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June 8, 2023

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

Attention: Leigha Worth, Executive Director

Dear Leigha Worth:

Re: FortisBC Inc. (FBC)

Application for Approval of a Certificate of Public Convenience and Necessity for the A.S. Mawdsley Terminal Station Project (Application) ~ Project No. 1599424

Response to the British Columbia Public Interest Advocacy Centre representing BC Old Age Pensioners' Organization, Active Support Against Poverty, Council of Senior Citizens' Organizations of BC, Disability Alliance BC, and Tenant Resource and Advisory Centre (BCOAPO) Information Request (IR) No. 1

On February 24, 2023, FBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-70-23 for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

For convenience and efficiency, if FBC has provided an internet address for referenced reports instead of attaching the documents to its IR responses, FBC intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1.0 Reference: Exhibit B-1, pages 1, 2, 12 (including Figure 3-2), 14 and 19 (Figure 3-7)

Preamble: The Application states:

"Power generated in the Kootenay region flows into WTS at 230 kV and 63 kV. The WTS power transformers (WTS T1 and WTS T2) transform from 230 kV to 63 kV. At 63 kV, power travels from WTS to the ASM Terminal Station, which is 1 kilometre (km) away, as shown in Figure 1-1, where it is transformed from 63 kV to 161 kV by the ASM Terminal Station power transformers (ASM T1 and ASM T2).

The Similkameen and Boundary area customers and communities rely on the connection between WTS and the ASM Terminal Station via 34 Line and the 63 kV to 161 kV conversion that is performed by ASM T1 and ASM T2 at the ASM Terminal Station for safe and reliable power." (page 1)

"ASM T1 and ASM T2 currently have a combined capacity of 160 MVA (80 MVA per transformer). 11E Line supply (i.e., the ASM Terminal Station) is subject to meeting both normal operation (N-0) and single contingency (N-1) transmission planning criteria." (page 2)

"At 161 kV, the ASM Terminal Station supplies power to 11E Line into the Boundary area. From 11E Line, power flows to 11W Line. Customers and communities in the Boundary area are supplied from substations connected directly to 11E Line and 11W Line. 11W Line connects to 48 Line, which carries power to BEN. At BEN, power is converted from 161 kV to 138 kV before flowing into 43 Line to supply customers and communities in the Similkameen area." (page 12)

"The customers and communities in the Similkameen and Boundary areas rely on the connection between WTS and the ASM Terminal Station via 34 Line, as well as the 63 kV to 161 kV conversion that is performed by ASM T1 and T2 at the ASM Terminal Station, for safe and reliable power." (page 14)

1.1 What is the (N-0) capacity capability of Line 34L? If different, please provide the winter and summer values at time of peak load.

<u>Response:</u>

The 34 Line summer and winter normal (N-0) ratings are 255 MVA and 261 MVA, respectively.

1.2 Does Line 34L have more than one circuit?

Response:

No, 34 Line is a single circuit from the Warfield Terminal Station (WTS) to the ASM Terminal Station.

1.3 What is the (N-1) capability limit of Line 34L and what is it based on? If different, please provide the winter and summer values at time of peak load

Response:

During a 34 Line N-1 contingency event where the source to the Boundary and Similkameen load is only 40 Line (230 kV) and 42 Line (63 kV), the maximum Boundary and Similkameen area load before voltage collapse occurs is approximately 200 MW. This load limit is the same for both summer and winter.

1.4 What is the (N-0) capacity capability of Line 11EL? If different, please provide the winter and summer values at time of peak load.

Response:

The 11E Line summer and winter normal (N-0) ratings are 167 MVA and 234 MVA, respectively.

1.5 Does Line 11E have more than one circuit?

Response:

No, 11E Line is a single circuit from the ASM Terminal Station to the Grand Forks Terminal Station (GFT).

1.6 What is the (N-1) capability limit of Line 11EL and what is it based on? If different, please provide the winter and summer values at time of peak load.

Response:

During an 11E Line N-1 contingency event where the source to the Boundary and Similkameen load is only 40L (230 kV) and 42L (63 kV), the maximum Boundary and Similkameen area load before voltage collapse occurs is approximately 200 MW. This load limit is the same for both summer and winter.

1.7 If either Line 34L or line 11EL have an (N-1) capability less than that shown for the ASM Terminal Station in Figure 3-7, please explain why the ASM Transformer (N-1) value is the relevant value when considering the ability to meet the (N-1) transmission planning criteria for the Similkameen and Boundary area.

Response:

Both 34 Line and 11E Line have a higher N-1 capacity limit than the current 80 MVA transformers installed at the ASM Terminal Station.

2.0 Reference: Exhibit B-1, pages 11, 18 and 19

Preamble: The Application states:

"Customers in the Boundary and Similkameen areas are supplied with power generated in the Kootenay region (shown in pink in Figure 3-1) and with power from a transmission interconnection to BC Hydro at Vaseux Lake Terminal Station in the north, as shown in the following single line diagram and further described below." (page 11)

"On average, the Boundary and Similkameen areas are supplied 67 percent of their load in the winter and 75 percent of their load in the summer by the ASM Terminal Station." (page 18)

2.1 Is the Vaseux Lake Terminal Station owned by BC Hydro or FortisBC?

2.1.1 If owned by FortisBC, please provide its (N-0) and (N-1) capacity capability values and explain what the later are based on.

Response:

The Vaseux Lake (VAS) Terminal Station transformers (500/230 kV) and the 230 kV portion of the station are owned by FBC. The normal and emergency ratings for VAS T1 and VAS T2 are based on the thermal equipment ratings and are provided in the following table.

Name	Summer Limits (MVA)		Winter Limits (MVA)	
	Normal	Emergency	Normal	Emergency
VAS T1	250	312	296	337
VAS T2	250	312	296	337

2.2 Please provide the capability (I.e., (N-0) value) for Line L40 and the Bentley Terminal Substation (BEN).

Response:

The normal (N-0) limits for 40 Line and the single transformer at BEN are shown in the table below.

Name	Summer (MVA)	Winter (MVA)
40L	337	476
BEN T1	168	205

2.3 Please provide the (N-1) capacity capability for Line L40 and the BEN and, in each case, what they are based on.

Response:

During a 40L or BEN T1 contingency event, the maximum Boundary and Similkameen area load before voltage collapse occurs is approximately 190 MW. This load limit is the same for both summer and winter.

2.4 Please provide a figure similar to Figure 3-7 that compares the historic (2017-2022) peak winter and summer load flows through BEN with the (N-0) and (N-1) capabilities of the delivery point.

Response:

A similar figure to Figure 3-7 cannot be completed for the BEN station. Figure 3-7 shows the ASM Terminal Station during an N-1 contingency event where one of the ASM transformers is out of service and load flows through the remaining transformer. BEN station only has one transformer and therefore does not have the same redundancy of transformers as the ASM Terminal Station does. Therefore, when there is an outage of BEN T1 (230/63 kV) there is no alternative transformer to transfer load to. During a 40 Line contingency event, the maximum Boundary and Similkameen area load before voltage collapse occurs is approximately 190 MW.

2.5 What determines the percentage of load in the Boundary and Similkameen areas that will be supplied via BEN versus the ASM Terminal Station at any given point in time?

Response:

Please refer to the response to BCUC IR1 2.16. The same factors that determine the proportion of Boundary and Similkameen areas' load served by the ASM Terminal Station are relevant for what percentage is served by BEN.

2.6 Please provide a schedule that sets out the historic (2017-2022) summer and winter peak load for the Boundary and Similkameen areas and indicate, for each season, the MW supplied via BEN and the ASM Terminal Station respectively.

Response:

The historical (2017-2022) summer and winter peak loads for the Boundary and Similkameen areas are provided in Table 3-2 of the Application.

