements in service, or a system with one element removed and the system adjusted.*

2. *As an example in applying the WECC Disturbance-Performance Table, a Category B disturbance in one system shall not cause a transient voltage dip in another system that is greater than 20% for more than 20 cycles at load buses, or exceed 25% at load buses or 30% at non-load buses at any time other than during the fault.*

3. *Additional voltage requirements associated with voltage stability are specified in Standard I-D. If it can be demonstrated that post transient voltage deviations that are less than the values in the table will result in voltage instability, the system in which the disturbance originated and the affected system(s) should cooperate in mutually resolving the problem.*

Table W-1

4. *Refer to Figure W-1 for voltage performance parameters.*

5. *Load buses include generating unit auxiliary loads.*

6. *To reach the frequency categories shown in the WECC Disturbance-Performance Table for Category C disturbances, it is presumed that some planned and controlled islanding has occurred. Underfrequency load shedding is expected to arrest this frequency decline and assure continued operation within the resulting islands.*

7. *For simulation test cases, the interconnected transmission system steady state loading conditions prior to a disturbance should be appropriate to the case. Disturbances should be simulated at locations on the system that result in maximum stress on other systems. Relay action, fault clearing time, and reclosing practice should be represented in simulations according to the planning and operation of the actual or planned systems. When simulating post transient conditions, actions are limited to automatic devices and no manual action is to be assumed.*

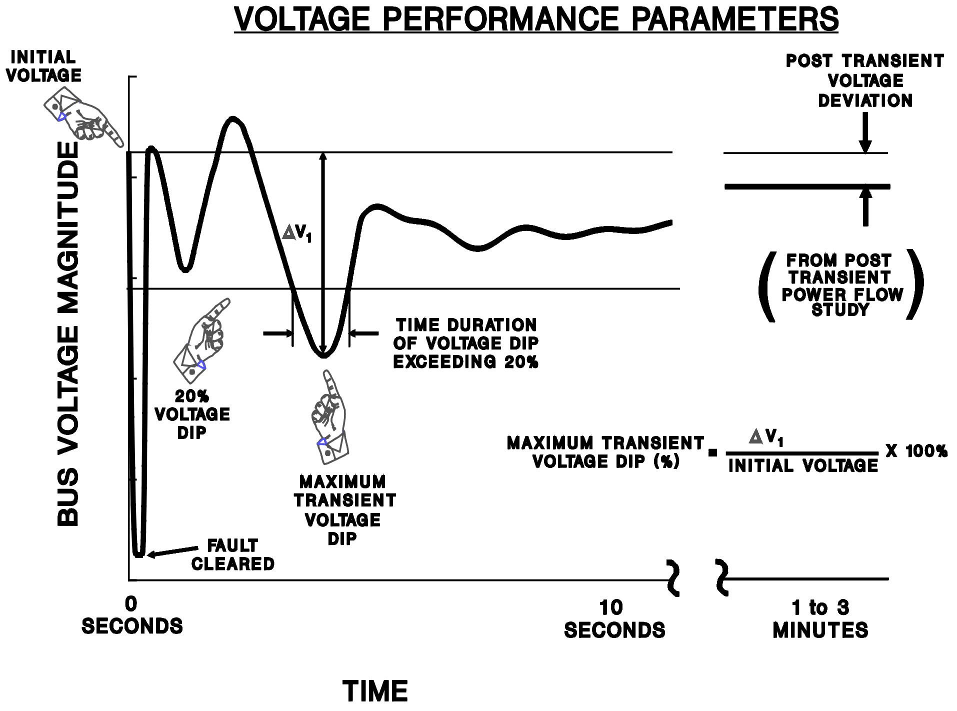


Figure W-1

Measurements

M1. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S1 are as defined in Category A (no contingencies) of Table I (attached) and summarized below:

- a. Line and equipment loadings shall be within applicable thermal rating limits.
- b. Voltage levels shall be maintained within applicable limits.
- c. All customer demands shall be supplied, and all projected firm (non-recallable reserved) transfers shall be maintained.
- d. Stability of the network shall be maintained.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S1.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Be supported by a current or past study that addresses the plan year being assessed.
2. Address any planned upgrades needed to meet the performance requirements of Category A.
3. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that with all planned facilities in service (no contingencies), established normal (pre-contingency) operating procedures in place, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands.

Assessments shall include the effects of existing and planned reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category A of Table I.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M1), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M2. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S2 contingencies are as defined in Category B (event resulting in the loss of a single element) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. No loss of customer demand (except as noted in Table I, footnote b) shall occur, and no projected firm (non-recallable reserved) transfers shall be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S2. Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

2. Assessments shall address any planned upgrades needed to meet the performance requirements of Category B.
3. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

System performance assessments based on system simulation testing shall show that for system conditions where the initiating event results in the loss of a single generator, transmission circuit, or bulk system transformer, and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. No planned loss of customer demand nor curtailment of projected firm transfers shall be necessary to meet these performance requirements, except as noted in footnote b of Table I. This system performance shall be achieved for the described contingencies of Category B of Table I.

Assessments shall consider all contingencies applicable to Category B, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category B of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category B of Table I.

The systems must be capable of meeting Category B requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near- (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M2), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M3. Entities responsible for the reliability of the interconnected transmission systems shall ensure that the system responses for Standard S3 are as defined in Category C (event(s) resulting in the loss of two or more elements) of Table I (attached) and summarized below:

a. Line and equipment loadings shall be within applicable thermal rating limits.
b. Voltage levels shall be maintained within applicable limits.
c. Planned (controlled) interruption of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
d. Stability of the network shall be maintained.
e. Cascading outages shall not occur.

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S3.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

2. Assessments of the near-term planning horizon shall be supported by a current or past study that addresses the plan year being assessed. For assessments of the longer-term planning horizon, a current or past study that addresses the plan year being assessed shall only be required if marginal conditions that may have longer lead-time solutions have been identified in the near-term assessment.

3. Assessments shall address any planned upgrades needed to meet the performance requirements of Category C.

System performance assessments based on system simulation testing shall show that for system conditions where (See Table I Category C)

1. The initiating event results in the loss of two or more elements, or
2. Two separate events occur resulting in two or more elements out of service with time for manual system adjustments between events,

and with all projected firm transfers modeled, line and equipment loadings are within applicable thermal ratings, voltages are within applicable limits, and the systems are stable for selected demand levels over the range of forecast system demands. Planned outages of customer demand or generation (as noted in Table I, footnote d) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed. This system performance shall be achieved for the described contingencies of Category C of Table I.

Assessments shall consider all contingencies applicable to Category C, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources to ensure that adequate reactive resources are available to meet the system performance as defined in Category C of Table I. Assessments shall also include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems, to ensure that protection systems and control devices are sufficient to meet the system performance as defined in Category C of Table I.

The systems must be capable of meeting Category C requirements while accommodating the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall also be conducted for near (years one through five) and longer-term (years six through ten) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses. Simulation testing beyond the five-year horizon should be conducted as needed to address identified marginal conditions that may have longer lead-time solutions.

Corrective Plan Requirements
When system simulations indicate an inability of the systems to respond as prescribed in this Measurement (M3), responsible entities shall provide a written summary of their plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon as described above. Plan summaries shall discuss expected required in-service dates of facilities, and shall consider lead times necessary to implement plans. Identified system facilities for which sufficient lead times exist need not have detailed implementation plans, and shall be reviewed for continuing need in subsequent annual assessments.

Reporting Requirements
The documentation of results of these reliability assessments and corrective plans shall annually be provided to the entities' respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M4. Entities responsible for the reliability of the interconnected transmission systems shall assess the risks and system responses for Standard S4 as defined in Category D of Table I (attached).

Assessment Requirements
Entities responsible for the reliability of the interconnected transmission systems (e.g., transmission owners, independent system operators (ISOs), regional transmission organizations (RTOs), or other groups responsible for planning the bulk electric systems) shall annually assess the performance of their systems in meeting Standard S4.

Valid assessments shall include the attributes listed below, and as more fully described in the following paragraphs:

1. Assessments shall be conducted for near-term (years one through five) planning horizons.

2. Assessments shall be supported by a current or past study that addresses the plan year being assessed.

System performance assessments based on system simulation testing shall evaluate system conditions of Table I Category D, with all projected firm transfers modeled.

Assessments shall consider all contingencies applicable to Category D, but shall simulate and evaluate only those that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining simulations would produce less severe system results.

Assessments shall include the effects of existing and planned facilities, including reactive power resources, and shall include the effects of existing and planned protection systems and control devices, including any backup or redundant protection systems.

Assessments shall consider the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed when evaluating the effects of Category D events.

Assessments shall be conducted annually and shall cover critical system conditions and study years as deemed appropriate by the responsible entity. They shall be conducted for near-term (years one through five) planning horizons. Simulation testing of the systems need not be conducted annually if changes to system conditions do not warrant such analyses.

Corrective Plan Requirements
None required.

Reporting Requirements
The documentation of results of these reliability assessments and mitigation measures shall annually be provided to the entities’ respective NERC Region(s), as required by the Region. Each Region, in turn, shall annually provide a summary (per Standard I.B. S1. M1) of its Regional reliability assessments to the NERC Planning Committee (or its successor).

M5. Entities responsible for the reliability of the interconnected transmission systems shall document their assessment activities in compliance with the I.B. Standard on Reliability Assessment to ensure that their respective systems are in compliance with these I.A. Standards on Transmission Systems. This documentation shall be provided to NERC on request. (S1, S2, S3, and S4)

Guides

G1. The planning, development, and maintenance of transmission facilities should be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations.

G2. Studies affecting more than one system owner or user should be conducted on a joint interconnected system basis.

G3. The interconnected transmission systems should be designed and operated such that reasonable and foreseeable contingencies do not result in the loss or unintentional separation of a major portion of the network.

G4. The interconnected transmission systems should provide flexibility in switching arrangements, voltage control, and other protection system measures to ensure reliable system operation.

G5. The assessment of transmission system capability and the need for system enhancements should take into account the maintenance outage plans of the transmission facility owners. These maintenance plans should be coordinated on an intra- and interregional basis.

G6. The interconnected transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

G7 Reliability assessments should examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Pre-contingency system conditions chosen for analysis should include contracted firm (non-recallable reserved) transmission services.

G8. Annual updates to the transmission assessments should be performed, as appropriate, to reflect anticipated significant changes in system conditions.

G9. Extreme contingency evaluations should be conducted to measure the robustness of the interconnected transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical (and in some cases not possible) to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to control or limit the scope of such cascading or system instability events and the significant economic and social impacts that can result.

G10. It may be appropriate to conduct the extreme contingency assessments on a coordinated intra- or interregional basis so that all potentially affected entities are aware of the possibility of cascading or system instability events.

WECC-G1 ***The contingencies specified for each Category in the NERC table and the outage frequency range provided in the WECC table provide a basis for***

estimating performance categories for disturbances that are not in the NERC Table or for disturbances that have sufficient data available to estimate their probability of occurrence.

WECC-G2 ***Each system should provide sufficient transmission capacity within its system to serve its load and meet its transmission obligations to others without unduly relying on or without imposing an undue degradation of reliability on any other system, unless pursuant to prior agreement with the system(s) so affected. Each system should provide sufficient transmission capacity, by ownership or agreement, for scheduling power transfers between its system and any other system. In transferring such power there should be no undue degradation of reliability on any system not a party to the transfer.***

WECC-G3 ***Each system should plan its system with adequate transfer capability so that its power transfers will not have an undue loop flow impact on other systems, and so that planned schedules do not depend on opposing loop flow to keep actual flows within the path transfer capability. A system adding facilities should recognize that the addition itself could result in a component of loop flow that should be accommodated. Loop flow is an inherent characteristic of interconnected AC transmission systems and the mere presence of loop flow on circuits other than those of the transfer path is not necessarily an indication of a problem in planning or in scheduling practices.***

WECC-G4 ***An initiating event of a three phase fault may be used for screening contingencies of two adjacent circuits. However, the required performance will be as specified in Table I for category C5 (Non three phase fault with Normal Clearing: Double Circuit Tower-line) events. Simulations meeting the criteria with a three-phase fault may be assumed to meet the criteria with a non-three phase fault and normal clearing.***

WECC-G5 ***Considerations in determining the probability of occurrence of an outage of two adjacent circuits on separate towers should include line design; length; location, environmental factors; outage history; operational guidelines; and separation between circuits.***

TERMS USED IN THE WECC PLANNING STANDARDS

Post Transient Voltage Deviation

In the context of these Planning Standards, post transient voltage deviation refers to "voltage drop" not "voltage rise," and the post-transient time frame is considered to be one to three minutes after a system disturbance occurs. This allows available automatic voltage support measures to take place, but does not allow the effects of operator manual actions or Area Generation Control response. The recommended simulation is a post transient power flow that simulates all automatic action but not manual actions and not area interchange control. The post transient voltage deviation standards do not fully identify all potential voltage collapse problems. Voltage collapse standards are discussed in greater depth in Standard I D.

Table I. Transmission Systems Standards — Normal and Contingency Conditions

Category	Contingencies		System Limits or Impacts				
	Initiating Event(s) and Contingency Element(s)	Elements Out of Service	Thermal Limits	Voltage Limits	System Stable	Loss of Demand or Curtailed Firm Transfers	Cascading[c] Outages
A - No Contingencies	All Facilities in Service	None	Applicable Rating[a] (A/R)	Applicable Rating[a] (A/R)	Yes	No	No
B – Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing:						
	1. Generator	Single	A/R	A/R	Yes	No[b]	No
	2. Transmission Circuit	Single	A/R	A/R	Yes	No[b]	No
	3. Transformer	Single	A/R	A/R	Yes	No[b]	No
	Loss of an Element without a Fault.	Single	A/R	A/R	Yes	No[b]	No
	Single Pole Block, Normal Clearing[f]:						
	4. Single Pole (dc) Line	Single	A/R	A/R	Yes	No[b]	No
C – Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[f]:						
	1. Bus Section	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	2. Breaker (failure or internal fault)	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	SLG or 3Ø Fault, with Normal Clearing[f], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[f]:						
	3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Bipolar Block, with Normal Clearing[f]:						
	4. Bipolar (dc) Line	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	Fault (non 3Ø), with Normal Clearing[f]:						
	5. Any two circuits of a multiple Circuit towerline[g]	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	SLG Fault, with Delayed Clearing[f] (stuck breaker or protection system failure):						
	6. Generator 8. Transformer	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No
	7. Transmission Circuit 9. Bus Section	Multiple	A/R	A/R	Yes	Planned/Controlled[d]	No

D[e] – Extreme event resulting in two or more (multiple) elements removed or cascading out of service	3Ø Fault, with Delayed Clearing[f] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section	Evaluate for risks and consequences. • May involve substantial loss of customer demand and generation in a widespread area or areas. • Portions or all of the interconnected systems may or may not achieve a new, stable operating point. • Evaluation of these events may require joint studies with neighboring systems.
	3Ø Fault, with Normal Clearing[f]: 5. Breaker (failure or internal fault)	
	Other: 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of-way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large load or major load center 12. Failure of a fully redundant special protection system (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant special protection system (or remedial action scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from disturbances in another Regional Council.	

Footnotes to Table I.

a) Applicable rating (A/R) refers to the applicable normal and emergency facility thermal rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable ratings may include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All ratings must be established consistent with applicable NERC Planning Standards addressing facility ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall security of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) electric power transfers.

c) Cascading is the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

d) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

e) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

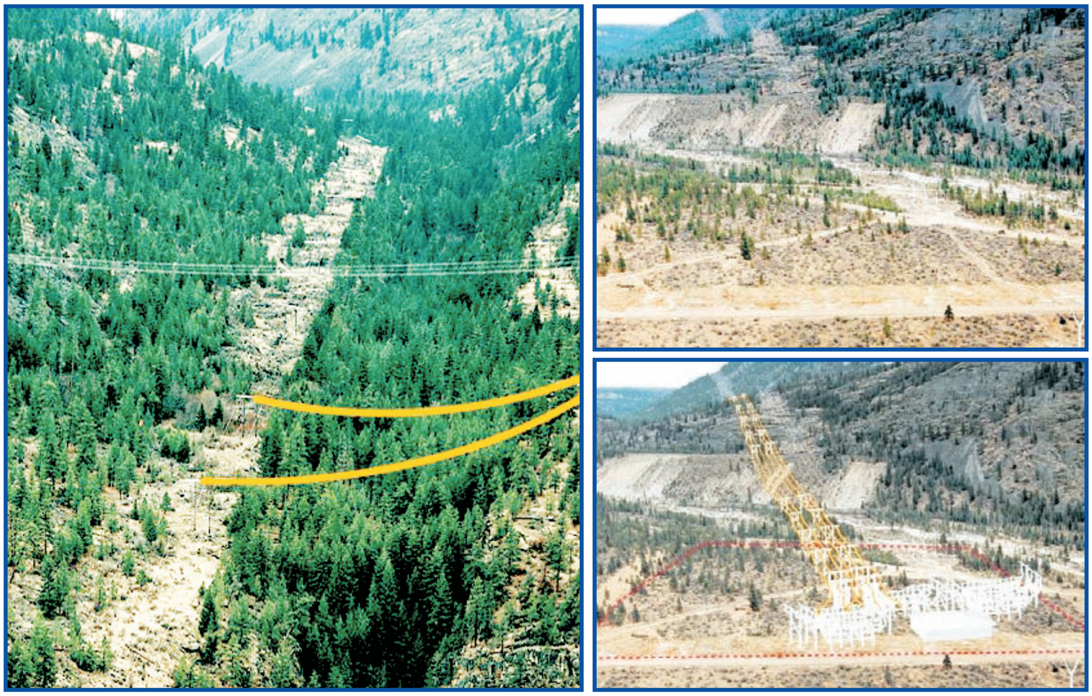
f) Normal clearing is when the protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer (CT), and not because of an intentional design delay.

g) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria

Aquila

Appendix 16.1a

Feasibility Study Report



Okanagan System
Impact Studies Update

MAIN REPORT

October 2002

ACRES
International

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Executive Summary

This report provides documentation of planning studies undertaken for the supply to the Southern Okanagan area of the transmission system owned and operated by Aquila Networks Canada. The report identifies the nature and timing of the constraints on supply to the Southern Okanagan, and reviews two alternative proposals for alleviating these constraints.

The supply in the Southern Okanagan is comprised entirely of power transmitted into the area from remote generation sources. Supply to the Aquila service area in the Okanagan is provided over four transmission circuits, as follows:

a. the Aquila-owned 161-kV circuit 11L line between Warfield and Oliver
b. supply from the BC Hydro transmission grid, from a BC Hydro 138-kV circuit emanating from the Nicola Substation near Merritt
c. supply from the BC Hydro transmission grid, from the 230-kV bus at BC Hydro's Vernon Terminal Station. Supply is taken over two Aquila-owned 230-kV transmission lines from Vernon to Kelowna.

The total supply capability over these circuits is not adequate to meet Okanagan area peak demand beyond 2004 with all circuits in service. Furthermore, prolonged outages will occur if a single major transmission circuit is forced out of service during heavy load periods.

The most critical forced outage condition is the loss of the 230-kV 73L line between Kelowna and Penticton. When this circuit is lost, all supply to the area south of Kelowna (Penticton, Oliver, Osoyoos, Hedley, Keremeos and Princeton) must be provided through 11L line and the 138-kV supply from BC Hydro out of Nicola. These two sources are capable of delivering forecast peak loads in the Southern Okanagan through the winter of 2003/04. But during the winter of 2004/05, Aquila will not have sufficient transmission capabilities to restore supply to all load in the Penticton area, should the critical 73L line contingency occur near the system peak demand.

This study considers two portfolios of investment projects to solve future supply deficiencies in the Okanagan area. The first of these portfolios is the "O1" or "Substation" project portfolio, the main component of which is a 500/230/161-kV substation in the Oliver area. Two short (1.6 km) transmission line connections to 40L line are also required.

The second portfolio evaluated is the "O3" or "Line" portfolio, the backbone of which is a new, 172-kilometer 230-kV line from Warfield to Penticton.

The two options share some common elements, including terminal station upgrades at Mawdsley Terminal, Grand Forks Terminal, Oliver Terminal and R.G. Anderson Terminal to enable the meshed operation of 11L line through the Boundary region, and installation of a communications backbone between the Kootenay and Okanagan areas.

Future investment requirements, which are required to maintain adherence to N-0 (normal conditions) and N-1 (single element contingency) supply criteria for power supply to the Okanagan area, have also been considered for each of the two scenarios. In the future, two new transformers will replace the existing transformers at Oliver and 40L line will be rebuilt and upgraded to 230-kV. In the Line option, these investments are required in 2008, while in the Substation option they are required in 2012. In addition, the Line portfolio includes the upgrade of 11L line to 230 kV, and additional upgrades to the Grand Forks and R.G. Anderson Terminal Stations in 2012, in order to increase the capacity of Aquila owned facilities. This investment loosely equates the two options from a power transfer capability perspective.

At a 10% discount rate, the present values of the total capital investments for the Line and Substation options are approximately $78.6 and $54.4 million respectively, for all of the facilities required through 2013. The O3 Option requires about $24.2 million more in total capital investment than the O1 Option, and about $13.8 million greater capital investment in the initial year 2005, on a net present value basis.

From the technical performance standpoint, both the Substation and Line options meet the loading and voltage criteria under normal system operation for all the simulated operating conditions. Both options demonstrated the ability to survive all recognized single contingencies without system instability or violation of emergency loading or voltage limits (N-1 planning criteria). The Substation option gives the Aquila system the ability to withstand more two-element sequential transmission outages (N-2 planning criteria) within the Aquila system without customer load loss as compared to the line option. The line option would leave more customer load exposed to interruption for more such events.

The two options were also evaluated for their impact on transmission losses and wheeling requirements. Both options reduce overall transmission system losses, however, the Substation option results in greater loss savings overall. From the provincial perspective, the total transmission system losses for the Line option are 4.5 to 11 MW higher than that of the Substation option over the study period.

With respect to wheeling, the Line option has the advantage of significantly reducing Aquila’s reliance on wheeling of power to the Okanagan through BC Hydro’s transmission facilities. By providing a strong 230-kV supply to the Okanagan area, Aquila could eliminate the need for winter transfers of Penticton load onto BC Hydro supply from Vernon, substantially curtailing the peak power wheeled to Vernon. In addition the new 230-kV connection between the Kootenay and Okanagan areas would provide a transmission path for Kootenay generation integration.

The feasibility study concludes that the two reinforcement solutions are largely equivalent in their supply capability with a few performance related differences. The choice of a preferred solution rests on the outcome of an economic analysis, which should consider the effects of wheeling costs, losses and other factors.

1 Introduction

Based upon the findings of a long-range transmission planning exercise undertaken in 1998, Aquila Networks Canada (Aquila) proceeded with conducting further system studies (System Impact and Feasibility Study) in 1999 to identify and review the system reinforcement options for the Okanagan and Kootenay areas. Various transmission reinforcement options were studied and analyzed. With respect to the South Okanagan supply, the following two options were retained as the major reinforcement alternatives for further technical and economic comparisons.

South Okanagan Substation (O1 Option): 500/230/161-kV station near Vaseux Lake
East-West 230-kV line (O3 Option): 230-kV transmission line from Warfield to Penticton

The objective of this exercise is to scrutinize both the above options with respect to technical merit and preference and cost-effectiveness. The purpose is to provide the technical justification in support of a CPCN application to the BC Utilities Commission (BCUC) by Aquila.

This report contains documentation of the adopted planning methodology and criteria, the existing and committed transmission system and generation resources, system adequacy evaluations and system reinforcement options. The report continues with an exhaustive presentation of the system study results discussing impacts of both the reinforcement options on the BC Hydro and the Aquila systems.

The studies cover five test years (2005, 2006, 2009, 2010 & 2021) and two seasonal load/generation patterns (Winter Peak and Summer Peak). The simulations were carried out for all the elements in service, the critical single element contingencies, the selected double contingencies and when the system is subjected to a major disturbance. Accordingly, the performance of the two reinforcement alternatives has been compared with respect to their technical merits. The facility requirements for both the South Okanagan reinforcement options were also refined along with their respective cost estimates.

2 Conclusions

The implementation of either of the two identified transmission reinforcement portfolios (the 500-kV substation for the O1 Option or the East-West 230-kV line for the O3 Option) for the Southern Okanagan resolves all of the future supply deficiency problems throughout the duration of the 20-year study horizon. Both options are technically viable, provide a reliable supply source to the Okanagan Valley and significantly improve the performance of the Aquila transmission system. The following are concluded from the impact studies:

1. The need date for the first stage of South Okanagan reinforcements was established to be the winter peak of 2004/05. However, the reinforcement project implementation may be delayed by one year (to the winter peak of 2005/06) by virtue of committed voltage control measures that will reduce the area demand by 4-5 MW.

2. The development of either portfolio of transmission reinforcements will sufficiently strengthen the Okanagan supply network for normal operation and single element contingency situations. Following implementation of either portfolio, the system will be able to survive all recognized single-element contingencies within the Aquila transmission system without resorting to special Remedial Action Schemes (RAS). Under either portfolio, the system will also be able to withstand all recognized single-element contingencies on the BC Hydro transmission system without loss of load or generation, but the first stage of the O1 portfolio will rely on use of Remedial Action Schemes to avoid facility overloading for three identified contingencies. The automatic control action of this Remedial Action Scheme involves only the opening of a parallel transmission path, without load loss, and this is deemed to be an acceptable outcome.

3. In case of the O3 Option, 56L line alone cannot supply the Princeton, Oliver and Grand Forks area loads beyond 2008, following the contingency loss of line 11L between Trail and Grand Forks[1]. Hence, the 161-kV circuit 40L must be upgraded to 230-kV in year 2008, along with the Oliver terminal reinforcement, in order to maintain conformance with the N-1 planning criterion.

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[1] Stage 1 of O3 Option involves the opening of 161-kV circuit 40L at R.G Anderson in Penticton, leaving the Grand Forks-Oliver-Princeton corridor supplied only from the East by 161-kV circuit 11L and from the West by 138-kV circuit 56L. Since 63-kV circuits 9L and 10L out of Trail are scheduled to be retired between Rossland and Christina Lake before the next scheduled Condition Assessment (2007), these circuits will not be available to augment the supply to the Boundary country.

4. In O1 Option, the RG Anderson transformer T2 is overloaded during 2010 winter peak normal system operation. This necessitates the upgrading of 40L line to 230-kV operation in 2010. However, the upgrading can be deferred until 2012 by reducing the loading on RG Anderson T2 through reconfiguration of the existing 63-kV network.

5. At a 10% discount rate, the present values of the total capital investments for O3 and O1 options are approximately $78.6 million and $54.4 million respectively.

6. Both options reduce transmission losses from present levels, but loss savings across the British Columbia transmission system are highest under O1 Option. The results show that the total transmission system losses for O3 Option are 4.5 to 11 MW higher than that of O1 Option over the study period. This difference is primarily due to the difference in the transmission system voltage between the O1 Option (500-kV transmission) and the O3 Option (230-kV transmission).

7. In comparison to the O3 Option, the O1 Option results in higher power wheeling through BC Hydro transmission facilities, ranging from 136 MW to 198 MW between 2005 and 2013 and ranging from 433 MW to 485 MW between 2014 and 2021. The significant increase in power wheeling in the later period happens after the expiry of the Power Purchase Agreement with BC Hydro.

8. The O3 Option is somewhat more robust than the O1 Option in regard to recognized single-element contingencies, in that the O1 system is somewhat more heavily stressed in the aftermath of several recognized single contingencies.

9. Conversely, the O1 Option is somewhat more robust than the O3 Option in regard to recognized two-element contingencies, as the magnitude of load loss is greater for the O3 Option in comparison to the O1 Option.

10. The Aquila transmission system and the surrounding BC Hydro transmission system are not exposed to any stability problems as a consequence of either of the identified system developments.

3 Methodology and Criteria

3.1 Study Scope and Approach

The South Okanagan (SOK) development plan was investigated for overall cost and technical system impacts of the two prime transmission alternatives identified in recent studies. These two Aquila prime options and the BC Hydro 10-year development plan were the starting points for the system studies. The study evaluates the robustness of each transmission option with respect to local impacts on the Aquila system and assesses the overall performance of BC Hydro and Aquila integrated systems. Contingency and stability analysis tested the strength and capability of the reinforcement solutions. Evaluation of system loss savings and the assessment of energy wheeling requirements were also used to compare the performance of each option. The following sections discuss the study approach adopted to achieve the desired objectives.

3.1.1 Base Case

The load flow base cases were based on the following:

a) Load flow base cases of Aquila and BC Hydro integrated systems were prepared for future years incorporating the two identified reinforcement options. The load flow models for Aquila, BC Hydro, Alberta and the equivalent US systems were prepared in coordination with BC Hydro staff. The Aquila system includes all Aquila, CPC/CBT and Teck Cominco facilities and modeled as one integrated system. All models assumed that the Arrow Lakes Hydro-Selkirk 230-kV line would have an interconnection with the new 230-kV Brilliant Terminal Station (BTS).

b) The "Do Nothing" scenario of 2005 and the planned additions to the system during 2005, 2006, 2009, 2010 and 2021 were selected as study years, for reasons as follows:. 2005 since most of the proposed transmission facilities for South Okanagan are required by that time; 2006 to capture the transmission loss impact of the Brilliant generation expansion, expected to be in service by 2006; 2009 and 2010 to look ahead about five years when most of the additional generation would be in place; and 2021 as the study's horizon year.

c) Two operating conditions with typical load levels and generation patterns were simulated to capture the worst cases for each study year. These conditions are:
   - Winter Peak (WP)
   - Summer Peak (SP)

The winter peak case represents the peak load operating condition that the system has to withstand during the year. In the Aquila power system, peak demand is forecast to occur in January. Although the actual peak demand has been observed to occur in December, such actual peaks are lower than the following January forecasted peak. During the winter peak, the Aquila system not only experiences peak load but the generation capability of the river plants is also reduced, which makes this a low generation and high load scenario. The BC Hydro system is modeled with its peak demand with the generating plants in Selkirk area operating at their full rated output.

The summer peak case represents the peak load operating condition of the early summer period when the generation capability of power plants is at their maximum due to snow melting. For this scenario, a load of 74% of the winter peak is assumed that results in a heavy export of surplus power from Kootenay area. In addition, the SP case presents a good estimation of transmission losses and energy wheeling requirements. The load in the BC Hydro system is modeled at 70% of the winter peak for various years and the Selkirk area generation is dispatched to its maximum capability.

d) The interchanges between the neighbouring systems were assumed according to a joint study between BC Hydro and Aquila in October 2000. This study defines the amount of power exchange for each operating condition across the interface with the neighboring systems. Base case simulations were carried out under the assumption that the power exchange or interchanges are constant for all Aquila options/configurations.

3.1.2 Power Wheeling

Based on the load flow studies, critical system performance parameters have been calculated. These parameters are the wheeling of power from the Kootenay to Okanagan area and the transmission system losses.

For the purpose of evaluation of wheeled power to the Okanagan, the amount of total power and energy delivered into the Okanagan "zone" was considered instead of merely the demand forecast numbers for winter peak conditions. Accordingly, load flow studies were performed for 2005, 2006, 2009, 2010 and 2021 including the "Do Nothing" scenario of 2005. For the intermediate years, linear interpolation has been used to fill in the values. The "zone" has been defined in the O1 Option as 11L at Oliver, 72L & 74L at Vernon and the 500-kV bushing of the Vaseux Lake Terminal Station transformers. Similarly, in case of the O3 Option, the "zone" constitutes 11L at Oliver, 72L & 74L at Vernon, and the RG Anderson end of the new 230-kV East-West line.

In addition, power-wheeling requirements have been evaluated based on the following:

- For both O1 and O3 options, 200 MW of power purchase under the existing Power Purchase Agreement, delivered in the Okanagan area for the period 2005 to 2013 and 0 MW thereafter;
- The deemed capacity for Aquila transmission facilities will be assumed as 350 MW for O3 Option and 120 MW for O1 Option;
- Yearly power wheeling requirements for O1 and O3 will be estimated after deducting the power purchase amount and the respective deemed capacities of Aquila facilities from the total power injected into Okanagan area.

3.1.3 Transmission Losses

With respect to the O1 and O3 options, the transmission losses were observed from the perspective of the Aquila system only, the combined BC Hydro & Aquila systems, and the BC Hydro system only. Accordingly, the loss variations (MW) were captured for the base development scenario of each option during peak winter loading conditions. These peak load losses have been used in the system impact analysis to calculate and compare the energy losses for each option.

3.1.4 Contingency Analysis

The performance of the two reinforcement alternatives has been evaluated under normal, N-1 and N-2 contingencies of the transmission elements for 2006, 2010 and 2021 study years. The contingency analyses targeted the thermal loading capabilities of the transmission lines and the voltage excursions against the specified criteria (see Section 3.2 below). Both N-1 and N-2 contingency analyses were performed for all the potential outages of transmission elements. For N-2 contingencies, the system was not adjusted or re-dispatched after simulating the first element contingency.

3.1.5 Stability Analysis

Transient stability studies were performed to assess and compare the stability performance of the two options when the system is subjected to a major disturbance. For this purpose, three phase faults were simulated at various locations in and around the Aquila service area followed by an outage of a single transmission line. The stability of the system was observed to be in accordance with the WECC (Western Electricity Coordinating Council) criteria discussed in the next section.

3.2 Planning Criteria

Member utilities of the WECC must demonstrate that their respective transmission systems are adequate and would not cause any cascading disturbances in the interconnected neighboring utilities. Accordingly, the identified reinforcement options have been tested against the guidelines stipulated in the transmission planning criteria. The WECC, Aquila Networks Canada and some BC Hydro transmission planning criteria are discussed below.

3.2.1 WECC

WECC provides the following guidelines for minimal performance requirements of neighboring systems for disturbances in the system under evaluation.

For N-1 Contingency:

- Post transient voltage deviation should be less than ±5% of the pre-contingency voltage.
- Minimum transient frequency is 59.6 Hz.
- Maximum transient voltage dip is 25%, and maximum duration of a voltage dip exceeding 20% should be less than 20 cycles.

For N-2 Contingency:

- Post transient voltage deviation should be less than ±10% of the pre-contingency voltage.
- Minimum transient frequency is 59.0 Hz.
- Maximum transient voltage dip is 30%, and maximum duration of a voltage dip exceeding 20% should be less than 40 cycles.

3.2.2 Aquila

The supply capability of Aquila's radial transmission system has two physical limitations: voltage limit and thermal capacity. A meshed system operation allows more flexibility in regard to these limitations.

Aquila has a high winter peak load due to heating loads; consequently, the transmission elements experience heavy loadings in winter. Also in summer, the line conductors and transformers may be loaded to their thermal limits when high temperatures significantly reduce their thermal ratings. This is mainly true for the Okanagan area due to increased air conditioning and irrigation loads.

Forecast load increases are modeled to identify lines and transformers that may reach their thermal limit and areas where voltages may drop below allowed limits. Accordingly, system studies have been performed taking into account the normal and emergency ratings of transmission facilities for normal and emergency operating conditions of Aquila and BC Hydro interconnected power systems. Both the bulk transmission (161-kV & 230-kV) and the sub-transmission (63-kV & 138-kV) systems have been planned to meet the following criterion for all loading conditions.

- Normal operation; voltages are limited to ±5% of nominal voltage on the primary side of the major substation.

- Post-contingency; voltages are limited to ±10% of nominal voltage.

