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FORTISBC INC.
OTR PROJECT CPCN EXHIBIT B-11

May 13, 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 - Information Requests

Please find enclosed FortisBC Inc.'s responses to BC Utilities Commission Information Request No. 3, and Information Request No. 2 from Mr. C. Danninger, Mr. C. Harlingten, Mr. H. Karow, Mr. K. Cairns on behalf of SOFAR and Mr. Alan Wait. Twenty copies will be couriered to the Commission.

Sincerely,

David Bennett
Vice President, Regulatory Affairs
and General Counsel

cc: Registered Intervenors

93.0 Alternative Transmission Routes

Reference: Exhibit B-8, BCUC IR 83.2 and 83.3, and Danninger IR 3; Exhibit B-1-1, pp. 32, 40

FortisBC estimates that the Wiltse proposed route would cost $1.55 million more than 1A, require 1.3 km of new ROW, be no different than 1A for 8 of the 11 non-financial factors, and have an increased risk of delay, potential First Nations impacts and slightly higher environmental impacts.

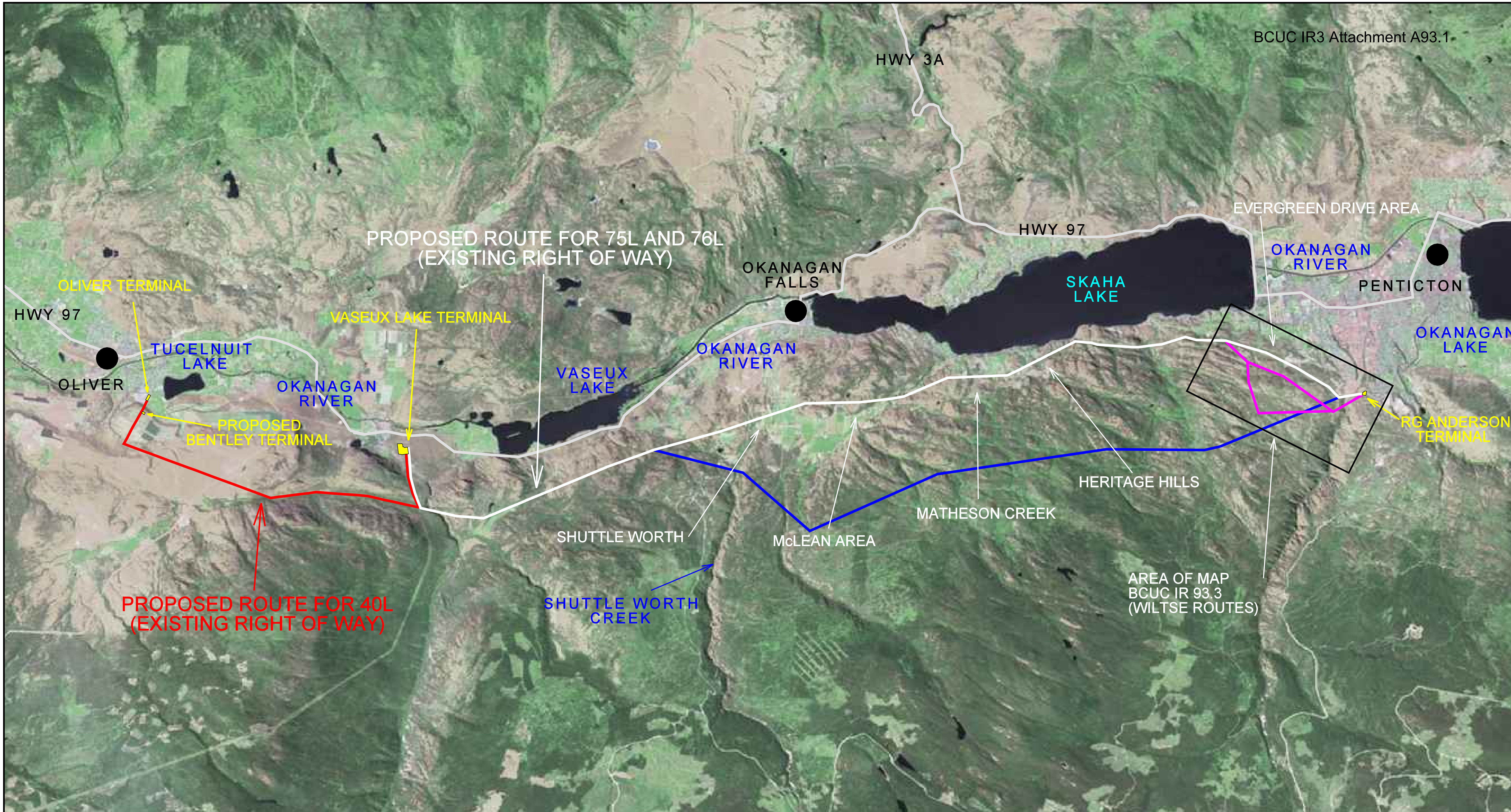
Fortis describes its upland alternative 2A as costing approximately $20 million more than 1A, requiring 19.2 km of new ROW, and having significant environmental issues, safety concerns, and maintenance challenges.

Q93.1 Why did FortisBC include 2A rather than the Wiltse proposed route (or a comparable alternative) in its CPCN Application?

A93.1 It is the view of FortisBC that the routes proposed by Wiltse Holdings Inc. (“Wiltse”) are not, in a material way, “alternatives” to the OTR Project preferred route. As seen in BCUC IR3 Attachment A93.1 following, all but approximately 4.3 kilometers of the line would remain on the existing right-of-way.

FortisBC investigated alternatives to the existing right-of-way at the request of stakeholders during the public consultation process. Residents of the Heritage Hills, McLean Creek and Shuttleworth Creek areas were among those stating a preference for a higher elevation route. Unlike Alternative 2A, the Wiltse routes do not address the concerns of residents in those areas.

BCUC IR3 Attachment A93.1



LEGEND

EXISTING TRANSMISSION CIRCUIT L40	red line
EXISTING TRANSMISSION CIRCUIT L76	green double line
PROPOSED UPLAND ROUTE	blue line
WILTSE ROUTES	magenta line

NOTE: REFER TO BCUC IR 93.3 FOR DETAILS OF WILTSE ROUTES

PRODUCED BY PHOTOGRAMMETRY SERVICES, BC HYDRO
DIGITAL ORTHOPHOTO METRIC MAP
UTM ZONE 11, NAD83
BCGS REFERENCE: 82E
ORTHOPHOTO GENERATED AND
RECTIFICATION BASED ON DEM COMPILED
FROM 1:20,000 SCALE AERIAL PHOTOGRAPHY,
TAKEN SEP 17, 2005

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FORTIS BC - OTR PROJECT
OVERVIEW WITH WILTSE ROUTES
ORTHOPHOTO MAP

DRAWING NUMBER	REV
BCUC IR 93.1	A

Q93.2 Does FortisBC consider the Wiltse proposed route preferable to 2A?

A93.2 In some (non-financial) respects the Wiltse proposed route may be preferable to Alternative 2A. Generally, the Wiltse proposed route requires approximately 1.5 kilometers of new rights-of-way (0.8 kilometers on Crown land and 0.7 kilometers on private property, including property owned by the City of Penticton), compared to approximately 19 kilometers through Crown land for Alternative 2A.

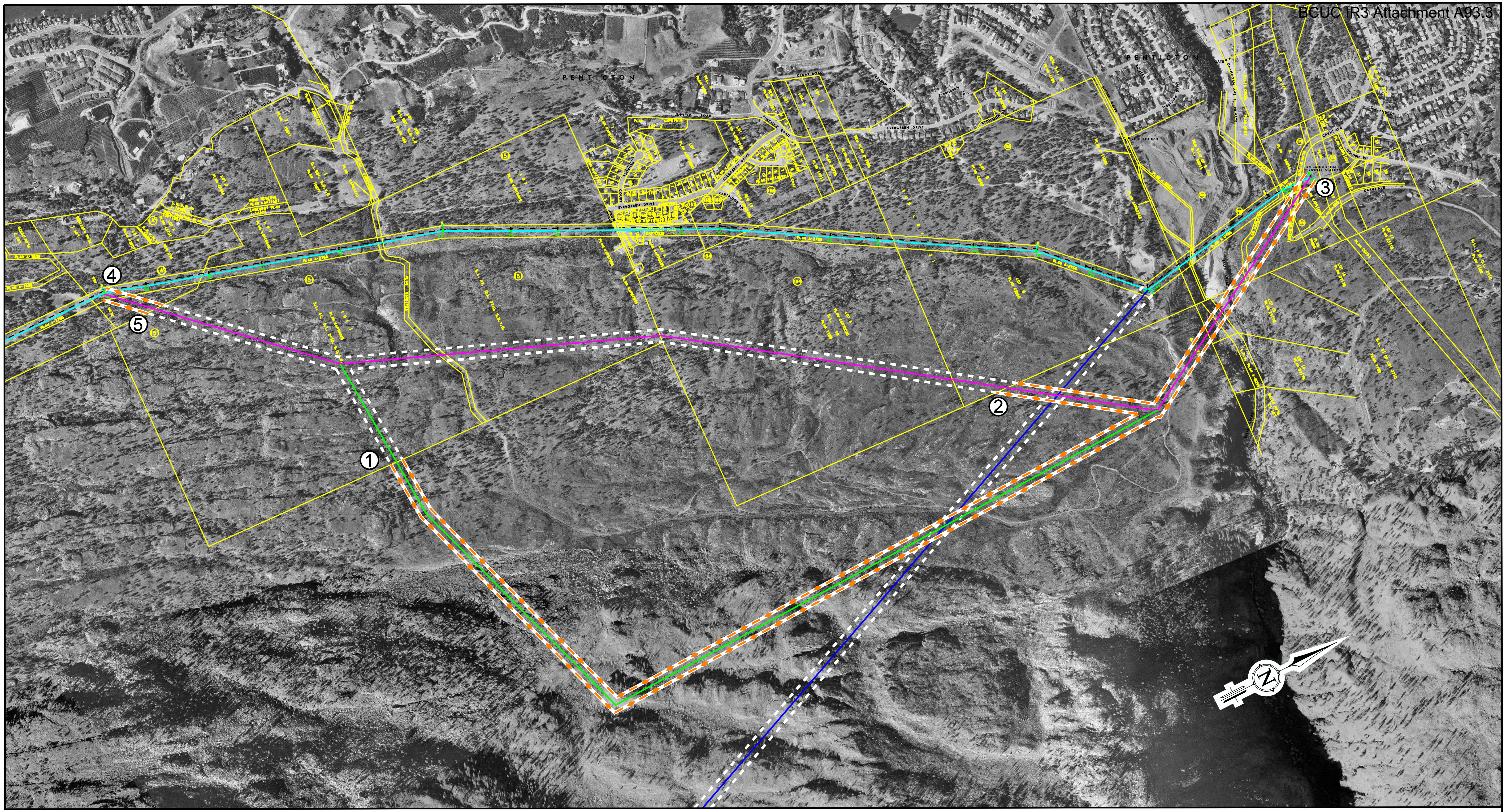
Environmental and archaeological assessments have not been carried out, however the shorter length of greenfield construction suggests that this aspect may favour the Wiltse proposed route over Alternative 2A.

FortisBC notes, however, that the location of the Wiltse proposed route may give rise to significant concerns from some stakeholders, in particular private land owners on whose properties new rights-of-way would be required to facilitate this alignment. Public consultation would be required to determine other stakeholder concerns.

From a financial perspective, the rate impact of the Wiltse proposed route is preferable to Alternative 2A. Incremental costs associated with the Wiltse proposed route are expected to be paid by Wiltse, while the incremental cost of Alternative 2A is $26.5 million.

Q93.3 Please identify the portions of the 1.3 km of new ROW required for the Wiltse proposed route which create the risk of delay and the potential First Nations and environmental impacts.

A93.3 The portion at the north end of the Wiltse proposed route (Exhibit C16-1) which creates the risk of delay is between reference points 2 and 3 (BCUC IR3 Attachment 93.3) prior to the line entering RG Anderson Terminal. This section of the Wiltse proposed route requires new right-of-way across Crown land which would require ILMB approval and may be subject to similar risks and impacts as discussed in Section 4.3.5 of the CPCN Application (Exhibit B-1-1). This section also crosses two private properties and two parcels owned by the City of Penticton. A section approximately 200 meters at the south end of the Wiltse proposed route (between reference points 4 and 5 in BCUC IR3 Attachment 93.3) also crosses one private property adjacent to the Wiltse property. In order to facilitate the Wiltse proposed route FortisBC would be required to negotiate new rights-of-way with these three private land owners and the City of Penticton. There is a risk that these landowners would not be in agreement with the crossings.



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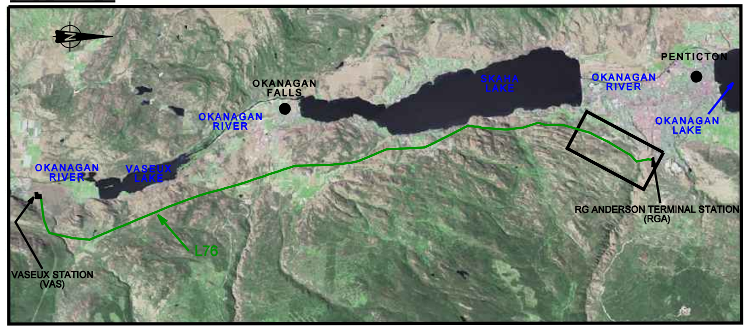

LEGEND

EXISTING R/W FORTISBC ALT. 1A	
WILTSE ROUTE PREFERRED	
WILTSE ROUTE PROPOSED	
UPLAND ROUTE FORTISBC ALT. 2A	
NEW R/W OUTSIDE OF WILTSE PROPERTY	
REFERENCE POINT	1

CADASTRAL BOUNDARY	
PROPERTY LINE LIST NUMBER	

300 0 300 600m

AS SHOWN

PRODUCED BY PHOTOGRAMMETRY SERVICES, BC HYDRO
DIGITAL ORTHOPHOTO METRIC MAP
UTM ZONE 11, NAD83
BCGS REFERENCE: 82E
ORTHOPHOTO GENERATED AND
RECTIFICATION BASED ON DEM COMPILED
FROM 1:20,000 SCALE AERIAL PHOTOGRAPHY,
TAKEN SEP 17, 2005

NOTE:
1) Cadastre was computed by Survey Services. BC Hydro Accuracy +/- 0.25 metres.

No.	BY	DATE	DESCRIPTION	No.	BY	DATE	DESCRIPTION			
								DESIGNED BY		
								DRAWN BY	GJB	2008.04.28
								CHECKED BY		
								APPROVED BY		

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FORTIS BC - OTR PROJECT
76L VAS - RGA
WILTSE PROPERTY SECTION BCUC IR 93.3
ORTHOPHOTO MAP

DRAWING NUMBER	REV
BCUC IR 93.3	A

94.0 Financial Factors Comparison

Reference: Exhibit B-8, BCUC IR 92.3; Order No. G-58-06

Order No. G-58-06 approved a Negotiated Settlement which included depreciation rates but stated on page 3 that "no precedent value is established by the settlement."

Q94.1 Why should a 3 percent depreciation rate be used for assets with 45 to 50 year estimated service lives?

A94.1 The relationship between depreciation rates and service life of assets was discussed in FortisBC's 2006 Revenue Requirements application. (FortisBC response to BCUC IR Q57.2.1, dated March 8, 2006)

> **Q57.2.1 The depreciation rate is not indicative of the estimate life of the asset. Is there a change in methodology from how depreciation rates were set from the last depreciation study?**
>
> A57.2.1 As indicated in response to BCUC Q57.1, the depreciation rates as developed in this study are generally based on the average service life estimate, the estimated net salvage requirement and the aged surviving balance distribution at the time of the study. Additionally, this deprecation study incorporated a "Remaining Life" concept wherein any gains and losses from historic retirement transactions are amortized over the estimated remaining life of each account.
>
> The average service life estimates, and estimated composite remaining life have been developed using the concept of interim retirement dispersion. In this manner, it is not anticipated that all plant installed in any given year lives will retire at the same time. For example, if plant is estimated to have an average service life of 20 years, it could be anticipated that some of the plant may retire as early as year 1 and other plant may live to 40 years, and that there may be a period of significant retirement activity between the ages of 15 to 25. However, the overall average of the estimated retirements is 20 years. If more retirement activity occurs later than the average age used in the previous depreciation study, the accumulated depreciation account will be in a surplus position. Conversely a

deficient accumulated depreciation position results if more retirement activity has been occurring prior to the estimated average service life.

The same influence is also caused by the cost of retiring plant at the time it is retired. For example, if no net salvage is incorporated in the depreciation rate, but at the time of retirement a significant cost of retiring the plant occurred, an accumulated depreciation deficient will result. The Gannett Fleming depreciation study developed a correction to the accumulated depreciation position over the composite remaining life of the each account. As such, the depreciation rates as presented in the Gannett Fleming study are not solely indicative of the estimated life of the plant.

The Negotiated Settlement Agreement (NSA) approved in Order G-58-06 set the depreciation rates for the term of the Performance-Based Regulation (PBR) term defined therein. The statement that “no precedent value is established by the settlement” was included to clarify that the parties to the NSA had not reached an agreement on certain issues related to depreciation, and accepted the rates only for the term of the PBR Plan. The depreciation rates will be reviewed again in a future Revenue Requirements application.

95.0 Capacity Available at BC Hydro Vernon Interconnect

Reference: Exhibit B-8, BCUC IR 69.3

Q95.1 Further to the response to BCUC IR No. 69.3, please provide a full description of the steps that FortisBC would need to take in order to make the full 499 MVA available at the Vernon Interconnect, and the timeframe that it is likely to take to accomplish this.

A95.1 The Vernon import limit, while primarily contractual, is also based on technical limitations. The limit is set by BCTC based on its planning criteria. FortisBC's understanding is that the limitation is an average import capacity based on two main factors: 1) the total and contingency capacity of the Vernon-area transmission network; and 2) post-contingency voltage drop criteria. Increasing the limit would require BCTC and FortisBC to participate in joint planning studies and negotiations to determine whether any system improvements are required and how they would be funded. Studies of this magnitude could take one year or more to complete. BCTC would then be responsible for constructing any required infrastructure upgrades in its system. FortisBC is unable to speak for BCTC and how quickly these upgrades could be completed. FortisBC is also unable to speak for BCTC as to whether BCTC would be prepared to consider a contractual change, once the technical review has been completed.

Q95.2 Please quantify the initial and ongoing costs that would be required to make the full 499 MVA available at the Vernon Interconnect.

A95.2 In the absence of the technical studies identified in the response to Q95.1 above, FortisBC provides the following examples of system improvements that may be required:

- addition of reactive support in the Kelowna or Vernon areas;
- construction of additional transmission facilities; or
- addition of generation resources in the Okanagan area.

One possible scenario would be the addition of a third 230 kV transmission line between Ashton Creek and Vernon Terminal. This would be an approximate 50 kilometer transmission line, likely on new right-of-way. The cost of this line could be in excess of $55 million (order of magnitude estimate).

96.0 Timing of 150 Mvar SVC and Capacitor Banks

Reference: Exhibit B-8, BCUC IR 71.1

Q96.1 For Option (b), with the SVC at Bell in service, why did FortisBC use the criterion of N-2 compliance to determine that the two capacitor banks need to be installed for 2013?

A96.1 The capacitor banks are shown as required in 2013 to present a fair comparison with the OTR Project as proposed. In the same way that the SVC is planned for addition following the completion of the OTR Project to maintain N-2 compliance, the capacitor banks would also be required for continued N-2 compliance if the SVC was installed first. The Okanagan winter peak load in the 2012/2013 time frame is forecast to be at a level where voltage violations or even a blackout may occur following N-2 contingencies if additional reactive compensation is not provided by installing the capacitor banks.

Q96.2 With the SVC at Bell in service, when would the two capacitor banks be needed to meet N-1 compliance? In that year, how many hours per year of load could not be met if the two capacitor banks were not in service?

A96.2 With the SVC at the DG Bell Terminal station in service, the capacitor banks at FA Lee and DG Bell are not required for N-1 compliance. There are two critical (N-1) outages: an outage of 73 Line (RG Anderson - DG Bell), or the SVC itself. In both cases the violation of the voltage criteria occurs at a load level which is beyond the current twenty-year planning horizon.

Q96.3 Assuming OTR proceeds without the two capacitor banks, when would the SVC need to go into service in order to meet an N-1 criterion? In that year, how many hours per year of load could not be met if the SVC was not in service?

A96.3 If the OTR Project proceeds without the FA Lee and DG Bell capacitor banks, the SVC will be needed when the Okanagan load level exceeds the technical limit of approximately 500 MW (forecast to occur in 2011/2012). The Okanagan load is expected to be above this level for two hours in 2011 and six hours in 2012.

Q96.4 Assuming OTR proceeds with the two capacitor banks, why does FortisBC consider that the SVC will need to be in service for 2011? When would the SVC need to go into service in order to meet a N-1 criterion? In that year, how many hours per year of load could not be met if the SVC was not in service?

A96.4 If the OTR Project proceeds with the FA Lee and DG Bell capacitor banks, the SVC will be needed to satisfy the N-1-1/N-2 criterion when the Okanagan load exceeds 430 MW. In the 2005 SDP the Okanagan load was forecast to exceed this level in 2010/2011.

To meet the N-1 criterion the SVC needs to go into service when the Okanagan load is approximately 562 MW. The load is forecast to exceed this level in 2018/2019 and is expected to be above this level for approximately six hours in that year.

Q96.5 Please repeat BCUC Table A71.1 using the assumption for Option (b) that the two capacitor banks are not installed until each of them is needed for N-1 compliance.

A96.5 Please refer to the response to Q96.2 above, which clarifies that with the introduction of SVC as in Option (b) of BCUC IR2 Table A71.1, the capacitor banks will not be necessary for N-1 compliance. A table comparable to BCUC IR2 Table A71.1 shows the elimination of the capacitor costs in 2011-2013. BCUC IR3 Table A96.5 (a) below considers NPV and rate impact in terms of revenue requirements going out till 2030 (i.e. twenty years from the OTR in-service date of 2010).

BCUC IR3 Table A96.5 (a)

Option (b) - OTR Project with SVC only and no capacitors

Description	2008	2009	2010	
	($000s)			
30 Mvar capacitor at LEE				
30 Mvar capacitor at DGB				
150 Mvar SVC at DGB	2,247	11,797	12,269	
Total:	**2,247**	**11,797**	**12,269**	**26,312**
NPV	**18,934**			
NPV of Rate Impact	**0.71%**			
Max One Time Rate Impact	**1.12%**			

For the purpose of comparison, BCUC IR3 Table A96.5 (b), below shows NPV and rate impact in terms of revenue requirements going out till 2030 (i.e., twenty years from the OTR in-service date of 2010).

BCUC IR3 Table A96.5 (b)

Option (b): OTR Project with SVC initially and capacitors in 2013

Description	2008	2009	2010	2011	2012	2013	
	($000s)						
30 Mvar capacitor at LEE				211	1089	898	
30 Mvar capacitor at DGB				205	1056	870	
150 Mvar SVC at DGB	2,247	11797	12269				
Total:	**2,247**	**11,797**	**12,269**	**416**	**2,145**	**1,767**	**30,641**
NPV	**21,199**						
NPV of Rate Impact	**0.79%**						
Max One Time Rate Impact	**1.17%**						

Q96.6 What discount rate was used to calculate NPV? Was the discounting to 2008 or another year?

A96.6 A discount rate of 10 percent was used to calculate the NPV. Future costs and expenditures are discounted to 2008.

97.0 Timing of SVC and Capacitor Banks

Reference: Exhibit B-8, BCUC IR 2.71.1, 2.88.3, 2.89.0

In responding to the following questions, please assume that Option (b) is implemented - that is, that the SVC is installed as part of OTR and the capacitor banks are deferred to a future date. FortisBC states that the capacitor banks will be required in 2013 to meet continued N-2 compliance.

Q97.1 **Based on the statement that the capacitor banks are required in 2013 to continue to meet the N-2 criterion, can it be assumed that the criterion will be met through 2013 without the banks?**

A97.1 Yes, assuming that the Okanagan peak load remains below 508 MW (currently forecast for 2013), the N-2 criterion can be met without the additional capacitor banks.

Q97.2 **How long past 2013 would the installation of the capacitor banks have to be deferred to make the NPV of Option (b) equal to the NPV of Option (a)?**

A97.2 The installation of the capacitors in Option (b) has to be deferred from 2011-2013 (refer to BCUC IR2 Table A71.1) to 2015-2017 timeframe to make the NPV of (Modified) Option (b) equal to the NPV of Option (a).

Q97.3 **How much of a reduction in FortisBC's load forecast would be required to allow deferral of the capacitor banks for the time given in response to the previous question?**

A97.3 The previous question assumes installation of SVC prior to the capacitor banks. As stated in the responses to Q96.2 and Q96.5 above, the capacitor banks will not be necessary for N-1 compliance. However, for N-2 / N-1-1 compliance, capacitor banks will be required when the Okanagan (Kelowna and Penticton) load exceeds 508 MW. The response to Q97.6 below assumes installation of capacitor banks during 2015-2017. The Okanagan peak load is expected to be 564 MW in 2017. Hence a reduction of 56 MW (564 – 508) in FortisBC's load forecast would be required to allow a deferral of the capacitor banks for the time given in response to Q97.2 above (i.e. 2017).

Q97.4 Does FortisBC consider that new rate options associated with AMI, such as time-of-use rates or critical peak pricing, might influence the need for the capacitor banks before 2013?

A97.4 The requirement for the capacitor banks is load related. FortisBC stated in the response to BCUC IR2 Q89.1:

> *FortisBC has not ascribed any load reduction targets or estimates in its AMI Application or the Amended Application currently before the Commission, and will require more data to be collected after the installation of the infrastructure in order to do so. Therefore, the impacts of AMI have not been incorporated into the forecasts in the OTR Project. Any load impact resulting from the installation of AMI would not be realized in time to defer the need for the OTR Project. FortisBC also notes that of the Okanagan regions 100,000 customers, 34 percent are not served directly by FortisBC and are not currently included in the installation of AMI.*

Full implementation of the AMI Project will not be completed until 2010, following which rate design options, supported by load analysis, would need to be examined and approved. Load reductions sufficient to influence the timing of the capacitor banks are unlikely to be achieved.

Q97.5 Please provide a table that shows, for each of the three "blue" scenarios highlighted in the response to BCUC IR No. 1 Q9.4.5 and for each of the N-0, N-1, and N-1-1/N-2 operating states, the following data:

a. the number of hours per year in which load cannot be met, as already provided;

b. the annual energy at risk (MWh), i.e., the energy represented by the area between the annual load duration curve and the horizontal line representing the transmission capacity in the corresponding operating state;

c. the probability that the system is in the corresponding operating state;

d. the product of (b) and (c), which will be (roughly) the expected value of the energy loss associated with the operating state; and

e. the sum of the (d) values for the N-0, N-1, and N-1-1/N-2 operating states, which will be a "back of the envelope" estimate of expected unserved energy in the years 2011, 2016, and 2024.