The following tables show the distribution of load served from each of the ASM Terminal Station and the Bentley (BEN) Terminal Station. The remaining load is served from 42 Line.

Please also refer to the response to BCUC IR1 2.11 for an explanation why the peak loads shown in the tables below are not directly comparable to the peak loads shown in Table 3-2 of the Application. The factors impacting the ASM Terminal Station peak load flows set out in the response to BCUC IR1 2.11 also impact the peak load flows at the BEN Terminal Station.

	2017	2018	2019	2020	2021	2022
Load served from ASM in Summer (MW)	115	130	131	124	130	135
Load served from ASM in Winter (MW)	44	119	99	122	62	118

	2017	2018	2019	2020	2021	2022
Load served from BEN in Summer (MW)	18	29	37	28	9	42
Load served from BEN in Winter (MW)	54	25	13	21	52	28

2.7 Figure 3.7 shows that the Boundary and Similkameen areas are connected to BC Hydro's Nicola Substation. Is there any ability to supply the Boundary and Similkameen areas from this substation?

2.7.1 If not, why not?

2.7.2 If yes, what are the (N-0) and (N-1) winter and summer supply capabilities?

2.7.3 If yes, why has there historically been no supply provided from this substation?

Response:

While there is a theoretical ability to supply some Similkameen area load from BC Hydro's Nicola substation, the connection would not be sufficient to solve the current issues of N-1 reliability and load growth in FBC's Boundary and Similkameen service area. Portions of Similkameen load have at times been supplied from BC Hydro's 1L251 Line, however, this has only ever been provided on a temporary basis. The capabilities of BC Hydro to supply the Similkameen load fluctuate based on BC Hydro's customers' load levels at that time.

3.0 Reference: Exhibit B-1, page 19

Preamble: The Application states:

"For clarity, Figure 3-7 displays the peak load flowing through the ASM Terminal Station compared to the capacity when only one power transformer is in-service."

The Application (footnote 13) further explains Figure 3-7 as follows:

"ASM Terminal Station peak historical load (2017 – 2022 Summer) flows presented. Average percentage of load supplied from the ASM Terminal Station applied to total Boundary and Similkameen area load forecast (Table 3-3, 2022 Winter - 2027)."

3.1 Please confirm that the 2017-2022 summer and winter ASM Transformer Flows shown in Figure 3-7 are based on actual flows at the time of the summer and winter peak.

3.1.1 If not confirmed what are they based on?

<u>Response:</u>

Confirmed.

3.2 Please confirm that the forecast (2023-2027) summer and winter ASM Transformer Flows are based on the Average percentage of load supplied from the ASM Terminal Station applied to total Boundary and Similkameen area load forecast per Footnote 13.

3.2.1 Are the "average" values used based on: i) the average historic summer and winter percentages at the time of the winter and summer peak or ii)

3.2.2 If based on the latter (i.e. as described in (ii)) please re-do Figure 3-7 where the forecast summer and winter ASM Terminal Flows are based on the average historic percentage provided via the ASM Terminal at the time of the summer and winter peak respectively.

<u>Response:</u>

Confirmed. The average values are based on 2017-2022 historical summer and winter percentages at the time of the ASM Terminal Station winter and summer peak. Please also refer to the response to BCUC IR1 2.19.

3.3 Please provide a figure similar to Figure 3-7 but for the BEN Terminal Substation.

3.3.1 If the forecast summer and winter BEN peak flows are based on the average historic percentages for total load supplied during the winter and summer periods, please provide a revised version whether the forecast summer and winter peak BEN Flows are based on the average historic percentage provided via BEN at the time of the summer and winter peak respectively.

Response:

Please refer to the response to BCOAPO IR1 2.4.

4.0 Reference: Exhibit B-1, pages 17-18

FortisBC's Kelowna Bulk Transformer Addition (KBTA) Project CPCN Application,

Exhibit B-2, BCUC 4.4

Preamble: The current Application states:

"Unlike a resource planning forecast, which is a "weather-normalized" forecast used to determine FBC's resource requirements, the forecast for system planning purposes must account for possible weather extremes that directly impact winter and summer peak loads, to ensure sufficient capacity is available under these conditions. FBC accomplishes this through the use of a "1-in-20" year load forecast." (page 17)

The response to FortisBC's KBTA Project CPCN Application - BCUC 4.4 states:

"The system-wide 1-in-20 load forecast is developed in a series of steps:

- 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.
- The method yields 20 values for the 2020 winter peaks corresponding to 20 base years from 2000 to 2019. The maximum peak of these 20 values is defined as the 1-in-20 winter peak for 2020. The 1-in-20 summer peak is derived in the same manner. The resulting 2020 peaks are then escalated with growth rates to compute the 1-in-20 forecast peaks over the planning horizon.
- 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, taking into account the need to ensure adequate capacity on the Duck Lake substation based on the peak forecast provided by BC Hydro, as described in the response to BCUC IR1 2.3.1.

4.1 Please confirm that the 1-in-20 load forecast prepared for the current application followed the same steps as outlined in the response to BCUC 4.4.

4.1.1 If not confirmed please explain how the preparation of the 1-in-20 load forecast used in the current Application differs.

Response:

Confirmed. Please also refer to the response to BCUC IR1 2.8.

4.2 With respect to step #1 (as described in BCUC 4.4), were the historical years 2003 to 2022 used in the preparation of the current 1-in-20 load forecast?

4.2.1 If not, what years were used?

Response:

Confirmed. Please also refer to the response to BCUC IR1 2.8.

4.3 With respect to step #2 (as described in BCUC 4.4) what were the historical and forecast net energy growth rates used?

Response:

The following table provides the historical and forecast net energy growth rates.

Year	Net Load Growth	Year	Net Load Growth
2003	1.8%	2023	0.9%
2004	1.5%	2024	0.4%
2005	3.6%	2025	0.6%
2006	1.7%	2026	0.4%
2007	0.1%	2027	1.3%
2008	-0.3%	2028	1.3%
2009	2.3%	2029	1.3%
2010	-4.4%	2030	1.2%
2011	3.8%	2031	1.2%
2012	-1.1%	2032	1.2%
2013	2.2%	2033	1.2%
2014	-1.1%	2034	1.2%
2015	-1.9%	2035	1.2%
2016	0.1%	2036	1.1%
2017	6.2%	2037	1.1%
2018	-1.8%	2038	1.1%
2019	2.8%	2039	1.1%
2020	-1.6%	2040	1.0%
2021	5.3%	2041	0.9%
2022	3.4%		

4.4 With respect to steps #3 and #4 (as described in BCUC 4.4) please provide a schedule that sets out the 2022 peak values for January, for February, November, and December, as well as June, July, August derived by applying the described methodology to each of the years 2003 to 2022 (or the alternative years identified in previous response), identify the resulting 1-in-20 winter and summer 2022 peaks and provide the 1-in-20 winter and summer peak system forecast through to 2027.

Response:

The table below shows the forecast system peaks (before DSM), excluding historical coincident peaks from a large FBC industrial customer and historical General Wheeling Agreement (GWA) losses from FBC's System Control Center (SCC).

Table 1: 2022-2027 Peak Values (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	839	765	695	573	542	780	702	697	589	605	825	842
2023	846	772	701	578	547	786	708	703	594	611	833	850
2024	850	775	704	581	549	789	711	706	596	613	836	853
2025	855	779	708	584	552	794	715	710	600	617	841	858
2026	858	782	711	586	554	797	718	713	602	619	844	861
2027	869	792	720	594	562	808	727	722	610	627	855	873

5.0 Reference: Exhibit B-1, page 18

FortisBC's KBTA Project CPCN Application,

Exhibit B-2, BCUC 4.4

Preamble: The current Application states:

"Looking forward, the load forecast for the Boundary and Similkameen areas for summer and winter 2023 through 2027 is shown in Table 3-3 below. Table 3-3 shows the forecasts of peak load based on historical data which are used in power flow simulations to determine compliance with FBC's Transmission Planning Criteria, and also includes forecast load growth related to electric vehicles (EVs) and load from one known large capacity customer. Greater EV adoption and new government policy favouring electrification have the potential to result in increases beyond the "1-in-20" load forecast shown below."

