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June 8, 2023

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

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 Utilities Commission (BCUC) 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 BCUC 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): Registered Interveners

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A. APPROVALS SOUGHT AND EXECUTIVE SUMMARY

1.0 Reference: APPROVALS SOUGHT AND EXECUTIVE SUMMARY

Exhibit B-1 (Application), Section 1.2.1, p. 5; BCUC Rules of Practice and Procedure, Section 18.01(a)(iii)

Confidential Filings Request

On page 5 of FortisBC Inc.'s (FBC) Application for a Certificate of Public Convenience and Necessity (CPCN) for the A.S. Mawdsley (ASM) Terminal Station Project (Project) (Application), FBC states:

> FBC requests that certain Appendices to the Application (together, the Confidential Appendices) be filed on a confidential basis, pursuant to section 19 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-178-22.

Further on page 5 of the Application, FBC identifies the following Appendices as those requested to remain confidential:

- Appendices A-1, A-2, F-1, F-2, and F-3: Engineering Drawings including General Arrangement and Single Line Diagrams for ASM Terminal Station and WTS Expansion; and
- Appendices G-1, G-2, and H: Cost Estimates and Financial Schedules.

Section 18.01(a)(iii) of the BCUC Rules of Practice and Procedure states:

If a party wishes to keep confidential any information in a document filed in any matter before the BCUC, in addition to the document, at the time of filing, the party must file:

(a) A request that all or any part of the document must be held in confidence which must:

[…]

(iii) provide, with explanation, a period of time for which the document should remain confidential.

1.1 For each of the Confidential Appendices mentioned in the preamble, please provide, with explanation, a period of time for which the document should remain confidential.

Response:

FBC requests that the following Appendices remain confidential in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23, for the reasons described below.

- Appendices A-1, A-2, F-1, F-2, and F-3 should be kept confidential on the basis that they contain operationally sensitive information pertaining to the configuration of the FBC system which could be used for actions by unknown parties with malicious intent and could impede FBC's ability to work safely and reliably.

- Appendices G-1, G-2, and H should be kept confidential on the basis that they contain financial information that could compromise the tendering and bidding process for the ASM Project, as well as future FBC projects and other FBC work. A compromised tendering and bidding process would negatively impact FBC's ability to secure competitive pricing for its projects and would therefore potentially harm customers through the increased rate impacts of increased project costs.

B. PROJECT NEED AND JUSTIFICATION

2.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.1, p. 10, Section 3.2, pp. 12, 15, Section 3.3.1.2.1, pp. 17-19; FBC Application for a CPCN for the Kelowna Bulk Transformer Addition proceeding, Exhibit B-2, BCUC IR 6.6.1

FBC's Transmission System Planning Criteria and Load Growth

On page 10 of the Application, FBC states:

> FBC's electricity demand in the Boundary and Similkameen areas has exceeded FBC's Transmission System Planning Criteria (N-1 system reliability) with the current capacity of the ASM Terminal Station power transformers. In the event of an outage or failure of one of the two ASM Terminal Station transformers, FBC will not be able to reliably maintain service during peak periods.

On page 15 of the Application, FBC states:

> On the 161 kV side, ASM T1 and ASM T2 supply into 11E Line through a single circuit breaker (ASM CB11).

In response to BCUC Information Request (IR) 6.6.1 in the FBC Application for a CPCN for the Kelowna Bulk Transformer Addition Project (KBTA CPCN application) proceeding, FBC stated:

> A.S. Mawdsley (ASM) transformers T1 & T2 located at FBC Warfield are currently protected by a single high side circuit breaker. In case of a fault, both the transformers are out of service, which does not meet N-1 planning criteria. Options for the ASM transformers and station upgrades are currently under review.

2.1 In the event of an outage or failure of one of the two ASM transformers, please explain whether FBC can currently maintain service to downstream load during peak periods with the current configuration of the ASM terminal station.

2.1.1 If yes, please explain how service is maintained in light of the explanation provided in response to IR 6.6.1 in the KBTA CPCN application proceeding referenced in the preamble.

2.1.2 If not, please explain why service cannot be maintained, including whether the current configuration of ASM with a single high side circuit breaker is a contributing factor. Please also explain since when this has been the case.

2.1.2.1 Please also discuss the service impacts to FBC customers in the event of an outage or failure of one of the two ASM

transformers during peak periods including potential outage duration and number of customers affected.

Response:

ASM T1 and T2 are configured with a single high side circuit breaker to 11E Line. As a result, any transformer fault or bus fault results in an outage to both transformers and 11E Line. Post contingency flow with only one transformer in service results in that transformer being overloaded. Due to this overloading, FBC cannot currently maintain service to downstream load. FBC identified the potential for overloading in 2019.

In the event of an outage or failure of one of the two ASM transformers during peak periods, FBC would be forced to either shed load or reduce system reliability by opening 11E Line. Although the number of customers and amount of load needing to be shed will fluctuate based on how overloaded the remaining ASM transformer is, in the worst case scenario, up to 27,146[1] customers (all the customers in the Boundary and Similkameen area) could be impacted. By opening 11E Line, FBC reduces reliability of supply only to the Boundary region and if another contingency event occurred, it would cause a full blackout to the Boundary region.

Based on 2022 historical actuals, if a failure of one of the two ASM transformers occurred, the remaining transformer would have been overloaded for approximately 23 percent of the year.

2.2 In the event of an outage or failure of both of the ASM transformers during peak periods, please discuss the service impacts to FBC customers including potential outage duration and number of customers affected.

Response:

In the event of an outage or failure of both ASM transformers during peak periods, voltage collapse will occur when the Boundary and Similkameen area loads reach approximately 200 MW. Boundary and Similkameen area loads will need to be curtailed to under 200 MW until both transformers can be put back into service. The length of curtailment would depend on the severity of the transformer failure.

[1] As explained in the response to ICG IR1 1.1, FBC identified an error in the number of customers presented in Table 3-1 of the Application and has corrected this table in the response to ICG IR1 1.1. As a result, the total number of customers in the Boundary and Similkameen areas is 27,146, not 26,183.

2.3 Please discuss whether FBC has access to mobile transformer(s) of suitable size and voltage to support ASM station in the event of outage or failure of one of the two ASM transformers. If not, please explain why not.

Response:

FBC does not own or have access to a mobile transformer of suitable size and voltage to support the ASM Terminal Station in the event of outage or failure of one of the two ASM transformers.

It is not practical to build a mobile transformer that could support the ASM Terminal Station because the physical size would not comply with BC Highway Load Restrictions.

2.4 Please describe all outage(s) or failure(s) of either ASM transformer over the past 5 years.

Response:

FBC provides the following table which describes all of the outages or failures of the ASM transformers over the past five years (i.e., January 1, 2018 to present).

FBC notes that transformers have various functional failures; not all functional failures impede a power transformer's ability to perform its primary function. In the case of ASM T1 and T2, the primary function is to convert electricity from 63 kV to 161 kV. The table below lists the historical failure data for ASM T1 and T2, regardless of functional failure type and system impact.

Date	Element	Outage/Failure	Status	Cause / Description
May 16, 2018	Station	Outage	Restored	Trip and reclose due to 11E Line fault.
Oct. 22 - 26, 2018	Station	Outage	Restored	34 Line work.
Oct. 30, 2018	Station	Outage	Restored	11E Line work.
Nov. 20, 2018	ASM T2	Failure & Outage	Resolved	Temperature gauge's well gaskets failed. Transformer oil leak from gasket. Repaired.
Dec. 20, 2018	ASM T1	Failure & Repair	Resolved	Alarm. Low oil in the main tank. Investigation and top-up completed.
Mar. 26-27, 2019	Station	Outage	Restored	ASM T1-2 MOD switch repair and ASM CB11E circuit breaker MRS testing.

Date	Element	Outage/Failure	Status	Cause / Description
July 25, 2019	Station	Outage	Restored	Trip and reclose due to 11E Line fault.
Oct. 21–23, 2019	Station	Outage	Restored	11E Line work.
Oct. 28 – Nov.1, 2019	ASM T2	Failure & Outage	Resolved	Transformer maintenance. Insulation power factor results indicated a deterioration of solid insulation. Multiple oil leaks at the hatches on top of the transformer found during maintenance. A temporary fix was applied.
Dec. 2, 2019	ASM T2	Failure (Indicator)	On-going	Insulation power factor results indicate a deterioration of solid insulation.
Feb. 1, 2020	Station	Outage	Restored	Trip and reclose due to 11E Line fault.
Feb. 7 - 8, 2020	Station	Outage	Restored	11E Line work.
Jun. 7, 2020	Station	Outage	Restored	Trip and reclose due to 11E Line fault.
Jan. 2, 2021	Station	Outage	Restored	11E Line fault.
May 27, 2021	Station	Outage	Restored	Trip and reclose due to 11E Line fault.
June 1 – 2, 2021	Station	Outage	Restored	11E Line work.
Sep. 7-10, 2021	ASM T1	Outage	Restored	Power transformer and circuit switcher equipment maintenance.
Oct. 9-20, 2021	Station	Outage	Restored	11E Line work.
2022 - Present	ASM T1 & ASM T2	Failure (Indicator)	On-going	LTC Dissolved Gas Analysis indicates abnormal gas levels and a potential internal fault. Heavy arcing might be related to heavy loading and damaged LTC contacts. Internal inspection and assessment are scheduled for second quarter of 2023.
May 7, 2022	Station	Outage	Resolved	Trip and reclose due to 11E Line fault.
June 13 - 24, 2022	Station	Outage	Resolved	11E Line and Ponderosa Substation work.
Oct. 9, 2022	Station	Outage	Resolved	Forest fire on 11E Line.
May 23-26, 2023	ASM T1	Outage	Restored	LTC contacts. Internal inspection and assessment. Oil replaced. Report pending.
May 29-June 2, 2023	ASM T2	Outage	Restored	LTC contacts. Internal inspection and assessment. Oil replaced. Report pending.

On page 17 of the Application, FBC states:

> Typical industry transmission planning standards require the system to be planned such that all projected customer loads are served during both normal (N-0)[3] operation, as well as during single contingency (N-1)[4] operation. Likewise, FBC's Transmission Planning Criteria also specify that customer load should be able to be supplied under both N-0 and N-1 conditions.
>
> [3] Normal operation, also referred to as N-0 reliability, means that with all major elements of the power system in service, the network can be operated to meet projected customer demand in order to avoid a load loss (customer outage).
>
> [4] Single contingency, also referred to as N-1 reliability, means that an outage of a single element with all other elements of the power system in service (i.e., outage of a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) results in no load loss.

2.5 Footnote 4 above provides a partial list of power system elements that N-1 planning criteria is applied to. Please provide a complete list of power system elements that FBC applies N-1 planning criteria to.

Response:

FBC applies N-1 planning criteria to the following power system elements:

- a single transmission line;
- transformers;
- generating units and power conditioning units, such as a shunt capacitor bank;
- a shunt reactor bank;
- a series capacitor;
- a series reactor;
- a synchronous condenser;
- a static VAR compensating device; and
- a filter bank, or other similar device that can be removed from the system by protection equipment.

2.6 Please discuss whether all transmission facilities that FBC considers to be part of FBC's interconnected system achieve N-1 planning criteria.

2.6.1 For those facilities that do not, please discuss why not.

2.6.2 For those facilities that do not, please explain whether FBC has plans to achieve N-1 planning criteria in the future.

Response:

Yes, all parts of FBC's interconnected system achieve N-1 planning criteria. Currently there are no other N-1 contingencies that are not satisfied within FBC's system. As the load grows, reinforcement plans will be applied so that the N-1 planning criteria is met.

2.7 Please provide a map of FBC's Transmission System labelled to identify which parts of the system FBC's considers to be part of the interconnected system where N-1 planning criteria applies, and which parts of the system are not considered part of the interconnected system where N-1 planning criteria does not apply.

Response:

Please refer to Confidential Attachment 2.7 which includes a single line drawing for FBC's interconnected system with the radial lines highlighted. The N-1 planning criteria applies to the entire FBC system with the exception of the radial lines.

Attachment 2.7 is being filed confidentially in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-72-23. Attachment 2.7 should be kept confidential on the basis that it contains sensitive technical information pertaining to the Company's assets. Public disclosure of the technical and engineering information contained in Attachment 2.7 elevates the risk of potential harm to FBC's assets by persons with malicious intent, which could result in damage to the assets and/or limit, restrict or impair their operation. Disclosure of this information could reasonably be expected to result in harm to the safety of the public, the Company's employees, and the assets themselves. A confidential version of this response is being filed with the BCUC under separate cover.

Further on page 17 of the Application, FBC states:

> Peak load forecasting for system planning purposes (as is necessary for the current Application) differs from forecasting energy and peak load for resource

(energy) supply purposes in one important way. 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. This forecast is higher than the expected load forecast under normal conditions, meaning that there is a 5 percent probability that loads will be higher than the "1-in-20" year forecast. This forecast is used as the basis for determining compliance with FBC's transmission planning standards and is also consistent with industry practice.

On page 18 of the Application, in Table 3-2, FBC provides the Boundary and Similkameen Areas' Historical Actual Peak Loads:

	2017	2018	2019	2020	2021	2022
Summer (MW)	122	121	133	135	148	173
Winter (MW)[10]	128	131	142	145	163	187

Further on page 18 of the Application, FBC provides Table 3-3 showing Boundary and Similkameen Areas' peak load forecast, and states:

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.

	2023	2024	2025	2026	2027
Summer (MW)	163	163	165	165	168
Winter (MW)[12]	177	178	178	181	183

Further on pages 18 and 19 of the Application, FBC states:

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.

2.8 Please describe FBC's process for preparing a "1-in-20" year peak load forecast for the Boundary and Similkameen areas. Please include all underlying calculations and assumptions.

Response:

The system-wide (which includes the Boundary and Similkameen areas) "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 2003-2022 is recorded.
- Historical net energy growth rates are derived from actual 2003-2022 sales. Forecast net energy growth rates are used to escalate the peaks into future years as described below.
- Assuming that the weather in 2022 will be similar to the weather of base year 2003, the corresponding January peak in 2022 is obtained by applying to the base year the cumulative growth of years 2003-2022. The 2022 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 2004 to 2022.
- The method yields 20 values for the 2022 winter peaks corresponding to 20 base years from 2003 to 2022. The maximum peak of these 20 values is defined as the 1-in-20 winter peak for 2023. The 1-in-20 summer peak is derived in the same manner. The resulting 2023 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 Boundary and Similkameen area peak forecast in Table 3-3 is the sum of the load distributed to the Boundary and Similkameen area substation buses in that manner.

FBC has not included the specific calculations because they are derived from a series of complex and inter-related models that would not be transparent to external parties.

2.9 Please explain whether the system "1-in-20" year peak load forecast was used to inform the "1-in-20" year forecast for the Boundary and Similkameen areas.

2.9.1 If so, please discuss how the system "1-in-20" year peak load forecast used to inform the "1-in-20" year forecast for the Boundary and Similkameen areas compares to that presented in FBC's 2021 Long-Term Electric Resource Plan.

Response:

The system "1-in-20" year peak load forecast was used to inform the "1-in-20" year forecast for the Boundary and Similkameen areas, as explained in the response to BCUC IR1 2.8.

The following table sets out the winter and summer peak forecast values through 2027 from both the system "1-in-20" year peak forecast from FBC's 2021 Long Term Electric Resource Plan (LTERP) and the updated forecast used to inform the "1-in-20" year forecast for the Boundary and Similkameen areas, as provided in the Application.

Both forecasts were created using the same method. The updated forecast peaks are higher as a result of the inclusion of recent extreme weather events such as the June 2021 "heat dome".

		2020	2021	2022	2023	2024	2025	2026	2027
2021 LTERP	Winter	818	833	838	838	849	859	871	883
	Summer	639	661	674	674	676	687	697	708
ASM CPCN	Winter			846	850	855	858	869	880
	Summer			780	786	789	794	797	808

2.10 Please explain whether the "1-in-20" year peak load forecast provided in the Application incorporates the peak demand observed during the June 2021 extreme heat event.

2.10.1 If not, please explain why not.

Response:

Yes, the "1-in-20" year peak load forecast provided in the Application incorporates the peak demand observed during the June 2021 extreme heat event.

2.11 Please confirm, or explain otherwise, that the historical actual peak load in Table 3-2 is the peak load of the Boundary and Similkameen areas and is not representative of the peak load for the ASM Terminal Station.

2.11.1 If confirmed, please provide historical actual summer and winter peak load for the ASM Terminal Station in a similar format as Table 3-2.

Response:

FBC confirms that the historical actual and forecast peak loads in Table 3-2 and Table 3-3, respectively, of the Application represent the peak loads for the entire Boundary and Similkameen area and are not representative of the peak load for the ASM Terminal Station only.

FBC provides the historical actual summer and winter peak load for the ASM Terminal Station in the updated tables below; however, FBC notes that the peak load flows through the ASM Terminal Station are not directly comparable to the peak loads for the Boundary and Similkameen area shown in Tables 3-2 and 3-3 in the Application. The peak loads shown in Tables 3-2 and 3-3 are representative of FBC customer loads (i.e., customer demand) in the area only, whereas peak loads at the ASM Terminal Station include load flows for other reasons besides customer loads and therefore, in some cases, peak loads as measured at the ASM Terminal Station (shown in the Updated Table 3-2 below) are higher than the peak loads shown in Table 3-2 of the Application.

Updated Table 3-2: ASM Terminal Station Historical Actual Peak Loads, 2017-2022

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

The load flow through the ASM transformers is determined by three main factors: (1) the Boundary and Similkameen load (i.e., customer demand); (2) generation dispatch (with generation from the Waneta hydroelectricity facility (WAN) having the greatest impact)[2]; and (3) system configuration.

The fluctuations shown in the actual winter peak load flow values in the Updated Table 3-2 above are mainly due to the fluctuations in WAN generation dispatch. The summer peak load flow is more consistent because typically WAN generating units are all online during this time. This generated power flows through the ASM Terminal Station (and through FBC's service territory) to serve the Boundary and Similkameen area loads and at some points to other parts of FBC's service territory to be used outside the Boundary and Similkameen area. Therefore, peak loads as measured at the ASM Terminal Station differ from the peak loads for the area presented in Tables 3-2 and 3-3 of the Application.

The forecast values shown in the Updated Table 3-3 below use a calculated average of historical contributions of the ASM Terminal Station and BEN Terminal Station to the Boundary and Similkameen load. This causes the forecast to be more consistent (i.e., less fluctuations) as compared to the historical values.

Updated Table 3-3: ASM Terminal Station Peak Load Forecast, 2023-2027

	2023	2024	2025	2026	2027
Summer (MW)	123	123	124	124	126
Winter (MW)	119	120	120	122	123

[2] The Waneta hydroelectric facility (WAN) is owned by BC Hydro. As WAN generation increases so does the flow along 34 Line and ASM T1 and T2. WAN generation is dispatched by BC Hydro based on provincial system requirements, therefore FBC does not have control over the WAN generation dispatch.

2.12 Please confirm, or explain otherwise, that the forecasted peak load in Table 3-3 is the peak load of the Boundary and Similkameen areas, and is not representative of the forecasted peak load for the ASM Terminal Station.

2.12.1 If confirmed, please provide the forecasted summer and winter peak load for the ASM Terminal Station in a similar format at Table 3-3.

Response:

Please refer to the response to BCUC IR1 2.11.

2.13 Please reproduce Table 3-3 to provide Boundary and Similkameen Areas' peak load forecast from 2023 to 2040.

2.13.1 Please provide a graphical representation of this data.

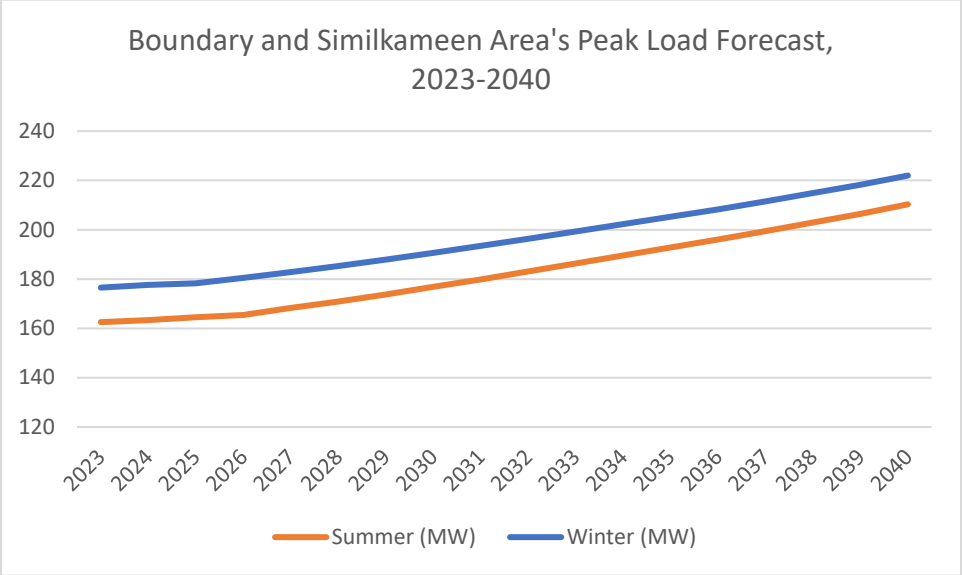
Response:

Please refer to the following Expanded Table 3-3 and Figure 1, which provide the Boundary and Similkameen areas' peak load forecast from 2023 to 2040.

Expanded Table 3-3: Boundary and Similkameen Areas' Peak Load Forecast, 2023-2040

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Summer (MW)	163	163	165	165	168	171	174	177	180
Winter (MW)	177	178	178	181	183	185	188	191	193
	2032	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Summer (MW)	183	186	190	193	196	199	203	206	210
Winter (MW)	196	199	202	205	208	211	215	218	222

Figure 1: Boundary and Similkameen Areas' Peak Load Forecast, 2023-2040



2.13.2 Please discuss any potential factors that may cause peak load to exceed the forecasted values. In the response, please discuss how, if at all, these factors may impact the need for the proposed Project.

Response:

The following factors may cause peak load to exceed the forecast values:

- Extreme weather conditions become more frequent and more volatile;
- Unanticipated new large industrial loads materialize in the area; and
- EV adoption occurs sooner than anticipated.