For simplicity, it may be assumed that the probabilities of N-1 and N-1-1/N-2 events are evenly distributed throughout the year, though FortisBC is free to alter this assumption if it is appropriate to do so. The probabilities used may be those provided in the response to BCUC IR No. 1 Q10.5.

A97.5 Following is the "back of the envelope" analysis as requested. However, FortisBC recommends caution in deriving conclusions from this information. The value obtained is not truly EENS (Expected Energy Not Served) for a number of reasons:

1. The analysis is simplistic and assumes that all demand exceeding the

capacity limit (for the entire year) is exposed to one contingency event. This would not be the case in reality as a contingency does not last for the entire year. This assumption results in an overstatement of the expected energy not served.

2. Additionally, the specific likelihood of one or more individual elements being out of service and causing an N-1 or N-2 outage has been ignored. Including this outage probability is impractical in this simple calculation as all elements have different discrete and joint probabilities. This assumption results in an overstatement of the expected energy not served.

3. Finally, the assumption is made that during a contingency only the exact amount of demand exceeding the system capacity can be shed. This is unrealistic as load must be shed in blocks (typically by tripping transmission lines) and almost always results in over-shedding. This assumption results in an understatement of the expected energy not served.

Thus, the values obtained are not realistic in absolute sense, but may be used for comparative purposes (for example, in a comparison with the values shown in the response to Q98.1 below).

BCUC IR3 Table A97.5

Year	Scenario	Load not met (hrs)	Annual energy at risk (MWh)	Probability of system in corresponding operating state (parts per million)	Simplistic expected energy not served (MWh / year)
		a	b	c (= a / 8760)	d = b x c
2011	N-1	0	0	0	0
	N-1-1 / N-2	42	1,344	4,795	6.4
2016	N-1	0	0	0	0
	N-1-1 / N-2	177	5,381	20,205	108.7
2024	N-1	27	777	3,082	2.4
	N-1-1 / N-2	809	31,114	92,351	2,873.4
				e (Sum of all years):	2,991

Q97.6 In its response to BCUC IR No. 1 Q7.4, FortisBC stated 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.” In FortisBC’s view, does this statement apply with respect to the capacitor banks?

A97.6 Yes, as stated in the response to Q96.3 above, the capacitor banks are also required to meet N-1 criterion.

Q97.7 What are the operational considerations, if any, associated with putting the SVC in service before the capacitor banks?

A97.7 In terms of functionality, an SVC would be able to perform the same function as fixed capacitor banks. However, SVCs are complex devices and would have higher ongoing operation and maintenance costs than the much simpler capacitor banks.

98.0 Timing of SVC and Capacitor Banks

Reference: Exhibit B-8, BCUC IR 2.71.1

Q98.1 Please repeat the previous question's "back of the envelope" analysis of expected unserved energy for the case in which neither the SVC nor the capacitor banks are installed.

A98.1 Following is the "back of the envelope" analysis as requested. FortisBC notes that the same cautions described in the response to Q97.5 above apply for this calculation as well.

As noted, the values obtained are not realistic in absolute sense, but may be used for comparative purposes (for example in a comparison with the values shown in the response to Q97.5 above).

BCUC IR3 Table A98.1

Year	Scenario	Load not met (hrs)	Annual energy at risk (MWh)	Probability of system in corresponding operating state (parts per million)	Simplistic expected energy not served (MWh / year)
		a	b	c (= a / 8760)	d = b x c
2011	N-1	2	13	228	0.003
	N-1-1 / N-2	267	7,731	30,479	236
2016	N-1	25	564	2,854	1.6
	N-1-1 / N-2	786	26,002	89,726	2,333
2024	N-1	127	4,556	14,497	66
	N-1-1 / N-2	2,112	104,110	241,096	25,100
				e (Sum of all years):	27,737

Q98.2 FortisBC states that Option (a) is preferable in part because the high-cost SVC can be better timed for installation when required. Please describe the factors that could defer or accelerate the requirement for the SVC.

A98.2 As discussed in the response to Q97.7 above, SVCs are complex devices which have significant ongoing operating costs. In order to minimize these costs it is desirable to optimize the design and size of the SVC as much as possible. The studies and design reviews for this type of project would consume a significant amount of planning and engineering resources (both internal and external).

Since the SVC is primarily needed for N-1-1/N-2 support following the OTR Project, FortisBC feels that it would be prudent to defer the detailed studies and design for this facility.

99.0 Conductor Sizes Vaseux to Anderson

Reference: Exhibit B-8, BCUC IR 73.4, 80.1

Q99.1 Further to the response to BCUC IR 73.4, what would be the additional cost of using Bunting rather than Drake conductor for Alternative 1B?

A99.1 The additional cost of using Bunting rather than Drake conductor is estimated to be in the order of approximately seven percent.

Q99.2 For Alternative 1B, please provide a comparison of Drake and Bunting conductors in terms of thermal capacity, capacity considering radio interference, annual cost of losses, structure height, visual impact and other significant factors.

A99.2 The comparison of Drake and Bunting conductors with Drake conductor to a base of 1.0 is provided below:

BCUC IR3 Table A99.2

	Drake conductor	**Bunting conductor**
Diameter (mm)	28.13	33.08
DC Resistance @ 20°C (ohms/ km)	0.0701	0.04734
Approximate annual cost of losses (energy only)	$85,000	$57,400
Thermal capacity @ 75°C (A)	907	1,139
Radio Interference (dBA)	53.5 (1)	49.2
Audible Noise - Fair weather (L5 dBA)	25.8	22.7
Audible Noise - Rain (L5 dBA)	50.8	47.4
Sag for 350 m span @ 50% max. tension under loaded condition (m)	12.5	14
Structure Height Impacts	Though the Bunting may sag 1 to 2 meters more than the Drake conductor, not all spans are impacted because of the terrain. Other factors such as insulator swing limit the reduction in height, therefore the difference will be minor, perhaps 1 in 5 structures.	
Visual Impact	It is believed the 5 mm difference in diameter will not be discernable.	

Note (1) The preliminary radio interference estimate calculations show a small 0.5 dBA excursion above the 53 dBA limit for the Drake conductor. If Alternative 1B is selected, the final design engineering will assess the risks of real excursion and if justified, would identify the minor adjustments to the final design to reduce such risk. If adjustments are needed they could include a small increase to the conductor size which would likely be smaller than Bunting or they would be to phase spacing or height or in combination. Any such adjustments would fall well within the contingency budget of the line and would not affect the overall project estimate.

100.0 Conductor Sizes Vaseux to Anderson

Reference: Exhibit B-8, BCUC IR 2.73.4, 2.80.1

In its response to BCUC IR No. 2 Q55.3, FortisBC states that, in general, electromagnetic interference associated with corona discharge is not a problem for transmission lines operating at voltages below 345 kV. In its response to BCUC IR No. 2 Q80.1, FortisBC states that for Alternative 1A with compact phase spacing, the conductor size was increased from 795 kcmil (Drake) to 1192 kcmil (Bunting) to achieve compliance.

Q100.1 Please provide a copy of the interference and audible noise guidelines, and provide the calculations used to check compliance with those guidelines for both Drake and Bunting.

A100.1 The guideline applied for radio or electromagnetic interference is a BC Hydro Engineering Standard, titled Transmission Line Radio Interference and is attached (BCUC IR3 Attachment A100.1). This engineering standard is used by BC Hydro to develop transmission lines that meet Industry Canada's Spectrum Management and Telecommunications Policy Interference-Causing Equipment Standard, ICES-004, titled "Alternating Current High Voltage Power Systems".

The guideline applied for audible noise is a BC Hydro Engineering Standard, titled Transmission Audible Noise is also in BCUC IR3 Attachment A100.1.

The resultant calculations for Alternative 1A are shown in BCUC IR3 Table A100.1 below.

BCUC IR3 Table A100.1

Conductor	**Maximum Radio Interference** (dB*u*V/m) Regulatory Limit =53	**Audible Noise** (L5 dBA) Guide Limit = 55	
		Fair weather	Rain
Drake	56.7	27.8	52.8
Bunting	52.6	24.7	49.7

BC hydro	ENGINEERING STANDARD TRANSMISSION ENGINEERING	
Subject: TRANSMISSION LINE RADIO INTERFERENCE	Dsgn Rev Acpt Date March 17/2000	ES 41-K SECTION 4.1

This Technical Standard provides information for line designers to follow, and to develop transmission lines that will meet The Federal radio interference (RI) limits prescribed in the Radio Interference Regulations of the Radiocommunication Act. Measurement requirements are also given. For more details, please refer to Engineering Memorandum No. 6053.

1. RADIO INTERFERENCE LIMITS

RI from transmission lines in fair weather shall be designed with maximum levels below those in Table 1, given for CISPR meter at 0.5 MHz, and at 15 m horizontal distance from the outermost conductor. Maximum levels at other frequencies from 0.15 to 30 MHz shall be corrected to the reference frequency using Figure 1.

Table 1
Maximum Fair Weather RI Limits

Nominal phase to phase voltage (kV)	Maximum RI limit (dBμV/m)
138	49
230	53
287	53
360	56
500	60
765	63

2. CALCULATION METHOD

a) The BPA Corona and Field Effects program is to be used.
b) Calculate median (L_{50}) fair weather RI levels at 1 MHz, and at 15 m from the outermost conductor, using parameters as follows:

i) The voltages to be used for 500, 230, and 138 kV class lines are: 525, 242 and 140 kV, respectively.
ii) The antenna height shall be 1.5 m.
iii) Use the average height of the conductors along the span.
iv) Use the appropriate altitude. If less than 300 m, use zero (sea level).
v) Use the correct phasing for multiple circuits, e.g., in the case of a double circuit line, or two or more circuits on a right-of-way.
vi) No corrections for atmospheric conditions (air density, humidity and wind) are to be applied.

c) Convert the value in (b) to CISPR at 0.5 MHz by adding 3 dB.
d) Convert the value in (c) to the maximum fair weather value by adding 10 dB.
e) An allowance is to be made, where applicable, for the increase in RI which would result from any nearby HVDC converter equipment, series capacitor stations, or noisy line hardware.

3. MEASUREMENT REQUIREMENTS

a) Measurements are required for each new line 138 kV and above which is longer than 10 km, for each existing line which has been altered by adding a tap line or by changing the design parameters, any new station, and any existing station which has been changed in any way (e.g., adding a transformer bank).
b) For power lines, measurements are required at three sites: near both ends and at the middle.
c) RI measurements shall be taken within six months after being placed in operation; results shall be retained for at least five years and made available for examination on the request of the Minister.
d) Measurements shall be taken using CISPR instruments.
e) Measurements shall be taken at a horizontal distance from the outermost conductor equal to 15 m. Where measurements cannot be taken at 15 m, measurements shall be taken: i) at the nearest convenient distance and corrected to 15 m using Figure 2; or ii) at distances that are greater or lesser than 15 m, and using interpolation to determine the correct reading at 15 m.
f) A lateral profile at 0.5 MHz is also to be taken out to a distance of 80 m from the outer phase per IEEE standard.
g) A radio noise spectrum for the range 0.01 to 30 MHz shall also be taken at 15 m horizontal distance from the outermost conductor per IEEE standard.
h) Measurements are to be taken by experienced staff using properly calibrated equipment. Details of the measurement procedures and the necessary precautions are given in Section 7 of Engineering Memorandum No. 6053.

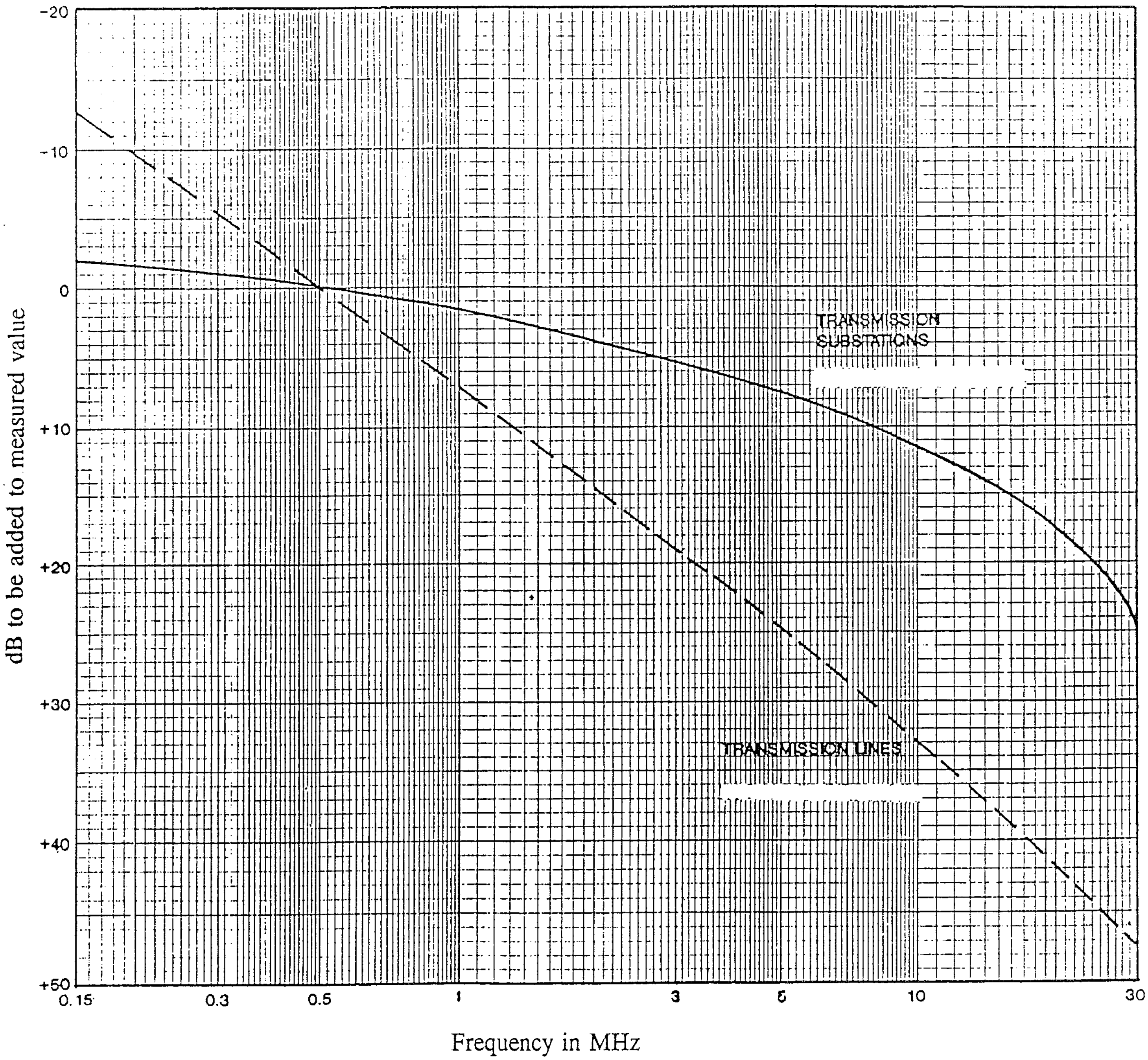

Figure 1 Frequency Correction Factors

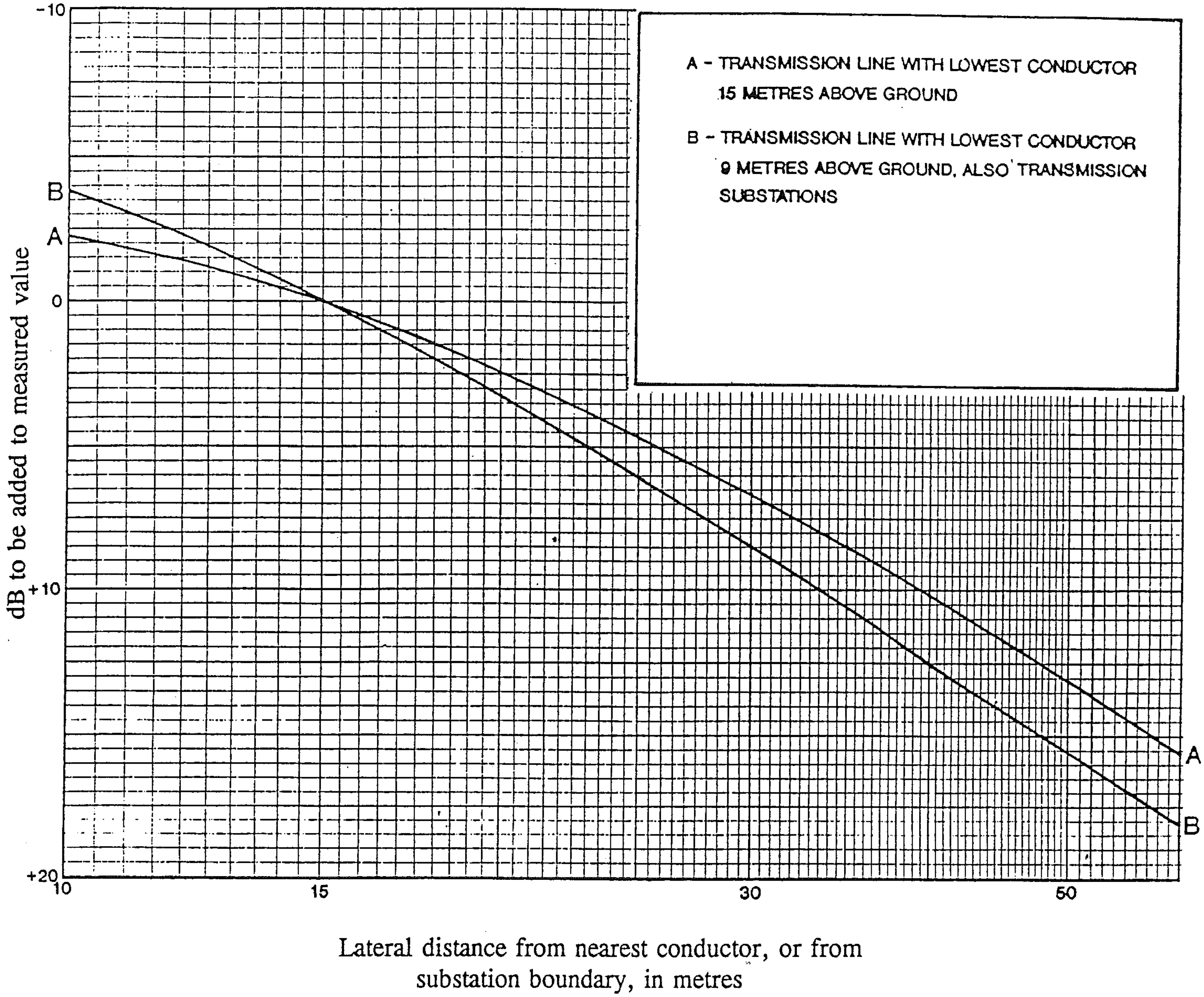

Figure 2 Lateral Distance Correction Factors

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BC hydro	ENGINEERING STANDARD TRANSMISSION ENGINEERING	
Subject: TRANSMISSION LINE AUDIBLE NOISE	Dsgn Rev Acpt Date March 17/2000	ES 41-K SECTION 4.2

This document provides information for line designers to follow; the objective being to ensure that the audible noise (AN) produced by power lines is within acceptable limits. Measurement guidelines for transmission lines are also given. The Document is based on Engineering Memorandum No. 6052 (the "AN Report"); the draft of which was prepared for BC Hydro by Paul S. Wong of P.W. International.

Sound energy is measured in decibels (dB) referenced to 20 μPa, which is the threshold of hearing. Since the sensitivity of the human ear is a function of frequency of the sound and the subject sound involves components covering a wide frequency spectrum, the overall energy in the entire frequency spectrum is measured using a weighting network. The most widely used weighting network is referred to as type "A", and the resulting units are referred to as dBA.

1. ACCEPTABLE AN LEVELS

Transmission lines shall be designed to produce a L_5 rain AN level at the edge of the right-of-way below 55 dBA in residential, urban, suburban and rural areas (including Indian lands), and below 70 dBA in wilderness areas.

By-laws in some urban communities limit residential noise levels to 55 dBA in the daytime and 45 dBA in the night-time. The limits apply to continuous sound. As explained in the AN Report, transmission lines will not be designed to a 45 dBA limit. Instead, BC Hydro shall resolve each justified AN complaint by using solutions such as those described in the Section 6.1 of the AN Report. Ideally using feedback from the public consultation process, community reaction could be gauged; and if necessary, changes to a transmission line design within the affected zone can be made at an early stage to result in lower AN levels. Such changes could be an increase in phase spacing and/or conductor diameter. Community psychoacoustic response may turn out to be an important factor in the final design of a certain section(s) of a new transmission line.

2. CALCULATION METHOD

a) The BPA Corona and Field Effects program shall be used.
b) Calculate the L_5 rain AN level, which is the level likely to be exceeded only 5% of the time, at the edge of the right-of-way using the following parameters:

   i) Use voltages of 525, 242 and 140 kV respectively for 500, 230 and 138 kV class lines.
   ii) Use a microphone height of 1.5 m.
   iii) Use **average** height of the conductors along the span.
   iv) Use appropriate altitude. If less than 300 m, use zero (sea level).
   v) Use correct phasing for multiple circuits, e.g., a double circuit line, or a right-of-way with two or more single circuits.
   vi) No corrections for atmospheric conditions (air density, humidity and wind) shall be applied.

3. MEASUREMENT GUIDELINES

Unlike radio interference, there are no AN measurement requirements or procedures from government agencies or CSA. When there is a need to characterize AN performance of transmission lines, measurements shall be carried out in accordance with the IEEE standard procedures for audible noise measurements. Short term measurements shall be carried out as follows:

a) Measurements shall be taken at three sites: near both ends and the middle of a transmission line.
b) Measurements shall be taken in fair and foul weather.
c) ANSI instruments shall be used.
d) A random-incidence microphone with a diameter of 1.25 cm shall be used, unless a larger 2.5 cm microphone is required for more sensitivity.
e) Microphone shall be oriented vertically at a height of 1.5 m.
f) A windscreen with less than 2 dB insertion loss shall be used for protection.
g) Measurements shall be taken at several distances perpendicular to a line at mid-span: at the centreline, between centre and outside phases, and at 15, 30, 45, and 60 m horizontally from the outside phase; and at other points of interest, such as the edge of the right-of-way.
h) For each measurement location, the minimum data that shall be recorded are: the A-weighted sound level, and the unweighted levels in the 125, 1000 and 8000 Hz octave bands. Whenever possible, octave band levels from 31.5 to 16 kHz shall be taken fully. In checking compliance with specific

regulations that limit pure tones, measurements shall be made according to that particular regulation. This may involve using one-third or even one-tenth octave band filters.

i) The measuring system shall be calibrated with a portable acoustical calibrating device immediately before and after each series of measurements.

j) Discrete frequency components, particularly the 120 Hz hum, can vary as much as 20 dB for small lateral displacements of the microphone position. Maximum and minimum values shall be reported together with microphone positions relative to the standard location.

k) Power line operating conditions and characteristics, as well as weather conditions at the time of measurements shall be recorded as fully as possible.

l) Measurements shall be taken by experienced staff using properly calibrated equipment. Details of the measurement procedures and necessary precautions are given in Section 7 of the AN Report.

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Q100.2 If corona discharge is generally not a problem below 345 kV, why have design adjustments been required on the proposed 230 kV line?

A100.2 Corona discharge is generally not a problem below 345 kV for typical conductor sizes in common line configurations. For Alternative 1A, the compact double circuit configuration, while this configuration fits best in the available right-of-way and minimizes magnetic and electric fields, it increases corona effects due to the tighter phase spacing. The Drake conductor also is on the smaller end of the scale of conductors used for 230 kV lines and is thereby closer to the corona limits in normal configurations. When the Drake is assessed in the compact double circuit Alternative 1A configuration it was determined the radio interference limits would be exceeded and conductor size was increased to Bunting for compliance.

Q100.3 What options, other than or in combination with conductor size, were considered to achieve compliance?

A100.3 The primary method to control corona in line design is to select a sufficient conductor size such that the conductor surface circumference lowers the localized electrical field gradient around the conductor that causes corona. Phase spacing is also used to reduce phase to phase voltage gradients at the conductor but increasing the phase spacing reduces magnetic field mitigation.

Q100.4 Ignoring interference and noise guidelines, what is the minimum conductor size that would provide line capacity sufficient to match the transmission path's transformer capacity? In your response, please consider both single and bundled conductors.

A100.4 The radio interference criteria are a federal regulation under the Radio Communication Act and as such cannot be ignored in transmission line design. Notwithstanding the application of the regulation, for Alternative 1A and a 750 MVA transmission path transformer capacity (375 MVA per circuit, or 940 amps), the minimum standard conductor size for a bundled conductor is 266 kcmil "Partridge". The reason for identifying "Partridge" is that it is the smallest multi-stranded core conductor, which is preferred for transmission purposes over a single core wire. The characteristics of 266 kcmil "Partridge" are as follows:

- Al Area: 135.2 mm^2
- Overall Diameter: 16.3 mm
- Stranding: 26/7
- Unit Mass: 546 kg/km
- Rated strength: 50,000 N
- Ampacity: 475 A x 2 = 950 A
- DC Resistance @ 20°C: 0.2123 ohms/km

The minimum standard conductor size for a single conductor is 795 kcmil "Drake". The characteristics of "Drake" are as follows:

- Al Area: 402.8 mm^2
- Overall Diameter: 28.13 mm
- Stranding: 26/7
- Unit Mass: 1626 kg/km
- Rated strength: 138,000 N
- Ampacity: 905 A @ 75°C or 988 A @ 90°C.
- DC Resistance @ 20°C: 0.0701 ohms/km

Q100.5 If the minimum conductor size(s) were used, what interference or audible noise guidelines would be violated, and by how much?

A100.5 For Alternative 1A, if present phase spacing is maintained to mitigate magnetic field, the minimum conductor sizes identified in the response to Q100.4 above would not comply with Industry Canada Radio Interference Regulations and BC Hydro Audible Noise standards. The allowable limits and values that result with each are shown in BCUC IR3 Table A100.5.

Conductor	**Maximum Radio Interference** (dB*u*V/m) Regulatory Limit =53	**Audible Noise** (L5 dBA) Guide Limit = 55	
		Fair weather	Rain
Partridge	56.6	24.1	49.1
Drake	56.7	27.8	52.8

Q100.6 If there are conductors smaller than Bunting that can provide sufficient line capacity and meet interference and noise guidelines, is there merit in installing such conductors now with a view to (perhaps) replacing them with larger conductors as transmission-line loading increases?

A100.6 For Alternatives 1A or 1B, there would be no merit in upgrading conductors at a later date. The structures would have to be designed and built for the ultimate conductor size. Full re-conductoring of a double circuit line is a significant project in itself requiring prolonged outages of both lines. The costs and system risks would outweigh deferral savings for an interim reduced conductor size. The “Bunting” conductor is in the range of the smallest size that meets interference regulation and audible noise guidelines. The radio interference regulation and noise criteria cannot be ignored in transmission line design, especially in a developed area such as the Okanagan.