The response to BCUC 4.4 states:

""The system-wide 1-in-20 load forecast is developed in a series of steps:

- 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.
- The method yields 20 values for the 2020 winter peaks corresponding to 20 base years from 2000 to 2019. The maximum peak of these 20 values is defined as the 1-in-20 winter peak for 2020. The 1-in-20 summer peak is derived in the same manner. The resulting 2020 peaks are then escalated with growth rates to compute the 1-in-20 forecast peaks over the planning horizon.
- 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, taking into account the need to ensure adequate capacity on the Duck Lake substation based on the peak forecast provided by BC Hydro, as described in the response to BCUC IR1 2.3.1."

5.1 Were the summer and winter peak load forecasts for the Boundary and Similkameen areas as set out in Table 3-3 developed using the same approach as described in step #5 of BCUC 4.4?

5.1.1 If yes, please provide the 2023-2027 non-coincident peak forecasts for each of the substations in the Boundary and Similkameen area, the resulting total for each year and the scaling factors used for each year to determine the Boundary and Similkameen area peak load forecast.

5.1.2 If yes, please describe how the non-coincident peak forecast for each of the substations was developed and how the adjustment for EV and the one known capacity customer were incorporated into these forecast (i.e., what were the specific adjustments for EV and the known capacity customer and were they included before or after the scaling to reconcile with the overall system 1-in-20 peak load forecast?).

5.1.3 If not, please fully describe how the Boundary and Similkameen area peak load forecast was derived and provide the supporting calculations.

Response:

Yes, the summer and winter peak load forecasts for the Boundary and Similkameen areas as set out in Table 3-3 were developed using the same approach described in step #5 of FBC's response to BCUC IR1 4.4 in the KBTA CPCN Application proceeding.

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 is 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:

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

EV load is included in the total system load forecast and is scaled according to the distribution load allocation. The known capacity customer's load is excluded from scaling.

The following tables provide the 2023-2027 non-coincident peak forecasts for each of the substations in the Boundary and Similkameen area.

Table 1: Summer Non-Coincident Peak Forecast

Name	2023	2024	2025	2026	2027
Pine Street	18.6	18.8	18.9	19.1	19.2
Osoyoos	17.9	18.3	18.7	19.2	19.8
Keremeos	13.8	13.9	13.9	14.0	14.2
Hedley	2.5	2.5	2.6	2.7	2.7
Oliver	12.6	12.8	13.1	13.3	13.6
Princeton	17.0	17.2	17.5	17.8	18.1
Nk'Mip	13.8	14.0	14.3	14.5	14.8
Terasen Similkameen	1.9	1.9	1.9	1.9	1.9
Mascot	0.7	0.7	0.7	0.7	0.7
Christina	5.0	5.1	5.3	5.4	5.6
Ruckles	10.6	10.7	10.7	10.7	10.7
Grand Forks Terminal	8.4	8.5	8.5	8.5	8.6
Kettle Valley	10.8	10.9	11.0	11.1	11.3
Roxul	9.1	9.1	9.1	9.1	9.1
Ponderosa	24.0	24.0	24.0	24.0	24.4
Total	**166.7**	**168.2**	**170.0**	**172.0**	**174.8**
Scale Factor	0.97	0.97	0.96	0.96	0.96

Table 2: Winter Non-Coincident Peak Forecast

Name	2023	2024	2025	2026	2027
Pine Street	14.7	14.8	14.9	15.1	15.3
Osoyoos	15.4	15.6	15.8	16.1	16.5
Keremeos	13.7	13.8	13.9	14.0	14.1
Hedley	6.1	6.1	6.2	6.3	6.4
Oliver	12.8	13.0	13.2	13.4	13.6
Princeton	22.1	22.3	22.6	22.9	23.3
Nk'Mip	11.8	12.1	12.3	12.6	12.9
Terasen Similkameen	2.2	2.2	2.2	2.2	2.2
Mascot	0.6	0.6	0.6	0.6	0.6

Name	2023	2024	2025	2026	2027
Christina	4.5	4.6	4.7	4.9	5.1
Ruckles	11.6	11.6	11.6	11.6	11.7
Grand Forks Terminal	8.7	8.8	8.8	8.8	8.9
Kettle Valley	14.4	14.5	14.7	14.8	15.1
Roxul	9.1	9.1	9.1	9.1	9.1
Ponderosa	24.0	24.0	24.0	24.0	24.4
Total	**171.7**	**173.1**	**174.7**	**176.5**	**179.1**
Scale Factor	1.03	1.03	1.02	1.03	1.03

5.2 Please explain, particularly in light of the EV and know capacity customer adjustments, why the resulting 2023-2027 peak load forecast for the Boundary and Similkameen areas (per Table 3-3) is less than the actual peak load experienced in 2022 (per Table 3.2).

Response:

The 1-in-20 peak load forecast used by FBC relies on 20 years of historical winter and summer peaks and escalates those values by the compounded system load growth rate. All the specific circumstances impacting actual peak load, such as existing EV load and customer adjustments, are intrinsic in the actual historical data used to calculate the 1-in-20 forecast and therefore, a high peak load year like 2022 does impact the forecast results. Please also refer to the response to BCUC IR1 2.8 for the detailed process for preparing the 1-in-20 year peak load forecast.

The 1-in-20 year peak load forecast is a probabilistic method and all else equal should be exceeded, on average, once every 20 years. A circumstance where the actual results exceed forecast is to be expected approximately 5 percent of the time, and FBC does not believe that its load forecasting methodology should be modified when this expected situation occurs.

6.0 Reference: Exhibit B-1, page 19

Preamble: The Application states:

"In recent years, certain new load and generation conditions have caused FBC to exceed N-1 system planning. FBC has been able to manage this load through operational changes; however, these changes to system operation are not sustainable in the long-term."

6.1 Please explain how FBC has been able to manage this load through operational changes.

Response:

Please refer to the response to BCUC IR1 2.21.

6.2 Please explain why these operational changes are not sustainable in the long-term.

Response:

Please refer to the response to BCUC IR1 2.21.

7.0 Reference: Exhibit B-1, page 21 and Appendix B, page 4 and Figures 2, 3, 4, 5, 6 & 8

Preamble: The Application states (page 21):

"The Condition Assessment Report calculated the Total Risk of Failure for ASM T1 and ASM T2 to be higher than FBC's accepted tolerances (2 percent), which is based on CEATI industry findings. The calculated Total Risk of Failure in the Condition Assessment Report was based on the most recent dissolved gas analysis (DGA) and the available test/maintenance data. As a result, the Condition Assessment Report categorized both ASM T1 and ASM T2 as being in the "Urgent" (Code Red) category, meaning that immediate attention is needed.

Appendix B states (page 4):

"The Hitachi Energy approach to fleet risk screening involves a combination of the risk of failure assessment and the relative importance of a transformer to the utility system. **Figure 1** shows an analysis tool used in this approach. This represents the analysis for an example fleet of transformers that have a diverse risk of failure characteristics as well as a diverse relative importance. Using **Figure 1**, each transformer in the fleet is assigned a risk of failure and a relative importance and displayed on the risk management plot. Those that fall in the Red Zone are transformers with a combination of high risk of failure and/or higher importance for the system. These are classified as Urgent, or those requiring immediate action. The next transformers are those in the Yellow or Priority zone."