If the above factors increase the load in the Boundary and Similkameen areas higher than what is forecast, then the need for the Project becomes even greater.

In addition, this Project is required due to the condition of the existing transformers. An increase in peak load above forecast values will increase the ASM transformer loadings which will negatively affect the condition of the transformers.

2.13.3 Please discuss any potential factors that may cause peak load to be less than the forecasted values. In the response, please discuss how, if at all, these factors may impact the need for the proposed Project.

Response:

The following factors may cause peak load to be less than the forecast values:

- Extreme weather conditions become less frequent or less volatile;
- Existing large industrial loads in the area reduce (or shut down) operations; and
- EV adoption occurs later than anticipated.

However, even if the above-described factors materialized and resulted in a lower actual peak load than what is forecast for the Boundary and Similkameen areas, FBC would still need to proceed with the Project due to the overloading condition that occurs during a contingency event at the ASM Terminal Station. Additionally, and irrespective of the three factors listed above, the Project is required to address the condition of the existing transformers at the ASM Terminal Station which, based on the recently completed Condition Assessment Report, has classified the ASM transformers as being at a high risk of failure (i.e., Project Objective #2 described in Section 4.1 of the Application).

On page 12 of the Application, FBC states:

> Power generated in the Kootenay region flows into the 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 km away, where it is transformed from 63 kV to 161 kV by the ASM Terminal Station power transformers (ASM T1 and ASM T2).
>
> 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.

2.14 Please discuss, at a high level, FBC's long term plan with respect to the Kootenay, Boundary and Similkameen areas. Please discuss whether FBC has any material

changes planned to system's configuration in this area, and describe any other projects planned for this area over the next 10 years.

2.14.1 Please discuss how the Project aligns with FBC's long term plan for the area.

Response:

The ASM Terminal Station Project is the first of three projects that form FBC's long-term plan for the Kootenay, Boundary and Similkameen areas.

In the Kootenay region, FBC has planned upgrades to 20 Line to provide adequate capacity during normal and single contingency conditions. This upgrade project was identified in FBC's 2021 Long Term Electric Resource Plan (LTERP) as taking place in the 2028-2029 timeframe (Table 6-3, page 130).

For the Boundary and Similkameen areas, in addition to the ASM Terminal Station CPCN Project, FBC is planning to undertake a transmission project within the next 10 years which involves the addition of a second 230 kV line from Vaseux Lake to Bentley station and the addition of a second 168 MVA (230/63 kV) transformer at Bentley. The purpose of this project is to prevent voltage instability in the case of a 40 Line N-1 contingency by providing a secondary path from Vaseux Lake to Bentley. As currently configured, the Similkameen region will experience low voltage violations when the combined load of the Similkameen and Boundary regions reaches approximately 190 MW. FBC notes that this transmission project was not included in FBC's 2021 LTERP because at the time the LTERP was developed, FBC was able to offload to BC Hydro through 56 Line when necessary. This operational procedure is no longer available to FBC due to a BC Hydro large load customer that is limiting the amount of load FBC can transfer.

There are no other material changes identified in the Kootenay, Boundary and Similkameen areas at this time.

2.15 Please confirm, or otherwise explain, that the Boundary and Similkameen areas' total load is supplied via ASM and by the interconnection to British Columbia Hydro and Power Authority (BC Hydro) at Vaseux Lake Terminal Station.

Response:

Confirmed.

2.16 Please identify the factors that determine the proportion of the Boundary and Similkameen areas' load served by ASM.

2.16.1 Please explain, with rationale, whether the same proportion of Boundary and Similkameen areas' load will be served by WTS at completion of the Project or whether the proportion will change

2.16.1.1 If the proportions will change, please identify the changes expected and discuss how, if at all, other sources (such as the interconnection to BC Hydro at Vaseux Lake Terminal Station) will be impacted.

Response:

The proportion of load served by the ASM transformers depends on the following factors:

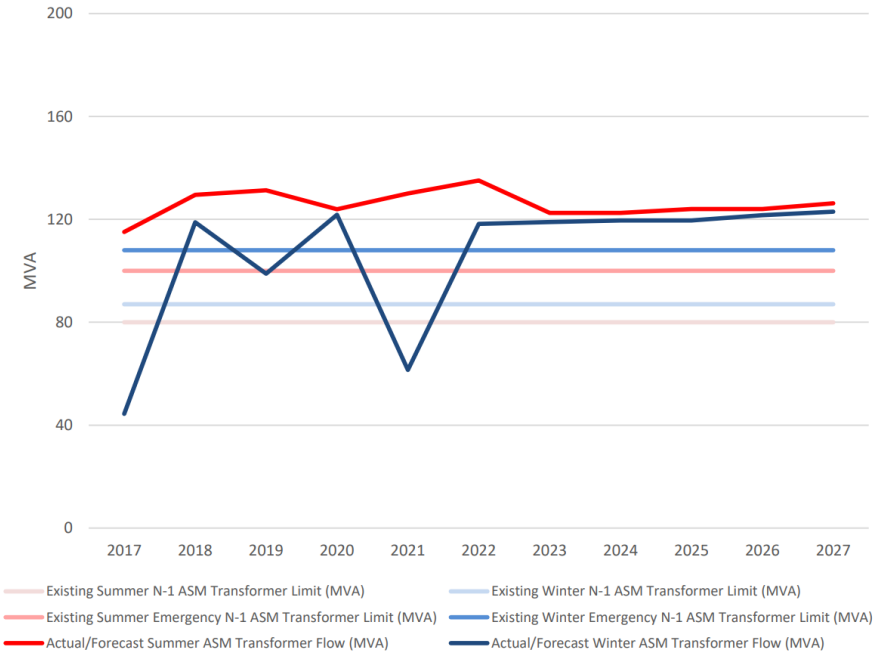
1. Boundary and Similkameen area load;
2. Provincial generation dispatch (with Waneta Hydro Station generation having the greatest impact); and
3. System configuration.

The proportion of load served in the Boundary and Similkameen areas will not change significantly with the new transformers installed at WTS. The ASM Terminal Station is approximately 1 km from WTS, and this short distance is not impactful enough to alter the percentage of load served in the Boundary and Similkameen areas.

On page 19 of the Application, FBC provides the following figure and 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.

Figure 3-7: ASM Terminal Station's Contribution to the Boundary and Similkameen Areas' Total Load Compared to the N-1 Transformer Limits[13]



Further on page 19 of the Application, FBC 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.

2.17 Please explain how the following values are determined, and discuss any factors that may cause each to change:

i. Existing summer N-1 ASM transformer limit;

ii. Existing winter N-1 ASM transformer limit;

iii. Existing summer emergency N-1 ASM transformer limit; and

iv. Existing winter emergency N-1 ASM transformer limit.

Response:

The ASM transformer limits are determined as follows:

i. Both the ASM T1 and ASM T2 summer normal limits are equal to 80 MVA. The limits are equal to 100 percent of the continuous MVA rating shown on the transformer manufacturer's nameplate.

ii. Both the ASM T1 and ASM T2 winter normal limits are equal to 88 MVA. The limits are equal to 110 percent of the continuous MVA rating shown on the transformer manufacturer's nameplate.

iii. Both the ASM T1 and ASM T2 summer emergency limits are equal to 100 MVA. The limits are equal to 125 percent of the continuous MVA rating shown on the transformer manufacturer's nameplate.

iv. Both the ASM T1 and ASM T2 winter emergency limits are equal to 108 MVA. The limits are equal to 135 percent of the continuous MVA rating shown on the transformer manufacturer's nameplate.

Operation above the normal limit but below the emergency limit is only allowed by FBC operating procedures for a maximum period of six hours. Operation above the emergency limit is not allowed by FBC operating procedures and must be corrected immediately.

The transformer ratings for FBC's transformers have been verified through engineering analysis and are consistent with and use the methodology described in the IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators (IEEE Standard C57.91-2011) and CSA Standard C88-2016 Power Transformers and Reactors.

The limits would only be changed due to an equipment change or modification. For example, loss of cooling could result in a temporary de-rating of a transformer. Replacement of a transformer or its interconnecting equipment could result in a permanent change in the rating of a transformer.

2.18 Generally speaking, please describe the ratings and limits associated with FBC's transformers (i.e. normal ratings, emergency limits). Please also describe which ratings and limits are impacted by seasonal temperatures.

Response:

FBC has a normal rating limit and an emergency rating limit for its transformers for summer and winter seasonal operating conditions. The seasonal operating limits are updated bi-annually, with summer limits normally starting in the month of May and winter limits normally starting in the month of November. Actual limit change dates are determined based on expected weather forecasts. Summer limits are static and are based on a 40 degree Celsius, 24-hour average ambient temperature. Winter limits are static and are based on a 0 degree Celsius, 24-hour average ambient temperature.

2.19 Please reconcile Tables 3-2 and 3-3 with Figure 3-7 and FBC's statement that "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."

Response:

Tables 3-2 and 3-3 show the historical and forecast values of the Boundary and Similkameen area loads. The Boundary and Similkameen area loads are only one factor that determines the loadings of the ASM transformers. The other factors that affect the ASM transformer loadings are the provincial generation dispatch (with Waneta Hydro Station generation having the greatest impact) and the system configuration at that time.

The historical values shown in Figure 3-7 are the actual ASM transformer loading values for years 2017-2022.

To calculate the actual historical values in Table 3-2, historical data was used for 34 Line, 40 Line and 42 Line. These three lines feed the Boundary and Similkameen area loads. From this data, a percentage was calculated identifying how much of the Boundary and Similkameen area load was served from the ASM transformers (34 Line). The table below shows the historical percentages that were calculated.

	2017	2018	2019	2020	2021	2022
% of BND & Similkameen region load served from ASM in Summer	78%	74%	71%	75%	83%	70%
% of BND & Similkameen region load served from ASM in Winter	43%	76%	82%	83%	52%	-

Based on the values provided in the above table, FBC calculated the average percentage of load that the ASM transformers supply to the Boundary and Similkameen areas in the summer (i.e., the sum of the annual summer percentages divided by six) and in the winter (i.e., the sum of the annual winter percentages divided by five).

These average percentages were then multiplied by the forecast values in Table 3-3 to produce the forecast values in Figure 3-7.

2.20 Please describe the new load and generation conditions that have caused FBC to exceed N-1 system planning as mentioned in the preamble.

Response:

New industrial load in the Boundary region and having maximum Waneta generation online during the summer to meet summer peak requirements have caused FBC to exceed N-1 system planning criteria.

2.21 Please describe the operational changes mentioned in the preamble that allowed FBC to manage the new load and generation conditions and identify how long these changes have been implemented.

2.21.1 Please explain why these changes are not sustainable long-term.

Response:

The flow through the ASM transformers can be reduced by opening the 11 Line path as dictated by the peak duration requirements. Alternatively, FBC could shed load in the Boundary and/or Similkameen areas. The amount of load shedding required would be determined by the percentage of post contingency ASM transformer overloading. These operational solutions would only be resorted to in a contingency condition where the remaining ASM transformer is overloaded.

Since 2019, FBC has put these operational procedures in place to be implemented when necessary. However, these post contingency operational changes are in violation of FBC's Transmission Planning Criteria and therefore are not sustainable in the long-term.

The operational change of opening 11 Line causes the Boundary region to be fed radially (only from one source) from the Kootenays. This operational change will reduce the reliability of supply to the Boundary region, and a contingency event while in this configuration would cause a blackout in the Boundary region, leaving approximately 4,090 customers without power.

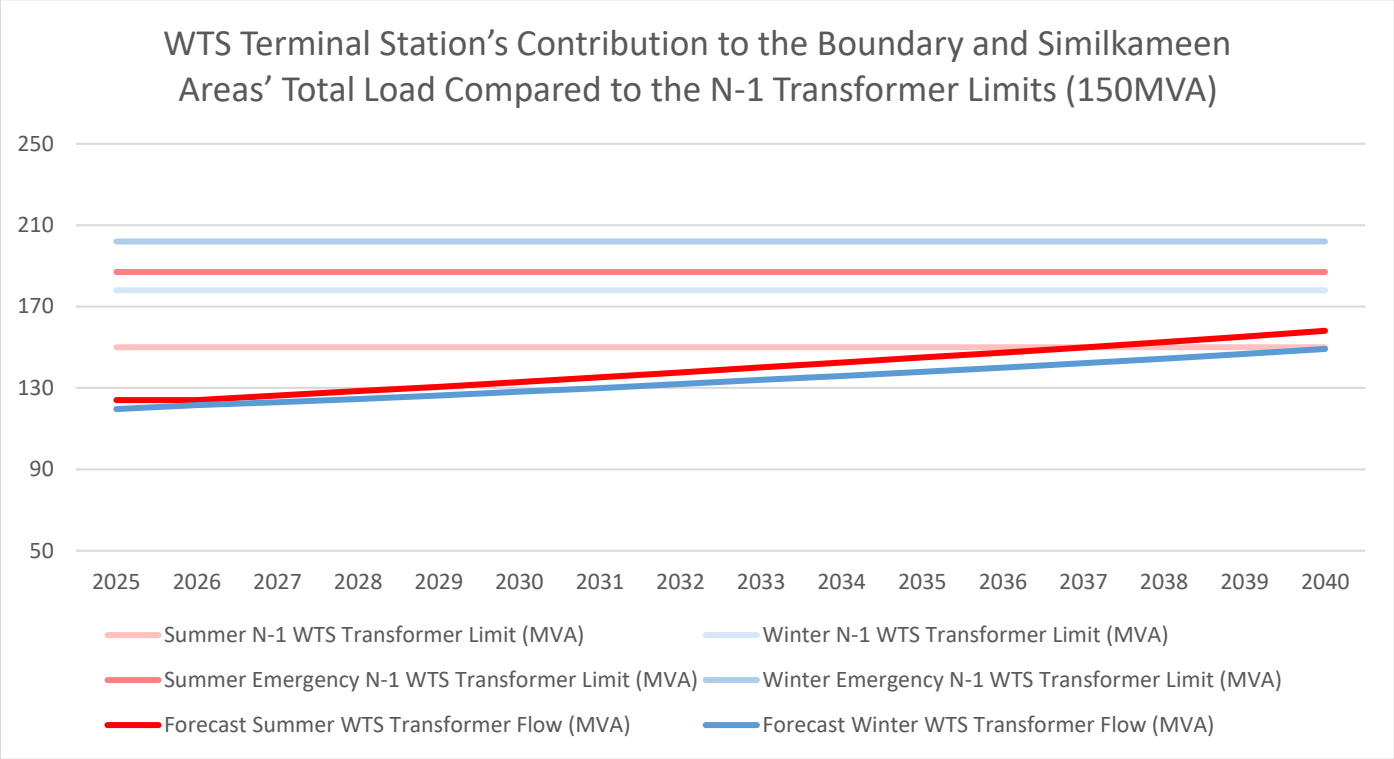
2.22 Please produce a graph similar to Figure 3-7 that displays the following information from Project completion to 2040 for WTS:

i. Forecasted load at WTS;

ii. Summer and Winter N-1 limits and N-1 emergency limits.

Response:

Please refer to the following figure.



2.22.1 Please explain how each of the N-1 limits are determined and discuss any factors that may cause each to change.

Response:

The ratings of distribution and transmission transformers for both normal and emergency conditions at FBC are determined based on the maximum continuous MVA ratings provided on the manufacturer's nameplate. These normal and emergency ratings are defined as follows:

- Summer Normal Rating = 100 percent of the continuous rating shown on the manufacturer's nameplate.
- Summer Emergency Rating = 125 percent of the continuous rating shown on the manufacturer's nameplate.
- Winter Normal Rating = 100 percent of the 0 degrees Celsius continuous rating shown on the manufacturer's nameplate. (If the 0 degrees Celsius rating is not on the nameplate, then 110 percent of the continuous rating shown on the manufacturer's nameplate is used for the normal winter rating.)
- Winter Emergency Rating = 135 percent of the Summer Normal Rating.

These ratings have been verified by FBC engineering analysis and are consistent with and use the methodology described in the IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators (IEEE Standard C57.91-2011) and CSA Standard C88-2016 Power Transformers and Reactors. If the nameplate is not available, the ratings from the bill of materials, manufacturer reference documentation, or other reference drawings can be used to confirm the equipment ratings.

These limits would only be changed due to an equipment change or modification. For example, loss of cooling could result in a temporary de-rating of a transformer. Replacement of a transformer or its interconnecting equipment could result in a permanent change in the rating of a transformer.

2.22.2 Please explain whether the capacity of the proposed new transformers at WTS becomes the limiting factor for the overall capacity of WTS.

2.22.2.1 If not, please identify the component(s) that limit the overall capacity of WTS and explain what the capacity of WTS will be upon completion of the Project and how the station capacity is determined.

Response:

The new transformers at WTS will not become the limiting factor for the overall WTS capacity. WTS is a flow through transmission facility that does not have a single rating or capacity. Each transmission line and transformer connected to WTS will have a facility rating which will be equal to the most limiting rating of any current carrying conductor or equipment that comprises that transmission line or transformer facility.

The N-1 ratings for the new transformers at WTS are as follows, with the 11E Line ratings provided for reference:

- Summer Normal Rating = 150 MVA (11E Line rating = 167 MVA)
- Summer Emergency Rating = 187.5 MVA (11E Line rating = 188 MVA)
- Winter Normal Rating = 165 MVA minimum (11E Line rating = 234 MVA)
- Winter Emergency Rating = 202.5 MVA (11E Line rating = 249 MVA)

3.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.3.1.2.2, pp. 20-21, Section 3.3.2, pp. 21-22, Appendix B, pp. 12, 14-16

Transformer Condition Assessment

On pages 20 and 21 of the Application, FBC states:

> The loading of substation transformers above the normal nameplate rating has a significant impact on their remaining expected lifespan. […]
>
> Prolonged loading in the emergency range increases the winding hot spot temperature and decreases the expected remaining life of the transformer […] If a transformer is lightly loaded throughout its in-service life, the winding insulation can be expected to last longer; conversely, insulation life can be expected to be less than a year if the transformer is overloaded on a consistent basis. Each hour that a transformer is loaded above its nameplate rating brings a corresponding increase in the winding hotspot temperature and has a substantial negative impact on the transformer's remaining expected lifespan.
>
> Given that the existing transformers at the ASM Terminal Station are extremely important system assets with replacement lead times in excess of a year, FBC submits that planned loading above their nameplate rating is not an acceptable practice.

3.1 Please explain the conditions that would lead FBC to operate ASM T1 and/or ASM T2 in the emergency range.

Response:

FBC only allows operation of transformers in their emergency ranges if unplanned system conditions occur. Unplanned system conditions can include extreme weather, unexpected line outages, and/or unexpected equipment outages. Operation in the emergency range is only allowed for a maximum period of six hours. If a transformer has been operated in the emergency range for a period of time, the transformer must be operated below the emergency range for the same amount of time before the six-hour emergency range operation timeline can be used again. The maximum emergency range loading period has been limited to six hours in order to not significantly reduce the expected remaining life of FBC's transformers.

3.2 Please describe how FBC monitors and tracks the loading of substation transformers in the emergency range.

3.2.1 Please explain how this data is used in evaluating the remaining life of a substation transformer and how often these evaluations take place.

Response:

Currently, FBC monitors and tracks loadings using power quality meters and its historian system.

FBC's power transformer loss of life calculations are performed based on the loading record in historian, recorded ambient temperature, and dissolve gas analysis results using FBC's interpretation of the IEEE C57.91-2015 method. Hitachi, the consultant who performed the ASM T1 and ASM T2 evaluation, applied the same methodology from IEEE C57.91-2015 when performing their condition assessment of the ASM T1 and ASM T2 transformers.

Due to current data processing capabilities, FBC performs loss of life calculations only for:

- Units which currently reach loading levels at and above their 100 percent normal rating; and
- Evaluating the impact of overloading on critical units due to P1 and P2 contingencies as defined by NERC.

On pages 14 to 16 of Appendix B to the Application, Hitachi states:

- The T1 unit has been loaded 36.2 MVA on average over the years 1999 to 2013 and overloaded at 87.5 MVA on average for 29.5 hours.

[…]

- The T1 unit has been loaded 28.4 MVA on average over the years of 2020 and 2021, and as such has little loss of insulation life.

[…]

- The calculation of insulation life for T1 is based on the similar MVA load during the years of 1965 to 1998 to the years of 1999 to 2013, and the similar MVA load during the years of 2014 to 2019 to the years of 2020 and 2021.

Additionally, on pages 14 to 16 of Appendix B to the Application, Hitachi states:

- The T2 unit has been loaded 36.0 MVA on average over the years 1999 to 2013 and overloaded at 86.9 MVA on average for 28.3 hours

[…]

- The T2 unit has been loaded 28.6 MVA on average over the years of 2020 and 2021, and as such has little loss of insulation life.

[…]

- The calculation of loss of insulation life for T2 is based on the similar MVA load during the years of 1971 to 1998 to the years of 1999 to 2013, and the similar MVA load during the years of 2014 to 2019 to the years of 2020 and 2021.

3.3 Please confirm, or explain otherwise, that the data used to calculate insulation loss of life for both ASM T1 and ASM T2 was limited to the periods of 1999 to 2013 and 2020 to 2021.

3.3.1 If confirmed, please discuss FBC's rationale for taking this approach

3.3.2 If confirmed, please explain whether data exists for the periods of 1965 to 1998, and 2014 to 2019, and if so, discuss the expected impact on insulation loss of life should it be included in the calculations.

3.3.2.1 If this data does not exist, please explain why not

Response:

Not confirmed. For calculating insulation loss of life, Hitachi assessed ASM T1 and ASM T2 based on loading data from 1999 to 2021 and the load forecast from 2022 to 2031. Hitachi was provided the following:

- Historian metering data showing actual system loading from 2014-2021;
- Metering data from the metering software archives for the period of 2005-2014; and
- Average and peak loading data extrapolated from the monthly energy supply and peak load reports for 1999-2014.

Loading data prior to 1999 was not available, as data was not collected or archived due to technology limitations. Therefore, assumptions were made regarding system average and peak loads for the years prior to 1999.

