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June 8, 2023

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: Christopher P. Weafer

Dear Christopher P. Weafer:

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 Commercial Energy Consumers Association of BC (CEC) 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 CEC IR No. 1.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

1. Reference: Exhibit B-1, pages 3 and 13

> **1.1.3 Aging Infrastructure and Equipment Condition Issues**
>
> ASM T1 and ASM T2 are 57 and 51 years old, respectively. The risk of failure is increasing with each passing year. FBC contracted a qualified third-party consultant to assess the health of ASM T1 and ASM T2. The consultant's findings, provided in Appendix B, confirmed FBC's assessment of the units and categorized ASM T1 and ASM T2 as having an "Urgent" Total Risk of Failure, meaning that immediate attention is required. This is further discussed in Section 3.

> **1.1.6 Project Costs and Rate Impact**
>
> The total Project cost estimate is $35.179 million (AACE Class 3 Estimate) in as-spent dollars, including AFUDC and removal costs. As described in Section 6, the Project will result in a levelized delivery rate impact of 0.63 percent over the 53-year analysis period. For an average FBC residential customer consuming 11,000 kWh per year, this is equivalent to an average bill impact of $7.80 in 2027.

1.1 Please explain whether or not FBC identified this project as being required at this time during the most recent MRP process and accepted by the Commission as an expected capital project during that proceeding.

1.1.1 Please provide, or provide a link to, the supporting evidence.

Response:

FBC identified that the transformers at the ASM Terminal Station required replacement in its 2020-2024 MRP Application[1]. The expenditures were included as part of FBC's Station (T&D) transformer replacement expenditures beginning in 2024. Subsequently, in FBC's Annual Review for 2023 Rates Application[2], FBC identified that the ASM Terminal Station transformer replacements would be filed as a CPCN application (as opposed to the costs being included in FBC's regular sustainment capital), as the estimated costs exceeded the $20 million materiality threshold. FBC provided further explanation regarding the factors that led to the ASM Project capital costs exceeding the materiality threshold in the response to BCUC IR1 14.6 in the FBC 2023 Annual Review proceeding[3]. FBC's updated capital forecasts for 2023 and 2024 were approved by the BCUC in the 2023 Annual Review Decision and Order G-382-22 (page 18)[4].

[1] Section 3, Table C3-35 and page C-92 of the 2020-2024 Multi-Year Rate Plan Application https://docs.bcuc.com/Documents/Proceedings/2019/DOC_53564_B-1-FortisBC-2020-2024-Multi-YearRatePlan-Application.pdf

[2] Page 210, FBC Annual Review for 2023 Rates https://docs.bcuc.com/Documents/Proceedings/2022/DOC_67371_B-2-FBC-2023-AnnualReview-Application.pdf

[3] https://docs.bcuc.com/Documents/Proceedings/2022/DOC_68206_B-3-FBC-Resp-BCUC-IR1.pdf

[4] https://docs.bcuc.com/Documents/Other/2022/DOC_69327_G-382-22-FBCAnnualReview-2023Rates-Decision.pdf

1.2 Please provide FBC's CPCN threshold level.

Response:

FBC's CPCN threshold is $20 million, as approved in the 2020-2024 MRP Decision and Order G-166-20 (page 133).

