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August 20 2020

British Columbia Public Interest Advocacy Centre
Suite 803 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc. (FBC)

Project No. 1599088

Application for a Certificate of Public Convenience and Necessity for the Kelowna Bulk Transformer Addition Project (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Council of Senior Citizens' Organizations of BC, Active Support Against Poverty, Disability Alliance BC, and the Tenant Resource and Advisory Centre (BCOAPO) Information Request (IR) No. 2

On April 24, 2020, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-107-20 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

20.0 Reference: Exhibit B-2, BCUC 1.4.4

Preamble: The response states:

> "The hour for each peak (excluding self-generating customers and wheeling losses) in January, February, November, December, as well as June, July and August for each year in the period 2000-2019 is recorded.
>
> Historical net energy growth rates are derived from actual 2000-2019 sales. Forecast net energy growth rates are used to escalate the peaks into future years as described below.
>
> Assuming that the weather in 2020 will be similar to the weather of base year 2000, the corresponding January peak in 2020 is obtained by applying to the base year the cumulative growth of years 2000-2019. The 2020 peaks for February, November, and December, as well as June, July, August are obtained in the same manner. The calculation is then repeated for the remaining 19 base years from 2001 to 2019."

20.1 Please confirm specifically what "peaks" the first paragraph is referring to (i.e., are they the peaks for the Kelowna area or FBC's overall system peaks?).

20.1.1 If the "peaks" used are the overall system peaks, please explain why the peaks for the Kelowna area are not used.

Response:

The peaks referred to in the preamble are the overall system peaks. The Kelowna area forecast is the sum of the load allocated to Kelowna area substations, as described in the sixth bullet of FBC's revised response to BCUC IR1 4.4, filed concurrently. In this manner the Kelowna area forecast is calibrated to the system-wide coincident peak.

20.2 Please explain why self-generating customers and wheeling losses are excluded.

Response:

Please refer to the revised response to BCUC IR1 4.4, filed concurrently.

Self-generating customers' peak loads are excluded from the system peaks because their loads are intermittent and would introduce variability if included. The Power Supply department provides both the monthly peak and the self-generating customer load for the hour in which the monthly peak was set. The self-generating customer load for that hour is then subtracted from the monthly peak. The variability of the self-generating customer loads is demonstrated in the following table, which shows the amount of load (in MW) excluded from the monthly peaks to calculate the system peak load forecast.

Table 1: Self-Generating Customer Loads at Time of System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	-	-	-	-	-	-	-	-	-	26	-	-
2016	-	38	-	28	-	38	-	-	-	-	-	-
2017	1	23	18	-	10	-	-	-	10	37	-	-
2018	-	-	-	-	3	11	16	-	-	-	-	-

The wheeling losses that are excluded are the losses transferred to BC Hydro under the Amended and Restated Wheeling Agreement that result from the transfer of power over BC Hydro lines from the Kootenay area to both Creston and the Okanagan. These are not losses incurred on the FBC system, but rather on the BC Hydro system. BC Hydro wheeling losses are included in the load forecast used for power purchase expense as they are an obligation to BC Hydro that FBC must meet, and are therefore excluded from a 1 in 20 year load forecast analysis that is concerned with loads on the FBC system. Table 2 below shows the wheeling losses scheduled for delivery to BC Hydro at the system peak hour.

Table 2: BC Hydro Wheeling Losses at Time of System Peak (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	6	7	7	4	3	5	10	7	3	8	9	10
2016	8	7	6	8	5	4	10	7	7	4	8	10
2017	9	7	6	5	5	4	8	11	10	11	11	15
2018	9	7	6	5	5	4	8	11	10	11	11	15

20.3 If available, please cite other instances in BC or elsewhere in North America where a CPCN for a system addition was granted on the basis of evidence provided in the justification that excluded the impacts of self-generating customers and wheeling losses.

Response:

FBC has not researched other CPCN applications in this regard and submits that its forecasting method should be evaluated on its own merits. The reasons for FBC's approach to forecasting are provided in the response to BCOAPO IR2 20.2.

20.4 Please explain why net energy growth rates as opposed to peak growth rates are used.

Response:

FBC forecasts system peak demand in the manner described because it has not identified a sufficiently robust method of directly forecasting peak demand.

Please also refer to the revised response to BCUC IR1 4.4, filed concurrently. The growth rates used are for gross energy.

20.4.1 If net energy growth rates are used, please explain what role the historical 2000-2019 peak data referenced in the first paragraph has in developing the peak load forecast.

Response:

Please refer to the revised response to BCUC IR1 4.4, filed concurrently.