On page 21 of the Application, FBC states:

> ASM T1 and ASM T2 are 57 and 51 years old, respectively. The condition of both transformers continues to deteriorate with age, with their risk of failure increasing with each passing year.
>
> FBC commissioned Hitachi Energy, a third-party consultant and global leader in power transformers to perform a comprehensive condition assessment for ASM T1 and T2 in 2022 (Condition Assessment Report) [...] The Condition Assessment

Report includes an analysis of the Total Risk of Failure of ASM T1 and ASM T2, which is defined to include the potential failure of the transformer main core/coil assembly, as well as any other condition that would require the transformer to be removed from service for a significant period. 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.

On page 12 of Appendix B to the Application, Hitachi Energy provides the following table showing total risk of failure of ASM T1 and ASM T2:

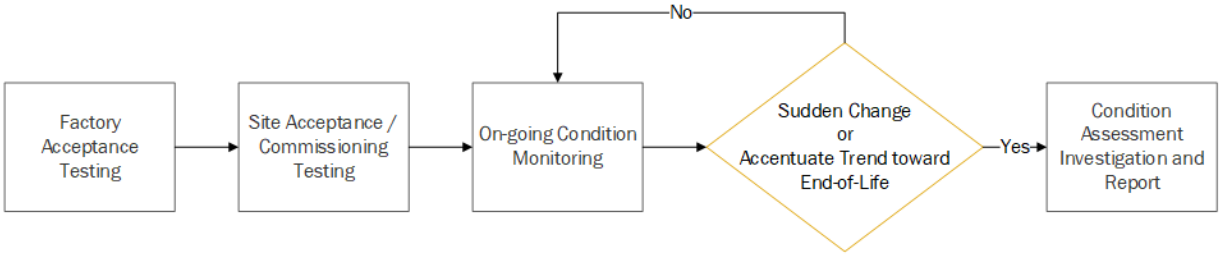
ID No.	Position	Total Risk of Failure	Relative Importance	Location	Serial Number	Manufacturer	YoM
1	T1	2.41	100	ASM	285738	CGE	1965
2	T2	2.35	100	ASM	287735	CGE	1971

Table 2 – Transformers Color Coded by Risk

3.4 Please provide a description of FBC's approach for evaluating the condition of transformers over their entire expected lifespan. In the response, please describe the frequency of evaluation, and the testing, analysis and reporting that occurs at each evaluation.

Response:

FBC's approach to evaluating the condition of transformers over their life span is an on-going process intended to provide the necessary data to monitor and assess transformer health. The resulting test data and condition trends are used in transformer condition assessments. FBC's condition assessment approach is illustrated in the following figure and further explained below.



Transformer condition monitoring includes:

- Inspections – Periodicity: 3 months
- Oil Dissolved Gas Analyses (DGA) including moisture monitoring.

- Main Tank Testing – Periodicity: 1 year
- Onload Tap Changers (LTC) with in-oil interruption – Periodicity: 2 years
- LTCs with in-vacuum interruption – Periodicity: 2 years

- Oil Quality Testing (Main Tank & LTC) – Periodicity: 2 years
- Furan and Oxidization inhibitor, Main Tank only – Periodicity: 6 years
- Comprehensive electrical and mechanical diagnostics– Periodicity: 6 years

If equipment condition is unstable, the test periodicity is reduced accordingly.

Transformers that undergo condition assessment investigation and report include:

- Loss of life calculation due to paper/solid insulation aging, based on loading (historical and future)
- Insulating oil aging
- Bushing's condition
- Core and winding condition
- LTC condition

3.4.1 Please discuss FBC's rationale for taking this approach and briefly describe how, if at all, the approach has evolved over time.

Response:

FBC's transformer maintenance approach (as described in the response to BCUC IR1 3.4) was established based on FBC's operating particularities and benchmarking surveys conducted by the Centre for Energy Advancement through Technological Innovation (CEATI). FBC continuously evaluates its transformer maintenance approach. Transformer testing and periodicities are continuously adjusted based on industry advancements and changes in data interpretation.

Evaluation of the insulating paper, the remaining degree of polymerization, or the transformer aging process is performed using FBC's proprietary software developed by the University of British Columbia, as per IEEE C57.91-2015 "Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators".

Hitachi utilized their own approach, which applies the same methodology from IEEE C57.91-2015, when performing their condition assessment of the ASM T1 and ASM T2 transformers.

3.4.2 Please explain whether Total Risk of Failure is calculated for each evaluation.

3.4.2.1 If not, please explain why not.

Response:

In the Condition Assessment Report (Appendix B), Hitachi's subject matter experts calculated the Total Risk of Failure for each transformer.

FBC used risk of failure data from CIGRE WG 12-05 "An international survey on failures in large power transformers" in its internal reviews. FBC considers this internal approach to be appropriate due to its relatively small transformer population and in consideration of the volume of work that would be required to fully assess each piece of equipment after each maintenance cycle, independent of the actual equipment condition.

3.5 Please explain FBC's rationale for adopting an accepted tolerance of 2 percent for Total Risk of Failure.

3.5.1 Please identify when this was adopted by FBC and describe the accepted tolerance prior to the adoption of 2 percent

3.5.2 Please describe any conditions that would cause FBC to operate transformers at a Total Risk of Failure greater than 2 percent for an extended period of time.

Response:

The CEATI 30/113 - 2018[3] report completed by Doble Engineering, *Translating the Health Index Into Probability of Failure*, specifies the following:

> Even if it were possible to calculate a [Probability of Failure (PoF)] accurately, an acceptable PoF would need to be determined for each individual asset. A PoF of 2% may be acceptable for a transformer located in a substation with no immediate neighbors and supplying non-critical load but would probably not be acceptable for

[3] CEATI adopted a new numbering system in 2023. All previously published project reports were renumbered.

a transformer located in a densely populated area supplying the central business district of a major city. Other factors to consider would be the location within the system, the redundancy in the system, the availability of a spare transformer or spare components, etc.

FBC adopted the recommendations of the CEATI report upon its publication in 2018. Prior to the CEATI report being published, there was no guidance regarding the acceptable Total Risk of Failure (TRoF)[4] for a utility.

The ASM transformers are critical to FBC's network operation and, due to their condition, overloading will potentially lead to unforeseen failures. Therefore, FBC has concluded that a PoF higher than 2 percent for the ASM transformers is not acceptable.

FBC may decide to continue to operate a power transformer, even if the TRoF exceeds the 2 percent threshold, in the following scenarios:

- Additional network redundancy, or offloading capabilities, was available;
- Equipment refurbishment to reduce the TRoF to more acceptable levels was available and scheduled;
- Spare transformers of adequate size were available;
- A station upgrade project with a defined execution timeline was in place; or
- There were no other reasonable alternatives.

3.6 Please discuss, at a high level, how the rate of deterioration and the total risk of failure has changed over the entire lifetime of both ASM T1 and ASM T2.

Response:

FBC does not have sufficient data within its maintenance records prior to 2013 and is therefore unable to provide the rate of deterioration and changes to the TRoF over the entire lifetime of both ASM T1 and ASM T2. However, based on industry statistics, network power transformers have a relatively stable and low probability of failure for approximately the first 35 years of operation, if designed and manufactured properly[5]. After 35 years, the rate of deterioration and probability of failure increase exponentially with each passing year.

The Hitachi report states that transformers "which are older than 50-years statistically have a higher expected general failure rate"[6]. ASM T1 and T2 are both older than 50 and their age,

[4] FBC notes that the Hitachi report refers to "Total Risk of Failure" whereas the CEATI report refers to "Probability of Failure". FBC considers these terms to be interchangeable.
[5] ABB - Hitachi *Fit at 50* white papers.
[6] Appendix B, page 20.

coupled with the factors and issues described in the response to BCUC IR1 3.6.1, indicate that the deterioration of the transformers is consistent with the industry statistic trends noted above. Currently, the three key aspects of operation contributing to a TRoF greater than 2 percent for ASM T1 and ASM T2 are risk of short-circuit failure, risk of paper/solid insulation failure, and the risk of accessories failure.

3.6.1 Please provide any additional evidence to support the statement "the condition of both transformers continues to deteriorate with age, with their risk of failure increasing with each passing year."

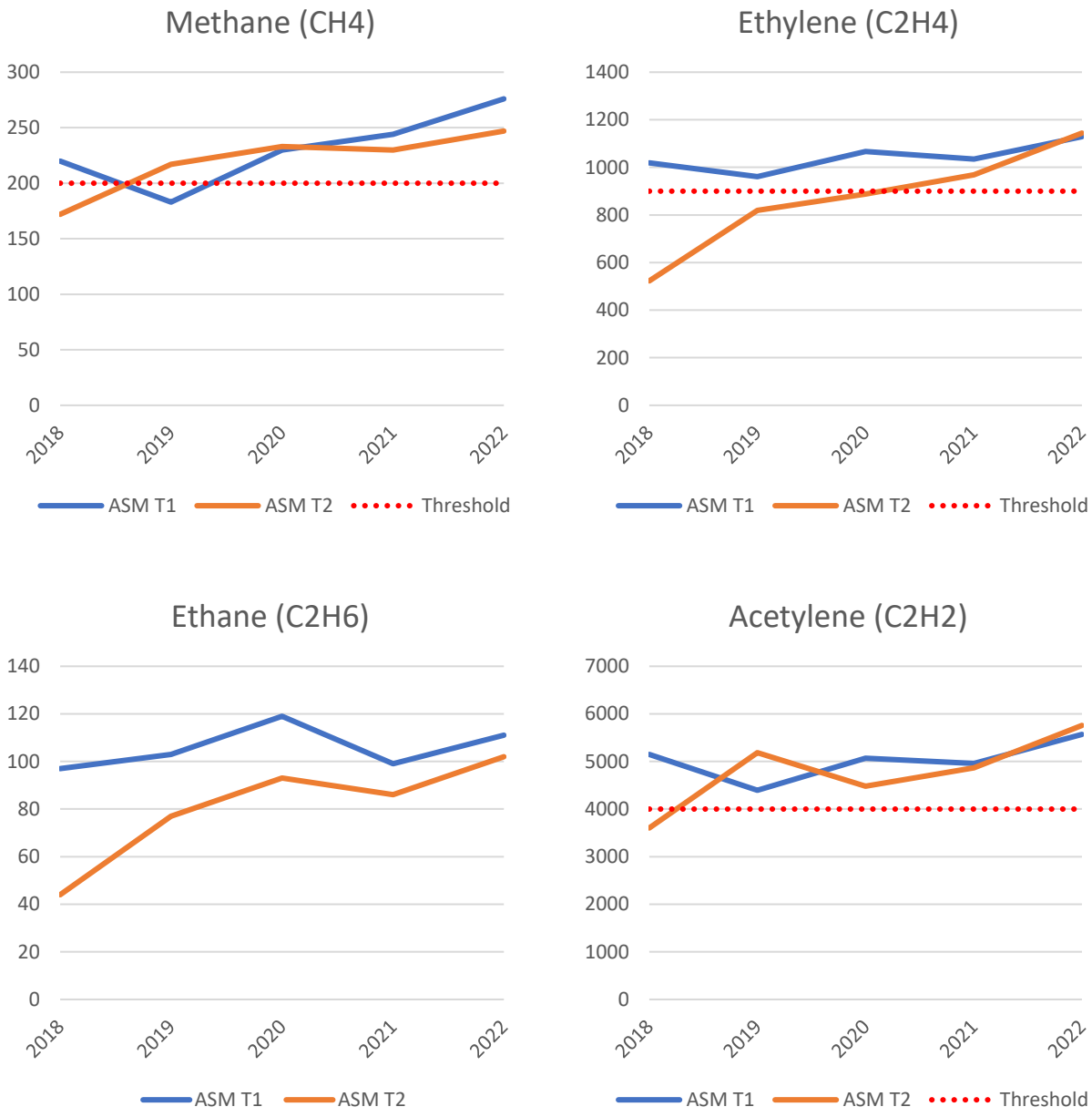
Response:

FBC considers the evidence provided in the Condition Assessment Report (Appendix B to the Application) and described in Section 3.3 of the Application to fully support the need for the Project to address the risk of failure posed by the deteriorating condition of the ASM transformers. In particular, FBC highlights the following:

1. The Condition Assessment Report indicates that insulation loss of life is a cumulative process, related to loading and operation. Based on historical and forecasted loading, the annual insulation deterioration trends anywhere between 0.1 and 0.8 percent. System conditions which result in overloading of either of the two ASM units will dramatically decrease life expectancy.

2. As noted on page 22 of the Application, ASM T1 and T2 were manufactured with a CGE LR83 type On-Load Tap Changer (LTC). For this type of LTC, normal contact life expectancy is 80,000 operations. Currently, the ASM T1 and T2 LTCs have exceeded 80,000. While beyond normal life expectancy, both LTCs still operate at least twice daily. The LTCs' Dissolved Gas Analysis (DGA) collected through oil sampling is displayed in the below figures from 2018 to 2022. Although the LTCs have undergone oil replacement, dissolved gas thresholds have exceeded the industry best practice thresholds for this type of tap changer. It also portrays violent arcing during voltage adjustment and a fast decrease, year over year, in the LTCs' condition.

3. The ASM T1 and ASM T2 main tank oil was replaced between 2013 and 2014. DGA performed through oil sampling shows the main tank dissolved gases have increased each year. Although the oil is less than 10 years old, dissolve gas levels have reached similar levels to before the replacement in both transformers. Dissolved gases in the insulating oil indicate that the transformers' internal solid insulation is deteriorating.



3.7 For each of ASM T1 and ASM T2, please identify how long the transformer has been above a 2 percent total risk of failure.

Response:

FBC estimates that the Total Risk of Failure has been above 2 percent since approximately 2018-2019.

As explained in the response to BCUC IR1 3.5, prior to the CEATI report being published in 2018, there was no industry guidance regarding the acceptable Total Risk of Failure. Based on the findings of the CEATI report and FBC's internal assessment of the ASM transformers, FBC determined that the failure risk of the transformers was likely above the acceptable range. Thus, FBC identified that these transformers would require replacement in the 2020-2024 MRP application, as noted in the response to CEC IR1 1.1, and retained a qualified third-party consultant (Hitachi) to perform a comprehensive condition assessment for the ASM transformers to further validate FBC's findings.

Further on pages 21 and 22 of the Application, FBC states:

> Table 3 of the Condition Assessment Report provides the reasons for the risk of failure for each of the ASM transformers. For each transformer, this includes the fact that the operation count for the load tap changer (LTC) contacts has exceeded the maximum recommended by the manufacturer. The LTC is the second most failed component for this type of transformer, and the early observation is that the failure rate per in-service transformer is higher for older units (i.e., those greater than 50 years old, like ASM T1 and ASM T2), than for the general population of power transformers.
>
> ASM T1 and ASM T2 were manufactured with a CGE LR83 type LTC. This model of LTC is known for high amounts of arcing that occurs with each operation, which has the effect of degrading the insulating oil and the LTC contacts. While the original equipment manufacturer (OEM) recommended replacement of LTC contacts every 80,000 operations, this type of tap changer has not been supported by the original manufacturer since 2004. The ASM T1 and ASM T2 LTCs have been inspected and assessed multiple times to monitor their changes in condition. Currently, the ASM T1 LTC has recorded 98,000 operations, while the ASM T2 LTC has reached 394,000 operations. Both ASM T1 and ASM T2 LTCs require a more detailed assessment in 2023 to determine possible actions to mitigate their risk of failure until a long-term solution (i.e., the proposed Project) is implemented.

3.8 Please explain how, and at what frequency, FBC tracks the condition of the insulating oil and the condition of the LTC contacts.

Response:

FBC tracks the LTC insulating oil and contact condition as follows:

- Inspections are performed every three months.
- Oil Dissolved Gas Analysis Sampling & Testing is performed annually.
- Oil Quality Sampling & Testing is performed every two years.

Comprehensive electrical and mechanical diagnostics testing on the LTCs are performed every six years.

Please also refer to the response to BCUC IR1 3.4.

3.8.1 Please identify when (i.e.: in what year) each of the ASM T1 LTC and ASM T2 LTC reached 80,000 operations.

Response:

Based on FBC's maintenance records, both ASM transformers have been above the 80,000 operations threshold since before 2013, but FBC is unable to determine a specific year or timing that the threshold was crossed.

3.8.1.1 If 80,000 operations were reached for the ASM T1 LTC and/or ASM T2 LTC prior to 2004, please explain why they were not previously replaced.

Response:

As noted in the preamble, the original manufacturer of the LTC equipment has not been in business since 2004; such that repairing and refurbishing the ASM T1 and T2 LTCs was not an option. Despite the inability to repair and refurbish the LTCs, FBC was able to continue to operate the ASM transformers because of regular maintenance, in -time oil processing, oil replacement, and use of spare parts procured before the original manufacturer went out of business. However, as the overall condition of the ASM transformers (including the LTCs) continued to deteriorate over time, and with the additional guidance on the acceptable Total Risk of Failure provided by the 2018 CEATI report, the need to replace the ASM transformers has now become critical.

3.9 Please explain the reasons for the differences in LTC operations between ASM T1 and T2.

3.9.1 Please identify any risks that may exist as a result of T2 reaching more operations as compared to T1.

Response:

Since the filing of this Application, FBC has identified an error in the number of operations stated for the ASM T1 LTC.

Based on the site inspection performed in May 2023, the ASM T2 LTC has 394,575 operations and the ASM T1 LTC has 98,183. However, the ASM T1 LTC has an operation counter with only 5 digits, while the ASM T2 LTC has a 6-digit counter. These transformers perform in parallel (one transformer follows the other) and therefore the LTC operation counts should be similar. FBC expects that the ASM T1 LTC counter would have rolled over four times, meaning that the 98,183 on the counter likely reflects 398,183 operations.

FBC's expectation that the number of LTC operations between ASM T1 and T2 are similar is further validated by the results of the dissolved age analysis (DGA) which indicates that the ASM T1 and ASM T2 tap changes are in similar condition.

3.10 Please describe the "more detailed assessment" that is required for the ASM T1 LTC and ASM T2 LTC.

3.10.1 If the assessment is complete, please explain when it occurred and discuss the results and resulting actions FBC will take to mitigate the risk of failure, if any.

3.10.2 If the assessment is not complete, please identify when it will occur and discuss any potential actions FBC could take to mitigate the risk of failure.

Response:

The more detailed assessment of the ASM T1 LTC and ASM T2 LTC will consist of:

- Inspection – Visual assessment and examination of the internal components (i.e., the arcing tips on the stationary contacts, erosion on the main moving contacts, and wear of the drive mechanism);

- Controls and Functionality – Manual, local, and remote electrical operation of the LTC;
- Components Cleaning;
- Insulating Oil Replacement; and
- Contact Pressure Adjustment (if required).

The assessment will indicate if there are any available corrective actions and the remaining time until the LTC condition will become a threat to operations.

The field work associated with the assessment was completed June 2, 2023. FBC continues to operate the on-load tap changers as-is until the assessment report is available and possible actions are provided for mitigating the risk of failure until a long-term solution (i.e., transformer replacement) can be implemented.

C. EVALUATION OF ALTERNATIVES

4.0 Reference: EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 1.1.4, p. 3; Section 4.3, pp. 23-24; Section 4.3.4, p. 39; Section 10, p. 74

Cost Estimates for other Project Alternatives

On pages 23 and 24 of the Application, FBC lists the following six alternatives considered for the Project:

- Alternative 1: Status Quo
- Alternative 2: Like-for-like Replacement of the ASM Terminal Station Transformers (ASM T1 and ASM T2)
- Alternative 3: Rebuild the ASM Terminal Station and Expand the Existing Site Footprint
- Alternative 4: Build a New Terminal Station at a Greenfield Site and Demolish the ASM Terminal Station
- Alternative 5: Expand the WTS Site and Demolish the ASM Terminal Station
- Alternative 6: Retain the Existing ASM Terminal Station and Add a New Transformer at WTS

On page 39 of the Application, regarding the assessment of Alternatives 3 and 5, FBC states: "The financial evaluation considered the levelized rate impact resulting from each alternative over the 53-year analysis period."

On page 3 of the Application, FBC identifies Alternative 5 as the preferred Project Alternative.

On page 74 of the Application, FBC states that it has "experienced high levels of customer load growth in the Boundary and Similkameen areas (which are served by the ASM Terminal Station)."

4.1 Please discuss whether FBC prepared cost estimates for Project Alternatives 4 and 6.

4.1.1 If yes, please provide the capital costs and identify the level of project definition with reference to the AACE International cost estimate classification system.

Response:

FBC determined that Alternatives 4 and 6 were not feasible during the early screening stage for the Project and therefore did not prepare cost estimates.

While Alternative 4 could meet the Project objectives, FBC determined that procuring a greenfield location was not feasible. As explained in the Application (Section 4.2.4), FBC investigated multiple potential greenfield sites during the early screening stage, but ultimately determined that it would not be reasonable or practical to attempt to pursue this option further (including developing a Class 4 level cost estimate) due to the logistical complexities and cost implications of attempting to procure new land, particularly when FBC can utilize two existing land parcels for this Project (i.e., the ASM Terminal Station land and the WTS land).

Alternative 6 did not meet the Project objective of replacing aging infrastructure and was determined not feasible because of the complexities associated with a transmission corridor between WTS and the ASM Terminal Station. Please refer to the response to ICG IR1 5.3 for further explanation of the issues associated with Alternative 6.

In accordance with Section 2 of the BCUC's CPCN Guidelines, FBC conducted cost estimates on the feasible alternatives (Alternatives 3 and 5) only.

5.0 Reference: EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.1, p. 23; Section 4.2.3 pp. 24, 26; Section 4.3.1, p. 30

Alternative 3 – Description and Scope

On page 23 of the Application, FBC identifies the following Project objectives:

1. Increase the 161 kV capacity to the Boundary and Similkameen areas to maintain safe and reliable service to customers in these areas.
2. Address aging infrastructure which, based on the recently completed Condition Assessment Report, classifies the transformers as being at a high risk of failure.

On page 26 of the Application, FBC states:

> 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.
>
> This alternative would meet both Project objectives and is technically feasible. Accordingly, FBC evaluated this alternative further based on non-financial and financial criteria…

5.1 Please explain, with rationale, the necessity of the transmission work described in the preamble above for alternative 3 with reference to the Project objectives.

Response:

Reconfiguration of 9 and 10 Line into one high-capacity line is required to meet the N-1 reliability criteria during the event of a 34 Line outage. Rebuilding 9 and 10 Line into one high-capacity transmission line is required to match 34 Line capacity. With this complete, there would be two separate lines from WTS to the ASM Terminal Station, providing a redundant path.