7.1 In each of the referenced Figures the vertical scale reports the relative risk value. Please explain more fully: i) what these risk values represent (i..e., Do they represent the probability of failure (e.g. in Figure 2 do the probabilities range from 0.13% to 0.15% whereas in Figure 5 the probabilities range from less than 2% to more than 2%)); ii) how should they be interpreted and iii) what value level represents a high risk of failure.

Response:

FBC provides the following discussion regarding the results provided by Hitachi Energy in Appendix B to the Application:

i) Risk of Failure, as represented in Appendix B, is a number intended to give an indication regarding the probability of failure of a unit in a year due to one of the key Risk Factors. Figure 7 of the report represents the Total Risk of Failure (TRoF), which is a cumulative function of all key Risk Factors. This approach to calculating expected loss, based on failure rates, does not consider the age of the transformers.

Figures 2 through 6 in Appendix B are showing the risk of failure from one particular Risk Factor only. In particular, Figure 2 is showing the risk of short circuit failures in the transformers and Figure 5 is showing the risk of accessory failures in the transformers.

ii) Hitachi has provided the interpretations of risk as follows:

- "Figure 2 shows a histogram of the transformers as a function of the relative risk of short circuit. Both units are showing low short circuit risk."[1]
- "Figure 3 shows there is no associated thermal risk to the transformers."[2]
- "Figure 4 shows the distribution of the relative risk of dielectric failure for the population of transformers. The units with the highest risk of dielectric failures are identified in the histogram."[3]
- With regard to auxiliary devices (bushings and tap changer), Figure 5 shows that ASM T2 has a higher risk than ASM T1.[4] As shown in Figure 5, both ASM T1 and ASM T2 have an associated risk in this category of approximately 1.8.
- "Figure 7 shows a plot of the risk of failure vs. importance for unit. The Urgent, Priority, and Normal boundaries were also shown on this plot, so that the transformer could be categorized. From Figure 7 we see that both transformers are in the Urgent (Red) category. Figure 8 shows a histogram of the failure rate of the transformer, which is a combination of the information from each of the individual risk categories."[5]

iii) As discussed in the response to BCUC IR1 3.5, FBC has adopted the recommendations from the CEATI 30/113-2018[6] report that a Probability of Failure (PoF) of 2 percent or higher is a high risk of failure. The table below provides FBC's interpretation of the PoF thresholds contained in the CEATI report[7] and ABB - Hitachi *Fit at 50* white paper.

PoF (Estimate)	Response Time for Intervention	Risk Level (FBC)
12%	1 month	Critical
4%	1 year	High
2%	2 years	

1 Appendix B, page 6.
2 Appendix B, page 6.
3 Appendix B, page 7.
4 Appendix B, page 8.
5 Appendix B, page 11.
6 CEATI adopted a new numbering system in 2023. All previously published project reports were renumbered.
7 CEATI, Stations Equipment Asset Management Program, REPORT No. T163700-30/113 (May 2018). "Translating the Health Index into Probability of Failure" by Doble Engineering.

PoF (Estimate)	Response Time for Intervention	Risk Level (FBC)
1.5%	5 years	Moderate
1%	15 years	
<0.5%	N/A	Normal[8]

7.2 What does a "high risk of failure" mean (e.g. does it mean a risk/probability of failure greater than 2% as discussed on page 21 of the Application)?

Response:

The Hitachi report (Appendix B) refers to "high risk of failure" in terms of the likelihood of a failure event (i.e., probability of failure) and the associated impact of failure (i.e., "Importance"). Based on Figure 7 in Appendix B, Hitachi has classified ASM T1 and ASM T2 as having a "high risk of failure" based on the probability of failure being greater than 2 percent and the transformers level of "Importance".

7.3 If FortisBC's accepted tolerance is risk of failure of 2% and transmission planning criteria are (N-1) does this mean that the planning criteria results in the risk of customer outages being 0.04% (i.e., the risk of two failures coinciding)?

7.3.1 If not, please explain.

Response:

No, the risk of failure of 2 percent and the Transmission Planning Criteria of N-1 cannot be combined to calculate the risk of customer outages. Transmission Planning Criteria considers the system operation under contingency events, independent of the probability of failure of transformers (or other components of the electric system).

[8] ABB - Hitachi *Fit at 50* white papers.

8.0 Reference: Exhibit B-1, Appendix B, page 10

Preamble : Appendix B states:

"For each transformer, a risk of failure was calculated, and a relative importance was indicated. The results were plotted, grouped, and separated into four distinct categories. Those with the highest risk of failure that would warrant removing from service are categorized into the critical category. Those with high risk of failure, but not so high as to warrant removal from service, and those with higher importance and moderate risk of failure or above were categorized into the "Urgent" (Code Red) category, meaning that immediate attention is needed. Those with a significant, but somewhat lower risk of failure or importance were categorized into a middle or "Priority" (Code Yellow) level, meaning that action is needed within about one year. The remaining units, with lower risk of failure and importance were in the "Normal" (code green) category."

8.1 What level of risk failure is required in order for the transformer to be categorized in the critical category (i.e., warranting removal from service)?

8.2 What level of risk failure is required in order for the transformer to be categorized as "high risk"?

8.3 What level of risk failure is required in order for the transformer to be categorized as "high moderate risk"?

8.4 For transformers of importance ascribed to ASM T1 and T2, what level of risk would lead to them be categorized to the Priority level?

8.5 For transformers of importance ascribed to ASM T1 and T2, what level of risk would lead to them be categorized as Normal?

<u>Response:</u>

Please refer to the response to BCOAPO IR1 7.1.

9.0 Reference: Exhibit B-1, pages 11-12 and 24

Preamble: The Application states:

"Customers in the Boundary and Similkameen areas are supplied with power generated in the Kootenay region (shown in pink in Figure 3-1) and with power from a transmission interconnection to BC Hydro at Vaseux Lake Terminal Station in the north, as shown in the following single line diagram and further described below." (page 11)

"This alternative (Alternative 2) would not increase the 161 kV supply which, as explained in Section 3, is necessary for FBC to meet its N-1 transmission planning criterion in the event of a station outage. FBC would not be able to continue to support load growth in the Boundary and Similkameen areas. Like the status quo, this alternative would lead to a shortage in transmission capacity, resulting in a level of customer service that is below established standards." (page 24)

9.1 Is it possible to increase the supply of power from the transmission interconnection to BC Hydro at Vaseux Lake Terminal Station based on the current facilities in place?

9.1.1 If not, why not?

9.1.2 If yes, by how much could the supply be increased

9.1.3 If yes, would this increase support the load growth in the Boundary and Similkameen areas in conjunction with Alternative 2?

9.1.4 If yes and this increase would support the load growth in the Boundary and Similkameen areas under Alternative 2, please explain why Alternative 2 with increased supply from Vaseux Lake Terminal is not a feasible alternative?

9.1.4.1 Note: If it is a feasible alternative please provide an evaluation of this "alternative" using the same criteria and approach as outlined in Section 4.3

Response:

No, it is not possible to increase the supply of power from the transmission interconnection to BC Hydro at Vaseux Lake Terminal Station based on the current facilities in place or if upgrades were undertaken on FBC's facilities.

The flow through this station is determined by the overall provincial generation dispatch and the network configuration. The provincial generation dispatch is decided by BC Hydro (Balancing Authority and Planning Coordinator) and the network configuration is then determined by the actual system conditions at that time. The supply of power FBC is able to receive from this interconnection is therefore limited by these factors.

9.2 Is it possible to increase the supply of power from the transmission interconnection to BC Hydro at the Vaseaux Lake Terminal with appropriate upgrades to FortisBC facilities?