Q100.7 What is the cost premium of Bunting over the minimum conductor size?

A100.7 Notwithstanding the application of the interference and noise criteria, the cost premium of “Bunting” conductor over the minimum conductor sizes identified in the response to Q100.4 above, are provided below:

If the selected conductor is two bundle 266 kcmil “Partridge”, the cost premium of using “Bunting” conductor is one percent of the direct cost.

If the selected conductor is a single 795 kcmil “Drake”, the cost premium of using “Bunting” conductor is six percent of the direct cost.

101.0 Elimination of 161 kV Service at Bentley

Reference: Exhibit B-8, BCUC IR 75.1, 75.2; Wait IR 4

Q101.1 Please discuss why a second transformer is needed at Grand Forks prior to the removal of Lines 9 and 10. Why does FortisBC not plan on the basis that the second transformer is needed when the alternate 63 kV supply source is no longer available?

A101.1 The second transformer is not needed at Grand Forks prior to the removal of 9 and 10 Lines. Currently, there are three sources of supply for the Grand Forks area 63 kV load: Grand Forks Transformer 1 (161-63 kV), and 9 Line and 10 Line from Warfield. FortisBC's N-1 planning criterion requires that there should be at least two sources of transmission supply for Grand Forks. Removing 9 Line and 10 Line would violate the N-1 planning criterion unless an alternate supply source was provided. The proposal is to take advantage of the fact that the OTR Project will make the ex-Oliver Transformer 1 available for relocation. The future installation of this second transformer at Grand Forks would then allow the retirement of 9 and 10 Lines. The installation of the ex-Oliver Transformer 1 at Grand Forks (along with the retirement of 9/10 Lines) will be the subject of a future Capital Plan filing.

Q101.2 What is the expected salvage value of Oliver Transformer 1? What is the estimated cost to refurbish this transformer and install it at Grand Forks?

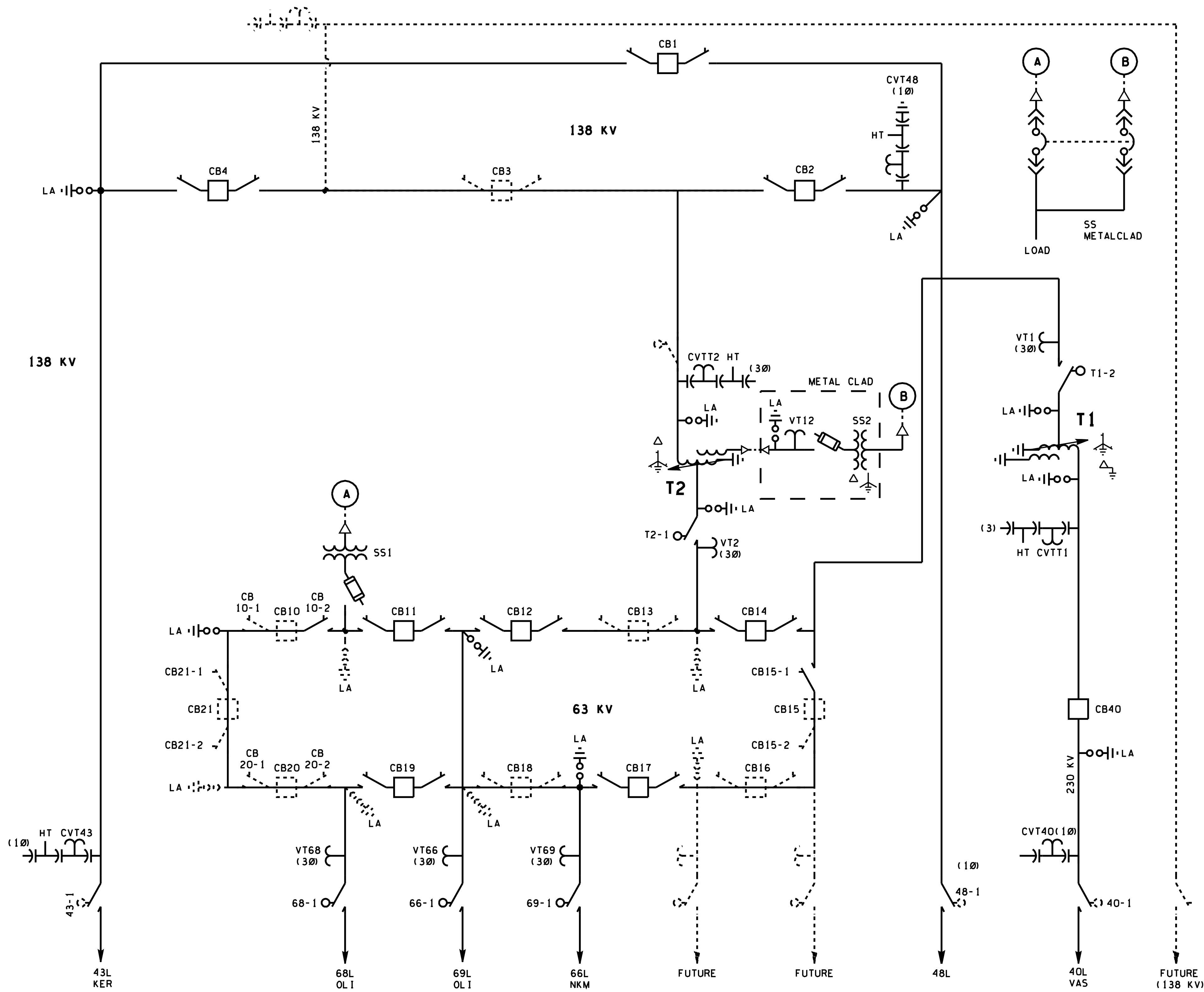
A101.2 Based on recent transformer removal experience, the expected salvage value is approximately $15,000. A conceptual estimate to refurbish Oliver Transformer 1 and install it at Grand Forks (along with the required station work) is approximately $5 million.

Q101.3 Further to Wait IR No. 4, what impact would the elimination of 161 kV service at Bentley and conversion of Line 11 to 138 kV have on the Transmission Wheeling Agreement with BCTC? What would be the annual cost impact on FortisBC as a result?

A101.3 FortisBC does not expect that the General Wheeling Agreement would be impacted as the reduction in operating voltage does not materially affect the path transfer capability compared to the present-day system.

Q101.4 Further to BCUC Table A75.2 and Drawing Number 3-385-SK1 on page 20 of Appendix C in Exhibit B-1-2, please provide a One-Line Diagram (or a marked-up version of Drawing 3-385-SK1) that shows the configuration of Bentley Station if 161 kV service was eliminated from the Project.

A101.4 Please see BCUC IR3 Attachment A101.4.



BChydro ENGINEERING

BC HYDRO DWG NO. 304J-P06-B1 R 0

BENTLEY TERMINAL (BEN)

ONE-LINE DIAGRAM
2010 STAGE

No.	BY	DATE	DESCRIPTION	No.	BY	DATE	DESCRIPTION			
								DESIGNED BY	BLA	1MAY08
								DRAWN BY	KLR	
								CHECKED BY		
								APPROVED BY		

FORTISBC

DRAWING NUMBER	REV
3-385-SK1A BCUC1R101.4	0

Q101.5 Further to Table G4 on page 7 of Appendix G in Exhibit B-1-3, please provide a more detailed cost estimate for Bentley Station as proposed in the Application, and a second cost estimate for the Station as it would be if 161 kV service was eliminated from the Project.

A101.5 Column 1 in BCUC IR3 Table A101.5 below is a cost estimate of the Bentley Terminal as filed in the CPCN Application (Exhibit B-1-1) to a preliminary design level of +20/-10 percent. Column 2 is a cost estimate of the Bentley Terminal eliminating the 161 kV service at a planning level estimate of +35/-15 percent.

BCUC Table A101.5

	Column 1	Column 2
	BEN Per CPCN	**BEN w/o T3 161 kV**
Engineering Substation Design	**1,749**	**1,552**
Equipment		
Transformers	4,708	2,194
230-161kV Switchgear	490	435
138 kV Switchgear	150	300
63 kV Switchgear	855	749
Station Ancillaries	471	342
Material		
Civil Site	1,070	1,065
Foundation and Oil Containment	749	603
Steel Structures	1,010	1,010
Control Building	264	264
Station Electrical	803	749
SCADA/P&C	663	663
Miscellaneous	841	642
Subtotal Supply Contracts	**12,074**	**9,017**
Construction Contracts		
Civil Site	1,156	1,156
Foundation and Oil Containment	1,519	1,295
Steel Structures	706	706
Control Building	186	186
Station Electrical	2,247	2,033
SCADA/P&C	394	346
Subtotal Construction Contracts	**6,208**	**5,721**
Testing & Commissioning	819	631
Direct Cost Totals	**20,850**	**16,921**
BCH EPC Services	**3,019**	**3,019**
Contingency	**3,472**	**2,818**
Inflation	**3,649**	**2,961**
Total	**30,990**	**25,719**

Q101.6 Further to BCUC Table A75.2, please discuss why the cost savings at Bentley under Option (b) are limited to those shown. Please expressly review the equipment and costs related to 161 kV metering, controls and breakers.

A101.6 The cost reductions attributable to the removal of Bentley Transformer 3 are offset by the same work required to install the transformer at the Mawdsley end of 11 Line instead. For example, the transformer, protection and control design and civil work costs (foundations, oil containment, etc.) would still be incurred - only the location of the work would change. Installing the transformer at Mawdsley has a higher cost due to the work being done in the energized station as opposed to Bentley, which will be greenfield construction.

It is not expected that there would be any reduction in the size of the Bentley site, so there is no reduction in the site preparation and grounding requirements. The only equipment that would not be required at Bentley (or Mawdsley) would be one breaker (and associated disconnects) in the 63 kV ring bus.

Q101.7 BCUC Table A75.2 is responsive to the information request. Nevertheless, due to the significance of the issue, please also provide a comparison of the two Options in terms of their revenue requirements going out at least 20 years from the OTR in-service date and showing the annual totals in nominal dollars and discounted dollars. Please include the total NPV of revenue requirements for each Option for the comparison period, and identify the discount rate and base years used to calculate NPV.

A101.7 The requested analyses were carried out using discount rates of 6 percent, 8 percent and 10 percent, and the base year is 2008.

BCUC IR3 Table A101.7 - Part 1

Option A

Item Summary	Discount Rates	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19
Total Revenue Requirement for Project (Nominal Dollars)		0	(7)	482	482	480	477	476	1,546	1,537	1,524	1,510	1,493
Total Revenue Requirement for Project (Discounted Dollars)	6.0%	0	(7)	429	405	381	356	335	1,028	964	902	843	786
Total Revenue Requirement for Project (Discounted Dollars)	8.0%	0	(7)	413	383	353	325	300	902	830	762	699	640
Total Revenue Requirement for Project (Discounted Dollars)	10.0%	0	(6)	398	362	328	296	269	793	717	646	582	523
Net Present Value of Revenue Requirements at 6% DR	6.0%	**12,095**											
Net Present Value of Revenue Requirements at 8% DR	8.0%	**9,796**											
Net Present Value of Revenue Requirements at 10% DR	10.0%	**8,038**											

Item Summary	Discount Rates		Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Total Revenue Requirement for Project (Nominal Dollars)			1,474	1,454	1,431	1,407	1,382	1,356	1,328	1,299	1,269	1,238	1,207
Total Revenue Requirement for Project (Discounted Dollars)	6.0%		733	681	633	587	544	503	465	429	396	364	335
Total Revenue Requirement for Project (Discounted Dollars)	8.0%		585	534	487	444	403	366	332	301	272	246	222
Total Revenue Requirement for Project (Discounted Dollars)	10.0%		470	421	377	337	301	268	239	212	189	167	148
Net Present Value of Revenue Requirements at 6% DR	6.0%	**12,095**											
Net Present Value of Revenue Requirements at 8% DR	8.0%	**9,796**											
Net Present Value of Revenue Requirements at 10% DR	10.0%	**8,038**											

Option B

Item Summary	Discount Rate	Dec-08	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19
Total Revenue Requirement for Project (Nominal Dollars)		0	(17)	1,174	1,176	1,171	1,162	1,152	1,140	1,126	1,111	1,095	1,077
Total Revenue Requirement for Project (Discounted Dollars)	6.0%	0	(16)	1,045	987	928	869	812	758	707	658	611	567
Total Revenue Requirement for Project (Discounted Dollars)	8.0%	0	(16)	1,007	933	861	791	726	665	608	556	507	462
Total Revenue Requirement for Project (Discounted Dollars)	10.0%	0	(16)	971	883	800	722	650	585	525	471	422	377
Net Present Value of Revenue Requirements at 6% DR	6.0%	**11,918**											
Net Present Value of Revenue Requirements at 8% DR	8.0%	**10,055**											
Net Present Value of Revenue Requirements at 10% DR	10.0%	**8,597**											

Item Summary	Discount Rate		Dec-20	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27	Dec-28	Dec-29	Dec-30
Total Revenue Requirement for Project (Nominal Dollars)			1,058	1,039	1,018	996	974	951	927	903	878	853	827
Total Revenue Requirement for Project (Discounted Dollars)	6.0%		526	487	450	416	383	353	325	298	274	251	229
Total Revenue Requirement for Project (Discounted Dollars)	8.0%		420	382	347	314	284	257	232	209	188	169	152
Total Revenue Requirement for Project (Discounted Dollars)	10.0%		337	301	268	239	212	188	167	148	131	115	102
Net Present Value of Revenue Requirements at 6% DR	6.0%	**11,918**											
Net Present Value of Revenue Requirements at 8% DR	8.0%	**10,055**											
Net Present Value of Revenue Requirements at 10% DR	10.0%	**8,597**											

For the purpose of comparison, the table from BCUC IR2 A75.2 is reproduced below considering as above NPV and Rate Impacts in terms of revenue requirements going out till 2030 (i.e., twenty years from the OTR in-service date of 2010) at a discount rate of 10 percent.

BCUC IR3 Table A101.7 - Part 2

Option (a) - OTR Project with future voltage conversion of 11 Line to 138 kV

	Description		2008	2009	2010	2011	2012	2013	2014	2015	
			($000s)								
1	Install Bentley T3 as described in CPCN			4,719							
2	Relocate Bentley T3 to Mawdsley and install								2,071		
3	Purchase and install one 138/63 kV transformer at Grand Forks Terminal								6,904		
4	Add one 138 kV breaker at Bentley to complete ring bus and re-terminate 48L								1,381		
5	Switch Kettle Valley to 138 kV operation								138		
6	**Total:**		**0**	**4,719**	**0**	**0**	**0**	**0**	**10,494**	**0**	**15,213**
7	**NPV**	**8,038**									
8	**NPV of Rate Impact**	**0.31%**									
9	**Max One Time Rate Impact**	**0.59%**									

Option (b) - OTR Solution modified to include conversion of 11 Line to 138 kV

	Description		2008	2009	2010	2011	2012	2013	2014	2015	
			($000s)								
10	Delete Bentley T3 and install at Mawdsley instead			5,073							
11	Purchase and install one 138/63 kV transformer at Grand Forks Terminal			5,898							
12	Add 138 kV breaker at Bentley to complete ring bus			1,180							
13	Switch Kettle Valley to 138 kV operation			118							
14	One 63 kV breaker position at Bentley			(590)							
15	Delete 161 kV requirement from Bentley T2			(177)							
16	**Total:**		**0**	**11,502**	**0**	**0**	**0**	**0**	**0**	**0**	**11,502**
17	**NPV**	**8,597**									
18	**Rate Impact**	**0.33%**									
19	**Max One Time Rate Impact**	**0.51%**									

102.0 Wiltse Route Alternative

Reference: Exhibit B-8, BCUC IR 83.1, 83.2, 83.3, 83.4

Q102.1 In response to BCUC IR 83.2, FortisBC states that as each of the Wiltse routes requires new rights-of-way, they would be subject to the same acquisition risks and timelines as the Upland routes. BCUC Attachment A83.1 indicates that the Wiltse "Proposed Route" could be modified so that it is all on Wiltse property and rejoins the Alternative 1 route more or less where the Alternative 2 route joins it. Please discuss the effect, if any, of this modification to the Wiltse route on concerns about acquisition risks and timelines.

A102.1 This "modified Wiltse route" would have some advantages over the Wiltse proposed route. New right-of-way would need to be acquired only from Wiltse, compared to the Wiltse proposed route which would also require rights-of-way from other parties, as described in the response to Q93.3 above. Potential First Nations issues associated with Crown land affected by the Wiltse proposed route would also be avoided.

Environmental and archaeological assessments would be required for either route. It is the policy of FortisBC to engage in public consultation prior to agreeing to relocation of existing transmission facilities, and while it is possible that stakeholders, as yet unidentified, may have objections to either of the routes, it is not known whether the nature or degree of interest from stakeholders would differ depending on the route selected.

At this time the Company does not know whether there may be significant differences in the timing of the engineering or procurement phases between the two routes.

Q102.2 Please discuss other impacts that a modified Wiltse routing that is all on Wiltse property would have on Alternative 1A.

A102.2 All of the impacts that can be reasonably foreseen prior to conducting environmental/archaeological assessments, public consultation and preliminary engineering have been discussed in the response Q102.1 above.

Q102.3 Please discuss the impacts that a modified Wiltse routing that is all on Wiltse property would have on FortisBC's assessment of the Wiltse "Proposed Route" relative to the Alternative 1A route.

A102.3 The most significant impact of the modified Wiltse route, relative to the Alternative 1A, would be a delay in the in-service date for 75 Line/ 76 Line in the range of three to six months. Preliminary engineering for Alternative 1A is largely complete; however preliminary engineering for a different route (including the Wiltse proposed or Wiltse preferred) would not commence prior to a Commission decision on this Application unless Wiltse elected to advance the payment schedule outlined in the response to Q102.6 below.

Environmental and archaeological assessments would be required following preliminary engineering and prior to public consultation. The nature or extent of public interest in such a route modification is not known.

Q102.4 Notwithstanding that overall FortisBC ranks the Wiltse alternatives lower than Alternative 1A, please confirm that FortisBC is prepared to proceed with such a modification to its routing providing Wiltse supplies the new right-of-way and pays all incremental costs to the OTR Project.

A102.4 FortisBC is prepared to proceed with such a modification to the line route providing Wiltse supplies the new right-of-way and pays all incremental costs to the OTR Project, and the modification does not generate public opposition or otherwise jeopardize the OTR Project schedule.

Q102.5 How would FortisBC propose to deal with incremental Project costs that result from delays to the Project that result from modifying the routing?

A102.5 Wiltse would be expected to pay for any incremental costs caused by delays associated with any modification to the OTR Proposed route.

Q102.6 When would FortisBC need to have the modifications to routing confirmed and agreement on a contribution in-aid-of construction, to avoid a delay in the completion of the Project?

A102.6 FortisBC's requirements to avoid further delays are characterized below. A final schedule acceptable to FortisBC and Wiltse would be determined during the assessment stage described below.

1

Timeline	Stage	Deliverable
45 days following CPCN approval	Assessment	FortisBC will provide an estimate to complete a preliminary assessment and detailed estimate (Invoice 1).
30 days following preliminary estimate	Confirmation	Wiltse Holdings Ltd. to provide FortisBC a written approval to proceed along with payment 1.
90 days following written approval to proceed and Payment 1	Detailed Estimates	FortisBC will provide detailed estimates for (a) environmental assessment and consultation, (b) permitting, (c) engineering, (d) procurement; and (e) construction and commissioning (Invoices, in series).
15 days in advance of work commencing on each phase	Phased Approval	Wiltse Holdings Ltd to provide FortisBC a written approval to proceed along with payments, in series, prior to commencement of each of the defined phases.
45 days following completion of commissioning		FortisBC to issue final invoice or credit based on actual costs.

103.0 EMF Profile Across ROW

Reference: Exhibit B-8, BCUC IR 57.6, 57.7, 57.8; BCOAPO IR 8.3, Harlingten IR 8.1, Karow IR 9

Q103.1 The responses to BCUC IR 57.6 and BCOAPO IR 8.3 show maximum case EMF highest readings on the ROW of 54 and 46 mG for Cross Section C (Alternative 1A) and Cross Section E (Alternative 1B), respectively. KAROW Attachment A9 shows maximum case EMF highest readings of 37.63 and 53.34 mG for Alternative 1A and Alternative 1B, respectively. The response to Karow IR 9 states that the calculations are based on opposing phasing configuration to mitigate opposing fields. Please confirm that FortisBC intends to design the transmission lines under any alternatives so as to mitigate magnetic fields to the extent it is reasonably possible to do so.

A103.1 FortisBC confirms that it will design the transmission lines, under any Alternatives, so as to mitigate magnetic fields to the extent it is reasonably possible.

Q103.2 Please reconcile the maximum case EMF readings that are provided in the various IR responses, identify the set of estimates that FortisBC believes best represents the expected situation with the new transmission lines, and explain why this is the most accurate estimate.

A103.2 Magnetic field calculations were prepared over the period of March 2007 to February 2008 as the different alternatives were developed. When the magnetic field calculations were all being re-run for the response to Karow IR1 Q9 (Exhibit B-9) for magnetic fields down to the 0.3 MG level, two discrepancies were noted as follows:

1) For Alternative 1A the magnetic field calculations from March 2007 and

carried forwarded in the CPCN Application and the previous responses to information requests are based on the double circuit single pole structure identified as the Davit Arm in BCUC IR2 Attachment A74.1 and in Appendix C page 23 (Exhibit B-1-2), as opposed to the Braced Post double circuit single pole type shown in BCUC IR2 Attachment A74.1 and Appendix C, page 22 (Exhibit B-1-2). Both structures types are used in Alternative 1A preliminary design but the Braced Post structure is the more prevalent one. The magnetic field calculations were run on the Braced Post structures for Karow IR1 Q9 (Exhibit B-9). Due to the wider phase spacing of the Davit Arm structure the magnetic fields near the structure are slightly higher than the Braced Post structure. Either single pole structure performs better than all other Alternatives for magnetic field mitigation.

2) The magnetic field calculations for the existing 76 Line and Alternatives 1B and 1C were originally run with slightly different average conductor height parameters. The existing 76 Line and Alternative 1B and 1C calculations have been re-run to be consistent with the other cases and the updated results are slightly higher than the earlier study. The change in results does not shift the relative performance of the existing 76 Line, or Alternatives 1B and 1C versus other Alternatives.

With regard to which set of data best represents the expected situations for the transmission lines, the magnetic field calculations for the existing 76 Line and Alternatives 1A, 1B and 1C run for Karow IR1 Attachment A9 (Exhibit B-9) are the best representation for those cases and are the most accurate estimates at this point in preliminary engineering.

The magnetic field studies for Alternative 1A Braced Post and Davit Arm structures are accurate estimates and can be referenced where relevant. The Braced Post is more representative of overall performance of Alternative 1A, while the Davit Arm might be considered the more conservative case for Alternative 1A.

With regards to Karow IR1 Attachment A9 (Exhibit B-9), the request was for the information to be relevant to the Heritage Hills area. In that line section there are both Davit Arm and Braced Post structures. The magnetic field profiles for both the Davit Arm and Braced Post structures are provided in the response to Karow IR2 Q4 and the David Arm structure was added to BCUC IR3 Attachment A103.3f below.

Q103.3 Depending on what FortisBC now considers to be the most accurate estimate of EMF readings, please file updates to BCUC IR 57.6, 57.7, 57.8; BCOAPO IR 8.3, Harlingten IR 8.1, and Karow IR 9 as required.

A103.3 Based on the response to Q103.2 above, the estimates of EMF are included in BCUC IR3 Attachment A103.3 as follows:

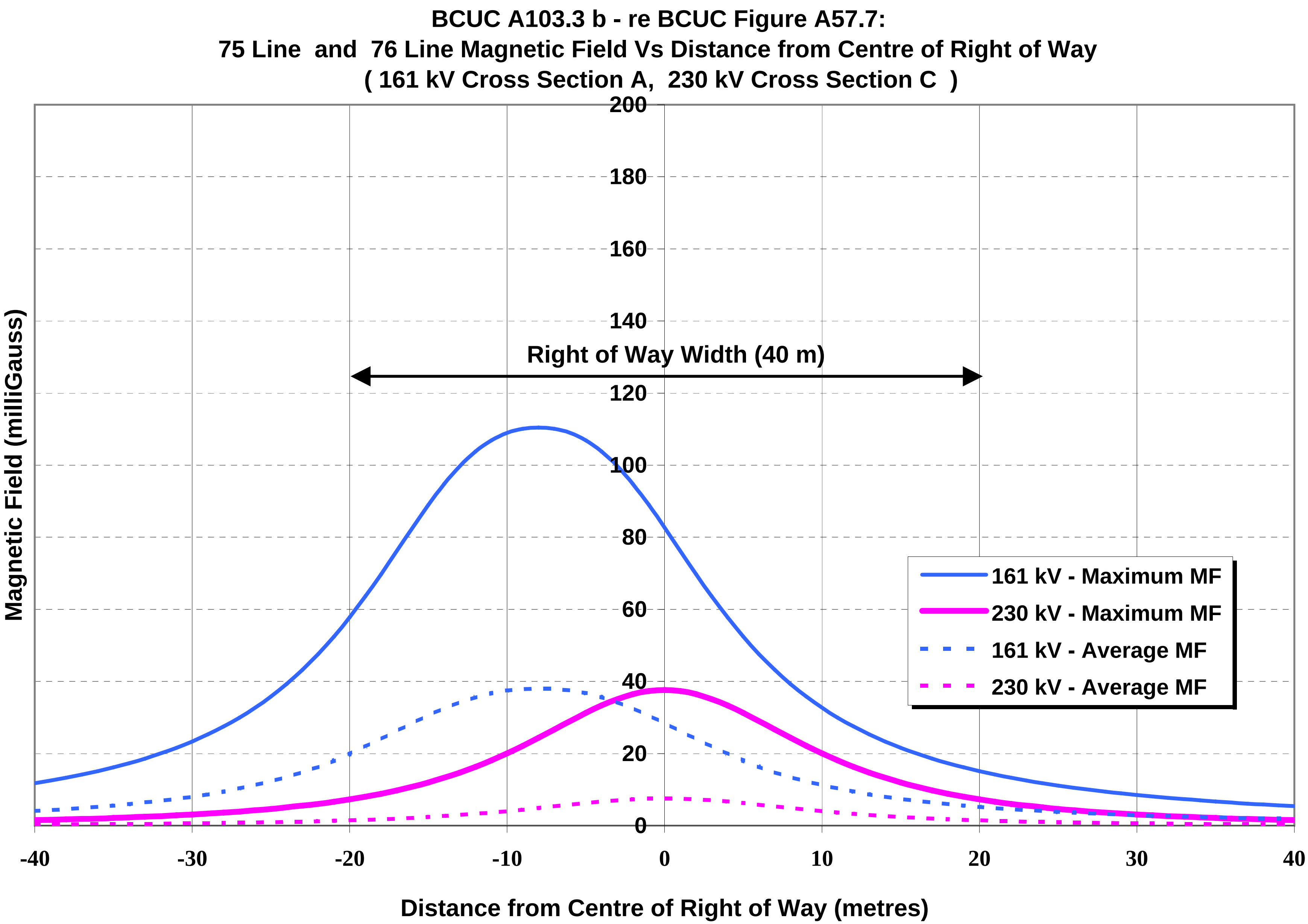
BCUC A103.3 a - re BCUC Table A57.6
BCUC A103.3 b - re BCUC Figure A57.7
BCUC A103.3 c - re BCUC Figure A57.8;
BCUC A103.3 d - re BCOAPO Figure A8.3,
BCUC A103.3 e - re Harlingten Table A8.1, and
BCUC A103.3 f - re Karow Attachment A9.