On page 24 of the Application, FBC states:

> Under Alternative 3, FBC would undertake a full rebuild of the ASM Terminal Station in order to increase the station capacity…The ASM Terminal Station would be converted from a 63 kV bus with two transformers to a six node 63 kV ring bus, with four transmission nodes and two transformer nodes.

5.2 Please discuss FBC's rationale for converting the bus at the ASM Terminal Station to a ring bus configuration in Alternative 3.

Response:

The rationale for converting the ASM Terminal Station 63 kV bus to a ring bus is to provide a reliable and operationally flexible system configuration that would utilize the existing 9 Line and 10 Line infrastructure between ASM and WTS to provide a secondary high capacity supply from WTS to ASM and continue to serve the Cascade (CSC) substation with this same infrastructure.

5.3 Please explain whether FBC considered maintaining the existing bus configuration under Alternative 3.

5.3.1 If not, please explain why not.

Response:

FBC considered maintaining the same bus configuration but ultimately rejected this approach because maintaining the existing 63 kV one-node bus configuration would result in the ASM Terminal Station continuing to only have one source (34 Line) from WTS, which would not improve the reliability compared to the proposed ring bus.

On page 30 of the Application, FBC states:

> …FBC determined that Alternatives 3 and 5 met the Project objectives and should be evaluated further, as they address the risk of transformer failure, increase the 161 kV capacity to the Boundary and Similkameen areas, fulfill FBC's Transmission Planning Criteria, and maintain reliable service.
>
> In each of Alternative 3 and Alternative 5, the transformers to be installed (at the ASM Terminal Station and WTS, respectively) are 53/161 kV transformers with a rating of ONAN/ONAF 90/120/150 MVA, which is the current industry standard size for transformers in applications of this type.

5.4 Please explain how FBC determined the capacity of the transformers considered for the feasible alternatives.

Response:

FBC performed power flow simulations that incorporated the Boundary and Similkameen load forecast and the Waneta generation dispatch. From these results, industry standard transformer sizes were selected for the feasible alternatives.

5.5 Please explain whether transformers of different capacity were considered.

5.5.1 If yes, please provide a description of the analysis that took place to select the preferred capacity.

5.5.2 If no, please explain why not.

Response:

Yes, four different sizes of transformers were considered: 80 MVA, 120 MVA, 150 MVA, and 200 MVA.

The ASM transformer forecast (please refer to the response to BCUC IR1 2.22 for the graphical forecast) was reviewed and it was determined that both the 80 MVA and 120 MVA transformer sizes would not provide enough room for growth over the planning horizon. The 80 MVA transformer is already overloaded and the 120 MVA transformer would be overloaded within less than 10 years after installation.

11E line has a very similar summer emergency rating to the 150 MVA transformer and therefore any transformer size higher than 150 MVA would be too large, as the limiting factor in the area becomes 11E line. For this reason, the 200 MVA sized transformers were rejected.

The 150 MVA transformer was therefore chosen as it will give sufficient room for growth in the area over the planning horizon, without being too large.

6.0 Reference: EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.2.6, pp. 29-30; Section 4.3.3, p. 38, Table 4-3

Feasibility of Alternative 6

On pages 29 and 30 of the Application, FBC states regarding Alternative 6:

> While this option would provide increases in capacity and some redundancy to the system, FBC determined that this option is not feasible as it is not practical or cost-effective due to construction, operability/maintainability and safety limitations and constraints […]
>
> Several limitations and constraints were found with this alternative, including issues with the existing corridor between WTS and the ASM Terminal Station (circuit spacing, infrastructure congestion, topography, and access limitations), protection and control requirements, and an increase to system fault levels. For example, the transmission corridor between the ASM Terminal Station and WTS is not wide enough to comply with 161 kV circuit spacing while also continuing to be occupied by multiple 63 kV transmission lines. […]
>
> Although additional land could be acquired, the availability of useable land is limited due to the terrain. Further, this alternative fails to meet the Project objective of replacing aging infrastructure. As such, FBC rejected this option in the screening stage.

In Table 4-3, on page 38 of the Application, FBC describes the land availability of Alternative 5 (preferred alternative) and includes additional requirements for the Statutory Right-Of-Ways (SRW) to complete the transmission work.

6.1 Please discuss the differences between the land acquisition requirements under Alternative 6 and the SRW acquisition requirements under the preferred alternative.

Response:

Both Alternative 5 (i.e., the preferred alternative) and Alternative 6 require additional Statutory Rights of Way (SRW). However, during the screening stage, FBC determined that the SRW acquisition requirements for Alternative 6 would be greater than Alternative 5. In addition to acquiring land for the station, Alternative 6 requires land rights to be acquired for a new transmission corridor to extend the 11E Line to WTS as an independent line.

7.0 Reference: EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.2, p. 33, Tables 4-2 - 4-3; FBC Application for a CPCN for the Kelowna Bulk Transformer Addition Project Application proceeding, Exhibit B-1 (KBTA CPCN application), Section 4.5, pp.32-33; Exhibit B-2, BCUC IR 16.1

Evaluation Framework for Feasible Alternatives

On page 32 of the KBTA CPCN application, FBC identified the following categories for the technical criteria used in the evaluation of alternatives:

1. Meets Single Contingency (N-1) Transmission Planning Criteria
2. Safety and Operability
3. Potential for Future Expansion
4. System Reliability
5. Project Risk

Further on page 32 of the KBTA CPCN application, FBC stated:

> For the three alternatives, each technical criterion was scored either 1 (Fair), 2 (Good), or 3 (Best). The scores for each criteria were then weighted as indicated in Table 4-1 to determine a total technical score for each alternative.

On page 33 of the KBTA CPCN application, FBC provided Table 4-1 showing its list of non-financial criteria and the respective weight applied to each criterion. Table 4-1 is reproduced in part below:

PARAMETERS FOR RATING	WEIGHT
Technical Criteria	
N-1 Criteria Considerations	10%
Safety	10%
Operability	20%
Complexity of protection and switching schemes	5%
Removal of legacy infrastructure	5%
Potential for future expansion	20%
Reliability	20%
Subtotal Techincal Criteria Score	**90%**
Project Risks	
Schedule Risk	2.5%
Lands Risk	2.5%
Environmental Risk	2.5%
Archaeological Risk	2.5%
Subtotal Risk Criteria	**10%**
Total Technical and Risk Criteria Score	**100%**

In response to BCUC IR 16.1 in the KBTA CPCN application proceeding, FBC stated, "The weight given to each criterion was established based on input gathered from FBC's internal stakeholders.:

On page 33 of the Application, FBC provides Table 4-2, which provides the scoring applied to each of the non-financial criteria:

Score	Impact Evaluation
3	Best Choice
2	Good Choice
1	Acceptable Choice
0	Poor Choice

In Table 4-1 on page 33 of the Application, FBC provides the following list of non-financial evaluation criteria and weights:

Category	Criteria	Individual Weight[22]
Infrastructure	System Reliability	7.2%
	Potential for Future Expansion	8.8%
Safety	Personnel Safety	4.9%
	Construction Safety	4.9%
	Ground Grid Integrity	5.2%
Environmental & Archeological	Ecological	8.1%
	Air-quality, GHG Reductions	6.8%
	Archaeology	8.1%
Community & Stakeholder Relations	Land Use & Adjacent Infrastructure	5.4%
	Community Impact	7.2%
	Economic Growth	5.4%
Indigenous	Indigenous Relations	8.0%
Technical	Land Availability	4.0%
	Constructability	8.0%
	Operations Accessibility and Operability	8.0%
	Total	**100%**

7.1 Please explain the reasons for the differences in the scoring approach for the Project as compared to the approach taken in the KBTA Project.

7.2 Please explain how FBC determined the individual weight for each of the non-financial evaluation criteria considered for the Project.

7.3 Please explain the reasons for the differences between the KBTA CPCN application and this Application with respect to individual weights for each of the following criteria:

i. Safety
ii. Operability
iii. Reliability
iv. Potential for Future Expansion

Response:

The scoring approach, evaluation criteria, and weights given to each criterion were established through engagement and collaboration of FBC's internal stakeholders. FBC applies its understanding of existing and emerging issues and risks, and previous experience from similar projects, in designing the scoring approach and setting the weight values. FBC also takes the specific attributes of the Project area and assesses and incorporates feedback provided by Indigenous communities, public stakeholders, and customers. All of these considerations resulted

in a different scoring approach, evaluation criteria, and weightings for the ASM Project compared to the KBTA CPCN Application.

With respect to the differences in weightings between the KBTA CPCN Application and the ASM Project, the weightings applied to an individual criterion are done in the context of each specific project and the importance that criterion has in meeting the objectives of the project. A more important criterion will have a higher weighting so that its consideration has a higher impact on the scoring. A less important criterion that still merits inclusion in the analysis will have a lower weighting to reduce its impact on the scoring.

The weightings applied to the criteria for the ASM Project reflect how the alternatives can meet the objectives of the Project, the specific attributes of the Project (such as where the Project is located in FBC's service territory), and other considerations that internal stakeholders deem important. The KBTA CPCN Application has separate project objectives and considerations than the ASM Project and thus the weightings will differ for the criteria.

FBC provides the following discussion on each of the individual criteria and their weightings for the ASM Project and specifically addresses the differences in weights between the ASM Project and the KBTA Project related to the Safety, Operability, Reliability, and Potential for Future Expansion criteria.

Infrastructure Category

This category, which encompasses both the System Reliability and Potential for Future Expansion criteria in the ASM Project alternatives evaluation, was given a cumulative ranking of 16 percent.

For the ASM Project, the "System Reliability" criterion was given a weighting of 7.2 percent to recognize the importance of the reliability, availability, and sustainability of electrical supply on the transmission and substation facilities in normal and emergency situations into the long-term given load growth in the region. FBC notes that "System Reliability" was still assigned a high weighting relative to many other criteria for the ASM Project. For the KBTA Project, "Reliability" was assigned a 20 percent weighting. The difference in weights between the ASM Project criterion and the same KBTA criterion is attributable to the fact that the ASM Project criteria are more refined (i.e., more criteria items) than the KBTA Project and that other criteria, such as Indigenous Relations, have increased in importance.

The rationale for the difference in weightings for the "Potential for Future Expansion" criterion between the ASM Project (8.8 percent) and the KBTA Project (20 percent) is similar to the rationale for the different weightings in the "System Reliability" criterion. The "Potential for Future Expansion" criterion was given the highest weighting of all criteria for the ASM Project because of the increased importance in the ability to meet future system needs. The flexibility to expand the function of a terminal station efficiently and cost-effectively in the future is a valuable attribute. The load forecast shows an expectation of continued growth and therefore, the ability to expand for future growth is an important consideration.

Safety Category

In contrast to the KBTA Project, the Safety Category for the ASM Project is further broken down into three criteria, with the combined total weighting of the three criteria equaling 15 percent. As mentioned on page 31 in Section 4.3.2 of the Application, the Safety category considers the short- and long-term safety implications of the Project's construction, maintenance, and operation. For the KBTA Project, Safety was assigned a 10 percent weighting. The reason for the differences in classification and weighting between the two projects is that there is a larger scope of safety factors applicable to the ASM Project compared to the KBTA Project.

Environmental & Archeological Category

The Environmental & Archeological Category was assigned a higher weighting for the ASM Project at 23 percent. This weighting has been broken down into three criteria in order to separately weight and assess the ecological and archaeological impacts of the ASM Project as well as the impact on air quality and GHG reductions. The higher weighting assigned to this category for the ASM Project is in consideration of environmental impacts and the geographical location of the Project area.

Community & Stakeholder Relations Category

The weighting of 18 percent for this category for the ASM Project represents FBC's commitment to engaging with the communities the Project serves and limiting impacts to those communities where possible.

Indigenous Category

Indigenous engagement is recognized by FBC as key to the Project's success. As such, Indigenous engagement was given its own category in recognition of FortisBC's commitment to meaningful engagement, the need to consider potential impacts to Indigenous communities, and the need to incorporate Indigenous feedback into the Project, consistent with FortisBC's Statement of Indigenous Principles.

Technical Category

FBC's approach to the Technical Category is different for the ASM Project compared to the KBTA Project. The difference is primarily due to FBC's approach to providing greater refinement and granularity to its evaluation criteria for the ASM Project, which resulted in more categories and, within those categories, individual weightings assigned to each criterion. Thus, while the Technical Category appears to have a much lower weighting for the ASM Project (20 percent), this is because the Technical Category used in the KBTA Project (weighting of 90 percent) encompassed all of the criteria with the exception of the KBTA project risks.

The KBTA Project criterion "Operability", which was assigned a weight of 20 percent, is comparable to the "Constructability" and "Operations Accessibility and Operability" criteria in the ASM Project, which combined have a weighting of 16 percent. These criteria were given equally

high weights and, overall, the weighting is comparable to the KBTA "Operability" weighting, representing that these criteria continue to have a high level of importance on short- and long-term project outcomes.

FBC notes that the "Land Availability" criterion was given lesser weight compared to the other ASM Project Technical criteria because both feasible alternatives had lower complexities related to land acquisition. Further, alternatives with high land risk factors were eliminated during pre-screening.

7.4 Please explain why each of the following criteria were included in the KBTA CPCN application, but were excluded from consideration in the evaluation criteria for the Project:

i. N-1 Criteria Considerations

ii. Complexity of Protection and Switching Schemes

iii. Removal of Legacy Infrastructure

iv. Schedule Risk

Response:

With regard to (i) N-1 Criteria Considerations and (iv) Schedule Risk, these criteria are included in the evaluation criteria for the ASM Project.

The N-1 Considerations criterion was incorporated into the Infrastructure category as part of the System Reliability criterion for the ASM Project. The Schedule Risk criterion was incorporated into the Technical category as part of the Constructability criterion for the ASM Project.

FBC confirms that the (ii) Complexity of Protection and Switching Schemes and (iii) Removal of Legacy Infrastructure criteria were excluded from the ASM Project evaluation criteria.

The Complexity of Protection and Switching Schemes criterion was included for the KBTA CPCN Application to assess the various bus configurations for the 138 kV system. The ASM Project only considered a ring bus configuration, as it was the only configuration that could meet the Project objectives; therefore, this criterion is not relevant.

The Removal of Legacy Infrastructure criterion was included for the KBTA CPCN Application to evaluate eliminating the risk of damage to the transformers due to faults in the distribution system by removing distribution feeder load from the LEE T3 tertiary windings. This does not apply to the ASM Project because there is no distribution load on the tertiary of the ASM T1 and ASM T2 transformers.

7.5 Please explain whether FBC gathers input or feedback from public stakeholders and / or Indigenous communities on the criteria and weights considered in the evaluation of alternatives.

7.5.1 If yes, please explain how this was considered in the weighting used for the Project.

7.5.2 If not, please explain why not.

Response:

FBC fosters a culture of continuous learning and improvement. During evaluation criteria development, FBC reevaluates the FBC project evaluation criteria and weights and incorporates feedback provided on previous projects by Indigenous communities, public stakeholders, and customers.

For example, during recent FBC substation projects, FBC received community feedback and changed the project criteria accordingly, including expanding criteria related to nuisance factors (lightning, noise, aesthetics) and construction related impacts to the community.

8.0 Reference: EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.3.3, p. 34, Table 4-3; p.35, Table 4-3;pp. 36, 3839, p. 40, Table 4-4, Appendix C

Comparison of Alternatives 3 and 5

On page 34 of the Application, FBC provides Table 4-3, which provides the scores applied to each criterion for Alternatives 3, and 5. The table is reproduced in part below:

Criteria	Alternative 3 Rebuild ASM Terminal Station	Alternative 5 Expand WTS
	1	2
System Reliability (Weighting - 8.8 %)	• Reliability to the CSC will be impacted during construction. • Redundant lines between the ASM Terminal Station and WTS will share a corridor and could be subject to the same outage events (for example, a tree fall). Customers could continue to experience poor power performance as a result.	• Customers on the east end of 11E Line no longer experience poor power performance (low voltage) in a 34 Line outage event. • Less equipment installation required, limiting the additional number of failure points, providing optimal improvements in equipment reliability.
	0	2
Potential for Future Expansion (Weighting - 7.2%)	• Future site expansion is limited by topography to the south and west, proximity to third-party infrastructure to the east, and other FBC facilities/operations to the north.	• Provides adequate space for future additional 161 kV transmission infrastructure (i.e., secondary 161 kV transmission egress). • The land and topography in and around WTS could provide possibilities for other future station or transmission works (63 kV or 230 kV).

8.1 Please explain whether under Alternative 3 "Potential for Future Expansion" considers that further expansion may still be available in the future at WTS.

8.1.1 If so, please explain why Alternative 3 receives a score of 0 for "Potential for Future Expansion."

8.1.2 If not, please explain why not.

Response:

The "Potential for Future Expansion" criterion described in Section 4.3.2 of the Application considers the station's ability to accommodate additional transmission lines or more capacity in the future. The criterion did not assess the option of using other locations to provide more capacity for transmission lines; therefore, Alternative 3's evaluation only considered future expansions at the ASM Terminal Station site.

Alternative 3 was ranked as "0" because the ASM Terminal Station site would not be able to accommodate a third 63 kV / 161 kV transformer or additional transmission lines at the 63 kV or 161 kV level in the future.

When evaluating Alternative 3 against this criterion, FBC only evaluated the future expansion potential of the ASM Terminal Station to ensure an "apples-to-apples" assessment was undertaken between Alternatives 3 and 5. For clarity, the ranking of "2" for Alternative 5 considered only the expansion potential on the WTS site and did not consider the expansion potential on the existing ASM Terminal Station site.

The potential for expansion utilizing combinations of both sites was considered in a separate alternative – Alternative 6 contemplated maintaining the ASM Terminal Station on its existing site and utilizing WTS. However, as explained in Section 4.2.6 of the Application and further elaborated on in the responses to BCUC IR1 6.1 and ICG IR1 5.3, this alternative was rejected in the early screening stage. In particular, Alternative 6 requires 11E Line to 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.

8.2 Please explain why reliability to the CSC will be impacted during construction under Alternative 3.

Response:

Normal configuration of the CSC substation has both 9 Line and 10 Line energized for optimal reliability. Due to the complexity of the 9/10L re-configuration for Alternative 3, either 9 Line or 10 Line will need to be periodically de-energized for construction and preparation, temporary works, cut overs and conversion of the circuits at the ASM Terminal Station. While these temporary line outages will not involve customer outages at CSC, they could temporarily reduce reliability while one of the lines is de-energized to complete the Alternative 3 reconfiguration.

In Table 4-3 on page 35 of the Application, FBC provides a summary of the Alternatives' performance under the "Construction Safety "criterion:

Criteria	Alternative 3 Rebuild ASM Terminal Station	Alternative 5 Expand WTS
Construction Safety (Weighting – 4.9%)	2	2
	• Close proximity to a Canadian Pacific Railway (CPR) railroad; however, construction is not anticipated to interfere with CPR operations. • CPR operations could cause brief delays with construction and/or congestion. • Potential for high volume of traffic due to construction, which could impact the traffic flow of the greater Warfield Operations and by extension neighbouring public space and traffic intersections. • Multiple transmission line crossings that will need to be managed and coordinated during construction.	• Adjacent to various third-party underground infrastructure. • Some disturbance to neighbouring third-party operations is expected; disturbances can be limited to the construction window and managed through collaboration and coordination with these neighbouring entities. • Some third-party infrastructure may require relocation; however, this is a routine undertaking with known hazards and can be managed with existing mitigation plans. • Multiple transmission line crossings that will need to be managed and coordinated during construction.

On page 38 of the Application, FBC provides a summary of the Alternatives' performance under the "Construction" criterion:

Criteria	Alternative 3 Rebuild ASM Terminal Station	Alternative 5 Expand WTS
Construction (Weighting – 8%)	1	3
	• Numerous outages required during construction. • High construction risk. • Complex project staging with multiple stages. • High site congestion. • Brownfield construction practices. • Land limitations pose significant risk. • Transmission work is more extensive resulting in a higher frequency of outages and greater total outage time.	• Less outages during construction, both in frequency of outages and total outage time. More outage flexibility and opportunity to schedule outages for points of lowest impact. • Lower construction risk. • Simpler project staging. • Site congestion can be easily managed. • Application of greenfield construction practice for majority of construction window.

On page 39 of the Application, FBC states:

> As explained in Table 4-3 above (under the criterion of "Construction"), Alternative 5 has better constructability, lower construction risk, and less equipment procurement risk than Alternative 3. This is reflected in the lower estimated capital cost for Alternative 5 as compared to Alternative 3, as shown in Table 4-4 below.

On page 40, FBC provides Table 4-4, the Financial Evaluation Summary of Alternatives 3 and 5 as follows:

Table 4-4: Financial Evaluation Summary of Alternatives 3 and 5

	Alternative 3: Rebuild ASM	Alternative 5: Expand WTS
Capital Costs, including AFUDC[29], AACE Class 4, As-spent ($ millions)	43.517	28.378
Incremental O&M Expense in 2027, As-spent ($ millions)	0.014	0.002
Total PV of Incremental Revenue Requirement over 53 Years ($ millions)	57.736	37.372
Levelized Rate Impact over 53 Years (%)	0.82	0.53

8.3 Please explain why the equipment procurement risk under Alternative 3 is lower than the equipment procurement risk under Alternative 5.

Response:

FBC is unclear where in the Application the BCUC is referencing when it states in the question that "the equipment procurement risk under Alternative 3 is lower than the equipment procurement risk under Alternative 5".

On page 39 of the Application, and as provided in the preamble to this IR, FBC states that "Alternative 5 has better constructability, lower construction risk, and less equipment procurement risk than Alternative 3." [Emphasis added]

Further, and as shown in Table 4-3 (and provided in the preamble), Alternative 3 ranks lower than Alternative 5 under the Construction criterion, indicating that the constructability risks are higher (i.e., the risks are worse) for Alternative 3 than Alternative 5.

The reason that Alternative 3 ranks less favorably (i.e., worse) in the Construction criterion is that the construction staging plan is much more complex and procuring material to meet these specific stages of construction would be a challenge. Therefore, more risk exists with unexpected material delays, which would negatively impact the Project schedule and budget for Alternative 3.