9.2.1 If not, why not?

9.2.2 If yes, by how much could the supply be increased and what facility upgrades would be required?

9.2.3 If yes, would this increase support the load growth in the Boundary and Similkameen areas in conjunction with Alternative 2?

9.2.4 If yes and this increase would support the load growth in the Boundary and Similkameen areas under Alternative 2, please explain why Alternative 2 along with the necessary upgrades to increase supply from Vaseux Lake Terminal is not a feasible alternative?

9.2.4.1 Note: If it is a feasible alternative please provide an evaluation of this "alternative" using the same criteria and approach as outlined in Section 4.3

Response:

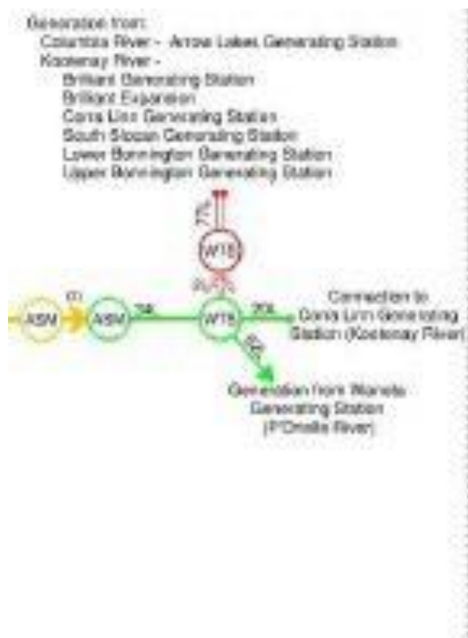
Please refer to the response to BCOAPO IR1 9.1.

10.0 Reference: Exhibit B-1, pages 12 and 24-26

Preamble: The Application states (page 26):

"Transmission work required as part of Alternative 3 includes the rebuilding of 9/10 Line (which runs from WTS to the ASM Terminal Station) into one high-capacity transmission line, as well as re-terminating 9 Line (to Cascade Substation (CSC)) and 10 Line (to CSC) at the ASM Terminal Station 63 kV bus."

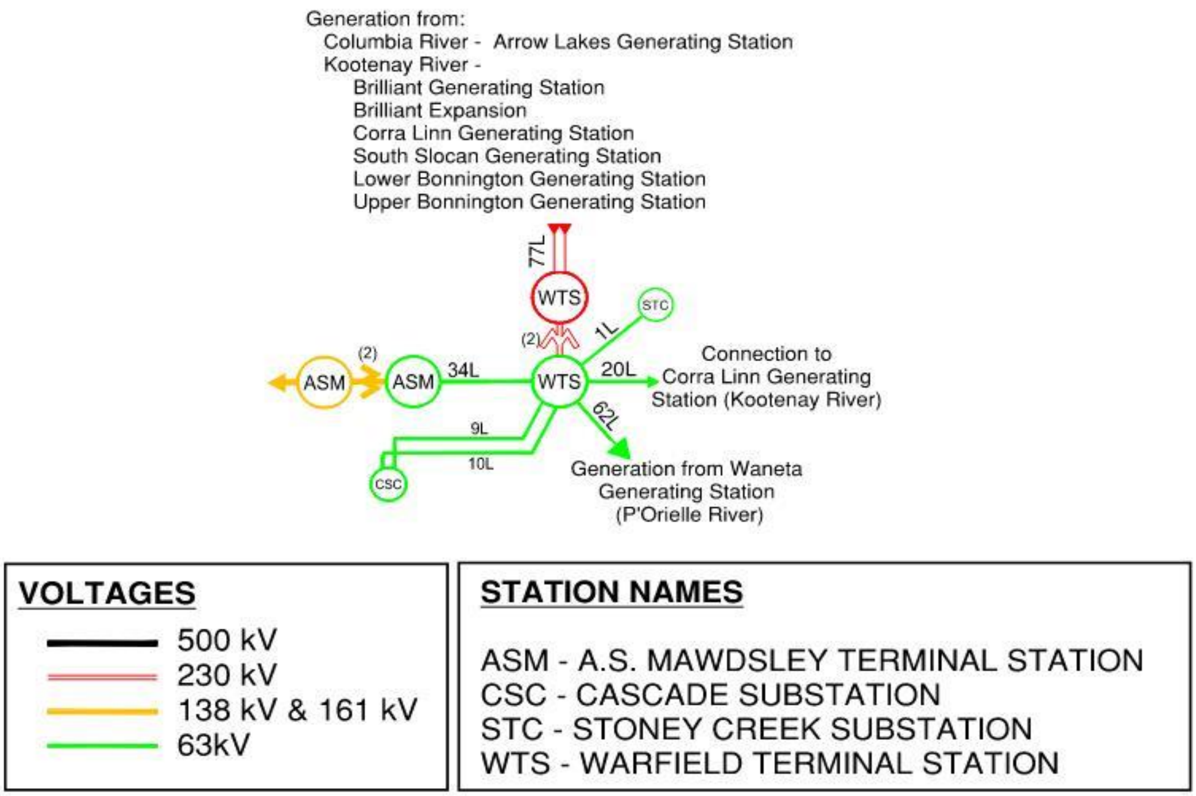
The Application provides the following schematic for the connections between WTS and the ASM Terminal (Figure 3-2)



10.1 Figure 3-2 only show Line 34L as running between WTS and ASM. However, Alternative 3 makes reference to "the rebuilding of 9/10 Line (which runs from WTS to the ASM Terminal Station) into one high-capacity transmission line". Please reconcile.

Response:

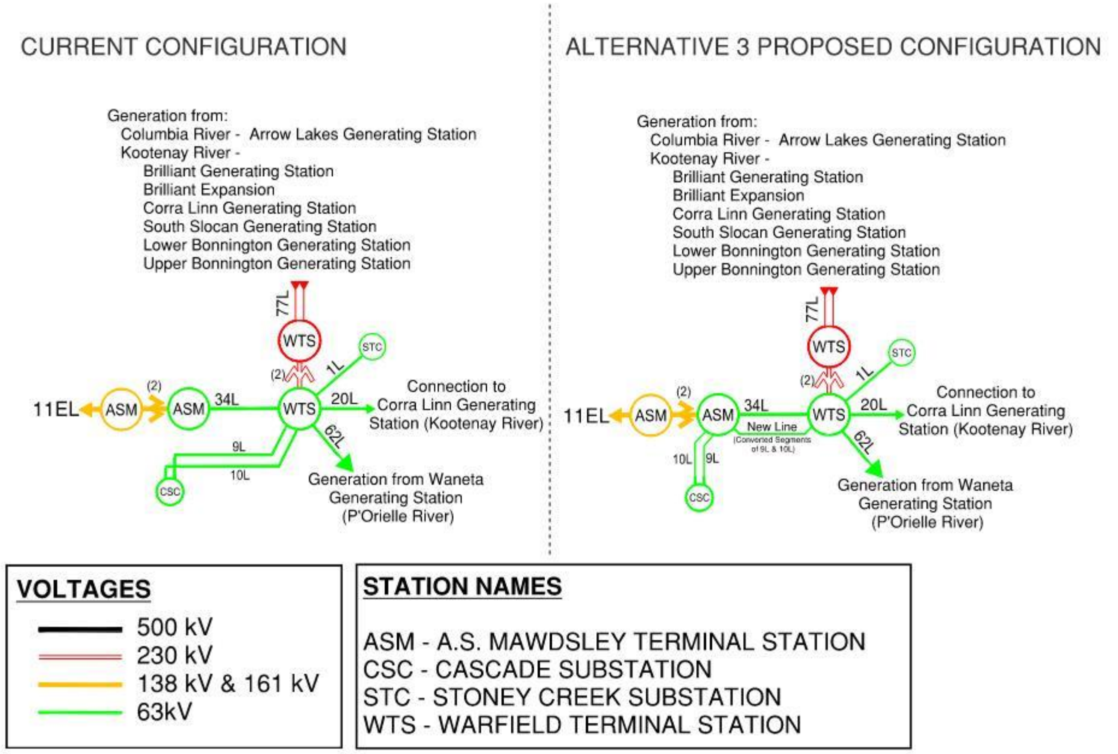
As stated in the footnote to Figure 3-2 (i.e., Footnote 2), local transmission to the West Kootenays from WTS was removed for simplicity; thus, 9/10 Line was not included in this figure. Please refer to the diagram below showing the transmission lines coming in and out of WTS.