20.5 Are the energy growth rates used those for the Kelowna area or for FBC's system overall?

Response:

The energy growth rates for developing the peak forecast are for the FBC system overall. As explained in the response to BCOAPO IR2 20.1, the Kelowna area peak load forecast is coincident to the FBC system peak load forecast. Since the system peak is determined by system-wide load, it is necessary to use the corresponding system-wide energy growth rates when forecasting system-wide peak loads.

20.5.1 If the "energy growth rates" used are for the system overall, please explain why energy growth rates for the Kelowna area are not used.

Response:

Please refer to the response to BCOAPO IR2 20.5.

20.6 Please explain how using the cumulative growth for the years 2000-2019 is consistent with an assumption that "the weather in 2020 will be similar to the weather in the base year 2000".

Response:

Please refer to the revised response to BCUC IR1 4.4, filed concurrently, which provides an illustration of the method for calculating the peak load forecast. The statement that "the weather in 2020 will be similar to the weather in the base year 2000" referred to the fact that the non-normalized 2000 peak demand is escalated by the actual and forecast cumulative energy load and becomes one of the inputs to determine future peak load.

20.6.1 Isn't the calculation of the resulting growth rate also dependent on the weather in 2019 as it will impact the 2019 value used in the calculation?

Response:

Yes. Historic energy growth rates used are non-normalized and therefore include the impact of weather. Please also refer to the revised response to BCUC IR1 4.4, filed concurrently.

20.6.2 Indeed, aren't all 20 calculated growth rates dependent upon the weather and resulting load in 2019?

Response:

Yes. Please also refer to the response BCOAPO IR2 20.6.1 and the revised response to BCUC IR1 4.4, filed concurrently.

20.6.3 If the weather was particularly "mild" in 2019 such that energy used was less than "normal", wouldn't this impact all of the growth rates calculations? If not, why not?

Response:

The actual energy growth rates used to escalate the base year peak loads are based on non-normalized energy load. The calculation also includes actual growth rates for years in which weather is more severe than normal and in aggregate the growth rates would include both mild and severe weather years. The impact of the most severe weather on peak load is captured by escalating the non-normalized peaks, as illustrated in the revised response to BCUC IR1 4.4.

20.7 Please explain how the calculation can be performed using 2019 as the base year when 2019 is the last year for which there is historical data.

Response:

Please refer to the revised response to BCUC IR 4.4, filed concurrently.

20.8 What were the resulting 20 winter and summer growth rate values calculated?

Response:

FBC does not escalate by winter and summer growth rates but rather the annual gross energy growth rate. The gross energy growth rates which were used to escalate the peaks are included in the sample calculation provided in the revised response to BCUC IR1 4.4, filed concurrently.

20.8.1 Please reconcile the highest winter and summer growth rates with the growth implicit in the winter and summer peak forecasts set out in Table 3-5 (Exhibit B-1).

Response:

FBC cannot reconcile the highest winter and summer growth rates with Table 3-5 since FBC uses the overall system gross load growth rate, not winter and summer growth rates, to forecast the peak.

21.0 Reference: Exhibit B-2, BCUC 1.4.4

Exhibit B-5, ICG 1.5.1 and 1.5.2

Preamble: The response to BCUC 1.4.4 states:

"Area peak forecasts are created by allocating 1-in-20 system peak forecast among FBC's substations. This is done by scaling the Distribution Planning forecast, which is the sum of non-coincident substation peak forecasts to the system peak (the coincident peak). The Kelowna area peak forecast in Table 3-5 is the sum of the load distributed to Kelowna area substation buses in that manner".

The response to ICG states:

"As explained in the response to BCUC IR1 4.4, area peak forecasts are created by taking the total forecast system load in the Resource Planning forecast and distributing this load among FBC substations based on the Distribution Load Forecast prepared by regional engineers".

21.1 The responses make reference to a Distribution Planning forecast and a Distribution Load Forecast.

21.1.1 Are these both references to the same forecast?

21.1.2 How are the forecast(s) prepared?

21.1.3 Are they consistent with the system peak load forecast?

Response:

Yes, the Distribution Planning Forecast and the Distribution Load Forecast are the same.

In the Distribution Load Forecast, the forecast for each substation feeder is based on the summer and winter peaks over the last five years. The slope of the seasonal peaks from the last five years is applied to the maximum peak from the last five years.

The forecast also takes into consideration developments or load transfers that are planned for that year. Any development or load transfer that has been entered into the forecast will be added or subtracted from the forecasted values that were calculated.