2. Reference: Exhibit B-1, page 10 and 11

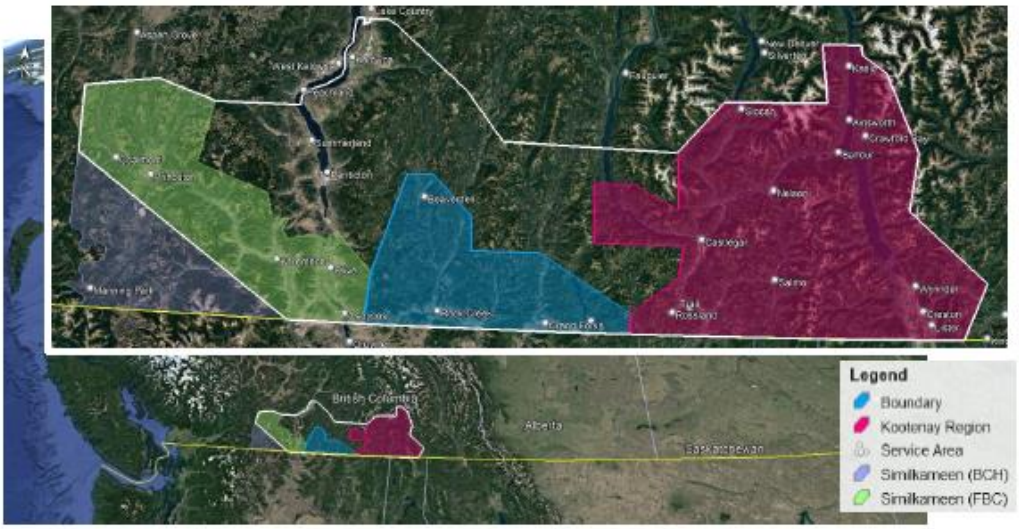
3.2 SYSTEM OVERVIEW AND DESCRIPTION

The Boundary and Similkameen areas are located within the Southern Interior of British Columbia. The Boundary area spans from the Canadian Border to the United States in the south to Beaverdell in the north, and from Christina Lake in the west to Osoyoos in the east. The Similkameen area spans from the Canadian Border to the United States in the south to Allison Lake in the north, and from Osoyoos in the west to Manning Provincial Park in the east. The Similkameen area straddles both the FBC and BC Hydro service territories. FBC's service territory covers the east and north of the Similkameen from Osoyoos in the southeast to Allison Lake. The southwest corner (Manning Park) of the Similkameen area is in BC Hydro's service territory. For the purpose of this document, the term "Similkameen area" will be used to refer to

[1] Appendix B, p. 18.

only the customers and the communities of the Similkameen area that are in FBC's service territory (i.e., excluding the southwest corner within BC Hydro's service territory). Figure 3-1 shows the portions of the Boundary and Similkameen areas that are within FBC's service territory.

Figure 3-1: FBC Service Territory in the Boundary and Similkameen Areas of BC's Southern Interior



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

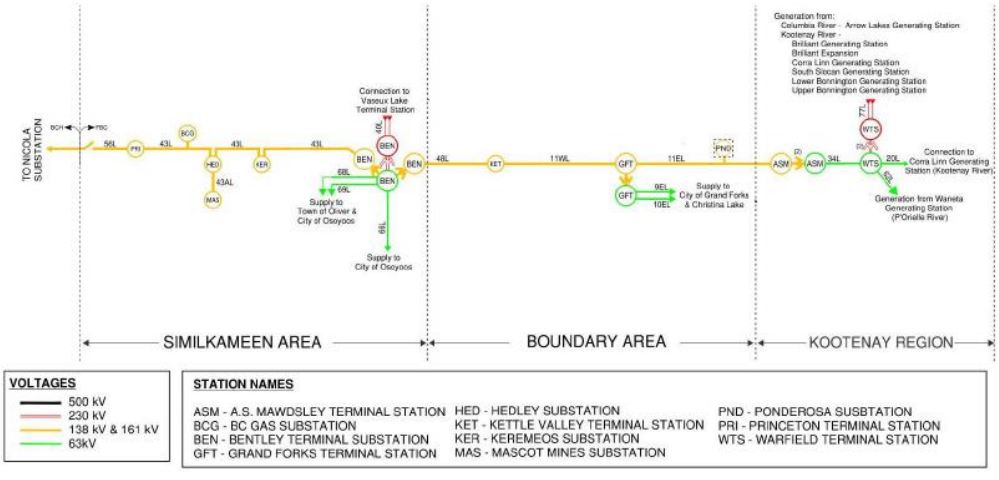
2.1 Please confirm that the area directly above and to the left of the Kootenay region is also served by FBC.

Response:

The area within the white outline on Figure 3-1 is served by FBC.