10.2 Please provide an expanded version of Figure 3-2 that shows the Cascade Substation and the current (as well as the new) positions for the 9 Line and the 10 Line.

Response:

The following diagram shows the current configuration of WTS, including transmission to Cascade Substation (CSC), and the proposed reconfiguration under Alternative 3.



10.3 Please explain why, under Alternative 3, it is necessary to re-terminate the 9 Line (to Cascade Substation (CSC)) and the 10 Line (to CSC) at the ASM Terminal Station 63 kV bus.

Response:

FBC clarifies that the current configuration of 9 Line and 10 Line runs past the ASM Terminal Station from WTS to CSC but does not connect into the ASM Terminal Station. Under Alternative 3, 9 Line and 10 Line will be converted to one high-capacity transmission line that is connected into the ASM Terminal Station.

FBC requires the redundant line from WTS to the ASM Terminal Station (a second 34 Line) to be able to comply with N-1 contingency planning criteria. The conversion will only impact the segment of the line that runs from WTS to the ASM Terminal Station. The segments of 9 Line and 10 Line that run from the ASM Terminal Station to CSC that will not be converted will need to be re-terminated into the ASM Terminal Station. This is to continue to provide a supply path from WTS to CSC, via the ASM Terminal Station. Please also refer to the response to BCOAPO IR1 10.2.

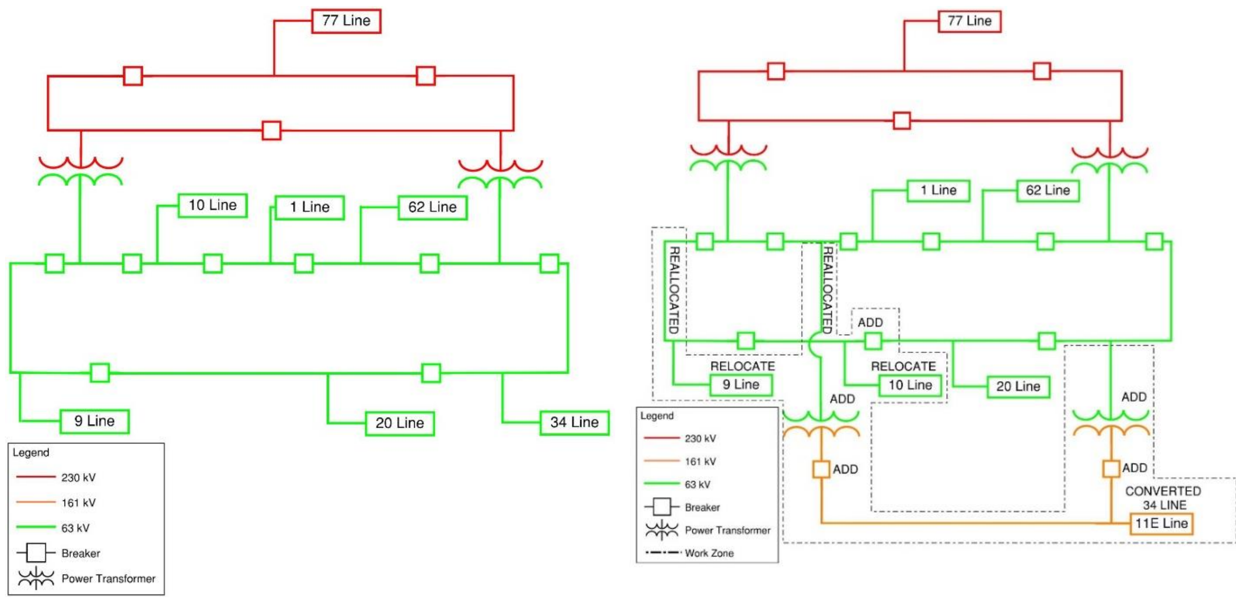
11.0 Reference: Exhibit B-1, pages 12 (Figure 3-2) and 28 (Figure 4-4)

11.1 Figure 3-2 only shows Lines 34L, 20L, 62L and 77 L as connecting to WTS. In contrast, under the existing configuration, Figure 4-4 also shows Line 1, Line 9 and Line 10 as connecting to WTS but not Line 34L. Please reconcile.

Response:

In the Application, Figure 3-2 was simplified to only show transmission lines relevant to the supply to the Boundary and Similkameen areas and their connection to generation (as explained in Footnote 2 of the Application). Please refer to the response to BCOAPO IR1 10.1 for the expanded Figure 3-2 with all WTS transmission connections.

FBC notes that 34 Line was inadvertently excluded from Figure 4-4 (a) in the Application. The diagram below provides the corrected Figure 4-4 with 34 Line included in Figure 4-4 (a). No correction to Figure 4-4 (b) is required, however, FBC has included Figure 4-4 (b) for completeness.



(a) Current Configuration

(b) Preliminary Proposed Re-configuration

11.1.1 What are the functions of Line 1, Line 9 and Line 10 under the existing configuration?

Response:

Under the existing configuration, 1 Line supplies the Stoney Creek Substation, which is a distribution substation that supplies the City of Trail. 9 Line and 10 Line supply the Cascade Substation, which is a distribution substation that supplies the City of Rossland.

12.0 Reference: Exhibit B-1, pages 24 and 29-30

12.1 Would combining Alternatives 2 and 6 represent a feasible alternative that addresses both the load growth and the condition of the existing ASM transformers?

12.1.1 If not, why not?

12.1.2 If yes, please provide an evaluation of this "alternative" using the same approach and criteria as set out in section 4.3.

Response:

No, combining Alternatives 2 and 6 would not represent a feasible alternative to address both the load growth and the condition of the existing ASM transformers. While Alternative 2 may address the condition of the existing ASM transformers, adding Alternative 6 to address load growth does not change the specific challenges, described in Section 4.2.6 of the Application, that caused FBC to determine that Alternative 6 is unfeasible. In particular, Alternative 6 requires that 11E Line be extended back to WTS. Based on the terrain and current land use between the ASM Terminal Station and WTS, it is not feasible to extend 11E Line as an additional independent line. Please refer to the response to ICG IR1 5.3 for a detailed explanation of the land challenges related to Alternative 6.

13.0 Reference: Exhibit B-1, pages 32 – 39

Preamble: The Application states:

"Table 4-1 below shows the weighting applied for each of the non-financial evaluation criteria." (page 32)

"Table 4-2 below shows the scoring applied to each of the non-financial evaluation criteria." (page 33)

"As the table above demonstrates, based on the non-financial criteria, Alternative 5 is superior to Alternative 3." (page 39)

13.1 Given that for all non-financial criteria except "Land Availability" Alternative 5 scored higher than Alternative 3, is it fair to conclude that the actual weights applied to each of the non-financial criteria have little to no impact on the overall outcome of the evaluation?

<u>Response:</u>

FBC disagrees with the statement in this IR. Please refer to the response to BCUC IR1 7.1 for a detailed explanation of the scoring approach, evaluation criteria and weights developed for this Application.

14.0 Reference: Exhibit B-1, pages 39-40 and Appendix C

Preamble: Appendix C provides the following comparison of the Project costs based on Alternatives 3 and 5.