From the feeder level forecast, the substation transformer forecast is created. The transformer forecast is the sum of the feeder seasonal peaks attached to the transformer and multiplied by the transformer diversity. The transformer diversity factor is calculated as transformer peak load divided by the sum of the connected feeder peak loads:

$$Transformer\ Peak\ (yr\ 0-20) = \sum(Connected\ Feeder\ Peaks * Transformer\ Diversity\ Factor)$$

The Distribution Planning Forecast is different than the system level peak load forecast. The main difference is that the distribution forecast consists of non-coincident peaks whereas the system forecast is a coincident peak. This is why FBC must scale down the non-coincident peaks in the distribution planning forecast to the system peak (the coincident peak) as described in the revised response to BCUC IR1 4.4, filed concurrently.

21.2 Please explain more fully how the "scaling" is done in terms of how is the scaling factor calculated and what is it applied to (For Example - is the Distribution Planning Forecast for the area consistent with the system peak forecast used for resource planning and the difference between the "1 in 20" system peak forecast and the system peak forecast used for resource planning used to "scale up" the Distribution Planning Forecast).

Response:

The scaling factor is calculated by taking the system level 1-in-20 peak load and dividing it by the sum of the individual station loads in the Distribution Planning Forecast. This is completed for each year in the forecast to calculate a scaling factor for each year. The scaling factors are then multiplied by each forecast station load value in the Distribution Planning Forecast for each year.

21.3 Please clarify whether the forecast set out in Table 3-5 is: i) a forecast of the coincident peak for the Kelowna area or ii) a forecast of the sum of the non-coincident peaks for the substations in the Kelowna area.

Response:

The forecast in Table 3-5 of the Application is a forecast of the coincident peak for the Kelowna area.

21.3.1 Please reconcile the response with the description of the forecast process.

Response:

Both responses accurately describe the forecasting process. FBC provides the following clarification to the response in ICG IR1 5.1.

As explained in the revised response to BCUC IR1 4.4, area peak forecasts are created by taking the total forecast system load in the Resource Planning Forecast (the coincident 1-in-20 system peak forecast) and distributing this load among FBC substations (by scaling the Distribution Planning Forecast to the Resource Planning Forecast).

21.3.2 If it is a forecast of the sum of the non-coincident peaks for the substations in the Kelowna area, please explain why this is the appropriate forecast to use for purposes of determining area needs.

Response:

Please refer to the response to BCOAPO IR2 21.3.

22.0 Reference: Exhibit B-2, BCUC 1.4.13

22.1 Do the peak load forecast for LEE and DGB assume the same growth rate for both or are individual growth rates forecast for each substation?

Response:

The regional growth rate for the Kelowna area is the same for all substations supplied from LEE and DGB. However, the Distribution Load Forecast for transformers at each substation also reflects individual growth trends for each distribution feeder. Since the LEE and DGB terminal transformers normally supply different distribution substations, the growth rates for LEE and DGB vary slightly from one another.

22.1.1 If individual growth rates are forecast for each substation, please i) explain how the individual growth rates are forecast and ii) reconcile this with the explanation of the forecast process provided in response to BCUC 1.4.4.

Response:

The response to BCOAPO IR2 22.1 confirms that the growth rates for LEE and DGB vary slightly. The process described in the response to ICG IR2 21.3.1 explains how the system peak forecast is allocated among FBC's substations.

23.0 Reference: Exhibit B-2, BCUC 1.7.1, 1.7.2 and 1.7.3

Preamble: Exhibit B-1, pages 16-17 states:

> "The summer peak load is forecast to reach the transformer limit of 315 MW in 2021 and to exceed the limit in 2022 as set out in Table 3-5, and the forecast winter peak load will exceed the winter transformer limit of 370 MVA in 2027." (emphasis added)

BCUC 1.7.2 states:

> "The summer peak load level of 315 MW is considered to be the summer transformer limit because it is the maximum load that a reconfigured area system can manage while remaining within normal operating limits, as determined by power flow studies. The corresponding winter peak load is 370 MW." (emphasis added)

Exhibit B-1, page 19 states:

> "For example, summer emergency limits for LEE T3 and T4 are both much lower in summer at 159 MW, as compared to their respective winter emergency limits of 189 MW and 195 MW".

BCUC 1.7.3 sets out the emergency summer limits for LEE T3 and T4 as 199 MW while the emergency winter limits are reported as 215 MW.

23.1 With respect to pages 16-17 and BCUC 1.7.2, please clarify whether the winter transformer limit is 370 MW or 370 MVA.

Response:

The winter transformer limit after a LEE transformer outage is 370 MW.

23.2 With respect to page 19 and BCUC 1.7.3, please clarify what the winter and summer emergency limits are for LEE T3 and T4.

Response:

Please refer to the response to BCUC IR2 36.2.

24.0 Reference: Exhibit B-2, BCUC 1.7.7

24.1 Please provide a revised version of the Power Flow Analysis Before Reconfiguration Table showing the % of emergency ratings.