BCUC A103.3 a – re BCUC Table A57.6

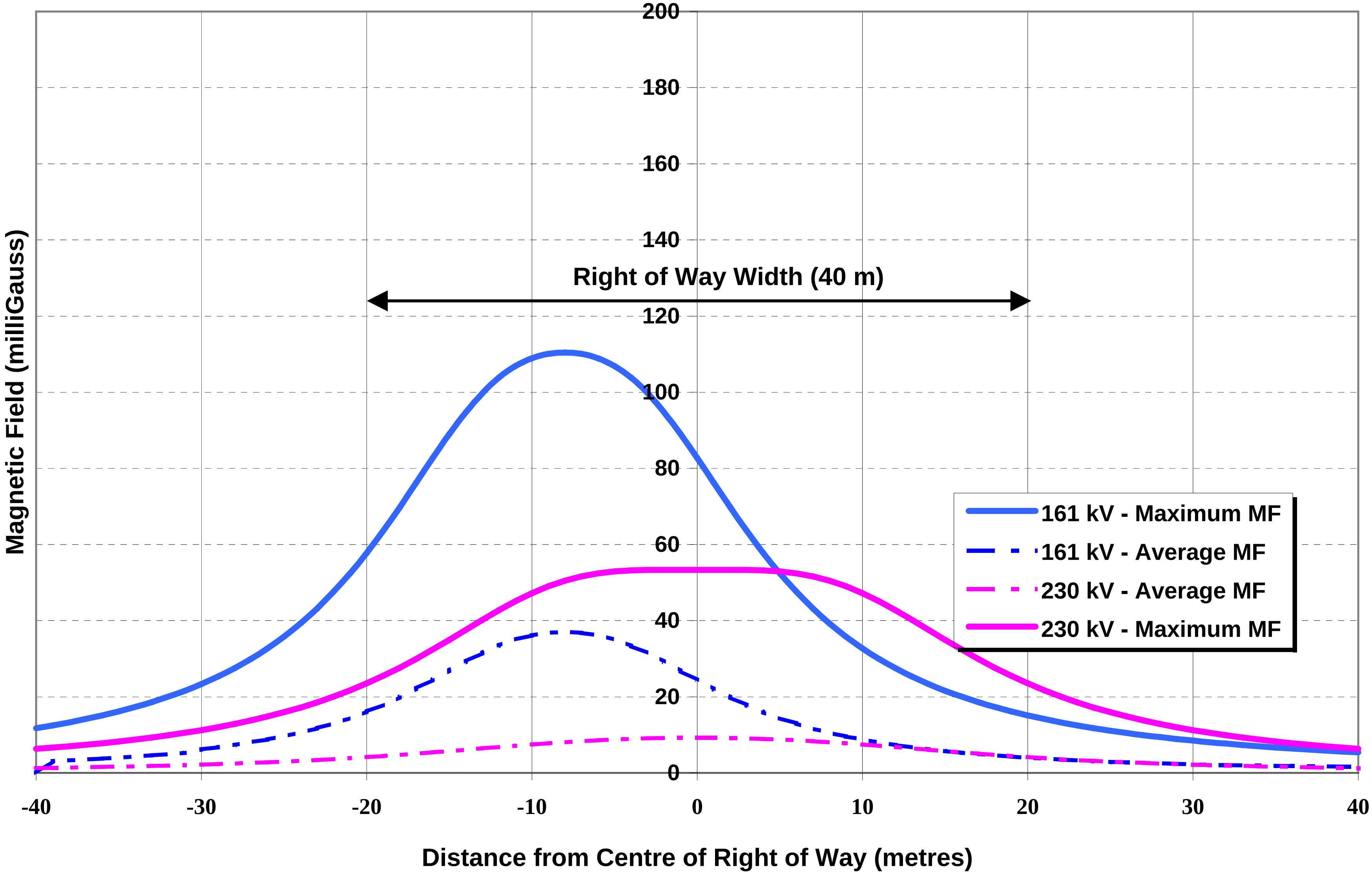
Magnetic Fields Maximum and Edge of Right-of-Way
(Reference IR: 57.6, 57.7, 57.8, 57.9, 57.10, 57.11)

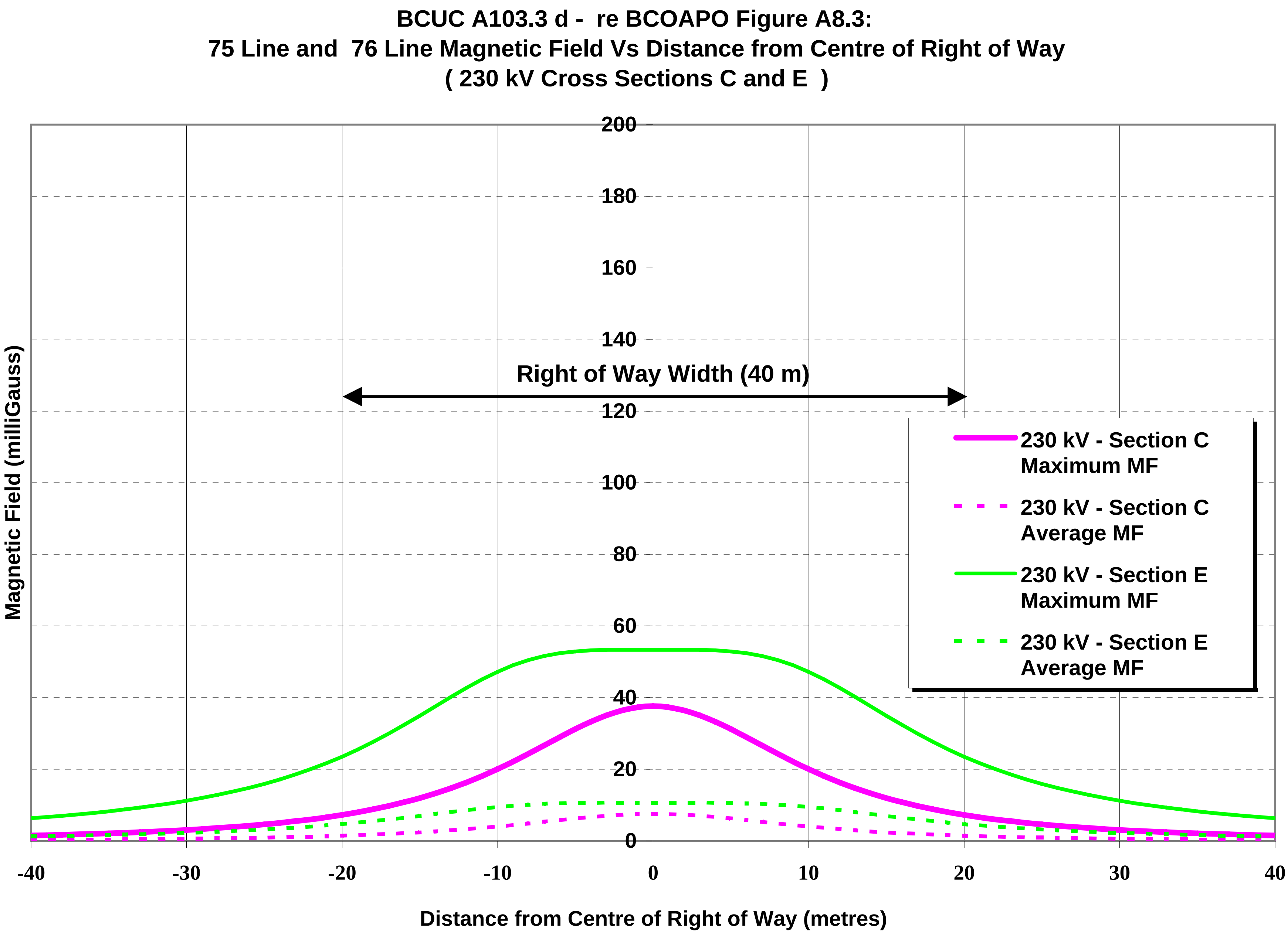
		Average Case Magnetic Field (mG)			Maximum Case Magnetic Field (mG)		
IR #	**Configuration**	**Maximum On Right-of-Way**	**Edge of Right-of-Way (side)**		**Maximum On Right-of-Way**	**Edge of Right-of-Way (side)**	
			East	**West**		**East**	**West**
	40 Line - Cross Section A at 161 kV (Existing)	17	2	7	71	10	31
	76 Line - Cross Section A at 161 kV (Existing)	37	5	20	109	15	58
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)	8	1	1	38	7	7
57.8	75 Line and 76 Line - Cross Section E, at 230 kV (Post OTR)	11	5	5	53	24	24
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)	37	11	11	183	54	54
57.11	76 Line High Capacity - Cross Section C, at 230 kV (Post OTR)	20	7	9	101	33	44

Note ICNIRP Guideline is 833 mG.


BCUC A103.3 b - re BCUC 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)
Magnetic Field (milliGauss)
200
180
160
140
120
100
80
60
40
20
0
Right of Way Width (40 m)
161 kV - Maximum MF
230 kV - Maximum MF
161 kV - Average MF
230 kV - Average MF
-40
-30
-20
-10
0
10
20
30
40
Distance from Centre of Right of Way (metres)

BCUC A103.3 c - re BCUC 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)




BCUC A103.3 d - re BCOAPO Figure A8.3:
75 Line and 76 Line Magnetic Field Vs Distance from Centre of Right of Way
(230 kV Cross Sections C and E)
Magnetic Field (milliGauss)
200
180
160
140
120
100
80
60
40
20
0
Right of Way Width (40 m)
230 kV - Section C Maximum MF
230 kV - Section C Average MF
230 kV - Section E Maximum MF
230 kV - Section E Average MF
-40
-30
-20
-10
0
10
20
30
40
Distance from Centre of Right of Way (metres)

BCUC A103.3 e re Harlinten Table A8.1 - Magnetic Field at 5m Intervals to Edge of Right of Way

		40 Line - Cross Section A at 161 kV (Existing)		76 Line - Cross Section A at 161 kV (Existing)		40 Line - Cross Section B at 230 KV		75 Line and 76 Line - Cross Section C at 230 kV		75 Line and 76 Line - Cross Section E, at 230 kV		75 Line and 76 Line - Cross Section D, at 230 kV		76 Line High Capacity - Cross Section F, at 230 kV		76 Line High Capacity - Cross Section C, at 230 kV	
	Distance from Centre of Right of Way (m)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)	Average Case (mG)	Maximum Case (mG)
	-25											10.7	53.5				
	-20	7.4	31.0	19.9	57.8	5.5	21.1	1.5	7.3	4.7	23.5	13.9	69.2	10.8	53.8	8.8	44.0
	-15	12.5	51.9	30.6	89.0	8.5	32.7	2.4	12.0	7.0	35.0	14.8	74.0	16.2	81.1	12.0	60.0
	-10	16.8	69.8	37.4	108.9	11.6	44.8	4.0	20.0	9.5	47.2	12.2	60.9	24.6	122.8	16.1	80.3
	-5	16.2	67.5	36.8	106.9	12.8	49.2	6.3	31.2	10.6	52.9	6.9	34.3	33.3	166.3	19.6	98.1
Centre	**0**	11.3	47.1	28.4	82.7	11.5	44.4	7.5	37.6	10.7	53.3	2.4	12.0	36.6	183.2	19.7	98.6
	5	6.6	27.7	18.0	52.4	8.3	32.0	6.3	31.2	10.6	52.9	6.9	34.3	33.2	166.3	16.2	81.2
	10	4.1	16.9	11.3	32.7	5.4	20.7	4.0	20.0	9.5	47.2	12.2	60.9	24.6	122.8	12.1	60.7
	15	2.6	11.0	7.4	21.6	3.5	13.6	2.4	12.0	7.0	35.0	14.8	74.0	16.2	81.2	8.9	44.5
	20	1.8	7.7	5.2	15.1	2.4	9.3	1.5	7.3	4.7	23.5	13.9	69.2	10.8	53.8	6.6	33.1
	25											10.7	53.5				

Note: Section D right of way is +/- 25.5m (51m) , all others +/- 20m (40 m)

BCUC A103.3 f - re Karow Attachment A9 - Magnetic Field (mG) Vs Distance (m)											
		Existing 76 Line at 161kV		Alternative 1A - Double Circuit Single Pole (Braced Post)		Alternative 1B - Double Circuit H-frame		Alternative 1C - Single Circuit High Capacity H-frame		Alternative 1A - Double Circuit Single Pole (Davit arm)	
	Distance from Centre of Right of Way (m)	Existing 76 Line Average Case	Existing 76 Line Maximum Case	Alternative 1A Braced Post- Average Case	Alternative 1A Braced Post Maximum Case	Alternative 1B Average Case	Alternative 1B Maximum Case	Alternative 1C Average Case	Alternative 1C Maximum Case	Alternative 1A Davit Arm Average Case	Alternative 1A Davit Arm Maximum Case
	-300								**0.3**		
	-295								0.31		
	-290								0.32		
	-285								0.33		
	-280								0.34		
	-275								0.35		
	-270								0.37		
	-265								0.38		
	-260								0.39		
	-255								0.41		
	-250								0.43		
	-245								0.44		
	-240								0.46		
	-235								0.48		
	-230								0.5		
	-225								0.53		
	-220								0.55		
	-215								0.58		
	-210								0.6		
	-205								0.63		
	-200								0.67		
	-195		**0.31**						0.7		
	-190		0.32						0.74		
	-185		0.34						0.78		
	-180		0.36				**0.3**		0.82		
	-175		0.38				0.32		0.87		
	-170		0.4				0.34		0.92		
	-165		0.42				0.36		0.98		
	-160		0.45				0.38		1.04		
	-155		0.48				0.41		1.11		
	-150		0.51				0.43		1.18		
	-145		0.54				0.46		1.26		
	-140		0.58				0.5		1.36		
	-135		0.62				0.53	**0.29**	1.46		
	-130		0.66				0.58	0.31	1.57		
	-125		0.72				0.62	0.34	1.7		
	-120		0.77				0.68	0.37	1.84		
	-115		0.84				0.74	0.4	2		
	-110	**0.31**	0.91				0.81	0.44	2.19		
	-105	0.34	0.99				0.89	0.48	2.4		
	-100	0.37	1.08				0.98	0.53	2.65		
	-95	0.41	1.19				1.09	0.59	2.93		
	-90	0.45	1.31				1.21	0.65	3.26		
	-85	0.5	1.46			**0.27**	1.36	0.73	3.65		**0.3**
	-80	0.56	1.63			0.31	1.54	0.82	4.12		0.36
	-75	0.63	1.83		**0.27**	0.35	1.75	0.93	4.67		0.43
	-70	0.71	2.07		0.33	0.4	2.02	1.07	5.35		0.52
	-65	0.81	2.36		0.41	0.47	2.35	1.24	6.19		0.64
	-60	0.93	2.71		0.51	0.55	2.76	1.45	7.24		0.8
	-55	1.09	3.16		0.65	0.66	3.3	1.72	8.58		1.02
	-50	1.28	3.72		0.84	0.8	4	2.07	10.33	**0.26**	1.32
	-45	1.53	4.44		1.11	0.99	4.97	2.53	12.65	0.35	1.75
	-40	1.85	5.39	**0.3**	1.51	1.26	6.31	3.17	15.83	0.48	2.37
	-35	2.29	6.67	0.42	2.11	1.66	8.27	4.07	20.35	0.66	3.31
	-30	2.91	8.48	0.61	3.07	2.25	11.23	5.4	27	0.96	4.79
	-25	3.82	11.1	0.93	4.62	3.19	15.93	7.45	37.27	1.44	7.2
Edge of R/W	-20	5.19	15.1	1.46	7.28	4.71	23.51	10.77	53.83	2.26	11.28
	-15	7.42	21.58	2.4	11.97	7	34.95	16.23	81.17	3.69	18.4
	-10	11.25	32.71	4.01	20.04	9.46	47.21	24.56	122.82	6.08	30.36
	-5	18.03	52.43	6.25	31.23	10.6	52.92	33.26	166.29	9.19	45.87
Centre of R/W	0	28.44	82.7	7.54	37.63	10.68	53.34	36.64	183.2	10.8	53.94
	5	36.75	106.87	6.25	31.23	10.6	52.92	33.26	166.29	9.19	45.87
	10	37.45	108.92	4.01	20.04	9.46	47.21	24.56	122.82	6.08	30.36
	15	30.59	88.97	2.4	11.97	7	34.95	16.23	81.17	3.69	18.4
Edge of R/W	20	19.87	57.77	1.46	7.28	4.71	23.51	10.77	53.83	2.26	11.28
	25	12.31	35.82	0.93	4.62	3.19	15.93	7.45	37.27	1.44	7.2
	30	8.02	23.34	0.61	3.07	2.25	11.23	5.4	27	0.96	4.79
	35	5.55	16.15	0.42	2.11	1.66	8.27	4.07	20.35	0.66	3.31
	40	4.05	11.76	**0.3**	1.51	1.26	6.31	3.17	15.83	0.48	2.37
	45	3.07	8.92		1.11	0.99	4.97	2.53	12.65	0.35	1.75
	50	2.4	6.99		0.84	0.8	4	2.07	10.33	**0.26**	1.32
	55	1.93	5.61		0.65	0.66	3.3	1.72	8.58		1.07
	60	1.58	4.61		0.51	0.55	2.76	1.45	7.24		0.8
	65	1.32	3.85		0.41	0.47	2.35	1.24	6.19		0.64
	70	1.12	3.26		0.33	0.4	2.02	1.07	5.35		0.52
	75	0.96	2.8		**0.27**	0.35	1.75	0.93	4.67		0.43
	80	0.83	2.42			0.31	1.54	0.82	4.12		0.36
	85	0.73	2.12			**0.27**	1.36	0.73	3.65		**0.3**
	90	0.64	1.87				1.21	0.65	3.26		
	95	0.57	1.67				1.09	0.59	2.93		
	100	0.51	1.49				0.98	0.53	2.65		
	105	0.46	1.34				0.89	0.48	2.4		
	110	0.42	1.21				0.81	0.44	2.19		
	115	0.38	1.1				0.74	0.4	2		
	120	0.35	1.01				0.68	0.37	1.84		
	125	0.32	0.92				0.62	0.34	1.7		
	130	**0.29**	0.85				0.58	**0.31**	1.57		
	135		0.78				0.53		1.46		
	140		0.73				0.5		1.36		
	145		0.67				0.46		1.26		
	150		0.63				0.43		1.18		
	155		0.59				0.41		1.11		
	160		0.55				0.38		1.04		
	165		0.51				0.36		0.98		
	170		0.48				0.34		0.92		
	175		0.45				0.32		0.87		
	180		0.43				**0.3**		0.82		
	185		0.4						0.78		
	190		0.38						0.74		
	195		0.36						0.7		
	200		0.34						0.67		
	205		0.33						0.63		
	210		0.31						0.6		
	215		**0.3**						0.58		
	220								0.55		
	225								0.53		
	230								0.5		
	235								0.48		
	240								0.46		
	245								0.44		
	250								0.43		
	255								0.41		
	260								0.39		
	265								0.38		
	270								0.37		
	275								0.35		
	280								0.34		
	285								0.33		
	290								0.32		
	295								0.31		
	300								**0.3**		

104.0 Changes to Project since System Development Plans

Reference: Exhibit B-8, BCUC IR 2.68.2

BCUC Table A68.2 identifies a number of project components, such as upgrades at Anderson and Vaseux Terminals, that were not identified in the 2005 SDP or the 2007 SDP Update.

Q104.1 What were the changes in assumptions, objectives, design parameters, etc., that resulted in the addition of these components to the OTR?

A104.1 In 2005, the assumption was that costs allocated for the double circuit line from Vaseux Lake to Penticton would cover all necessary costs for the connection to the two terminals. Preliminary engineering confirms that this is not the case. Further assessment defined the scope of protection and control and line termination equipment at Vaseux Lake and RG Anderson Terminal stations.

105.0 Need for Project: Load Forecast – Linear Model and Adjustments

Reference: Exhibit B-8, BCUC IR 2.85.4

Q105.1 Please provide a table of the actual winter peak load numbers associated with the graph shown in BCUC IR 2.85.4.

A105.1 Please see BCUC IR 3 Table A105.1 below.

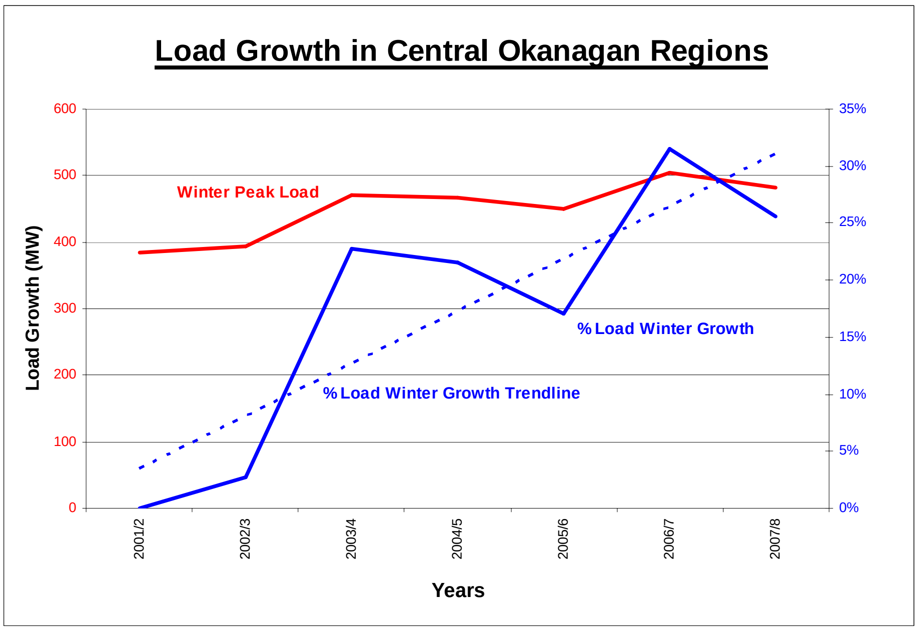
BCUC IR 3 Table A105.1

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08
Central Okanagan Load Growth (MVA)	384	394	471	466	449	505	482
% Growth	0	3	23	22	17	32	26

Q105.2 If actual load data are available for 2007/08, please provide a version of Figure A85.4 incorporating this additional data, and include this data in the table filed in response to the previous question.

A105.2 Please see BCUC IR3 Figure A105.2 below.

BCUC IR3 Figure A105.2



106.0 Need for Project: Load Forecast – Linear Model and Adjustments

Reference: Exhibit B-8, BCUC IR 2.85.6 and BCOAPO IR 4.1

Q106.1 Please provide the historical average winter temperatures for the OTR area for at least the past 20 years.

A106.1 Following are the average winter temperatures recorded at the Penticton airport for the past 20 years. These values are the average of the mean monthly temperatures for the four “winter” months November through February.

BCUC IR3 Table A106.1 Penticton Airport Average Winter Temperature

Winter Years	Average Temp (º C)
1988/89	-0.70
1989/90	1.58
1990/91	-0.13
1991/92	2.80
1992/93	-2.13
1993/94	0.85
1994/95	0.90
1995/96	-0.23
1996/97	-1.50
1997/98	1.93
1998/99	2.68
1999/00	2.00
2000/01	-0.18
2001/02	2.35
2002/03	2.83
2003/04	-0.10
2004/05	0.88
2005/06	1.23
2006/07	0.43
2007/08	0.13

Q106.2 Please explain and show how the winter temperatures observed during the last five years compare to the historical average temperatures for the OTR area, and to the lowest average temperature observed over the past 20 years.

A106.2 Based on the data shown in BCUC IR3 Table A106.1, the average winter temperature for the previous 20 years is 0.78 °C. The average temperature for just the last five years is 0.51 °C, which is slightly below the long-term average. The lowest observed average temperature was -2.13 °C in 1992/93.

Q106.3 In the event that the region's 20-year, historical low winter temperature was repeated, how would that winter peak load compare to the actual winter peak loads that FortisBC observed during the last five years?

A106.3 The lowest recorded winter over the last 5 years was that of 2003/04 recording an average temperature of -0.1 °C which does correspond to a higher than normal winter peak load of 471MVA for that year. FortisBC does not incorporate weather correction in its load forecast (please refer to the response to BCUC IR2 Q85.6) and as such would be unable to accurately determine the winter peak load for comparison, however, it is acknowledged that the winter peak loads would be higher than normal.

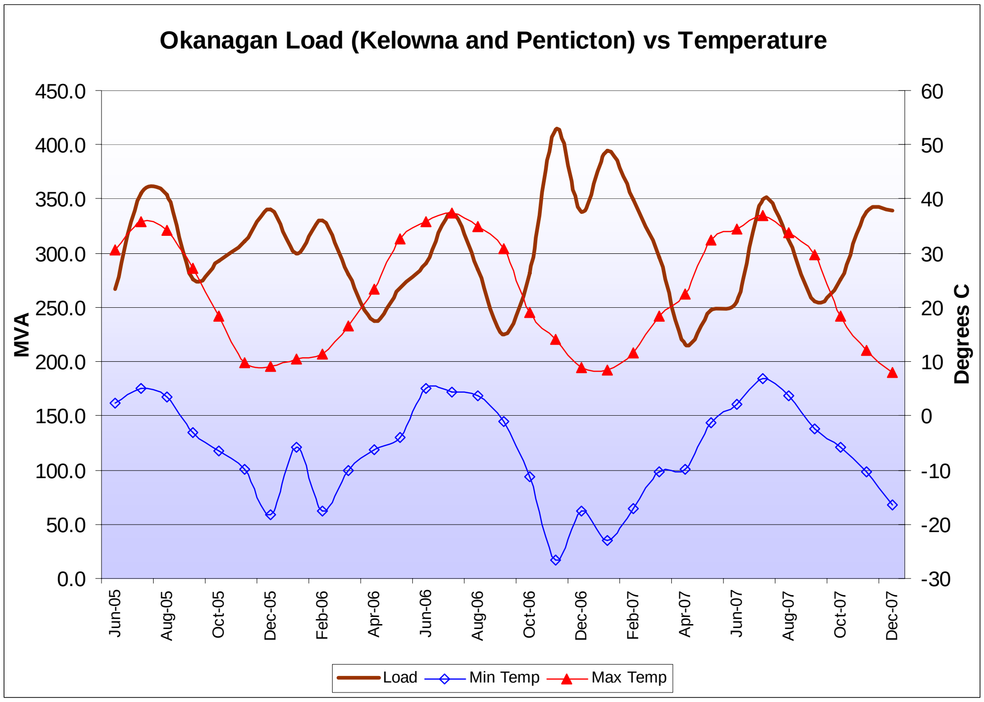
Q106.4 In the event that the region's 20-year, historical low winter temperature was repeated, how would that winter peak load compare to the FortisBC OTR forecast winter peak load at each of 2010, 2020, and 2027?