- Thermal loading on transmission lines is limited to 80% of the thermal rating as determined by seasonal ambient temperature conditions expected at the time of peak electrical load, and conservative conductor temperatures (80°C for ASC, 100°C for ACSR)

- Thermal loading is limited to 100% of the emergency rating as determined by the seasonal ambient temperature and an elevated permissible component temperature (100°C for ASC, 150°C for ACSR)

- The normal ratings of Aquila transformers in summer and winter are 100% and 115% of nameplate rating respectively, while the emergency ratings for summer and winter are 125% and 135% of name plate rating (ref. ANSI/IEEE C57.92-18981).

For multiple contingencies (i.e. outage of more than one element), it is not economical to provide duplicate systems to maintain full service and thus some level of prolonged interruption may occur.

The reliability regime used may be designated as an "N-1" regime with respect to long-term outages. This means that the planned system should be capable of withstanding contingency loss of only a single element without any long-term outages. In this context, a "long term" outage is any service interruption where supply is restored only upon repair of the failed element.

3.2.3 BC Hydro

The BC Hydro and Aquila transmission systems are interconnected at various points and thereby, both systems share the impacts of disturbances on either system. Only one rating is used for normal and emergency loading conditions for BC Hydro facilities around the Aquila area. One or more of the following limits the power transfer capability of BC Hydro circuits:

- Thermal - Design temperature at emergency current rating not to exceed 90 degrees C in order to prevent the loss of conductor strength due to annealing.
- Ground Clearance - Lines are designed to maintain minimum standard ground clearances at maximum design temperature.
- Voltage drop - Up to 10% voltage drop (steady state) is allowed.
- Voltage rise - Up to 10% voltage rise (steady state) is allowed.

4 Study Basis and Assumptions

4.1 Load Forecast

The feasibility study is based on a detailed load forecast prepared in September 2000. Subsequent load forecasts have not differed materially from the 2000 forecast. Future load scenarios of the BC Hydro system were obtained from BC Hydro. Accordingly, a joint peak load forecast was developed that is shown in Table 4.1. The system studies conducted for the performance evaluation of the two selected options for Okanagan Transmission Reinforcement were based on this load forecast. The peak demand annual load growth of the systems is graphically shown in Figure 4.1.

4.2 Generation

Aquila, Teck Cominco, CPC/CBT and BC Hydro are the four major power producers in the Kootenay area. Existing and planned generation capacity additions are provided in Table 4.2. Figure 4.2 gives an overview of generation expansion in the Kootenay area. The generation dispatch for all the study years takes into account the availability of existing generation and scheduled additions.

4.2.1 Aquila

Aquila Networks Canada owns four hydro generating plants on the Kootenay River with a present total capacity of 211.6 MW. Over the next few years, an additional capacity of 17 MW will be available after upgrading and life extensions are complete. Table 4.2 shows the plant-specific detail of capacity additions.

4.2.2 Teck Cominco

Teck Cominco owns the Waneta Power Plant on the Pend D’Oreille River. The plant is located at the confluence of the Pend D’Oreille and Columbia Rivers. The installed capacity of the plant has reached 425 MW following upgrades to two of its four units. The remaining units will also be upgraded during the next few years providing an additional 50 MW of capacity.

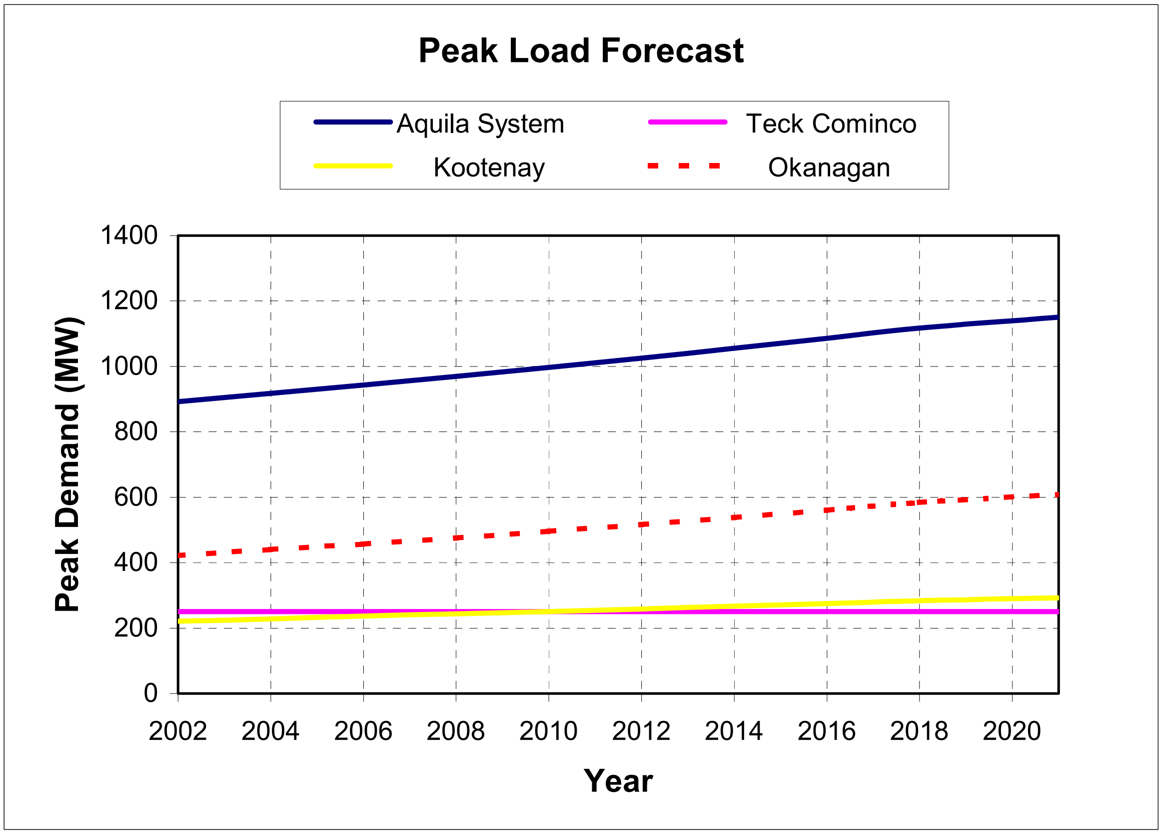
Peak Load Forecast
Table 4.1

Unit = MW

Year	2002	2004	2006	2008	2010	2012	2014	2016	2018	2020
BC Hydro	8820	--	9431	--	9879	--	--	--		10153*
Aquila System	893	917	943	969	997	1025	1055	1086	1118	1150
Teck Cominco	250	250	250	250	250	250	250	250	250	250
Aquila	643	667	693	719	747	775	805	836	868	900
Kootenay	221	228	236	244	251	259	267	275	284	292
Kootenay Valley	123	127	133	137	142	147	152	157	162	167
Trail Area	51	52	53	55	56	57	59	60	61	63
Boundary	47	49	50	52	53	55	57	58	60	62
Okanagan	422	440	456	476	496	517	539	561	584	608
Kelowna area	224	237	247	258	270	282	295	308	321	335
Penticton area	125	130	134	138	142	147	152	157	162	167
Princeton and Oliver area	73	73	76	80	83	87	92	96	101	106

* For the period 2010~2021, BC Hydro demand was increased for Kootenay area only.

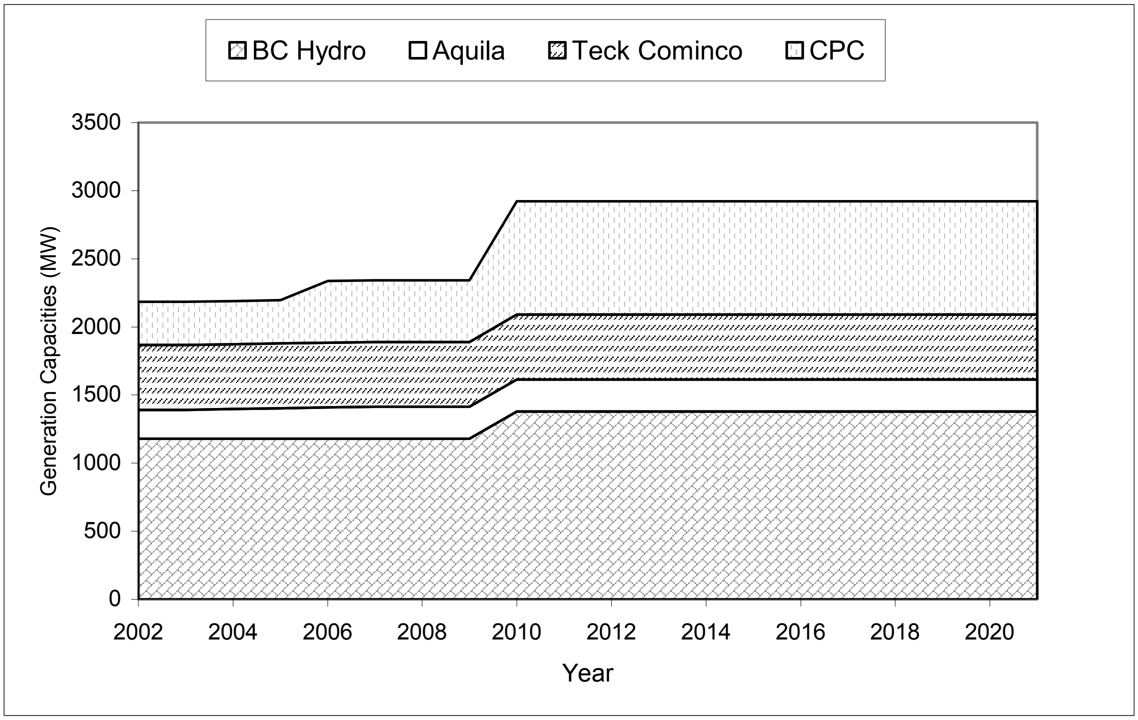
Peak Load Forecast
Figure 4.1



Existing and Planned Generation
Table 4.2

		Existing	Increments/Additions								Total by
		2002	2003	2004	2005	2006	2007	2008	2009	2010	2021
Aquila	L. Bonnington	44.5		3	3						50.5
	U. Bonnington	59.5		2	2						63.5
	South Slocan	56.3			1.5	1.5					59.3
	Corra Linn	51.3				2	2				55.3
	Subtotal	211.6	211.6	216.6	223.1	226.6	228.6	228.6	228.6	228.6	228.6
CPC	Brilliant	148									148
	Arrow Lake	170									170
	Brilliant Expansion					135					135
	Waneta Expansion									380	380
	Subtotal	318	318	318	318	453	453	453	453	833	833
Teck Cominco	Waneta	425	25	25							475
	Subtotal	425	450	475	475	475	475	475	475	475	475
BC Hydro	K. Canal	580									580
	Seven Mile	600	210								810
	Subtotal	1180	1390	1390	1390	1390	1390	1390	1390	1390	1390
Total in the area		2134.6	2369.6	2399.6	2406.1	2544.6	2546.6	2546.6	2546.6	2926.6	2926.6

Existing and Planned Generation
Figure 4.2



4.2.3 CPC/CBT

The CPC/CBT (Columbia Power Corporation and Columbia Basin Trust) jointly own the 3x37 and 1x32 MW Brilliant Generating Station on the Kootenay River near Castlegar. An additional capacity of 5 MW will be available after upgrade/life extension planned in the current year. Aquila has a long-term contract with CPC/CBT to purchase all the generating output from the Brilliant Generating Station.

The Arrow Lakes Generating Station, at the site presently known as Keenleyside Dam, is under construction and was modeled as having 170 MW generating capacity once complete. The contract completion date for the power plant is in year 2003, but the plant first produced power before the end of 2001.

According to CPC/CBT's plans, Brilliant Expansion with 135 MW of generation is supposed to be put into commercial operation by 2006. The Arrow Lakes Hydro to Selkirk 230-kV transmission line will be looped into the Brilliant Terminal Station to dispatch this additional generation to the system.

CPC owns the water rights for expansion of the Waneta Generating Station. An additional 380 MW of generation is planned at this site. For the purpose of this study, it is assumed that it will be connected to Selkirk directly. The in-service date for this generation project is 2010.

4.2.4 BC Hydro

BC Hydro owns the following hydropower generation facilities in the Kootenay area:

- Kootenay Canal Generating Station: Present nameplate rating is 529 MW, to be re-rated up to 580 MW.
- Seven Mile Plant: Present nameplate rating with 3 units is 607.5 MW. BC Hydro is in the process of installing a fourth unit with 210 MW capacity next year.

4.3 Transmission System

Aquila supplies electric power to two distinct geographic areas of British Columbia. In the east, it serves the Kootenay area which spans the southern part of BC from Creston to Rock Creek, and extends north on Kootenay Lake to Kaslo, and to Slocan City through the Slocan Valley. In the west, Aquila serves the Okanagan area that includes the cities of Kelowna and Penticton, and extends to Osoyoos in the south and Princeton in the west.

An overview of the Aquila service area is shown in Figure 4.3

4.3.1 Aquila Existing System Overview

Aquila generation sources are located in the Kootenay area. These generation sources are dispatched by the Kootenay area transmission system to deliver power to Aquila customers in the Kootenay area. Aquila also relies heavily on the transmission network between the Kootenay and Okanagan areas to supply customers in the Okanagan. This network includes lines such as 11L line from Warfield to Oliver and BC Hydro's 500-kV and 230-kV lines. The interconnections with BC Hydro in the Kootenay area play a very important role in supplying power to the Okanagan area.

Warfield is a main dispersion point for power generating facilities since the power is transmitted at 63-kV to Teck Cominco's Tadanac and Warfield Switching Stations. Two short 63-kV lines connect the Warfield Switching Stations to A.S. Mawdsley Terminal where power is transformed to 161-kV and further transmitted to the Okanagan via line 11L.

Substations connected to the 63-kV river lines supply loads in the South Slocan, Castlegar and Trail areas. A 63-kV loop that originates at the Corra Linn Generating Plant connects to a substation for supply to the City of Nelson and continues south to Salmo and back to Trail. A radial 63-kV line, originating from South Slocan, picks up the loads in the Slocan Valley.

The largest power consumer in the Aquila service area is Teck Cominco with 250 MW load. Waneta Power Plant mainly supplies this load via four 63-kV lines terminating at Warfield substation. Teck Cominco is also interconnected with the Boundary Dam generation (owned by Bonneville Power Administration (BPA)) through a 230-kV line from the Waneta Power Plant to the Boundary Generating Station, south of Nelway.

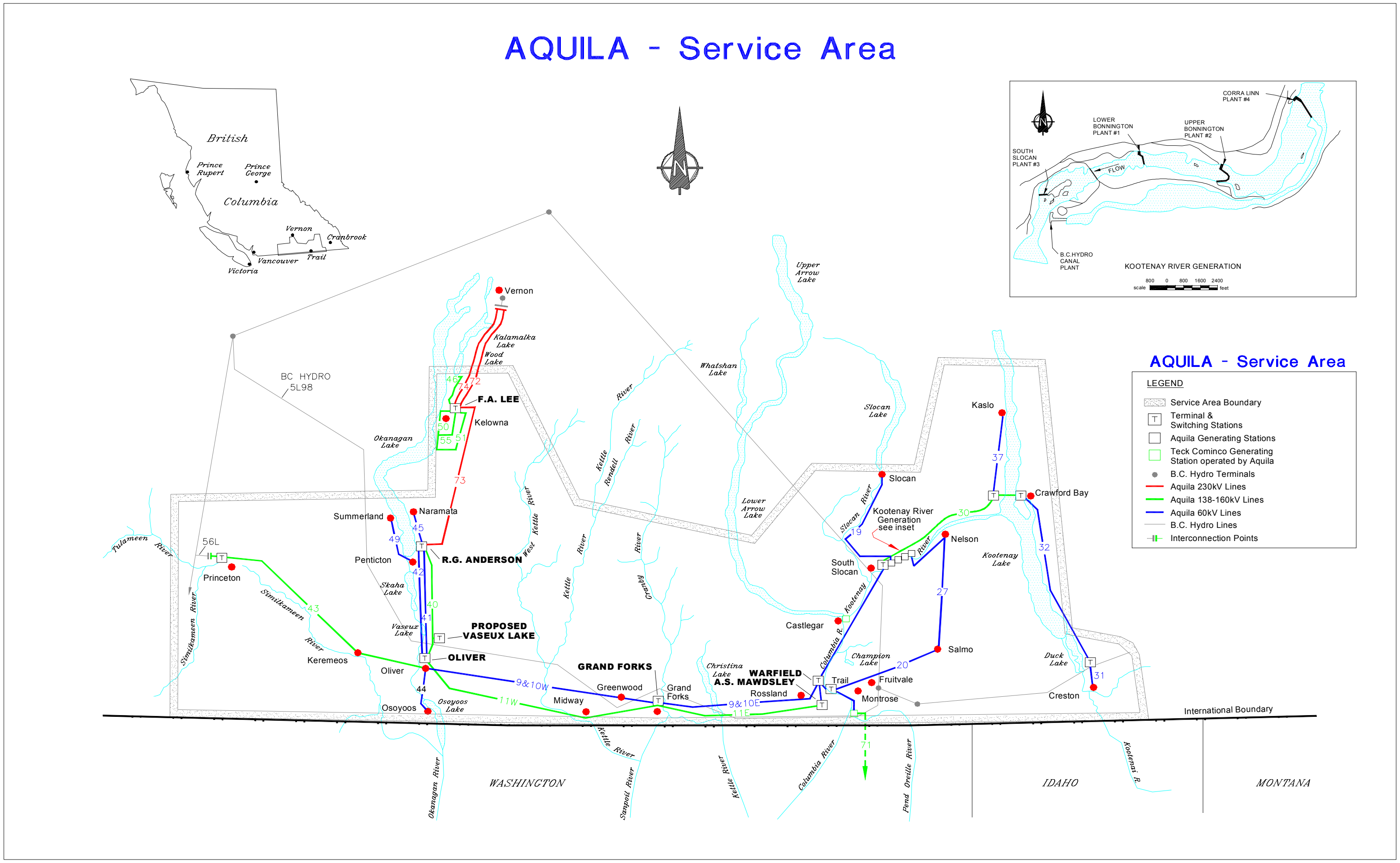
Aquila Networks Canada and Teck Cominco each own a section of a 161-kV line that extends from South Slocan to Kimberley. Aquila owns the section from South Slocan to Crawford Bay and taps this line on the west side of Kootenay Lake to supply Kaslo at 63-kV, and on the east side to supply the Crawford Bay area. Teck Cominco owns the section of the 161-kV line from Crawford Bay to Kimberley where it supplies the Teck Cominco mining operation. The mining operation has been closed recently, and the Crawford Bay-Kimberley line section will be retired unless the Columbia Power Corporation (CPC) exercises an option to purchase this line.

A 63-kV line extends from the 161/63-kV terminal at Crawford Bay to Creston to supply part of the Creston load. The remainder of the Creston load is supplied by the 230/63-kV A.A. Lambert Terminal Station that taps BC Hydro's 230-kV line connecting Cranbrook and Nelway.

There are some inherent weaknesses in the existing Aquila transmission system to supply power to both Kootenay and Okanagan areas. To overcome the transmission limitations and constraints in the Kootenay area, a major reinforcement project is already underway and is briefly described below. The constraints and limitations for the Okanagan supply area are discussed in the next chapter along with the reinforcement options.

An Overview of the Aquila Service Area

Figure 4.3



4.3.2 Aquila Committed Projects

Kootenay 230-kV System Development:

This project consists of the development of a 230-kV transmission system between the Kootenay Canal generating station and a new Warfield Terminal Station. This system will replace the aging 63-kV transmission lines in the Kootenay valley. According to previous studies, this scheme secures the Kootenay system from loss of load and/or generation for most of the single element contingencies. The benefits include elimination of safety hazards on the river line corridor and a dramatic improvement in the visual impact of the facilities in the valley. It will also significantly reduce energy losses and maintenance costs in comparison to the existing 63 kV lines. The BCUC has approved the following major transmission components for reinforcement of the Kootenay area:

- A 29.6 km 230-kV line using Narcissus conductor from Brilliant to Warfield
- A 20.1 km 230-kV line using Drake conductor from Kootenay Canal to Brilliant
- A second 63-kV tie line from South Slocan to Kootenay Canal including the addition of a second 230/63-kV transformer
- A new 230/63-kV substation near Brilliant (known as the Brilliant Terminal Station (BTS)) with 2x168 MVA transformers
- A new 230/63-kV terminal near Warfield (known as the Warfield Terminal Station (WTS) with 2x200 MVA transformers
- Decommission the existing river lines (1-8) from Brilliant to Warfield
- Decommission five of the six river lines between South Slocan and Brilliant
- Ancillary rehabilitation work in the Kootenay 63-kV system

Only the Waneta to Warfield 230-kV transmission line section was not approved for implementation. The BCUC acknowledged the requirement to reroute the Waneta-Boundary 230-kV line (71L) to Nelway, instead of Boundary. Although the BCUC declined to order completion of this portion of the project, Teck Cominco and BC Hydro are making the improvements jointly. Furthermore, Teck Cominco is building a new 63-kV Emerald Switching Station (ESS) near WTS that will replace the existing Tadanac Switching Station.

The commercial in-service date of this project is scheduled for April 2003. Presently, it is under construction.

4.3.3 CPC/CBT Existing and Committed Transmission Facilities

230-kV Arrow Lakes Hydro to Selkirk Line:

CPC has built the 170 MW Arrow Lakes Hydro Generating Station at Hugh L. Keenleyside Dam, 14.5 km west of the new BTS. The generation is dispersed via a new 230-kV, 48 km line between Arrow Lakes Hydro and Selkirk substations. In 2003, this circuit will be interconnected at the new BTS on its way to Selkirk for improved reliability.

230-kV Waneta Expansion to Selkirk line:

Along with the Waneta Expansion project, it is assumed that an additional 230-kV line would be needed from Waneta Expansion to Selkirk substation without interconnecting at the existing Waneta 230-kV substation. The project is scheduled to be in service by 2010.

4.3.4 BC Hydro Existing and Planned Facilities

British Columbia is part of the Western Interconnected System that includes BC, Alberta, the Western United States and Northern Mexico. The BC control area is linked to the US Pacific Northwest through two 230-kV lines in the Kootenay area (one is owned by BC Hydro and the other is owned by Teck Cominco), and two BC Hydro 500-kV lines between Vancouver, BC and Bellingham, Washington.

BC Hydro’s 500-kV system loops the Aquila service area as can be seen in Figures 5.4 to 5.6 and on the schematic diagrams presented in Appendix A. The loop extends from the Selkirk Substation (south-east of Trail) to Ashton Creek (northwest) and then to Nicola (southwest), with the Selkirk to Nicola line in the south. Aquila is interconnected to BC Hydro’s Kootenay Canal Generation Plant at 63-kV, Vernon substation at 230-kV, Princeton Substation at 138-kV, and Creston Substation at 230-kV.

Major BC Hydro transmission lines in the Kootenay area are listed below:

- One 500-kV line; Selkirk (SEL) to Ashton Creek (ACK)
- One 500-kV line; Selkirk to Nicola (NIC)
- Two 500-kV lines; Ashton Creek to Nicola (NIC)
- One 500-kV line; Selkirk to Cranbrook (CBK) and to Alberta's Langdon station (at Calgary)
- Two 230-kV lines; Kootenay Canal (KCL) to Selkirk
- Two 230-kV lines; Seven Mile (SEV) to Selkirk

- One 230-kV line; Boundary Dam (BPA) to Nelway via a phase shifting transformer at Nelway
- One 230-kV line; Selkirk to Nelway
- One 230-kV line; Nelway (NLY) to Aquila's AA Lambert Station in Creston and to Cranbrook (CBK)

There is no significant addition in the BC Hydro system in the Kootenay area except the upgrading of transformers at the Selkirk Substation. Currently, there are three transformers (2 x 672 MVA+ 1 x 1200 MVA) at Selkirk Substation. One of the 672 MVA transformers is expected to be replaced by a 1200 MVA transformer in the near future.

A schedule of major transmission reinforcement projects within the Kootenay area is presented in Table 4.3 below.

Commissioning Schedule of Major Transmission Projects
Table 4.3

Project Name	**Major components**	**In service Date**
Arrow Lakes Hydro/Selkirk 230 kV Line	48-km 230 kV Line	January, 2002
Selkirk 500 kV Transformer Upgrade	The second 1200 MVA Xfmer	Fall, 2004
Kootenay 230 kV System	Major development	April, 2003

4.4 System Modeling

4.4.1 Operating Conditions

As mentioned in the previous chapter under Section 3.1, two generation/load operational conditions (winter peak and summer peak) have been simulated for each of the study years. The load flow base cases were prepared based on the load and generation levels given in Table 4.4. The generation patterns for the years 2005, 2006, 2009, 2010 and 2021 are shown in Tables 4.5.

Operating Conditions
Table 4.4

System		Winter Peak (WP)	Summer Peak (SP)
BC Hydro	Load	100% of WP	69% of SP
	Generation	Heavy Output	Light Output
Aquila	Load	100% of WP	74% of SP
	Generation	Heavy Output	Heavy Output

Generation Dispatch (MW)
Table 4.5

Plants	Winter Peak					Summer Peak				
	2005	2006	2009	2010	2021	2005	2006	2009	2010	2021
L. Bonnington	31	31	31	31	31	47	48	48	48	48
U. Bonnington	27	27	27	27	27	45	52	52	52	52
South Slocan	28	32	32	32	32	54	54	54	54	54
Corra Linn	20	20	20	20	20	48	51	51	51	51
Brilliant	136	136	136	136	136	148	148	148	148	148
Waneta	450	450	450	450	450	450	450	450	450	450
Arrow Lake	170	170	170	170	170	150	150	150	150	150
Brilliant Exp.	--	135	135	135	135	135	135	135	135	135
Waneta Exp.	--	--	--	380	380	--	--	--	380	380
Kootenay Canal	536	536	536	536	536	580	580	580	580	580
Seven Mile	800	800	800	800	800	800	800	800	800	800
Total	2198	2337	2337	2717	2717	2457	2468	2468	2848	2848

4.4.2 Power Interchanges

Table 4.6 gives the power interchange values of the Aquila and BC Hydro systems. The values represent the historical power exchange at interfaces for each operating condition of the years 2005, 2006, 2009, 2010 and 2021.

The key aspects of the power interchanges are presented below:

- Aquila will import (on an “as needed” basis) power in the future from or via BC Hydro’s nearby transmission network
- BC Hydro imports 0 MW from Alberta
- BC Hydro imports up to 2000 MW during summer peak operating conditions.

4.4.3 Transmission Facility Loadings

As a general planning philosophy, the transmission system must have a sufficient number of elements so that failure of a single element during peak load periods or other high-stress conditions does not overload the remaining transmission facilities.

Accordingly, the system studies were carried out following the circuit-loading criterion of Aquila and BC Hydro transmission facilities discussed in Section 3.2. Tables 4.7 and 4.8 give normal and emergency winter and summer ratings for major transformers and transmission lines in the two interconnected systems.

4.5 Capital Costs

Cost estimates for the required facilities have been provided at feasibility level. Feasibility-level comparisons use appropriate cost estimates at a ±10% accuracy level based on the identified facility requirements, preliminary layout and design work

Interchange Among the Interconnected Systems (MW)
Table 4.6

Year	Power Interchanges		Winter Peak (WP)	Summer Peak (SP)
2005	BC Hydro	To US	323	-1967
	BC Hydro	To Alcan	-147	0
	BC Hydro	To Alberta	0	0
	Aquila	To BC Hydro	-260	33
	Aquila	To US	0	0
2006	BC Hydro	To US	323	-2000
	BC Hydro	To Alcan	-147	0
	BC Hydro	To Alberta	0	0
	Aquila	To BC Hydro	-270	0
	Aquila	To US	0	0
2009	BC Hydro	To US	323	-2000
	BC Hydro	To Alcan	-147	0
	BC Hydro	To Alberta	0	0
	Aquila	To BC Hydro	-330	-40
	Aquila	To US	0	0
2010	BC Hydro	To US	323	-2000
	BC Hydro	To Alcan	-147	0
	BC Hydro	To Alberta	0	0
	Aquila	To BC Hydro	-330	-40
	Aquila	To US	0	0
2021	BC Hydro	To US	323	-2000
	BC Hydro	To Alcan	-147	0
	BC Hydro	To Alberta	0	0
	Aquila	To BC Hydro	-510	-170
	Aquila	To US	0	0

Transformer Ratings (MVA)
Table 4.7

Location	Nameplate	Normal		Emergency	
	MVA	Summer	Winter	Summer	Winter
230-kV Warfield Terminal Stations	2x200	2x200	2x230	2x250	2x270
S. Slocan/Canal Tie Transformers*	2x168	2x168	2x168	2x220	2x220
230-kV Brilliant Terminal Station	2x150	2x150	2x172	2x187	2x202
Waneta 230 kV Substation	2x150	2x150	2x172	2x187	2x202
500-kV Vaseux Lake Terminal Station	2x250	2x250	2x287	2x312	2x337
500-kV BC Hydro Selkirk Substation*	2x672 1x1200	2x672 1x1200	2x672 1x1200	2x672 1x1200	2x672 1x1200

Note: * BC Hydro's criteria

Major Transmission Line Ratings (MVA)
Table 4.8

Lines	Length/Code	Normal		Emergency	
	Km/Conductor	Summer	Winter	Summer	Winter
230-kV BTS-WTS (77L)	29.6/Narcissus	370	477	552	663
230-kV KCL-BTS (79L)	20.1/Drake	339	407	545	604
230-kV ALH-BTS-SEL **	48	455	455	535	535
63-kV Tie between WTS and ESS (62L)	0.8/2xNarcissus	202	260	302	360
230-kV KCL-SEL*		420	420	420	420
230-kV WAN-NLY (71L)	15.5/Narcissus	370	477	552	663
230-kV E-W Line (O3)	172/Drake	339	407	545	604
230-kV VNT-LEE (72L/74L) each	27/Drake	339	407	545	604
230-kV ACK-VNT * each (2L255/2L256)		378.0/420	378.0/420	378/420	378/420
161-kV GFT-OLI (11L)	84.3/Hawk	170	204	245	280
161-kV OLI-RGA (40L)	21.8/Hawk	170	204	245	280

Note: * BC Hydro's criteria

** Provided by CPC

5 Constraints and Limitations for Okanagan Supply

5.1 Okanagan Supply Constraints

The supply system into the Okanagan consists of Aquila's 11L line from Warfield (161-kV) and interconnections with BC Hydro at Vernon (230-kV) and Princeton (138-kV). The Okanagan transmission system operates in a radial fashion. The supply capabilities of the above feeding points are determined based on winter peak load conditions and typical operation configuration. Loosely, the sum of individual supply limits of three paths may be considered as the total supply capability into the entire Okanagan area during the coincident winter peak load.

The power transfer capability for 11L is assumed as 120 MW at the receiving end (Oliver). The limiting flows are driven by the risk of voltage collapse during contingency situations. It is noted that this supply limit is reached when 11L picks up about 30 MW of load at Grand Forks Terminal. Currently, a Load Shedding Remedial Action Scheme exists to keep loading on 11L within its voltage stability limit.

Under normal system operation, BC Hydro criteria requires that voltage at the Vernon 230-kV bus be maintained at 1.0 pu or higher during peak load conditions, and that Aquila maintains a unity power factor at Vernon's 230-kV delivery point. A 40 MVAr capacitor bank was installed on the 138-kV Vernon bus in December 2001 to meet the above-mentioned criteria. Each year, the Vernon supply capability gradually decreases due to projected growth in BC Hydro's Vernon area load. BC Hydro cannot commit to supply the Princeton interconnection point with more than 55-60 MW through 56L.

Keeping in view the above constraints, the maximum supply limits (during the normal system operations) for each of the supply points to the Okanagan area is given below in Table 5.1.

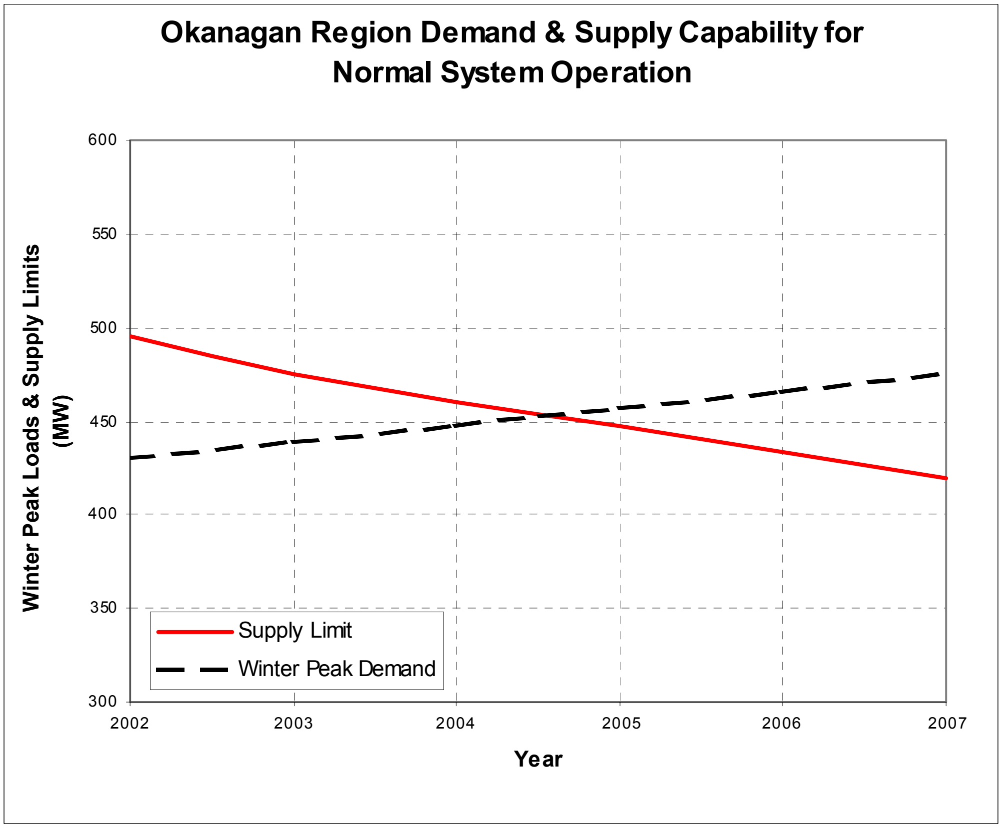
Maximum Supply Limits (MW)
Table 5.1

Supply	2002	2003	2004	2005	2006	2007
11L	120	120	120	120	120	120
Vernon	320	300	285	272	257*	245*
Princeton	55	55	55	55	55	55

* Assumed based on the descending pattern.

The combined supply capability into the entire Okanagan area is a function of capabilities, load conditions and critical contingencies throughout the entire area, however, a simple sum of the supply capabilities might be compared with the Okanagan area load forecast. The comparison shown in Figure 5.1 calls upon a capacity increase solution for the area since it would be difficult to meet the Okanagan area demand beyond 2004.