Response:

Please see the table below showing the percentage of emergency ratings before reconfiguration:

Kelowna Summer Peak Load (MW) (Data from Table 3-4 & 3-5)	Year	Condition	Power Flow Analysis (Before System Reconfiguration)					
			LEE T3		LEE T4		DGB T2	
			MVA	% of Emergency rating	MVA	% of Emergency rating	MVA	% of Emergency rating
300.5	2019	All elements in service	109	51.9	109	51.9	86	34.4
		LEE T3 out	-	-	183	87.1	122	48.8
		LEE T4 out	183	87.1	-	-	122	48.8
		DGB T2 out	152	72.4	152	72.4	-	-
309.5	2020	All elements in service	112	53.3	112	53.3	89	44.5
		LEE T3 out	-	-	188	89.5	126	50.4
		LEE T4 out	188	89.5	-	-	126	50.4
		DGB T2 out	157	74.8	157	74.8	-	-
314.6	2021	All elements in service	114	54.3	114	54.3	90	36
		LEE T3 out	-	-	191	91	128	51.2
		LEE T4 out	191	91	-	-	128	51.2
		DGB T2 out	159	75.7	159	75.7	-	-
319.8	2022	All elements in service	116	55.2	116	55.2	92	36.8
		LEE T3 out	-	-	195	92.9	131	52.4
		LEE T4 out	195	92.9	-	-	131	52.4
		DGB T2 out	162	77.1	162	77.1	-	-

24.2 With respect to the Power Flow Analysis After Reconfiguration results for 2022, are the values shown for DGB when either LEE transformer is out the maximum load that can transferred to DGB?

Response:

Yes, following the outage of a LEE transformer, the system is reconfigured to transfer maximum load to DGB in order to reduce the loading on the remaining LEE transformer.

24.3 With respect to the Power Flow Analysis After Reconfiguration results for 2022, the sum of the individual transformer loadings when all elements are in-service is only 216 MVA whereas the area load forecast is 319.8 MW. Please reconcile.

Response:

The table in the response to BCUC IR1 7.7 contained a typographical error. In year 2022, after reconfiguration with all elements in service the flow on each of the LEE transformers is 101 MVA while the flow on the DGB transformer is 121 MVA (initially shown as 12 MVA). The total flow in the three transformers supplying the Kelowna load is therefore 323 MVA (101 x 2 + 121 = 323 MVA). A revised table, with the correction highlighted, is provided below.

Kelowna Summer Peak Load (MW) (Data from Table 3-4 & 3-5)	Year	Condition	Power Flow Analysis (After System Reconfiguration)					
			LEE T3		LEE T4		DGB T2	
			MVA	% of normal rating	MVA	% of normal rating	MVA	% of normal rating
300.5	2019	All elements in service	96	57	96	57	112	55
		LEE T3 out			160	95	144	72
		LEE T4 out	160	95			144	72
		DGB T2 out (1)	154	93	154	93		
309.5	2020	All elements in service	99	59	99	59	115	57
		LEE T3 out			165	98	148	74
		LEE T4 out	165	98			148	74
		DGB T2 out (2)	160	96	160	96		
314.6	2021	All elements in service (3)	100	59	100	59	117	58
		LEE T3 out			167	100	151	75
		LEE T4 out	167	100			151	75
		DGB T2 out (4)	162	98	162	98		

Kelowna Summer Peak Load (MW) (Data from Table 3-4 & 3-5)	Year	Condition	Power Flow Analysis (After System Reconfiguration)					
			LEE T3		LEE T4		DGB T2	
			MVA	% of normal rating	MVA	% of normal rating	MVA	% of normal rating
319.8	2022	All elements in service (5)	102	61	102	61	121	60
		LEE T3 out (6)			169	101	155	77
		LEE T4 out (6)	169	101			155	77
		DGB T2 out (7)	166	100	166	100		

25.0 Reference: Exhibit B-2, BCUC 1.7.3 and 1.7.7

Preamble: BCUC 1.7.3 states:

"For the Kelowna area, the average Power Factor is 0.98, which is close to unity. To be more conservative when modelling load flows, FBC generally applies a 0.95 Power Factor when converting MVA to MW".

25.1 For purposes of the transformer MVA loads to meet the forecast area MW load for the forecast years (2020-2022) set out in the response to BCUC 1.7.7, what Power Factor was used for each year (such that the sum of the transformer loads matches the area load)?

Response:

The power factors for the individual substations are provided in the table below:

Substation	Power Factor
Glenmore	0.99
Hollywood	0.99
OK Mission	0.98
Recreation	0.99
Sexsmith	0.98
Saucier	0.99
Joe Rich	0.97
Duck Lake	0.98
Duck Lake BCH	0.95
D.G. Bell	0.99
Lee	0.97
Ellison	0.98
Black Mountain	0.97
Big White	0.97
Benvoulin	0.99

The same power factor is used for all years.