A106.4 FortisBC would be unable to determine accurately the winter load peaks for each of these years; however, it is acknowledged that the load forecast would be higher than normal. Please also see the response to Q106.3 above.

Q106.5 To the extent that actual load and temperature data are available for 2007/08, please provide versions of BCUC Figure A85.4 and BCUC Figure A85.6 incorporating those additional numbers.

A106.5 Please see the response to Q105.2 above. The update for BCUC IR2 Figure A85.6 is shown below as BCUC IR3 Figure A106.5. Please note that this data represents the Kelowna and Penticton loads only.

BCUC IR3 Figure A106.5



Project No. 3698488: Okanagan Transmission Reinforcement (OTR) Project
Requestor Name: Chris Danninger
Information Request No: 2
To: FortisBC Inc.
Request Date: April 24, 2008
Response Date: May 13, 2008

Original question and answer:

Q2.6 Figure 4-2-1B in the application shows existing L76 structure at Allendale Lake Road. Figure 4-2-1C shows the same view with the single pole double circuit configuration, FBC's preferred option. Unfortunately, the single pole structure is not shown at the correct scale but much shorter than it would be in reality (on the photo approx. 36 instead of 45 mm). Figures 4-2-1F and 4-2-1G show the same error of similar magnitude in the Heritage Hills area. Figures 4-2-1D and E also show this error, however, to a lesser degree. This is very misleading to the reader, because it understates the impact the new structures will have on the viewscape. Why did FBC choose not to show the new structure at its proper scale?

A2.6 The scale of the renderings presented in Figure 4-2-1C, Figure 4-2-1F, and Figure 4-2-1G is correct. The proposed structure renderings are based on the height of structures determined by the preliminary design. Final design may identify some change in height relative to the existing facilities. The proposed double circuit mono-pole structure is a compact design which has a horizontal distance between the outer conductors that is not significantly different than the horizontal distance between two adjacent wires of the existing 161 kV line.

Issue:

As described in section 4 of the application, Fig. 4-2-1 C shows the proposed single pole double circuit structure on the existing brownfield right-of-way. According to Fig. 4-3-1 B the existing structures of L76 are approximately 15.8 m high (cross section A) where as the proposed single pole double circuit structure will be approximately 30.5 m in height (cross section C). This means that the new structure will be 1.93 times as high as the old structure.

The context in Section 4 of the Application suggests to the reader that Figures 4-2-1 B and C are presented to provide a realistic visual comparison of the existing structure near Allendale Road (L76-69) and the proposed new structure (L75/76-42).

As the scale of all picture elements in both images is identical and the new structure is placed at the exact location of the existing one (which means that the

distance between the structure and the observer remains the same), the new structure on Fig. 4-2-1 C would have to be shown 1.93 times as high as the existing one on Fig. 4-2-1 B.

As the old structure on Fig. 4-2-1 B measures about 22.5 mm from base to cross beam the single pole on Fig. 4-2-1 C should measure 43.4 mm. Instead it measures only 36 mm. This means that only 65 percent of the increase in structure height is depicted by Fig. 4-2-1 C. This is clearly misleading to the reader as it results in a serious understatement of the impact the new structures will have on the viewscape.

Q1 Please confirm the correctness of the above reasoning or explain why it is incorrect.

A1 Figure 4-3-1B shows typical profiles and dimensions for the different structure types that would be used for the straight sections of the lines. BCUC IR2 Attachment A74.1 shows these typical structures and structure types that would be used when the line must change angles at a deflection point on its route.

The heights of the structures shown in these figures are typical and will vary on a location by location basis as a result of site and span specific design considerations. In Figure 4-2-1B the existing 161 kV pole structure is approximately 17.2 meters (56.5 feet) above ground while the preliminary design height for Alternative 1A for this structure is 27.4 meters (90 feet) as shown in SOFAR IR2 Attachment A25.1. In this case the existing structure is slightly above typical height while the proposed structure is slightly below typical height. The approximate 65 percent height increase, as depicted is therefore correct.

Alternative 1A structure heights will vary over a range of about 27.4 meters (90 feet) to 36.6 meters (120 feet) with one or two sites potentially taller. The typical height is 30.4 meters (100 feet). Please also refer to the response to SOFAR IR2 Q25.1.

Q2 If the reasoning is correct, please confirm that similar misleading understatements were portrayed by Fig. 4-2-1F and G as well as Fig. 4-2-1D and E as described in the original question of IR #1.

A2 As discussed in the response to Q1 above, the reasoning is not correct based on the differences of site specific structure heights versus typical dimensions provided in Figure 4-2-1B.

Q3 Please provide all renderings, i.e. Fig. 4-2-1 C, G and E, with structures showing the correct height and proportions.

A3 The renderings previously provided represent the structure heights and proportions was well as reasonably possible based on the existing structures and the preliminary designs.

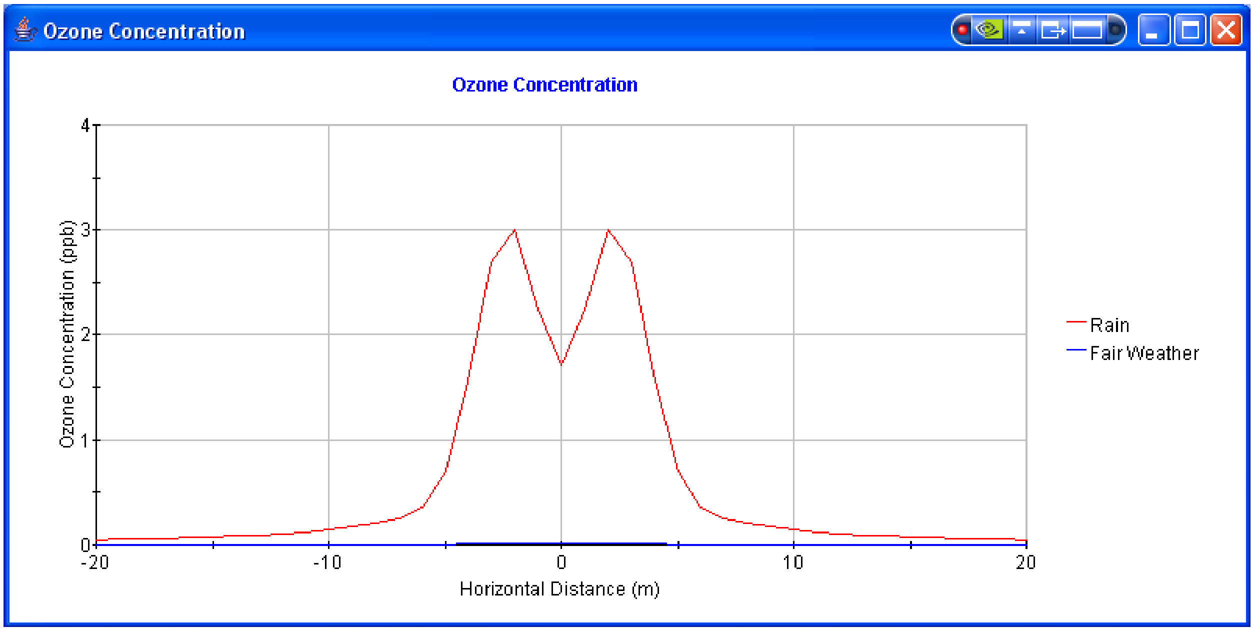
1. Corona Ion Emissions

Q1.1 In your response to IR#1 it appears that you have given figures for the level of Corona Ion emission at the edge of the ROW for the various options. Please indicate the level of Corona Ion emissions on average and at a maximum at the centre of the ROW

A1.1 As indicated in the response to Harlingten IR1 Q5.1 (Exhibit B-9) emissions related to corona are minimal for all Alternatives. The indicator values for ozone provided in Harlingten IR1 Table A5.1 are the maximum found anywhere within the right-of-way. The calculations were run for conditions leading to maximum emissions including being run at the same elevation as the conductors. For example, the calculated values for ozone are maximum during wet weather conditions and not detectable during dry weather. At ground level, on the right-of-way, ozone is not detectable under even maximum conditions due to the low level of emissions and dispersion. An average condition is difficult to define but based on the typically drier weather of the Okanagan Valley would be below one part per billion and well below ambient ozone levels.

Harlingten IR2 Figure A1.1 below shows the ozone concentration under worst case conditions that would be measured for Alternative 1A for rainy and dry weather conditions. Harlingten IR2 Figure A1.1 below also shows that the maximum level is three parts per billion near the centre of the right-of-way.

Harlingten IR2 Figure A1.1



2. Public Health & Safety

Q2.1 In describing the Electric & Magnetic Fields emanating from the Power Lines, you quote the WHO by saying "Compliance with the International Guidelines provides adequate protection for acute effects. Please state exactly what the International Guideline states with regard to long term non thermal exposure that is applicable to this project.

A2.1 The guideline cited by WHO states:

These guidelines for limiting exposure have been developed following a thorough review of all published scientific literature. The criteria applied in the course of the review were designed to evaluate the credibility of the various reported findings (Repacholi and Stolwijk 1991; Repacholi and Cardis 1997); only established effects were used as the basis for the proposed exposure restrictions. Induction of cancer from long-term EMF exposure was not considered established, and so these guidelines are based on short-term, immediate health effects such as stimulation of peripheral nerves and muscles, shocks and burns caused by touching conducting objects, and elevated tissue temperatures resulting from absorption of energy during exposure to EMF. In the case of potential long-term effects of exposure, such as an

> *increased risk of cancer, ICNIRP concluded that available data are insufficient to provide a basis for setting exposure restrictions, although epidemiological research has provided suggestive, but unconvincing, evidence of an association between possible carcinogenic effects and exposure at levels of 50/60 Hz magnetic flux densities substantially lower than those recommended in these guidelines.*
> [Guidelines for Limiting Exposure to Time-Varying Electric, Magnetic, and Electromagnetic Fields (up to 300 GHz). Health Physics 74 (4): 494-522; 1998.]

Note that ICNIRP's reference to "elevated tissue temperatures resulting from absorption of energy during exposure to EMF" pertains to higher frequency electromagnetic fields (> 100kHz), not lower frequencies from sources such as power lines.

Q2.2 Table 18.2 gives the maximum levels of 1000mg Magnetic Field exposure for the general Public (that probably should have been 833mg). Please quote from the ICNIRP guideline you reference how that level is applicable to the residents who live with the exposure 24/7.

A2.2 The ICNIRP's recommended limits for human exposure to magnetic fields (1000 mG at 50Hz and 833 mG at 60Hz) are ceiling limits on exposure and do not prescribe a recommended limit on the duration of exposure at levels below this limit.

Q2.3 Please comment of the following statement:

With the amount of credible scientific evidence now accumulating, FortisBC should be concerned about the legal implications of any attempts to down-play the evidence for EMF health hazards. In both the asbestos and tobacco industries, similar attempts to suppress hazard information eventually resulted in multi million dollar litigation and massive pay-outs, specifically because of their attempts to suppress information indicated industries knew of the risk but still knowingly exposed workers and the public. By FortisBC proposing to take positive and corrective action to reduce EMF exposure by invoking Precautionary and Prudent avoidance and recommending the Alternate Route they could avoid heading down "tobacco road" to extremely costly litigation.

A2.3 The proposed OTR Project is expected to reduce, not increase EMF exposure. FortisBC does not have an interest in downplaying any evidence in regard to EMF or other issues.

FortisBC develops its policies based on the current state of the science and health policy recommendations of Health Canada and other national and international health agencies.

3. Construction Schedule

Q3.1 In your CPCN you gave a Schedule for the OTR project. I find it strange that in the section for VAS to RGA you are procuring material, having it delivered and starting construction before the Design work is complete. It also appears that you are starting Construction before the material is procured. Could you produce a schedule for Option 1A that is a little more specific with regards to timing.

A3.1 FortisBC's response to BCUC IR2 Q79.1 states that more detailed scheduling will be completed in the July-August 2008 timeframe.

Some of the overlaps noted relate to the staged design and procurement of long lead equipment and materials. Shorter lead time materials are typically designed and specified after the major items are defined. Construction contract preparations, which also begin prior to 100 percent design completion. Design is completed to the extent necessary for tender pricing and the final construction drawings are issued after contract award.

1. Reference:

Q5 Has Fortis queried the BC Assessment Branch to determine the impact of electropollution (various electric forces mentioned question 19.) caused by/ associated with/ /emanating from power lines, including the proposed line?

A5 No, FortisBC has not queried the BC Assessment Branch

Q1 Please query the BC Assessment Branch as per Q5 and supply the BC Assessment's response.

A1. As a matter of general policy, the BC Assessment Authority does not apply a 'standard' or 'rule of thumb' adjustment to property values on the basis of either the existence of rights-of-way or easements on properties, or for EMF levels.

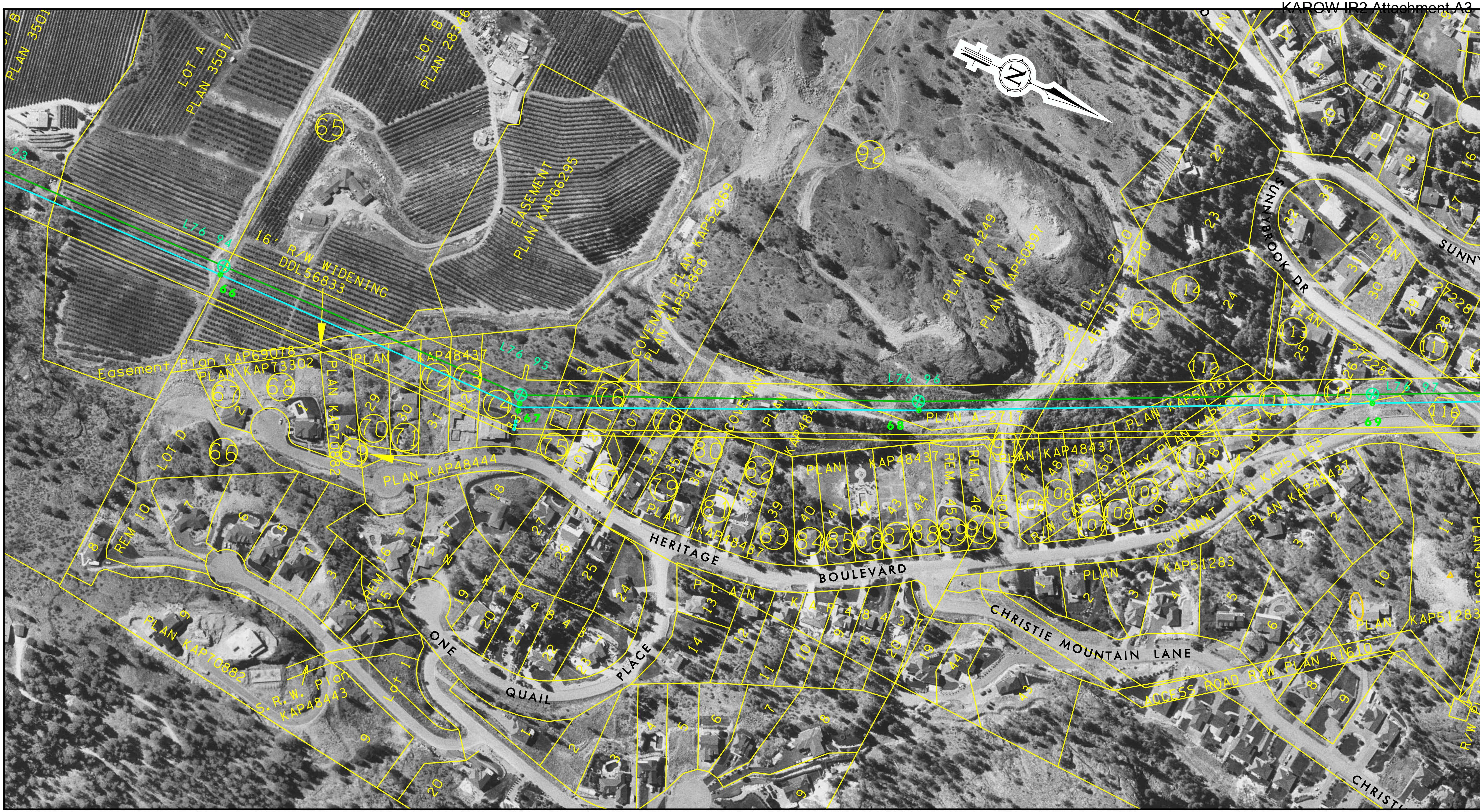
2. Reference:

Q6 Please provide an aerial map (1:2,000) transmission line around Heritage Hills residential area so to being able to see the impacts on and the numbers of properties nearest on both side of the to be upgraded transmission line.

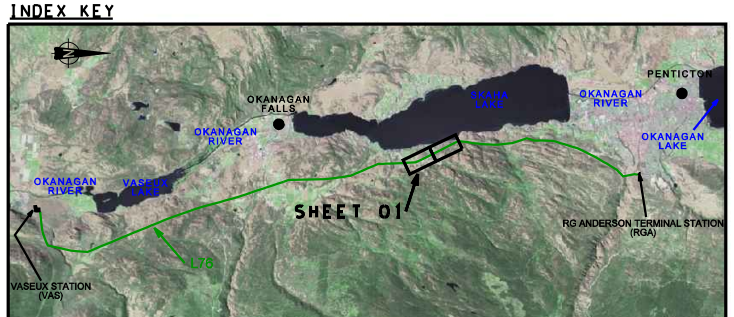
A6 FortisBC has provided 1:5,000 aerial maps of the transmission line around Heritage Hills in Appendix E (Exhibit B-1-2) (Drawing Number 76L-T07-D2; sheets 10 of 25 & 11 of 25). These maps show the number of properties along both sides of the transmission line through the Heritage Hills area.

Q3. Please supply areal maps 1:2000 as requested and supplied on same order in other hearings, so that approximate distances can be taken out/measured from centre of power line and buildings. The other scale 1:5000 is to small to do so.

A3. Karow IR2 Attachment A3 (2 pages) shows aerial mapping of the Heritage Hills area at a scale of 1:3000. The scale was chosen to show the area with adequate detail and still display within the maps approximately +/- 300 meters from the centre of the right-of-way corresponding to the magnetic field values provided in the response to Karow IR1 Q9 (Exhibit B-9).



INDEX KEY



LEGEND

EXISTING L76 CIRCUIT

PROPOSED CIRCUIT

CADASTRAL BOUNDARY

PROPERTY LINE LIST NUMBER

100 0 100 200m

AS SHOWN

PRODUCED BY PHOTOGRAMMETRY SERVICES, BC HYDRO
DIGITAL ORTHOPHOTO METRIC MAP
UTM ZONE 11, NAD83
BCGS REFERENCE: 82E
ORTHOPHOTO GENERATED AND
RECTIFICATION BASED ON DEM COMPILED
FROM 1:20,000 SCALE AERIAL PHOTOGRAPHY,
TAKEN SEP 17, 2005

NOTE:
1) Cadastre was computed by Survey Services, BC Hydro
Accuracy +/- 0.25 metres.

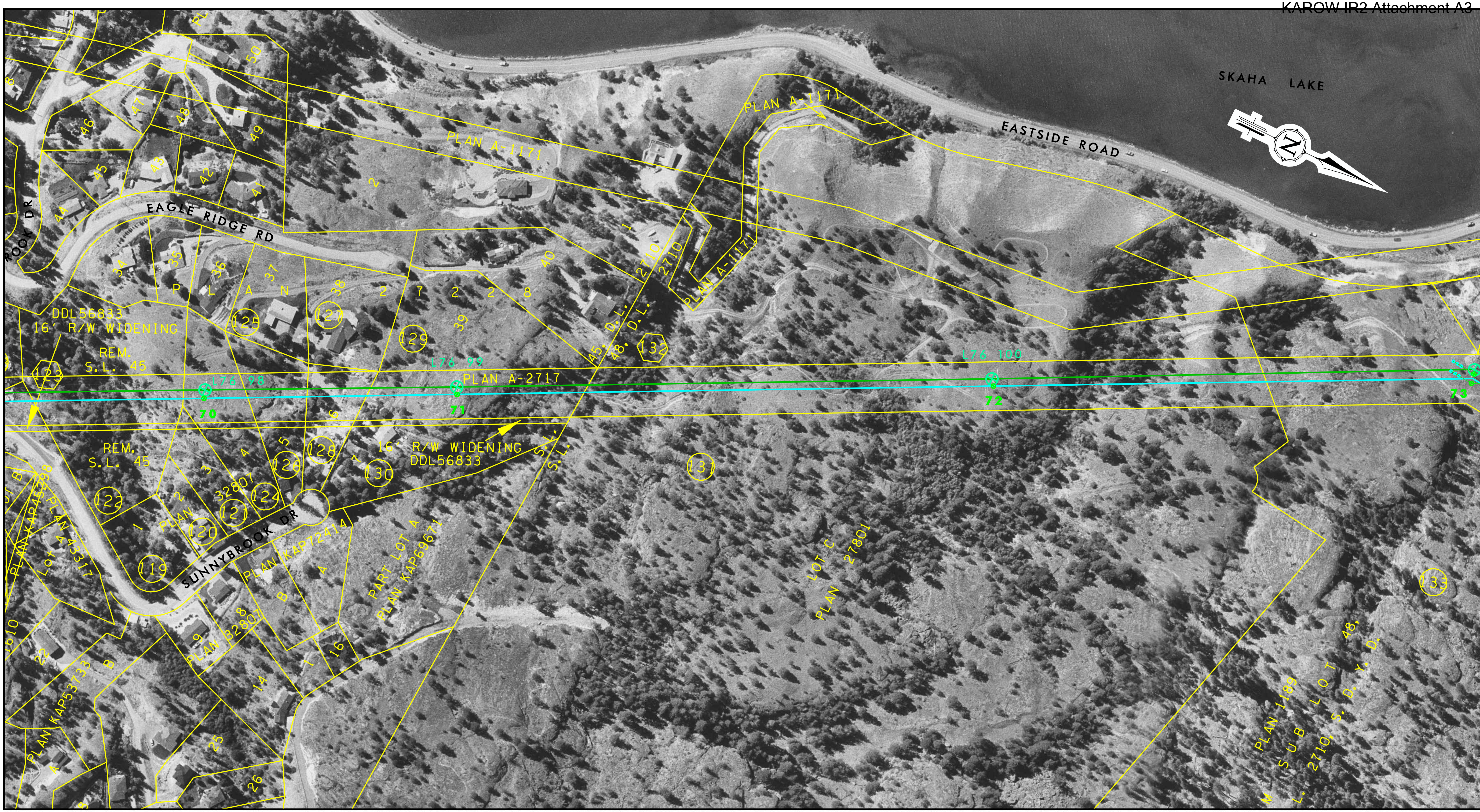
No.	BY	DATE	DESCRIPTION	No.	BY	DATE	DESCRIPTION			
								DESIGNED BY		
								DRAWN BY	GJB	2008.04.28
								CHECKED BY		
								APPROVED BY		

FORTISBC

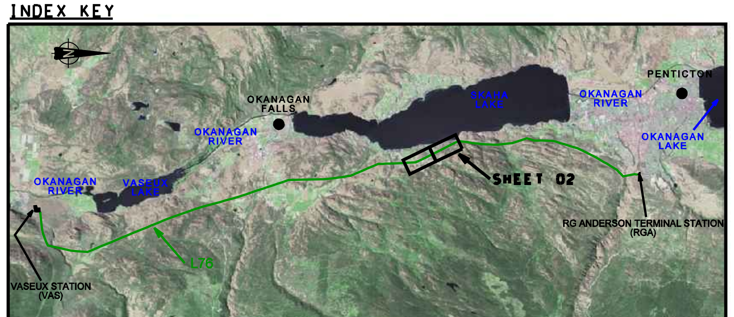
BChydro ENGINEERING

FORTIS BC - OTR PROJECT
HERITAGE HILLS
76L VAS - RGA
KAROW IR#2 03
ORTHOPHOTO MAP SHEET 1 OF 2

DRAWING NUMBER	REV
KAROW IR#2 03	B



INDEX KEY



LEGEND

EXISTING L76 CIRCUIT
PROPOSED CIRCUIT

CADASTRAL BOUNDARY
PROPERTY LINE LIST NUMBER

100 0 100 200m

AS SHOWN

PRODUCED BY PHOTOGRAMMETRY SERVICES, BC HYDRO
DIGITAL ORTHOPHOTO METRIC MAP
UTM ZONE 11, NAD83
BCGS REFERENCE: 82E
ORTHOPHOTO GENERATED AND
RECTIFICATION BASED ON DEM COMPILED
FROM 1:20,000 SCALE AERIAL PHOTOGRAPHY,
TAKEN SEP 17, 2005

NOTE:
1) Cadastre was computed by Survey Services. BC Hydro Accuracy +/- 0.25 metres.