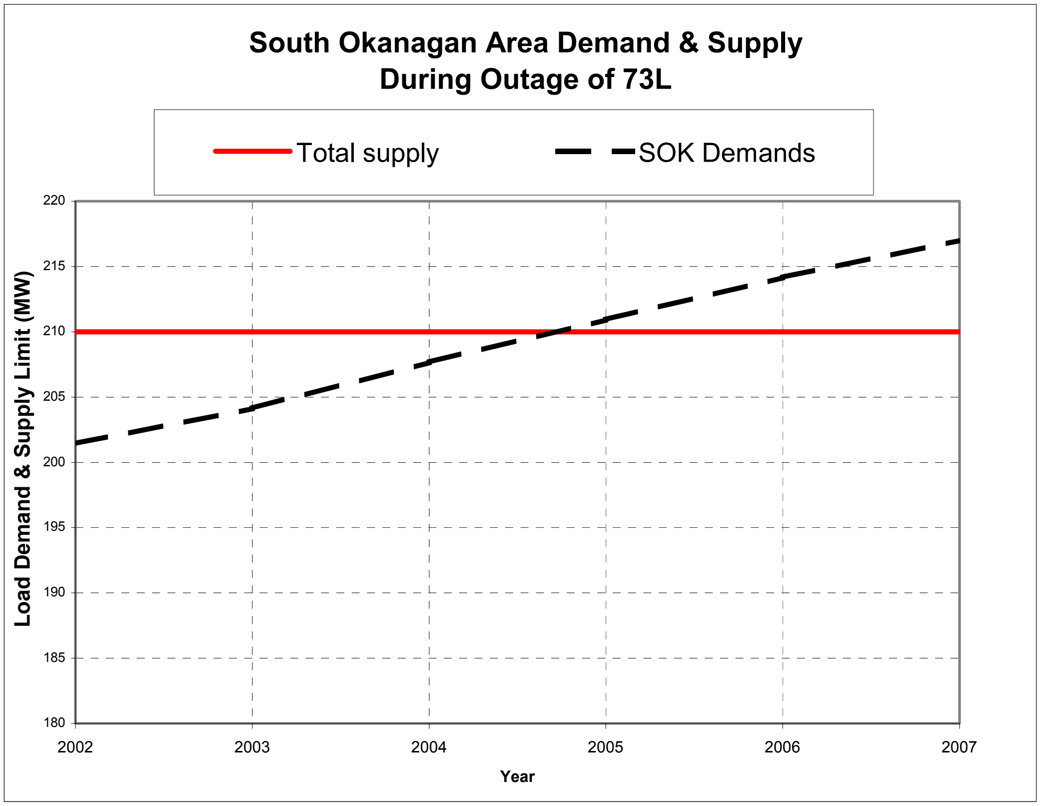
Okanagan Area Demand Vs Supply Capability
Figure 5.1



The supply capabilities shown in Figure 5.1 relate to normal system operating conditions with all elements in service. During the single-element contingency situations, the Vernon supply limit is no longer applicable. The most critical contingency on Aquila facilities is the loss of the 230-kV circuit 73L between Kelowna and Penticton. Upon loss of this circuit, Aquila is left with only 11L from Trail and the 56L/43L connection to BC Hydro's Nicola station. With reconfiguration of the system to carry more loads on 56L/43L, it is possible to pick up some of the Penticton load normally supplied from BC Hydro via 73L at peak.

However, there is a limit to the overall supply capability through the combination of 11L (130 MW under emergency) and 56L/43L (80 MW under emergency), and loads in the Southern Okanagan will grow to exceed this limit (210 MW) as illustrated in Figure 5.2 below:

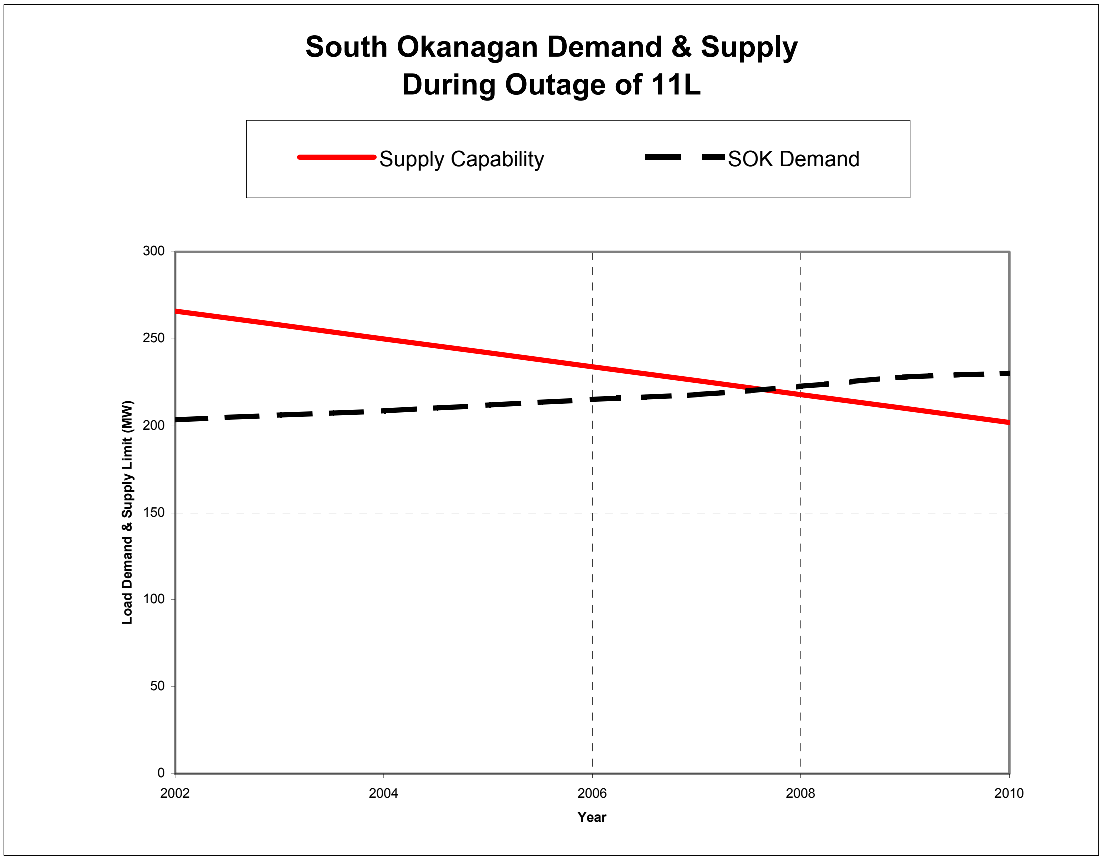
Southern Okanagan Demand Supply for 73L Outage
Figure 5.2



As shown, the area load growth (after the loss of 73L) exceeds the supply capability during the period 2004-2005, demanding a reinforcement solution of the area.

The other severe single-element contingency is the loss of the 161-kV circuit 11L from Trail to Oliver. With this circuit out of service, Aquila is left with only the 73L circuit and the 56L/43L combination to serve Southern Okanagan loads. This is a relatively stronger combination of supply points than that of 11L-56/43L combinations, and can support up to 220 MW of load. The Southern Okanagan load growth in comparison to this limit is shown in Figure 5.3 below. As may be observed from Figure 5.3, the 220 MW supply limit can serve the load until 2007-2008; thereafter some reinforcement solution would be needed.

Southern Okanagan Demand Supply for 11L Outage
Figure 5.3



In view of the above, the bulk supply system into the Okanagan will be incapable of meeting the following conditions within the next six years:

Okanagan Supply Constraints
Table 5.2

Condition	Year	Impact
Peak load under normal operating conditions (all facilities in service)	2005	Load shedding over peak hours
An outage on 73L between Kelowna and Penticton	2004	Loss of load in the Penticton area
An outage on 11L between Trail and Oliver	2008	Loss of load in the Penticton area

Simply put, there are not enough facilities in the Okanagan supply system to meet the criteria of N-0 and N-1 reliability regimes in the near future. Presently, the major transmission system is operated in a radial fashion, giving rise to a less reliable supply system.

5.2 Okanagan Reinforcement Options

Prior studies have considered four portfolios of investment projects to solve all future supply deficiencies in the Okanagan area. These portfolios include option 1 (O1 Option), featuring a 500/230/161-kV Terminal Station in the Oliver area; option 2 (O2 Option), a new 230-kV line from Ashton Creek to Penticton; option 3 (O3 Option), a new 230-kV line from Warfield to Penticton; and option 4 (O4 Option), a new turbine generating station in the South Okanagan. These four options are briefly described here.

5.2.1 O1 Option: 500/230/161-kV South Okanagan Substation

BC Hydro’s 500-kV line (designated as 5L98) runs from the Selkirk substation in the Kootenay area to the Nicola substation in the Merritt area, and passes over Aquila’s 161-kV line (40L) near Vaseux Lake, north of Oliver. Aquila has long entertained plans to construct a 500/230/161-kV substation tied to this line to supply the Okanagan area. The Master Plan identified the following major components:

- Three 500-kV breakers to form a ring bus configuration on the 500-kV side
- Three 230-kV breakers to form a ring bus configuration on the 230/161-kV side
- One 300 MVA 500/230/161-kV dual winding transformer with On-Load Tap Changer (OLTC) operated at secondary voltage of 161-kV
- Two 1.2-km 161-kV lines looping the existing 40L line into the substation
- Two 230-kV breakers at the Oliver Terminal, one at the Grand Forks Terminal, and one at AS Mawdsley Terminal in Warfield to allow meshed operation of 11L line.
- Remedial Action Scheme facilities to isolate the impact of contingencies in BC Hydro’s 500-kV transmission lines between Selkirk, Nicola, and Ashton Creek.

The final system configuration with South Okanagan 500/230/161-kV substation solution is shown in Figure 5.4

5.2.2 O2 Option: North – South Transmission Reinforcement

With two 230-kV lines from Vernon to Kelowna in service, the North - South Reinforcement option looks at the bulk Okanagan supply from Vernon. With power deliveries from BC Hydro at Vernon constrained by line capacity on the Ashton Creek – Vernon 230-kV circuits and the voltage at BC Hydro's Vernon Terminal Station, the identified solution was the construction of a 230-kV circuit from Ashton Creek to Kelowna. In order to secure supply into Southern Okanagan, a second 230-kV circuit is required between the FA Lee Terminal in Kelowna and RG Anderson Terminal in Penticton.

The North – South Reinforcement option consists of the following transmission facilities:

- A 95-km single circuit 230–kV line using 927 ASC conductor from Ashton Creek to FA Lee
- A 60-km single circuit 230–kV line using 795 ASCR conductor from FA Lee to RG Anderson
- A second 150/168 MVA 230/63-kV transformer at RG Anderson
- Necessary line and transformer terminations at Ashton Creek, FA Lee, and RG Anderson
- Two 230-kV breakers at the Oliver Terminal, one at the Grand Forks Terminal, and one at AS Mawdsley Terminal in Warfield to allow meshed operation of 11L line.

The ultimate system configuration for North – South reinforcement option is presented in Figure 5.5

5.2.3 O3 Option: East – West Transmission Reinforcement

The primary motivation for this option is to avoid high wheeling charges for delivering power to the Okanagan through the BC Hydro transmission facilities. By providing a strong 230-kV supply to the Okanagan, Aquila could substantially curtail the BC Hydro power supply amount at Vernon, and thereby reduce the peak power wheeled to Vernon. In addition, the new 230-kV connections between Aquila's two areas would provide a transmission path for the Kootenay generation integration. The East-West transmission line solution would be comprised of the following as identified in the Master Plan:

- A 195-km single circuit 230-kV line using 927 ASC conductor from Waneta to RG Anderson
- One 150/168 MVA 230/63-kV transformer at RG Anderson
- Necessary line and transformer terminations at Waneta and RG Anderson.
- Two 230-kV breakers at the Oliver Terminal, one at the Grand Forks Terminal, and one at AS Mawdsley Terminal in Warfield to allow meshed operation of 11L line.

The eventual system configuration under this option is shown in Figure 5.6

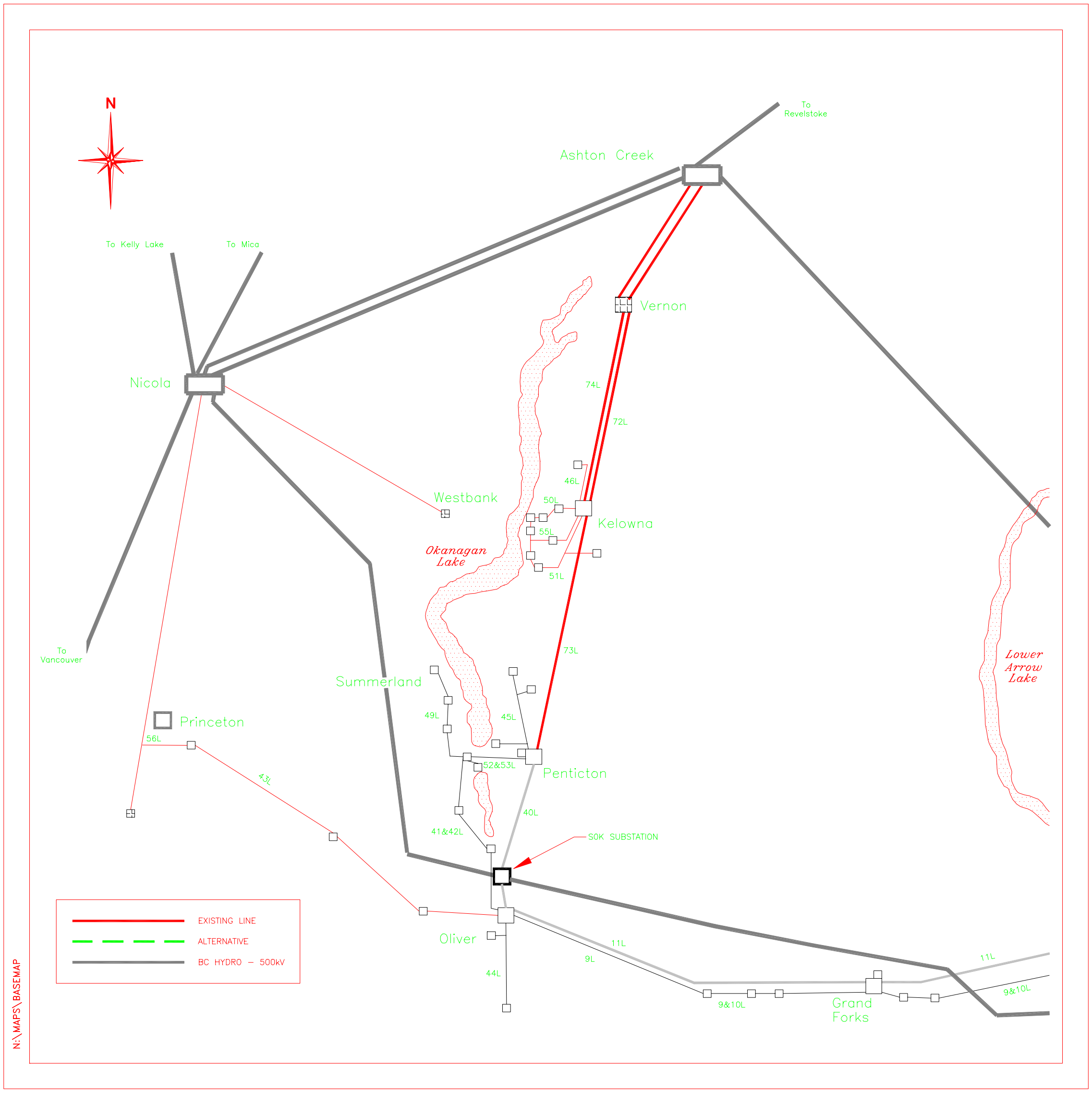
5.2.4 O4 Option: South Okanagan Generation Supply

A resource option was considered as a means of delaying the capital cost of major transmission projects. With some generation capacity located in Southern Okanagan area, the system peak loading could be reduced below the existing transmission capacity into the area. Two different sizes of the Gas Combustion Turbines (GCT) were considered for economic concerns: a 25 MW unit and a 40 MW unit. The basic requirement for this option is the installation of the GCT, the gas pipeline, and the necessary switchyard for the connection of the generator (s) into the system.

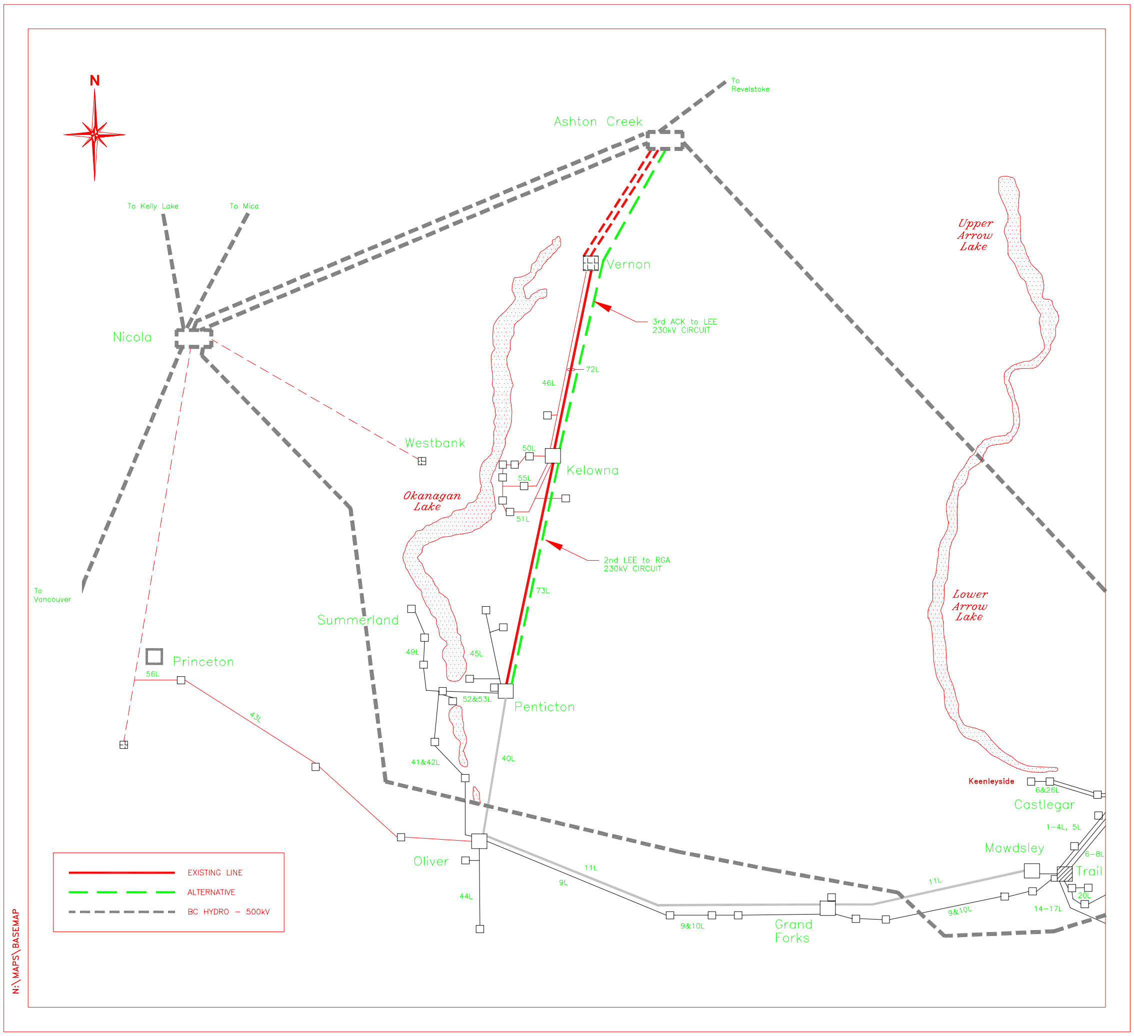
5.3 Selected Reinforcement Options

The four reinforcement options for Okanagan supply system were previously studied in detail and compared for their technical viability and economic merits. More recently, O1 and O3, with some modifications, were retained as the major reinforcement alternatives for further technical and economic comparisons. Accordingly, only these two solutions will be discussed in the following chapters.

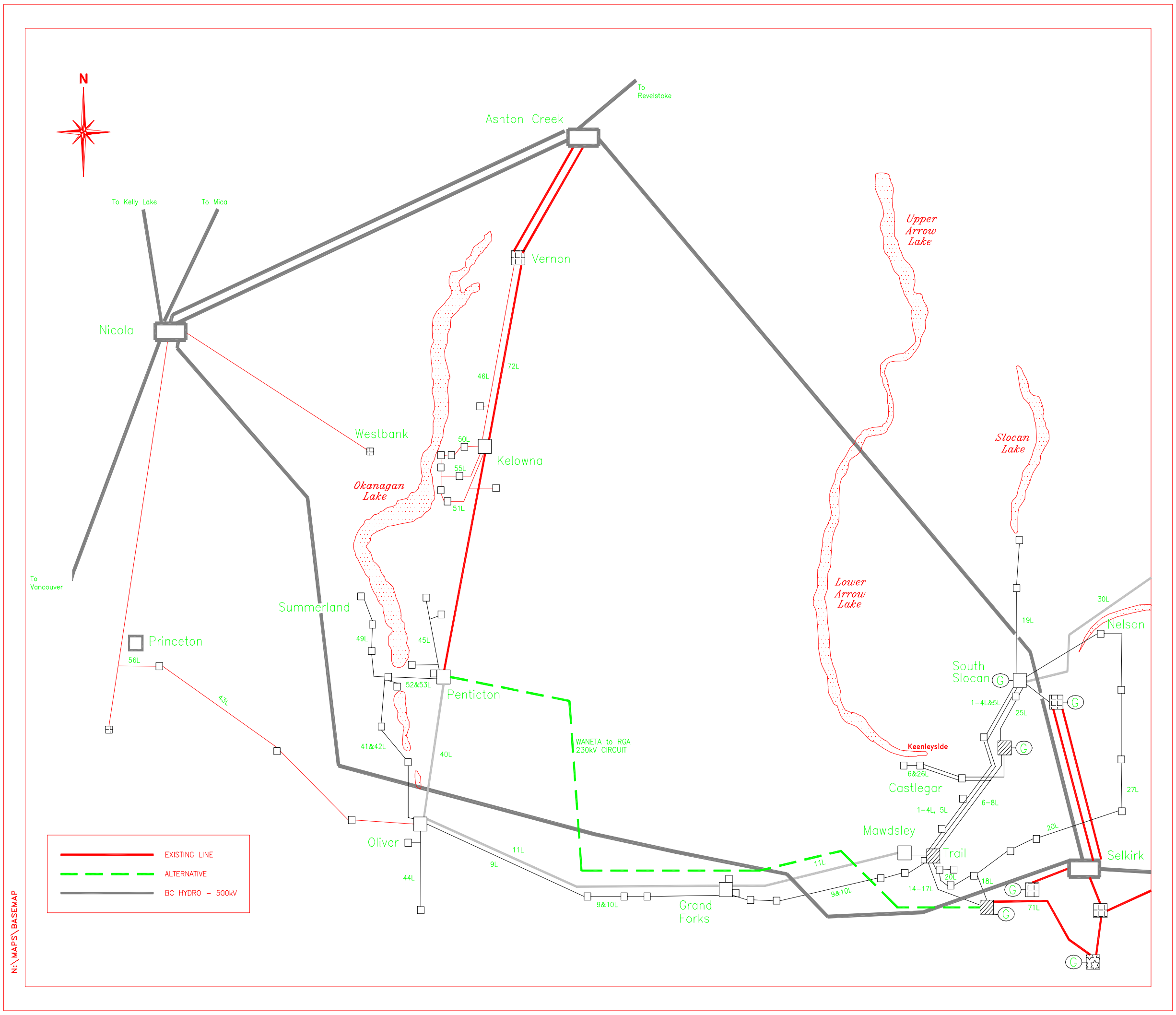
South Okanagan 500/230-kV Substation Option (O1 Option)
Figure 5.4



North –South Transmission Reinforcement Option (O2 Option)
Figure 5.5



East – West Transmission Reinforcement Option (O3 Option)
Figure 5.6



6 Feasibility Review of Reinforcement Options

In conforming to Aquila planning criteria and the base analysis presented in the previous chapter, the in-service date for South Okanagan system reinforcement is established as December 2004. However, in view of the short lead-time for the implementation of any South Okanagan solution, it is necessary to opt for some temporary solution in order to defer the in-service date for one winter peak season. Accordingly, this chapter starts with the review of some project deferral opportunities. Further, it discusses a modified version of the two selected reinforcement options and presents an outline of their functional specifications. It concludes with a comparison of the two options in terms of their capital cost expenditures, transmission system losses, power and energy wheeling requirements and reliability impacts.

6.1 Opportunities for Project Deferral

There are a number of options that could be employed to achieve the desired goal of staving off one or two years of load growth of about 8 to 10 MW. First, the implementation of a traditional Demand Side Management (DSM) load control program may be looked at. Second, an operational measure may be taken to reduce the load by 2-3% by depressing the system voltage about 5% from its nominal value during system peak conditions. There are supply side options but those are considered to be uneconomical due to the short duration of service requirement.

6.1.1 Demand Side Management

The first two initiatives identified below are traditional DSM load control programs; the third item is a more recent DSM approach to reduce the demand in peak periods, and the last two are supply side options.

1. Domestic Hot Water (DHW) tank controls: There are about 15,000 residential Aquila customers in Oliver and Penticton areas. Nearly two-thirds of these customers have electric hot water tanks (equals approximately 10,000 tanks), with a diversified load of ~1 kW that equals 10 MW of shiftable load.

2. Electric Thermal Storage (ETS) Heaters: These heaters can be controlled, with or without employing Time of Use rates. Potential is the same residential pool, of which one third have electric space heating, conservatively 25% would participate,

i.e. 1250 ETS installations @ 5 kW, equaling 6.25 MW of shiftable load. Aggressively we could aim for 50% of the electric heat market, which would yield ~10+ MW.

3. A General Service Load Response program: This would target large commercial and industrial customers. Such a program involves a mix of economics with one-on-one technical marketing to assist customers in identifying droppable loads during peak demand periods. According to an E-source survey, at a price point of 10 times the tariff energy rate, customers are willing to shed 10% of their load. Assuming ~1/2 of the South Okanagan load is General Service, this would yield 10 MW.

4. General Service backup generators: This would involve taking an inventory of customer-owned generators, determining their availability, ways to dispatch, payment required to operate, etc. Synchronizing controls would be necessary in many cases, as backup generators are often not equipped to run in parallel with the grid. Also, depending on anticipated operating hours and emissions, a dual fuel conversion might be necessary, i.e. to run on natural gas in lieu of diesel.

5. Skid mounted diesel generators: Aquila would lease and operate as need be, perhaps adjacent to the existing substations. This is not necessarily a DSM solution, but obviously a short-term measure that may be considered.

Before fleshing out any of the above-mentioned DSM alternatives, it would help to further define the necessary load reduction, i.e. timing and frequency thereof. Obviously the solution to a 2-hour load shift x 10 occurrences over the course of a winter would be a lot different than achieving a six hour (4 - 10 pm) load shift, Mon-Fri from Nov 1st - Mar 1st inclusive. From a system control perspective, there would be an ongoing advantage to having an ~10 MW load reduction "switch" that could be employed to reduce power purchase costs.

Preliminary Cost Estimates

The costing of the various alternatives, or combination thereof, will require considerable time and effort. A conceptual estimate to implement option 1 or 2 would be in the order of $2 to $4 million. Options 3 or 4 would involve much less capital cost, but considerable marketing effort (i.e. costs) and some systems costs (i.e. to automatically dispatch the customers' load shedding regime and/or back-up generator). Additionally, the customers would have to be compensated for their load interruptions or generator operation.

Under option 5, the leasing cost for a 1 MVA generator is ~$240K over a 24 month lease. (N.B. the lease is normally limited to 350 operating hours per annum.) In addition to the lease cost there would be shipping & set-up charges, and operating costs such as fuel and maintenance. That extrapolates to $2+ million if a total of 8 units were ultimately employed.

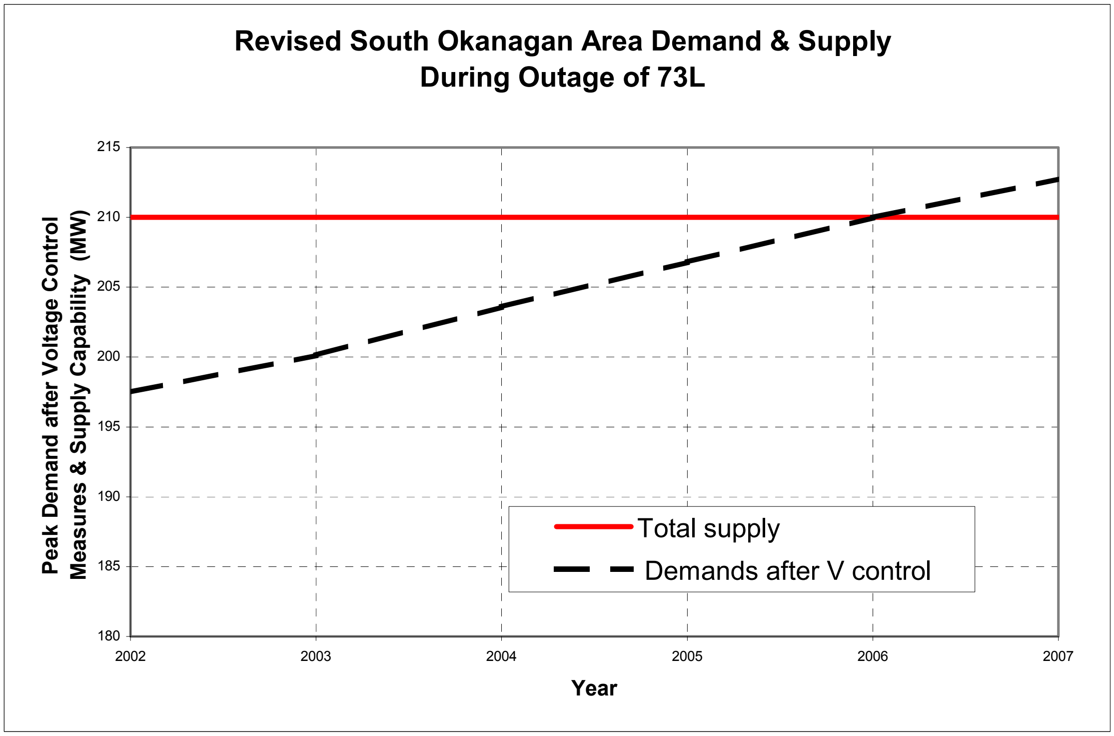
In summary, DSM solutions involve expenditures in the range of $2 million to $4 million dollars in order to reduce South Okanagan demand by 8 to 10 MW and may therefore be considered an expensive alternative.

6.1.2 Temporary Voltage Control Measures

Typically, a 5% reduction in voltage is expected to decrease the demand by 2-3% of the area for which voltage is being controlled. As a temporary operational measure, voltage in South Okanagan area may be reduced during the winter 2004 peak load conditions in order to reduce the demand in that area. Consequently, the demand in the South Okanagan area may be met during the winter peak load conditions of 2004, should the critical 73L contingency occur near system-peak demand.

Incidentally, some voltage control equipment is already installed in the South Okanagan area, and is continually being augmented. After all control equipment is in place, the area demand can be reduced by 4-5 MW during the peak conditions of winter 2004 and 2005. In view of that, the revised demand and supply capability comparison is shown in Figure 6.1.

Revised South Okanagan Demand Vs Supply Capability (73L Outage)
Figure 6.1



6.2 Functional Specifications of South Okanagan Reinforcement Options

Prior studies have considered two portfolios of investment projects to solve all future supply deficiencies in the Okanagan area. These portfolios include the O1 project portfolio, featuring a 500/230/161-kV substation in the Oliver area, and the O3 project portfolio, featuring a new 230-kV line from Warfield to Penticton. The functional specifications of the required facilities with respect to each option are described in the following sections.

6.2.1 O1 Option: 500-kV South Okanagan Substation

As indicated in the previous chapter, a 500-kV line (designated as 5L98) owned by BC Hydro, runs from the Selkirk substation in the Kootenay area to the Nicola substation in the Merritt area. This 500-kV line passes over Aquila's 161-kV line (40L) near Vaseux Lake, north of Oliver. Aquila has long entertained plans to construct a 500/230-kV substation tied to this line to supply the Okanagan area. Initially, the substation will operate at 500/161-kV voltage levels. Although the complete solution consists of a two-stage development, most facilities would be required in 2005. The second stage development would be required around 2012, whereas the actual in service date of additional facilities would depend on load growth in the area.

The facility requirements for the O1 Option have been modified to include the two 250 MVA transformers instead of one 300 MVA transformer as originally proposed in the Master Plan studies. This change is mainly to enhance the overall reliability of the Okanagan supply network in the early years and to avoid supply capability problems in later years in case of long-term outage of a single 500/230-kV transformer, say 2015 and beyond.

In 2005, the 500-kV substation solution will comprise the following:

(1) New 500-kV Substation near Oliver

- Three 500-kV breakers to form a ring bus configuration on the 500-kV side
- Two 250 MVA 500/230/161-kV dual winding transformers with On-Load Tap Changer (OLTC)
- Three 230-kV breakers to form a ring bus configuration on the 230/161-kV side.

(2) Upgrade of RG Anderson Terminal

- Enhancement of switching capability for Transformer T2 by improving the associated protection equipment.

(3) Upgrade of Oliver Terminal

- Two 230-kV circuit breakers to form a ring bus configuration along with the associated accessories and protection equipment
- Two short 161-kV lines (about 1.2 km, built to 230-kV standards) looping the existing 40L line into the new 500/230/161-kV substation, allowing power from BC Hydro's 500-kV line to be fed north to Penticton and south to Oliver
- Remedial Action Scheme facilities to isolate the impact of contingency in BC Hydro's 500-kV transmission lines at Selkirk/Nicola/Ashton Creek.

(4) Upgrade of A.S. Mawdsley Terminal Station

- One 230-kV circuit breaker at Mawdsley switchyard for switching of the existing 11L along with protection and station service improvements.

(5) Upgrade of Grand Forks Terminal Station

- One 230-kV circuit breaker at Grand Forks Terminal in parallel with the existing two breakers making a three-switch ring arrangement plus associated protection improvements.

(6) Telecommunication Equipment

- Fiber optic or digital microwave communications will be required with Aquila's System Control Center and with certain BC Hydro protection equipment in order to facilitate simultaneous metering requirements and enable preemptive protection schemes to operate.

After 2012, the RG Anderson transformer T2 is overloaded during normal system operation. This necessitates the conversion of 40L line to 230-kV operation. Consequently, the following additional facilities will be required to meet system reinforcement needs and to enhance the power supply reliability of the Okanagan area.

(7) Reinforcement and upgrading of Oliver substation to 230-kV

- Two 168 MVA transformers: One four winding (230/138/63/13.8-kV) transformer and another two winding (230/161/63-kV) transformer. The two winding transformer will be connected to 11L at 161-kV but a 230-kV connection provision should be kept for future use when the 11L would be upgraded to 230-kV
- Two 138-kV circuit breakers plus associated accessories and protection equipment
- Two 63-kV circuit breakers plus associated accessories and protection equipment.

(8) Upgrading 40L line to 230-kV from 161-kV

- Both sections of 40L are rebuilt and converted to 230-kV
- Protection reinforcement to allow meshed operations of Okanagan supply system.

(9) Upgrade of RG Anderson Terminal

- Two 230-kV circuit breakers to form a ring bus configuration along with the associated protection equipment.