25.1.1 The values used do not appear to be 0.95 per BCUC 1.7.3. If this is the case, please explain why?

Response:

When translating the equipment ratings in MVA to system load in MW, FBC applies a 0.95 Power Factor and rounds to the lowest whole number value. For example, at line 10 of the table provided in the response to BCUC IR1 7.3, which is reproduced below, the summer normal rating expressed as MW is 95 percent of the summer normal rating in MVA at line 3. For LEE T3, $0.95\,x\,168 = 159.6$. Rounding down to the lower integer results in a value of 159 as shown in line 10.

Line	Particulars		LEE T3	LEE T4	DGB T2
1	Equipment Ratings (MVA)				
2	Maximum Nameplate Rating (40^{o} C)		168	168	200
3	Summer Normal Rating	100% * Line 2	168	168	200
4	Summer Emergency Rating	125% * Line 2	210	210	250
5	Maximum Nameplate Rating (0^{o} C)		199.5	205.8	237.5
6	Winter Normal Rating	100% * Line 5	199.5	205.8	237.5
7	Winter Emergency Rating	135% * Line 3	226.8	226.8	270.0
8					
9	System Load (MW)				
10	Summer Normal Rating	95% * Line 3	159	159	190
11	Summer Emergency Rating	95% * Line 4	199	199	237
12	Winter Normal Rating	95% * Line 6	189	195	225
13	Winter Emergency Rating	95% * Line 7	215	215	256

26.0 Reference: Exhibit B-3, BCOAPO 1.3.1 and 1.3.2

26.1 With respect to BCOAPO 1.3.1, what do the 1,000 housing units per annum translate into in terms of an annual growth rate (%) in housing units for the period through to 2030?

Response:

The document provided by the City of Kelowna in Footnote 10 of the Application[1], indicates that the City of Kelowna had a total of 53,900 dwelling units as of 2015. Based on this figure, 1,000 housing units per annum represents an average annual growth rate of approximately 1.7 percent through to 2030.

26.2 How does this compare with the historical growth in housing units (i.e. over last 10 or 20 years)?

Response:

The document provided by the City of Kelowna in Footnote 10 of the Application[2] indicates that Kelowna had an increase of 4,230 units over the five-year period ending in 2015. This represents an eight percent growth over this period, or an average annual growth rate of approximately 1.6 percent. Information is not readily available for any other period.

[1] https://www.kelowna.ca/sites/files/1/docs/related/ff-population_and_housing.pdf
[2] https://www.kelowna.ca/sites/files/1/docs/related/ff-population_and_housing.pdf

27.0 Reference: Exhibit B-3, BCOAPO 1.4.1

Exhibit B-1, page 15, lines 12-15

Preamble: Exhibit B-1 states:

"FBC forecasts regional load growth using trends in historical regional load data".

27.1 The Application's description of the FBC forecast for regional load growth suggests it is based on historical growth rates whereas the response to BCOAPO 1.4.1 suggests that the forecast for regional load growth involves the use of econometric models for some customer segments and customer surveys for other segments. Please clarify the basis for the regional load growth forecast.

Response:

The regional load growth refers to the distribution level peak load forecast. This forecast is for all feeders and transformers. The statement "FBC forecasts regional load growth using trends in historical regional load data" is correct when talking about the distribution forecast.

The response to BCOAPO IR1 4.1 does not refer to the distribution level forecast but instead refers to the system level energy forecast, which does include econometric models. Since the energy growth rates derived from the energy forecast are used to inform the peak load forecast, the new loads that are implicitly captured in the energy forecast through the use of econometric models (and which were the subject of BCOAPO IR1 4.1) are also implicitly captured in the resulting peak load forecasts.

27.2 Is this regional load growth forecast the same as the Distribution Planning Forecast referred to in BCUC 1.4.4?

27.2.1 If not, what is the difference and which one is used in the determination of the 1 in 20 year load forecast for the area?

Response:

Yes, the regional (peak) load forecast is the Distribution Planning Forecast. The Distribution Planning Forecast is used in the development of the 1-in-20 forecast for the Kelowna area as described in the revised response to BCUC IR1 4.4.

28.0 Reference: Exhibit B-3, BCOAPO 1.5.1, 1.6.1, 1.6.2 and 1.6.2.1

Exhibit B-2, BCUC 1.7.7

28.1 The responses to BCOAPO 1.6.1 & 1.6.2.1 and BCUC 1.7.7 all suggest that not all of the 200 MVA capability of the DGB transformer can actually be used to service the area load. Please confirm that this is the case.

28.1.1 If confirmed, please explain why the response to BCOAPO 1.5.1 suggests that the full capability of DGB (190 MW) can be used to supply area load.