Breakdown of the Project Cost Estimate for Alternatives 3 and 5 at AACE Class 4 estimate level ($millions)

		Alternative 3: Rebuild ASM (Class 4)		Alternative 5: Expand WTS (Class 4)	
Line	Particular	2022 $	As-Spent $	2022 $	As-Spent $
1	Station Construction Costs	25.704	27.832	15.608	17.015
2	Transmission and Distribution Construction Costs	1.888	2.049	1.525	1.663
3	Fibre Construction Costs	1.260	1.370	0.238	0.260
4	Removal Costs	1.176	1.309	1.381	1.540
5	Project Management and Owner's Costs	1.999	2.176	1.542	1.681
6	**Subtotal Project Capital Cost**	**32.027**	**34.737**	**20.293**	**22.158**
7	Contingency	3.482	3.794	2.746	2.999
8	**Subtotal Project Capital Cost w/Contingency**	**35.508**	**38.531**	**23.039**	**25.157**
9	CPCN Preliminary Engineering Costs	0.751	0.760	0.751	0.760
10	AFUDC	-	4.226	-	2.460
11	**Total Project Cost**	**36.260**	**43.517**	**23.791**	**28.378**

14.1 Please outline the key reasons for Alternative 3's construction costs (in as spent dollars) being roughly $10 M higher than that for Alternative 5.

Response:

The key reasons for the construction costs being higher for Alternative 3 are as follows:

- Alternative 3 includes eight high voltage breakers with associated structures, switches, protection, control, metering, cabling, conduit, grounding and telecommunication equipment, whereas, Alternative 5 includes three high voltage breakers and associated equipment.
- Alternative 3 includes the addition of a new control building at the ASM Terminal Station, whereas Alternative 5 uses space in the existing building at WTS for the expansion.
- Alternative 3 involves rebuilding the ASM Terminal station, with mostly brownfield construction staging. Much of the equipment would need to be removed a section at a time and power rerouted to keep the station energized to supply power to customers. On the other hand, Alternative 5 involves expanding WTS with mostly greenfield practices and little construction staging required.

14.2 For each of the two alternatives, how were the contingency amounts determined?

Response:

For each of the two alternatives, the contingency was determined following AACE contingency guidelines. Please refer to the response to BCUC IR1 15.3 for additional detail.

14.3 At page 39 the Application states: "Alternative 5 has better constructability, lower construction risk, and less equipment procurement risk than Alternative 3." However, the contingency amount for Alternative 5 represents 13.5% of the Project Capital Cost, whereas for Alternative 3 the contingency amount represents less than 11% of the Project Capital Cost. Given the better constructability, lower construction risk and less equipment procurement risk for Alternative5, please explain why the contingency percentage is higher.

Response:

FBC clarifies it has applied the same assumptions for contingency on the base capital cost estimates for both Alternatives 3 and 5.

As noted in Section 6.2 of the Application, FBC applied a contingency of 15 percent for the Station construction and removal costs, excluding the add-on costs which are calculated on top of the base station capital cost estimate. These add-on costs include material handling costs, indirect costs, and provincial sales taxes. Alternative 3 further includes site preparation costs with an inbuilt contingency to address brownfield construction staging (as further explained in the response to BCOAPO IR1 14.1) so a second contingency is not added on top of the existing contingency.

A contingency of 10 percent is applied for the Transmission, Distribution, and Fibre modification components for both Alternatives 3 and 5. Please refer to the response to BCUC IR1 15.1 for further explanation of the basis of these contingency amounts.

The percentages referred to in this question compare the total contingency with the Project capital cost, which includes the aforementioned add-on costs. As these add-on costs are based on the underlying base capital cost estimates, which are different for each alternative, and the contingency is not calculated on top of them, the overall allocation of contingency to the Project cost estimate is different for the two alternatives.

15.0 Reference: Exhibit B-1, pages 40 & 55 and Appendix C

Preamble: The Application provides the following breakdown of the Class 4 Project Cost Estimate for Alternatives 3 and 5. (Appendix C)

Breakdown of the Project Cost Estimate for Alternatives 3 and 5 at AACE Class 4 estimate level ($millions)

		Alternative 3: Rebuild ASM (Class 4)		Alternative 5: Expand WTS (Class 4)	
Line	Particular	2022 $	As-Spent $	2022 $	As-Spent $
1	Station Construction Costs	25.704	27.832	15.608	17.015
2	Transmission and Distribution Construction Costs	1.888	2.049	1.525	1.663
3	Fibre Construction Costs	1.260	1.370	0.238	0.260
4	Removal Costs	1.176	1.309	1.381	1.540
5	Project Management and Owner's Costs	1.999	2.176	1.542	1.681
6	**Subtotal Project Capital Cost**	**32.027**	**34.737**	**20.293**	**22.158**
7	Contingency	3.482	3.794	2.746	2.999
8	**Subtotal Project Capital Cost w/Contingency**	**35.508**	**38.531**	**23.039**	**25.157**
9	CPCN Preliminary Engineering Costs	0.751	0.760	0.751	0.760
10	AFUDC	-	4.226	-	2.460
11	**Total Project Cost**	**36.260**	**43.517**	**23.791**	**28.378**

The Application also provides the following breakdown of the Class 3 Cost Estimate for Alternative 5. (page 55)

Table 6-1: Breakdown of the Project Cost Estimate ($ millions)

Line	Particular	2022 $	As-Spent $	Reference
1	Station Construction Costs	20.453	22.270	Section 5.1.2
2	Transmission and Distribution Construction Costs	1.771	1.925	Section 5.1.3 and 5.1.4
3	Fibre Construction Costs	0.148	0.161	Sections 5.1.5
4	Removal Costs	0.984	1.092	Sections 5.1.2 to 5.1.5
5	Project Management and Owner's Costs	2.004	2.182	Sections 5.3
6	**Subtotal Project Capital Cost**	**25.361**	**27.631**	**Sum of Line 1 to 5**
7	Contingency	3.318	3.615	Section 6.2
8	**Subtotal Project Capital Cost w/Contingency**	**28.679**	**31.247**	**Sum of Line 6 to 7**
9	CPCN Preliminary Engineering Costs	0.751	0.760	Section 6.4.1
10	AFUDC	-	3.171	Conf. App. H, Sch 6, Ln 26 + 31 (2024-2026)
11	**Total Project Cost**	**29.430**	**35.179**	**Sum of Line 8 to 10**

15.1 Please outline the key reasons for the increase in Alternative 5's Station Construction Costs (2022$) as between the Class 4 and Class 3 estimates.

Response:

The key reasons for the increase in Alternative 5's Station Construction Costs (2022$) from the Class 4 estimate to the Class 3 estimate are:

- The two power transformer quotes came in much higher for the Class 3 estimate compared to the Class 4, due to ongoing supply chain issues and market volatility. FBC also included a risk allowance for the Class 3 estimate to account for further increases to the power transformer costs.
- After stakeholder review, FBC included an aesthetic, sound mitigating concrete wall along part of the station fence line in the Class 3 estimate. Chain link only was used in the Class 4 estimate.
- A Geotech report on soil conditions for the proposed expansion area was completed as part of the Class 3 estimate. The result was less favourable building and drainage conditions compared to the assumptions made for the Class 4 estimate.
- A preliminary archaeological assessment was done for the Class 3 estimate, and risk dollars were added in the Class 3 estimate to cover archaeological finds including monitoring, analysis, and recording.

15.2 To what extent would these reasons also lead to an increase in a Class 3 cost estimate for Alternative 3 (as compare to the Class 4 cost estimate in Appendix C), if one was to be prepared?