No.	BY	DATE	DESCRIPTION	No.	BY	DATE	DESCRIPTION

DESIGNED BY		
DRAWN BY	GJB	2008.04.29
CHECKED BY		
APPROVED BY		

FORTISBC

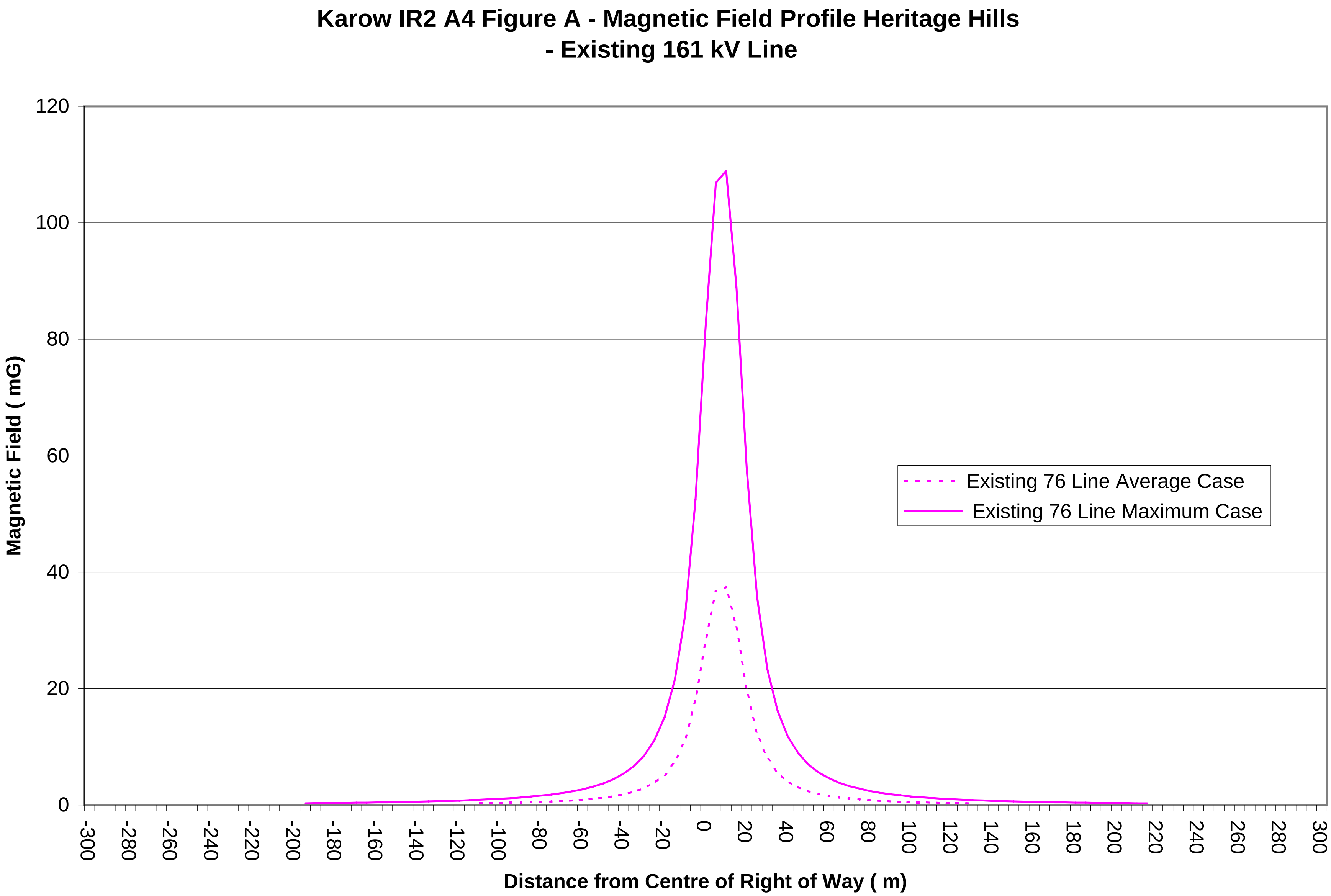
BChydro ENGINEERING

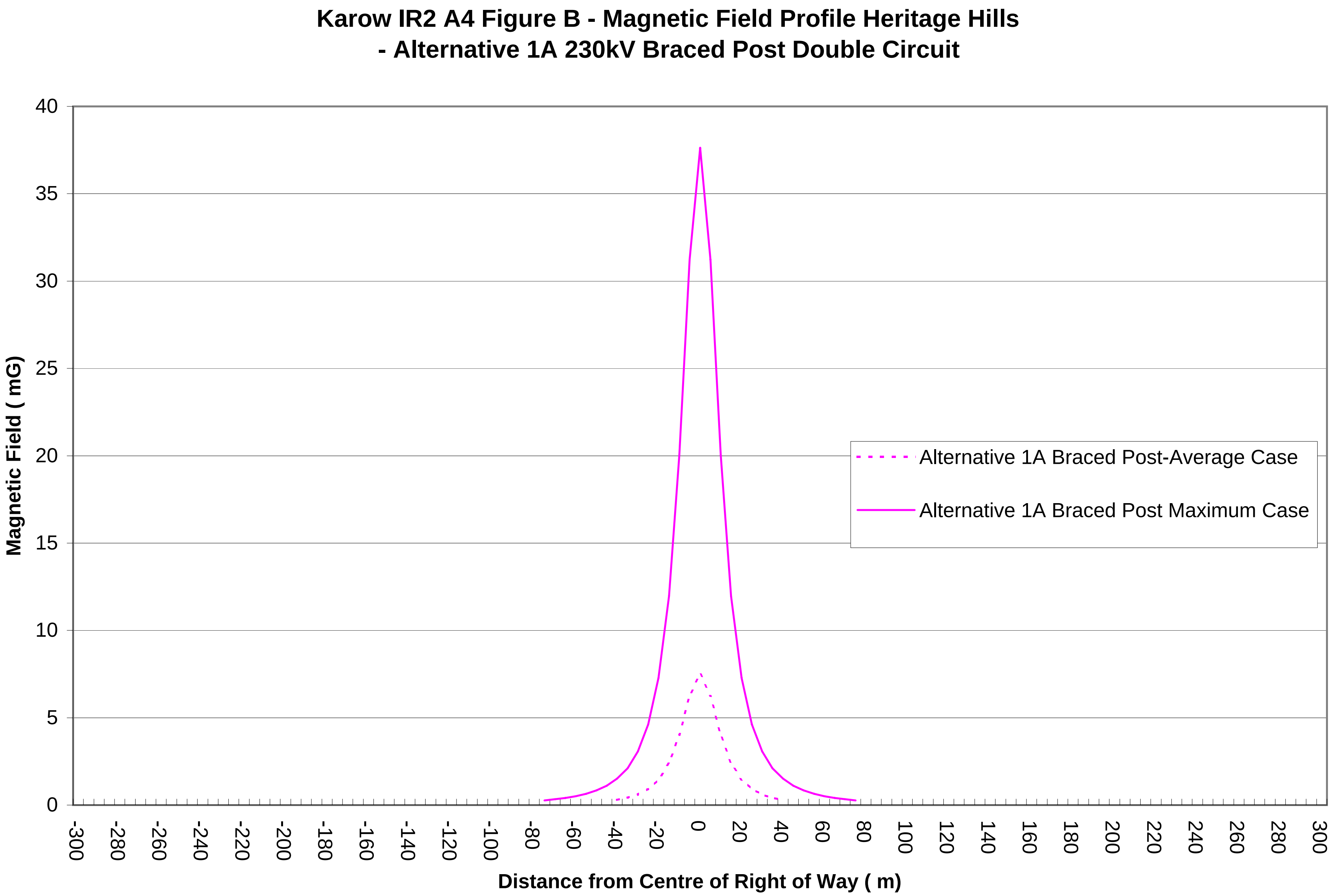
FORTIS BC - OTR PROJECT
HERITAGE HILLS
76L VAS - RGA
KAROW IR#2 03
ORTHOPHOTO MAP SHEET 2 OF 2

DRAWING NUMBER	REV
KAROW IR#2 03	B

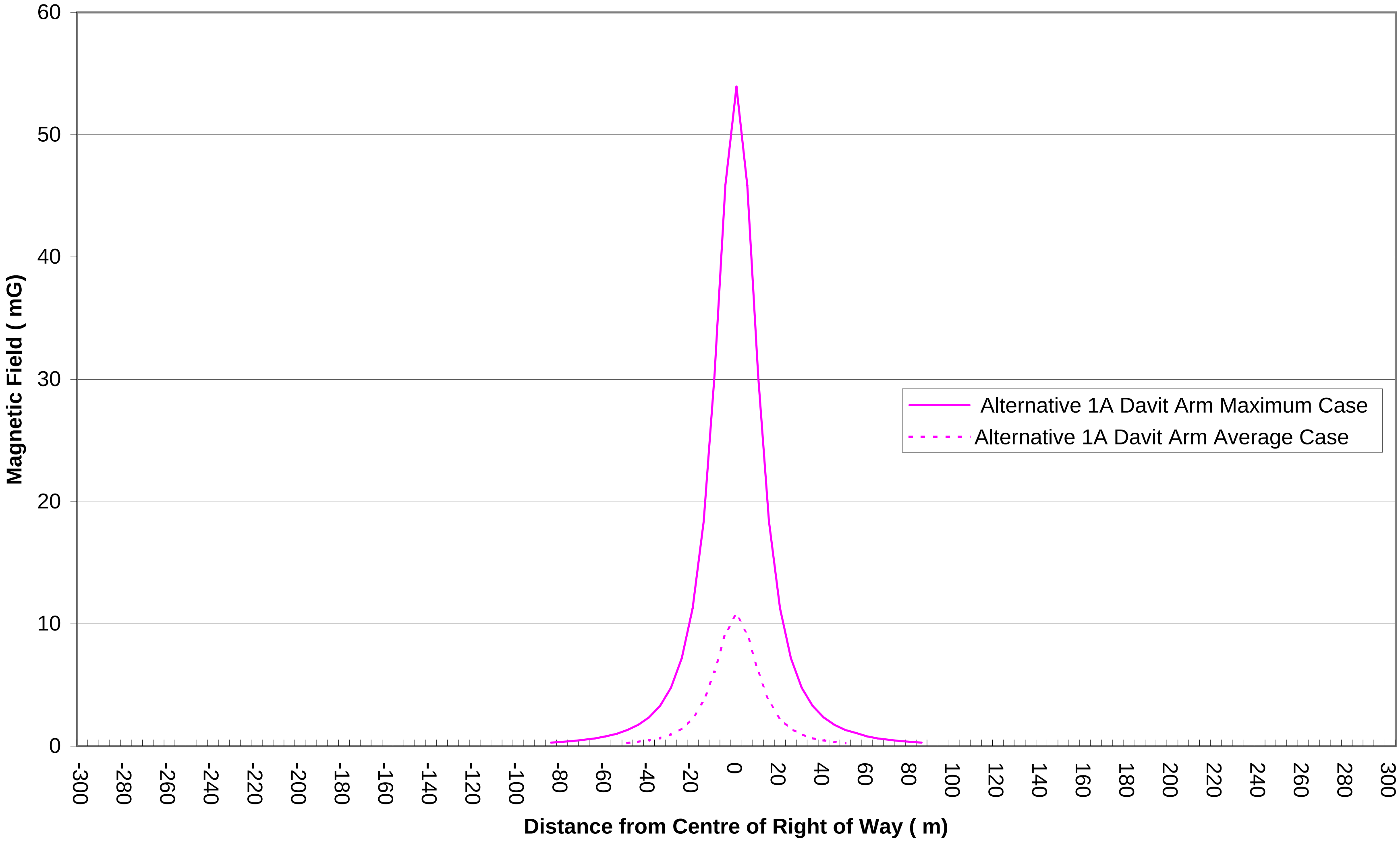
Q4. Please provide magnetic field profile (as far as to the 0.3 milliGauss border) for medium and maximum load on both sides of the proposed to be upgraded line in the Heritage Hills area, this for every 5 meters from centre of line a present time and after upgrade.

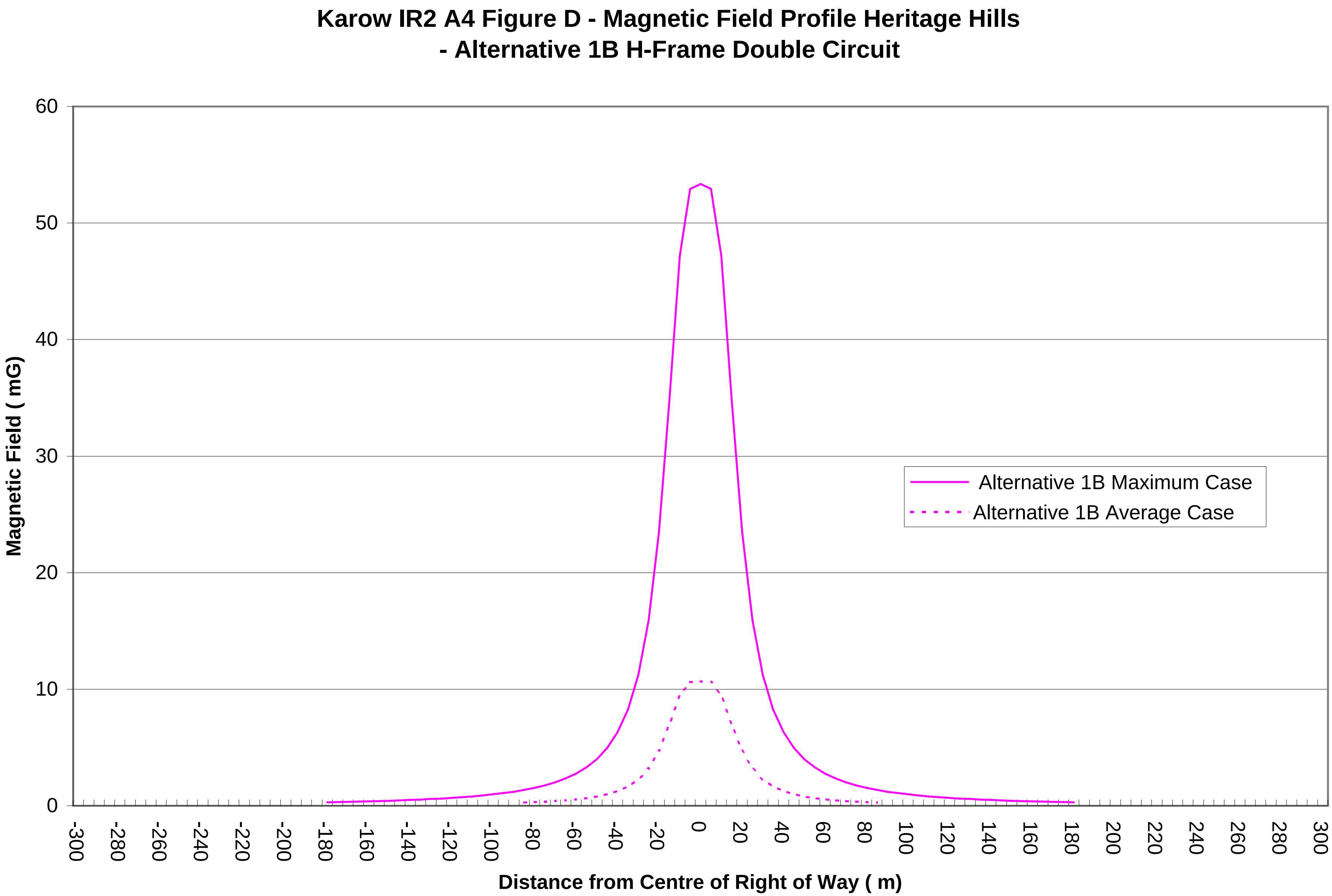
A4. Please see Karow IR2 Attachment A4 - Figures A to E for the requested profiles down to 0.3 mG for the Existing Line, and for Alternatives 1A, 1B and 1C.

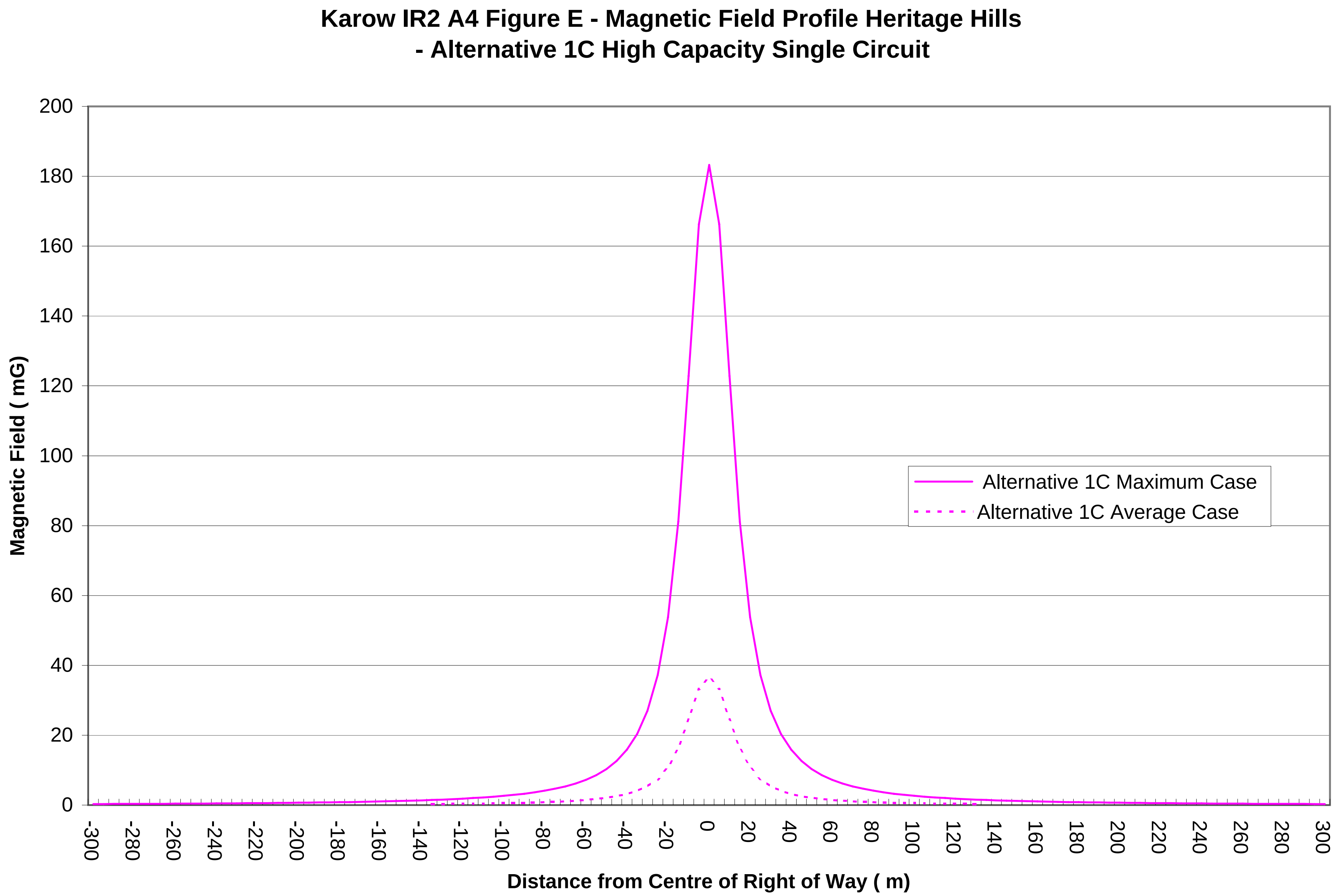

Karow IR2 A4 Figure A - Magnetic Field Profile Heritage Hills
- Existing 161 kV Line
Magnetic Field (mG)
120
100
80
60
40
20
0
Existing 76 Line Average Case
Existing 76 Line Maximum Case
-300 -280 -260 -240 -220 -200 -180 -160 -140 -120 -100 -80 -60 -40 -20 0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300
Distance from Centre of Right of Way (m)


Karow IR2 A4 Figure B - Magnetic Field Profile Heritage Hills
- Alternative 1A 230kV Braced Post Double Circuit
Magnetic Field (mG)
0
5
10
15
20
25
30
35
40
Alternative 1A Braced Post-Average Case
Alternative 1A Braced Post Maximum Case
-300
-280
-260
-240
-220
-200
-180
-160
-140
-120
-100
-80
-60
-40
-20
0
20
40
60
80
100
120
140
160
180
200
220
240
260
280
300
Distance from Centre of Right of Way (m)

Karow IR2 A4 Figure C - Magnetic Field Profile Heritage Hills - Alternative 1A 230 kV Davit Arm Double Circuit




Karow IR2 A4 Figure D - Magnetic Field Profile Heritage Hills
- Alternative 1B H-Frame Double Circuit
Magnetic Field (mG)
60
50
40
30
20
10
0
-300 -280 -260 -240 -220 -200 -180 -160 -140 -120 -100 -80 -60 -40 -20 0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300
Distance from Centre of Right of Way (m)
Alternative 1B Maximum Case
Alternative 1B Average Case


Karow IR2 A4 Figure E - Magnetic Field Profile Heritage Hills
- Alternative 1C High Capacity Single Circuit
Magnetic Field (mG)
200
180
160
140
120
100
80
60
40
20
0
Alternative 1C Maximum Case
Alternative 1C Average Case
-300 -280 -260 -240 -220 -200 -180 -160 -140 -120 -100 -80 -60 -40 -20 0 20 40 60 80 100 120 140 160 180 200 220 240 260 280 300
Distance from Centre of Right of Way (m)

Q5. Please state, whether FortisBC agrees that magnetic fields from power lines typically fall off (down) very slowly with much longer distance compared to household appliances as per my Q12 in my IR#1, also compared to FortisBC response in A 13 *"intensity of magnetic fields diminishes quickly with distance "* (yellow highlighted by Karow)

A5. The intensity of the magnetic field will diminish with distance more slowly from a power line than for household appliances.

6. Reference:

Q14 Please state all possible measures that can mitigate EMF levels

A14 A wide variety of measures may be conceived to minimize EMF levels and could involve the voltage, load, conductor configuration and phasing, and location of the source, singly or in combination.

Q6. Please provide samples (including pictures) and each the average magnetic and electric field reduction rate.

A6. The detailed information requested is not readily available, but in short the magnetic and/or electric field can be reduced by a variety of means including:

a. reductions in load;
b. operating a line at a higher voltage, thus reducing the current flow necessary to meet any given load demand;
c. conductor configurations that place the conductors in a vertical or delta configuration and/or reductions in the distance between phase conductors;
d. maximizing the mutual cancellation of the field from adjacent lines by phase selection;
e. raising the phase conductors higher above ground; and

f. increasing lateral distance from the line.

7. Reference:

Q17 Please state, whether Fortis will ever install or allow to install by other companies radio/microwave transmitter antennas on the to be upgraded power line pylons or anywhere on the new and existing substation in/near that are/ will be connected to the upgraded lines. If so, please give details.

A17 FortisBC has not been approached, nor has it sought to offer access to power line structures for the purposes of installing third-party telecommunications antennas. In general, the mountainous terrain of the FortisBC service area does not lend itself to having telecommunications antennas installed in the valley bottom where most transmission lines are located.

Q7. Please state, whether Fortis can/will assure/promise that in future no microwave/radiowave transmitters will be ever installed on all the towers involved with the proposed upgraded line.

A7. FortisBC has no plans to install, or allow the installation of the types of communication equipment mentioned.

8. Reference:

Q18 Please, in layman's language, explain the difference of single phase magnetic fields and rotating magnetic fields, and state what kind of magnetic fields the proposed transmission line, and distribution lines usually have.

A18 A single phase conductor produces a field vector that changes its direction in a straight line (linear polarization). The field vectors from three-

phase transmission and distribution lines are not necessarily linearly polarized and the field vector rotates during a cycle, tracing out an ellipse. The field is then described as elliptically polarized and the ratio of the minor to major field axis defines the ellipticity or degree of polarization. When the two axes of the ellipse are of equal magnitude, the ellipse forms a circle and the field is a circularly polarized field. The proposed line is a three-phase transmission line with an elliptically polarized field, and this type of field is shared by most transmission and distribution lines

Q8 Please state a few of the main studies that involve work with straight line (linear polarized) and rotating (elliptical and circular polarized) magnetic fields. With these studies of both groups, please indicate clearly which fields have been investigated in.

A8. FortisBC has made no claims regarding field polarization and therefore has not referenced any specific studies that are relevant to this issue.

9. Reference:

A19 All the items noted may be associated with the generation, transmission and utilization of a safe and efficient electrical service, but should not be confused with forces.

Q9. Please state, if these items are not compared to forces, why then do those items have an physical impact on all conductive material, thus creating i.e. voltages and secondary magnetic and electric fields even in human bodies,, which are indeed very conductive.

A9. The items referred to are stray voltages, ground currents, harmonics, transients, radio and microwaves, and coronas. FortisBC has stated that these phenomena “should not be confused with forces” because they are akin to sources whose effects are mitigated or eliminated by the environment. An engineering study of stray current, for instance, may detect currents in the conduction path completing the utility power circuit. Such detection does not imply that nearby persons or materials are affected by stray currents or experience any measurable force because of stray currents.

Reference: A13…continued:

Two of the items listed above - harmonics and transients - are most often produced at troublesome levels by customers' equipment, rather than utility equipment

Q10. Please state whether those troublesome harmonics and transients from neighboring customers can travel over distribution lines and transmission lines to the next neighbor or in any service area from each kind of line.

A10. Yes, it is possible for harmonics and other power quality disturbances to travel some distance between customers via the transmission and distribution lines. This distance will vary depending on the magnitude of the disturbances and the relative impedances of the customer and utility equipment.

Q11. Please state how those harmonics and transients can be prevented, in either case by the utility company and by the customer.

A11. Both of these issues can be corrected by the installation of filtering equipment either on the customer or utility side. Since the customer producing power quality disturbances will also be affected by them, most customers install their own filtering equipment.

In one previous case of wide-scale harmonic issues where the problem could not be localized to a single customer, FortisBC installed a substation harmonic filter to reduce the distortion to acceptable levels.

12. Reference:

Q21 Please state whether property devaluation are associated to near by power lines, please provide sources for this response.

A21 It is the opinion of FortisBC that the OTR Project will not impact property values. Please refer to the response to SOFAR/Wiltse Q5.1.

Q12 Please provide several documents that FortisBC's opinion is relied on.

A12. FortisBC's opinion is based on the expert opinion provided by Interwest Property Services, (1991), which is provided in Appendix K of the CPCN Application (Exhibit B-1-3).

Q13. Please state, whether FortisBC is aware about studies that do indicate property values impact by nearby power lines.

A13. FortisBC is generally aware that studies have been performed to investigate hypotheses about potential relationships between transmission lines and property values but is not aware of any research studies that would shed light on this hypothesis in this locale at this time.

14. Reference:

Q24 Please compare the BioInitiative Report with Health Canada recommendations.

A24 Health Canada states, "You do not need to take action regarding typical daily exposures to electric and magnetic fields at extremely low frequencies."

http://www.hc-sc.gc.ca/iyh-vsv/environ/magnet_e.html

The Bioinitiative report states, "ELF limits should be set below those exposure levels that have been linked in childhood leukemia studies to increased risk of disease, plus an additional safety factor." (p. 22)

Q15. Please state, whether FortisBC agrees that childhood leukemia has been <u>linked and/or associated</u> in childhood leukemia and other biological adverse effects (Please note: please do not state or use the meaning cause/causation, this is not what is addressed in this question.)

A15. The question is not clear.

16. Reference:

Q25 Please state whether Health Canada guidelines address long-term exposure and non-thermal biological effects in its guidelines for ELF-EMF exposures? If not, please state why not and provide reference.

A25 Health Canada states, "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."

Health Canada's rationale, in part, is that "There have been many studies about the effects of exposure to electric and magnetic fields at extremely low frequencies. Scientists at Health Canada are aware that some studies have suggested a possible link between exposure to ELF fields and certain types of childhood cancer. However, when all of the studies are evaluated, the evidence appears to be very weak.

Q16 Please state whether Health Canada guidelines address <u>long-term exposure and non-thermal biological effects</u> in its guidelines for ELF-EMF exposures? Please answer just with yes or no.

A16. Health Canada has not published guidelines to limit exposure to ELF-EMF as indicated in the quote. The quote from Health Canada also references epidemiology studies that involve estimates of long-term exposure and which were considered in their evaluation of research. Except perhaps under some artificial condition in a laboratory, no exposures to ELF-EMF in the environment would be sufficient to produce heating of organisms and so any responses observed would be non-thermal or due to other factors.