28.1.2 If not confirmed, please reconcile with the response to BCOAPO 1.6.1.

Response:

Confirmed. As described in Section 4.3 and 4.4.3.1 of the Application, the full capacity of DGB T1 cannot be utilized in the event of a LEE transformer outage due to transmission line capacity constraints on lines 51L and 60L.

The response to BCOAPO IR1 5.1 indicates that the three remaining transformers could support up to 570 MW of summer peak load in the event of a single terminal transformer outage (3 x 190 MW = 570 MW). This is based on the expected ratings of the transformers only. The response further goes on to refer to 570 MW as a "theoretical transformer capability", while the new summer load threshold is established at the lower 550 MW load level. The 550 MW and 570 MW load levels are expected to materialize far into the future; because the geographic dispersal of the load cannot be accurately predicted, FBC is not able to accurately perform load flow studies to determine how much load would be supplied from DGB and LEE at that time.

28.2 The response to BCOAPO 1.6.2.1 states that, after the system reconfiguration, the loading on the DGB transformer is 150 MVA. For what forecast year does the 150 MVA apply?

Response:

This response is based on a load level of 315 MW, which is marginally higher than the forecast summer peak load for 2021 (314.6 MW).

28.3 With respect to Exhibit B-1, Table 3-5, please provide the portion (MWs) of the Kelowna area load that would be served by DGB in the event of an outage at either of the LEE transformers, both before and after reconfiguration in each year from 2020-2028.

Response:

Please refer to the response to BCUC IR1 4.13 for the 2020-2028 peak load forecast (in MW) and the portion of that load normally served from LEE and DGB.

Please refer to the table below for the load (in MVA) served by the existing T2 transformer at DGB and a single transformer at LEE in the years 2025 and 2029, both before and after 138 kV network reconfiguration. FBC provided these years as power flow studies were readily available and are sufficiently representative of system power flow at load levels documented in Table 3-5. Note that the table below does not contemplate other constraints such as 60L and 51L transmission line capacity that limits the amount of load that can be supplied from DGB or LEE transformer loading limits.

	Single Transformer In Service at LEE 138 kV System in Normal Configuration		Single Transformer In Service at LEE 138 kV System Reconfigured	
	DGB Loading (MVA)	LEE Loading (MVA)	DGB Loading (MVA)	LEE Loading (MVA)
2025 Summer	134	210	157	185
2029 Summer	145	223	170	197
2025 Winter	150	229	174	202
2029 Winter	158	241	184	213

28.4 At what point in time in the future is the load that would be served by DGB after reconfiguration expected to exceed 190 MW (or 200 MVA) based on the 1 in 20 load forecast?

Response:

With existing infrastructure, it would not be possible to serve 190 MW (or 200 MVA) from DGB after reconfiguration at summer peak. 60L and 51L transmission line capacity constraints, as described in Sections 4.3 and 4.4.3.1 of the Application, would prevent DGB from supplying this amount of load. The response to BCOAPO IR2 30.3 addresses the future year in which DGB T2 capacity would be fully utilized after reconfiguration with the reconductoring of 60L and 51L complete.

29.0 Reference: Exhibit B-5, ICG 1.5.2

29.1 Are the substation peak load forecasts set out in ICG 1.5.2, a non-coincident peak load forecast for each substation (i.e., the peak for each substation) or the coincident peak load forecast for each substation (i.e., the peak for the substation at the time of the Kelowna area peak)?

Response:

The load forecasts set out in the response to ICG IR1 5.2 are coincident peak values.

29.2 Are the forecast values in the Application, Table 3-5 simply the sum of the substation forecasts (per ICG 1.5.2) for the respective year?

29.2.1 If not, how do the values in Table 3-5 relate to those provided in response to ICG 1.5.2?

Response:

Yes, the forecast values in the Application on Table 3-5 are the sum of the values provided in response to ICG 1.5.2.

30.0 Reference: Exhibit B-3, BCOAPO 1.6.1, 1.6.2, 1.6.2.1 and 1.9.1

Preamble: At present it appears that, in the event of an outage at one of the LEE transformers the system cannot be reconfigured so as to fully utilize the 200 MVA capability of the DGB transformer.

30.1 Please explain more fully why, based on the geographical distribution of the load (per BCOAPO 1.6.1) DGB cannot be used fully to supply the area load whereas the transformers at LEE can.

Response:

As depicted in Figure 3-2 of the Application, LEE has four interconnected 138 kV lines, whereas DGB has only two 138 kV lines. The 60L/51L transmission line path is the only unique path available to supply load from DGB. The normal rating (or emergency limit) of 60L/51L is approximately 145 MVA while the emergency rating (or reasonability limit) of 60L/51L is approximately 161 MVA. LEE and DGB are connected via transmission lines 58L and 54L through Black Mountain (BLK) station. Additionally, as noted in the response to BCOAPO IR1 6.1 and documented in the tables provided in the response to ICG IR1 5.2, the most heavily loaded stations in the Kelowna area are geographically closer to LEE.