Response:

FBC expects that approximately 70 percent of the cost increases in the Class 3 estimate for Alternative 5 would also be applicable to a Class 3 estimate for Alternative 3. FBC provides the following explanation for the approximate cost increases to Alternative 3 with reference to the four reasons for the cost increases to Alternative 5 provided in the response to BCOAPO IR1 15.1:

- The power transformer cost increase, which comprises the largest component of the cost increases, would also be applicable to a Class 3 estimate for Alternative 3.
- The concrete wall would not be required for Alternative 3 because the substation is part of a larger parcel of FBC land with no neighbors nearby.
- A Geotech report could also be unfavorable with respect to Alternative 3, but it is a much lower risk as the land has already been developed and there is less site preparation work required compared to Alternative 5.

- The risk dollars associated with the archaeological finds would be the same for Alternative 3.

16.0 Reference: Exhibit B-1, page 47

Preamble: The Application states:

"The application processes for permits and approvals will be initiated and managed by Engineering in detailed design. This will include but is not limited to Environmental, Archaeological, MOTI, CPR, and any/all other permits, approvals, and authorizations."

16.1 Please indicate the various approval authorities from which approval/permits will be required.

Response:

FBC will require approvals/permits from the Ministry of Transportation and Infrastructure (MOTI), Canada Pacific Rail (CPR), and Teck Metals Ltd.

16.2 Has FortisBC had any initial discussions with any of these authorities regarding the approvals/permits that will be required?

16.2.1 If yes, please indicate with which authorities such discussions have taken place and whether any issues have been identified to date regarding obtaining the necessary approvals/permits.

16.2.2 For those authorities (if any) with which FortisBC has not had any initial discussions, does FortisBC anticipate any problems/issues with obtaining the necessary approval/permits?

Response:

FBC has an approved Agreement to Grant with Teck Metals Ltd. for the Transmission and Station SRWs.

FBC has not yet had any discussions with MOTI or CPR on this specific scope of work. Approval/permit discussions will begin once the Application is approved, and design begins. FBC does not anticipate any problems/issues obtaining the necessary approvals/permits.

17.0 Reference: Exhibit B-1, page 50

Preamble: The Application states:

"Engineering and procurement for the Project will begin immediately upon BCUC approval. FBC has standard equipment specifications for equipment relevant to the Project scope, which reduces risk for ordering the long-lead time materials. The longest procurement lead time is for the power transformers, which will be competitively bid, and this process typically takes two to three months to select a supplier, and an expected further 18 to 24 months for manufacture."

17.1 What is the basis for the 18-24 month estimate for manufacturing the power transformers? In particular, to what extent does it reflect recent experience and supply chain issues?

Response:

The 18-24 month estimated procurement lead time is based on transformer manufacturer estimates at the time FBC prepared the Application. FBC has experienced increased delivery times for the majority of its equipment due to ongoing supply chain issues. For example, an FBC transformer that was ordered in January 2023 has a 22-month lead time.

18.0 Reference: Exhibit B-1, page 52

Preamble: The Application states:

> "Purchase all equipment from established suppliers and, where possible, with agreed purchase prices. Competitive tendering will be used to ensure lowest cost at best value products. Contingency may be used in the case of higher than anticipated foreign exchange or raw material escalation."

18.1 What percentage of the Project's Capital Cost ($27.631 M – as spent $) is subject to foreign exchange risk?

<u>Response:</u>

While FBC is unable to provide a specific percentage of the Project's capital cost that would be subject to foreign exchange risk, the percentage of the cost would be small. All of the services and contractors on site for both engineering and construction will be sourced and paid in Canadian dollars with the potential exception of certain specialty services; however, the impact of those specialty services' costs would be minimal. The only risk to foreign exchange is on certain materials, such as circuit breakers, disconnect switches and the commodities associated with construction of the transformers. As foreign exchange rates change, those items may be impacted. Any unfavorable variances to foreign exchange will be absorbed through the Project's contingency.

19.0 Reference: Exhibit B-1, page 55

Preamble: The Application states:

"A base capital cost estimate of $25.361 million (excluding contingency) in 2022 dollars developed by FBC in conjunction with PICA Engineering Ltd. (with respect to the station component of the Project) and DBS Energy Services Inc. (with respect to the transmission, distribution and fibre modification components of the Project) using the AACE Class 3 International Recommended Practices 18R-97 and 97R-18 as guides."

19.1 What was the role of PICA Engineering Ltd. (with respect to the station component of the Project) and DBS Energy Services Inc. (with respect to the transmission, distribution and fiber modification components of the Project) in developing the base capital cost estimate? For example, did they independently develop cost estimates or just review the estimates prepared by FBC?

Response:

PICA Engineering Ltd. was contracted to independently develop the cost estimate for the station component, and DBS Energy Services Inc. was contracted to independently develop the cost estimate for the lines (transmission, distribution, and fibre modification) component.

20.0 Reference: Exhibit B-1, pages 55-56

Preamble: The Application states:

"A total contingency estimate of $3.318 million in 2022 dollars (approximately 13.1 percent of the base capital cost estimate of $25.361 million in 2022 dollars) was added to the base capital cost estimate. This contingency was estimated based on applying a contingency of 15 percent for the station construction and removal costs before materials handling and provincial sales tax (as detailed in the basis of estimate for the station components in Confidential Appendix G-1), and a contingency of 10 percent for the transmission, distribution and fiber modification components (as detailed in Confidential Appendix G-2)."

20.1 What was the basis/rationale for using 15 percent and 10 percent as the appropriate contingency allowances?

Response:

Please refer to the responses to BCUC IR1 15.1 and 15.3.

21.0 Reference: Exhibit B-1, page 60

Preamble: The Application states:

"As discussed in Section 6.3 above, there will be additional wheeling costs in 2025 and 2026 for the outages to the 34 Line conversion. The outage wheeling costs are estimated to result in a rate impact of 0.07 percent and 0.08 percent in these years, respectively, when compared to the approved 2023 rates. FBC notes these costs are expected to occur in 2025 and 2026 only, thus having no rate impact in 2027 and beyond."

21.1 Please explain why these additional wheeling costs are not considered to be part of the cost of project and, therefore, capitalized and depreciated over the life of the Project.

Response:

As discussed in Section 6.3 of the Application, the outages due to the 34 Line conversion will result in additional wheeling costs to cover the Okanagan transmission shortfall under the BC Hydro Open Access Transmission Tariff (OATT). FBC's accounting treatment of this incremental BC Hydro wheeling cost as a power purchase expense is consistent with the approved treatment resulting from the FBC 2010 Annual Review and 2011 Revenue Requirements Negotiated Settlement Agreement (NSA) and Order G-184-10[9].

Specifically, on page 9 of Appendix A, FBC agreed to the following resolution regarding Upgrade Life Extension (ULE) power purchase costs:

> FBC will treat ULE incremental power purchase costs as a power purchase expense beginning in 2012 on future ULE projects.

9 https://docs.bcuc.com/Documents/Proceedings/2010/DOC_26625_G-184-10_FortisBC-2011-RRA-Negotiated-Settlement.pdf

22.0 Reference: Exhibit B-1, page 69

Preamble: The Application states:

"FBC initiated consultation with Project stakeholders and Indigenous communities prior to the submission of this CPCN Application. The Project is anticipated to have minimal impact on area residents and FBC is committed to meaningful engagement with stakeholders and Indigenous communities as the Project progresses. FBC will continue to maintain open lines of communication and collaborate with stakeholders and Indigenous communities on any outstanding interests or concerns brought forward throughout the duration of the Project, including planning, construction and restoration."

22.1 Has FortisBC received any additional feedback from stakeholders or Indigenous communities since the filing for the Application?

22.1.1 If yes, have additional concerns or issues regarding the Project been raised and, if so, what are they and how has FortisBC responded?

Response:

FBC has not received any additional feedback from stakeholders or Indigenous communities since the filing of the Application.