8.3.1 Please provide a breakdown of equipment procurements costs for Alternative 3 and Alternative 5.

Response:

A breakdown of the equipment procurement cost forecasts included in the Application for Alternative 3 and Alternative 5 is provided in the following table. FBC notes that equipment procurement costs will not be confirmed until purchase orders are issued, which will occur subsequent to approval of the Application.

Equipment	Alternative 3 (ASM) ($ millions)	Alternative 5 (WTS) ($ millions)
Transformers	8.500	8.500
Circuit Breakers	0.879	0.476
Arrestors	0.051	0.031
Switches	0.851	0.244
Instrument Transformers	0.479	0.167
Total	**10.760**	**9.418**

8.4 Please explain why, under "Construction", Alternative 3 has a higher construction risk than Alternative 5, given that both Alternatives have a score of "2" under "Construction Safety".

Response:

In the Safety category, the "Construction safety" criterion considers other entities working on private infrastructure adjacent or in proximity to FBC assets during construction. Both alternatives have similar challenges; therefore, the weightings have been scored equally.

In the Technical category, the "Construction" criterion considers the existing above and below ground constraints related to construction activity, requirements for non-routine construction techniques, specialized crews and equipment, access restrictions, available construction footprint, and impacts on schedule and conflicts with adjacent infrastructure.

From a "Construction" perspective, Alternative 3 has a higher construction risk due to being in close proximity to energized equipment (Brownfield site) and will require complex staging and outage planning for the duration of the Project.

Alternative 5 would be completed on a greenfield construction site, resulting in simpler outage planning and staging.

On page 36 of the Application, FBC provides a summary of the Alternatives' performance under the "Ecological "criterion:

	1	2
Ecological (Weighting – 8.1%)	• Land is already disturbed by station and transmission infrastructure. • Located within the City of Trail and has been subjected to historical deposition of aerial emission from local lead and zinc smelting facilities. • Potential high metal concentration in soils, triggering the Contaminated Sites Regulation. • As owner of the site, FBC would be responsible to undertake proper soil disposal for station and transmission ground disturbances.	• Land is already disturbed by station and transmission infrastructure. • Located within the City of Trail and has been subjected to historical deposition of aerial emission from local lead and zinc smelting facilities. • Potential high metal concentration in soils, triggering the Contaminated Sites Regulation. • WTS land is owned by Teck Metals Ltd. who is responsible for proper disposal of the contaminated soils; FBC would collaborate with Teck Metals Ltd. • Transmission work will include minimal ground disturbance. FBC would be responsible to undertake proper soil disposal.

8.5 Please further explain why under "Ecological", Alternative 3 is given a lower score than Alternative 5. Please discuss whether FBC's assessment of "Ecological" criterion is based on the alternatives' performance during short-term construction or during the long-term system operation.

Response:

The "Ecological" category identifies where the least amount of impact would occur; therefore, the lower the "Ecological" score, the higher environmental considerations for the Alternative. The greatest impact will occur during short-term construction as the long-term system operation will be consistent with all other FBC substations where standardized environmental controls are in place.

For Alternative 3, the rating of 1 "Acceptable Choice" was due to the heavily treed ravine to the northeast of the property. The construction plan would require significant impact to these lands and subsequent restoration post-construction.

For Alternative 5, the rating of 2 "Good Choice" was due to the fact that the property is already significantly developed and that minimal disturbance to undisturbed lands is required.

D. PROJECT DESCRIPTION

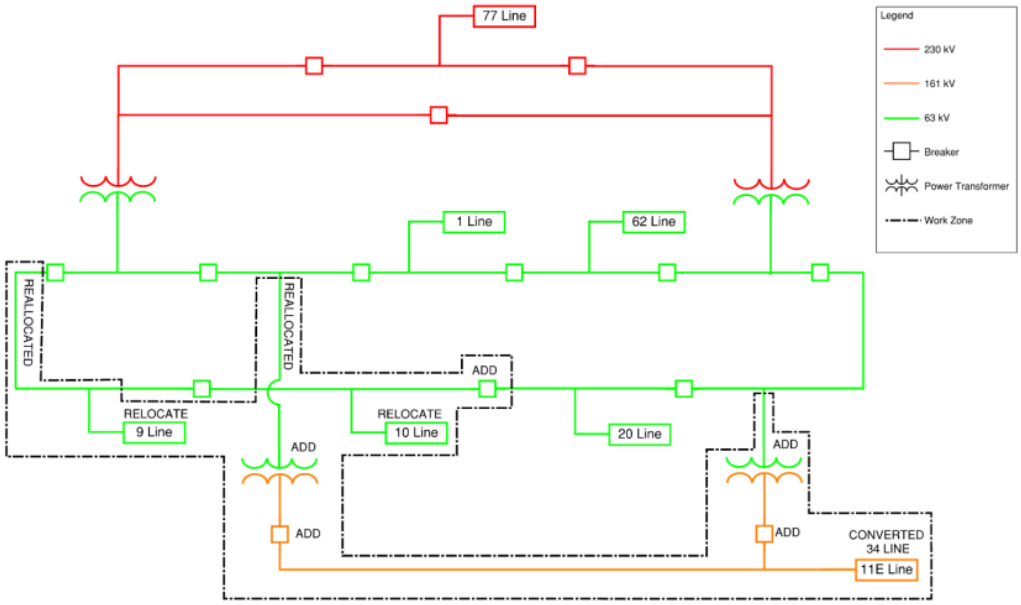
9.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.1, p. 42

Proposed WTS Configuration

On page 42 of the Application, FBC provides the following preliminary simplified single line diagram for WTS following completion of the Project:

Figure 5-1: Proposed WTS Simplified Single Line Diagram



9.1 Please provide rationale for WTS stepping down from 230 kV to 63 kV before stepping up from 63 kV to 161 kV.

9.1.1 Please explain whether FBC considered any other configurations of WTS as part of the proposed Project, such as stepping down from 230 kV directly to 161 kV.

9.1.1.1 If yes, please explain the configurations considered and why they were rejected.

9.1.1.2 If no, please explain why not.

Response:

The proposed WTS alternative of stepping down from 230 kV to 63 kV before stepping up from 63 kV to 161 kV matches what is currently at the ASM Terminal Station. The ASM Terminal Station and WTS are near each other and moving these transformers will have minimal effects on the system.

An alternative WTS configuration of 230/161 kV was considered and rejected due to the following reasons:

- It would have introduced a new class of transformers to the FBC system; and
- This class of transformers would require a spare to satisfy the spare equipment strategy (TPL-001-4 Requirement 2.1.5).

Also, the existing WTS footprint is large, with the 230 kV yard at one end of the station, while the 63 kV ring bus is presently physically well situated near the transmission line corridor which will serve the new 161 kV line leaving the station. This is also the prior location of the existing 34 Line, which will be converted.

10.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 1.1.1, p. 1; Section 5.5, p. 50

Construction Activities

On page 1 of the Application, FBC states:

> The Similkameen and Boundary area customers and communities rely on the connection between WTS [Warfield Terminal Station] 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.

On page 50 of the Application, FBC states, "34 Line conversion will require several outages (1 to 2 weeks in duration each) over the duration of construction."

10.1 Please explain whether any FBC customers will be affected by 34 Line outages.

10.1.1 If yes, please provide details on the number of expected outages, number of customers affected, and what actions FBC plans to take to minimize outage durations.

10.1.2 If yes, please describe FBC's communication plan for customers affected by 34 Line outages.

Response:

FBC does not anticipate direct customer outages to the Similkameen and Boundary areas as a result of 34 Line outages during construction because the area can also be fed from 11W Line, 11E Line, 48 Line and/or 40 Line transmission lines. However, customers may experience outages if an unanticipated outage event occurs while 34 Line is de-energized and is not readily available to return to service upon an unscheduled system event.

This risk during Project construction will occur approximately three times for 2-3 weeks each time during 34 Line conversion activities and could impact various customers in the Similkameen and Boundary areas. FBC will be planning mitigation strategies to minimize impacts to customers through comprehensive and rigorous work planning, detailed work procedures, ensuring spare materials are in place, restoration plans, and by scheduling work outside of high load periods.

FBC will contact customers directly if an outage will be affecting them.

On page 50 of the Application, FBC states:

> Initially, FBC will focus on relocation of the 9 Line and 10 Line transmission egress at WTS to maintain supply to CSC [Cascade Substation] throughout construction.

A brief outage **may** [emphasis added] be required to CSC to perform transmission cutovers.

10.2 Please describe the function of CSC within FBC's transmission system.

Response:

CSC is a distribution substation that converts 63 kV to 13 kV and supplies the community of Rossland.

10.3 Please outline the scenario(s) in which a CSC outage will be deemed necessary. In the response, please include the point in the project timeline when the need for the outage will become known, and the project cost/schedule implications should a CSC outage be deemed necessary.

10.4 Please explain whether any FBC customers will be affected by a CSC outage, should it be deemed necessary. In the response, please describe any actions FBC plans to take to prevent, or mitigate the length and impact of, a CSC outage.

10.4.1 If yes, please describe FBC's notification strategy for customers affected by the CSC outage, should it be deemed necessary.

Response:

The current Project plan for construction and staging of the transmission line work is expected to be completed without an outage to CSC by using live line work methods and detailed work procedures.

However, outages may be required for installing the new 9L2/10L2 steel structures with a large crane, due to site congestion and cutting over the new 9 Line and 10 Line transmission line positions into their new associated bays at WTS. The cost impacts for a possible outage would be expected to be less than $50 thousand and cause approximately three days impact to the Project schedule. Outage needs would be confirmed once the new 9L/10L bays are constructed and new transmission poles installed.

In the unlikely event that an outage to CSC is required, the outage would impact all Rossland area customers. Restoration (return to service) plans would be completed as part of the detailed design during planning and staging of the work activities. Customers would be notified through the standard FBC notification process, which would include a combination of mailers, call center notifications, newspapers, radio, and posters, if an outage is required.

On page 50 of the Application, FBC states:

> FBC will then proceed to focus on installing and energizing the two WTS transformers (WTS T3 with WTS T4) and 11E Line. The ASM Terminal Station will remain on standby until both WTS T3 and T4 are in service.

10.5 Please explain any advantages and drawbacks to maintaining the ASM Terminal Station on standby until both WTS T3 and T4 are in service.

Response:

The ASM Terminal Station will enter standby mode after WTS T3 is put into service and 11E Line is interconnected to 34 Line to extend it back to WTS. The table below explains the advantages and disadvantages to maintaining the ASM Terminal Station on standby until both WTS T3 and T4 are in service.

Maintaining reliability to the area until the Project is complete is the most important consideration when determining whether to keep the ASM Terminal Station on standby service. FBC considers that the disadvantages, as set out the below table, are acceptable in order to maintain reliability to this area, even with the risk of ASM transformer failure. In addition, the costs to maintain the ASM Terminal Station on standby are minimal compared with the benefits of maintaining reliable service for the customers; therefore, this alternative has been chosen.

Advantages	Disadvantages
• A secondary station to supply 11E Line is available in the event that WTS T3 experiences an early-life failure (within the first three months of operation) and WTS T4 is not yet available. • Time to restore will be shorter than if the station was not available and the above-mentioned event occurred.	• FBC will continue to incur O&M expenses for the ASM Terminal Station and its equipment while in standby. • Increased Project costs to restore the ASM Terminal Station (i.e., return 34 Line connection between ASM and WTS and return 11E Line connection to ASM). • ASM Terminal Station transformers will continue to rise in probability of failure. One or both ASM transformers could fail while offline.

10.6 Please describe the scenario(s) in which the ASM Terminal Station will need to be recalled from standby, outlining any project schedule impact.

Response:

The ASM Terminal Station will have to be recalled from standby if WTS T3 were to experience an early-life failure[7] and WTS T4 were not yet available. This would impact the Project schedule by causing a delay in the construction timeline because resources would be redistributed to restore the ASM Terminal Station to service.

[7] Early-life failures are defined as the phenomenon when new (or overhauled) equipment fails upon start-up or early in its operating lifespan.

11.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.1.1, pp. 42-43

Required Statutory Rights of Way Not Yet Obtained

On page 42 of the Application, FBC states:

> WTS facilities are located within an FBC SRW, referred herein as SRW1, , which allows for substation works of 63 kV and/or 230 kV infrastructure. The expansion of WTS will remain within the existing SRW1 boundary. In 2022, FBC entered into an Agreement to Grant with the Landowner (Teck Metals Ltd.) of the relevant land to modify the existing SRW1 legal agreement terms that would allow for substation works of 63 kV to 230 kV infrastructure.

11.1 Please outline any remaining steps required to complete the modification of SRW1, and identify when FBC expects to obtain the revised SRW1 agreement.

11.1.1 Please outline any potential project cost and schedule impacts resulting from delays in obtaining SRW1.

11.2 Please outline the "standard SRW processes" that FBC follows.

11.3 Please outline any remaining steps required to secure the necessary SRW from Teck, and identify when FBC expects the SRW will be obtained.

11.3.1 Please outline any potential project cost or schedule impacts resulting from delays in obtaining SRW2.

11.4 Please explain why the required SRW from MOTI will be acquired during detailed design, and not earlier.

11.4.1 Please discuss whether FBC has had any preliminary discussions with MOTI regarding the SRW.

11.4.1.1 If yes, please discuss whether any issues were raised with respect to obtaining the SRW.

11.4.1.2 If not, please explain why not.

11.4.2 Please outline any project cost and schedule risks should there be delays in obtaining the required SRW from MOTI.

Response:

FBC clarifies that the SRWs are required from Teck, and that it will require a permit (rather than an SRW) from MOTI as the applicable lands are not titled). The SRW and permit processes, statuses, and likelihoods/implications of delays are further described below.

FBC and Teck have settled on the form of modification agreement, which will have the effect of revising the SRWs to allow for substation works of 63 kV to 230 kV once executed and registered

in the Land Title Registry. The Agreement to Grant is subject to customary subject conditions including, among others, FBC being satisfied with the outcome of its due diligence investigations with respect to the Project and FBC obtaining BCUC approval for the Project. With the exception of FBC obtaining BCUC approval for the Project, the timing of the subject conditions is within FBC's control. Upon the subject conditions being satisfied, FBC will prepare the SRW agreements in registrable form, deliver the SRW agreements to Teck for signature, and submit the fully-executed SRW agreements for registration at the applicable Land Title Office.

FBC expects the SRW agreements will be registered in the applicable Land Title Office within 2-3 months of FBC satisfying the subject conditions in the Agreement to Grant.

With regard to the permit process with MOTI, FBC has not yet had preliminary discussions with MOTI or submitted a permit application, as FBC requires additional details and requirements in order to submit a permit application or enter into preliminary discussions with MOTI. FBC will receive these additional details and requirements during the Project's detailed design phase. FBC must first confirm the required SRW changes or alterations before the permit application. For instance, if necessary, an alternate transmission structure design solution and adjustments to the centerline alignment can be implemented to minimize impacts to the SRW requirements.

After this, FBC will submit the permit application to MOTI. The permit process will be advanced early in the Project. While the property does not appear to be a useable piece of land for MOTI (due to steep side slopes and proximity to the ASM Terminal Station), any potential difficulties will be identified early in the Project schedule.

In the unlikely circumstance that the SRW agreements and/or the permit are delayed, the impact to the transmission schedule could range from 3-6 months and could result in additional Project costs of up to approximately $0.5 million. However, FBC does not expect that the agreements or permit will be delayed and, even if a delay were to occur, the resulting schedule impacts are not likely to be on the critical path of the overall Project. FBC accordingly considers the Project cost and schedule risk associated with the SRWs and permit to be minimal.

12.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.1.2, p. 45; Section 1.1.5, pp. 3-4; Section 7.1, p. 61

ASM Land and Equipment Use After Decommissioning

On pages 3 and 4 of the Application, FBC describes the Project scope as follows:

- Reconfiguring the 63 kV egress at WTS for 34 Line, 9 Line, and 10 Line;
- Expanding the WTS footprint;
- Installing two additional 63/161 kV transformers, reconfiguring the 63 kV ring bus, and adding a 161 kV radial bus;
- Converting 34 Line to 161 kV rating then connecting 11E Line from the ASM Terminal Station to WTS by repurposing 34 Line as an extension to 11E Line; and
- Demolishing the ASM Terminal Station above grade.

On page 45 of the Application, FBC states:

> Following the completion of the work at WTS, the demolition of the ASM Terminal Station will proceed, which includes:
>
> - Salvage equipment as required;
> - Demolish existing buswork, connectors and bus supports;
> - Demolish existing superstructures;
> - Remove all field cabling; and
> - Abandon station foundations (after cutting off anchor bolts), conduits, secondary oil containment, fire suppression building, ground grid, and control building.

12.1 Please describe the future use of the ASM Terminal Station land.

12.1.1 Please describe any alternative future uses of the ASM Terminal Station land considered by FBC, the evaluation process undertaken for each, and why each was rejected

12.1.2 If FBC intends to keep the ASM Terminal Station Lands, please discuss the costs associated with holding the land (such as taxes etc.) and whether there are risks are associated with holding the land (such as environmental risks, etc.).

12.1.3 If FBC intends to sell the ASM Terminal Station Lands, please discuss whether the sales proceeds will be used to lower the Project cost. If yes, please explain how this will impact associated O&M costs and the Project cost, including any the rate impact to FBC customers.

Response:

FBC does not intend to sell the ASM Terminal Station land. The ASM Terminal Station is located on a portion of the larger FBC Warfield Compound parcel and thus the land parcel contains other buildings/structures and is being used by the FBC Warfield Operations for purposes other than just the ASM Terminal Station functions. For clarity, the land is not subdivided between FBC Warfield Operations and the ASM Terminal Station.

FBC will consider this land and its suitability for other system infrastructure projects in its long-term planning once the station is demolished. However, FBC has not yet undertaken any detailed evaluations of the potential future use(s) for how the portion of the land containing the ASM Terminal Station will be used in the future at this time.

The costs associated with the overall FBC Warfield Compound land parcel are the rate base return earned on the land and property taxes. FBC notes, however, that these costs will be incurred regardless of whether or not the ASM Terminal Station continues to operate, as FBC's Warfield Operations are also utilizing the land. Specifically with regard to property taxes, in 2023, BC Assessment valued the entire 15.7 acre Warfield Compound at $380 thousand. Total property taxes paid on the land for the site are estimated to be $22 thousand.

FBC does not consider there to be environmental risks associated with holding the land.

12.2 Please explain whether the requirement to demolish the ASM Terminal Station above grade is driven by the planned future use of the site. If not, please explain the need to demolish the ASM Terminal Station above grade.

Response:

No, demolishing the ASM Terminal Station above grade is not driven by any planned future use of the site. It is needed to eliminate any environmental risks, as well as the O&M resources that would be required to maintain equipment if it were not removed.

12.3 Please discuss whether there are any risks or future responsibilities with respect to the ASM Terminal Station assets that will remain below grade, such as environmental risks or responsibilities. If yes, please describe these risks and/or responsibilities. If not, please explain why not.

12.3.1 Please compare these risks/responsibilities to other alternatives, such as removing all decommissioned assets, including those below grade.

Response:

There is the potential for a portion of the concrete foundations, ground conductor and some empty conduits and sorbweb containment for both transformers to remain below grade. Whether or not materials remain onsite post decommissioning or are removed will be determined during the decommissioning process. During decommissioning, samples will be taken of the waste items to determine characteristics and level of contaminants. Once the contaminants are identified and it is determined that a waste disposal plan is required, the plan will be developed and executed with contaminated materials being handled per the regulatory requirements disposed of at an authorized facility. All materials that have the potential for future environmental risk will be removed as part of the decommissioning process with only inert material being left in place. FBC notes that there are costs associated with removal of any material, and therefore it is most cost-effective to leave inert materials in place rather than to remove and send for disposal.

12.4 Please discuss any cyber security risks associated with the decommissioning of equipment at the ASM Terminal Station, including any mitigation measures planned. In the response, please identify any cyber security standards applicable to this work.

Response:

Cyber security risks associated with decommissioning equipment at the ASM Terminal Station would be related to unauthorized retrieval of information from disposed of devices capable of being programmed or storing data. As part of information security described in FBC's Cybersecurity Policy, FBC requires decommissioning procedures specific to each programmable device in order to prevent the unauthorized retrieval. This is done by utilizing sanitation methods, which depend on whether the programmable device will be repurposed or removed entirely from the environment. If the device is to be reused within FBC, the device will be reprogrammed as required by FBC technicians. If the device is to be disposed of, there are processes for each type of device to guarantee no FBC programming or data remains on the device prior to disposal.

12.4.1 Please identify and discuss cyber security risks associated with other areas of the Project scope. In the response, please identify any cyber

security standards applicable to this work, and how FBC meets or will meet these requirements.

Response:

FBC's Corporate Security Risk Management Program (CSRMP) is designed to ensure all digital equipment used by FBC, including for this and other projects, are secured based on the requirements of the CSRMP. The requirements for this Project ensure that all digital equipment being configured and installed follows FBC's established standards. Standards include specific security configuration requirements for every digital device, as well as incorporating all digital devices into FBC's overall security architecture. This includes the multiple layers of defense required by the CSRMP for all digital devices.

On page 61 of the Application, FBC states, "The WTS is an active FBC substation located within an SRW on a larger parcel owned by Teck Metals Ltd."

12.5 Please discuss any risks and benefits associated with consolidating FBC's transformation infrastructure onto land owned by Teck Metals Ltd.

Response:

From a land tenure perspective, it is customary for FBC to install and operate its infrastructure (including stations) on land owned by a third party (including Teck) by way of an SRW agreement. In the case of this Project, FBC has reviewed its existing land tenure agreements to identify the additional land tenure necessary to facilitate the consolidation. As a result, FBC has entered into an Agreement to Grant with Teck to modify SRW1 to ensure the consolidation fits within the uses permitted under SRW1. With these agreements in place, FBC considers any risks associated with consolidating FBC's transformation infrastructure onto land owned by Teck as low.

Teck's transmission and generation network has an interconnection point to FBC's system via WTS. FBC has a long-standing history of working cooperatively with Teck regarding power transmission and generation. This interconnection provides a mutual joint benefit to both parties.