30.2 Is this limitation on the use of DGB related at all to the location of the lines and breakers serving the area?

Response:

Yes, as described in the response to BCOAPO IR2 30.1, the limiting factor to the amount of load that can be served from DGB is line 60L capacity.

30.3 Is it possible through the installation of addition lines/breakers to increase the load that can be transferred to the DGB transformer after reconfiguration?

30.3.1 If not, why not?

30.3.2 If yes, what additional facilities would be required, what would be the associated cost, what would be the increase in the ability to the DGB transformer to carry load after reconfiguration and what would be the new need date for Kelowna system?

30.3.3 If yes, why was this not considered as an alternative?

Response:

Yes, it is possible to increase the load that can be supplied from DGB if transmission lines 60L and 51L were reconductored as laid out in the description and scope of Alternative C in Section 4.4.3.1 of the Application.

The cost to reconductor 60L and 51L is approximately 80-90 percent of the "Total Lines Work" cost summarized in Table B-5 in the Application Confidential Appendices. If this scope were completed, the DGB T2 transformer could carry up to 180 MVA of load in the year 2025 with additional reconfiguration beyond what was described in the response to BCUC IR1 7.5. This modified reconfiguration would see HOL and SEX substations added to the load supplied via 60L. Further reconfiguration is not possible as voltage would be at low limits and the loading on the remaining LEE transformer would be at 99.5 percent of the emergency limit.

As described in the response to BCOAPO IR1 6.2, loading on DGB T2 would be 150 MVA after reconfiguration at the 315 MW load level. Reconductoring lines 60L and 51L could provide approximately 22 MW of incremental capacity, since 2025 load levels would be approximately 337 MW. This line upgrade would defer the need for a terminal transformer addition by three years, as the transformer would need to be in service prior to summer 2026 rather than prior to summer 2023.

This alternative was considered at a high level in the early stages of the Project, but was ultimately rejected because of the fact that the relatively high capital cost of the line reconductoring only resulted in a limited benefit, deferring the need for an addition transformer for only three years.

31.0 Reference: Exhibit B-2, BCUC 1.16.1, 1.16.5 and 1.16.6

31.1 There appears to be some overlap in the considerations related to the Safety, Operability, Complexity of Protection and Switching Schemes and Reliability. What are the distinguishing differences that warrant there being four separate criteria for purposes of the evaluation?

Response:

As acknowledged in the response to BCUC IR1 16.1, there are some relationships between the criteria, and the weighting of criteria in Table 4-1 of the Application incorporates these relationships. FBC provides further detail below on the differences between the criteria:

- The safety criteria is intended to capture the potential for crews to have a clear zone of isolation and ample working space when equipment is out of service for maintenance.
- The operability criteria is intended to capture the ease with which equipment can be taken out of service or load can be transferred within the bus (e.g. the number of switching steps).
- The complexity of protection and switching schemes is intended to capture the complexity of relay settings and the potential for human error and mis-operation.
- The reliability criteria is intended to capture overall expected outage frequency and duration associated with the bus configuration, as typically measured by SAIFI/SAIDI reliability indices.

32.0 Reference: Exhibit B-1, page 26

Preamble: The Application states: "Ring bus is today's minimum industry standard for this type of terminal substation".

32.1 What is the basis for the statement that "Ring bus is today's minimum industry standard for this type of terminal substation"?

<u>Response:</u>

FBC surveyed sixteen utilities in North America and found that the preferred bus configurations for terminal substations in this voltage class were ring bus and breaker-and-a-half. As noted in Section 4.3.1 of the Application, the capital cost of a breaker-and-a-half configuration is higher than ring bus. As such, FBC considers that ring bus is the minimum standard in terms of providing very good reliability and operability at a lower cost than other preferred bus configurations.

33.0 Reference: Exhibit B-3, BCOAPO 1.8.1

33.1 What was the estimated DR potential of the largest 53 Commercial and Industrial (C&I) accounts in the Kelowna area?

Response:

The estimated DR potential of the largest 53 C&I accounts in the Kelowna area was 5.7 MW in summer and 4.2 MW in winter. As discussed in the response to BCOAPO IR1 8.1, FBC anticipated that participation would be lower than the estimated total potential.