17. Reference:

Q28 Assuming new sometimes down the road ELF-EMF in the range of 2-20 milliGauss have been proved to be related/associated/attributed to residents' medical problem, in case of claims, does FortisBC have third party insurance?

A28 FortisBC does not agree that there is any demonstrated causal relationship between ELF-EMF in the range of 2-20 milligauss and "medical problems". FortisBC does carry property and liability insurance.

Q17. Please state, whether FortisBC is aware about ELF-EMF in the range of 2-20 milliGauss being associated and/or linked to adverse biological effects (Please note: the cause/causation is not addressed in this question, but the link and/or association).

A17. FortisBC is generally aware that the ELF-EMF research literature includes publications in which biological responses to ELF magnetic field at intensities similar to those identified have been studied. As to the interpretation to whether any responses are adverse, the reviews of this research by health agencies should be consulted, e.g., WHO Environmental Health Criteria Report 232, June 2007.

Q18.a Please state, whether FortisBC is aware about the court order in favor of the plaintiff in the v. Wyk vs Public Service Company of Colorado (source: http://caselaw.lp.findlaw.com/scripts/getcase.pl?court=co&vol=1999app\ct062410&invol=1)

A18a The enclosed document is not a court order in favour of the plaintiff. The document is a judgment of the Court of Appeals of Colorado dated June 24, 1999.

Q18b. and please state FortisBC position about this court case.

A18b FortisBC takes no position with respect to the judgment of the Court of Appeals of Colorado. The matter was referred to the Supreme Court of Colorado for further determination. The matter was heard by the Supreme Court on July 2, 2001, which determined that intangible invasions do not support a claim for inverse condemnation and do not constitute trespass. The Supreme Court further determined that the plaintiff may proceed to litigate the issue of an alleged intentional nuisance against the defendant. However, FortisBC is not aware whether the issue of an alleged intentional nuisance was litigated further.

Q19. Please state, whether FortisBC accepts the fact that EMF has been accepted as a toxic substance by te National Institutes of Health · U.S. Department of Health and Human Services

Source:

http://www.niehs.nih.gov/research/resources/library/consumer/hazardous.cfm#emf

http://www.niehs.nih.gov/research/resources/library/consumer/hazardous.cfm

A19. No. To FortisBC's knowledge, neither of the links indicated provide information that contradicts the conclusions regarding EMF that the Director of the National Institute of Health Sciences submitted to the US Congress in 1999.

20. Reference:

Q27 With regards of ELF-EMF exposures within the scope of the subject project, how will FortisBC address/apply the precautionary principle, this also in light of ever increasing scientific findings, that ELF-EMF are associated to biological effects as far down to 2-4 milliGauss?

A27 FortisBC draws guidance on EMF from Health Canada and other national and international health agencies. The latest report from the World Health Organization in June 2007 concluded that any actions taken to reduce EMF exposure should be proportional to the strength of scientific knowledge regarding its potential effects on human health. This is called the precautionary principle.

Since the research has not established that EMF is a cause of any long-term health effect, steps to reduce personal or public EMF exposure should be low in cost and not compromise the health, social, and economic benefits that come from electricity

Q20. Please state why FortisBC is differing from the international accepted version of the Precautionary Principle, see below highlighted by Karow:

International Commission for Electromagnetic Safety (ICEMS)
http://www.icems.eu/
The Precautionary Principle
The Precautionary Principle states, when there are indications of possible adverse effects, though they remain uncertain, the risks from doing nothing may be far greater than the risks of taking action to control these exposures. The Precautionary Principle shifts the burden of proof from those suspecting a risk to those who discount it

Science and Environmental Health Network
http://www.sehn.org/precaution.html
The Science and Environmental Health Network is working to implement the precautionary principle as a basis for environmental and public health policy. The principle and the main components of its implementation are stated this way in the 1998 Wingspread Statement on the Precautionary Principle:

"When an activity raises threats of harm to human health or the environment, precautionary measures should be taken even if some cause and effect relationships are not fully established scientifically. In this context the proponent of an activity, rather than the public, should bear the burden of proof. The process of applying the precautionary principle must be open, informed and democratic and must include potentially affected parties. It must also involve an examination of the full range of alternatives, including no action." - Wingspread Statement on the Precautionary Principle, Jan. 1998

The precautionary principle, virtually unknown here six years ago, is now a U.S. phenomenon. In December 2001 the New York Times Magazine listed the principle as one of the most influential ideas of the year, describing the intellectual, ethical, and policy framework SEHN had developed around the principle.

In June 2003, the Board of Supervisors of the City and County of San Francisco became the first government body in the United States to make the precautionary principle the basis for all its environmental policy.

A20. There is no single "international accepted version of the Precautionary Principle" as stated in Q20. There are many definitions with varying tenets and emphasis. The description of the precautionary principle referenced relates to definitions developed by Health Canada and the World Health Organization.

21. Reference:

A27 FortisBC draws guidance on EMF from Health Canada and other national and international health agencies. The latest report from the World Health Organization in June 2007 concluded that any actions taken to reduce EMF exposure should be proportional to the strength of scientific knowledge regarding its potential effects on human health. This is called the precautionary principle. Since the research has not established that EMF is a cause of any long-term health effect, steps to reduce personal or public EMF exposure should be low in cost and not compromise the health, social, and economic benefits that come from electricity

Q21. Please state whether FortisBC does acknowledge and in the proposed subject project considering that environmental sensitivity recently is becoming more and more of an issue. For example The Canadian Human Rights Commission (CHRC) reported:

http://www.chrc-ccdp.ca
Policy on Environmental Sensitivities
Individuals with environmental sensitivities experience a variety of adverse reactions to environmental agents at concentrations well below

those that might affect the "average person". This medical condition is a disability and those living with environmental sensitivities are entitled to the protection of the Canadian Human Rights Act, which prohibits discrimination on the basis of disability. The Canadian Human Rights Commission will receive any inquiry and process any complaint from any person who believes that he or she has been discriminated against because of an environmental sensitivity. Like others with a disability, those with environmental sensitivities are required by law to be accommodated.

http://www.weepinitiative.org/Canadian%20Human%20Rights.html
Approximately 3% of Canadians have been diagnosed with environmental sensitivities, and many more are somewhat sensitive to traces of chemicals and/or electromagnetic phenomena in the environment ///snip by Karow//

This specific CHRC report is dealing with accommodations, thus electromagnetic sensitive residents near power lines have the right that their sensitivity be respected. This issue needs to be dealt with accordingly, i.e. power line corridors need to /can be at safe distances away as suggested in the BioInitiative Report.

A21. FortisBC acknowledges that access to opinion and information on the subject of environmental sensitivity is increasing, at least in part due to the prevalence of internet based sources.

Major beneficiaries of the OTR

18. Reference: Exhibit B-8, SOFAR IR 1.2

Q18.1 Please provide the number of direct and indirect customers in each of the following three areas - Kelowna, Penticton, and the area described by FortisBC in response A1.2, as being "…within the Vaseux to Penticton corridor…".

A18.1 The numbers requested are provided in SOFAR IR2 Table A18.1 below.

SOFAR IR2 Table A18.1

	Customer Class	Oliver and Area	Penticton and Area [1]	Vaseux to Penticton Corridor [2]	Kelowna and Area	Total
1	**FortisBC Direct Customers [*]**	**13,476**	**5,152**	**1,995**	**45,947**	**66,570**
2	Indirect Customers	0	21,211	0 [3]	12,955	34,166
3	**FortisBC Direct and Indirect Customers**	**13,476**	**26,363**	**1,995**	**58,902**	**100,736**

[*] Customer count as of October 31, 2007
[1] Penticton and Area includes: Summerland, Naramata and Skaha Lake West.
[2] Vaseux to Penticton Corridor includes: Skaha Lake East, Vaseux Lake East and Okanagan Falls FortisBC customers only.
[3] City of Penticton customers are indirect customers included in the Penticton and Area count.

Copies of right of way agreements, easements and statutory rights of way

19. Reference: Exhibit B-8, SOFAR IR's 6.1 and 6.2, FortisBC Responses A6.1 and 6.2

Q19.1 Please provide an explanation of the contents of the column entitled "RW Charge" contained in the table described as SOFAR/Wiltse Attachment A6.1. In particular please explain the acronym "N/R" and the meaning behind differentiating among charge numbers by bolding some charge numbers and leaving other un-bolded.

A19.1 SOFAR/Wiltse Attachment A6.1 should be disregarded and replaced with SOFAR/Wiltse Attachment A6.1 Updated - May 13, 2008 as noted in ERRATA 3.

SOFAR/Wiltse Attachment A6.1 does not include the N/R acronym and the bolding helps to identify which charge numbers pertain to transmission line rights-of-way.

Q19.2 FortisBC has no basis in law for declining to provide the documents requested in SOFAR's IR 6.2. The response to Q6.2 was to refer SOFAR back to FortisBC's response contained in A6.1. The only part of A6.1 that relates in any way to Q6.2 is the sentence "FortisBC does not disclose the names or contact information of individuals."

SOFAR's request was to produce, for each and every parcel on the existing right of way on which the OTR project is being proposed to be built, a copy of each legal title as well as a copy of each and every right of way agreement, easement or statutory right of way.

The legal title to every surveyed parcel of property in British Columbia, and a copy of every charge on those titles, is contained in the publicly

available records of British Columbia's Land Title and Survey Authority. Indeed, the integrity of BC's land title system is founded upon the principle of public disclosure. In other words, every title and charge is open to public scrutiny and available for copying. The excerpt below is published by the Land Title and Survey Authority on its website (http://www.ltsa.ca/land-title/security-of-land-title):

Torrens Principles

Land title in BC operates under a system which is based on the principles of the 'Torrens' registry system. Sir Robert Torrens was an Australian politician and civil servant who in the 1850's was unhappy with the current land conveyancing system. Based on his experience in registering the ownership of ocean vessels, he devised a method of making land registration conclusive. The Colony of Vancouver Island adopted a Torrens system of land title registration in 1861, the second jurisdiction in the world to do so. The Torrens system is now used by countries around the world.

Assured Title

Under the Torrens system, legal ownership of land can only be changed by the act of registration on a public register, and the issuance of a 'Certificate of Indefeasible Title'. A title that is indefeasible cannot be defeated, revoked or made void. The person who has a title has a right, good against the world, to the land. Evidence of the right to land is constituted by an indefeasible title which includes the name of the owner and a listing of any mortgages, agreements for sale, leases, easements, covenants, rights-of-way or other registered charges which may pertain to the title. There are a limited number of exceptions to the principle of indefeasibility which are set out in the *Land Title Act*, the statute which governs BC's land title system.

The beauty of the BC system is that it eliminates the need for exhaustive and, expensive searches back through the historical chain of ownership to prove that a title is valid and unencumbered. A prospective purchaser need only examine the current title to obtain a full list and description of all interests that affect the title.

A further statement of the public nature of land title records can be found at ***http://www.ltsa.ca/records***, and is set out below:

Access to Records

Home > Records > Access to Records

Access to land title and survey records in BC is possible through the following channels:

- A lawyer, notary public, land surveyor
- A title services (title search) company: look under 'Title Services' in the yellow pages or use the TELUS Business Finder to find a Title Search Agent (also known as a Registry Agent)
- A BC Government Agent
- In person at an LTSA Land Title Office in either Kamloops, New Westminster or Victoria

These sources have access to LTSA electronic documents through the BC OnLine or GATOR systems. These online systems require fee-based user accounts and passwords.

Fees are payable to obtain copies of land title and survey records, as set out in the LTSA's customer fees listing. Additional fees are payable to private sector service providers, if you use their services.

Legal Descriptions or Parcel Identifier Numbers

Legal descriptions or Parcel Identifier Numbers (PIDs) are often required to access land title and survey records. Legal descriptions and PIDS can be found on a property's tax assessment notice and on certain land title records. Provided that a civic street address is known for the property, legal descriptions and PIDs may also be available by contacting BC Assessment Authority.

To access specific documents, please refer to the sections below.

- Title Searches
- Land Title Documents
- Survey Plans
- Field Books
- Crown Grants

Title Searches

To conduct a title search, you will need to supply one of the following pieces of information to one of the channels listed at the top of this page:

- Legal description of the parcel of interest
- Nine-digit parcel identifier number (PID)
- Current title number

Titles cannot be searched using a civic street address.

Land Title Documents

Each registered land title document is assigned a document reference number which when registered is recorded on the property's title in the LTSA's ALTOS system. The document number is the access point for its retrieval.

A land title document's registration number is found in the top margin of the first page of the document. A document's registration number may also be found on the title search or certificate of title for the land in question. For a transfer document, the registration number is the title number indicated on a title search or certificate of title. All other registered land title documents are listed on the title search or certificate of title under the heading "Charges, Liens and Interests".

Once a land title document's registration number has been identified, it may be retrieved online through any of the channels listed above. If a specific document is unavailable through the online system, it may be obtained in person at a Land Title Office or through a Title Search/Registry Agent services company.

Survey Plans

Survey plans of private land that have not been scanned must be obtained at the specific Land Title Office that houses the original record. Crown land survey plans that have not been scanned are available only from the Authority's Surveyor General's Office.

Online Cadastre enables users to obtain a free 'view only' representation of cadastral information.

To retrieve a survey plan for viewing or copying, a plan number is required. For private land, the survey plan number is part of the property's legal description. For Crown land, the survey plan number can be found on the GATOR system by lawyers, notaries, land surveyors and title search agents.

Field Books

Field books may be accessed by sending your order to the LTSA's Records Distribution Services, Surveyor General Division. A photocopy of the field book information will be mailed to you or a .PDF image may be created and sent to you by e-mail.

To retrieve a field book for viewing or copying, you will need to know the property's legal description.

FortisBC has the staff and capability to obtain all of the titles, right of way agreements, easements and statutory rights of way requested in Q6.2.

Please provide all the documents listed in SOFAR Q6.2.

A19.2 FortisBC intends to respect the privacy of the affected individuals and will not disclose their names or contact information unless so directed by the Commission. If SOFAR desires this information and it is publicly available, then SOFAR may itself obtain the information.

Average reliability statistics

20. Reference: Exhibit B-8, SOFAR IR 7.2 and FortisBC response A7.2

Q20.1 FortisBC states "FortisBC feels it is inappropriate to compare the reliability of 79 Line to the average outage rate of the entire FortisBC service territory."

Irrespective of FortisBC's view of the appropriateness of the comparison sought in A7.2, that is a matter for argument. Please provide the comparison and reliability statistics sought in A7.2.

A20.1 FortisBC operates a total of 68 transmission lines. SOFAR IR2 Table A20.1 below shows the average outage rates due to line faults for each year since 2004:

SOFAR IR2 Table A20.1

Year	Number of Line Faults	Average Outage rate [(1)]
2004	96	1.41
2005	48	0.71
2006	96	1.41
2007	67	0.99

(1) Number of faults / total number of lines

Thus, the average outage rate (total outages all years / [number of lines x number of years]) is 1.13. As noted in the response to SOFAR/Wiltse IR1 Q7.2, the historical outage rate of the "high-elevation" 79 Line (for the same period) is 2.0 outages per year.

Coincident outages

21. Reference: Exhibit B-8, SOFAR IR 8.1 and FortisBC response A8.1

Q21.1 According to the Application, the placement of lines 72 and 74 on a common corridor increased their risk of a coincident outage (lightning strike, for example). FortisBC's response A8.1 states in reference to Lines 72 and 74 "The capacity of 73 Line to supply Kelowna for the loss of both these lines (which, as noted, are in a common corridor) is highly limited." Further along the response states "These double-circuit corridors will be solidly connected via the 73 Line 230 kV transmission line (with no intermediate transformation)." Doesn't it follow logically that if, as FortisBC says, 73 Line's ability to support a coincident loss of 72 and 74 Lines is "highly limited" that 73 Line's ability to support a coincident loss of 75 and 76 Lines is also highly limited? Furthermore, doesn't it also logically follow that because 75 and 76 Lines, in addition to being on the same corridor, are on the same poles their risk of a coincident outage is greater than the risk facing 72 and 74 Lines? SOFAR's IR 8.1 asked if it would make more sense from a risk management perspective to put 75 and 76 Lines on separate corridors so as to reduce the risk of exposing 73 Line to a coincident outage on the two new lines from the Vaseux Terminal. Please discuss.

A21.1 The response to SOFAR/Wiltse IR1 Q8.1 has been misinterpreted. The reference to 73 Line having "highly limited" capacity is with respect to the present-day system only. Once the Vaseux Lake-RG Anderson transmission path is upgraded to 230 kV as proposed in the CPCN Application, the capacity bottleneck of 73 Line will be removed. This bottleneck only occurs because RG Anderson Transformers 1 and 2 are currently connected in series with 73 Line. Once the transformer is removed from the path, the line will then be fully capable of supplying the Kelowna load from the south (in the event of an N-2 outage on 72 Line/74 Line), or for supplying the Penticton load from the north (in the event of an N-2 outage on 75 Line/76 Line).

22. Reference – Exhibit B-8, SOFAR IR10 and FortisBC Response 10.1

Q22.1 The question was not whether FortisBC has made a commitment to consult on pole locations which SOFAR does not dispute. The question was "What form will that consultation take?" For example, is FortisBC going to notify landowners as to a time when they will be consulted? What form will that notification take – phone call, letter, etc.? How long in advance of construction will the notification and consultation occur? How long will landowners have to respond? Please advise.

A22.1 FortisBC will endeavour to meet with landowners personally in instances where structures are located on the right-of-way adjacent to or on their property during the engineering and construction process. During this consultation process, FortisBC will attempt to accommodate individuals' preferences in regard to pole locations, but not to the extent that changes may affect adjacent stakeholders. Landowner meetings will take place early in the final design stage and prior to the construction tendering process.

FortisBC will contact affected landowners along the corridor by letter to schedule these meetings.

Modifications to reduce visual impact on Heritage Hills

23. Reference – Exhibit B-8, SOFAR IR 10.2, Exhibit B-1-1, Appendix E, Sheet 10 of 25

Q23.1 Sheet 10 of Exhibit E shows a widened right of way entitled "16' R/W Widening DDL 56833". Please provide a copy of that widening agreement and its registration particulars.

A23.1 A copy of the widening agreement is filed as BCUC IR1 Attachment A25.3d (Exhibit B-3). The agreement allows FortisBC to cut brush and remove danger trees and limit owners' structures to 20 feet or less in height within the 16 foot strip.

Q23.2 Please calculate the additional cost, if any, of re-routing the proposed line around the east of the Heritage Hills subdivision from a point near Matheson Road, into S.L. 9, Plan 1189 and re-connecting with the existing route by following the boundary between Sub Lots 45 and 48 of District Lot 2710.

A23.2 With the limited information provided in the question, only a conceptual level review and cost estimate comparison can be provided. The existing right-of-way for the subject section is approximately 2.4 kilometers and the route requested above ("Matheson route") is approximately 4.4 kilometers or approximately 2.0 kilometers of additional line length. The Matheson route would proceed east through S.L. 9, Plan 1189 onto Crown land north then down the boundary of Sub Lots 45 and 49 of District Lot 2710 back to the existing right-of-way.

As the Matheson route includes new rights-of-way over private and Crown property, a slightly longer route length over rougher terrain, and requires additional dead-end structures, several incremental costs are anticipated, as shown in SOFAR IR2 Table A23.2 below.

SOFAR IR2 Table A23.2

		($millions)
1	Additional public and First Nations consultation	0.10
2	Additional right-of-way acquisition:	0.50
3	Additional environmental Assessment	0.10
4	Additional right-of-way clearing and access	0.30
5	Additional design, construction and material costs	4.00
6	FortisBC overhead and management costs	0.90
7	**Total Incremental Cost**	**5.90**

More engineering would be required to assess technical feasibility. The Matheson route may also be subject to similar acquisition risks and timelines as the alternate Upland route as identified in Section 5.6 of the CPCN Application (Exhibit B-1-1).

24. Reference – Exhibit B-8, BCUC IR2 Q73.3 and FortisBC Response A73.3 and Attachment 73.3

Q24.1 In Response 10.2 to SOFAR IR1, FortisBC estimates that the cost savings by using double-circuit H-frame structures in the 2.1 kilometre Heritage Hills section would be approximately $1.02 million. Attachment 73.3 identifies what appear to be six single pole structures across the Heritage Hills section. If, instead of using single poles, H-frame poles were used at this location would the savings be the same $1.02 million cited in Response 10.2?

A24.1 As stated in the response to SOFAR/Wiltse IR1 Q10.2 the cost saving of approximately $1.02 million refers to using H-frame poles rather than single pole structures in the Heritage Hills area as shown in BCUC IR2 Attachment A73.3.

Q24.2 **outage and reliability statistics for that line with the average outage statistics for the rest of FortisBC's bulk transmission system.**

A24.2 This question is incomplete.

25. Reference – Exhibit B-8, FortisBC Response 74.1 and Attachment 74.1

Q25.1 **If a double circuit H-frame construction was used as contemplated by Alternative 1B, would the height of the poles be at least 26.82 metres as set out in Attachment 74.1 Figure D? And if a guyed 2 pole alternative was employed, the pole height would be at least 30.48 metres as set out in Figure C, correct?**

A25.1 Figure 4-3-1B shows typical profiles and dimensions for the different structure types that would be used for the straight sections of the lines. BCUC IR2 Attachment A74.1 shows those typical structures as well as typical structure types that would be used when the line must change angles at a deflection point on its route which includes the guyed two-pole structures.

The heights of the structures shown in these figures are typical and may vary on a location by location basis as a result of site and span specific design considerations. The guyed two-pole structures, when applied for deflection points, are designed for the site and span specific heights needed to transition the conductors across the angle change.

SOFAR IR2 Attachment A25.1 shows structure information for the existing 76 Line, and Alternatives 1A and 1B from the tap point above Vaseux Lake Terminal station to RG Anderson Terminal station based on preliminary design. SOFAR IR2 Attachment A25.1 illustrates that structure type and height will vary as required by the conditions of that part of the line.

To assist in reviewing the information in SOFAR IR2 Attachment A25.1 the following description of the columns is provided:

Ortho Map and Field Structure - specific map sheet and structure number in Appendix E, 76L-T07-D2 (Index item 3)

Max Structure Height - above ground height of the structure (If it is a two pole structure the height is measured from the centre of the right-of-way between the poles to the top of the poles.)

Structure Type - structure types shown in BCUC IR2 Attachment A74.1.

Pole Base - pole installation - directly buried or attached to a concrete foundation

The information, including pole heights, is based on preliminary design and is subject to change during detailed or final design for a number of reasons including:

- Site survey and geotechnical review information;
- Further optimization of structures and conductors for cost, performance and constructability considerations; and
- Input of property owners.

Therefore the information in SOFAR IR2 Attachment A25.1 is provided for information and discussion only and cannot be relied upon as a final parameter for any particular structure at this time but is still representative of the expected final design.

Comparison of Preliminary Structure Configurations on Existing Route From Vaseux Tap to RG Anderson Terminal.