12.5.1 Please explain whether these risks and benefits were considered in FBC's evaluation of its project alternatives.

12.5.1.1 If so, please briefly discuss how they were considered.

12.5.1.2 If not, please explain why not.

Response:

FBC considered the risks and benefits associated with consolidating its transformation infrastructure onto land owned by Teck as part of the project alternatives evaluation. In particular, FBC evaluated the risks and benefits of land consolidation in the following areas:

- "Potential for Future Expansion" criterion considered the WTS's land size and topography.
- "Safety" category considered impacts of consolidation on personnel safety, construction safety, and ground grid safety both in the short and long terms.
- "Community & Stakeholder Relations" category considered the impacts to Teck and the neighboring community.
- "Land Availability" criterion considered FBC's existing SRW scope and the necessary amendments that were secured in the Agreement to Grant with Teck.
- "Constructability" criterion considered accessibility, staging, and scheduling associated with consolidating the FBC's transformation infrastructure onto land owned by Teck
- "Operations Accessibility, and Operability" criterion considered the accessibility, operability, and maintainability to existing infrastructure during consolidation. It also considered the long-term accessibility, operability, and maintainability post consolidation.

12.5.2 Please discuss the terms of FBC's agreement for land use with Teck Metals Ltd. and any modifications to these agreements required as a result of the Project (other than the SRWs discussed above).

Response:

In addition to the SRW1 and SRW2, the following are existing land use agreements (SRWs) with Teck Metals Ltd. that are currently registered:

- **FBC SRW LA78349** restricted to Plan NEP75571 - for the construction, operation and maintenance of 1L and 20L heading east from WTS. Terms include the right to alter, reconstruct, protect, inspect, repair, remove, replace and service the electrical works with access over the Lands to and from the facilities. Ancillary rights are also included in the terms of this SRW.
- **FBC SRW LA78347** restricted to Plan NEP75570 - for the construction, operation and maintenance of 62L heading to Emerald. Terms include the right to alter, reconstruct, protect, inspect, repair, remove, replace and service the 62L works with access over the Lands to and from the facilities. Ancillary rights are also included in the terms of this SRW.

- **FBC SRW LA78336** restricted to Plans NEP77541 and NEP78060 – for the construction, operation and maintenance of 77L going north from WTS. Terms include the right to alter, reconstruct, protect, inspect, repair, remove, replace and service the electrical works with access over the Lands to and from the facilities. Ancillary rights are also included in the terms of this SRW.

- **FBC SRW KP1208** - Blanket SRW for the construction, operation and maintenance of electric distribution facilities. No additional facilities permitted without the prior written consent of Teck.

- **FBC SRW 32900D** restricted to Plan NEP1661 – for the maintenance of electrical power transmission lines.

- **FBC SRW CA4157090** and **CA4157091** restricted to Plan EPP46062 – for the transmission and distribution of electrical energy, including the right to install, construct, maintain, inspect, repair, alter, operate, abandon, remove and replace the electrical works. Ancillary rights are also included in the terms of this SRW.

No modifications to the foregoing agreements will be required as a result of the Project.

E. PROJECT COSTS

13.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 6.2, p. 55; Appendix C

Project Cost Estimate

On page 55 of the Application, FBC states: "[t]he total Project cost estimate is $35.179 million in as-spent dollars, including cost of removal and AFUDC [Allowance for Funds Used During Construction]."

Appendix C of the Application provides a summary of capital costs including a breakdown of the project cost estimate for Alternative 5 at AACE Class 4 estimate level.

On page 55 of the Application, FBC provides a breakdown of the Project cost estimate at AACE Class 3 estimate level and states: "[t]he expected accuracy for a Class 3 cost estimate, as defined by the AACE, is low: -10 percent to -20 percent and High: +10 percent to +30 percent." [Emphasis added]

13.1 Please complete the table below to illustrate the range of the Project Costs at AACE Class 3 estimate level:

13.1.1 Please discuss the probabilities of the Project being at either the low or high end of these estimates.

Alternative	Project Cost	Low Estimate		High Estimate		
		Cost Decline 20%	Cost Decline 10%	Cost Increase 10%	Cost Increase 20%	Cost Increase 30%
5	$35.179M					

Response:

Please see Table 1 below for the range of Project costs at the AACE Class 3 estimate level in the format requested in this IR.

FBC notes the $35.179 million as shown in the preamble above includes the base capital cost estimate of $25.361 million in 2022 dollars, plus contingency, escalation, CPCN preliminary engineering costs (with actuals up to the end of 2022), and AFUDC. As explained on page 55 of the Application, the base capital cost estimate is developed to the AACE Class 3 level while the rest of the costs are either calculations on top of the base capital cost estimate (i.e., contingency, escalation, and AFUDC) or actual costs already incurred (i.e., the CPCN preliminary engineering costs). As such, for the purpose of illustrating the range of Project costs at the AACE Class 3 estimate level, FBC only varied the base capital cost estimate between -20 percent to +30 percent

while maintaining the same assumptions for contingency and escalation, as well as the same Project schedule for the AFUDC calculation. For example, FBC applied the same 13.1 percent of contingency to all ranges of base capital cost estimate shown in Table 1 below, and the same annual escalation factors in percentage as set out in the response to BCUC IR1 16.2.

As defined by the AACE, the variation at the low or high end of these estimates (including contingency) is done with 50 percent confidence.

Table 1: Project Costs Range at AACE Class 3 Estimate Level

Alternative	Project Cost	Low Estimate		High Estimate		
		Cost Decline 20%	Cost Decline 10%	Cost Increase 10%	Cost Increase 20%	Cost Increase 30%
5	$35.179M	$28.323M	$31.751M	$38.606M	$42.034M	$45.461M

14.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 4.3.4, p. 39; Section 6.4.2, p. 59; FBC Application for a CPCN for the Kelowna Bulk Transformer Addition proceeding, Exhibit B-1, Section 6.4.2, p. 55

Project Analysis Period

On page 39 of the Application, FBC states:

> [t]he financial evaluation considered the levelized rate impact resulting from each alternative over the 53-year analysis period. The 53-year analysis period is based on a 50-year post-project analysis period from 2027 (all assets estimated to enter FBC's rate base in 2027) plus three years for the estimated construction schedule from 2024 to 2026. [Emphasis added]

On page 55 of FBC's KBTA CPCN application, FBC stated: "[t]he Project construction period is between 2021 and 2022 […]. A 40 year cost of service model, equivalent to the life of the assets, was used to evaluate the rate impact." The construction period for the project was not included as part of the 40-year analysis period.

14.1 Please explain the reasons for the differences between the Application, which includes the construction period as part of the analysis period, and the KBTA CPCN Application, which did not include the construction period in the analysis period.

Response:

For clarity, the financial analysis completed for both the KBTA CPCN Application and this Application includes the construction period.

The statement in the preamble, which FBC notes is not part of the quote from the KBTA CPCN Application, that "The construction period for the project was not included as part of the 40-year analysis period", is incorrect. FBC did not state in the KBTA CPCN Application that the 40-year analysis period did not include the construction period.

The financial schedules provided in Confidential Appendices C-1 to C-3 of the KBTA CPCN Application show that the financial analysis completed for the KBTA CPCN Application included the years' 2020 to 2059 (40 years). As cited in the preamble above, the construction period for the KBTA Project was estimated to be between 2021 and 2022, therefore, years' 2020 to 2022 were the construction period and were part of the 40-year analysis period used in the financial analysis for the KBTA CPCN Project.

14.2 Please discuss the financial implications of using a 50-year analysis period instead (i.e., excluding the 3-year construction period from the analysis period) and provide the levelized rate impact and total present value (PV) of the incremental revenue requirement over 50-years for the Project at AACE Class 3 estimate level.

Response:

As discussed in the response to BCUC IR1 14.1, the financial analyses for both the KBTA and ASM Projects are consistent and include the construction period as part of the overall analysis period.

It would be inappropriate and inconsistent with FBC's approach to the financial analysis of CPCN projects to exclude the construction period from the analysis. Using a 50-year analysis period (post-Project from 2027) and excluding the 3-year construction period would not reflect the full extent of the incremental impact to FBC's revenue requirement due to the ASM Project. Specifically, excluding the 3-year construction period from 2024 to 2026 would exclude the impact of the outage wheeling costs to FBC's cost of energy in years' 2025 and 2026 as discussed on page 58 of the Application. These additional wheeling costs to cover the shortfall under the BC Hydro Open Access Transmission Tariff (OATT) are a direct impact to FBC's revenue requirement due to the ASM Project; therefore, if the analysis period excludes the construction period, then the financial analysis would understate the PV of incremental revenue requirement and the levelized rate impact.

On page 59 of the Application, FBC states:

> [o]nce the assets are placed into service (estimated to be in 2026), the associated capital cost will enter rate base as part of the opening balance in the appropriate plant asset accounts, for inclusion in FBC's rate base in the following year (estimated to be January 1, 2027).

14.3 Please confirm, or explain otherwise, that all assets are being placed into FBC's rate base at the same time (i.e., assets will be placed into service all at once and not in phases) on January 1, 2027.

14.3.1 If not confirmed, please explain whether placing assets into service at the same time would change the levelized rate impact over the 53-year analysis period and if so, please provide the impact in dollars and percentage.

Response:

Confirmed. As noted in Section 6.4.2 of the Application, all assets are estimated to be placed into service in 2026 and will therefore enter FBC's rate base in the following year on January 1, 2027. This is the approved treatment for CPCN project capital costs and this treatment is reflected in the ASM Project's financial analysis and levelized rate impact calculation.

14.4 Please discuss the impact, if any, to the analysis period and project costs should additional delays materialize during the 3-year construction period.

Response:

FBC included a contingency of $3.318 million in 2022 dollars (approximately 13.1 percent of the base capital cost estimate of $25.361 million) to address the potential of delays to the Project schedule and higher than anticipated raw material costs or foreign exchange escalation. The construction schedule in Figure 5-5 of the Application also considered prolonged lead-times based on the current labour and materials supply market. There are risk mitigation measures presented in Section 5.6 of the Application that FBC expects to undertake should there be delays to the Project schedule.

Please refer to the response to BCUC IR1 13.1 for a range of impacts to the total Project costs if the base construction cost estimate is increased by a range of 10 percent to 30 percent.

FBC also notes that even if the ASM Project is delayed during the 3-year construction period, the analysis period would not change. The analysis period is chosen based on FBC's current expectation of the Project in terms of schedule and cost as well as the expected life of the assets. For the purpose of creating an apples-to-apples comparison in terms of the PV of incremental revenue requirement and levelized rate impacts, all alternatives or scenarios should be based on the same analysis period. It would not be appropriate to compare the PV of one alternative or scenario over a 53-year analysis period to another alternative or scenario over a 55- or 60-year analysis period.

15.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 5.6, pp. 52, 54; Section 6.2, pp. 55-56; FBC Application for a CPCN for the Kelowna Bulk Transformer Addition proceeding, Exhibit B-1, Section 5.7, p. 48; Section 6.2.4, p. 53

Contingency Costs

On pages 55 and 56 of the Application, FBC 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 […], and a contingency of 10 percent for the transmission, distribution and fibre modification components.

15.1 Please explain why the transmission, distribution and fibre modification contingency amount of 10 percent differs from the station construction and removal costs contingency of 15 percent.

Response:

The contingency for the transmission, distribution, and fibre modifications reflects a lower assessed risk and lower potential for specific scope escalation due to better-defined scope requirements. Detailed design was completed for these modifications in order to determine a viable design and staging plan. Accordingly, the preliminary design was able to formulate and define the scope details, and the costs related to the work were assessed as having lower overall risk, which is reflected in the lower contingency.

Conversely, the contingency for the station construction and removal costs are reflective of a higher assessed risk and potential for scope escalation. The station construction and removal components of the Project carry very different risks and unknowns than the transmission, distribution and fibre modification components of the Project. The complications and intricacies of the station construction are greater and therefore are assigned a higher contingency because the upgrades are being done in an existing energized substation where there is a higher potential risk for scope creep.

On page 53 of FBC's KBTA CPCN application, FBC stated:

> FBC has applied a contingency amount to the estimates (before materials handling and provincial sales tax) of 15 percent for all construction and removal, other than

for transmission and distribution line construction at 20 percent, and line removal costs at 7 percent. Contingency amounts that have been applied are based on FBC experience.

15.2 Please explain the reasons for the differences between the transmission and distribution modification components contingencies in this Application (10 percent) and the transmission and distribution line construction contingency in the KBTA CPCN application (20 percent).

Response:

The contingencies used on the various components and or projects reflect the amount of uncertainty and variability that will remain in the detailed design stage. The KBTA CPCN Application line construction costs reflected a higher contingency largely because there were unknowns for items such as additional detailed soil investigation, construction coordination efforts, complications with sequencing, and drainage on site that were intertwined with substation construction activities.

For the ASM Project, a rigorous detailed design was conducted to ensure there was a practical design and workable construction staging and therefore there is less uncertainty and variability for this Project as compared to the KBTA Project. Identified construction risks that have been mitigated and accounted for include material warehousing yard interference, temporary fence removals, restricted/congested areas for line being worked on with nearby energized circuits, possible delays in getting daily outage/switching arrangements for working clearances, access through third-party areas, installation of live-line coverup where safety may be a concern, complicated scheduling for construction work, and coordination of multiple crews for minimizing outages/exposure. Therefore, the contingency amount was adjusted to reflect the detailed design efforts.

15.3 Please explain how FBC determined the contingency of 15 percent for the station construction and removal costs and a contingency of 10 percent for the transmission, distribution and fibre modification components. Please include whether the contingency amounts are based on FBC's experience.

15.3.1 Please explain why FBC's chosen method will provide an accurate estimate for contingency costs.

15.3.2 If FBC's experience was used, please explain which past construction projects and experience were used to determine the contingency amounts for the Application. Please include why this past experience is relevant for the ASM Terminal Station project.

Response:

FBC's chosen method follows AACE contingency guidelines using an experienced estimating team who have been involved in many FBC projects. The contingency for the ASM Project was determined based on the level of assessed risk and potential for scope escalation considering the level of design completed as part of the Class 3 estimate and using judgement based on past asset and estimating experience. Past projects used as a guide include the Grand Forks Terminal Station Reliability Project, Ruckles Substation Rebuild Project, and Kelowna Bulk Transformer Addition Project.

On page 52 of the Application, FBC provides Table 5-1: Risk Register, which is reproduced in part below:

Type of Risk	Risk Description	Mitigating Actions	Likelihood of Occurrence (Low / Medium / High)
Cost	Raw material costs increase due to inflation/market value.	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.	Medium
	Actual costs of construction are higher than estimated.	FBC will carefully monitor and control the budget.	Medium

On page 54 of the Application, FBC states: "[a]ny cost impacts that may arise from these risk factors are expected to be manageable within the Project contingency…"

15.4 Please confirm, or explain otherwise, that any anticipated foreign exchange and raw material escalation are included in the 15 percent and 10 percent contingencies mentioned in the preamble above.

15.4.1 If not confirmed, please explain why not.

Response:

Confirmed. Materials costs for the Project are based on Class 3 estimates that rely on current budgetary pricing, and it is expected that the Project contingencies can be used to account for typical variations, inflation, and general increases in estimated costs that may occur due to foreign exchange or raw material escalation.

However, the contingency does not account for any extreme events that may significantly impact material costs (e.g., major scale weather events, pandemics, market crashes/surges, commodity

spikes, etc.). If an extreme event were to occur during the execution of the Project, it is expected that the materials costs would be reviewed and reevaluated at that time to properly reflect current pricing, schedules, expedited deliveries, and the related items.

There are no events that are currently expected to significantly impact the Project's materials costs or that require the materials costs to be re-evaluated at this time.

On page 48 of FBC's KBTA CPCN application, FBC provided Table 5-1: Risk Register, which is reproduced in part below:

Type of Risk	Risk Description	Mitigating Actions	Likelihood of Occurrence (Low / Medium / High)
Cost	Raw materials cost increase due to inflation/market value	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	Low
	Actual costs of construction higher than estimated	Detailed class three estimate completed for construction	Low

15.5 Please explain the reasons for the differences between the KBTA CPCN application, which had a cost risk rated as low and a contingency estimate of 15 percent for all construction and removal, 20 percent for transmission and distribution line construction, and 7 percent for line removal costs; and this Application, which has a cost risk rated as medium and a contingency estimate of 15 percent for the station construction and removal costs and 10 percent for the transmission, distribution and fibre modification components.

Response:

FBC classified the ASM Project as a medium cost risk primarily due to market volatility, unpredictable commodity escalation, extended procurement timelines, and contaminated soil disposal risks. As a medium cost risk, these risks are more likely to materialize than for a low-cost risk classed project such as the KBTA Project; therefore, FBC has reflected those cost risks directly in the Class 3 estimate for the ASM Project through the Identified Risk Allowance categories, including a material escalation cost. This keeps the contingency for the ASM Project at similar levels to other projects.

16.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 6.2, pp. 55-56; Section 6.3, p. 58; FBC Application for a CPCN for the Kelowna Bulk Transformer Addition proceeding, Exhibit B-1, Section 6.2.6, p. 54

Cost Escalation

On page 55 of the Application, FBC provides a breakdown of the Project cost estimate in Table 6-1.

On page 56 of the Application, FBC states:

> [t]o convert the base capital cost estimate and contingency from 2022 dollars to as-spent dollars over the period from 2023 to 2026, a total escalation of $2.568 million was applied to the Project cost estimate. Of the total escalation of $2.568 million, $2.271 million corresponds to the escalation on the base capital cost estimate and $0.297 million corresponds to contingency.

16.1 Please provide, in the same format as Table 6-1, the project escalation in dollars and percentage for each line item listed in Table 6-1.

16.1.1 If the cost escalation percentages differ between line items, please explain why.

Response:

Please see Table 1 below, which provides the Project escalation in dollars and in percentage for each line item listed in Table 6-1 of the Application.

FBC notes that the year-over-year escalation factors from Q4 2022 to Q4 2026 (see the response to BCUC IR1 16.2 for the individual escalation factors by years) are the same for all line items in Table 1 below; however, the removal costs and the CPCN Preliminary Engineering Costs have different cost escalations in percentage terms than the rest of the line items because of the timing of when these costs are incurred.

As noted in Section 5.5 of the Application, the removal costs are expected to occur only in 2026 and therefore have four years of escalation applied (from 2022 to 2026). On the other hand, the construction of the ASM Project is expected to occur over a 3-year period from 2024 to 2026; therefore, some of the construction costs only have 1 or 2 years of escalation applied, resulting in less overall escalation in percentage terms than the removal costs (i.e., 9 percent for the construction costs compared to 11 percent for the removal costs, as shown in Table 1 below). Similarly, only a small portion of the CPCN Preliminary Engineering Costs (i.e., $0.282 million as shown on page 56 of the Application) are forecast to the end of 2023 with the rest of the costs being actual costs incurred in 2021 and 2022. Therefore, escalation is only applied to the forecast

portion to the end of 2023, resulting in less escalation in percentage terms (i.e., 1 percent) for the CPCN Preliminary Engineering Costs than the rest of the line items shown in Table 1 below.

Table 1: Updated Table 6-1 with Breakdown of Project Escalation in $ millions and %

Line	Particular	Base Cost	Escalation	As-Spent $	Escalation on Base Cost
1	Station Construction Costs	20.453	1.818	22.270	9%
2	Transmission and Distribution Construction Costs	1.771	0.153	1.925	9%
3	Fibre Construction Costs	0.148	0.013	0.161	9%
4	Removal Costs	0.984	0.108	1.092	11%
5	Project Management and Owner's Costs	2.004	0.178	2.182	9%
6	**Subtotal Project Capital Cost**	**25.361**	**2.271**	**27.631**	**9%**
7	Contingency	3.318	0.297	3.615	9%
8	**Subtotal Project Capital Cost w/Contingency**	**28.679**	**2.568**	**31.247**	**9%**
9	CPCN Preliminary Engineering Costs	0.751	0.009	0.760	1%
10	AFUDC	3.171		3.171	
11	**Total Project Cost**	**32.601**	**2.577**	**35.179**	**8%**

16.2 Please provide FBC's calculation of the average cost escalation percentage applied to the total project cost estimate.

Response:

As explained on page 56 of the Application, FBC used the forecast of capital expenditure escalation from the Wood Mackenzie Market Report (provided in Appendix G-3 of the Application) for electric transmission and distribution utilities across North America over the period from Q2 2022 to Q4 2024. For 2025 and 2026, FBC assumed the same percentage increase as 2024. Please refer to Figure 1 below for the screen capture of the capital expenditure escalation forecasts for electric utilities from the Wood Mackenzie Market Report that FBC used to derive for the total escalation. Please also see Table 1 below which shows the capital index (average) from the Wood Mackenzie Market Report from Q2 2022 to Q4 2024, the year-over-year increase in percentage, as well as the cumulative escalation factor from 2022 in percentage calculated for each year from 2022 to 2026.

Figure 1: Wood Mackenzie Market Report – Electric Transmission and Distribution Capital Index, Actual Q1 2020 to Q1 2022, and forecast from Q1 2022 to Q4 2024

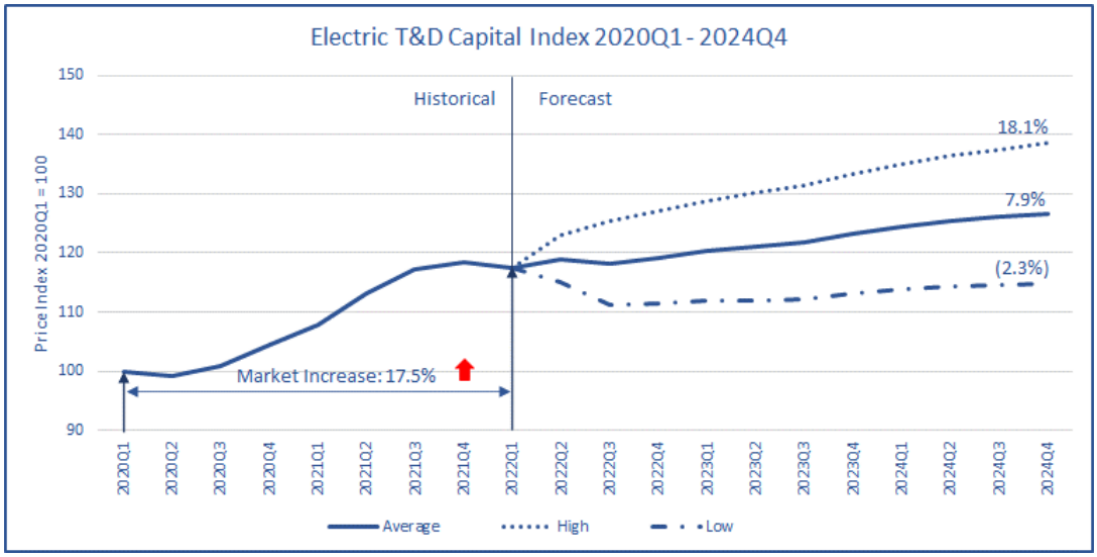


Table 1: Calculation of Escalation Factor in Percentage Applied to the ASM Project Capital Costs

Year	Capital Index (Average) - From Wood Mackenzie Report	YoY Increase (%)	Cumulative Escalation from 2022
2022	119.23		100.00%
2023	123.21	3.34%	103.34%
2024	126.72	2.85%	106.28%
2025		2.85%	109.31%
2026		2.85%	112.42%

Further on page 56 of the Application, FBC states:

> The escalation was derived based on a market report developed by Wood Mackenzie for FBC which provided a forecast of capital expenditure escalation for the period from Q2 2022 to Q4 2024 for electric transmission and distribution utilities across North America, with specific indices such as labour applied specific to British Columbia. For the escalation beyond Q4 of 2024 (i.e., 2025 and 2026), FBC assumed the same percentage increase as 2024.