6.2.2 O3 Option: East West 230-kV Transmission Line

The East-West 230-kV line originates from Warfield Terminal Station near Trail and terminates at RG Anderson substation in Penticton providing an additional transmission path between the Kootenay and Okanagan areas. The proposed East-West 230-kV line follows an elevated line route in proximity to BC Hydro's 500-kV circuit, with the exception of a few minor diversions. As in the case of O1 Option, this supply option also consists of the staged development of facilities that are mainly concentrated in 2005 and 2008.

In 2005, the East-West transmission line solution would comprise the following:

(1) 230-kV Transmission Line from Warfield to Penticton

- A 172-km single circuit 230-kV line using Drake conductor from Warfield Terminal Station to RG Anderson Terminal Station. The 230-kV line would be constructed using wooden two-pole (H-frame) structures to provide the necessary clearances and strength. Pole spacing along most of the route would range from 200 to 250 meters.

(2) 230-kV Line Termination at Warfield Terminal Station

- One 230-kV circuit breaker at Warfield for East-West line termination along with the associated accessories.

(3) 230-kV Line Termination at R.G. Anderson Terminal Station in Penticton

- Terminal upgrade of RG Anderson to 230-kV by adding two 230-kV circuit breakers along with the associated protection equipment.

(4) Terminal Upgrade at A.S. Mawdsley Terminal Station

- One 230-kV circuit breaker at Mawdsley for switching of the existing 11L line along with protection and station service improvements.

(5) Terminal Upgrade at Grand Forks Terminal Station

- One 230-kV circuit breaker at Grand Forks Terminal in parallel with the existing two breakers making a three-switch ring arrangement, plus associated protection improvements.

(6) Terminal Upgrade at Oliver Terminal Station

- Two 230-kV circuit breakers and busbar construction to create a four-switch ring arrangement plus associated protection improvements.

(7) Telecommunication Equipment

- Fiber optic or digital microwave communications will be required with Aquila's System Control Center and with certain BC Hydro protection equipment in order to facilitate simultaneous metering requirements and enable preemptive protection schemes to operate.

After an outage of 11L from Mawdsley to Grand Forks, 56L alone cannot supply the Princeton, Oliver and Grand Forks area loads beyond 2008 when 9L and 10L line sections between Cascade and Christina Lake will be dismantled, as these lines are very old and require heavy capital expenditures for their maintenance. This configuration requires that 40L is open from the RG Anderson end until the next stage of development. Failing to meet the N-1 criteria dictates the upgrading of 40L to 230-kV along with the Oliver terminal reinforcement in 2008. The functional specifications of the required facilities are given below:

(8) Reinforcement and upgrading of Oliver substation to 230-kV

- Two 168 MVA transformers: One four winding (230/138/63/13.8-kV) transformer and another two winding (230/161/63-kV) transformer. The two winding transformer will be connected to 11L at 161-kV but a 230-kV connection provision should be kept for future use when the 11L would be upgraded to 230-kV
- Two 138-kV circuit breakers plus associated accessories and protection equipment
- Two 63-kV circuit breakers plus associated accessories and protection equipment.

(9) Upgrading of 40L line from 161-kV to 230-kV

- Both sections of 40L line rebuilt and converted to 230-kV
- Protection reinforcement to allow meshed operations of Okanagan supply system.

6.3 Capital Cost Estimates

The total investment costs for the development of each portfolio (O1 and O3) are shown in Table 6.1, specifying the transmission facilities required in 2005, 2008 and beyond. The table not only includes the development costs related to a particular option but also covers the investment needed to improve the operation and maintenance of the system.

Project Cost Estimates
($1,000, Year 2002 Dollars)
Table 6.1

	Project Capital	
	Option O1	**Option O3**
2005 - Substation (in service)		
South Okanagan 500/230-kV Substation		
500-kV Portion	18,871	-
230/161 kV Portion	22,830	-
Land Cost	800	-
Total for SOK Substation	***42,501***	-
Remedial Action Schemes (40L)	1,000	-
RGA Upgrade	500	5,172
Warfield Expansion	-	1,800
Grand Forks Modification	4,135	4,135
Mawdsley Terminal Upgrade	2,622	2,622
Oliver Terminal Upgrade	3,751	3,751
Nicola Protection Upgrade	250	250
Telecomunication Equipment	5,000	5,000
Sub-total	***17,258***	***22,730***
2005 - Transmission Line		
Warfield to RGA 230 kV	-	51,796
40L to 500-kV substation	962	-
Total for Year 2005	***60,721***	***74,526***
2008 - Substation		
Oliver Expansion with addl Xfmers	-	8,306
RGA 230 kV Upgrade breaker	-	2,025
Sub-total	-	***10,331***
2008 - Transmission Line		
Line 40 Rebuild (75% of new)	-	5,824
Total for Year 2008	***0***	***16,155***
2012 - Substation		
Oliver Expansion with addl Xfmers	8,306	-
RGA 230 kV Upgrade breaker	4,672	-
Sub-total	***12,978***	***0***
2012 - Transmission Line		
Line 40 Rebuild (75% of new)	5,824	
Total for Year 2012	***18,802***	***0***
2013 - Substation		
2x100 MVAr SVC's at GFT and RGA	-	17,188
Line 11 Upgrade to 230-kV (75% of new)	-	21,212
Total for Year 2013	***0***	**38,400**
Total Project Capital	**79,523**	**129,081**
Discounted value at 10%	**54,392**	**78,571**

6.4 System Impact Analysis

The system performance analysis was carried out by simulating winter-peak and summer-peak load conditions in the following study years, as identified and described in Section 3.1.1:

- 2005 (Do Nothing scenario)
- 2005 (First stage of development of Okanagan supply solutions)
- 2006(First stage of development of Okanagan supply solutions and Brilliant Generation Expansion)
- 2009 (Second stage of development of Okanagan supply solutions for O3)
- 2010 (Waneta Expansion Generation)
- 2021 (Horizon year with all the planned facilities)

Both reinforcement O1 and O3 options have been simulated for the above mentioned study years and operating conditions (WP and SP) in order to compare the strength and weakness of the respective configuration. The performance of each option is discussed subsequently.

6.4.1 Normal System Operation

All the base case schematic load flow diagrams for normal system operation are given in the Appendix B. Load flow analysis of the simulated options reveals that:

1. Both O1 and O3 options meet the loading and voltage criterion for all the simulated operating conditions.

2. The existing 11L circuit to South Okanagan area is lightly loaded in both the alternative options. This impact is profound in O1 Option since 11L runs parallel to a 500-kV circuit in an integrated network. After the first stage of O3 implementation (during 2005 and 2008), 11L operates in radial fashion to supply the boundary area, as the Oliver substation has not yet been upgraded to 230-kV.

3. During the study horizon, about 160 to 300 MW flow through 500-kV substation, whereas East-West 230-kV line transmits about 160 to 250 MW from the Kootenay to the Okanagan area for the system conditions analyzed.

4. Both options drastically reduce the burden on the Vernon 230-kV supply network and almost eliminate the need for Princeton 138-kV supply through BC Hydro's 56L circuit. The power flow out of Vernon will be in the range of 250 to 300

MVA depending upon the choice of Okanagan supply solution. It may now be ascertained that Aquila would no longer have to rely heavily on the 56L circuit to supply the loads from Keremeos to Princeton areas during normal system operation.

6.4.2 Power Losses

The transmission system losses for Aquila and BC Hydro were calculated from the transmission system facilities in Kootenay and Okanagan areas belonging to the respective owners. It was concluded that after the implementation of either of the two supply solution options (O1 and O3) for the Okanagan area, the overall transmission system losses decrease in comparison to the "Do Nothing" scenario. However, each solution option has a different impact on transmission system losses. The reduction of power losses may not justify a project by itself; however, it may provide an incremental benefit to either of the compared options, making a project more economical.

Hence, for the purpose of economic comparison of the two selected options, the loss variation impacts were observed from the perspective of Aquila's system only as well as from the provincial perspective, i.e., by monitoring transmission losses in the integrated transmission network of British Columbia. Accordingly, the loss variations (MW) were captured for both supply options (O1 and O3) by simulating the peak winter loading conditions of 2005, 2006, 2009, 2010 and 2021.

Tables 6.2 and 6.3 provide the changes in the transmission system losses from the Aquila-only and the provincial grid perspectives respectively. Similarly, Figures 6.2 and 6.3 graphically show these loss variations within the Aquila transmission system only and for the total BC integrated transmission grid, respectively.

It may be observed that from the provincial perspective, the total transmission system losses for the O3 Option are 4.5 to 11 MW higher than that of the O1 Option over the study period. This difference is primarily caused by the difference in transmission system voltage between O1 and O3 (500-kV versus s 230-kV), as Okanagan supply solutions. This loss difference (between both solutions) is even greater from the Aquila perspective, since in the O1 Option, more losses occur on BC Hydro facilities than the O3 Option.

Also, the upgrade of 40L line to 230-kV contributes a great deal in loss savings for O1 Option, as more power directly reaches RG Anderson to supply the Kelowna area and less power will be transmitted on 11L line.

Aquila Transmission Network Loss Variation for O1 and O3 Options
Table 6.2

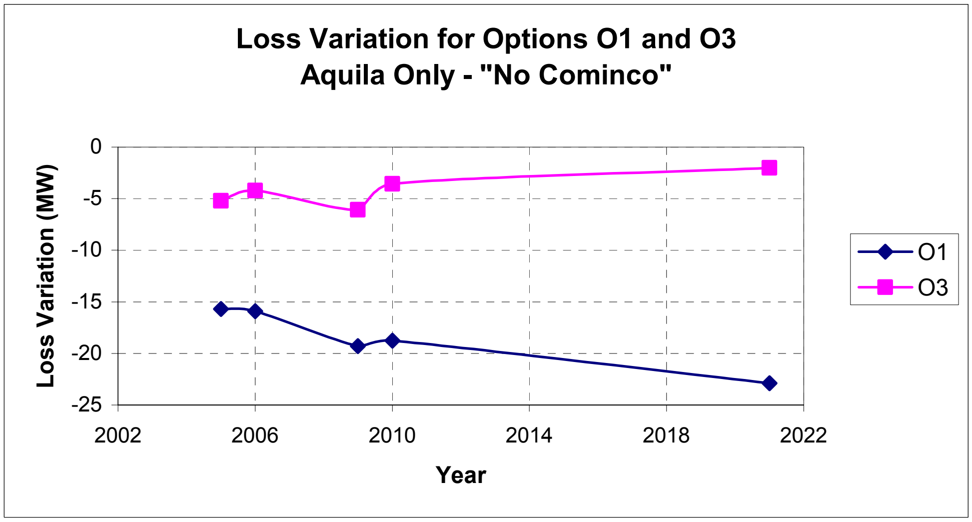
Year	O1 Option (MW)	O3 Option (MW)
2005	-15.69	-5.21
2006	-15.9	-4.22
2009	-19.28	-6.07
2010	-18.78	-3.57
2021	-22.89	-2.02

The negative numbers in the table above and below indicate that there is a reduction of transmission losses after the implementation of either of the supply solutions for Okanagan area.

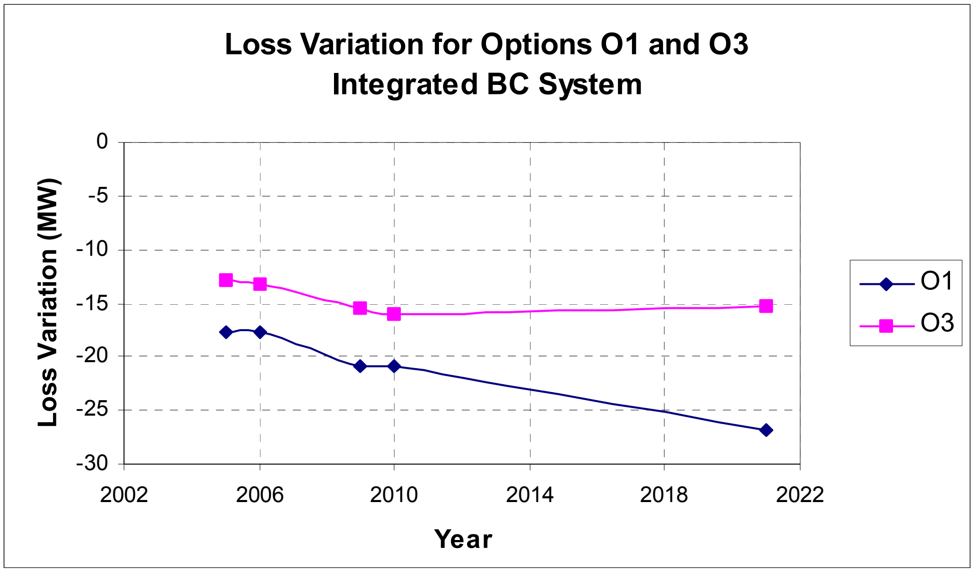
British Columbia Integrated Transmission Grid Loss Variation for O1 and O3 Options
Table 6.3

Year	O1 Option (MW)	O3 Option (MW)
2005	-17.63	-12.77
2006	-17.62	-13.17
2009	-20.78	-15.53
2010	-20.9	-16.01
2021	-26.85	-15.35

Aquila Transmission Network Loss Variation for O1 and O3 Options
Figure 6.2



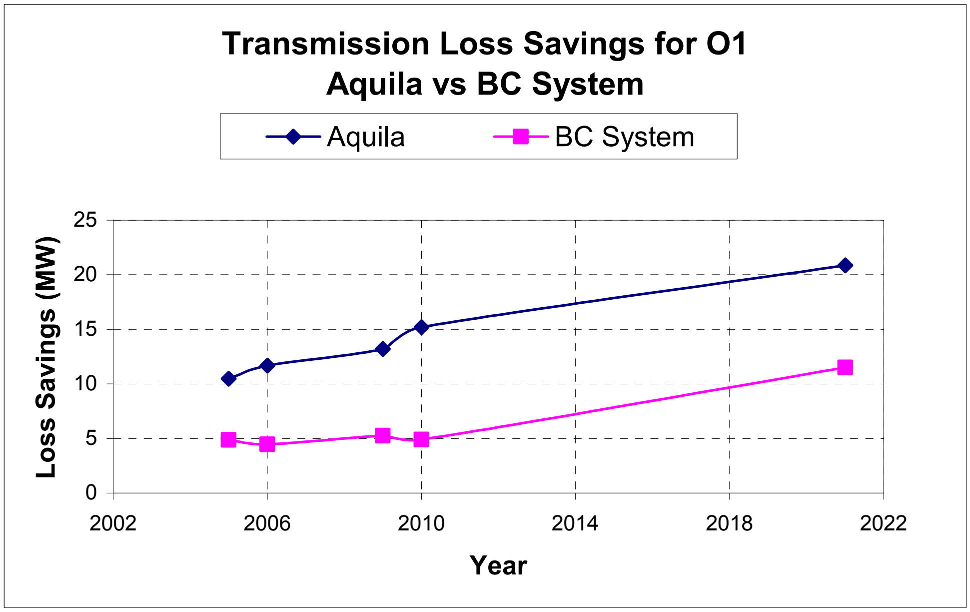
BC Integrated Transmission Network Loss Variation for O1 and O3 Options
Figure 6.3



As may be observed from the above tables and figures, both supply options reduce transmission system losses but the O1 Option renders more loss savings. In addition, the loss benefits of O1 are greater in the Aquila-system only scenario as compared to the total

BC integrated grid perspective. The differential loss benefits (in MW) of O1 Option in comparison to O3 Option are shown in Figure 6.4 below.

Transmission Loss Savings of O1 Option in comparison to O3 Option (O1-O3)
Figure 6.4



6.4.3 Power and Energy Wheeling

The wheeling power estimate is based on power delivery requirements into the Okanagan area under reasonable assumptions regarding the related power purchase forecast, load growth and the accepted rating for Aquila's internal circuit(s) to supply the area. Accordingly, the amount of wheeling power varies depending on the Okanagan supply solution selected.

To establish the maximum power wheeling requirements for the Okanagan area, simulation studies were carried out for the winter-peak and summer-peak load conditions in 2005, 2006, 2009, 2010 and 2021. The power flow values for intermediate years were estimated by interpolation. An Available Transmission Capacity (ATC) approach was utilized to estimate the wheeling power requirements. In this approach, a deemed capacity has been assigned to Aquila owned transmission facilities. The maximum wheeling power estimate is calculated by subtracting the power purchase amount and the accepted deemed capacity of Aquila facilities from the actual power delivery to the Okanagan area via all transmission facilities. The power purchase amount has been assumed to be 200 MW between 2005 and 2013 and 0 MW afterwards. The deemed capacity for the O1 Option is 120 MW. The O3 Option will have a deemed capacity of 350 MW between 2005 and 2013 and 600 MW beyond 2013 with additional facility investments. The difference between the actual power flow on the Aquila transmission facilities and the respective deemed capacity of those facilities has been termed as inadvertent flow on the BC Hydro facilities. Loss compensation would be owing to BC Hydro for this inadvertent flow on their facilities. Accordingly, the Tables 6.5 and 6.6 show the estimated power and energy wheeling requirements for O1 and O3 options

Consistent with the prior planning reviews, the above tables re-affirm that although the O1 Option exhibited lower total capital costs, the O1 Option default wheeling rate causes the O3 Option to offer greater benefits to Aquila ratepayers because of opportunities for significant reductions in the wheeling amounts for delivering power to the Okanagan through the BC Hydro transmission facilities. Presently, Aquila wheels about 150 MW from the Kootenay area to the Okanagan area over BC Hydro transmission facilities. At the current general wheeling agreement (GWA) rate, Aquila pays over $3 million per year to BC Hydro. However, the availability of this rate after 2005 is uncertain, and in the worst case, the Aquila ratepayers could be subjected to the full WTS tariff rate. In addition, the wheeling requirement in the Okanagan area will increase with the increase of load over the study horizon. This benefit offered by the O3 Option can be overcome by the use of a lower the default wheeling rate for the O1 Option.

For the purpose of economic comparison of the two alternative reinforcement options (O1 and O3), the relative wheeling change amounts corresponding to winter peak loading conditions will be modeled in the Revenue Requirement Analysis, which is a subject of the CPCN application. As may be observed from Table 6.5, in comparison to O3 Option more power would have to be wheeled for O1 Option. For instance, the wheeling power amount would vary from 136 MW to 198 MW during the 2005 to 2012 period to meet winter peak conditions.

Estimated Wheeling Power Requirements for Options O1 and O3.
Table 6.5

Description	Options	Winter Peak																
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
		MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW	MW
Total Demand Forecast of Okanagan Area	O1 & O3	448	457	467	476	486	496	506	517	527	538	549	561	572	584	596	608	621
Total Input Power Flow To Okanagan Area Including Losses	O1	456	465	475	485	495	506	518	530	542	553	565	577	589	601	613	625	637
	O3	454	463	472	482	492	503	514	526	538	550	561	573	585	596	608	620	631
E-W 230 KV Line Deemed Capacity	O3	230	230	230	230	230	230	230	230	230	300	300	300	300	300	300	300	300
E-W 230 KV Line Actual Flow	O3	159	170	187	189	174	184	186	188	189	191	193	195	196	198	200	202	210
11L Line Deemed Capacity	O1	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
	O3	120	120	120	120	120	120	120	120	120	300	300	300	300	300	300	300	300
11L Line Actual Flow	O1	44	50	49	48	48	54	54	54	54	54	54	54	54	54	55	55	55
	O3	70	73	78	80	75	79	80	81	82	84	85	86	87	88	89	90	92
Power Purchase at Okanagan	O1 & O3	200	200	200	200	200	200	200	200	200	0	0	0	0	0	0	0	0
Inadvertant Flow	O1	76	71	71	72	72	66	66	66	66	66	66	66	66	66	66	65	65
	O3	121	107	85	81	101	86	84	81	78	145	142	140	137	134	131	128	119
Power Wheeling to Okanagan	O1	136	145	155	165	175	186	198	210	222	433	445	457	469	481	493	505	517
	O3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	20	31
Power Wheeling Delta	(O1) - (O3)	136	145	155	165	175	186	198	210	222	433	445	457	469	481	485	485	485

Estimated Energy Wheeling Requirements for Options O1 and O3.
Table 6.6

Description	Options	Winter Peak																
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Energy Demand Forecast of Okanagan Area	O1 & O3	2204	2244	2296	2347	2399	2450	2502	2555	2610	2666	2722	2780	2841	2901	2963	3026	3091
Total Energy Inflow To Okanagan Area	O1	2230	2271	2324	2377	2429	2483	2540	2598	2657	2716	2776	2835	2897	2958	3018	3080	3143
	O3	2223	2262	2315	2367	2419	2472	2529	2586	2644	2703	2762	2821	2882	2942	3003	3064	3126
Total Power Demand Forecast of Okanagan Area	O1 & O3	448	457	467	476	486	496	506	517	527	538	549	561	572	584	596	608	621
System Load Factor	O1&O3	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
Total non-Wheeled Energy to Okanagan (W = X + Y + Z)	O1	1791	1803	1814	1826	1838	1850	1863	1875	1888	1051	1051	1051	1051	1051	1051	1051	1051
	O3	2223	2262	2315	2367	2419	2472	2529	2586	2644	2543	2574	2605	2637	2669	2701	2734	2767
Transmitted Energy on UNC Facilities (X)	O1	385	434	428	423	417	470	470	471	472	473	474	475	476	477	477	478	479
	O3	970	1050	1175	1224	1162	1260	1307	1355	1405	1997	2042	2088	2135	2183	2232	2282	2383
Purchased Energy (Y)	O1	740	751	763	775	787	799	811	824	837	0	0	0	0	0	0	0	0
	O3	740	751	763	775	787	799	811	824	837	0	0	0	0	0	0	0	0
Inadvertent Energy (Z)	O1	666	618	623	629	634	582	581	580	579	578	577	576	576	575	574	573	572
	O3	513	460	377	369	471	412	410	407	403	1056	1047	1039	1030	1020	1009	998	937
Wheeled Energy to Okanagan	O1	439	468	510	551	591	632	678	723	769	1665	1724	1784	1846	1907	1967	2029	2092
	O3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wheeling Load Factor (info only)	O1	0.37	0.37	0.37	0.38	0.39	0.39	0.39	0.39	0.40	0.44	0.44	0.45	0.45	0.45	0.46	0.46	0.46
	O3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Wheeling Loss Factor (info only)	O1	0.21	0.21	0.21	0.22	0.22	0.22	0.22	0.23	0.23	0.27	0.27	0.27	0.28	0.28	0.28	0.29	0.29
	O3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00
Wheeled Losses O1	GWh	26.57	28.31	30.84	33.34	35.77	38.26	40.99	43.72	46.54	100.7	104.3	107.9	111.7	115.3	119	122.8	126.5
Transmitted MW Losses O1 - O3	MW	-10.48	-11.68	-12.19	-12.7	-13.21	-15.21	-15.72	-16.24	-16.75	-17.27	-17.78	-18.3	-18.81	-19.33	-19.84	-20.36	-20.87
Transmitted GWh Losses O1 - O3	GWh	-34.89	-38.88	-40.58	-42.28	-43.97	-50.63	-52.34	-54.06	-55.77	-57.48	-59.2	-60.91	-62.62	-64.33	-66.05	-67.76	-69.47
Total GWh Losses O1 - O3	GWh	-8.312	-10.57	-9.734	-8.939	-8.201	-12.37	-11.35	-10.33	-9.23	43.25	45.13	47.04	49.04	51.01	52.97	55.01	57.07

6.4.4 Reliability Impacts

The 1998 T&D Master Plan reviewed the reliability impacts of various supply options, and concluded that substantial reliability enhancements would be available with any supply reinforcement. For either the O1 or the O3 Option, customers in the Penticton area would be served by a meshed and fully redundant supply source, rather than the radial supply source that exists today. With the system upgraded, circuits 11L and 40L will cause virtually no customer supply interruptions, leading to a reduction in system-wide SAIFI of 1.28 outages per year (approximately 25%) and SAIDI of 0.05 hours (approximately 2%) per year. This determination is based on the three-year average (1999 – 2001) of total transmission and distribution system outages, including momentary outages.

To the extent that differences exist in the reliability performance of the two options, these differences exist in the relative strength of the two systems under weakened conditions. These differences tend to favor the O3 solution over the O1 solution for N-1 contingency scenarios because of the greater number of 230-kV circuits in the Okanagan and Boundary areas. On the contrary, N-2 contingency scenarios favor the O1 Option over the O3 Option due to less exposure to customer interruptions.

6.4.5 Environmental Impacts

The draft project feasibility study included an overview of environmental assessment of the proposed project components to identify and rate potential environmental and socio-community impacts. Project components that were expected to benefit the environment or communities along the proposed right-of-way were also discussed.

Overall, it is anticipated that the O3 Option, the East-West Reinforcement, would present more significant potential impacts on the environmental and socio-community values. Although much of the new transmission line would be constructed along existing corridors and adjacent to existing transmission rights-of-way, some sections of the new line would be in a new corridor in potentially valuable habitat. This is particularly the case in the south Okanagan between Oliver and Penticton.

Along forested portions of the alignment, tree removal will result in the loss of habitat for forest-dwelling species, and for those species that rely on trees for nesting, denning, foraging and shelter. Proactive re-vegetation and noxious weed control will be particularly important in the environmentally sensitive ponderosa pine/bunchgrass parkland and shrub-steppe habitats on the Osoyoos Indian Reserve, immediately east of Oliver.

Timber removal along one side of the right-of-way and installation of the new line will also result in an incremental increase in visual impacts along the existing corridor and affect visual resources in areas of new corridor. The expanded right-of-way could also affect private property.

From Oliver to Vaseux Lake, the new transmission line would be constructed adjacent to the 40L line alignment, helping to minimize the requirement for new access and potential impacts to sensitive grassland and shrub-steppe vegetation communities. Between Vaseux Creek and Penticton, the proposed corridor diverts away from the 40L line right-of-way to avoid the residential area located east of Skaha Lake. Sensitive areas within the proposed corridor include the Vaseux Protected Area and the Derenzy Bighorn Sheep Habitat Resource Management Zone.

The proposed site of the substation is located in the arid Antelope-brush grasslands, a highly sensitive habitat that occurs in Canada only in the South Okanagan. Nonetheless, construction of the O1 Option, the South Okanagan Substation, would entail somewhat less environmental and socio-community impact than the O3 Option.

7 Further Technical Assessment of Selected Reinforcement Options

7.1 Contingency Analysis

The adequacy and robustness of the alternative reinforcement options (O1 and O3) have been tested and compared by analyzing the impact of single element and double element contingencies on the operation of an Aquila and BC Hydro integrated power network. The analysis is based on planning criteria outlined in Section 3.2.

7.2 N-1 Contingencies

Tables 7.1 and 7.2 provide a summary of study results for all recognized single element contingencies (N-1 operating regimes simulated for Aquila and BC Hydro integrated network) in the vicinity of Aquila's system for O1 Option and O3 Option respectively. The results constitute two operating conditions (WP and SP) and three study years (2006, 2010 and 2021). Primarily, only those areas and transmission lines are studied which have an impact on either or both of the systems and provide meaningful results to the system impact analysis.

The switching configuration at BC Hydro's Vernon 230-kV station is such that it is not capable of sectionalizing a fault that happens on the BC Hydro 230-kV line 2L255 from Ashton Creek to Vernon. When Ashton Creek to Vernon line 2L255 is tripped, the Aquila 230-kV line from Vernon to FA Lee (72L) will be forced out of service, leaving only one circuit for supplying the Aquila load from Ashton Creek to Kelowna. However, the opposite is not true; a fault on Aquila's 72L line does not impact BC Hydro's line.

For winter peak base cases, the N-1 contingency study results indicate that the Aquila system generally meets the planning criteria over the study horizon after either Okanagan reinforcement solution (O1 or O3) is implemented. The exception is a Vaseux Lake Terminal-Nicola 500-kV line outage in the case of O1 Option, which causes overloading of RG Anderson transformer T2. This overloading will be eliminated by the upgrading of 40L to 230-kV.

During summer peak operating conditions, some of the system components get severely overloaded in all study years under the O1 Option configuration solution because power flows get redirected to the underlying meshed transmission system for certain 500-kV system outages. Unmeshing the underlying transmission system, with no loss of load, can eliminate these overloads. In contrast, O3 Option performs relatively better for the same contingencies in terms of system impacts without violating any operating criteria. Specifically, the N-1 contingency impacts with respect to both options are discussed below:

With O1 Solution

For winter peak loading conditions in all study years, the BC Hydro and Aquila integrated transmission network does not experience abnormal load flows during any single element contingencies within the Aquila transmission system. However, RGA 161/63-kV T2 transformer overloads to 112% and 130% during winter peak conditions of 2005 and 2010 respectively, for an outage of the Nicola to Vaseux 500-kV circuit in the BC Hydro network. This overloading problem disappears after the second stage development of O1 Option after 2012 when the 40L line is rebuilt and operates at 230-kV along with Oliver and RG Anderson 230-kV upgrades.

It is anticipated that the RGA transformer can withstand a short duration overload while generation is re-dispatched to reduce the aforementioned abnormal flows to normal values, should such a contingency occur during winter peak operating conditions. No Remedial Action Scheme (RAS) is envisaged for such overloading incidences of short duration during single element contingency events.

In contrast, during summer peak loading conditions in 2006, 2010 and 2021, there are three system elements that undergo abnormal load flows during single element contingency events. The elements with abnormal flows are listed below:

- Kootenay Canal to Selkirk 230-kV Lines
- RG Anderson 161/63-kV T2 and 230/69-kV T1 Transformer
- Mawdsley 161/63-kV T1&T2 Transformers

The single element contingency events that impact the above listed transmission elements are discussed below:

Kootenay Canal to Selkirk 230-kV single circuit outage: BC Hydro's Kootenay Canal to Selkirk 230-kV lines get overloaded (106 – 109 %) for either parallel circuit outage in all the study years. Barring other solutions, operator action to re-dispatch generation would reduce loading on these lines to normal operating range.

Nicola to Vaseux 500-kV line outage: This contingency severely overloads the RGA 161/63-kV T2 transformer. The overloading is 137% in 2006 and 165% in 2010. In an integrated operation with heavy East to West flow, the outage of the Nicola-Vaseux line results in high power flow through the Aquila system. This can be mitigated by opening the underlying meshed system.

Selkirk to Vaseux 500-kV line outage: This contingency causes the steady state solution of the load flow computer model to diverge both in the years 2006 and 2010. At least 50 MW of generation has to be shed in the Kootenay region in order to get the case converged. This outage causes overloading of Mawdsley 161/63-kV transformers to 106% and 126% in 2006 and 2010 respectively. The inherent technical constraint for the O1 solution lies in the fact that strong BC Hydro 500-kV circuits run and operate in parallel with the relatively weak Aquila 161-kV line, which inadequately shares the power transfer from East to West in case of a 500-kV circuit outage. It may be concluded that the outage of the Selkirk to Vaseux 500-kV circuit demands a RAS solution concerning opening up a loop north of RG Anderson or shedding generation in the Kootenay area during 2006 and 2010. This problem does not exist after the upgrading of 40L line to 230-kV.

Selkirk to Ashton Creek 500-kV line outage: This contingency also causes the steady state load flow solution to diverge in all the study years. More than 400 MW of generation has to be shed in the Kootenay area to allow the computer model to converge. This outage also causes overloading of RGA 161/63-kV T2 to 109% and 119% in 2006 and 2010 respectively. As indicated earlier, the overloading problem of RGA T2 is resolved after the upgrading of 40L line to 230-kV.

We understand that RAS schemes are already in place in relation to overloading of the Kootenay Canal - Selkirk double circuit line. However, additional RAS schemes will need to be employed to open the 73L line or to shed generation in Kootenay area for any contingency on 500-kV lines that emanate from Selkirk westward to Vaseux and Nicola. Opening up 73L line would break the loop and return transformer loading to a normal operating range.

Table 7.1 O1 Option: N-1 Contingency Results Unit: Load Flow: MW
Voltage: p.u.

Season	Contingency	2006	2010	2021 (40L upgraded to 230-kV)
Winter Peak	BTS-WTS 230-kV	OK	OK	OK
	MAWDSLY-GFT 161-kV (11E)	OK	OK	OK
	ACK-VNT-LEE 230-kV	OK	OK	OK
	BTS-SEL 230-kV	OK	OK	OK
	VAS-SEL 500-kV	OK	OK	OK
	NIC-VAS 500-kV	Overloading on: RGA T2=112%	Overloading on: RGA T2=130%	OK
	ACK-SEL 500-kV	OK	OK	OK
Summer Peak	BTS-WTS 230-kV	OK	OK	OK
	ACK-VNT-LEE 230-kV	OK	OK	OK
	BTS-SEL 230-kV	OK	OK	OK
	KCL-SEL 230-kV	Overloading on: Other KCL-SEL 230-kV =109%	Overloading on: Other KCL-SEL 230-kV =108%	Overloading on: Other KCL-SEL 230-kV =106%
	NIC-VAS 500-kV	Overloading on: RGA T2=137%	Overloading on: RGA T1=106% RGA T2 =165%	OK
	VAS-SEL 500-kV	Gen Shedding of 50 MW, Overloading on: ASM T1/T2=106%	Gen Shedding of 50 MW, Overloading on: ASM T1/T2=126%	OK
	SEL-ACK 500-kV	Gen Shedding of 200 MW. Overloading on: RGA T2=109%	Gen Shedding of 400 MW Overloading on: RGA T2= 119%	Gen Shedding of 50 MW

With O3 Solution

The summary results of N-1 contingency analysis are presented in Table 7.2. For both operating conditions in 2006, no violation of the operating criteria was observed during any single element contingency in either the Aquila and BC Hydro systems if the East-West 230-kV Line is built to supply the Okanagan region. However, some of the single element contingencies pose problems in 2010 for both operating conditions (WP and SP) before upgrading 40L line and associated terminal stations to 230-kV operation.

During winter peak conditions of 2010, RGA 163/63-kV T2 overloads and the voltage in the Penticton region falls below 0.90 p.u for a contingency of 11L line section between Mawdsley and Grand Forks Terminal. In summer peak operating conditions of 2010, 500-kV line *(Nicola to Selkirk and Selkirk to Ashton Creek)* contingencies in the BC Hydro system cause the load flow to diverge. After shedding from 50 to 300 MW of generation in the Kootenay area, these N-1 load flow cases converge. No operating criteria violation occurs for an outage of Nicola to Selkirk line and all the transmission facilities operate within their respective capabilities. However for an outage of the Selkirk to Ashton Creek 500-kV line, voltages in the Penticton and Princeton areas fall below 0.90 p.u.

After upgrading 40L line to 230-kV operation, no operating criteria violations occur for any N-1 contingency in the system.

It may be concluded that the severities of the single element contingencies in the integrated transmission system are relatively moderate in the O3 Option in comparison to the O1 Option.

Table 7-2 O3 Option: N-1 Contingency Results Unit: Load Flow: MW

Voltage: p.u.

Season	**Contingency**	**2006**	**2010**	**2021 (40L upgraded to 230-kV)**
Winter Peak	East-West 230-kV Line	OK	OK	OK
	BTS-WTS 230-kV	OK	OK	OK
	MAWDSLY-GFT 161-kV (11E)	OK	Overloading: RGA T1=112% 63-kV Penticton Buses=0.89p.u	OK
	ACK-VNT-LEE 230-kV	OK	OK	OK
	BTS-SEL 230-kV	OK	OK	OK
	NIC-SEL 500-kV	OK	OK	OK
	ACK-SEL 500-kV	OK	OK	OK
Summer Peak	BTS-WTS 230-kV	OK	OK	OK
	BTS-SEL 230-kV	OK	OK	OK
	KCL-SEL 230-kV	OK	OK	OK
	NIC-SEL 500-kV	OK	Gen. Shedding of 300 MW	OK
	SEL-ACK 500-kV	Gen. Shedding of 50 MW	Gen. Shedding of 300 MW, Low voltage at: Penticton & Princeton 63-kV Buses=0.88 p.u.	OK

7.3 N-2 Contingency Analysis

In compliance with WECC requirements, N-2 contingencies (restricted mainly to Aquila transmission system) were simulated for winter peak conditions in 2006, 2010 and 2021 with O1 and O3 solution options. The key observations pertaining to each Okanagan supply solution option are listed below.