PRELIMINARY - PROVIDED FOR INFORMATION AND DISCUSSION ONLY

		Existing Line (76L)			Proposed Alternative 1A			Proposed Alternative 1B		
Ortho Map Appendix E (76L-T07-D2) Reference Sheet	Field Structure No.	Max Structure Height (ft) above Ground	Structure Type	Pole Base	Max Structure Height (ft) above Ground	Structure Type	Pole Base	Max Structure Height (ft) above Ground	Structure Type	Pole Base
1	2	3	4	5	6	7	8	9	10	11
pg 2 of 25	76L-35	56.5	Guyed 3-Pole Dead End structure.	Direct Buried	95	2-Pole Guyed DE.	Pole With Concrete Foundation	101.5	2-Pole Guyed DE.	Direct Buried
	76L-37	61	H-Frame Double X-braced with Side Guy.		130	Monopole with Davit X-arms		110.5	Double H-Frame Tangent.	
	76L-38	56.5	Guyed 3-Pole Dead End structure.		105	2-Pole Guyed with Braced-Post.		101.5	2-Pole Guyed with Braced-Post.	
	76L-39	56.5	H-Frame Tangent		100	Monopole with Davit X-arms		88	Double H-Frame Tangent.	
pg 3 of 25	76L-40	52	Guyed 3-Pole Light Angle structure.	Direct Buried	90	2-Pole Guyed with Suspension Insulator.	Pole With Concrete Foundation	101.5	2-Pole Guyed with Suspension Insulator.	Direct Buried
	76L-41	52	H-Frame Tangent		90	Monopole with Braced-Post.		79	Double H-Frame Tangent.	
	76L-42	43			90			79		
	76L-43	43			90			79		
	76L-44	47.5			120			97		
	76L-45	56.5			95			92.5		
	76L-46	52			95			83.5		
pg 4 of 25	76L-47	56.5	H-Frame Tangent	Direct Buried	105	Monopole with Davit X-arms	Pole With Concrete Foundation	83.5	Double H-Frame Tangent.	Direct Buried
	76L-48	56.5	Guyed 3-Pole Dead End structure.		95			83.5		
	76L-48A	65.5	H-Frame Double X-braced with Side Guys.		105			88	Monopole with Davit X-arms	
	76L-49	52	Guyed 3-Pole Dead End structure.		105			92.5	Double H-Frame Tangent.	
	76L-50	52	H-Frame Tangent		100	Monopole with Braced-Post.		79		
	76L-51	47.5			90			79		
pg 5 of 25	76L-52	56.5	H-Frame Tangent	Direct Buried	90	Monopole with Davit X-arms	Pole With Concrete Foundation	79	Double H-Frame Tangent.	Direct Buried
	76L-53	52			90	Monopole with Braced-Post.		79		
	76L-54	56.5			100	Monopole with Davit X-arms		88		
	76L-55	52			95	Monopole with Braced-Post.		83.5		
	76L-56	47.5			95	Monopole with Davit X-arms		101.5		
	76L-57	56.5	Guyed 3-Pole Dead End structure.		95	2-Pole Guyed with Braced-Post.		92.5	2-Pole Guyed with Braced-Post.	
	76L-58	61	H-Frame Double X-braced with Side Guys.		130	Monopole with Davit X-arms		97	Double H-Frame Tangent.	
pg 6 of 25	76L-59	56.5	H-Frame Tangent	Direct Buried	135	Monopole with Davit X-arms	Pole With Concrete Foundation	115	Double H-Frame Tangent.	Direct Buried
	76L-60	56.5			90	Monopole with Braced-Post.		79		
	76L-61	56.5			100	Monopole with Davit X-arms		88		
	76L-62	56.5	H-Frame Tangent DE.		105			101.5		
	76L-63	47.5	H-Frame Tangent		95	Monopole with Braced-Post.		92.5		
	76L-64	52			100	Monopole with Davit X-arms		79		
pg 7 of 25	76L-66	52	H-Frame Tangent	Direct Buried	100	Monopole with Braced-Post.	Pole With Concrete Foundation	79	Double H-Frame Tangent.	Direct Buried
	76L-67	52			90			79		
	76L-68	56.5			110			83.5		
	76L-69	56.5			90			83.5		
	76L-70	56.5			105	Monopole with Davit X-arms		97		
	76L-72	43	Guyed 3-Pole Dead End structure.		90	2-Pole Guyed with Suspension Insulator.		83.5	2-Pole Guyed with Suspension Insulator.	
	76L-73	56.5	H-Frame Tangent		105	Monopole with Braced-Post.		92.5	Double H-Frame Tangent.	
pg 8 of 25	76L-74	56.5	H-Frame Tangent	Direct Buried	100	Monopole with Davit X-arms	Pole With Concrete Foundation	79	Double H-Frame Tangent.	Direct Buried
	76L-75	47.5			90			79		
	76L-76	47.5			135			101.5		
	76L-77	43	Guyed 3-Pole Dead End structure.		90			79		
	76L-78	56.5	H-Frame Tangent		90	Monopole with Braced-Post.		79		
	76L-79	56.5			150	Monopole with Davit X-arms		115		
pg 9 of 25	76L-81	47.5	H-Frame Tangent DE.	Direct Buried	110	Monopole with Davit X-arms	Pole With Concrete Foundation	88	Monopole with Davit X-arms	Direct Buried
	76L-82	43	H-Frame Tangent		90	Monopole with Braced-Post.		101.5	Double H-Frame Tangent.	
	76L-83	47.5	Guyed 3-Pole Light Angle structure.		90	2-Pole Guyed with Suspension Insulator.		101.5	2-Pole Guyed with Suspension Insulator.	
	76L-84	52	H-Frame Tangent		115	Monopole with Braced-Post.		142	Double H-Frame Tangent.	
	76L-85	52			105			133		
	76L-86	52			100			97		
	76L-87	47.5			90			88		
	76L-88	43	Guyed 3-Pole Light Angle structure.		100	2-Pole Guyed with Suspension Insulator.		101.5	2-Pole Guyed with Suspension Insulator.	
pg 10 of 25	76L-89	47.5	Guyed 3-Pole Dead End structure.	Direct Buried	90	Monopole with Braced-Post.	Pole With Concrete Foundation	88	Double H-Frame Tangent.	Direct Buried
	76L-90	47.5	H-Frame Tangent		100	Monopole with Davit X-arms		92.5		
	76L-91	47.5			120			92.5		
	76L-92	79			145			124		
	76L-93	47.5	H-Frame Tangent		105	Monopole with Davit X-arms		101.5	Double H-Frame Tangent.	
	76L-94	52			120			120		
	76L-95	47.5	Guyed 3-Pole Light Angle structure.		110	2-Pole Guyed with Suspension Insulator.		97	2-Pole Guyed with Suspension Insulator.	
	76L-96	56.5	H-Frame Tangent		110	Monopole with Davit X-arms		97	Double H-Frame Tangent.	
pg 11 of 25	76L-97	47.5	H-Frame Tangent	Direct Buried	100	Monopole with Braced-Post.	Pole With Concrete Foundation	88	Double H-Frame Tangent.	Direct Buried
	76L-98	52			90			79		
	76L-99	43			90	Monopole with Davit X-arms		88		
	76L-100	43	H-Frame Tangent		90	Monopole with Davit X-arms		79	Double H-Frame Tangent.	
	76L-101	56.5	Guyed 3-Pole Light Angle structure.		110	2-Pole Guyed DE.		140	2-Pole Guyed DE.	
	76L-102	47.5	H-Frame Tangent		110	Monopole with Davit X-arms		142	Double H-Frame Tangent.	
	76L-103	47.5	Guyed 3-Pole Dead End structure.		95	2-Pole Guyed with Suspension Insulator.		124	2-Pole Guyed DE.	
	76L-104	47.5			105			124	2-Pole Guyed with Suspension Insulator.	
pg 12 of 25	76L-105	56.5	H-Frame Tangent	Direct Buried	90	Monopole with Braced-Post.	Pole With Concrete Foundation	79	Double H-Frame Tangent.	Direct Buried
	76L-105A	56.5			120			106		
	76L-106	56.5			90			79		
	76L-107	47.5			95	Monopole with Davit X-arms		79		
	76L-108	56.5	Guyed 3-Pole Dead End structure.		120	2-Pole Guyed with Braced-Post.		142	2-Pole Guyed with Braced-Post.	
	76L-109	43	H-Frame Tangent		110	Monopole with Braced-Post.		133	Double H-Frame Tangent.	
	76L-110	56.5	Guyed 3-Pole Dead End structure.		115	2-Pole Guyed with Braced-Post.		137.5	2-Pole Guyed with Braced-Post.	
pg 13 of 25	76L-112	56.5	Guyed 3-Pole Dead End structure.	Direct Buried	105	2-Pole Guyed DE.	Pole With Concrete Foundation	106	2-Pole Guyed DE.	Direct Buried
	76L-113	43	H-Frame Tangent		100	Monopole with Braced-Post.		115	Double H-Frame Tangent.	
	76L-114	56.5	Guyed 3-Pole Small Angle structure.		110	2-Pole Guyed with Suspension Insulator.		155.5	2-Pole Guyed with Suspension Insulator.	
	76L-115	56.5	H-Frame Tangent		120	Monopole with Davit X-arms		106	Double H-Frame Tangent.	
	76L-116	56.5	Guyed 3-Pole Dead End structure.		110	2-Pole Guyed with Suspension Insulator.		119.5	2-Pole Guyed with Suspension Insulator.	
pg 14 of 25	76L-116A	56.5	H-Frame Tangent	Direct Buried	100	Monopole with Braced-Post.	Pole With Concrete Foundation	119.5	Double H-Frame Tangent.	Direct Buried
	76L-117	56.5			90			79		
	76L-118	52			100			83.5		
	76L-119	56.5			100			88		
	76L-120	56.5	Guyed 3-Pole Dead End structure.		110	2-Pole Guyed with Braced-Post.		115	2-Pole Guyed with Braced-Post.	
	76L-121	47.5	H-Frame Tangent		100	Monopole with Braced-Post.		88	Double H-Frame Tangent.	
	76L-122	43			100	Monopole with Davit X-arms		83.5		
	76L-123	47.5			95			79		
	76L-124	56.5	Guyed 3-Pole Small Angle structure.		150			128.5		
pg 15 of 25	76L-125	56.5	H-Frame Tangent	Direct Buried	105	Monopole with Davit X-arms	Pole With Concrete Foundation	97	Double H-Frame Tangent.	Direct Buried
	76L-126	56.5			100	Monopole with Braced-Post.		92.5		
	76L-127	43			90			83.5		
	76L-128	52	Guyed 3-Pole Light Angle structure.		90	2-Pole Guyed with Suspension Insulator.		88	2-Pole Guyed with Suspension Insulator.	
	76L-129	47.5	H-Frame Tangent		90	Monopole with Braced-Post.		92.5	Double H-Frame Tangent.	
	76L-130	61	Guyed 3-Pole Dead End structure.		100	2-Pole Guyed DE.		106	2-Pole Guyed DE.	
	76L-131	56.5			90			92.5		
	76L-Stn	60	Substation Bay		60	Substation Bay		60	Substation Bay	Concrete Foundation

Structure list Identified at Heritage Hills.

Note:

1. **The Structure List for Alternative 1A and 1B are prepared based on Preliminary Design only and therefore subject to change.**
2. **The height of the Structures may change during detailed design based on final site survey information, structure and conductor optimization and property owner input. For two-pole structures the height shown is from the centre-line of the right of way to the top of the structure.**
3. **Field Structures numbered 76L-65, 76L-80 and 76L-111 do not exist, and therefore are not shown on the maps nor on the list above.**
4. **Existing Field Structures numbered 76L-36 (pg 2 of 15), 76L-128A and 76L-132 (pg 15 of 25) are not required per Preliminary Design of 1A and 1B and therefore are not listed above but are shown on the maps.**

26. Reference – Exhibit B-9, Attachments A10.7 a – d and Attachment A10.8

Q26.1 If a single pole double circuit configuration was used would the poles and conductors be at very similar heights as the H-frame structures and conductors shown in the Attachments and in particular Attachment A10.8?

A26.1 Please refer to the SOFAR IR2 Attachment A25.1 above for the preliminary design heights for the structures through the Heritage Hills section for Alternatives 1A and 1B. The Field Structure numbers are 76L-93 to 76L-99, and the height differences between Alternatives 1A and 1B vary from being equal, to 1B structures being 0.61 meters (2 feet) to 3.96 meters (13 feet) shorter. For structure 76L-94 in the centre of the rendering SOFAR/Wiltse IR1 Attachment A10.8, preliminary design for both Alternatives 1A and 1B indicate that 36.58 meter (120 foot) structures would be needed for both Alternatives.

Q26.2 Please provide another rendering of Attachment 10.8 showing the poles and conductors that would exist if one of Lines 75 and 76 was placed onto the existing right of way corridor while the other line was placed onto a separate corridor as contemplated by Alternative 3.

A26.2 Please refer to SOFAR IR2 Attachment A26.2 which shows the single circuit 76 Line constructed with H-frame steel flat galvanized poles on the existing route. Alternative 3 would have the second circuit, 75 Line, on the Upland route. The proposed structure renderings are based on height of structures determined by preliminary design, final design may identify some change in height relative to existing structures. The above ground height of the pole structure in the centre of the rendering is 17.2 meters (65 feet).

SOFAR IR2 Attachment A26.2

Upland Route and Big Horn Sheep

27. Reference: Exhibit B-8, SOFAR IR12.9 and FortisBC Response A12.9

Q27.1 Isn't it the case that Big Horn Sheep habitat and food sources are improved by opening up forest cover, thinning forest cover and otherwise promoting the growth of bunchgrasses, antelope-brush, sagebrush, Saskatoon and mock orange which provide food for Big Horn Sheep? And isn't it the case that the initial and ongoing clearing required by the Alternate Upland Route will open up forest cover and promote the growth of a new food source for Big Horn Sheep?

A27.1 FortisBC concurs that food sources for ungulates including Big Horn Sheep can potentially be enhanced under some circumstances most notably when areas are opened through a homogenous dense coniferous forest. However, much of the forest cover on the alternate route is variable in composition, density and canopy. There is a relatively open forest canopy in much of the area with conditions encouraging good forage growth so any benefit is at best limited.

The additional small incremental benefit of increased carrying capacity of a right-of-way will likely be offset by the negative effects from other factors such as:

- increased access,
- increased hunting pressure and improved hunting success,
- changes in predator effectiveness,
- landscape fragmentation, as well as
- loss of thermal protection.

Forested areas also provide effective escape cover from hunting and predators and also provide thermal insulation and buffering from significant temperature shifts such as summer heat and protection from wind in cold weather, helping the animals conserve energy.

The Government of BC has published a Conservation Status Summary on the Bighorn Sheep on their Species Explorer website which suggests habitat alienation and fragmentation from a number of land use activities are primary threats to conservation of the species. This summary states:

> *"Primary threats are habitat loss, degradation and fragmentation; livestock ranching (through disease transmission, range depletion and resource competition); and harassment by the public (Demarchi 2002; Demarchi et al. 2000a, 2000b; A. Fontana, pers. comm.; F. Harper, pers. comm.). Overharvesting was a threat historically, but provincial wildlife management and conservation efforts have controlled this (Ministry of Environment, Lands and Parks 1996). Small herds, particularly isolated ones, are most vulnerable.*
>
> *Demarchi et al. (2000a, 2000b) state that the greatest threat to bighorns is habitat alienation, whether it is by residential or urban developments, transportation corridor development, mining, dams, agricultural development (including livestock grazing on private land), golf courses, ski hills, etc. Bighorns were displaced many years ago from much of their lowland range in the Okanagan Valley (Demarchi et al. 2000b)."*

Reference: http://a100.gov.bc.ca/pub/eswp/search.do - search for Big Horn Sheep

Q1. Ref. BCUC IR #69.4: Please indicate when and where FortisBC applied to, or notified the BCUC that it was taking measures that would effectively remove line 41 from service.

A1. The disconnection of 41 Line from the Oliver Terminal was approved by Order C-1-06 - Nk'Mip (East Osoyoos) Substation and Transmission Project CPCN. This was done to free up a 63 kV breaker position at the Oliver Terminal to supply the new 66 Line to Nk'Mip Substation.

FortisBC has yet not determined when 41 Line itself will be salvaged and this work is not included within the scope of the OTR Project.

Q2. Ref. BCUC IR #14.5: The answer indicates Anderson transformer T2 is to be replaced by a 230/63/25 KV transformer. Please explain why the tertiary winding, when FortisBC is trying to phase out other multiple voltage transformers.

A2. FortisBC has previously indicated a desire to retire "non-standard" operating voltages (i.e. 161 kV and 4 kV), not "multiple voltage" transformers. In fact, high voltage transmission transformers typically have a wye-connected autotransformer winding configuration as this is usually the most economical design. This type of transformer is normally equipped with a third (tertiary) winding for three reasons:

1. To prevent the flow of third-harmonic currents into the transmission network;
2. To provide a path for zero-sequence current to flow (to allow the main windings to act as a ground source for the transmission system); and
3. To provide a source for a station service supply.

The 25 kV rating of the tertiary winding is a FortisBC standard voltage and is used at a number of substations.

Q3. If the conductor size varies for different OTR options, please provide the wire size and capacity for each option, Vaseux to Penticton.

A3. The conductor sizes and capacity for the various Alternatives are as follows:

Alternative	**Conductor Name**	**Size (kcmil)**	**Capacity - Summer** (amps[(1)])	**Capacity - Winter** (amps [(2)])
1A and 2A	Bunting	1,192	1,250	1,528
1B, 2B and 3	Drake	795	988	1,230
1C	Lapwing	1,590	1,495	1,831

Notes: [(1)] Summer capacity of conductor based on 90°C conductor temperature, 30°C ambient, 2 feet/ second wind

[(2)] Winter capacity of conductor based on 90°C conductor temperature, 10°C ambient, 2 feet/ second wind

Q4. Is the Vaseux Terminal designed so that a third 250 MVA transformer could be easily installed?

A4. Yes, the Vaseux Lake Terminal was designed for an ultimate configuration of three 500/230 kV transformers.

Q5. What is the 330 MW limitation at Vernon based upon, BCTC physical plant or the existing wheeling contract with FortisBC? If it is physical plant, can FortisBC provide and idea of what is required to increase that limit for Kelowna supply?

A5. Please refer to the response to BCUC IR3 Q95.1.

Q6. At the present time, is it possible to feed the Anderson 63 KV bus from either transformer T1 or T2 using only 73 line 230 KV power and of course only one of the transformers at a time?

A6. No, only Transformer 1 has the required 230/63 kV rating. While Transformer 2 can be operated with a voltage of either 161 kV or 230 kV, it is presently connected on the 161 kV tap. Changing this connection is non-trivial and requires entry into the transformer tank.

Q7. At Anderson, can transformer T2 presently be isolated from the 63 KV bus and take 230 KV power from line 73 to feed 161 KV power into 76 line south if such was required, while Penticton is supplied by transformer T1 from 73 line?

A7. No, RG Anderson Transformer 2 cannot be connected to operate at both 161 and 230 kV. The desired operating voltage (161 kV or 230 kV) is selected by an internal tap connection; it is not possible to bring out both voltages simultaneously.

Q8. Can FortisBC provide a short history of the gassing problems on Oliver transformer T2 over the last 5 years? Please include the date, transformer loading and remedial action taken at the time of gassing.

A8. The Oliver Transformer 2 gas detector relay has indicated high gas level alarms on a number of previous occasions. This goes back as far as July 1996 with suspected harmonic voltages and currents super-saturating the core of the transformer. This can cause arcing on the core and high temperatures due to increased core losses from the harmonic frequencies. An internal visual inspection revealed no obvious internal damage; however, there are many areas that are not accessible for inspection which may have hidden damage.

General maintenance in 2003 and 2008 has shown that the tap changer diverter tank compartments are also leaking into the main tank, which is likely the possible source of contamination to the main tank dissolved gas analysis (DGA) samples. The transformer loading on these occasions is unknown, but is not expected to have been excessive. DGA sampling is being done more frequently as this unit is under a close watch.

Q9. Please provide a list of all the times in the last 5 years that either of the Oliver transformers T1 or T2 were out of service because of some failure, or required maintenance. List the service interruptions in a similar manner to Table 3-1-3-4 at Tab 3, P.17.

A9. General maintenance and testing occurred on both Oliver transformers in October 2003. Both transformers had an outage time of approximately 10 days. General maintenance and testing also occurred in March 2008 with Transformer 1 having an outage time of approximately 10 days and Transformer 2 approximately 14 days. There have been no forced outages on these units in the last five years.

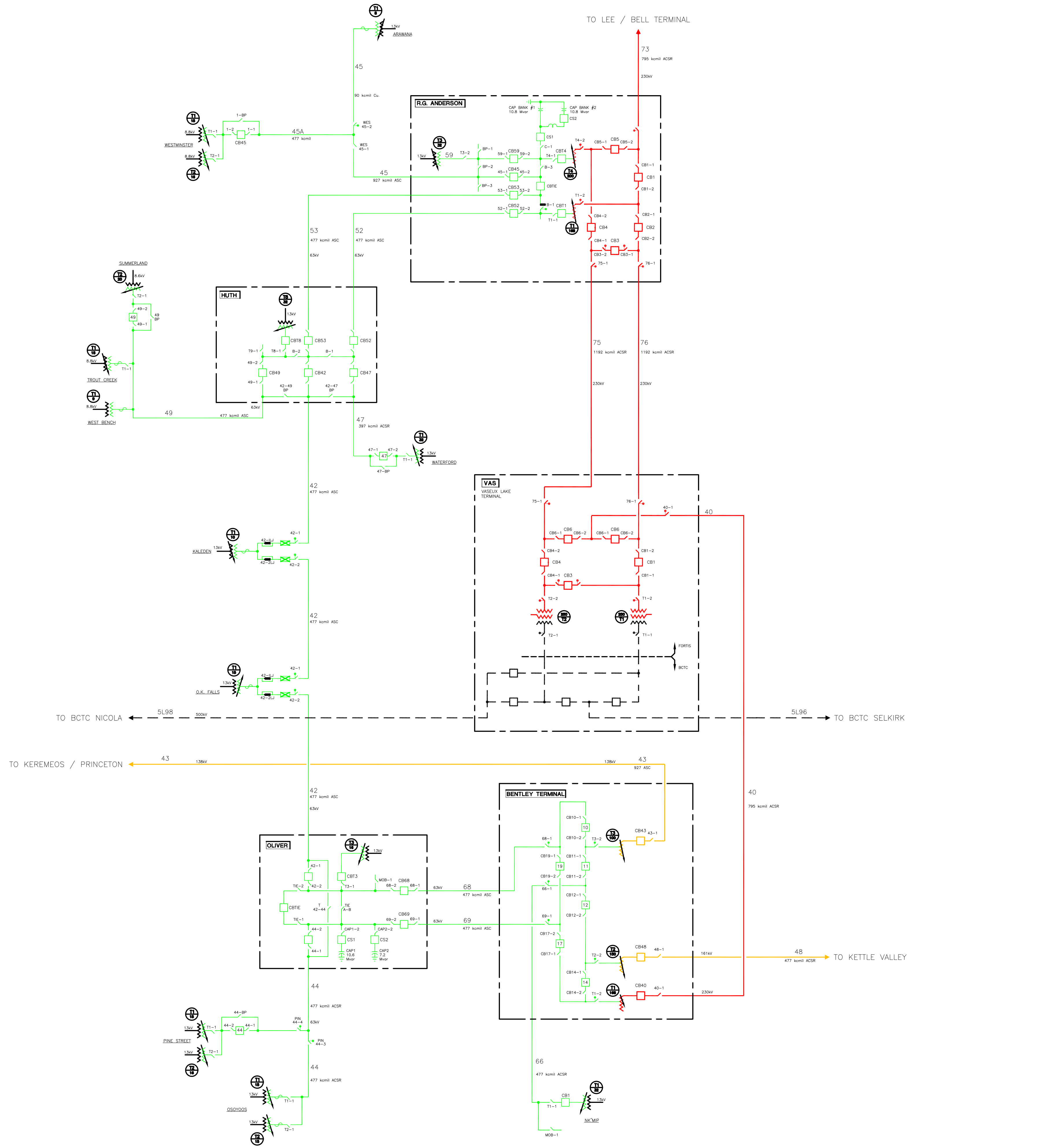
Q10. Can FortisBC confirm that Oliver transformer T2 can transform any of its 3 voltages into the other 2, depending on what voltage is being fed into the T2 transformer? Please provide the capacity limitations for each voltage feed in and the energy feed out at each other voltage.

A10. Oliver Transformer 2 is an unusual unit and has four operating voltages: 13 kV, 63 kV, 132 kV, 161 kV. While it is possible to have all four voltages energized simultaneously, due to the tapchanger arrangement it is not possible to regulate both the 63 kV and 132 kV voltages at the same time. The maximum total transformer capacity is 82 MVA, however the rating of the 161 kV and 63 kV windings is further limited to 60 MVA due to the design of the unit.

Q11. Under the present plan to bring Penticton transformer T2 to Bentley, will T2 be connected to 11 line at 161 KV as well as Vaseux 230 KV and the 63 KV bus?

A11. No, when RG Anderson Transformer 2 is relocated to Bentley, it will be reconnected to operate as a 230/63 kV transformer only. To assist in clarifying this response a complete single-line diagram of the South Okanagan transmission system following the completion of the OTR Project is attached as Wait IR2 Attachment A11.

Wait IR2 Attachment A11



GENERAL NOTES

1. ALL TRANSFORMER RATINGS ARE MAX. NAMEPLATE RATINGS AT 30°C. AMBIENT.
2. ALL TRANSFORMER AND GENERATOR RATINGS ARE IN MVA.

LEGEND

GENERATOR IDENTIFICATION
MVA RATING
TRANSFORMER IDENTIFICATION
MVA RATING
TERTIARY
MVA RATING
TRANSFORMER c/w ON–LOAD TAP CHANGER
AUTO–TRANSFORMER c/w ON–LOAD TAP CHANGER
TRANSFORMER c/w GROUNDED WYE WINDING
230kV
132kV & 161kV
63kV
OTHER UTILITIES
VACUUM INTERRUPTER
HIGH VELOCITY INTERRUPTER
SCADA CONTROLLED MOTOR OPERATED DISCONNECT
CIRCUIT SWITCHER

REV	DATE	MADE BY	DESCRIPTION
5			
4			
3			
2			
1			

FORTISBC

2012
SOUTH OKANAGAN AREA

DRAWN BY: APPROVED BY:

DRAWING NUMBER 4-000-0410 REVISION 0

Q12. The stated capacity of 11 line into Oliver to avoid voltage collapse is 120 MW. Does this capacity increase if the Boundary is using significantly less than 50 MW? If so, please quantify both winter and summer limits.

A12. Following the South Okanagan Supply Reinforcement Project, 11 Line became part of a meshed system. It is no longer required to transfer power to the Okanagan. The flow on 11 Line depends on the Boundary and Oliver/Similkameen load and to some extent on the overall system generation dispatch. The commercial/contractual capability to deliver 120 MW at Oliver was for a radial system when 11 Line was operated at high voltage in the range of 177 kV to deliver maximum power. At that time its ability to deliver the maximum power at Oliver was affected by the Boundary load connected to Grand Forks Terminal. Due to the meshed operation, this is no longer the case.

Q13. Since the Vaseux Terminal has been in service, has there been any times when there has been a complete loss of power, either from the BC Hydro supply, or the operation the Vaseux Terminal? If so, please list the outages as per Tab 3, P.17, Table 3-1-3-4.

A13. There have been a number of instances where both transformers were de-energized at Vaseux Lake to facilitate planned maintenance. The existing station configuration requires both transformers to be de-energized in order to isolate one (both transformers share a common switching zone). This work was done during light/medium load periods. FortisBC does not retain outage duration records for planned outages.

There have been no cases where both 500 kV sources to the station were lost.

There has been one forced transformer outage at Vaseux Lake in February 2006 (which resulted in a short outage to both transformers) due to a failure in one of the transformer pressure relief relays.

Q14. Reference Wait IR#7: In the event of a loss of 73 line, could the emergency supply from Vernon be increased to meet a Kelowna load in excess of 330 MW now? Please explain what happens if 73 line goes down and Kelowna is drawing 375 MW at the time.

A14. In the event of a transmission contingency that would result in exceeding the Vernon import limit, FortisBC would immediately request that BCTC review the import limit in real-time to determine if there was sufficient capacity to serve the demand. Depending on the state of the BCTC system at the time, it is possible that there would be sufficient capacity to permit a short-time violation of the limit. FortisBC does have sufficient commercial capacity arranged for the FortisBC-BCTC Okanagan Interconnection (Vaseux Lake plus Vernon combined), but if BCTC denied the transmission request to exceed the Vernon limit, then the only alternative would be to shed load in the Kelowna area.

Q15. Does FortisBC spray a fire retardant on wood poles to prevent fire damage at installation, on a regular program or rush in to spray when forest fires are approaching?

A15. No, FortisBC does not spray fire retardant on wood poles at installation nor as a regular program. FortisBC may spray fire retardant in the future should a forest fire approach infrastructure.

Q16. Has FortisBC made any changes to the lightning protection for lines 72 & 74 since 1997.

A16. No, there have been no changes to the lightning protection for 72 Line or 74 Line since 1997. Please also refer to the response to BCUC IR1 Q11.1.

Q17. Are there any lightning protection measures on 73 line? If so, please list.

A17. No, there are no lightning protection measures on 73 Line.

18. Please scrutinize the following stepped solution:

Q18a. Step 1, Change the Vaseux Terminal to 230 KV, build line 75 connecting to line 73, and reconnect line 40 to line 76 through the Vaseux gap at 161 KV. Would this meet the requirements of Kelowna, and for how long?

A18a. In the proposed arrangement a single outage (75 Line) will result in the complete loss of the Vaseux Lake source. During peak load conditions the loss of support (especially reactive support) from the Vaseux Lake source results in very low voltage in Kelowna and a voltage collapse in the Penticton, Oliver/Similkameen and Boundary areas. This arrangement does not meet the FortisBC planning criteria (N-1 or N-2). Also, please see the responses to Wait IR1 Q1 and Q2.

Q18b. Step 2, Build a new 230 KV line to a new Bentley Substation and install only one appropriately sized new 230/63 KV transformer at Bentley with a high capacity 63 KV line into the Oliver station 63 KV bus. Retain the 161 KV line to Penticton. Would this arrangement be adequate until line 11 is reduced from 161 KV to 138 KV?

A18b. Please see response to Q18a above.

Q18c. Step 3, Replace 76 line with a 230 KV line (Vaseux to Penticton) and install a matching transformer to T1 in the Anderson Substation, when line 11 is reduced to 138 KV. Add one 138/63 KV transformer to Bentley and make the proposed changes to the Oliver Substation. If this 3-step approach is practical, please include a time line for each step and explain how the final step would coincide with the requirements to otherwise make changes to line 11. Would it hasten the conversion of 11 line to 138 KV or not? Please explain why a second 138/63 KV transformer is required at Bentley in the OTR proposals.

A18c. Please see response to Q18a above.