On page 58 of the Application, FBC states:

Inflation: Two percent annually from 2027 onwards applied to the incremental O&M, property tax, and the future sustainment capital costs during the post-Project analysis period. FBC used the midpoint of the inflation-control target range of 1 to 3 percent, set by the Bank of Canada for long-term inflation forecasts for 2027 and beyond.

16.3 Please confirm, or explain otherwise, that a two percent inflation adjustment was applied on top of the cost escalation already applied to the incremental O&M, property tax, and the future sustainment capital costs during the post-project analysis period.

16.3.1 If confirmed, please provide the total escalation that was applied to the incremental O&M, property tax, and the future sustainment capital costs in dollars and percentage and explain why this is appropriate.

Response:

Confirmed. At the time of preparing the Application, FBC estimated the incremental O&M, property tax, and Project cost estimate in 2022 dollars. In order to convert these estimates from 2022 dollars to as-spent dollars, FBC applied both escalation as well as inflation, as explained further below:

1. **Incremental O&M:** As noted on page 58 of the Application, FBC expects the incremental O&M to be incurred from 2027 onwards when all assets have entered FBC's rate base. In order to convert the incremental O&M from 2022 dollars to as-spent dollars, FBC first applied the cumulative cost escalation percentage (as set out in the response to BCUC IR1 16.2) to convert the incremental O&M from 2022 dollars to 2026 dollars. Beyond 2026, FBC then applied the two percent inflation over the 50-year post-Project analysis period to convert these estimates from 2026 dollars to as-spent dollars. Please refer to Table 1 below which provides the incremental O&M estimates in 2022 dollars as well as the cumulative escalation and inflation used to calculate the as-spent dollars.

2. **Incremental Property Tax:** As noted on page 58 of the Application, FBC expects the incremental property tax from new infrastructure to be incurred from 2027 onwards. Similar to the incremental O&M, FBC applied the cumulative escalation percentage to convert the incremental property tax from 2022 dollars to 2026 dollars. Beyond 2026, FBC then applied the two percent inflation over the 50-year post-Project analysis period to convert the property tax from 2026 dollars to as-spent dollars. Please refer to Table 2 below which provides the 2027 incremental property tax estimate in 2022 dollars as well as the cumulative escalation and inflation used to calculate the 2027 dollars.

3. **Future Incremental Sustainment Capital:** The future replacement cost includes both escalation as well as inflation. To calculate these future replacement costs in as-spent dollars, FBC first escalated the Project capital cost estimate during the construction period from 2022 dollars to as-spent dollars, which reflects the final cost of the assets that will enter FBC's rate base in 2027. In FBC's analysis, when an asset is fully depreciated, it is assumed to be retired and replaced. The replacement cost is inflated by 2 percent per year from the escalated amount that was capitalized into rate base in 2027. For example, if an asset was capitalized in 2027 at $100 and fully depreciated over 10 years, then the analysis would include the asset being retired in year 11 (at $100) and a replacement asset being added in year 11, with the replacement value calculated as $122 ($100 x 1.02^10). This approach conservatively reflects the total potential Project impact over a 50-year post-Project analysis period and is consistent with how FBC typically performs its CPCN financial analysis.

Please refer to the response to BCUC IR1 16.4 for a discussion on the appropriateness of using the Wood Mackenzie Market Report to derive the escalation factors from 2023 to 2026, and also the appropriateness of using 2 percent inflation as the escalation factor for 2027 and beyond.

Table 1: Total Escalation Applied to Incremental O&M (in $000s and %) from 2027 to 2034

$000s	2027	2028	2029	2030	2031	2032	2033	2034
Incremental O&M (2022$)[1]	1.9	1.9	1.9	1.9	1.9	(6.3)	1.9	183.3
Escalation	0.3	0.3	0.4	0.4	0.5	(1.7)	0.6	58.1
Escalation (%)	15%	17%	19%	22%	24%	27%	29%	32%
As-spent Dollars[2]	2.2	2.2	2.3	2.3	2.4	(8.0)	2.5	241.4

Notes to Table:

1. As noted on page 58 of the Application, the incremental O&M is estimated over an eight-year window based on a breaker replacement every eight years. As such, Table 1 above provides the incremental O&M estimates over the eight-year period in 2022 dollars, plus escalation to as-spent dollars to the individual years from 2027 to 2034.

2. The incremental O&M in as-spent dollars from 2027 to 2034 aligns with Line 1 of Schedule 2 of Confidential Appendix H.

Table 2: Total Escalation Applied to Incremental Property Tax (in $000s and %) to 2027

$000s	2027
Property Tax - General, School and Other (2022$)	405.9
Escalation	59.5
Escalation (%)	15%
As-spent Dollars[1]	465.4

Note to Table:

1. The incremental property tax in 2027 dollars aligns with Line 13 of Schedule 2 of Confidential Appendix H.

On page 54 of FBC's KBTA CPCN application, FBC stated: "[t]he as-spent capital cost estimates in Table 6-1 include an annual price escalation of 2.0 percent over the period of execution based on the Conference Board of Canada Consumer Price Index forecast as of April 2020."

16.4 Please discuss the difference in cost escalations between the KBTA CPCN application and the Application and explain why the cost escalation as proposed in the Application is appropriate.

16.5 Please explain why FBC used Wood Mackenzie Supply Chain Consulting's market report to determine the cost escalation in this Application rather than Bank of Canada for long-term inflation forecasts or Consumer Price Index forecast.

16.5.1 Please discuss any implications of taking this approach.

Response:

The KBTA Project Application was developed in 2019 and filed with the BCUC in April 2020. At that time, the significant inflationary environment that FBC has experienced since 2021 and continuing into the present, was not anticipated or expected. The historical inflation as well as forecasts of inflation (e.g., CPI), including the target inflation set by the Bank of Canada, at that time were either at or close to 2.0 percent. As such, it was appropriate to use 2.0 percent as an assumption for cost escalation when developing the KBTA CPCN Project. FBC had no other reference sources that suggested inflation would increase significantly. FBC also notes that the KBTA Project application was prepared prior to the COVID-19 pandemic and, while the application process occurred during the pandemic, the pandemic was in its very early stages and the future impacts on supply chain, inflation, etc. were not yet known or being experienced.

In contrast, the ASM Project was developed in 2022 and filed with BCUC in early 2023. The significant inflationary environment that FBC is experiencing is known and has been reflected in actual construction costs. Continuing to use 2.0 percent for construction cost escalation in the short-term would not be appropriate and would understate the expected Project costs in as-spent dollars. This is the reason why FBC used the market report developed by Wood Mackenzie, as this report provides a forecast of capital expenditure escalation for electric transmission and distribution utilities across North America. The capital expenditure forecasts contained in the report are based on aggregate results across North America and include specific indices such as labour applied to British Columbia. Accordingly, the report is reflective of the construction cost environment that FBC is currently experiencing in lieu of a more typical 2.0 percent annual inflation.

FBC also notes that for costs (i.e., incremental O&M, property tax, etc.) expected to occur beyond 2027 over the 50-year post-Project analysis period, an annual 2.0 percent inflation has been applied as the escalation factor. FBC considers this approach reasonable and conservative as there are no available source references that would provide inflation forecasts over a 50-year period beyond 2027. Therefore, FBC has appropriately relied on the Bank of Canada mid-point inflation target of 2.0 percent as a proxy for future cost escalation over the 50-year post-Project period.

17.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 6.4.3, 6.4.4, p. 59; FBC Annual Review for 2023 Rates Application proceeding, Exhibit B-2 (2023 Annual Review), Section 12.3.1.1,

p. 122

Retirement of Existing Assets

On page 59 of the Application, FBC states:

> […], the Project includes the demolition of the three existing 63 kV A-frame structures, the demolition of the ASM Terminal Station, and the salvaging of existing fibre between WTS and SCC, with the total book value for the decommissioned assets estimated to be $4.470 million[37] by the end of 2026. These decommissioned assets will be retired from FBC's rate base by crediting the original value of $12.362 million to FBC's plant-in-service and debiting the same amount in accumulated depreciation, which is reflected in the opening balance of 2027 at the same time when all new assets enter FBC's rate base […]. [Emphasis Added]

In footnote 37 on page 59 of the Application, FBC states: "based on the original acquisition value of $12.362 million and accumulated depreciation of $7.892 million estimated at the end of 2026."

On page 122 of FBC's 2023 Annual Review, FBC stated: "FBC follows US GAAP for both financial and regulatory accounting purposes."

17.1 Please clarify whether FBC's treatment of the decommissioned assets highlighted in the preamble above is in accordance with US GAAP. and FBC's past regulatory accounting treatment.

17.1.1 If so, please advise of the relevant section(s) in US GAAP and discuss how it is applicable.

17.1.2 If not, please explain why not.

Response:

FBC's treatment of the decommissioned assets is consistent with its established regulatory practice for recording these transactions and is fundamental to the use of FBC's group depreciation methodology that uses these "experience adjustments" to determine revised useful lives and depreciation rates. These depreciation rates are determined through independent depreciation studies that are updated periodically. The treatment is also in accordance with US GAAP, which allows for the economic effects of rate-regulation to be represented in accounting records. ASC 980-10-05-5, Regulated Operations-Overall-Effect of Regulatory Accounting, states

that "*Regulators sometimes include costs in allowable costs in a period other than the period in which the costs would be charged to expense by an unregulated entity*" which has a consequence of creating assets or liabilities that otherwise wouldn't exist in a non-regulated business. In the case of the treatment of the decommissioned assets, due to past regulatory precedent, this accounting treatment is in accordance with US GAAP.

As part of providing a response to this question, it is important to understand the group accounting method used by FBC and other utilities in Canada for retirement of plant. For this purpose, FBC has provided a summary below from FortisBC Energy Inc.'s (FEI) 2012-2013 Revenue Requirements Application (pages 289 to 290):

> Historically, the FEU have followed recognized regulatory group accounting procedures in accounting for their property plant and equipment. The FEU also adhere to the BCUC Uniform System of Accounts, unless modified by Commission order. Under both of these procedures, on retirement of depreciable gas plant, Accumulated Depreciation is charged with the ledger value of the gas plant retired and the cost of removal less amounts recovered for salvage and insurance. It is only in rare cases where the forces of retirement are outside of the forces that were contemplated in determining depreciation rates that gains and losses on depreciable plant would be recognized in income. Therefore, under historical practice, all normal course gains and losses on retirement of assets are included in accumulated depreciation.
>
> This treatment is appropriate since group depreciation rates are set to recover the asset values over the average service life of the asset group, so that we expect some assets to be retired before their net book value reaches zero; others would be retired after their net book value reaches zero; and overall the gain/loss amount included in accumulated depreciation will have an immaterial value, with any material amounts recovered through changes to future depreciation rates. When depreciation rates are not adjusted to reflect the shorter service lives of assets, or retirements occur in a different pattern than was expected in the last accepted depreciation study, then the loss amount can build in accumulated depreciation.

An excerpt from the BCUC Uniform System of Accounts explains this more fully:

> The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group. It is not the intention of this classification to require the company to keep records of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated

depreciation is subdivided according to the utility department to which applicable, or to each group of gas plant accounts. When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization.

17.2 Please confirm, or explain otherwise, that FBC's treatment of the decommissioned assets highlighted in the preamble above is consistent with FBC's regulatory accounting treatment on previous projects.

17.2.1 If not, please explain why not and discuss FBC's rationale for taking this approach.

Response:

Confirmed. Please also refer to the response to BCUC IR1 17.1.

17.3 Please confirm, or explain otherwise, that a loss should be recorded on the retired assets with an estimated net book value (NBV) of $4.470 million at the time of decommissioning.

17.3.1 If so, please quantify, in dollars and percentage, the impact on project cost and the rate impact to FBC customers.

Response:

Not confirmed. FBC will not record a loss on disposition as an accounting entry. However, an estimated loss of $4.470 million will be reflected in FBC's accumulated depreciation (when the original value of the asset is debited to the accumulated depreciation) and will be recovered through FBC's depreciation rates. Under group asset accounting, the depreciation rates of each asset account are reviewed and updated periodically with new depreciation studies that are filed with the BCUC for approval. As such, at the time of each study, the future depreciation rates of each asset class will factor into any accumulated gains/losses in the asset class, which will then be returned to or recovered from customers through depreciation expense in future FBC revenue requirements.

17.4 Please explain whether FBC intends to sell or repurpose any of the decommissioned assets.

17.4.1 If FBC intends to sell, please explain whether the sales proceeds will be used to lower the project cost. If so, please quantify the impact on the project cost and the rate impact to FBC customers. If not, please explain why not.

17.4.2 If FBC intends to repurpose, please explain whether the costs to repurpose and maintain these assets have been included in the incremental revenue requirement and levelized rate impact. If not, please explain why not.

17.4.3 If FBC does not intend to sell or repurpose any of the decommissioned assets, please explain why not.

Response:

FBC does not intend to sell any of the decommissioned assets; however, if possible, FBC will repurpose some of the assets as spares for other stations for events such as emergency repairs. At this time, FBC does not have any specific plans of when and where these spares would be used. Furthermore, FBC does not expect there will be many pieces of equipment or assets that will be able to be repurposed due to their condition and vintage. As such, FBC is unable to determine at this time the cost and value of these assets if they were to be repurposed.

Consistent with past practice, the Project assets will be retired from FBC's rate base at the time they are decommissioned. FBC will keep the assets that can be used as suitable spares. At the time that these spares are repurposed, any costs incurred to make suitable and install the assets will be recorded in FBC's rate base.

On page 59 of the Application, FBC states: [t]he total Project cost estimate includes approximately $1.332 million (including AFUDC) of removal costs in as-spent dollars.

17.5 Please confirm, or explain otherwise, that the $1.332 million in removal costs are an asset removal obligation (ARO) for FBC.

17.5.1 If not, please discuss whether there will be an ARO associated with this CPCN project. If so, please confirm whether the ARO has been recorded

in accordance with US GAAP and accounted for in the project cost estimate.

Response:

Not confirmed. AROs are recognized for accounting purposes when legal obligations associated with the retirement of long-lived assets exist, which result in a liability being recorded in the period in which the obligation can be reasonably estimated, at the present value of the future retirement costs. In the case of the removal costs related to the demolition of the ASM Terminal station, which are discussed on page 45 of the Application, no ARO had been recognized since the uncertainties in estimating future asset retirement costs, including the period in which the costs would be incurred, were not able to be reasonably estimated.

FBC notes that ARO accounting results in the recognition of a liability in advance of incurring any required removal costs. Although an ARO was not recognized for the removal costs described on page 45 of the Application, FBC has pre-collected amounts for future removal costs of specified asset classes through historical depreciation expense, which has been recognized as a net salvage liability within accumulated depreciation. The amount to be pre-collected is determined through independent depreciation studies that are updated periodically, and this accounting treatment has been approved by Order G-202-15 as part of FBC's 2016 Annual Review[8].

As such, FBC's accumulated depreciation includes a net salvage provision where the removal costs associated with this Project will be recorded against.

[8] FBC Annual Review for 2016 Rates Decision and Order G-202-15, p. 12.

18.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 6.3, p. 58;

Incremental O&M and Property Tax

On page 58 of the Application, FBC states:

> […], the retirement of the existing ASM Terminal Station will eliminate the O&M [Operations and Maintenance] expenditures associated with the infrastructure at this site. The incremental O&M of the Project in 2027 (i.e., when all assets enter FBC's rate base) is minimal, estimated to be $2.180 thousand in as spent dollars, relating to substation equipment, plus annual inflation […]. Over an eight-year O&M window (based on a breaker replacement every eight years), the average incremental O&M is approximately $30.901 thousand per year.
>
> […]
>
> Incremental property tax of $0.465 million, in as-spent dollars, is estimated to be incurred from 2027 onwards because of new infrastructure. This incremental amount will be partially offset by the removal of the ASM Terminal Station, as both WTS and the ASM Terminal Station are located in the City of Trail.

18.1 Please provide the operations and maintenance (O&M) cost and property tax savings from the retirement of the ASM Terminal Station.

Response:

Please refer to Table 1 below which shows the total new O&M related to the expansion at WTS and the O&M savings resulting from the retirement of the ASM Terminal Station, in as-spent dollars, over an eight-year window (based on the timing of a breaker replacement).

FBC notes that the incremental O&M of $30.901 thousand per year as referenced in the preamble above is the average incremental O&M over the first eight years, from 2027 to 2034, as shown in Table 1 below. Over the eight-year O&M window, the average Gross O&M associated with the new expansion at WTS is $89.863 thousand per year, which is offset by average Gross O&M savings of $58.963 thousand per year due to the demolition of the ASM Terminal Station. The incremental Gross O&M from 2027 to 2034 in Table 1 aligns with Line 1 of Schedule 2 of Confidential Appendix H.

Table 1: New Gross O&M and O&M Savings ($000s)

Particular ($000)	2027	2028	2029	2030	2031	2032	2033	2034	Average
Preferred Alternative 5: Expanded WTS Site O&M	$33.797	$34.473	$35.163	$35.866	$36.583	$120.364	$38.061	$384.599	$89.863
Retired ASM Terminal Station O&M	($31.617)	($32.250)	($32.895)	($33.553)	($34.224)	($128.344)	($35.606)	($143.214)	($58.963)
Total Incremental O&M	**$2.180**	**$2.224**	**$2.268**	**$2.313**	**$2.360**	**($7.980)**	**$2.455**	**$241.385**	**$30.901**

Please refer to Table 2 below for the breakdown of the incremental property taxes of $0.465 million, in as-spent dollars, estimated to be incurred from 2027 onwards as noted in the preamble. Property taxes from the new infrastructure are estimated to be $0.549 million, in as-spent dollars, in 2027 and they are offset by property tax savings of $0.084 million, in as-spent dollars, from the retired ASM Terminal Station in 2027. The property tax amount of $0.465 million in 2027 aligns with Line 13 of Schedule 2 of Confidential Appendix H.

Table 2: Property Taxes from New Construction and Savings from Retirement ($000s)

Particular ($M)	2027
Property Taxes from New Construction	$0.549
Property Tax from Retirement of ASM Terminal Station	($0.084)
Incremental Property Taxes	$0.465

18.2 Please confirm, or explain otherwise, that the O&M cost and property tax savings from retirement of the ASM Terminal Station has been included in the average incremental O&M of $30.901 thousand and incremental property tax of $0.465 million.

18.2.1 If not confirmed, please explain why not, and provide the average incremental O&M and property tax with the savings included.

18.2.1.1 Please provide an update to the levelized rate impact and total present value (PV) of the incremental revenue requirement if the savings are included.

Response:

Confirmed. The financial analysis includes the O&M and property tax savings from the retirement of the ASM Terminal Station. Please refer to the response to BCUC IR1 18.1 for the breakdown between new O&M and property tax costs and savings. Since the financial analysis already includes the savings due to the retirement of the ASM Terminal Station, no updates to the levelized rate impact and total PV of the incremental revenue requirement are required.

19.0 Reference: PROJECT COSTS, FINANCIAL ANALYSIS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1, Section 6.2, p. 55; Section 6.3, p. 57

Incremental Revenue Requirements and Rate Impact

On page 55 of the Application, FBC states: [t]he expected accuracy for a Class 3 cost estimate, as defined by the AACE, is low: -10 percent to -20 percent and High: +10 percent to +30 percent.

On page 57 of the Application, FBC states: [t]he PV of the incremental revenue requirement of the Project is approximately $44.138 million and the levelized rate impact is 0.63 percent over the 53-year analysis period.

19.1 Please complete the table below to illustrate the variability in the PV of the 53-year Incremental Revenue Requirement for the Project.

Base PV	PV If:		Difference to Base PV if:	
	Cost Decline 20%	Cost Increase 30%	Cost Decline 20%	Cost Increase 30%
$44.138M				

19.2 Please complete the table below to illustrate the percentage rate impact and change in annual bill based on the calculations applied in the previous IR.

Base PV	% Rate Impact If:		Change in Annual Bill if:	
	Project Cost Decline 20%	Project Cost Increase 30%	Project Cost Decline 20%	Project Cost Increase 30%
$44.138M				

Response:

Please refer to Tables 1 and 2 below for the PV of incremental revenue requirement and levelized rate impacts, respectively, over the 53-year analysis period under the scenarios where the Project costs are 20 percent lower and 30 percent higher. Please also refer to the response to BCUC IR1 13.1 for the total Project cost as well as the assumptions included for each scenario.