With O1 Solution

The analysis highlighted two system bottlenecks as was partially identified in the N-1 contingency analysis.

Before upgrading 40L line to 230-kV, the simultaneous outage of the 230-kV double circuit from Vernon to FA Lee or from Ashton Creek to Vernon during winter peak conditions results in the most severe situation that leads to load shedding in the Kelowna area in all study years. However, this impact is alleviated after upgrading 40L line to 230-kV along with the associated terminal stations, namely, RG Anderson and Oliver substations. Also, the VAS 500/230-kV transformer gets overloaded to 125% in year 2021 for an outage of a parallel transformer along with the outage of the 161-kV ASM-GFT 11L line section due to increased demand in Okanagan Region.

It was observed that there are no abnormal load flows during any other N-2 contingencies within the Aquila transmission system.

With O3 Solution

After upgrading 40L line, RG Anderson and Oliver substations to 230-kV in year 2008, six different double-contingency outages (listed below) lead to load shedding in the Okanagan area during winter peak conditions.

- Two BC Hydro 230-kV lines from Ashton Creek to Vernon
- Two 230-kV lines from Vernon to FA Lee
- 161-kV 11L Trail / Grand Fork and 138-kV 56L Nicola / Princeton lines
- East-West 230-kV Trail / Penticton and 73L 230-kV RG Anderson / FA Lee lines
- 230-kV 40L Oliver/Penticton and 161-kV 11L Trail/Grand Fork lines
- 230-kV 77L Brilliant - Warfield and 230-kV 73L RG Anderson - FA Lee.

It may be concluded that the severities of the double contingencies (within the Aquila transmission system) are substantially lower in the O1 Option in comparison to the O3 Option.

7.4 Transient Stability Studies

Transient stability studies have been performed for both operating conditions in 2006 and 2010 in order to appraise the impact of major disturbances in the Aquila and BC Hydro interconnected systems. From a system stability perspective, 2010 may be considered the most stressed case, since all generation upgrades would be completed by then.

The winter-peak and summer-peak load conditions were subjected to three-phase to ground and single phase to ground faults in order to assess system stability under worst-case scenarios. The 500-kV and 230-kV transmission network surrounding the Okanagan area is heavily stressed with high power flows. For instance, during the summer peak, the total power flow on 5L91 and 5L98 transmission lines is 2400 MW and the voltage angle variation from Selkirk to Nicola is about 24 degrees in the O1 configuration.

Tables 7.3 and 7.4 summarize the transient stability performance results for 3-phase to ground and 1-phase to ground faults respectively. Simulation outputs for rotor angle swings and bus voltage plots are attached in Appendix C.

The simulation results indicate that:

1. The BC Hydro 500 kV circuits from Selkirk to Vaseux Lake Terminal Station (VAS), Vaseux to Nicola and Selkirk to Ashton Creek are the most stressed circuits that may cause abnormal load flows in the Aquila system for their outages. A 3-phase to ground fault cleared in 4 cycles was simulated at Selkirk 500-kV and VAS 500-kV buses with the corresponding tripping of Selkirk 500-kV and VAS 500-kV line. It was observed that the Aquila system remains stable.

2. The critical clearing time for 3-phase faults at Brilliant Terminal Station 230 kV bus is 11 cycles, whereas the Aquila system is stable for fault duration of 12 cycles at Warfield, Grand Forks, Oliver, RG Anderson, FA Lee high voltage and low voltage sides.

3. The Aquila system is also stable for 'stuck breaker' conditions, as the system stability must be maintained for 1-phase to ground faults under stuck breaker

situations. The simulations were carried out for 1-phase to ground fault at a specified bus with a delayed clearing of 16 cycles along with tripping of two transmission elements. Incidentally, the total clearing time for a stuck breaker condition in the Aquila 230-kV system translates to 12 cycles. Accordingly, a single-phase to ground fault with a stuck breaker at Brilliant Terminal Station 230-kV bus was simulated and it was observed that the critical clearing time was well above the maximum time taken for backup protection to clear the fault.

In conclusion, the studies revealed no conditions of system instability on either the BC Hydro system or the Aquila system, for the worst-case credible contingencies in either system.

7.5 Summary of Impact Studies

Based on established Aquila planning criteria, the capacities of all system elements are chosen to ensure electrical adequacy with all elements in service, and demonstrated ability to survive all recognized single contingencies without system instability or violation of emergency load or voltage limits (N-1 planning criteria). In the course of the technical studies, facility requirements and equipment capacity requirements have been refined to guarantee conformance with the N-1 criterion, and both the defined planning options meet this test.

The East-West line option, which increases the overall East-West transfer capability of the BC provincial grid, creates a system that is inherently stronger in the face of N-2 contingencies on the BC Hydro 500-kV system. On the other hand, the O3 Option also creates a system in which the worst-case N-2 events produce Aquila system configurations identical to today’s worst-case N-1 contingencies and customer load will be exposed to interruption.

The O1 Option, which features the Vaseux Lake Terminal Station, makes the Aquila system capable of withstanding any two sequential transmission outages within the Aquila system without customer load loss. The added robustness of the Vaseux Lake Terminal Station against “internal” contingencies is secured through greater dependence on the BC Hydro 500-kV system, and the studies have demonstrated that the capacity of the 500-kV system will be sufficient over the course of the 20-year planning horizon.

Table 7.3 Transient Stability Results for 3-Phase to Ground Faults

Option	Season	Disturbance		2006		2010	
		3-Phase Fault Location	Branch Tripped	Fault Duration (Cycles)	System Impact	Fault Duration (Cycles)	System Impact
O1 Option	Summer Peak	1. Bus VAS500	NIC-VAS 500-kV	4	Stable	4	Stable
		2. Bus BTS230	BTS-WTS (77L) 230-kV	12	Unstable	12	Unstable
				11	Stable	11	Stable
		3. Bus VAS161	VAS-RGA (40L) 161-kV	12	Stable	12	Stable
		4. Bus SEL500	SEL-ACK (5L91) 500-kV	4	Stable	4	Stable
		5. Bus SEL500	SEL-VAS (5L98) 500-kV	4	Stable	4	Stable
	Winter Peak	1. Bus VAS500	NIC-VAS 500-kV	4	Stable	4	Stable
		2. Bus BTS230	BTS-WTS (77L) 230-kV	12	Unstable	12	Unstable
				11	Stable	11	Stable
		3. Bus VAS161	VAS-RGA (40L) 161-kV	12	Stable	12	Stable
		4. Bus SEL500	SEL-ACK (5L91) 500-kV	4	Stable	4	Stable
		5. Bus SEL500	SEL-VAS (5L98) 500-kV	4	Stable	4	Stable
O3 Option	Summer Peak	1. Bus WTS230	WTS-RGA 230-kV	12	Stable	12	Stable
		2. Bus BTS230	BTS-WTS (77L) 230-kV	12	Unstable	12	Unstable
				11	Stable	11	Stable
		3. Bus SEL500	SEL-ACK (5L91) 500-kV	4	Stable	4	Stable
		4. Bus SEL500	SEL-NIC (5L98) 500-kV	4	Stable	4	Stable
	Winter Peak	1. Bus WTS230	WTS-RGA 230-kV	12	Stable	12	Stable
		2. Bus BTS230	BTS-WTS (77L) 230-kV	12	Unstable	12	Unstable
				11	Stable	11	Stable
		3. Bus SEL500	SEL-ACK (5L91) 500-kV	4	Stable	4	Stable
		4. Bus SEL500	SEL-VAS (5L98) 500-kV	4	Stable	4	Stable

Table 7.4 Transient Stability Results for 1-Phase to Ground Faults

Option	Season	Disturbance		2006		2010	
		1-Phase Fault Location	Branches Tripped	Fault Duration (Cycles)	System Impact	Fault Duration (Cycles)	System Impact
O1 Option	Summer Peak	1. Bus BTS230	BTS-WTS 230-kV BTS-KCL 230-kV	16	Stable	16	Stable
		2. Bus BTS230	BTS-WTS 230-kV 230/63-kV Brilliant transformer T8	16	Stable	16	Stable
	Winter Peak	1. Bus BTS230	BTS-WTS 230-kV BTS-KCL 230-kV	16	Stable	16	Stable
		2. Bus BTS230	BTS-WTS 230-kV 230/63-kV Brilliant transformer T8	16	Stable	16	Stable
O3 Option	Summer Peak	1. Bus BTS230	BTS-WTS 230-kV BTS-KCL 230-kV	16	Stable	16	Stable
		2. Bus BTS230	BTS-WTS 230-kV 230/63 kV Brilliant transformer T8	16	Stable	16	Stable
	Winter Peak	1. Bus BTS230	BTS-WTS 230-kV BTS-KCL 230-kV	16	Stable	16	Stable
		2. Bus BTS230	BTS-WTS 230-kV 230/63-kV Brilliant transformer T8	16	Stable	16	Stable

British Columbia Transmission
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South Interior Bulk System Development Plan

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British Columbia Transmission Corporation
Transmission System Planning

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Executive Summary

With approximately half of BC Hydro's heritage generation, the South Interior is one of the largest generation regions in British Columbia. The South Interior transmission system delivers energy generated in the South Interior, along with imports from Alberta and the U.S., to the load centres in the Lower Mainland and Vancouver Island, and provides wheeling service for FortisBC from the Kootenay area to the Okanagan area. Transmission system reinforcement is needed to alleviate existing system congestion,[1] provide additional transformer capacity, and, potentially, to increase transfer capacity to accommodate new facilities identified in BC Hydro's 2006 Amended Long-term Acquisition Plan (the "amended LTAP"), increased transfer requirements under the FortisBC General Wheeling Agreement, and increased imports from Alberta.

A major constraint on the South Interior transmission system is transformer capacity at Selkirk Substation. The substation is equipped with one 1200 MVA transformer and two 672 MVA transformers, which are insufficient to meet the present committed use under a transformer outage. To address this situation, BCTC has a Remedial Action Scheme (RAS) in place under which BCTC sheds local generation and trips the BC-US intertie at Nelway in the event of a transformer outage at Selkirk. These restrictions remain in place until the out of service transformer can be repaired.

Installation of a fourth transformer at Selkirk is required as soon as possible to meet the present committed use and eliminate the need for existing generation shedding. Increased transformer capacity will also be required to accommodate generation additions in the area and, potentially, increased FortisBC wheeling requirements and imports from Alberta. Without this reinforcement, the need for generation shedding will continue to increase and BCTC will continue to have to interrupt scheduled intertie flows in the event of a transformer outage. In addition to addressing transformer capacity, a new 1200 MVA transformer at Selkirk will reduce the net reactive power losses in the Selkirk transformers and the impedance between the area generators and the 500 kV grid. This will increase transfer capacity of the West of Selkirk cut-plane by approximately 165 MW and may delay the next capacity upgrade for several years.

The South Interior Bulk System is also currently limited by transfer capacity restrictions on the 5L96/5L98 (Selkirk-Vaseux-Nicola) and 5L91 (Selkirk to Ashton Creek) transmission path (the path is defined as the parallel system of lines between Selkirk and Nicola Substations) moving power west to Nicola.[2] In order to examine the power flows on this path, BCTC defined two cut-planes.[3] One cut-plane intersects 5L91 and 5L96 and is

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[1] Congestion is defined as occurring when the committed use for a cut-plane exceeds the total transfer capacity (TTC) as defined by the minimum limiting condition for that cut-plane. The minimum limiting condition will occur when one system element is out of service (N-1).

[2] Paths are defined as a combination of transmission lines and substations through which power must flow to reach point B from point A. The particular path definition will depend on the context that is being discussed.

[3] Cut-planes define a cross section of the transmission system that power flows across. Cut-planes are used to analyse and identify congested sections of the network.

termed the West of Selkirk cut-plane and the other intersects 5L79/76 and 5L96 and is termed the West of Ashton Creek/Selkirk cut-plane (see Figure 3). During the spring freshet period, committed use[4] on the West of Selkirk cut-plane exceeds its transfer capacity. In 2006, the congestion on this cut-plane increased to around 240 MW due to the need to import a portion of the Downstream Benefit Entitlement (DSBE) on the eastern US intertie. To address the present congestion, BCTC applies a series of generation shedding schemes to prevent a system voltage violation during a single contingency of 5L91, 5L96 or 5L98. The congestion on the Selkirk to Nicola path is expected to increase with the addition of planned generation in the region (Brilliant expansion, Revelstoke Unit 5, IPPs, etc.), higher FortisBC wheeling requirements,[5] and increased imports from Alberta. When the transfer on the West of Selkirk cut-plane is controlled under its transfer limit, there are currently no additional limitations on the West of Ashton Creek/Selkirk cut-plane.

The new transformer at Selkirk, combined with a planned upgrade of the FortisBC system in 2008,[6] will address system requirements until Revelstoke Unit 5 is added to the system in 2010. The potential addition of Revelstoke Unit 5, and increase in FortisBC wheeling requirements under the General Wheeling Agreement (GWA) or addition of IPPs will trigger the need for two new shunt capacitors in Ashton Creek to provide further voltage support and increase transfer capacity. If further generation is added in the South Interior (as is indicated in several scenarios) and/or FortisBC nominates a large amount of wheeling increase from the South Interior to the Okanagan or Alberta imports are increased, series compensation on 5L91 and 5L98 will be required.

If the Interior to Lower Mainland ("ILM") project proceeds, relieving constraints on the ILM path (potentially in 2014), increased power flow on the ILM path will consume more reactive power, reducing the Total Transfer Capacity (TTC) on the South Interior paths. The addition of a new shunt capacitor at Nicola Substation will restore some of this capacity.

The table below summarizes the potential South Interior reinforcements along with the incremental capacity added, cost and potential in-service dates identified in this report.

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[4] Committed use is the present or forecast use of the line for firm commitments. Precise descriptions of various committed use calculations are contained in the South Interior Path Utilization Forecast Report (Appendix 2).

[5] See Appendix 2, p. 13 for details with respect to these estimates.

[6] The FortisBC upgrades are part of the Vaseux 230 kV system upgrade project and include converting Vaseux 161 kV to 230 kV, building 230 kV lines to the R.G. Anderson Substation in Penticton, and installing two 30 MVAr shunt capacitor banks in the Lee and Bell Substations in Kelowna. In addition, the 500/230 kV transformers in Vaseux have on load tap changers to automatically adjust the 230 kV bus voltages to prevent large voltage variations (see Appendix 1).

Proposed Project	**Incremental Capacity addition**	**Total Project Cost**	**Proposed in-service Date**
Selkirk T4 Addition	960 MVA Summer 1100 MVA Winter 165 MW TTC	$17.8M	2008
Two 500 kV 250 MVAr Shunt Capacitors at Ashton Creek	330 MW (after Revelstoke 5)	$11M	2010
Series Compensation on 5L91 and 5L98	331 MW TTC	$51.9M	As early as 2010[7]
500 kV 250 MVAr Shunt Capacitor at Nicola	99 MW (after the ILM constraint is released)	$5M	2014

With the completion of these projects, the South Interior Bulk System will be able to meet the forecast requirements identified. Completion of these reinforcements will increase the transfer capacity of the West of Selkirk cut-plane close to its thermal limit of 2600 MW. Once this limit is reached, new transmission lines (5L97 and 5L99) would be required to accommodate any significant further generation additions or a higher level of imports.

Given current needs and timing requirements, BCTC is recommending that the following projects be including in the Capital Plan:

1. Definition and Implementation funding for a new 1200 MVAR transformer at Selkirk Substation for an in-service date of October 2008. The estimated cost for this project is $17.8 million.
2. Definition Phase funding for two 500 kV 250 MVAR switched shunt capacitor banks at Ashton Creek Substation. Definition Phase to be complete by March 2008. The Definition Phase estimate is $253K.
3. Definition Phase funding for two 2730 Amp nameplate, 50% series compensation stations in 5L91 and 5L98 lines. Definition Phase to be completed by September 2008. The Definition Phase estimate is $1,600K.

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[7] In-service date is dependent on timing of generation additions and/or increased trade commitments.

Table of Contents

1 Introduction

In the British Columbia Utilities Commission's (the "Commission") Decision of September 23, 2005 (G-91-05) on BCTC's F2006 Capital Plan, the Commission directed BCTC to submit a comprehensive System Development Plan for the South Interior Bulk System (the "South Interior System"). Over the past year, BCTC has conducted a number of detailed technical studies on this area including:

- South Interior Cut-plane Reinforcement Justification Report (SPA 2006-117) (Appendix 1)
- South Interior Transmission Path Utilization Forecast (SPA 2006-118) (Appendix 2)
- Selkirk 500/230 kV Transformer T4 Addition Justification (SPA 2006-115) (Appendix 3)

Based on these reports, a South Interior System Development Plan has been developed. Included in this report are:

- An overview of the South Interior System;
- A discussion of the study methodology used in developing the South Interior System Development Plan;
- A description of factors affecting South Interior capacity;
- The existing system capacity and constraints;
- Forecast usage;
- A discussion of reinforcement options; and
- Conclusions and Recommendations.

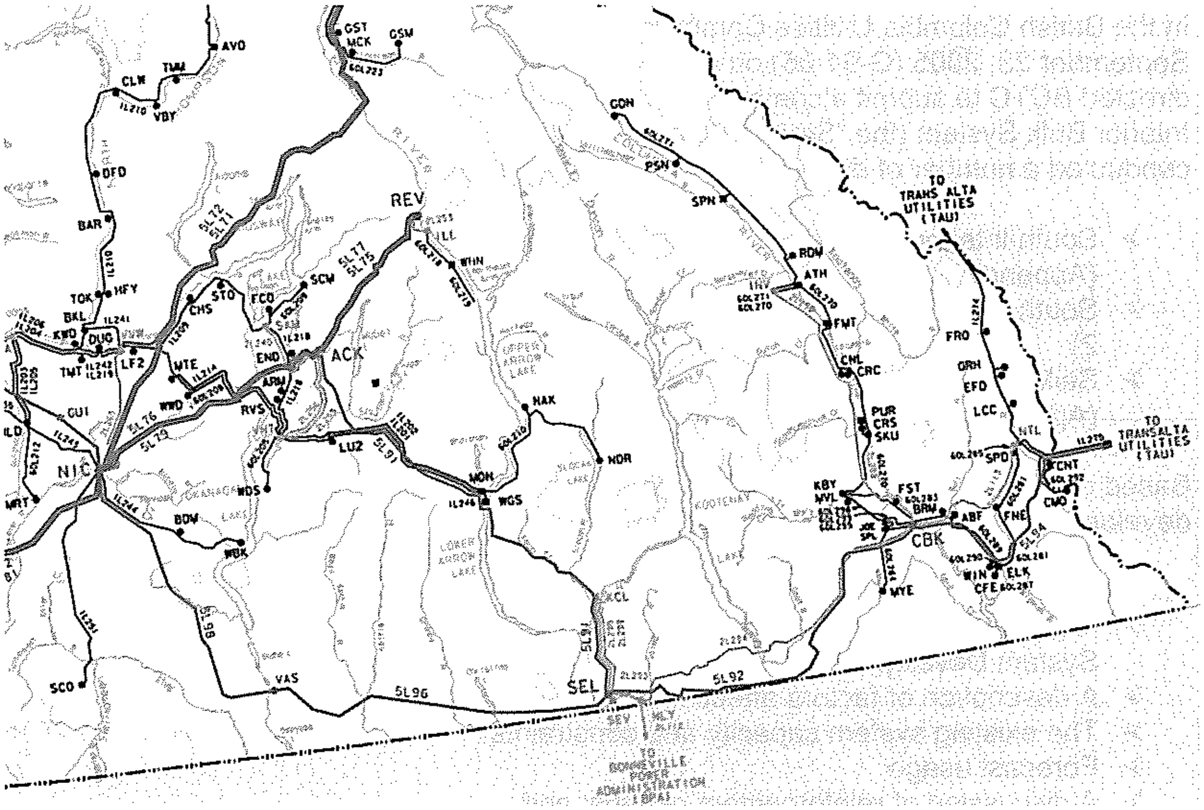
2 Overview of the South Interior Bulk Transmission System

2.1 The South Interior System

For the purposes of BCTC's transmission system planning, BCTC defines the South Interior System as all bulk system elements east of and including a part of the Nicola Substation, near Merritt.

With approximately half of BC Hydro's heritage generation, the South Interior is one of the largest generation regions in British Columbia. A network of 500 kV transmission lines and substations collect and deliver power from the Columbia and Kootenay area generating stations across the south interior, and deliver this power west to the Nicola Substation and east to Alberta, as well as providing power to serve load in the South Interior and wheeling power for FortisBC. The South Interior System is also interconnected with Alberta in the east and Washington State in the south providing system back-up and facilitating electricity trade.

Figure 1 – Map of the South Interior



Two major transmission paths collect electricity from the South Interior and move it west to Nicola, where it connects with the Interior to Lower Mainland (ILM) System. Selkirk Substation, located near Trail, acts as the primary collector station for power from generation located in the southeast corner of the province. Power from Kootenay Canal and Seven Mile generation plants is connected to Selkirk through two 230 kV lines from each plant (2L221 and 2L222 from Seven Mile and 2L295 and 2L299 from Kootenay Canal). This power is converted from 230 kV to 500 kV by three 230/500 kV transformers located at Selkirk. In addition to collecting local generation, Selkirk is the southeast interconnection point between BCTC, FortisBC, Alberta, and the US (through Nelway).

From Selkirk, power travels west over the Selkirk-Vaseux-Nicola (5L96/98) path and over 5L91 to Ashton Creek Substation where it is merged with power from the Revelstoke Generating Station. Power from Ashton Creek is then transferred over two 500 kV lines (5L76/79) to Nicola where it connects to the ILM path.

Power from the Mica Generating Station is carried over two transmission lines (5L71 and 5L72) directly to Nicola.

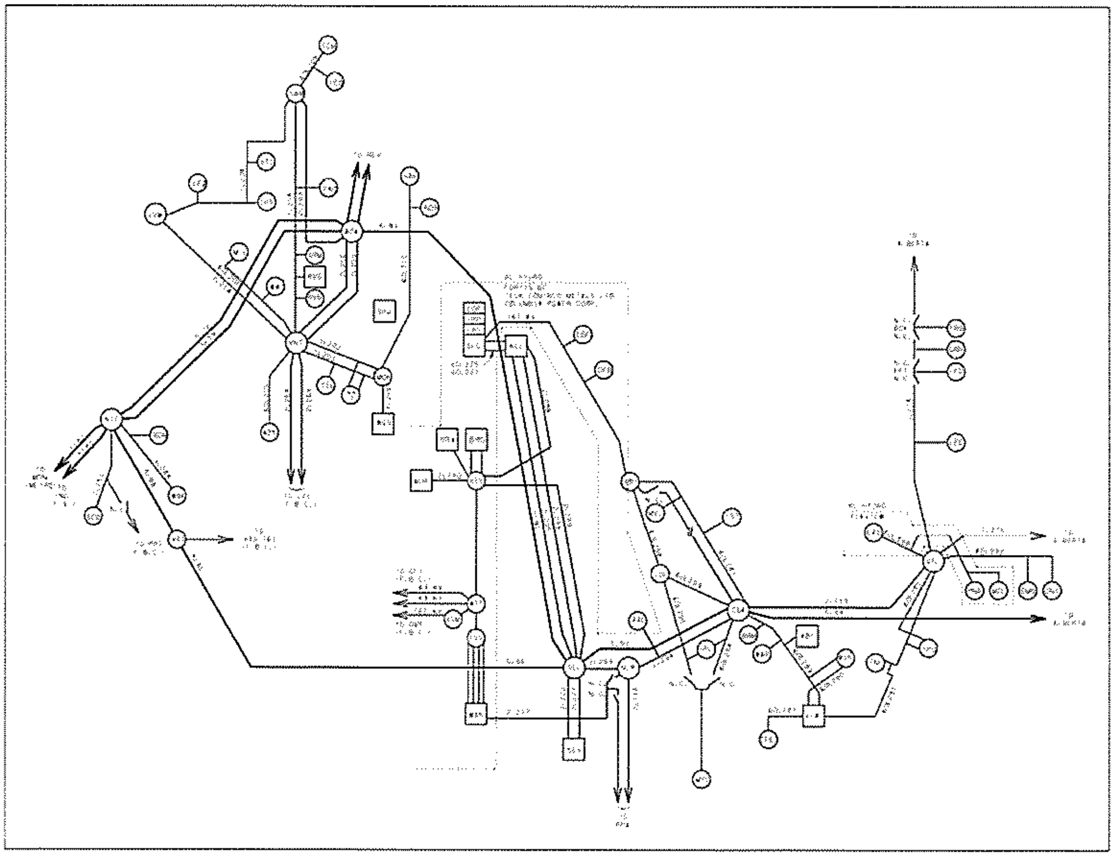
To serve loads in the Cranbrook area and firm exports to Alberta, two 500 kV lines and three 230 kV lines move power from Selkirk east. Circuits 5L92, 2L293, and 2L294 move power from Selkirk to Cranbrook Substation. From there, power is transferred to the Alberta border on 5L94 and to Natal Substation near Sparwood via 2L113 and then over two 138 kV lines to the Alberta border. Imports from Alberta reverse the flow from Alberta to Selkirk on these lines.

2.2 The Interties

The South Interior System is interconnected with the FortisBC system in south-eastern BC, Bonneville Power Authority's (BPA) system in the US and, as indicated, the Alberta Electric System Operator (AESO) in Alberta. As the transmission systems are interconnected, conditions in Alberta and eastern Washington and flows on the Interties can affect the capacity of the South Interior grid.

Figure 2 illustrates the Intertie connections in the South Interior System.

Figure 2 – The Interties in the South Interior System



2.2.1 The BCTC/FortisBC Intertie

The South Interior System and FortisBC's transmission system are connected in both the East Kootenay and Okanagan areas. In the East Kootenays, the two systems are interconnected at Kootenay Canal, Selkirk and Nelway at both the 230 kV and 63 kV level. In the Okanagan, two 230 kV transmission lines (2L263 and 2L264) connect the Vernon Terminal Station to FortisBC's substation in Kelowna. This intertie has the capacity to transfer about 200 MW of power from the transmission system to FortisBC. As described in more detail below, BCTC has a contract with FortisBC to move power over the South Interior System from FortisBC's generating stations in their Kootenay region to their customers in the Okanagan.

In 2005, FortisBC built a new 500 kV substation (Vaseux Lake) along the existing 5L96/5L98 transmission line between Selkirk and Nicola, providing a new intertie between the BCTC and FortisBC systems. This new intertie provides new supply and capacity benefits to the FortisBC service region, and benefits the BCTC system by allowing increased wheeling.

2.2.2 BC – Alberta Intertie

Although the BC to Alberta intertie consists of one 500 kV transmission line and two 138 kV lines, transient stability limitations require that after a 5L94 contingency the two 138 kV ties be tripped, except during low transfer conditions. As a result, the intertie is effectively limited to the capacity of only the 500 kV line at most transfer levels.

The WECC-approved path rating for the BC to Alberta path is 1200 MW. However, this level of transfer would lead to excessive load shedding in Alberta (after the loss of the intertie) and is only allowed under joint agreement between BCTC and the AESO. The normal TTC limit for the BC to Alberta transfers is presently set at 780 MW. The WECC-approved path rating for the Alberta to BC path is 1000 MW. However, there are limitations inside Alberta which restrict power transfers from Alberta to BC.

2.2.3 BC - US Eastern Intertie

Two interties – a 500 kV Westside intertie (5L51/5L52) and a 230 kV Eastside intertie – connect the transmission system with BPA's transmission system in Washington State. The Eastside Intertie includes a 230 kV line (2L112) from the Nelway Substation near Trail to BPA's Boundary Generating Station and a 230 kV transmission line owned by Teck Cominco (2L277/L71) from Waneta (in Trail) to Boundary via Nelway. 2L277/L71 is normally operated connected from Waneta through a tap to Nelway with the remaining section between the tap to Boundary open.

3 Study Methodology

The 2004 NITS Study conducted for BC Hydro identified voltage stability under an N-1 contingency as the dominant limitation for transfer capacity in the South Interior. The NITS Study identified two key congestion points in the South Interior: transformer capacity at Selkirk and transfer capacity west to Nicola. Since the NITS study, BCTC has completed a number of further studies to identify the capability and limitations of the South Interior System under a wide variety of conditions. These studies build on information provided in the NITS Study.

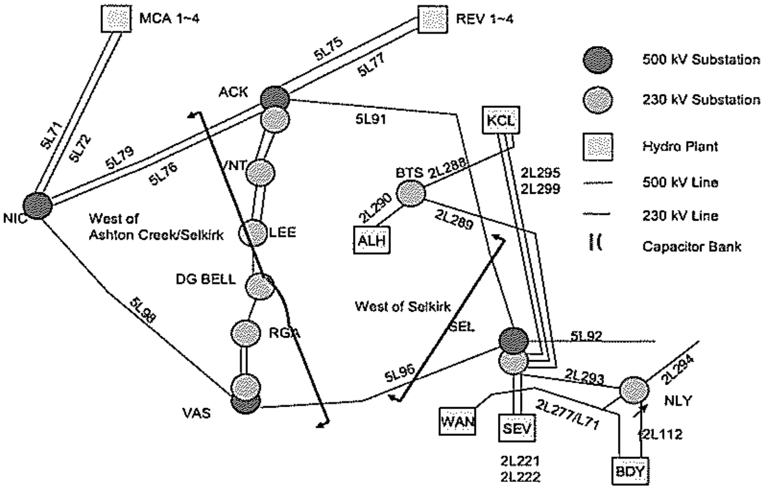
To better understand the existing use and future requirements for transformer capacity at Selkirk, BCTC conducted both a traditional committed use analysis and a transformer utilization study (Appendix 3). The report looked at the existing and forecast needs for transformer capacity, the amount of generation-shedding required in the event that one transformer is lost (e.g., N-1), and options for reinforcement.

To analyze the transfer capacity of the South Interior system, two cut-planes[8] were developed:

- The **West of Selkirk** cut-plane consists of 5L91 and 5L96. Power from the Selkirk Substation area flows west through this cut-plane towards Nicola Substation.
- The **West of Ashton Creek/Selkirk** cut-plane consists of lines 5L76, 5L79, and 5L96. Power from Ashton Creek to Nicola includes both power from Revelstoke and surplus power from Selkirk.

The West of Selkirk and West of Ashton Creek/Selkirk cut-planes are shown in Figure 3.

Figure 3 – Line Drawing of South Interior Transmission Circuits with Cut-planes



Using these cut-planes, BCTC conducted a South Interior Transmission Path Utilization Forecast (Appendix 2), which determined the committed uses on the lines for various scenarios (both present and future). At the same time, BCTC conducted a cut-plane study which included both voltage stability and transient stability studies and resulted in

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[8] See Appendix 1 for details.

the South Interior Cut-Plane Reinforcement Justification Report (Appendix 1). This study determined the existing capability of the system and options to add transfer capacity. The additional capacity options were evaluated for both heavy winter and heavy summer conditions. The cut-plane study also developed information on the potential increase in transfer capacity, reinforcement cost and cost per MW of increased transfer capacity in order to compare options.

These studies, combined with cost and risk information, were used to develop a range of reinforcement options for the South Interior and to identify a preferred South Interior System Development Plan.

4 Factors Affecting Use on the South Interior System

4.1 Factors Affecting Transformer Loading

The predominant power flow through the transformers at Selkirk is from generation on the Pend d'Oreille and Kootenay River systems and the Arrow Lakes, and imports from the U.S. (including a portion of the Downstream Benefits (DSBE)) on the 230 kV system, through the Selkirk transformers to the 500 kV system and to Nicola. In addition, some of the generation flows through the transformers to the 500 kV system to serve loads in the Cranbrook and east areas.

4.2 Factors Affecting Transmission Use

The power flows on the South Interior System are affected by a number of factors including:

- Amount of and dispatch pattern of local generation;
- Existing transmission contracts;
- BC Hydro's NITS contract;
- Required Transmission Reliability Margins; and
- Capacity on the ILM path.

The amount of power that can be moved through the South Interior System is also affected by capacity limitations on the ILM System. As the two systems are interconnected, electricity flowing to large load centres located in the Lower Mainland and Vancouver Island flows over both networks; upgrades or expansions of the South Interior System need to be considered in context of the ILM System capability.

Each of these factors is described in more detail below.

4.2.1 Generation

The South Interior is one of BC Hydro's largest electricity producing regions with a total installed nameplate capacity of 5264 MW. The two largest generating stations, Revelstoke and Mica, are directly interconnected into the 500 kV system and have a maximum observed continuous output of 2000 MW and 1805 MW, respectively. Three other facilities (Kootenay Canal, Seven Mile and Arrow Lakes Hydro) are operated by BC Hydro and connect into the 230 kV transmission system. The maximum continuous observed output of these facilities is:

- Kootenay Canal – 580 MW
- Seven Mile – 794 MW
- Arrow Lakes Hydro – 190 MW

How BC Hydro dispatches this generation varies depending on factors such as load, cost of energy, environmental considerations, and obligations under the Columbia River Treaty.

In addition to BC Hydro generation, there are also several hydro power plants that interconnect into the FortisBC system including Waneta, Brilliant, South Slocan, Lower Bonnington, Upper Bonnington, and Corra Linn. The total maximum observed continuous generation in the FortisBC system is about 813 MW. This generation is dispatched by BC Hydro under the terms of the Canal Plant Agreement.

The South Interior continues to be rich in electricity resources and several generation projects that could come on-line in the upcoming period have been identified. These projects include:

- 500 MW from Revelstoke Unit 5 in 2010;[9]
- 435 MW from the Waneta Expansion Project sometime after 2010 (Columbia Power Corporation);[10] and
- Various IPP projects (in 2006, BC Hydro awarded Energy Purchase Agreements to four projects in the South Interior with a combined plant capacity of up to 300 MW).[11]

BC Hydro also identified further potential generation at Mica and Revelstoke in its amended LTAP. Although Mica Unit 5 is not required until 2023 in BC Hydro's amended LTAP, it is advanced to 2014 in both contingency plans. In BC Hydro's contingency plans, Revelstoke Unit 6 is also identified as being required as early as 2017 and Mica Unit 6 as early as 2021. These three units would add an additional 1500 MW of capacity in the South Interior.

In addition to the specific projects mentioned, the potential for coal and/or coal bed methane generation in the region is currently being explored. This could add another 500 MW of generating capacity.

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[9] BC Hydro 2006 LTAP.

[10] Columbia Power, Waneta Expansion Project, Environmental Assessment Application.

[11] July 2006 BC Hydro CFT Results.

4.2.2 Existing Transmission Contracts

BCTC has several transmission contracts that affect the available capacity of the South Interior System.