34.0 Reference: Exhibit B-4, CEC 1.12.2

Exhibit B-2, BCUC 1.7.3

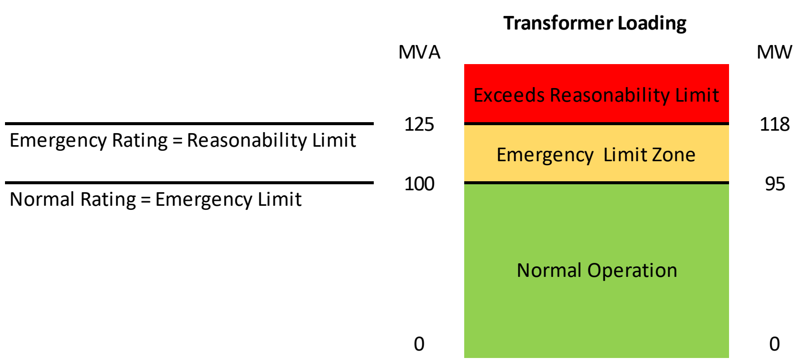
Preamble: The response states:

"For example, if the new LEE T2 transformer was rated at 100 MVA, the <u>emergency</u> limit would be approximately 95 MW. With LEE T4 out of service, LEE T2 and LEE T3 would carry the load in parallel with a limitation of 95 MW x 2 = 190 MW. This only represents an incremental capacity increase of 31 MW with regard to the summer N-1 limit" (emphasis added)

34.1 Based on the response to BCUC 1.7.3, please explain why the emergency rating of a 100 MVA transformer is 95 MW as opposed to 119 MW (i.e., 100 MVA * 125% (per BCUC 1.7.3) * 0.95 (Power Factor).

<u>Response:</u>

Please refer to the response to BCUC IR2 36.2. As described in that response, the normal rating is equivalent to the emergency limit, whereas the emergency rating (calculated as set out in this question, rounded to the lower integer as explained in the response to BCOAPO IR2 25.1.1) would be equivalent to the reasonability limit, as illustrated below.



34.2 Please explain why the loads must be carried in parallel such that LEE T3 can only carry 95 MW as opposed to its normal summer rating of 159 MW (per BCUC 1.7.3).

Response:

The LEE transformers are operated in parallel to ensure that the remaining transformer is able to carry the load in the event of an unplanned transformer outage, thereby mitigating the risk of an outage for a large number of customers. When two transformers are operated in parallel, the load capability is based on the lowest transformer rating (in this case the emergency limit of the hypothetical new 100 MVA transformer).

34.3 Please provide the derivation of the 31 MW.

Response:

The summer emergency limit for the existing LEE T3 and T4 transformers is 159 MW, as explained in the response to BCUC IR2 36.2.

The theoretical capability of 190 MW is based on one of the existing transformers operating in parallel with a transformer with a summer limit of 95 MW. Thus, the 31 MW figure is derived as follows:

190 MW – 159 MW = 31 MW of incremental capacity

35.0 Reference: Exhibit B-3, BCOAPO 1.5.1

Exhibit B-2, BCUC 1.11.3

35.1 Are the N-1 limits set out in Figures 3.3 and 4.1 (Exhibit B-1) based on the emergency or the normal ratings of the transformers?

Response:

The N-1 limits set out in Figures 3-3 and 4-1 of the Application are based on the normal ratings of the transformers. As illustrated in the response to BCUC IR2 36.2, loading above the normal rating of the transformer exceeds the operational emergency limit.

36.0 Reference: Exhibit B-2, BCUC 1.12.4, 1.12.4.1, 1.16.6 and 1.17.5

Exhibit B-3, BCOAPO 1.10.3

Exhibit B-1, page 34, lines 30-35

36.1 The references noted in the preamble all suggest that a split bus configuration requires more work effort on the part of FBC employees than a ring bus configuration due to safety and operational considerations. Can FBC provide an estimate as to what would be the additional annual O&M expense associated with Alternative B (using a split bus configuration) as compared to Alternative A (using a ring bus configuration)?

Response:

Due to the inherent complexity of switching and equipment isolation within a split bus configuration, FBC estimates that Alternative B would require up to $15,700 more in annual O&M expenditures, which were not included in the financial model, compared to Alternative A.

37.0 Reference: Exhibit B-3, BCOAPO 1.19.1

Exhibit B-2, BCUC 1.32.4

37.1 To date, what specific aesthetic improvements has FBC committed to and do these improvements address the issues raised by Letters of Comment or at the virtual Town Hall meeting?

Response:

To date, FBC has not committed to any specific aesthetic improvement options. Rather, FBC has committed to collaborating with the Tower Ranch community association representatives to review suggestions and input, including those raised in the Letters of Comment. Where practical, consideration will be given to the aesthetic options for the overall visual improvement of the Project.

As described in Sections 4.4.1.1 and 4.4.2.1 of the Application, the scope and estimates for Alternatives A and B include a solid fence or screening wall along the north side of the station.