3. Reference: Exhibit B-1, pages 12, 13 and 14

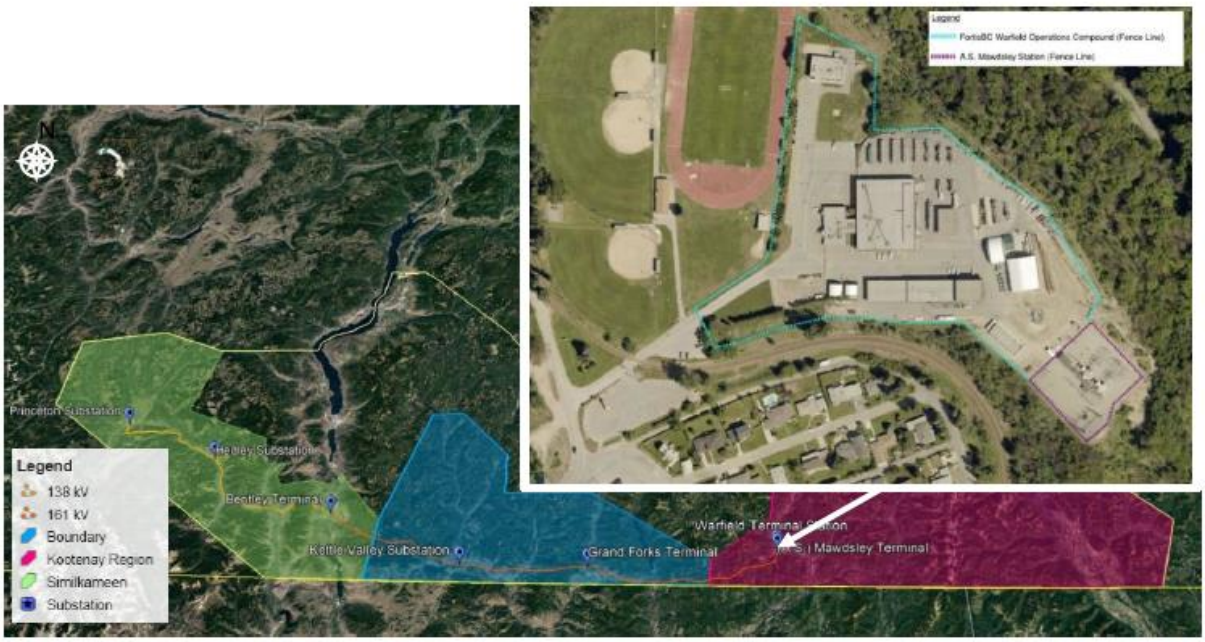
Figure 3-2: Boundary and Similkameen Power Supply Single Line Diagram[2]



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

The ASM Terminal Station is located in Trail, BC (see Figure 3-4), at the Southeast end of the FBC Warfield Operations Compound.

Figure 3-4: Aerial View of the ASM Terminal Station in Relation to the Boundary and Similkameen Areas



3.1 Please explain whether or not there could be any potential option for FBC to work cooperatively with other electricity providers in the US or Canada to meet the demands of the ASM terminal substation.

3.1.1 If yes, please explain whether or not FBC has considered this option.

3.1.2 If considered, please provide details of the consideration.

Response:

There is no potential option that would involve not replacing the existing ASM Terminal Station infrastructure in some form. The area load requirements whether met by FBC internal resources or imported resources from any other US or Canadian electricity provider will need a terminal substation to supply the Boundary area load, and, as FBC has explained in the Application, the existing ASM T1 and T2 transformers must be replaced.

4. Reference: Exhibit B-1, page 13 and page 13

> The Boundary and Similkameen areas cover a large geographical area. The areas account for approximately 19 percent of FBC's total summer and winter peak load.
>
> Based on 2022 customer data, FBC has approximately 26,000 direct customers in the Boundary and Similkameen areas, which are broken down by rate class in Table 3-1 below.

Table 3-1: FBC Similkameen and Boundary Area Customers by Rate Class

Rate Class	Customer Count
Residential	20,708
Small Commercial / Commercial	3,866
Large Commercial/Industrial	12
Irrigation	725
Lighting	869
Wholesale	3
Total	**26,183**

4.1 Please provide the equivalent table breaking down revenue by rate class.

Response:

While FBC does record revenue by rate class for the service area as a whole, a breakdown of revenue by rate class for the Boundary and Similkameen areas cannot reasonably be provided due to the number of billing variables for each customer class.

4.2 Please provide total, summer, winter and peak load for each rate class in the Similkameen and Boundary areas served by FBC, and please identify the % they represent of the total FBC total, summer, winter and peak load.

Response:

FBC is not able to break down peak load by rate class for the Boundary and Similkameen areas. FBC's metering equipment does not make this distinction when recording data.