- The Canal Plant Agreement: This agreement sets out a multi-party relationship between BC Hydro, BCTC, Columbia Power Corporation and Teck Cominco through which BC Hydro gains water rights on the Kootenay and Pend D'Oreille Rivers and the right to coordinate the generation schedule. In return, BC Hydro assumes the responsibility to deliver entitlements for firm monthly capacity and energy to the other parties. To fulfill that responsibility, BC Hydro has entered an agreement with BCTC to carry out the delivery of the entitlements.
- FortisBC General Wheeling Agreement ("GWA"): BCTC has an obligation to accept FortisBC's wheeling nominations from FortisBC's generation in the South Interior to delivery points located in the Okanagan area (Vernon Terminal and Vaseux Substation). The current nomination under the GWA is 230 MW but can be increased in steps up to 600 MW by 2014 with 5 years notice.
- BC Hydro NITS contract: Transmission Service is provided to BC Hydro under the Network Integrated Transmission Service (NITS) contact. Under NITS, BC Hydro designates which resources it wants to use to meet its network loads. It is then BCTC's obligation to ensure that the transmission capacity is available to move power from BC Hydro's designated resources to their designated loads.

4.2.3 Transmission Reliability Margins

Transmission Reliability Margin (TRM) is the amount of transmission transfer capacity necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change. The current TRM is 65 MW on the Alberta-BC path and 50 MW on the BC-US path.

4.2.4 Capacity on the ILM System

Most of the energy from the South Interior flows to the Lower Mainland over the ILM System.

As the South Interior and ILM Systems are interconnected, and power from the South Interior must flow over both systems to reach the major load centres, flows on the two paths must be considered together to fully understand the implications, costs, and benefits associated with each reinforcement alternative. The ILM System is already capacity constrained under certain conditions and requires coastal Reliability Must Run generation to meet load and support the transmission system. For the purposes of this report, BCTC assumes the capacity restrictions on the ILM system will be addressed by 2014 (the proposed in-service date of the ILM transmission reinforcement).

5 Existing South Interior Capacity and Constraints

The capacity of the South Interior System is currently limited by transformer capacity at Selkirk and transfer restrictions on the West of Selkirk cut-plane. As indicated, the 2004 NITS Study identified voltage instability under an N-1 contingency as the dominant limitation for transfer capacity in the area.

5.1 Overview of System Constraints – Transformer Capacity at Selkirk Substation

To analyze the need for transformation capacity at Selkirk, BCTC completed two studies of existing and future need. The first study used a traditional committed use methodology. This was supplemented by a transformer usage forecast study. Both methods are documented in Appendix 3.

The existing firm transformation capability of Selkirk is insufficient to meet existing transformation requirements. The 500/230 kV firm transformation capability is 1400 MVA in summer and 1600 MVA in winter. This does not meet the committed use for the 2006 to 2011 period of 1810-2070 MW in winter and about 2100-2360 MW in summer.[12] Under the Traditional Committed use analysis, generation shedding of between 210 MW (minimum) in winter (assuming no imports) and up to 960 MW (assuming high imports during spring freshet period) is required in the event of a transformer outage. The higher summer requirements are exacerbated by the lower transformer rating due to higher ambient temperatures.

The corresponding forecast peak usage, based on the new transmission utilization forecast methodology, in 2011/12 for the forecast scenario studied is shown to be 2250 MW in the summer and 1809 MW in the winter. Under this method generation shedding of between 210 MW in the winter and 750 MW in the summer would be required.

In general, BCTC Planning Standards do not permit the use of generation shedding for first single contingency conditions for determining system development requirements. This is based on a number of factors including:

1. Impact on generation equipment – Excessive generation shedding can lead to advanced ageing of the generator units.
2. Generation shedding for single contingencies on the transmission system compromises system reliability and could impact capacity reserve requirements.
3. Generation shedding reduces the flexibility for generation dispatch.
4. A deferral of system reinforcements by using generation shedding forgoes the benefits that can occur from reinforcements in one part of the system providing secondary benefits in another part of the system (e.g., the T4 transformer provides 165 MW of incremental TTC on the West of Selkirk cut-plane which defers West of Selkirk cut-plane investments and has a present value of $9 M).

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[12] The low and high figures in each range correspond to assumptions for the Nelway intertie import of zero or 300 MW.

Over the years, some exceptions to this Planning Standard have been permitted on the basis that the system impact was small (e.g., for smaller generation facilities interconnected with radial lines) or the cost of reinforcements was relatively large and the amount of shedding was limited and not expanding. This is not true in the case of Selkirk as new generation continues to be added in the area and Selkirk is a critical interconnection point for imports. In addition to generation shedding for a transformer contingency at Selkirk, BCTC also has to drop the Nelway - US intertie impacting import/export schedules.

5.2 Overview of System Constraints – Transmission Capacity West to Nicola

Using the two cut-planes, a historical Transmission Path Utilization Study was completed (Appendix 2). The historical five-year records (F2002-F2006) indicate that the transmission path flow pattern and magnitude vary from year to year based on a wide variety of factors including load requirements, water conditions, and the electricity market. However, analysis of historical use identified a number of general patterns or trends for electricity flow west to Nicola. The loading or power flow on both of the South Interior cut-planes is heavier in the summer (June-July) period with the peak usually corresponding to the spring freshet period. Peak flows increased significantly (300 to 400 MW) after 2003 and continued to rise after that time. Much of this increase is attributable to the addition of a fourth 200 MW generating unit at Seven Mile Generating Station in April 2003.

The West of Selkirk cut-plane has a capacity limitation for power transfer from Selkirk to Nicola. Currently, the Total Transfer Capability at this cut plane is limited to 1750 MW by a 5L91 contingency. The normalized committed use in 2005 was 1883 MW[13] during the freshet season. The normalized committed use in the summer of 2006 increased to 1990 MW because of the need to reserve capacity for part of the DSBE transfer to Nicola under the 2004 NITS Agreement. Therefore, currently there is a 240 MW transmission capacity shortfall on the West of Selkirk cut-plane. To address this situation in the short-term, BCTC applies a series of generation shedding schemes to reduce the power flow and prevent a system voltage violation from a single contingency of 5L91, 5L96 or 5L98.

The West of Ashton Creek/Selkirk cut-plane has a very close relationship with the West of Selkirk cut-plane. When 5L96 is out-of-service, power normally carried by 5L96 and 5L98 shifts to Ashton Creek through 5L91. The heavy power transfer through the West of Ashton Creek/Selkirk cut-plane requires more reactive power support at Ashton Creek, Nicola or Selkirk Substations. Currently, the total transfer capability is dominated by voltage instability on this cut-plane and is about 3210 MW in winter and 3510 MW in summer respectively. The historical operation data show the peak power transfer is about 3000 MW and occurs in summer. When the transfer on the West of

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[13] This committed use was determined from the South Interior Transmission Path Utilization Forecast. 1883 MW is the normalized transfer under zero interchanges at Alberta – BC tie and Eastern Intertie Boundary – Nelway. The actual peak transfer at West of Selkirk cut-plane was 2040 MW in 2005.

Selkirk cut-plane is controlled under its transfer limit, there are no additional limitations on the West of Ashton Creek/Selkirk cut-plane.

The proposed addition of 500 MW of generation at Revelstoke in 2010 (Revelstoke Unit 5) will increase the transfer requirement across the West of Ashton Creek/Selkirk cut-plane and result in a decrease in transfer capacity on the West of Selkirk cut-plane due to the interrelationship of the two cut-planes. The addition of Revelstoke Unit 5 will also cause the power flow on the ILM to reach its thermal limit when generation is the South Interior is maximized. Prior to the reinforcement of the ILM grid (currently scheduled for 2014), generation at Mica will need to be reduced when power flows from the South Interior are high (due to maximum generation levels or increased imports from Alberta). After the ILM grid is reinforced, the ILM system will become un-constrained allowing more power to flow from the South Interior System, particularly from Mica. The higher flows from Mica will consume more reactive power resulting in a reduction of transfer capacity on the South Interior cut-planes.

Due to the uncertainties of generation resource development by BC Hydro or IPP's and power exchanges with Alberta, FortisBC, or BPA, several scenarios were developed to forecast system requirements after the addition of Revelstoke 5.[14] As the summer transfer demands at the two cut-planes are much higher than those in the winter, the summer transfer demands were used in the South Interior Cut-plane Reinforcement Justification (Appendix 1). The scenario descriptions and the forecasted summer peak transfer demands at both West of Selkirk and West of Ashton Creek/Selkirk cut-planes are listed below in Figure 4. The forecasted transfer demand is shown as the hourly average peak value at the cut-plane in summer.

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[14] Please see Appendix 2 for details on this calculation.

Figure 4 - Transfer Demand Analysis for the South Interior

Considered Scenarios											Incremental CU (MW)		Transfer Demands (MW)	
Scenario Name	Description	Year	Import at Eastern Intertie	Import from Alberta	Generation Addition in Revelstoke	Super Coal	West of Selkirk Cut-plane IPPs	West of Ashton/Selkirk Cut plane IPPs	GWA	WAX	Cutplane "West of Selkirk"	Cutplane "West of ACK/SEL"	Cutplane "West of Selkirk"	Cutplane "West of ACK/SEL"
Scenario-1	LTAP Modified, Existing Committed Use,min DSBE & GWA	2009/ 2010	107	0	0	0	18	46	50	0	175	153	2058	3372
Scenario-2	LTAP Modified,Ex CU, Rev 5, GWA & min DSBE	2011/ 2012	107	0	500	0	138	166	118	0	363	773	2246	3990
Scenario-2a	LTAP Modified,EX CU, Rev 5, GWA, max DSBE	2011/ 2012	300	0	500	0	138	166	118	0	556	966	2439	4183
Scenario-2b	LTAP Modified,EX CU, Rev 5, Min DSBE,Waneta Expansion	2011/ 2012	107	0	500	0	138	166	0	450	695	1223	2578	4440
Scenario-2c	LTAP Modified,EX CU, Rev 5, Min DSBE,Alberta import	2011/ 2012	107	500	500	0	138	166	118	0	863	1273	2746	4490
Scenario-3	LTAP Modified,Ex CU, Rev 5, GWA & min DBSE	2014/ 2015	107	0	500	0	143	164	220	0	470	771	2353	3981
Scenario-3a	LTAP Modified,Ex CU, Rev 5, GWA & max DBSE	2014/ 2015	300	0	500	0	143	164	220	0	663	964	2546	4174
Scenario-3b	LTAP Modified Mid Near Term with Max DSBr and GWA	2014/ 2015	107	0	500	0	143	164	420	0	670	771	2553	3981
Scenario-4	LTAP modified - Horizon Year	2023/ 2024	107	0	1000	518	134	155	420	0	1179	1780	3062	4980

[rr1]

Note: The base case committed use in each of the above scenarios is 1883 MW as established in the Transmission Path Utilization Study.

The incremental forecast committed use as well as the total transfer requirement is shown in Figure 4. Incremental forecast committed use ranges between 363 MW and 863 MW by 2012 on the West of Selkirk cut-plane and 773 MW to 1273 MW on the West of Ashton Creek/Selkirk cut-plane.

Using this information, an estimate of the amount of forecast congestion on each path under both summer and winter conditions was developed for each scenario (Figure 5). For example, in Scenario 2, the West of Selkirk cut-plane could be congested up to 650 hours during the summer period. The congestion increases to 1337 hours if a higher level of US imports (300 MW) is assumed (Scenario 2a). If constraints within Alberta are relieved and higher levels of Alberta firm imports occur, this congestion will be worse and will extend to the winter period (up to 450 hours) (Scenario 2c).

Figure 5 – Cut-plane Congestion Analysis

SI Paths Forecasted Congestion Summary based on F2006 Flows

	West of Ashton Creek/Selkirk (5L76/79/96)						West of Selkirk (5L91/96)					
	Summer Congestion Forecast			Winter Congestion Forecast			Summer Congestion Forecast			Winter Congestion Forecast		
Scenario	Hours of Congestion	Max MW Congestion	GWH of Congestion	Hours of Congestion	Max MW Congestion	GWH of Congestion	Hours of Congestion	Max MW Congestion	GWH of Congestion	Hours of Congestion	Max MW Congestion	GWH of Congestion
1.	0	(402)	0.0	0	(630.6)	0.0	0	(126)	0.0	0	(590)	0.0
2.	0	(30)	0.0	0	(245.0)	0.0	650	256	50.5	0	(203)	0.0
2A.	23	163	1.8	0	(52.0)	0.0	1337	449	248.7	0	(10)	0.0
2B.	156	420	19.8	11	205.0	0.9	1721	588	463.5	59	129	2.9
2C.	219	470	29.0	21	255.0	1.6	2222	756	794.3	450	297	35.9
3.	0	(40)	0.0	0	(256.9)	0.0	1085	363	142.9	0	(97)	0.0
3A.	20	153	1.5	0	(63.9)	0.0	1661	556	407.4	34	96	1.3
3B.	0	(40)	0.0	0	(256.9)	0.0	1667	563	419.1	40	103	1.5
4.	980	960	313.8	529	742.3	99.7	3127	1072	1620.5	1980	611	419.0

Notes:

1. Forecasted flows are based on historical data from F2006 extrapolated to the Scenario Year
2. Max MW congestion provides the amount of forecast MW flow above or below the respective power transfer limits
3. Transmission path power transfer limits with and without REV 5 unit

	West of Selkirk Limit (MW)		***West of Ashton Creek/ Selkirk Limit (MW)***	
	Summer	Winter	Summer	Winter
Before REV 5	2184	2070	3774	3468
After REV 5	1990	1870	4020	3700

4. All scenarios except scenario 1 include REV generation. As such the "After REV 5" limit applies to scenarios 2 through 4

6 Discussion of South Interior Reinforcement Options

6.1 Reinforcing Transformer Capacity at Selkirk Substation

The initial studies conducted on increasing transformer capacity at Selkirk were limited by a preliminary assessment that the station did not have sufficient space to add an additional transformer. Based on this assessment, BCTC received approval from the Commission to replace T3 with a higher capacity transformer (Commission Order G-103-04). During detailed engineering studies, an option to tie the existing T2 and T3 transformers together in one position and create space for an additional transformer was identified.

The addition of a new 230/500 kV transformer (T4) with a rating of 1200 MVA and the reconnection of the existing transformers T2 and T3 (each 672 MVA) into one transformer zone would provide incremental firm capability of 960 MVA (summer) and 1100 MVA in winter. This would increase the firm capability of the station to 2360 MVA (summer) and 2700 MVA (winter). The estimated cost of the project is $17.8M.[15]

In addition, a new 1200 MVA transformer at Selkirk would reduce the net reactive power losses in the Selkirk transformers and reduce the impedance between the area generators and the 500 kV grid. This would have the added benefit of increasing the transfer capacity on the West of Selkirk cut-plane by approximately 165 MW. The value of this additional capacity is significant. For example, without the additional 165 MW TTC the Selkirk T4 transformer provides, one Ashton Creek Capacitor bank would have to be advanced to a 2008 in service date. In addition, the Series Capacitors on 5L91 and 5L98 would have to be advanced from 2014 to 2010 and the second Ashton Creek Capacitor bank deferred until 2014. The approximate NPV value of avoiding these advancements is $9 M.

BCTC evaluated two alternatives to the T4 reinforcement:

1. Replacing the existing T3 transformer with a higher capacity transformer (as previously approved); and
2. Adding an on-site spare transformer for one phase.

Replacing the existing T3 transformer (672 MVA) with a higher capacity 1200 MVA transformer costs slightly less than installing a fourth transformer (approx. $2 M). However, this option would only provide incremental firm capacity of 260 MVA in summer and 300 MVA in winter, effectively only meeting existing committed use. This is significantly less than the transformation capability of the T4 transformer which provides 960 MVA in the summer and 1100 MVA in the winter at a relatively insignificant marginal cost. The per unit cost of the T4 option is $18.5 k/MVA and the per unit cost of the T3 option is $64 k/MVA.

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[15] This is a P50 planning level estimate that includes overhead, IDC, but not inflation.

The option of an on-site spare for the largest of the existing transformers (1200 MVA) does not provide any additional firm station capacity nor would it affect the amount of generation shedding in the event of an N-1 contingency. However, it would reduce the duration of generation restrictions in the event of a single phase of T1 failure. The cost of this option is $4M.

6.2 Reinforcing System Capacity – West to Nicola

The installation of a new 1200 MVA transformer at Selkirk, along with planned FortisBC Vaseux 230 kV system upgrades, would provide approximately 434 MW of incremental TTC and address the short-term transfer capacity shortfalls by increasing the summer transfer capability at the West of Selkirk cut-plane up to 2184 MW in 2008.

Following 2008, there are two major potential system additions that would change the configuration of the system and affect both the committed use and the transfer capacity of the South Interior System: Revelstoke Unit 5 in 2010 and the reinforcement of the ILM grid in 2014. As indicated above, the integration of Revelstoke Unit 5 would require more transfer capacity at the West of Ashton Creek/Selkirk cut-plane and also decreases the transfer capacity at the West of Selkirk cut-plane because of the relationship between the two cut-planes. The reinforcement of the ILM path would relieve congestion on the ILM path, allowing for a higher level of transfer from South Interior and imports to Lower Mainland. However, this higher level of transfers will absorb reactive power and cause a reduction in the South Interior path ratings. At that point, additional shunt capacitors will be required in the Nicola Substation.

A number of potential transmission system reinforcements to increase transfer capability at the two cut-planes have been examined. Figure 6 provides cost estimates for these reinforcement options. The cost estimates are P50 planning level estimates and include direct costs, interest during construction (IDC), and corporate overhead.

Figure 6 - Cost Estimates for Individual System Reinforcements

Estimated Cost List

	Power Equipment Description	Estimated Cost ($M)*
1	500kV 250MVar Capacitor Bank in Ashton Creek, #1	4.95
2	500kV 250MVar Capacitor Bank in Ashton Creek, #2	5.48
3	500kV 250MVar Capacitor Bank in Nicola	4.60
4	500kV 250MVar Capacitor Bank in Selkirk	5.16
5	50% Series Compensation to 5L91	27.95
6	50% Series Compensation to 5L96	26.00#
7	50% Series Compensation to 5L98	23.96
8	50% Series Compensation to 5L97	26.00
9	50% Series Compensation to 5L99	18.49
10	New Line 5L97 - Selkirk to Vaseux	146.11
11	New Line 5L99 - Vaseux to Nicola	134.80

* Capital Totals Uninflated; # Based on 50% Series Compensation of 5L97

These options include single shunt capacitor bank, multiple shunt capacitor banks, transmission line series compensation, and combinations thereof. An overview of these options along with their incremental capability and cost per MW is provided in Figure 7 below.

Figure 7 - Transmission System Reinforcement Options After Selkirk Transformer Addition

Option	System Upgrades (new add-in)	Cost ($M)*	West of Selkirk --Summer						West of ACK/SEL--Summer					
			Before ILM			After ILM			Before ILM			After ILM		
			TTC (MW)	ΔTTC (MW)	Ratio k$/MW	TTC (MW)	ΔTTC (MW)	Ratio k$/MW	TTC (MW)	ΔTTC (MW)	Ratio k$/MW	TTC (MW)	ΔTTC (MW)	Ratio k$/MW
Before Revelstoke G5														
Base	No System Upgrade	0.0	2184	0					3774	0				
Option A	ACK-Cap-#1	5.0	2329	145	34	2214			3921	147	34	3801		
After Revelstoke G5														
Base	No System Upgrade	0.0	1993	0		1960	0		4024	0		3987	0	
Option A	ACK-Cap-#1	5.0	2069	76	65				4100	76	65			
Option B	ACK-Cap-#1 ACK-Cap-#2	10.8	2326	333	32	2227	267	40	4347	323	33	4249	262	41
Option C-1	ACK-Cap-#1 ACK-Cap-#2 NIC-Cap-#1	15.4	2366	373	41	2284	324	48	4395	371	42	4306	319	48
Option C-2	ACK-Cap-#1 ACK-Cap-#2 SEL-Cap-#1	16.0	2413	420	38	2271	311	51	4442	418	38	4292	305	52
Option D-1	Series Cap on 5L91and 5L98	51.9	2387	394	132	2217	257	202	4341	317	164	4178	191	272
Option D-2	Series Compensation on 5L91 and 5L98 ACK-Cap-#1	56.9	2540	547	104	2306	346	164	4494	470	121	4260	273	208
Option E	Series Compensation on 5L91 and 5L98 ACK-Cap-#1 ACK-Cap-#2	62.7	2654	661	95	2434	474	132	4602	578	109	4381	394	159
Option F-1	Series Compensation on 5L91 and 5L98 ACK-Cap-#1 ACK-Ca[-#2 NIC-Cap-#1	67.3	2675	682	99	2533	573	117	4624	600	112	4475	488	138
Option F-2	Series Compensation on 5L91 and 5L98 ACK-Cap-#1 ACK-Ca[-#2 SEL-Cap-#1	67.9	2786	793	86	2480	520	131	4722	698	97	4426	439	155
Option G-1	Series Cap on 5L91, 5L96 and 5L98	77.9	2450	457	170				4450	426	183			
Option G-2	Series Compensation on 5L91, 5L96 & 5L98 ACK-Cap-#1	82.9	2670	677	122	2355	395	210	4669	645	128	4356	369	225
Option H	Series Compensation on 5L91, 5L96 & 5L98 ACK-Cap-#1 ACK-Cap-#2	88.7	2825	832	107	2499	539	165	4821	797	111	4490	503	176
Option I-1	Series Conpensation on 5L91, 5L96 & 5L98 ACK-Cap-#1 ACK-Cap-#2 NIC-Cap-#1	93.3	2870	877	106	2591	631	148	4865	841	111	4580	593	157
Option I-2	Series Compensation on 5L91, 5L96 & 5L98 ACK-Cap-#1 ACK-Cap-#2 SEL-Cap-#1	93.9	2930	937	100	2577	617	152	4913	889	106	4567	580	162
Option J-1	Series Compensation on 5L91& 5L98 ACK-Cap-#1 ACK-Cap-#2 NIC-Cap-#1 New line 5L97 New line 5L99 with Series Compensation	366.7				3439	1479	248				5385	1398	262
Option J-2	Series Compensation on 5L91& 5L98 ACK-Cap-#1 ACK-Cap-#2 NIC-Cap-#1 New line 5L97 New line 5L99 with Series Compensation Series Compensation on 5L96 & 5L97	418.7				3840	1880	223				5825	1838	228

* Capital Totals Uninflated

Note: The planned sequence of options is option B, E, F1, J1, and J2

Each of the options in Figure 7 was evaluated for each of the potential future scenarios identified in Figure 4 (see Appendix 1 for details). This analysis indicates that the installation of two shunt capacitor banks in Ashton Creek, followed by series compensation on 5L91 and 5L98, and the addition of a shunt capacitor in Nicola (Option F-1), provides the most additional transfer capacity at the lowest cost and would be sufficient to meet the most likely future scenarios (2 and 3). These scenarios were deemed to be most likely because they include BC Hydro's amended LTAP, the requirements from BC Hydro's 2004 NITS, and estimated requirements for the FortisBC GWA.

As a result of this scenario analysis, BCTC is recommending staged reinforcements as follows:

1. Selkirk T4 (2008): In addition to addressing constraints at Selkirk Substation, the installation of Selkirk T4 provides a capacity addition of approximately 165 MW on the West of Selkirk cut-plane. Combined with the improvements provided by the planned upgrades by FortisBC to the Vaseux 230 kV system, this will increase West of Selkirk cut-plane to 2184 MW.
2. Two switched shunt capacitors at Ashton Creek (2010): The transfer capacity added by a new Selkirk transformer and the FortisBC upgrade in 2008 is not adequate to meet the transfer demands beyond 2010 or alleviate the impact of the Revelstoke G5 addition. If Revelstoke G5 is added without any additional system reinforcement, the transfer capability at the West of Selkirk cut-plane will be at least 250 MW[16] short by the summer of 2011. The addition of two shunt capacitors at Ashton Creek provide the needed transfer capacity at the lowest per MW cost.[17] This reinforcement will provide an incremental TTC of 330 MW at a per unit cost of $32k/MW.
3. Series Compensation on 5L91 and 5L98 (as early as 2010): If additional generation is added in the South Interior, or higher levels of imports occur (as indicated in several of the potential scenarios), additional transfer capacity will be required. At that time, series compensation on 5L91 and 5L98 will be required to increase transfer capability. Series compensation would add an additional 330 MW of incremental capability at a cost of $158 k/MW[18].
4. Nicola Shunt Capacitor (2014): Following the completion of ILM reinforcement, a shunt capacitor at Nicola would be needed to accommodate the increased flows made possible by the reinforcement of the ILM grid. Shunt compensation at Nicola would provide 99 MW of additional capability at a cost of $46.5k/MW after the series compensation on 5L91 and 5L98 is in service and the constraints on the ILM have been alleviated.

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[16] Based on a committed use of 2246 MW as listed in Scenario 2 in Figure 4.

[17] Even with the addition of the shunt capacitors, committed use is still expected to exceed the transfer capability by a small amount (19 MW) once constraints on the ILM are relieved.

[18] This is calculated by taking the difference in cost of options E and Option B divided by the difference in capability of these options shown in Figure 7.

With the completion of these projects, the South Interior System should be able to meet the forecast requirements based on the most probable future scenarios (2 and 3). Completion of these reinforcements would increase the transfer capacity of the West of Selkirk cut-plane close to its thermal limit of 2600 MW.

Once the thermal limit of the line is reached, new transmission lines would be required to accommodate any significant addition of new generation or increased imports. Construction of a new transmission line 5L97 (Selkirk – Vaseux) and a new series compensated transmission line (5L99 Vaseux – Nicola) could provide up to 906 MW of additional transfer capability West of Selkirk. New transmission lines with series compensation would require a significant investment of about $300 million. At the time new generation is being proposed for the area an economic analysis will be required to determine if the cost of new lines can be justified.

7 Potential Future Scenarios

7.1 Adding Additional Capacity at Mica and Revelstoke

As previously mentioned, BC Hydro's contingency plans indicate possible future additions at Mica (Mica 5 and 6) and Revelstoke (Revelstoke 6). If another unit were added at Mica, series compensation on 5L71 and 5L72 between Mica and Nicola would be required to support the higher load transfers. With series compensation, the two lines would have sufficient capability to deliver a total of 2500 MW from Mica to Nicola.

If BC Hydro then proceeds with Mica 6 or Revelstoke 6, additional transmission reinforcement is required. BCTC conducted a preliminary analysis of required additions and has identified the following likely reinforcements:

1. A new 500 kV Switching Substation at Downie;[19]
2. Looping 5L71 and 5L72 into Downie Substation;
3. A new 500 kV line from Revelstoke to Downie; and
4. A new 500 kV line from Mica to Downie.

These reinforcements would be required to integrate the new generation and reduce the risks associated with losing a whole generating station (e.g., the impact of a simultaneous loss of 3000 MW of generation) on the transmission system.

If Mica 6 or Revelstoke 6 proceeds, more detailed study would be required to evaluate all the options and identify the most cost-effective reinforcement option.

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[19] The Downie substation would be a major 500 kV switching station located at Downie Creek between Mica and Revelstoke. This substation would be designed to create a 500 kV tie between the Mica system and the Revelstoke system to allow generation from either station to flow to Nicola or Ashton Creek in the event of an outage to either system.

7.2 The Interties and Trade

7.2.1 Alberta

The capacity of the BC/Alberta intertie is currently limited by constraints within the Alberta system. These constraints are expected to be partially alleviated in 2009/2010 with the completion of a new 500 kV transmission line between Edmonton and Calgary. Full restoration of the intertie capacity is expected when Alberta adds a proposed second 500 kV circuit between Edmonton and Calgary (currently scheduled for 2010). Once this occurs, it is likely that the constraints for Alberta imports will be within the BCTC system. This Plan has identified these constraints and the upgrades required to alleviate them.

In June 2006, a BC-Alberta Electricity Transmission Subcommittee was established as a permanent sub-committee of the Alberta-British Columbia Electricity Policy Working Group. This subcommittee is undertaking a joint study to look at the feasibility of reinforcing the transmission intertie between Alberta and British Columbia. The subcommittee will develop recommendations for consideration of the Policy Working Group. A potential outcome of the recommendation could be an increase in firm imports, which would accelerate the needed reinforcements.

7.2.2 The Eastside (Nelway to Boundary) Intertie

In conjunction with BPA, BCTC is looking at ways to enhance the use and capacity of this intertie. An initiative is currently underway to separate the scheduling on the two interties with Washington State, which will allow BCTC and BPA to better manage scheduling activities and congestion. In addition, one of the projects being evaluated under BCTC's new Expansion Policy is the feasibility, costs and benefits associated with adding a phase-shifter at Nelway.

8 Conclusion

The South Interior System is currently limited by transformer capacity at Selkirk and transfer capacity restrictions on the West of Selkirk transmission path moving power west to Nicola.

The first step in this plan is the installation of a fourth transformer at Selkirk as soon as possible to provide additional transformer capacity of 960 MVA in summer and 1100 MVA of capacity in winter. This will reduce the need for generation shedding and line-tripping after an outage of the largest transformer and reduce the need for generation restrictions during forced outages. In addition, a new transformer at Selkirk will reduce the reactive power losses in the transformers resulting in an increase in transfer capacity on the West of Selkirk cut-plane of approximately 165 MW.

The new transformer at Selkirk, combined with the planned upgrade of the FortisBC system in 2008, will address system requirements until Revelstoke Unit 5 is added to the system in 2010. The addition of two new shunt capacitors in Ashton Creek would provide the additional capacity required to move the Revelstoke power and additional generation or increased wheeling. However, the committed use is still expected exceed the TTC by a small amount (19 MW) when the ILM constraint is relieved. BCTC is recommending proceeding with Definition Phase funding for this project at this time.

If additional generation or imports were added in the South Interior (as is indicated in several of the scenarios), series compensation on 5L91 and 5L98 would be required. Given the longer lead time needed for series capacitor stations, BCTC is recommending proceeding with Definition Phase funding for this project to reduce this lead time and to mitigate the risk of BCTC not being in a position to respond to customer needs in a timely fashion, which could be as early as 2010.

When the existing constraints are relieved on the ILM grid (currently planned for 2014), the increased power flow on the ILM path will consume more reactive power, reducing the total transfer capacity on the South Interior cut-planes. The addition of a new shunt capacitor installed at Nicola would restore some of this capacity.[20]

With the completion of these projects, capacity in the South Interior is expected to meet the forecast requirements over the next ten years. These reinforcements will increase the transfer capacity of West of Selkirk close to its thermal limit of 2600 MW. Once the thermal limit is reached, additional new transmission lines (5L97 and 5L99) would be required to accommodate any significant new generation additions or a higher level of imports; however, no definition work is proposed at this time because of the uncertainty of resource additions which would require these lines.

The timing and sequencing of projects in the South Interior is very sensitive to changes in generation resource additions, reinforcements to the ILM system and/or import levels. Changes in any of these could advance, defer or alter the specifics on any of the recommended projects.

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[20] Adding a shunt capacitor at Nicola will also contribute to increasing the TTC of the ILM path (in combination with two shunt capacitors at Meridian).

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COSTS OF SERVICE DISRUPTIONS TO ELECTRICITY CONSUMERS[†]

CHI-KEUNG WOO[§] and ROGER L. PUPP[‖,‡]

[§] Department of Economics and Finance, City Polytechnic of Hong Kong, 83 Tat Chee Avenue, Kowloon, Hong Kong

[‖] Analysis Group, Inc., 100 Bush Street, Suite 900, San Francisco, CA 94104, USA

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Abstract - After reviewing 16 recent studies, we (i) identify the general approaches used to estimate customer outage costs, (ii) ascertain the relative merits of each approach, and (iii) determine the extent to which existing studies can provide accurate and meaningful estimates. We present cost estimates on a common denominator, explain variations in the results, and suggest areas for future research.

1. INTRODUCTION

Electricity, unlike other forms of energy such as gas, oil or coal, cannot be economically stored, but rather must be provided on demand. Consequently, a major concern of all electric utilities is the level of reliability at which they can supply energy. Reliability is defined as the ability to deliver uninterrupted service on demand, to whatever degree required.[¶] Common engineering service reliability criteria are one-day-in-ten-years loss-of-load-probability, expected unserved energy, and reserve margins. A discussion of each is presented in Refs. 1-4. An electric utility traditionally chooses a particular level of service reliability by using probabilistic and deterministic standards and judgements based on experience. For instance, a utility may design their generating system to maintain adequate generation reserve margin to provide an acceptable level of service reliability. Similarly, the design of a transmission and distribution (T&D) network may rely on redundancy to satisfy reliability standards determined by historical practice.[5-7] Customer preferences for service reliability are typically not considered in these types of planning decisions. As a result, the cost and level of service reliability supplied by a utility may differ from what customers want and for what they are willing to pay. If so, the reliability level provided is not economically efficient for either the utility or the customer.

Most electric utilities have also traditionally ignored customer reliability preferences in product development. For example, a retail customer class is typically offered a standard service whose price does not necessarily closely correspond with customer value of service reliability.[8] As a result, customers who are willing to pay for premium uninterruptible service or are willing to accept a bill discount for interruptible service have not been given the opportunity to choose between these two. This is in sharp contrast to the

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[‡] Author to whom all correspondence should be addressed.

[¶] Reliability is distinct from service quality in that the latter refers to the provision of electricity within acceptable frequency and voltage ranges.

airlines and long-distance telecommunications industries, which offer a full spectrum of differentiated services from which customers can select options that best match their needs.[†]

Due to both customer dissatisfaction with utility electricity service and the financial risks of major plant additions, some electric utilities have recently begun to explore alternative methods to plan and price electricity supply. The result of this exploration is an increasing popularity of economic reliability planning and efficient pricing principles. To wit, (i) a reliability improvement should be undertaken if its benefits exceed its costs,[2-5,8,9,13,17] and (ii) the cost of an improvement should be reflected in the rate design.[2,8,9,11,13,18] Customer outage costs are an essential input for implementing these two important principles. We provide three notable examples. The first is from generation planning and marginal cost pricing. The benefit of new generation capacity is a decrease in expected customer outage costs. The reliability improvement obtained with additional capacity is economically efficient if the benefits of increased reliability exceed the costs of installing new capacity. Setting efficient electricity rates requires the change in expected customer outage costs and the capacity costs to be included in the rate design. Under a flat rate design, for example, the efficient price is the sum of the expected marginal fuel cost and the expected marginal outage cost. Under the economic reliability planning principle, the expected marginal outage cost at the long run equilibrium equals the marginal capacity cost.[2,8,13]

Our second example is the design of interruptible and curtailable (I/C) service. Offering I/C service at reduced rates to customers who have relatively low outage costs helps to both defer capacity expansion and decrease emergency power pool purchases.[9-11,13,15] Our final example is a T&D planning project. Repairing an aging transmission line after each failure may be more cost-effective than replacing the line. Another option may be to install switches to isolate faults so that distribution related outages are reduced. The costs of the switches must be balanced against the benefits to determine whether the reliability improvement is economically efficient. Benefits comprise reduced outage costs and corresponding lower maintenance costs.[5,7]

While the principles of economic planning and efficient pricing are well established, a utility may be unable to apply the principles because customer outage costs in each of the utility's service regions are generally unavailable. By reviewing some recent contributions to the estimation of customer outage costs, we (i) identify the general approaches used, (ii) ascertain the relative merits of each approach, and (iii) determine the extent to which existing studies can provide accurate and meaningful estimates which are transferable across utilities. If the existing estimates of different utilities varied little, a utility that has no information on their customers' outage costs may substitute the outage costs of another utility. Conversely, highly diverse estimates may indicate either a lack of consensus among experts regarding the magnitude of outage costs or a recognition that outage costs vary highly with customer characteristics. If the latter is true, utilities would need to collect outage costs estimates for their customers rather than substituting estimates from another utility.