Table 1: PV of Incremental Revenue Requirement if Project Cost is -20% or +30%

Base PV	PV If:		Difference to Base PV if:	
	Cost Decline 20%	Cost Increase 30%	Cost Decline 20%	Cost Increase 30%
$44.138M	$37.289M	$54.411M	-$6.849M	$10.273M

Table 2: Levelized Rate Impact and Annual Bill if Project Cost is -20% and +30%

Base Levelized Rate Impact	% Levelized Rate Impact If:		Base Annual Bill (2027)	Change in Annual Bill if:	
	Project Cost Decline 20%	Project Cost Increase 30%		Project Cost Decline 20%	Project Cost Increase 30%
0.63%	0.53%	0.77%	$ 7.80	$ 6.40	$ 10.00

F. ENVIRONMENTAL AND ARCHAEOLOGY

20.0 Reference: ENVIRONMENT AND ARCHAEOLOGY

Exhibit B-1, Section 5.1.2, p. 45; Exhibit B-1, Appendix E-1, p. 10

Soil Management

On page 61 of the Application, FBC states:

> As there is a likelihood of impacted surface soils within the footprint of the proposed expansion, a soil management plan is required. Initial discussions with Teck Metals Ltd. indicate that their licensed Teck Trail Operations Landfill can be used for soil disposal. Planning is being conducted with this approach, such that although there are no regulatory triggers for environmental investigations for soils relocated to a licensed facility, the licensed facility may still require some environmental data prior to acceptance. FBC will engage with a Qualified Environmental Professional (QEP) to ensure that all work will be completed in compliance with regulatory and disposal facility requirements.

Additionally, page 10 of Appendix E-1 (WTS Environmental Management Plan) to the Application states:

> The Teck landfill can accept metal contaminated soil from Teck Metals Ltd. properties in the Trail area provided it does not exceed leachable hazardous waste criteria (as determined by a TCLP test). If soil tests exceed Teck landfill requirements, Fortis BC will dispose of contaminated soils at a facility authorized to accept soils with the specified contaminant levels.

20.1 Please provide FBC's timeline for the creation of the soil management plan and discuss any factors that may cause delays.

20.1.1 Please outline the impact, if any, to the Project cost and schedule if the creation of the soil management plan is delayed.

Response:

Upon approval of the Application, FBC's external Qualified Environmental Professional (QEP) will commence soil sample collection at locations within the site where soil disturbance and removal will occur. The timeline for sampling will be one to two days depending on access and safety considerations. Samples will be sent to a qualified lab for analysis and the turnaround time is 10 to 14 business days. Development of a soil management plan will take from one to four days depending on soil characteristics. During the development of the plan, there will be discussions with authorized receiving sites to determine handling protocols and any logistics for transport of the materials, including discussions with Teck for the receipt of contaminated soils that do not meet leachable hazardous waste criteria.

Factors that may cause delays to this timeline include:

- Transport delays for getting samples to the lab;
- Delays in sampling at the lab; and
- Complications with disposal arrangements at receiving sites.

FBC does not anticipate the soil management plan being delayed, as FBC has been actively consulting with the external QEP and with Teck.

20.2 Please outline how the soil management plan will measure metal contamination in the soil against Teck's leachable hazardous waste criteria. In the response, please include the most recently measured TCLP test result from WTS substation.

Response:

Metal contamination in soil is regulated by the BC Hazardous Waste Regulation which defines leachable toxic waste as "a waste that produces an extract with a lead concentration greater than 5 mg/L, when subjected to the toxicity characteristic leaching procedure (TCLP)".

No TCLP tests have been taken from WTS to date.

20.2.1 Please explain whether FBC has identified alternative facilities authorized to accept contaminated soils, in the event WTS TCLP test results exceed Teck's leachable hazardous waste criteria. If not, please explain why not.

20.2.1.1 Please discuss any potential impact to project cost or schedule should WTS TCLP test results exceed Teck's Leachable hazardous waste criteria.

Response:

FBC's third party QEP has established working relationships and authorized the receiving facility in Swan Hills, Alberta. If the TCLP test results exceed the BC Hazardous Waste Regulation criteria, soil will be sent for disposal at Swan Hills. In this scenario, where soil is sent for disposal at Swan Hills, additional costs will be incurred for transporting the contaminated soil. FBC does not anticipate schedule impacts for this additional soil remediation.

21.0 Reference: ENVIRONMENT AND ARCHAEOLOGY

Exhibit B-1, Section 7.2, p. 62

Archaeological Impact Assessment

Page 62 of the Application states:

> A permit will be required under Section 12.2 of the *Heritage Conservation Act* (HCA) in order to undertake the AIA [Archaeological Impact Assessment], which FBC will obtain. In addition, Indigenous cultural heritage investigation permits will be obtained if identified as necessary during engagement with the Indigenous communities whose traditional territory overlap the Project area. Currently the Indigenous communities with traditional territory overlapping the Project area that have cultural heritage investigation permitting processes are the Okanagan Indian Band and Upper Nicola Indian Band.

21.1 Please explain whether FBC has obtained the permit required under Section 12.2 of the HCA.

21.1.1 If not, please describe the process for obtaining the permit and identify at what stage FBC is at in the process. Please also discuss any potential impacts to the Project scope, schedule or cost should the permitting process result in delays.

Response:

FBC has engaged Nupqu Limited Partnership (Nupqu) as an archaeological consultant for the Project. On behalf of FBC, Nupqu has obtained the *Heritage Conservation Act* (HCA) Section 12.2 multi-assessment Inspection Permit 2022-0110, which is applicable for undertaking the Archaeological Impact Assessment (AIA).

21.2 Please explain whether FBC has completed the engagement required to understand if Indigenous cultural heritage investigation permits are necessary for the Project.

21.2.1 If yes, please discuss the results of the engagement process and identify whether Indigenous cultural heritage investigation permits are required.

21.2.1.1 If required, please describe the process for obtaining the permits and identify where FBC is in the process.

21.2.1.2 If not required, please explain why not.

Response:

FBC, through its archaeological consultant Nupqu, has completed the engagement to determine whether Project-specific Indigenous cultural heritage investigation permits are required and, based on that engagement, FBC has not obtained Project-specific Indigenous cultural heritage investigation permits.

Nupqu notified the Okanagan Indian Band and the Upper Nicola Indian Band (the Indigenous communities with traditional territory overlapping the Project area that have cultural heritage investigation permitting processes) that they would be undertaking an AIA of the Project footprint.

The Okanagan Indian Band responded with a letter that they deferred the Project to the Osoyoos Indian Band and Lower Similkameen Indian Band. As part of the response, the Okanagan Indian Band did not request that a cultural heritage investigation permit be obtained.

The notification elicited an auto-reply response from the Upper Nicola Indian Band that contained their cultural heritage investigation permit application. Nupqu followed up via email to the Upper Nicola Indian Band regarding the cultural heritage investigation permit application process, and no response was received; therefore, no permit was obtained prior to the AIA being undertaken.

On page 62 of the Application, FBC states:

> Nupqu has recommended that an AIA be completed for areas where Project-related ground disturbance activities are anticipated in areas identified as having high archaeological potential through the AOA [Archaeological Overview Assessment] process. It is expected that the AIA will begin in 2023 and continue, as necessary, throughout construction.

21.3 Please discuss whether any Archaeological Impact Assessments have been completed to date. If yes, please summarize any key findings and / or recommendations.

Response:

Nupqu completed an AIA on April 18, 2023 under HCA Section 12.2 Multi-assessment Inspection Permit 2022-0110. A report describing the results and recommendations of the AIA is being prepared by Nupqu. Following completion of the AIA, Nupqu prepared a Letter of Notice included as Attachment 21.3 to this response.

In summary, no archaeological materials or sites were observed, recorded or are otherwise suspected within the location of the Project footprint. The Letter of Notice recommends that no

1 further archaeological work is required for the Project footprint but that a chance find / stop work
2 procedure be developed and provided to construction crew members.

3

G. CONSULTATION AND ENGAGEMENT

22.0 Reference: STAKEHOLDER CONSULTATION

Exhibit B-1, Section 8.2, pp. 65-66

Consultation with the Local Government

On page 65 of the Application, FBC states: "Both WTS and the ASM Terminal Station are located within the City of Trail and adjacent to the Village of Warfield."

On page 66 of the Application, FBC states:

> FBC recognizes the importance of meaningful consultation and of developing, maintaining, and enhancing strong stakeholder relationships. To support the successful completion of the Project, FBC's interactions with stakeholders will be open, transparent and continue until completion of the Project.

22.1 Please discuss if there has been any further communication with the City of Trail, Village of Warfield or any other local government or stakeholder regarding the Project since the date of filing of the Application. If so, please briefly summarize the communications and identify whether any issues were raised.

Response:

There has been no further communication with local governments or stakeholders since the date of filing. Please refer to the responses to BCUC IR1 25.2 and 27.3 for a description of the communication and engagement with Indigenous communities since the filing of the Application.

23.0 Reference: STAKEHOLDER CONSULTATION

Exhibit B-1, Section 8.2.1, p. 66

Noise Impacts at the WTS Station

On page 66 of the Application, FBC states:

> The ASM Terminal Station sits on a narrow projection of land with downhill sloping terrain on either side. Due to the age of the Station's infrastructure, a consistent buzz or hum from the Station can be heard in the neighbouring subdivision, as noted in the Stakeholder Consultation Log included as Appendix I-1. This hum would stop after the completion of the Project, when the new transformers are installed at WTS and the existing ASM Terminal Station transformers are decommissioned.

23.1 Please explain whether FBC has received any customer complaints or questions regarding noise levels with respect to the existing WTS station.

Response:

No, FBC has not received any customer complaints or questions regarding noise levels with respect to WTS.

23.2 Please discuss any potential impacts to noise levels at the WTS station from the installation of two additional transformers. As part of the response, please discuss any actions taken by FBC to identify and mitigate potential increases to noise levels from the operation of additional transformers.

Response:

FBC anticipates that the noise generated by the new transformers at WTS will blend into the existing ambient noise because it is immersed in an established industrial area and not in proximity to a residential area. When the transformer specification is issued to potential vendors during procurement, it will include proactive noise mitigation measures.

24.0 Reference: STAKEHOLDER CONSULTATION

Exhibit B-1, Section 8.2, p.66

Consultation with Local Residents

On page 66 of the Application, FBC states:

> Potential customer impacts during construction will be limited to those living in the subdivisions near the ASM Terminal Station site. As such, the primary focus of FBC's communication materials is to provide notice of the proposed Project and gather and respond to any feedback or concerns raised. […]
>
> In November 2022, FBC initiated engagement activities by sending Project notification letters (Appendix I-2) to the affected local governments, as well as residents within 250 metres of both the ASM Terminal Station and WTS sites.

24.1 Please provide a summary of any feedback received from local residents since filing of the Application.

Response:

FBC has not received any feedback from local residents since the filing of the Application.

24.2 Please explain whether construction notification letters will be provided to all stakeholders for the Project. In the response, please provide the approximate date(s) and preferred method (hand-delivery, email, etc.) of the notification(s), as applicable.

Response:

FBC will provide construction notification letters via email to the City of Trail, the Village of Warfield, the City of Rossland, and the Regional District of Kootenay Boundary. Additionally, James L. Webster School and the area residents will receive construction notification letters via mail. Based on the current Project construction schedule, construction is estimated to begin in the Spring of 2024; therefore, FBC would send the notifications in approximately February 2024.

25.0 Reference: CONSULTATION

Exhibit B-1, Section 1.1.7, p. 4

GENERAL

On page 4 of the Application, FBC states:

> FBC considers that the public consultation activities to the time of filing the Application have been sufficient, appropriate, and reasonable to meet the requirements of the CPCN Guidelines. FBC will continue to consult with stakeholders regarding construction timelines, mitigation of traffic disruptions (where applicable) and public safety.

25.1 Please explain whether the Project triggers the Crown's Duty to Consult. if yes, please provide a summary of the Crown's consultation to date.

Response:

Based on the nature of the Project and the approvals required, FBC does not expect that the Project will trigger the Crown's Duty to Consult; however, FBC will continue to engage with Indigenous communities.

25.2 Please provide a summary of any engagement activities with Indigenous Communities since filing of the Application. Please briefly summarize any engagement activities and identify whether any issues were raised.

Response:

Upon filing the Application, FBC sent a notice of filing to the nine identified Indigenous communities. FBC also provided the Application information and a notice of filing to the Colville Confederated Tribe and Adams Lake Indian Band, who were not included in the original nine communities identified through the British Columbia Consultative Database, but were identified by the archeological consultant on the Project. Since filing the Application, FBC has also discussed business opportunities related to the Project with the Lower Kootenay Band.

26.0 Reference: INDIGENOUS CONSULTATION

Exhibit B-1, Section 7.2, pp. 62-63; Section 8.1, p.65; Section 8.3.1, p.68; Appendix I-1;

Consultation with Indigenous Communities

On page 62 of the Application, FBC states:

> Nupqu has recommended that an AIA be completed for areas where Project-related ground disturbance activities are anticipated in areas identified as having high archaeological potential through the AOA process. It is expected that the AIA will begin in 2023 and continue, as necessary, throughout construction.

On page 63 of the Application, FBC states: "Prior to the AIA, Indigenous communities will be notified of the work and provided the opportunity to participate in the AIA."

26.1 Please confirm, or explain otherwise, that notification letters were sent to Indigenous communities regarding the work and provided the opportunity to participate in the AIA.

Response:

Confirmed. Nupqu, the Archaeology contractor, on behalf of FBC, provided notification and the opportunity to participate in the AIA to the following Indigenous communities:

- Adams Lake Indian Band
- Ktunaxa Nation Council
- Lower Similkameen Indian Band
- Okanagan Indian Band
- Okanagan Nation Alliance
- Osoyoos Indian Band
- Penticton Indian Band
- Shuswap Band
- Sinixt Nation (Colville Confederated Tribes)
- Splatsin First Nation
- Upper Nicola Indian Band

Of the above Indigenous communities, Osoyoos Indian Band, Splatsin First Nation, and Ktunaxa Nation Council participated in the AIA which was completed in April 2023.

In response to the notification and opportunity to participate in the AIA, Okanagan Indian Band and Penticton Indian Band deferred to Osoyoos Indian Band and/or Lower Similkameen Indian Band.

Shuswap Band stated that they would be unable to participate in the AIA and confirmed that they had no concerns with the AIA proceeding without their participation.

The Sinixt Nation expressed an interest in participating but was unable to due to previously scheduled engagements.

An auto-reply confirming receipt of the notification was received from Upper Nicola Indian Band and Adams Lake Indian Band.

A response to the notification was not received from Lower Similkameen Indian Band or the Okanagan Nation Alliance.

On page 68 of the Application, FBC provides the following table outlining the Indigenous communities identified in the First Nations Consultative Areas Database (CAD).

Table 8-1: Indigenous Communities Identified in CAD

Indigenous Communities	
Ktunaxa Nation Council	Penticton Indian Band
Lower Similkameen Indian Band	Shuswap Indian Band
Okanagan Indian Band	Splats'in First Nation
Okanagan Nation Alliance	Upper Nicola Indian Band
Osoyoos Indian Band	

In Appendix I-1 to the Application, FBC provides the following Indigenous Consultation log, summarizing the correspondences between FBC and the identified Indigenous communities.

Indigenous Community	Summary
Ktunaxa Nation	AOA report uploaded to the Ktunaxa Connect portal.
Upper Nicola Indian Band	AOA report sent via Nations Connect.
Splatsin First Nations	AOA report sent via Nations Connect.
Shuswap Indian Band	AOA report sent via Nations Connect.
Penticton Indian Band	AOA report sent via Nations Connect.
Okanagan Indian Band	AOA report sent via Nations Connect.
Osoyoos Indian Band	Sent notification that the request for a 60 day application review period can be accommodated.
Upper Nicola Indian Band	Environmental Management reports for ASM and WTS sent via Nations Connect.
Penticton Indian Band	Environmental Management reports for ASM and WTS sent via Nations Connect.
Shuswap Indian Band	Environmental Management reports for ASM and WTS sent via Nations Connect.
Splatsin First Nations	Environmental Management reports for ASM and WTS sent via Nations Connect.
Upper Nicola Indian Band	Environmental Management reports for ASM and WTS sent via Nations Connect.
Ktunaxa Nation	Environmental Management reports for ASM and WTRS sent via Ktunaxa Connect.
Osoyoos Indian Band	AOA report and Environmental Management reports for ASM and WTRS sent via sent via email to lands@oib.ca.

26.2 Please explain how FBC determines which materials (such as the AOA report, Environmental Management reports, etc.) are sent to which Indigenous communities.

Response:

Archaeology reports are sent to Indigenous communities identified in the Project footprint within Nations Connect and the British Columbia Consultative Areas Database (BCCAD). This approach is consistent with the Code of Conduct and Standards of Practice of the British Columbia Association of Professional Archaeologists (BCAPA).

The distribution of additional materials for Project engagement was determined through direct feedback from the Indigenous communities. The initial Project notification package that all identified communities received included a Project description letter, a kmz file of the proposed work, and a notice that the Environmental Management report and Archaeological Overview Assessment (AOA) were not completed but would be sent upon request. Upon completion, the AOA and Environmental Management reports were sent to the communities who requested them.

While responding to this IR, FBC discovered that the table in Appendix I-1 of the Application (and as provided in the preamble) erroneously showed the Upper Nicola Band receiving the Environmental Management report twice while the Okanagan Indian Band was omitted. FBC confirms that the Okanagan Indian Band did receive the Environmental Management report through Nations Connect on January 17, 2023.

Throughout the Project, if any community requests to receive additional Project materials, these materials will be provided.

27.0 Reference: INDIGENOUS PROCUREMENT PRACTICES

Exhibit B-1, Section 8.3.2, p. 68, Appendix I-1

Indigenous Procurement Opportunities

On page 68 of the Application, FBC states:

> …FBC will continue to discuss procurement opportunities for Indigenous contractors as the Project advances. FBC has been engaging with local Indigenous communities regarding procurement opportunities. FBC will continue to actively seek Indigenous business opportunities during this Project.

In the Stakeholder Consultation log, included in Appendix I-1 to the Application, FBC provides an entry of one in-person meeting between FBC and the Ktunaxa Nation regarding procurement opportunities with ASM.

27.1 Please explain how FBC's approach to Indigenous procurement for the Project compares to past projects completed by FBC. Please explain the reasons for any differences noted.

Response:

FBC's approach to Indigenous procurement for the Project is similar to the approach used for past projects. FBC maintains consistent working relationships with the Indigenous communities in its service area, continuously identifies what community owned or member owned companies exist in the area, and identifies their capacities and capabilities to determine how they can participate in FBC projects.

This institutional knowledge will be used to identify potential opportunities on the Project, by matching capacities and compatibilities with the work required on the Project, consistent with FBC's general approach to Indigenous procurement.

27.2 Please explain how FBC intends to "continue to discuss procurement opportunities for Indigenous contractors as the Project advances."

Response:

As discussed in the response to BCUC IR1 27.1, FBC is in contact with many of the communities notified about the Project and has frequent procurement conversations with their community owned and member owned businesses. Once the Project is approved, FBC will engage the communities on the procurement opportunities specific to the Project, with the expectation that some will participate in the RFP for the Project.

27.3 Please provide an update on any engagement with local Indigenous communities regarding procurement opportunities that has taken place since filing of the Application.

Response:

Since the filing of this Application, FBC has had initial engagement with the Lower Kootenay Band to discuss procurement opportunities related to the Project, including civil works opportunities.

27.4 Please explain how FBC intends to actively seek Indigenous business opportunities during the Project.

Response:

Please refer to the response to BCUC IR1 27.1.

27.5 At a high level, please discuss the outcomes of the meeting with the Ktunaxa nation, including any feedback received from the Ktunaxa Nation and any specific opportunities identified for Project work the ASM station.

Response:

Feedback from the procurement meetings with the Ktunaxa Nation was focused on identifying ways to engage community and member owned businesses. Some civil work was identified and FBC has already hired Nupqu, a Ktunaxa owned business, to perform the archaeological work.

27.6 Please discuss whether FBC has identified any other opportunities for local Indigenous communities at other Project areas.

Response:

As discussed in the response to BCUC IR1 27.3, FBC has identified and begun to discuss civil works opportunities with the Lower Kootenay Band. FBC will continue to work with local Indigenous businesses through the life of the Project to find potential opportunities.

Attachment 21.3

Nupqu Resource Limited Partnership
7334 Mission Road
Cranbrook BC V1C 7E5
Phone 250 420 2724

LETTER OF NOTICE

Archaeological Impact Assessment (AIA) under
BC Heritage Inspection Permit **2022-0110**

Date: April 28th, 2023
Company: FortisBC Inc.
To: Chris Wylie, *RPCA* (Archaeologist, FortisBC Inc.)
Prepared by: Lindsey Neill, *RPCA* (Project Manager, Nupqu Resource Limited Partnership)
Re: **Results of AIA for Proposed Upgrades to A.S. Mawdsley (ASM) Substation in Trail, BC.**

Summary Results: On April 18th, 2023, Nupqu Resource Limited Partnership (Nupqu) completed an archaeological field inspection under BC Heritage Inspection Permit 2022-0110 for the above proposed and identified development. Subsurface inspection was completed in the form of 38 shovel tests (35 cm x 35 cm), completed to a depth of approximately 60 cm to 80 cm below surface. No archaeological materials or sites were observed, recorded or are otherwise suspected within the location of the proposed ASM Substation upgrades.

Summary Recommendations: Nupqu therefore recommends that no additional inspections, investigations or archaeological resource management requirements are considered necessary or are otherwise required for the development area, provided that the proposed plans do not extend beyond the areas assessed.

It is further recommended that the proponent inform all staff and contractors that archaeological remains predating AD 1846, located on both public and private lands, or sites containing rock art or human burials, are automatically protected within the Province of British Columbia from intentional and inadvertent disturbance by the *Heritage Conservation Act* (RSBC 1996, Chapter 187).

To properly address any unanticipated discoveries of archaeological materials as a result of this development please ensure staff and contractors are aware of the following:

- All ground disturbance in the immediate vicinity of the suspected find(s) must be suspended at once,
- The Ministry of Forests, Archaeology Branch (250-953-3334) be informed, as soon as possible, of the location of the archaeological remains and the nature of the disturbance, and
- Any relevant First Nation communities are promptly informed about particulars of the unanticipated discoveries.

This letter is not intended to serve as an interim or final report. An interim report will be forwarded to your office while the final report will be prepared once the current field season is complete.

Should you have any questions or require further information please contact me at your convenience.

Lindsey Neill, BA, *RPCA*
Archaeologist/Project Manager
Office: 250.420.2724 ext. 2
Email: lindsey.neill@nupqu.com

CC: Adams Lake Indian Band
Ktunaxa Nation Council
Lower Similkameen Indian Band
Okanagan Indian Band
Okanagan Nation Alliance
Osoyoos Indian Band
Penticton Indian Band
Shuswap Band
Sinixt Nation (Colville Confederated Tribes)
Splatsin First Nation
Upper Nicola Band