5. Reference: Exhibit B-1, page 17

> ***3.3.1.1 FBC Planning Criteria and System Reliability Issues***
>
> 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.
>
> The normal operation (N-0) contingency planning criterion applies to all transmission facilities, while the single contingency (N-1) planning criterion applies to all transmission facilities that are part of the FBC interconnected system (which excludes radial transmission lines). Therefore, 11E Line supply (i.e., the ASM Terminal Station) is subject to meeting both normal operation and single contingency transmission planning criteria. FBC plans and constructs its interconnected transmission system to meet and maintain its N-1 planning contingency criterion. The system should be capable of meeting N-0 and N-1 performance at all times, including during minimum and maximum forecast load and generation conditions. The recently approved GFT Station Reliability Project CPCN[5] and the KBTA Project CPCN[6] proposed the addition of new terminal transformers in order to meet these planning criteria.

5.1 Please explain whether or not the N-1 planning criteria for the 11E Line supply is defined by any instant in a year when load may exceed the capability of one of the transformers.

Response:

Confirmed. FBC must meet N-1 planning criteria for all hours of the year and even the smallest event could be a violation.

5.2 Given that FBC has allowed the N-1 criteria to be exceeded since 2017, what is the frequency of instance where the capability of one of the transformers can be exceed before upgrade action is necessary, and what is the duration of instances where the capability of one of the transformers can be exceed before upgrade action is necessary?

5.2.1 Please confirm or otherwise explain that if the frequency and duration of the instances, where the N-1 criteria is exceeded for one of the transformers, is small, then the probability of a forced outage will likely be exceedingly small, thereby supporting the FBC decision not to react on the initial instances of exceeding the N-1 criteria.

Response:

FBC considers that upgrade action is necessary to ensure compliance with N-1 criteria and should be taken as soon as practical; therefore, the number and duration of instances or joint probabilities of failure related to transformer overloading are not the critical considerations in deciding to take upgrade action.

As explained in the response to CEC IR1 1.1, FBC identified the need for the ASM transformer replacements in the 2020-2024 MRP Application, and later identified the need for a larger ASM project in the 2023 Annual Review. Further, as explained in the response to BCUC IR1 2.21, FBC has been implementing operational changes to manage new load and transformer overloading since 2019; however, these changes are temporary and a permanent solution (i.e., the Project) must be undertaken.

Section 3 of the Application sets out in detail the drivers of the Project need that require FBC to proceed with the CPCN, which includes addressing N-1 system reliability criteria that are further impacted by load growth in the area, but also to address the high failure risk of the transformers at the ASM Terminal Station due to their age and condition.

Please also refer to the response to BCUC IR1 3.5 where FBC explains how it arrived at the conclusion that a Probability of Failure higher than 2 percent for the ASM transformers is not acceptable. Further, and as supported by the Condition Assessment Report prepared by Hitachi (Appendix B to the Application), FBC has considered many factors in its determination that the ASM transformers must be replaced, including the impact of overloading on the transformers and the results of the On-Load Tap Changers' Dissolved Gas Analysis. Please refer to the responses to BCUC IR1 3.6 and 3.6.1 for further details.

5.3 Please confirm or otherwise explain that the extent to which a utility relies upon the low joint probability of load exceedance and transformer incapability, with the failure of one of the transformers at the same time, is a utility judgement call with respect to when to proceed with upgrades.

Response:

Please refer to the response to CEC IR1 5.2.

5.4 Please describe in detail all of the aspects FBC has accounted for in making its judgement to proceed with this CPCN, and relate each judgement to the joint probability of a failure related to load exceeding the capability of a transformer and the failure of a transformer occurring at the same time.

Response:

Please refer to the response to CEC IR1 5.2.

5.5 Please provide the probability of both transformers failing at the same time and compare this to the probability of one of the transformers failing.

Response:

The calculated probability of either ASM T1 or T2 failing is 2.35 percent to 2.41 percent.

The calculated probability of both ASM T1 and T2 failing is 0.056 percent.

However, the above calculated probability does not take into account the increasing Risk of Failure over time associated with overloading of the remaining unit.

5.6 Please provide the historical data with respect to the frequency of load exceeding one of the transformer's capabilities from 2017 to present and provide the duration for the load exceeding the capabilities of one of the transformers for each instance.

Response:

FBC provides the following table showing the number of instances, hours and percentage of the year where load exceeded the capabilities of one ASM transformer. FBC clarifies that for all of these instances, both transformers were in service and thus not overloaded.