With these objectives in mind, the remainder of the paper is organized as follows. Because a variety of measures have been used in the literature, we define in Sec. 2 the concept of customer outage costs to eliminate any ambiguities that may arise in the subsequent discussion. In Sec. 3, we identify and evaluate the approaches commonly employed to estimate customer outage costs. In Sec. 4, we present the empirical results in 16 recent studies, a majority of which are based on outage cost survey data.[‡] We conclude in Sec. 5 by recapitulating the major findings and suggesting some areas for future research.

2. DEFINITIONS

The value of service reliability represents the maximum amount a customer is willing to pay for the particular level and type of service provided. As such, it reflects the usefulness and/or necessity of electric service to the customer. Although electricity is familiar to most users, the market for its reliability is not well developed. For example, since 1977, Pacific Gas and Electric Company has been offering interruptible and curtailable service options to approximately 1,000 large customers with monthly demand over 1,000 kW. However, less than 10% of these customers subscribed to any of these options.[22] It is difficult to judge consumers' willingness to pay (WTP) for different reliability levels, because there exists a limited amount of data on customer reliability/price choices. Accordingly, the amount customers are willing to pay for service reliability is often approximated by its opportunity costs which equals the value of unsupplied electricity. Thus, customer value of service reliability becomes synonymous with customer outage costs.

[†] Various form of reliability differentiation have been proposed in the literature including, (i) priority service in Refs. 9-10, (ii) simple interruptible service in Ref. 11, (iii) demand subscription service in Ref. 12, (iv) self-rationing in Ref. 13, and (v) proportional rationing in Refs. 14-15. However, their implementation is relatively limited as noted in Ref. 16.

[‡] For surveys of earlier works, see Refs. 19 and 20. A review of North American studies prior to 1988 is provided in Ref. 21.

Customer outage costs can be collected either *ex post* (i.e. after the fact) or *ex ante* (i.e. before the fact).[23,24] *Ex post* measures represent the economic costs incurred by households or firms when a service disruption occurs with certainty. *Ex ante* measures equal the maximum amount a customer is willing to accept (pay) for an increase (decrease) in the likelihood that an outage will occur in the future. An *ex ante* value of reliability does not depend on the actual realization of an outage. It is sometimes inferred from household purchases of a backup generator or household participation in a load management program.

Outage costs are commensurate with a customer's dependence on electricity during an outage. Outage costs vary significantly depending on the particular attributes of the outage. Attributes known to influence costs include: timing (season and time-of-day), advance notice, frequency, duration and severity. With the exception of severity, the meaning of the remaining attributes is self-evident. Severity is the extent of service disruption characterized by the following: (i) Full Outage - A complete or total loss of service, typically resulting from a distribution-related cause (e.g. storms, car-pole accidents, or vandalism), or transmission failure, rotating blackouts or enforcement of an interruptible service contract as described in Ref. 6; and (ii) Partial Outage - A curtailment of service due to a utility's public appeal for voluntary load reduction, or participating in a load management program targeted to a particular end-use such as air conditioning or water heating.[25]

3. APPROACHES

Description

Using the preceding concepts and definitions, we describe three techniques commonly employed to estimate outage costs. These procedures are the (i) proxy, (ii) market-based and (iii) contingent valuation methods.

Proxy methods use secondary data to measure customer willingness to pay for service reliability. The following are examples of proxies: (i) Average electricity tariff[26,27] - This method is based on the assumption that customers purchase electricity if consumption benefits are greater than costs. As a result, the average electricity tariff measures what customers are willing to pay for the last kWh purchased. (ii) Cost of maintaining backup power[28] - This approach assumes that electricity users act rationally and insure themselves against the damages caused by power failures when it is economic for them to do so. For instance, a firm's acquisition of a backup generator will reflect the marginal value of unsupplied electricity. Outage costs are derived by assuming that a competitive risk-neutral firm maximizes expected profit. At the margin, they equate the expected marginal costs of self-generating a kWh of the unsupplied utility electricity to the expected avoided outage costs due to this self-generated kWh. (iii) Value of foregone leisure/wage rate[7] - This method views the principal cost of a power failure as a loss of leisure. (iv) Value of foregone production (GNP per kWh consumed) - The gross national product (GNP) measures the value of goods and services produced by an economy. Because electricity is an essential input to all economic activities, it is argued that the GNP would be greatly reduced in the absence of electricity. Thus, the ratio of GNP to total electricity consumption may be used as an approximation of the aggregate effect of an outage on an economy.

In contrast to proxy techniques, market-based methods use data from observed customer behavior to infer outage costs. These approaches include (i) consumer surplus methods used in Refs. 29-32 and (ii) analysis of customer choice of I/C rate options as in Ref. 22. The consumer surplus approach estimates outage costs by equating them to the compensating variation. The compensating variation equals the area under customers' compensated demand curves.[33-34] Early applications of this method relied on readily available monthly or yearly aggregate demand function data which were used to approximate either daily or hourly electricity consumption by customers.[29] Hourly and daily consumption was then used to estimate outage costs. In more recent work, outage cost estimates were obtained from consumer surplus losses calculated from a system of time-of-use demand equations.[31]

Also, the market-based approach uses data that utilities have collected from recently introduced I/C rate options for their large commercial and industrial users. These options, and others similar to them, offer a customer a price discount in return for a lower reliability of service.[†] In this approach, it is assumed that customers rationally choose an option which maximizes their expected net benefit of electricity consumption. Each option has both a particular rate discount and level of reliability. An econometric analysis of customer choices will provide a market determined value of service reliability. The data may be used to infer the monetary compensation required for each customer such that they are indifferent between the discount/reliability choice they actually made and alternative choices they could have made. These compensation differentials among the options measure customer WTP for alternative reliability levels. The

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[†] For example, Pacific Gas and Electric Company rate E-20 for large light and power customers offers discounts for both the demand charge and the energy rate. Participation may result in service curtailment with varying degree of notice.[22]

procedures used to obtain such estimates are outlined in Refs. 25 and 35-38.

The contingent valuation method (CVM) is a third technique which may be used to collect outage costs. In the CVM approach, individuals are asked to reveal in a survey or experimental setting how much they value a hypothetical good which is not priced in the market. For instance, people have been asked "How much would you be willing to pay to clean-up this river?" A thorough description and assessment of this approach is contained in Ref. 39. CVM surveys have been widely used to estimate outage costs differentiated by outage attributes and customer characteristics. Empirical examples of the approach can be found in Ref. 35. Three contingent valuation techniques are discussed below.

The first technique is based on customer surveys of direct costs.[40-42] Customers are asked to identify the actions they would normally take to adjust to an outage. Next, they are asked to provide an estimate of the out-of-pocket and/or inconvenience costs of each action. The total outage cost is estimated as the sum of the individual costs. In the residential sector, the individual actions may include the use of candles for lighting; dining out or visiting friends; buying ice to preserve food; staying at a hotel or motel; or the use of a home generator, etc.[†] In the commercial and industrial sectors, specific costs comprise lost sales or production, spoilage, equipment repair and the expenses of making-up lost sales and production.

The second CVM technique asks customers in a survey to state the maximum amount of money they would be willing to pay (or accept) for an increment (or a decrement) in service reliability. The amount of money individuals are willing to pay (WTP) should approximately equal the amount of money that they are willing to accept (WTA) for a marginal change in service reliability. Willig[33] presents the theory from which this implication is drawn. It is possible that the WTP and the WTA may not by identical due to income effects. If these effects are negligible as assumed in this theory, the difference between WTP and WTA is slight. However, this hypothesis is contradicted by the empirical evidence presented in Refs. 37-38.

The last CVM technique we discuss is the analysis of customer preference data. In a survey, individuals are given a set of hypothetical mutually exclusive service alternatives. Each alternative depicts a different combination of service reliability and price. Individuals are then asked to rank the options by their order of preference or to choose the option that best meets their needs. Marginal rates of substitution and monetary values of willingness to pay can be inferred from these rankings.[25,37,38,40,43]

Evaluation

Here we evaluate the pros and cons of the three approaches. We summarize our findings in Table 1 which provides a synopsis of the relative merits of each method using the following criteria: (i) Data requirement Amount of data necessary for outage cost estimation, (ii) Computational cost Amount of research effort and time required for data analysis, (iii) Verifiability Extent to which the outage cost estimates are supported by observed customer behavior, and (iv) Outage attributes and customer demographics Extent to which the estimates reflect outage cost variations by these determining factors. In Table 1, the symbol + indicates that an approach scores well under a particular criterion while the symbol - indicates the opposite.

Table 1. Relative merits of outage cost estimation techniques.

Criterion	Proxy	Market-Based	Contingent Valuation
Data Requirement	+	-	+/-
Computation Cost	+	-	+/-
Verifiability	-	+/-	?
Outage Attributes	-	-	+
Customer Demographics	-	+	+

The major advantage of the proxy methods is that they are straightforward to apply and require minimal data. Thus, computational costs are relatively inexpensive. However, theoretical deficiencies and/or lack of detail may result in inaccurate outage cost estimates. This limits the usefulness of proxy outage cost estimates in a utility's planning and pricing activities, so that proxy methods score poorly under the remaining three categories. We argue why this is so by providing examples. First, the average electricity tariff proxy fails to quantify the total cost of a complete service disruption, because it only measures the value of the

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[†] In most cases the resulting estimates should be interpreted as an upper bound of customers' willingness to pay. This is because certain actions during the outage provide an associated consumption benefit. For example, dining out in a fine restaurant during an outage has a consumption benefit due to the enjoyment consumers obtain by having someone else cook for them.

marginal kWh lost. If the marginal cost of backup power exceeds the marginal outage cost, a rational firm would not invest in backup power. This implies that the marginal cost of backup power overestimates the marginal outage cost.

Second, the wage proxy inaccurately measures outage costs because labor-leisure tradeoff theory assumes workers can vary their hours of work to equate their wage with the marginal value of their leisure time. This tradeoff may be infeasible due to the traditional 40-hour work week, union restriction on hours worked, or insufficient employment alternatives. It also effectively ignores the cost to nonwage earning family members. Another weakness of this approach is that it is valid only for electricity-dependent leisure activities.

Our third example is the GNP/kWh consumed proxy approach in which the underlying production technology for GNP is assumed to be a fixed coefficient. This assumption is not supported by empirical evidence presented in Ref. 44. Outage costs estimates from any of the three proxy methods can not be verified. In addition, none of these approaches is able to sufficiently estimate differences in outage costs due to outage attributes and customer demographics. In summary, we conclude that the proxy method has three deficiencies and only two advantages. On balance, the disadvantages may result in inaccurate outage cost estimates. This seriously limits their usefulness in a utility's planning and pricing activities.

Next, we discuss the advantages and disadvantages of using each of the two market-based methods (customer choice and consumer surplus) in estimating outage costs. The customer choice approach can generate valid, defensible and verifiable outage cost estimates, because it uses data on actual customer subscriptions to reliability differentiated rates. If data on customer demographics is also available, the effect of these variables on outage costs can be econometrically estimated if computational cost is not of high concern. On the other hand, sufficient data is generally not available to adequately estimate outage costs and the effect of outage attributes on outage costs, so it scores poorly on the data requirement and outage attribute criteria.[†] Thus, we conclude in Table 1 that this market-based method does not score well under the data requirement, computational cost and outage attribute criteria, but it scores well for the verifiability and demographic criteria.

The market-based consumer surplus approach suffers from a number of theoretical deficiencies making it difficult to verify outage cost estimates. First, considerable care must be taken to ensure that the correct demand curve is identified by which we mean that it corresponds to the period of the loss. In addition, using this approach to estimate outage costs for a momentary outage as in Ref. 31 is generally infeasible, because it requires the estimation of a demand equation for a time period less than a minute.[‡]

Second, Munasinghe[7] notes that the consumer surplus measure may be inappropriate because an unexpected service disruption is not the same as a reduction of planned consumption caused by a price increase. He argues that actual outage costs may be significantly larger due to the unplanned nature of the outage.[¶] Finally, the consumer surplus approach requires an estimate of the price increase that would reduce the quantity demanded to zero. While this price increase is well defined for a linear demand equation,[32] most empirical demand equations are nonlinear. A finite price increase that would completely choke-off such demand may not exist. For example, the required price increase for the popular double-log demand equation is infinite, implying that the resulting consumer surplus loss due to the outage is also infinite.[34]

This approach performs poorly in evaluating the role of frequency and notice attributes on outage costs, because time-of-use data is collected for the purpose of determining how consumption varies with price. On the other hand, the effects of customer demographics and outage attributes such as duration and time-of-day on outage costs may be determined (if sufficient data on hourly loads and prices are available), but it requires extensive computational analysis.[45,46]

The last outage cost estimation approach we discuss is contingent valuation surveys. Depending on a utility's planning and pricing needs, the amount and detail of information collected on a survey can be

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[†] For example, PG&E's interruptible rate option offers a large rate discount with little difference in actual service reliability.[22] Thus, the data available from this rate option experiment would not be rich enough to predict what customers would choose when confronted with a menu of truly competing service options.

[‡] On the other hand, momentary outage costs can be estimated using the CVM approach. The authors of Ref. 40 estimated residential outage costs ranging from $0.18 to $1.88 (1989$) per interruption.

[¶] Ongoing research sponsored by NMPC and the Electric Power Research Institute (EPRI) attempts to address this issue using the hourly demand model.[46] Preliminary findings in this report support the hypothesis that actual outage costs due to an unexpected outage are higher than reductions in consumption due to price increases.

adjusted. A utility needing only a moderate amount of information may limit the length of a survey to a few pages and a couple of outage scenarios. Also, to limit computational costs, simple statistical techniques such as crude sample averages may be used to estimate outage costs from survey results. On the other hand, the utility may need much more detail. If so, the survey may contain a great number of demographic questions and collect much information on how outage attributes (such as duration, notice, etc.) affect outage costs. In addition, this more carefully designed survey may also be accompanied by a more thorough statistical analysis of the survey responses.[47-48] For example, survey data often contain up to 60% of zero cost responses, creating an estimation difficulty known as truncation bias. Statistical methods to correct for this bias are presented in Refs. 49-51, but it requires extra computational cost. For these reasons, Table 1 indicates that contingent valuation methods perform well under outage attributes and customer demographics criteria, but not as well under data requirement and computation cost criteria.

Verifiability of outage cost estimates obtained using CVM remains unknown, in particular because the results of CVM applications always show large disparities between reported WTP and WTA responses. In theory, there should be no empirical difference between these responses. However, typical reported WTP values ranges from one-fourth to one-third of reported WTA values. To date, researchers have been unable to definitively explain the persistence of this disparity. Various conjectures include both strategic response bias on the part of the respondent and cognitive dissonance. Coursey et al[52] designed a laboratory experiment to investigate if either of these conjectures can explain this disparity. In this experiment, individuals are given a drop of bitter tasting liquid, and asked both what they would be WTP and WTA to avoid and suffer the experience, respectively. A Vickrey auction mechanism is used to elicit the hypothesized values in the form of individual bids. The authors conclude the following: First, the observed divergences between WTP and WTA may be due to hypothetical bias resulting mainly from the lack of a market-like environment. This finding is consistent with results obtained from the analysis of survey data on customer subscription to hypothetical rate options. Choice sets that include unrealistic reliability levels such as a 1 five-second outage every 5 years vs 30 two-day outages every year tend to yield outage cost estimates that are unrealistically high.[43] More plausible estimates have been obtained when respondents have been confronted with a set of realistic service options as in Keane et al.[25]

Second, hypothetical bias is likely to yield outage costs responses above prices respondents would pay if the service were actually available in a market-like setting, because respondents are not required to purchase the product at the value they assign it. Third, WTP measures of value may correspond more closely to the true value than do WTA measures. Finally, extreme risk aversion in the form of a strong preference for the status-quo may also account for the disparity between WTA and WTP.[†] As shown in Refs. 37-38, this bias has important implications in estimating the value of service reliability, especially for those utilities interested in offering reliability-differentiated rates. The bias suggests that customers attach a strong premium to the current service level and are unwilling to select a non-firm service option unless the price discounts are sufficiently large to overcome the psychological barrier to participation. However, it is important to note that Cummings et al[39] document eight studies in which both CVM and actual market data were used to value the same commodity and each gave similar results. While outage cost estimates in the CVM approach are not directly verifiable at this time, this study indicates that these results are very reasonable.

4. SUMMARY OF PRIOR RESULTS

This section summarizes 16 recent studies on customer outage cost estimation. We choose these studies to (i) review the state-of-art approaches, (ii) demonstrate the differences in approaches and results by including some contributions not reviewed in prior survey articles,[19-21] and (iii) address the specific features of both the residential and nonresidential customer classes.[‡] Due to dissimilar measurement concepts, and outage attributes and customer demographics in the databases used in various studies, the outage cost estimates are diverse. In our summary, we attempt to reconcile differences among estimates.

Residential Sector

Table 2 lists the features and the empirical results of eight residential studies; 3 and 5 studies use *ex*

[†] See Ref. 53 for a discussion on the kinked value function which implies extreme risk aversion due to status-quo bias.

[‡] We have not discussed Refs. 37-38 in our review because the primary emphasis of these two papers is on investigating consumer rationality. Also, the numerical results in these papers are identical to those in Refs. 36 and 40. We have also excluded Ref. 54 because the authors use an input-output table to analyze the aggregate outage cost for the Egyptian economy. Because their study focuses on the macroeconomic impact of a capacity shortage rather than microeconomic effects, it is beyond the scope of our paper.

Table 2. Estimates of the value of service reliability and outage costs in the residential sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
						Bill Increase /k		
Doane, Hartman, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Not Studied	2	1	0	45.02/g	11.25/h	16.11/i
						Bill Decrease /l		
			5	2	0	12.82	6.41	9.18
			5	4	0	45.02	6.43	4.61
			15	2	0	12.82	6.41	9.18
			15	4	0	16.16	4.04	5.79
Keane, MacDonald, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Summer/ Afternoon				Bill Decrease /m		
			1	4	0	18.43	4.61	1.84
						Willingness-to-Pay /n		
Doane et al. (1990)/ New York, U.S.A.	Customer Survey/ Ex Post	Summer/ 8 a.m.	Not Studied	1	0	4.43	4.43	5.40
				4	0	6.4	1.6	1.89
				8	0	9.99	1.25	1.50
		Summer/ 2 p.m.	Not Studied	1	0	3.55	3.55	4.38
				4	0	4.88	1.22	1.46
				8	0	7.33	0.92	0.97
				1	1	3.55	3.55	4.38
				4	1	4.88	1.22	1.46
				1	4	3.55	3.55	4.38
				4	4	4.88	1.22	1.46
		Summer/ 6 p.m.	Not Studied	1	0	3.87	3.87	3.72
				4	0	5.35	1.34	1.28
		Winter/ 8 a.m.	Not Studied	1	0	6.71	6.71	7.14
				4	0	8.96	2.24	2.30
				8	0	13.38	1.67	1.73
		Winter/ 2 p.m.	Not Studied	1	0	6.11	6.11	6.57
				4	0	8.05	2.01	2.07
				8	0	12.06	1.51	1.38
		Winter/ 6 p.m.	Not Studied	1	0	7.30	7.30	6.08
				4	0	9.75	2.44	2.01
				1	1	7.13	7.13	5.94
				1	4	6.60	6.60	5.50
				4	1	9.50	2.38	1.96
				4	4	8.71	2.18	1.80

Notes:

a/ Based on the costs of the actions taken to mitigate the affect of an outage. Actions examined include the purchase and use of candles, an emergency lantern, and/or an emergency stove; purchase or rental of a small or large backup generator.

b/ N.A. = Not Available

c/ Based on the costs of the actions taken to mitigate the affect of an outage. Actions examined include using candles, flashlights, a propane gas stove or grill, a kerosene heater or wood stove, and/or a battery-operated radio; going out to eat, shop, visit friends; staying home and doing activities which do not require electricity; using a home generator.

d/ A partial outage resulting from a customer's voluntary response to the utility's public appeal 4 – 6 hours before a capacity shortage.

e/ The amount a customer is willing to pay for the service of a backup generator.

f/ Amount of annual bill increase that a customer is willing to pay to move from the current reliability level of two one-hour winter outage per year to a lower reliability level.

g/ The change in the annual bill divided by a change in frequency relative to the current reliability level.

h/ The change in the annual bill divided by a change in hours unserved relative to the current reliability level.

i/ The change in the annual bill divided by a change in kWh unserved relative to the current reliability level.

j/ Amount of annual bill decrease that a customer is willing to accept to move from the current reliability level of two one-hour winter outages per year to a lower reliability level.

k/ Amount of annual bill increase that a customer is willing to pay to move from the current reliability level of three 2-hour outages per year to a higher reliability level.

l/ The amount of annual bill decrease that a customer is willing to accept to move from the current reliability of three 2-hour outages per year to a lower reliability level.

m/ Amount of annual bill decrease that a customer is willing to accept to tolerate the loss of air-conditioning due to voluntary participation in a program.

n/ What is the most you would be willing to pay as a lump sum increase in your annual electricity bill to prevent this outage from occurring?

Table 2. Estimates of the value of service reliability and outage costs in the residential sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Munasinghe (1980)/ Cascavel, Brazil	Proxy-Wage Rate/ Ex Post	Not Studied/ Evening	Not Studied	1	0	3.06	3.06	1.73-2.66
Sanghvi (1983)/ Wisconsin, USA	Consumer Surplus/ Ex Post	Summer/ 12 noon	Not Studied	1	0	0.37	0.37	0.17
				2	0	0.75	0.37	0.18
				4	0	1.64	0.41	0.21
				12	0	19.27	1.60	0.77
		Summer/ 8 a.m.	Not Studied	1	0	0.37	0.37	0.23
				2	0	0.77	0.38	0.24
				4	0	1.84	0.46	0.28
				8	0	5.45	0.68	0.40
		Summer/ 4 p.m.	Not Studied	1	0	0.78	0.78	0.31
				2	0	2.05	1.03	0.32
				4	0	4.54	1.14	0.38
				8	0	7.27	0.90	0.37
						Direct Costs /a		
Wacker, Wojczynski, and Billinton (1983)/ Canada	Customer Survey/ Ex Post	Winter/ Evening	Monthly	1	0	1.46	1.46	N.A. /b
			Monthly	4	0	14.69	3.67	N.A.
			Weekly	4	0	22.72	5.68	N.A.
						Willingness-to-Pay		
			Monthly	4	0	6.55	1.64	N.A.
			Weekly	4	0	9.97	2.49	N.A.
			Daily	1	0	9.98	9.98	N.A.
						Willingness-to-Accept		
			Monthly	4	0	13.62	3.40	N.A.
						Direct Costs /c		
Doane, Hartman, and Woo (1988)/ California, U.S.A.	Customer Survey/ Ex Post	Winter/ Evening	Not Studied	1	0	12.15	12.15	16.19
				4	0	22.5	5.63	6.08
		Winter/ Morning	Not Studied	4	0	13.65	3.41	4.33
				12	0	45.82	3.82	4.67
		Summer/ Afternoon	Not Studied	1	0	4.14	4.14	5.51
				4	0	15.36	3.56	4.80
				12	0	42.97	3.58	4.29
				1	1	3.15	3.15	4.20
				5 /d	0	2.86	0.58	N.A.
		Any-Time	Not Studied	Momentary		1.88	N.A.	N.A.
						Willingness-to-Pay /e		
		Winter/ Evening	Not Studied	1	0	3.33	3.33	4.44
				4	0	5.40	1.36	1.46
		Winter/ Morning	Not Studied	4	0	3.38	0.85	1.07
				12	0	10.21	0.85	1.04
		Summer/ Afternoon	Not Studied	1	0	1.85	1.85	2.46
				4	0	4.07	1.02	1.28
				12	0	9.83	0.82	0.98
				1	1	1.11	1.11	1.47
		Any-Time	Not Studied	Momentary		0.18	N.A.	N.A.
						Bill Increase /f		
Goett, McFadden, and Woo (1988)/ California, USA	Customer Survey/ Ex Ante	Winter/ Morning	1	1	0	21.36 /g	21.36 /h	27.14 /i
						Bill Decrease /j		
			1	4	0	94.42	47.21	59.95
			2	4	0	N.A.	19.30	24.50
			4	1	0	21.36	21.36	27.14
			4	4	0	79.26	5.66	7.20

ante and *ex post* costs, respectively.[†] *Ex post* costs are approximated by using a wage rate proxy, consumer surplus and CVM. Munasinghe[55] uses a wage rate proxy and verifies its accuracy by comparing outage cost estimates obtained from it with the outage costs estimates acquired from a personal interview with 27 households. Sanghvi[31] adopts a consumer surplus approach in which a system of 24 hourly electricity demand equations is estimated using data from a time-of-use experiment. The area under the demand curve approximates the consumer surplus of electricity service. Doane et al,[40] Doane et al[47] and Wacker et al[56] estimate outage costs with household contingent valuation survey responses on both direct costs and WTP.

These authors employ different statistical techniques to estimates outage costs. Wacker et al[56] use descriptive statistics to summarize the survey results. A limited dependent variable regression model based on Heckman[51] is used by Doane et al[47] to quantify the effects of outage attributes and customer demographics on outage costs. These authors also correct for bias introduced by protest bids. A protest bid is a zero WTP answer from a respondent who is unwilling to pay for a reliability improvement for non-economic reasons. These reasons include the following: (i) "The utility should provide reliable service." (ii) "Even if I pay, the utility cannot eliminate outages anyway." In addition, these authors remove observations with a studentized residual over 3.5 from their analysis. Such observations are called outliers; they tend to be observations with huge reported outage costs. The outlier classification technique is explained in Belsley et al.[57]

Goett et al,[43] Keane et al[25] and Doane et al[36] use *ex ante* data obtained from contingent valuation surveys. Outage costs are inferred by analyzing the choices made by households among alternative reliability options each characterized by both a different bill discount and outage attributes such as expected frequency and duration.

Outage costs expressed as dollars per interruption are available for all studies in Table 2. In addition, outage costs for all non-momentary outages are stated in dollars per hour unserved. It would be ideal if all cost estimates could be normalized to dollars per kWh unserved to facilitate comparisons among results. However, less than half of the studies provide these normalized cost estimates, presumably due to the lack of data on energy unserved during an outage.

Obtaining dollar per kWh unserved by normalization of the cost per interruption is an important issue in presenting and using outage cost estimates. For instance, these estimates are used for system reliability planning. A unbiased estimate of dollar per kWh unserved equals the population estimate of the cost per interruption divided by the population estimate of the expected unserved energy per interruption.[58] To the extent that the cost per interruption is relatively stable for small changes in reliability, the economic benefit of a reliability improvement equals the product of the dollar per kWh unserved and the change in the population estimate of expected unserved energy.[3-5,7] Estimates of dollar per kWh unserved presented in Table 2 and later in Tables 3 and 4 are computed as above.[‡]

The per interruption cost estimates in Table 2 ranges from $0.18 to $94. After normalizing the per interruption costs by dividing by the duration of the outage, variations in the dollars per hour unserved estimates remain substantial. They range from $0.37 to $47 per hour unserved. Furthermore, normalizing dollars per interruption by kWh unserved indicates that cost differences cannot be adequately explained by energy unserved. For example, based on a survey of households' direct costs, Doane et al[40] finds the cost of a 4-hour outage is approximately $4 to $6 per kWh unserved, three to four times higher than WTP estimates obtained in the same survey. The *ex post* direct cost estimate for a 4-hour summer afternoon outage is approximately $4.8 per kWh unserved, three times the *ex ante* cost estimate of $1.84 per kWh unserved reported in Keane et al[25] for a partial load curtailment. Moreover, these estimates are substantially larger than the full outage cost estimate of $0.37 per kWh unserved in Sanghvi[31] for a summer afternoon outage of the

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[†] The estimates for countries outside the U.S. are first converted to U.S.$ using exchange rates published in the Statistical Abstract of the U.S. (1986). All estimates are then adjusted for inflation using the annual Consumer Price Index (CPI) available from the Monthly Labor Review (November 1990) published by the U.S. Bureau of Labor Statistics.

[‡] For reliability pricing purposes, the cost per interruption is not meaningful since reliability differentiation requires information on the distribution of the individual per unit outage cost $y_i = c_i/e_i$; where c_i = estimate of cost per interruption for Customer i; and e_i = estimate of expected unserved energy per interruption for Customer i. Suppose the rate discount for a simple interruptible service is d ($/kwh). Customer i who is assumed to be risk neutral will select the interruptible service if his/her expected per unit cost of electricity consumption $[(1 - p)(z - d) + p(c_i - z - d)] < z$; where p = probability of service interruption; z = energy rate for firm service; and (z - d) = energy rate for interruptible service. If c_j is the per unit cost of the "marginal customer" who is indifferent between the two services, the participation rate in the interruptible service program is $F(c \leq c_j)$ where F(c) is the cumulative distribution function of $c > 0$.[11] For a similar discussion on this point, see Ref. 21.

same duration. Below we discuss the factors that cause this diversity of results.

The consumer surplus approach adopted by Sanghvi[31] results in the lowest *ex post* cost estimates of \$0.18 to \$0.77 per kWh unserved which likely underestimate the *ex post* cost of an outage.[†] The *ex post* cost estimates derived from the WTP survey responses are the next lowest. Wacker et al[56] report that the average rate increase acceptable to a Canadian household to avoid a monthly 4-hour winter evening outage is approximately \$6.6 per interruption, corroborating the WTP estimate of \$5.4 in Doane et al.[40] The corresponding dollars per hour unserved estimates are between \$1.36 to \$1.64, which are approximately 50% of the Brazilian wage rate proxy in Ref. 7. It was found in Doane et al[40] that the *ex post* cost estimates derived from direct costs are \$12 to \$15 per interruption for a 4-hour morning outage. These estimates, however, are almost three times higher than the WTP estimates from the same surveys and two times those in Doane et al.[48] This difference is expected since the contingent valuation literature suggests that the compensation measurement of value typically exceeds the WTP value.[59]

Finally, *ex ante* measures of the value of service in Table 2 are generally higher than the *ex post* cost estimates. The estimates in Goett et al[43] are the highest. For example, the cost for a 1-hour winter morning outage is close to \$21 per hour unserved. The authors of three studies[36,47,48] show that this outcome can be partially explained by status-quo bias. The *ex ante* value of a partial load curtailment is reported in Keane et al[25] to be \$4.5 per hour unserved. After normalizing it by expected unserved energy, the estimate is \$1.84 per kWh unserved.

Winter outages impose higher costs on households than summer outages. Early evening outages are most costly followed by afternoon and morning outages. While an increase in outage frequency or duration raises the cost per interruption, the effect on the cost per hour unserved is unclear.[‡] Advance warning may reduce costs substantially, up to 40%. For example, the summer afternoon 1-hour direct cost estimate in Doane et al[36] reduces from \$5.51 to \$4.29 per interruption when advance notice is provided. Also, advance notice decreases the WTP estimate from \$1.85 to \$1.11 per interruption. On the other hand, Doane et al[47] find little effect of advance notice on outage costs.

Momentary outages impose some small costs on households ranging from \$0.18 to \$1.88 per interruption. As expected, the *ex ante* costs per hour unserved for total service disruption are generally higher than for partial load curtailment. Few residential studies have attempted to relate outage costs to customer demographics. However, a positive relationship between household income and outage costs is reported in Munasinghe.[55] Doane et al[40] and Doane et al,[47] using contingent valuation data, find that customer demographics account for substantial cost variations. For example, large users with electric appliances for space and water heating and cooking tend to have higher outage costs than small users who do not own these appliances. And, young urban dwellers who own electronic equipment as personal computers, VCR's and security alarm systems value service reliability more than other households not having these types of appliances. Not surprisingly, households in which either a home business is operated, or a family member has health problems, or there is a large family all have higher outage costs.

The results presented in Table 2 agree reasonably well with those presented in Table 2 of Ref. 19 and in Table 2 of Ref. 20.[¶] After adjusting for inflation, the similarity becomes more apparent. Most of the *ex post* full outage cost estimates in Table 2 and in Refs. 19 and 20 range from \$1 to \$6 per kWh unserved. The exceptions are the winter evening 1-hour direct cost estimate of \$16.2 per kWh unserved in Doane et al[40] and the (inflation adjusted) 2-minute WTP estimate of \$12 per kWh in Table 2 of Ref. 19. The similarity among the WTP estimates is even more striking, clustering around \$1 to \$2 per kWh unserved for outages lasting more than one hour. Based on this comparison, we conclude an upper bound estimate for total service disruption would be \$6 per kWh unserved. This estimate is higher than the estimate of \$1.36 to \$2.0 per kWh unserved (in 1989 prices) recommended in page 190 of Ref. 19.

Industrial Sector

Table 3 presents industrial outage cost estimates for six studies conducted in Israel, Canada and the United States. Two studies use *ex ante* data and four use *ex post* data. *Ex ante* costs in Bental et al[28] are

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[†] The theoretical premise of this approach is that the effect of an unexpected outage is the same as an instantaneous price increase that would completely "choke-off" demand. However, this price increase can only reduce planned consumption to zero but not necessarily the actual demand at the time of an unexpected outage.

[‡] In Refs. 31 and 56, for example, the authors indicate that the cost per hour unserved increases with frequency or duration. However, this finding was not supported by Refs. 36, 40, 43 and 48.

[¶] Because a majority of the residential studies cited in Fig. 2 of Ref. 21 are the same as those in our paper, we decided not to compare their summary with ours.

approximated by using the cost of owning and operating a backup generator. Also, these authors estimate the marginal cost of unserved energy by dividing the annual cost of owning and operating a 1 kw capacity backup generator by the expected yearly unserved energy. *Ex ante* outage costs in Gilmer et al[32] equal the loss in expected producer surplus caused by a change in service reliability. These authors show that the producer surplus lost due to an outage is the area under a linear electricity demand curve representing a firm's planned consumption at its expected unit cost of electricity. The total *ex ante* costs consist of the expected loss of profit and the cost of adjustment to the change in service reliability.

The four studies using *ex post* costs obtain them from contingent valuation surveys in which direct outage costs are reported. These studies primarily focus on the costs associated with full outages. The statistical techniques used to estimate direct outage costs vary among the studies. Descriptive statistics are used to examine the effects of causal factors on outage costs in Subramaniam et al.[60] Ordinary least squares regression is used by Fisher[61] to relate direct costs to customer characteristics and outage attributes. Woo et al[41] recognize that a sample truncation bias is caused by a large number of zero direct cost responses. They correct for this bias by using a two-step regression model to explain outage cost variations.

Doane et al[48] discovered that the distribution of the direct costs are log-normal with a few observations having very large values. As a result, they use a semi-log cost regression on a data sample that excludes outliers.[†] In addition to direct costs, Doane et al[48] measure industrial outage costs using data on WTP and WTA responses. However, they discovered that many firms exhibit strategic bias. Strategic bias occurs when WTP values are very small and close to zero while the WTA values are very large. The authors believe that this occurs because firms tend to relate WTP values to the best time an outage may occur such as when their plant is closed. On the other hand, firms associate WTA values to the worst time for an outage to occur such as when they are operating at full capacity. Due to this bias, the authors use direct costs in their outage cost analysis, because these costs are less likely to suffer from strategic bias.

The estimates of industrial outage costs are diverse, ranging from $324 to $1,334,055 per interruption. Even after adjusting for differences in outage duration, large variations still exist in cost per hour unserved estimates. For example, Subramanian et al[60] estimate outage costs ranging from $2,492 to $4,155 per hour unserved for a winter morning outage lasting one hour or more for firms without backup systems. Furthermore, large differences remain after adjusting outage costs by kWh unserved, so neither duration nor kWh unserved can adequately explain the differences in outage cost estimates among studies. For example, industrial *ex post* cost estimates in Fisher[61] range from approximately $8.3 to $26.7 per kWh unserved depending on the products produced and technology employed.

Bental et al[28] estimate *ex ante* outage cost by using backup generators as a proxy. They obtain lower estimates than Gilmer et al[32] who also use *ex ante* costs. The estimates range from $0.31 to $1.68 per kWh unserved depending on the expected number of unserved hours. This result is surprising because an industrial firm would install a backup generator only if it had a high value of service reliability. Thus, the cost of owning and operating a backup generator should reflect the high end of the range of industrial firms' *ex ante* outage costs.

Gilmer et al[28] report *ex ante* costs for an unspecified number of apparel manufacturing firms in the Tennessee Valley Authority service territory. Per interruption outage costs are over $1 million. After normalizing these costs by the amount of expected unserved energy, the per-unit outage costs are approximately $1.66 to $2.05 per kWh unserved. The highest outage cost estimates are those reported in the three contingent valuation studies. These estimates range from approximately $1,200 to $57,000 per interruption or $1,300 to $23,000 per hour unserved for outages lasting one hour or more. Fisher[61] presents normalized cost estimates ranging from $8.3 to $26.7 per kWh unserved. These estimates are substantially higher than the estimates of $1.7 to $7.3 per kWh unserved in Doane et al.[48]

The effects of outage attributes on industrial firms' outage costs are quite different from those for households. An increase in outage duration raises the industrial costs per interruption but at a decreasing rate. Perhaps after the first hour of an outage, additional costs become less significant (e.g. workers are sent home to reduce idle labor costs). Weekday outages occurring in the morning or the mid-afternoon are the most costly while weekend evening outages are the least costly. Seasonality does not appear to affect outage costs significantly. Estimates in Woo et al[41] indicate that outage costs per interruption decline when outages become more frequent. For a given number of unserved hours, industrial firms prefer fewer longer outages to a larger number of shorter outages. For example, the cost estimate for one 4-hour outage in Woo et al[41] is approximately 60% of the total costs of four 1-hour outages. Advance warning reduces outage costs sometimes

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[†] An observation is classified as an outlier if its studentized residual is greater than 2.0 so that the likelihood of misclassification is less than 5%. This procedure is presented in Ref. 57.

Table 3. Estimates of the value of service reliability and outage costs in the industrial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Bental and Ravid (1982)/Israel and USA	Proxy–Cost of Backup Generation/ Ex Ante	Not Studied	Not Studied	70 /a	0	N.A. /b	N.A.	0.31
				10 /c	0	N.A.	N.A.	1.68
Gilmer and Mack (1987)/ Tennessee, USA	Producer Surplus/ Ex Ante	Not Studied	0.1/year	4	0	1,334,055 /d	333,514	1.66 /e
			0.5/year	4	0	1,277,785	319,446	2.05
Subramaniam, Billington, Wacker (1985)/Canada	Cost Survey/ Ex Post	Winter/ Morning				Customers Without Standby System		
			Not Studied	1/60	0	324.3	19,468	N.A.
				1/3	0	2,061	6,182	N.A.
				1	0	4,155	4,155	N.A.
				4	0	9,965	2,492	N.A.
				8	0	25,097	3,137	N.A.
						Customers With Battery Standby System		
			Not Studied	1/60	0	5,259	315,571	N.A.
				1/3	0	11,436	34,307	N.A.
				1	0	17,904	17,904	N.A.
				4	0	38,727	9,682	N.A.
				8	0	57,189	7,148	N.A.
						Customers With Engine Standby System		
			Not Studied	1/60	0	10,874	652,468	N.A.
				1/3	0	14,015	42,045	N.A.
				1	0	22,821	22,821	N.A.
				4	0	39,060	9,764	N.A.
				8	0	56,752	7,094	N.A.
Fisher (1986)/ Massachusetts, USA	Cost Survey/ Ex Post	Summer/ Afternoon				Machinery		
			Not Studied	1/2	0	5,773	11,545	23.89
				1	0	11,380	11,380	22.74
				2	0	15,392	7,695	16.15
				4	0	20,503	5,126	18.83
						Electronic & Electrical Machinery		
			Not Studied	1/2	0	647	1,295	11.88
				1	0	1,375	1,375	9.12
				2	0	2,665	1,332	8.54
				4	0	4,814	1,203	8.33
						Measuring Analysis & Control Instruments		
			Not Studied	1/2	0	5,078	10,155	26.65
				1	0	9,478	9,478	19.11
				2	0	26,953	13,476	25.56
				4	0	37,460	9,364	17.96
						Other Manufacturing		
			Not Studied	1/2	0	9,077	18,155	19.40
				1	0	13,371	13,371	15.78
				2	0	22,565	11,282	15.20
				4	0	37,460	9,364	13.47
Woo and Gray (1987)/ California, USA	Cost Survey/ Ex Post	Summer/ Afternoon	1	1	1	14,450	14,450	57.91
			1	4	1	47,345	11,837	N.A.
			4	1	1	6,578	6,578	N.A.
			4	4	1	21,549	5,388	N.A.
			8	1	1	4,664	4,664	N.A.
			8	4	1	15,278	3,819	N.A.

Table 3. Estimates of the value of service reliability and outage costs in the industrial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
Doane et al. (1990)/ New York, U.S.A. /f	Cost Survey/ Ex Post	Summer/ 8 a.m.	Not Studied	8	0	49,392	6,174	4.41
		Summer/ 2 p.m.	Not Studied	1	0	10,460	10,460	7.29
				8	4	27,267	3,408	2.67
				8	24	17,256	2,157	1.69
		Winter/ 8 a.m.	Not Studied	8	0	62,064	7,758	5.57
		Winter/ 2 p.m.	Not Studied	4	0	20,064	5,016	3.79
				4	1	19,098	4,775	3.61
		Winter/ 6 p.m.	Not Studied	1	0	7,831	7,831	6.49

Notes:
a/ Estimated annual outage duration in Israel in 1980.
b/ N.A. = Not Available
c/ Estimated annual outage duration in the USA for 1980.
d/ Total costs per year for an unspecified number of small apparel manufacturing firms divided by the expected number of outages per year.
e/ Total costs per year divided by the expected unserved energy per year.
f/ Includes all large users with monthly billing demand over 1,000 kW.

Table 4 overleaf

Appendix 18.4a

Table 4. Estimates of the value of service reliability and outage costs in the commercial sector in 1989 U.S. $.

Study/Country	Method/ Cost Type	Season/ Time-of-Day	Frequency	Duration (Hours)	Notice (Hours)	Dollars Per Interruption	Dollars Per Hour Unserved	Dollars Per kWh Unserved
						Customers Without Standby System		
Billington, Wacker Subramaniam (1986)/ Canada	Cost Survey/ Ex Post	Winter/ Morning	Not Studied	1/60	0	79.1	4,714	N.A. /a
				1/3	0	334.5	1,002	N.A.
				1	0	828.3	828	N.A.
				4	0	3,036	759	N.A.
				8	0	8,161	1,020	N.A.
						Customers With Battery Standby System		
			Not Studied	1/60	0	16.95	1,050	N.A.
				1/3	0	218.1	654.3	N.A.
				1	0	696	696	N.A.
				4	0	2,941	736	N.A.
				8	0	8,030	1,003	N.A.
						Customers With Engine Standby System		
			Not Studied	1/60	0	2.3	122	N.A.
				1/3	0	853	2,559	N.A.
				1	0	2,189	2,189	N.A.
				4	0	5,862	1,466	N.A.
				8	0	14,309	1,789	N.A.
						Wholesale		
Fisher (1986)/ Massachusetts, USA	Cost Survey/ Ex Post	Summer/ Afternoon	Not Studied	1/2	0	2,112	4,225	6.95
				1	0	6,212	6,210	14.19
				2	0	12,578	6,290	16.30
				4	0	25,515	6,379	19.55
						Retail		
			Not Studied	1/2	0	293	585	15.35
				1	0	777	777	16.80
				2	0	1,216	608	13.11
				4	0	2,420	606	10.23
					0			
						Finance, Insurance & Real Estate		
			Not Studied	1/2	0	6,547	13,096	28.65
				1	0	9,299	9,299	15.92
				2	0	15,499	7,750	16.94
				4	0	27,815	6,954	20.13
						Services		
			Not Studied	1/2	0	9,077	18,155	8.69
				1	0	13,371	13,371	8.69
				2	0	22,565	11,282	9.20
				4	0	37,460	9,364	8.84
Woo and Train (1988)/ California, USA	Cost Survey/ Ex Post	Summer/ Afternoon	1	1	1	4,332	4,332	8.25
			1	4	1	14,118	3,529	N.A.
			4	1	1	2,885	2,885	N.A.
			4	4	1	9,400	2,349	N.A.
			8	1	1	2,495	2,495	N.A.
			8	4	1	8,130	2,032	N.A.

Note:
a/ N.A. = Not Available

substantially as discovered by Doane et al.[48] The cost for an 8-hour outage with 24-hour notice is $17,255 per interruption which equals 63% of the cost of an 8-hour outage with a 4-hour notice.

The more electricity-intensive the production process, the higher the cost per interruption. For instance, Doane et al[48] find that an outage is most damaging to firms with high load factors and greater dependence on such end uses as process heat and electronics. Prior outage experience tends to reduce outage costs as discovered by Fisher[61] and Subramaniam et al.[60] They indicate that large customers with backup systems tend to have higher costs per interruption. However, this finding is not supported by Woo et al[41] and Doane et al.[48,†]

The industrial outage cost estimates reported in Table 3 are generally higher than those reported in Table 3 of Ref. 19 and in Table 3 of Ref. 20. With the exception of the estimate of $58 in Woo et al,[41] the range for most of the cost estimates in Table 3 is $0.24 to $27 per kWh unserved for outages lasting one hour or more. However, Woo et al[41] admit that their estimate is too high partially due to the underestimation of the average industrial unserved energy. In summary, we note that the majority of the estimates in our Table 3 and Table 3 in both Refs. 19 and 20 are less than $10 per kWh unserved.

Commercial Sector

Table 4 presents the empirical results of three contingent valuation surveys in which commercial firms were asked to provide estimates of their *ex post* direct costs incurred as a result of a full outage. Commercial outage costs are extremely diverse as is true for both residential and industrial outage costs. Below we consider some of the factors accounting for the divergence of results. Again, part of the differences in results are due to the various statistical techniques used by the authors. On the other hand, the diverse results cannot be completely attributed to differences in type of cost data collected, because all three studies estimate commercial firms' *ex post* outage costs with direct cost survey response data. On the other hand, we do know that part of the diverse results are due to the attributes of the outages presented in the surveys.

The effects of outage attributes on commercial outage costs resemble those for industrial companies. An increase in duration raises costs per interruption, but at a decreasing rate. Weekday outages occurring during normal business hours are the most damaging, followed by early evening and late evening outages. Summer outages impose slightly higher costs than winter outages. Costs per interruption decline when outages become more frequent. Advance warning does not reduce outage costs significantly. Commercial firms, like industrial firms, prefer fewer but longer outages to more but shorter outages. For example, Woo et al[42] report that the cost of one 4-hour outage is approximately $2,000 less than the sum of the costs of four 1-hour outages.

Large commercial firms employing many workers have a higher cost per interruption than smaller firms with few employees. Financial service companies and food outlets value service reliability more than retail companies and wholesale stores. Firms with no prior outage experience are more likely to report zero cost than firms with outage histories. However, when these inexperienced firms report some outage costs, their estimates are higher than those of the experienced firms. Billinton et al[62] and Fisher[61] suggest that large users with backup systems tend to have higher costs per interruption. This finding is not supported by Woo et al.[42]

The commercial outage cost estimates in Table 4 generally agree with the estimates reported in Table 4 of Ref. 19. They range from $2.3 to $27 per kWh unserved.[‡] It should be noted that most of the estimates are quite large because commercial firms tend to have relatively small usage. Thus, even though the costs per interruption are small, the normalized values are fairly large such as over $10 per kWh unserved.

[†] While backup system ownership indicates a high *ex ante* value of service reliability, the *ex post* costs for firms with backup systems should be lower than firms without backup systems. For example, if the backup systems were sufficiently large, most of the negative effects of an outage on production could have been eliminated.

[‡] The exceptions are the estimates for outages less than one hour and those reported by Ref. 63 in Table 2 of Ref. 19.

5. CONCLUSION

In this paper, we have reviewed the general approaches used to estimate customer outage costs and have summarized the empirical results in 16 recent studies. The following findings emerge from our review: (i) The value of service reliability represents the maximum amount a customer is willing to pay for the particular level and type of service provided. As such, it reflects the usefulness and/or necessity of service to the customer. (ii) Unlike other industries (e.g. airlines and telecommunications), the market for reliability in the provision of electricity service is not well established. As a result, there is a limited price history with respect to reliability from which to judge customers' willingness to pay. (iii) Absent a market for reliability, the amount customers are willing to pay for service reliability is often approximated by the opportunity cost of unsupplied electricity. Thus, customer value of service reliability becomes synonymous with customer outage costs. (iv) Outage costs can be evaluated either *ex post* (i.e. after the fact) or *ex ante* (i.e. before the fact). *Ex post* measures refer to the unavoidable costs a household or firm incur as the result of a power outage that occurs with certainty. *Ex ante* outage cost valuations represent the maximum amount a customer is willing to pay for a change in the likelihood of an outage. (v) Major factors known to affect customer outage costs are customer demographics and such outage attributes as frequency, duration, timing, advance warning and severity. Thus, a valid approach should generate outage cost estimates that are sensitive to such causal factors. (vi) A variety of approaches have been used to estimate outage costs. These approaches include simple proxies, market-based methods and contingent valuation surveys. The methods differ in terms of their data requirement, their theoretical rigor, and their ability to develop costs estimates distinguished by season, time-of-day, duration, and advance notice. (vii) An evaluation of the three common approaches indicates that absent good market data on customer choice of service reliability, one may use CVM to quantify outage costs. This recommendation is based on CVM's relative merits in data requirement, computational costs, verifiability of results and sensitivity to important causal factors such as outage attributes and customer demographics. However, the results based on CVM should be verified when suitable data on customer choice of I/C rate options become widely available. (viii) As shown in Tables 2-4, the empirical estimates of outage costs are diverse. This diversity can be explained by differences in the methods used, outage attributes considered, and customer characteristics. Therefore, considerable care must be taken when using outage cost estimates for the purpose of reliability planning and pricing.

Based on the above findings, we conclude that the recent research on estimating customer outage costs have made significant advances, especially in the areas of collecting and analyzing survey data. However, there is a number of important questions that remain unanswered. (i) What causes WTP and WTA values to differ substantially? Is it status-quo bias? (ii) How and when can survey results be validated by market data? (iii) Should we estimate costs for deterioration in other service attributes such as voltage? (iv) Should partial outage costs deserve more attention because they are important inputs to generation reliability planning? (v) Can outage cost data be used in an integrated framework for efficient pricing of and planning for reliability differentiated services? Ongoing and future research will hopefully provide answers to these questions which would result in a more efficient use of limited resources used in the production and distribution of electricity service.[†]

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[†] For example, Niagara Mohawk Power Corporation (NMPC) continues to investigate the effect of status-quo bias on customer participation in an I/C rate program. The Electric Power Research Institute and NMPC have jointly funded a study on the development of the integrated approach to reliability pricing using outage cost survey data and a demand model structure identified using real time pricing data. Initial results indicate that outage cost survey data can be used to parameterize the hourly electricity demand model for predicting customer response to alternative pricing schemes (e.g., priority service, proportional rationing and real time pricing). The response predictions are then used for evaluating the relative economic efficiency of the pricing schemes.

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Appendix 18.4b

Overview and Commentary on Appendix 18.4a

Cost of Service Disruptions to Electricity Consumers
Chi-Kueng Woo and Roger l. Pupp

Prepared by: Willis Energy Services Ltd.
500 - 885 Dunsmuir Street
Vancouver, BC
V6C 1N5

Introduction

This is a brief overview of the paper prepared by Chi-Kueng Woo and Roger L. Pupp, *Cost of Service Disruptions to Electricity Consumers*, published in the *Energy* periodical, Vol. 17 No. 2 pp. 109-126, 1992, (Woo and Pupp paper). The Woo and Pupp paper reviewed the results of 16 studies from the United States, Israel, and Canada, completed before 1991.

The intervening years have not diminished the relevancy of the findings in the paper, or that of the completed studies. Those intervening years have seen much activity in the areas of energy market restructuring and utility reregulation. While unbundling of services and rates was a priority in many jurisdictions, the regulatory focus remained on utility costs and their impact on customer rates. The 1992 Energy Act (US) led to the opening of markets, which in turn led utilities to adopt a competitive business approach. Market competition, combined with unbundling meant that little attention, if any, was paid to improving the understanding of the costs to customers of power outages. Even the design and pricing of recent demand reduction programs and tariffs, aimed at large customers, are being driven by utility and electric system costs and constraints.

The reviewed studies collected utility customer information about customers' valuation of reliability or customers' costs of service interruption and unserved load. The research interest is economic efficiency, recognizing that customers’ preferences for levels of reliability are not routinely considered in utility system planning or utility rate design. The utility service level provided may differ from what customers want or that for which they are willing to pay. In addition, customer preferences about service reliability would be valuable input to utility customer services and rate design.

This paper will provide

- ☐ a table summarizing the research/investigation approaches to estimating costs of outages to customers, including comments about the merits of each,
- ☐ comments on findings by customer class,
- ☐ interruption cost estimates from the 1998 FortisBC 20 Year System Plan, and
- ☐ Woo and Pupp paper conclusions.

Definitions

Attributes of power outages - time of day/week/year, frequency, duration, severity, and notification.

ex ante - before the fact; studies that track the customers’ response to an outage that may occur sometime in the future, and infer customer willingness to pay (WTP) for an increase in reliability (accept a payment for a decrease in reliability (WTA)).

ex post – after the fact; studies that measure customers’ costs for an actual outage.

Full outage – complete loss of service.

Estimation Methods

Table 1 is a summary of three approaches to cost estimation, one of which was applied in each of the 16 reviewed studies. The methods differ in the types of data and amount collected, design ability to address the attributes of outages (timing, frequency, duration, and advance notice), and their adherence to theory rigor.

The proxy method, to estimate WTP, relies on data not directly related to the event or participants. The method is convenient in that minimal data is needed and results can be obtained quickly. However several important attributes of costs of outages are not addressed, including frequency, duration, and full outage cost. Results also do not account for customer differences and cannot be verified.

The market-based approach looks at customers' consumption profile and estimates the price at which customers would no longer take service. This approach also uses information about participants in interruptible load programs offered by utilities. The method suffers from lack of sufficient data due to the limited offerings and participation in such programs. This method does not address all the attributes of outages.

The contingency valuation method relies on surveys, in which questions can address the attributes of outages and collect customer demographic data. The survey data can be subject to reliable statistical analysis, producing results that are suitable for utility planning and rate design.

Table 1 Summary of Approaches to Estimation

Approach	Methods Applied	Comments	
Proxy		Limited usefulness for utility planning and pricing	
	Average electricity tariff	Value of unsupplied electricity viewed as the opportunity cost and is equated to customer cost of outage	Does not represent total cost of service interruption
	Cost of maintaining backup power		Cannot estimate differences in outage costs due to change in outage attributes and/or customer demographics
	Value of foregone leisure/wage rate		Work restrictions for labour and non wage earning people prove this a weak proxy
	Value of foregone production (GDP/kWh consumed)	May be used as an approximation of the aggregate effect of an outage on an economy	Cannot estimate differences in outage costs due to change in attributes and customer demographics
Market based methods		Difficult to verify and does not respond to change in outage attributes	
	Examine customer behaviour	Infer outage cost from customer actions	
	Consumer surplus	Estimate of losses. Measures customer response to price increases (reduce planned consumption).	The unexpectedness of power outages does not allow consumers to respond in the same manner as to a rapid price increase.
	Customer choice	Requires data on customer participation in reliability differentiated rate offerings	Insufficient data due to limited choices or options that have been available for customers and limited participation in utility offerings
Contingent valuation method (CVM)		Amount of information and level of detail collected is adjustable to utility needs	Cost estimates are not verifiable but are reasonable based on 8 documented studies that used both CVM and actual market data with similar results. (Cummings et al) Woo and Pupp paper, page
	Survey direct costs	Actions and cost to adjust to an outage	
	Survey maximum amount customers are willing to pay (accept)	WTP for a higher level of reliability is not held equal to WTA for a lower level of reliability by most customers	WTP values range from 0.25 to 0.33 of WTA
	Survey customer preferences	Analysis of customers' rank of mutually exclusive service alternatives, by hypothetical group	Hypothetical bias, participants knowing that they do not have to follow through with purchase behaviour, may lead to participants stating prices in the survey higher than they would actually pay

Table 2 below is a brief overview of the findings of the reviewed studies and shows customer interruption cost information previously filed with the BCUC in FortisBC's 20 Year Plan. The estimates are based on BC Hydro localization of the findings derived from a 1991 NSERC-sponsored survey conducted by the University of Saskatchewan and. These results are consistent with the findings of prior studies included in the Woo and Pupp paper.

Table 2 Overview of Findings in Reviewed Studies

Cost of Service Disruptions to Electricity Consumers Article by Chi-Kueng Woo and Roger L. Pupp July 30, 1991				University of Saskatchewan 1991*	
Customer Class	Studies	Results		Non-momentary Outage Cost	
		Momentary outage	Non-momentary outage	*Dollars per hour of interruption*	*Dollars per kWh/kW Unserved*
Residential	Proxy approach, 3 ex ante, 5 post ante	Small cost	Higher costs for home business, home health care, and large families	3,124	1.24 $/kWh-out 0.00 $/kW-out
Commercial	CVM empirical approach, 3 ex post, direct costs of full outage	Small cost	Diverse costs for customers based on outage attributes and size of customer operation As outage duration increases, costs increase at a declining rate Interruption costs decline with frequency of interruptions Prefer fewer outages with longer duration Small consumers have large normalized costs	1,041	16.29 $/kWh-out 7.76 $/kW-out
Industrial	Proxy, market, CVM approach, 2 ex ante - proxy, market, 5 ex post - CVM direct costs		As outage duration increases, costs increase at a declining rate Time of day and day of week do affect cost Prefer fewer outages with longer duration Notification reduces cost of outages High load factor and electricity intensity operations has higher interruption costs Outage experience reduces cost of ensuing outages	417	7.91 $/kWh-out 2.32 $/kW-out

*** University of Saskatchewan – Customer Interruption Costs (1991)**

Based on above costs, a representative customer population consisting of 1 MW of load (750 kW residential, 150 kW commercial and 100 kW small industrial) would experience costs of $1396 for a momentary outage, plus $4165 for every hour that the outage persists

Above values correspond to customer costs prevailing in 1994. Current values in any year to be calculated using annual escalation of 2.2%

Conclusions

The Woo and Pupp paper makes several conclusions regarding the value of service reliability to customers. The value of the service is a measure of the usefulness and/or necessity of electricity to customers. At the time of the review (1992) no market for reliability had been established by electric utilities. Even today such a market is only emerging, focused on large users and few customers. Because there is limited market data capturing customers' actual behaviour and costs, the value of reliability to customers has been equated to the cost of an outage. To estimate the cost of outages, given the absence of market data, the application of the contingency valuation method (CVM) to estimate the cost of outages is recommended because it addresses the attributes of outages and customer demographics, upon which reliable statistical analyses can be performed.

David Bennett
Vice President, Regulatory Affairs
and General Counsel

FortisBC Inc.
Regulatory Affairs Department
1290 Esplanade Box 130
Trail BC V1R 4L4
Ph: (250) 717 0853
Fax: 1 866 605 9431
regulatory@fortisbc.com
www.fortisbc.com

FORTISBC ~ NARAMATA SUBSTATION PROJECT EXHIBIT

July 16, 2007

Via Email
Original via Courier

Mr. R.J. Pellatt
Commission Secretary
BC Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC   V6Z 2N3

Dear Mr. Pellatt:

Re: FortisBC Inc. ("FortisBC") Naramata Substation Project 3698458
WHO and/or ICNIRP EMF guidelines

Further to your letter dated June 22, 2007, requesting FortisBC to file any new guidelines, noting changes, prior to the hearing and comment on how the changes, if any, impact on the site comparisons, please find enclosed twenty copies of FortisBC's filing.

Sincerely,

(original signed by Joyce Martin)

David Bennett
Vice President Regulatory Affairs
and General Counsel

cc: Registered Intervenors

World Health Organization Review - Electromagnetic Fields

In its letter dated June 22, 2007 (Exhibit A-8), the BCUC stated that:

> "Mr. Karow, in his letter to the Commission of June 18, 2007 (Exhibit C1-41), makes reference to the possibility of new WHO and/or ICNIRP EMF guidelines being issued prior to the hearing. The Commission requests that FortisBC file any new guidelines, noting changes, prior to the hearing and comment on how the changes, if any, impact on the site comparisons."

The World Health Organization ("WHO") has since published two documents:

1. Fact Sheet No 322, June 2007 entitled "Electromagnetic Fields and Public Health, Exposure to extremely low frequency fields ", which is attached, and
2. Environmental Health Criteria Monograph No. 238, Extremely Low Frequency Fields. The 400 page document can be found through a link to the WHO website www.who.int/peh-emf/publications/elf_ehc/en/index.html.

The WHO continues to recognize the exposure levels previously established by the International Commission on Non-Ionizing Radiation Protection ("ICNIRP"). The document evaluates EMF research and health risks, and makes policy recommendations related to electric and magnetic fields in the 0 Hz – 100 kHz range, focusing mainly on 50-60 Hz power frequency fields. The findings of the WHO relevant to this project are as follows.

EMF Standards and Precautionary Policies

The WHO report Environmental Health Criteria Monograph No. 238, states:

> 1.1.12 Protective Measures
>
> "It is essential that exposure limits be implemented in order to protect against the established adverse effects of exposure to ELF electric and magnetic fields. These exposure limits should be based on a thorough examination of all the relevant scientific evidence.
>
> "Only the acute effects have been established and there are two international exposure limit guidelines (ICNIRP, 1998a; IEEE, 2002) designed to protect against these effects.
>
> "As well as these established acute effects, there are uncertainties about the existence of chronic effects, because of the limited evidence for a link between exposure to ELF magnetic fields and childhood leukemia. Therefore the use of precautionary approaches is warranted. However, it is not recommended that the limit values in exposure guidelines be reduced to some arbitrary level in the name of precaution. Such practice undermines the scientific foundation on which the limits are based and is likely to be an expensive and not necessarily effective way of providing protection." (page 12)

The report goes on to say that

> "Provided there is no compromise to health, social and economic benefits of electric power, implementing very low cost precautionary procedures to reduce exposures is reasonable and warranted." (page 13)

Impact on Site Selection

There is no impact on the location of the substation site as a result of WHO's latest information. For the substation itself, magnetic fields at other projects have shown levels to be well below the ICNIRP guidelines and therefore the location of the substation is not affected by EMF levels or the new WHO findings. The Arawana Road site does however have additional transmission infrastructure associated with its location.

In response to BCUC Information Request No. 1, Q4.4.7, FortisBC stated that the magnetic fields for the transmission line with distribution under build are expected to be between 2.54 and 4.28 mG, well below the ICNIRP level of 833 mG. FortisBC's position is that the line design with its compactness, distribution underbuild, and phasing orientation is consistent with the WHO recommendation.

For the reasons mentioned above, FortisBC maintains its position that EMF is not a factor in this project.

World Health Organization

Fact sheet N°322
June 2007

Electromagnetic fields and public health
Exposure to extremely low frequency fields

The use of electricity has become an integral part of everyday life. Whenever electricity flows, both electric and magnetic fields exist close to the lines that carry electricity, and close to appliances. Since the late 1970s, questions have been raised whether exposure to these extremely low frequency (ELF) electric and magnetic fields (EMF) produces adverse health consequences. Since then, much research has been done, successfully resolving important issues and narrowing the focus of future research.

In 1996, the World Health Organization (WHO) established the International Electromagnetic Fields Project to investigate potential health risks associated with technologies emitting EMF. A WHO Task Group recently concluded a review of the health implications of ELF fields (WHO, 2007).

This Fact Sheet is based on the findings of that Task Group and updates recent reviews on the health effects of ELF EMF published in 2002 by the International Agency for Research on Cancer (IARC), established under the auspices of WHO, and by the International Commission on Non-Ionizing Radiation Protection (ICNIRP) in 2003.

ELF field sources and residential exposures

Electric and magnetic fields exist wherever electric current flows - in power lines and cables, residential wiring and electrical appliances. **Electric** fields arise from electric charges, are measured in volts per metre (V/m) and are shielded by common materials, such as wood and metal. **Magnetic** fields arise from the motion of electric charges (i.e. a current), are expressed in tesla (T), or more commonly in millitesla (mT) or microtesla (µT). In some countries another unit called the gauss, (G), is commonly used (10,000 G = 1 T). These fields are not shielded by most common materials, and pass easily through them. Both types of fields are strongest close to the source and diminish with distance.

Most electric power operates at a frequency of 50 or 60 cycles per second, or hertz (Hz). Close to certain appliances, the magnetic field values can be of the order of a few hundred microtesla. Underneath power lines, magnetic fields can be about 20 µT and electric fields can be several thousand volts per metre. However, average residential power-frequency magnetic fields in homes are much lower - about 0.07 µT in Europe and 0.11 µT in North America. Mean values of the electric field in the home are up to several tens of volts per metre.

Task group evaluation

In October 2005, WHO convened a Task Group of scientific experts to assess any risks to health that might exist from exposure to ELF electric and magnetic fields in the frequency range >0 to 100,000 Hz (100 kHz). While IARC examined the evidence regarding cancer in 2002, this Task Group reviewed evidence for a number of health effects, and updated the evidence regarding cancer. The conclusions and recommendations of the Task Group are presented in a WHO Environmental Health Criteria (EHC) monograph (WHO, 2007).

Following a standard health risk assessment process, the Task Group concluded that there are no substantive health issues related to ELF electric fields at levels generally encountered by members of the public. Thus the remainder of this fact sheet addresses predominantly the effects of exposure to ELF magnetic fields.

Short-term effects

There are established biological effects from acute exposure at high levels (well above 100 µT) that are explained by recognized biophysical mechanisms. External ELF magnetic fields induce electric fields and currents in the body which, at very high field strengths, cause nerve and muscle stimulation and changes in nerve cell excitability in the central nervous system.

Potential long-term effects

Much of the scientific research examining long-term risks from ELF magnetic field exposure has focused on childhood leukaemia. In 2002, IARC published a monograph classifying ELF magnetic fields as "possibly carcinogenic to humans". This classification is used to denote an agent for which there is limited evidence of carcinogenicity in humans and less than sufficient evidence for carcinogenicity in experimental animals (other examples include coffee and welding fumes). This classification was based on pooled analyses of epidemiological studies demonstrating a consistent pattern of a two-fold increase in childhood leukaemia associated with average exposure to residential power-frequency magnetic field above 0.3 to 0.4 µT. The Task Group concluded that additional studies since then do not alter the status of this classification.

However, the epidemiological evidence is weakened by methodological problems, such as potential selection bias. In addition, there are no accepted biophysical mechanisms that would suggest that low-level exposures are involved in cancer development. Thus, if there were any effects from exposures to these low-level fields, it would have to be through a biological mechanism that is as yet unknown. Additionally, animal studies have been largely negative. Thus, on balance, the evidence related to childhood leukaemia is not strong enough to be considered causal.

Childhood leukaemia is a comparatively rare disease with a total annual number of new cases estimated to be 49,000 worldwide in 2000. Average magnetic field exposures above 0.3 µT in homes are rare: it is estimated that only between 1% and 4% of children live in such conditions. If the association between magnetic fields and childhood leukaemia is causal, the number of cases worldwide that might be attributable to magnetic field exposure is estimated to range from 100 to 2400 cases per year, based on values for the year 2000, representing 0.2 to 4.95% of the total incidence for that year. Thus, if ELF magnetic fields actually do increase the risk of the disease, when considered in a global context, the impact on public health of ELF EMF exposure would be limited.

A number of other adverse health effects have been studied for possible association with ELF magnetic field exposure. These include other childhood cancers, cancers in adults, depression, suicide, cardiovascular disorders, reproductive dysfunction, developmental disorders, immunological modifications, neurobehavioural effects and neurodegenerative disease. The WHO Task Group concluded that scientific evidence supporting an association between ELF magnetic field exposure and all of these health effects is much weaker than for childhood leukaemia. In some instances (i.e. for cardiovascular disease or breast cancer) the evidence suggests that these fields do not cause them.

International exposure guidelines

Health effects related to short-term, high-level exposure have been established and form the basis of two international exposure limit guidelines (ICNIRP, 1998; IEEE, 2002). At present, these bodies consider the scientific evidence related to possible health effects from long-term, low-level exposure to ELF fields insufficient to justify lowering these quantitative exposure limits.

WHO's guidance

For high-level short-term exposures to EMF, adverse health effects have been scientifically established (ICNIRP, 2003). International exposure guidelines designed to protect workers and the public from these effects should be adopted by policy makers. EMF protection programs should include exposure measurements from sources where exposures might be expected to exceed limit values.

Regarding long-term effects, given the weakness of the evidence for a link between exposure to ELF magnetic fields and childhood leukaemia, the benefits of exposure reduction on health are unclear. In view of this situation, the following recommendations are given:

- Government and industry should monitor science and promote research programmes to further reduce the uncertainty of the scientific evidence on the health effects of ELF field exposure. Through the ELF risk assessment process, gaps in knowledge have been identified and these form the basis of a new research agenda.
- Member States are encouraged to establish effective and open communication programmes with all stakeholders to enable informed decision-making. These may include improving coordination and consultation among industry, local government, and citizens in the planning process for ELF EMF-emitting facilities.
- When constructing new facilities and designing new equipment, including appliances, low-cost ways of reducing exposures may be explored. Appropriate exposure reduction measures will vary from one country to another. However, policies based on the adoption of arbitrary low exposure limits are not warranted.

Further reading

WHO - World Health Organization. Extremely low frequency fields. Environmental Health Criteria, Vol. 238. Geneva, World Health Organization, 2007.

IARC Working Group on the Evaluation of Carcinogenic Risks to Humans. Non-ionizing radiation, Part 1: Static and extremely low-frequency (ELF) electric and magnetic fields. Lyon, IARC, 2002 (Monographs on the Evaluation of Carcinogenic Risks to Humans, 80).

ICNIRP - International Commission on Non-Ionizing Radiation Protection. Exposure to static and low frequency electromagnetic fields, biological effects and health consequences (0-100 kHz). Bernhardt JH et al., eds. Oberschleissheim, International Commission on Non-ionizing Radiation Protection, 2003 (ICNIRP 13/2003).

ICNIRP – International Commission on Non-Ionizing Radiation Protection (1998). Guidelines for limiting exposure to time varying electric, magnetic and electromagnetic fields (up to 300 GHz). Health Physics 74(4), 494-522.

IEEE Standards Coordinating Committee 28. IEEE standard for safety levels with respect to human exposure to electromagnetic fields, 0-3 kHz.

New York, NY, IEEE - The Institute of Electrical and Electronics Engineers, 2002 (IEEE Std C95.6-2002).

For more information contact:

WHO Media centre
Telephone: +41 22 791 2222
E-mail: mediainquiries@who.int

Corporate links