Year	2017	2018	2019	2020	2021	2022
Number of Hours	2,577	1,863	1,589	1,832	1,033	2,047
Percentage of Year	29%	21%	18%	21%	12%	23%
Number of Instances	170	208	178	175	107	212

6. Reference: Exhibit B-1, page 17

> ***3.3.1.2 Forecast Peak Load Growth will Result in Inability to Reliably Maintain Service***
>
> 3.3.1.2.1 BOUNDARY AND SIMILKAMEEN AREAS' HISTORICAL AND FORECAST PEAK LOAD
>
> 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[7]. FBC has been using a "1-in-20" year load forecast for planning purposes since at least 2011. This method was examined in FBC's Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan[8] and underpins FBC's capital plans, including those filed in the 2014-2019 Performance Based Rates Application and the 2020-2024 Multi-Year Rate Plan Application. The "1-in-20" year load forecast method was also used in FBC's KBTA Project CPCN application and was accepted by the BCUC Panel in its Decision and Order C-4-20[9].
>
> [7] The accuracy of the 1-in-20 forecast is expected to be 95 percent (a 5 percent chance that actual load will be higher). Industry practice requires that a quantitative risk factor, such as the 1-in-20 forecast, be incorporated into transmission planning studies such as the power flow models submitted by FBC to the Western Electricity Coordinating Council (WECC) for application in regional and system-wide transmission planning.

6.1 Please explain the benefits of using weather-normalized forecasts for load resource planning.

Response:

For the purposes of resource planning, FBC plans to the expected weather normalized forecast (which excludes weather extremes), because this is likely what will be experienced. If extreme weather develops, then FBC is able to secure additional resources if needed. If FBC acquired resources to meet the non-weather normalized forecast level, it could result in FBC entering into contracts or procuring resources that would not be fully utilized and add costs which would then be reflected in customer rates.

6.2 Please explain why FBC relies on a 1-in-20 years historical record for capacity planning purposes.

Response:

FBC does not rely on the 1-in-20 year historical record for capacity planning, but rather, FBC uses the historical data as an input to the forecast method to produce a 1-in-20 year load forecast.

As stated in the preamble, FBC's use of the 1-in-20 year forecast is consistent with industry practice and has been subject to recent review and was accepted by the BCUC in the FBC Application for a CPCN for the Kelowna Bulk Transformer Addition (KBTA) Project Decision and Order C-4-20 (page 12).

6.3 Please provide the future weather-normalized load forecasts for the next 20 years and the future capacity forecast for the next 20 years.

Response:

The following table contains the weather-normalized load forecast and the capacity forecast for the next 20 years.

Year	System Load GWh	Peak 1:20
2022	3,802	846
2023	3,835	850
2024	3,850	855
2025	3,873	858
2026	3,888	869
2027	3,939	880
2028	3,989	891
2029	4,039	902
2030	4,089	913
2031	4,139	924
2032	4,188	935
2033	4,237	946
2034	4,287	957
2035	4,337	967
2036	4,384	978
2037	4,431	988
2038	4,478	999
2039	4,525	1,010
2040	4,572	1,020
2041	4,614	1,031
2042	4,654	1,042

6.4 Please provide FBC's methodology for its 1-in-20 years load forecasting, and please explain whether or not the capacity planning is simply based on historical 1-in-20 year data or whether it is modified for anticipated future capacity requirements that are not embedded in the historical 1-in-20 years capacity forecasting data.

Response:

For a description of the method, please refer to the response to BCUC IR1 2.8.

The 1-in-20 year forecast is based on both historical data as well as the forecast gross load growth rate, which is not embedded in the historical 1-in-20 year capacity data.

6.5 In footnote 7 FBC states that Industry practice requires a quantitative risk factor 'such as the 1-in-20 forecast'. Is the 1-in-20 years historical data averaged for peak capacity requirement or is the largest peak in the last 20 years taken as the planning requirement for capacity purposes?

Response:

The 1-in-20 year peak capacity requirement is developed using the maximum peaks recorded in the last 20 years, along with system growth rates to bring all the values forward to the base year (2022). The maximum values are then escalated using the system load growth rates to produce the 20-year forecast. The actual recorded maximum peaks are not used alone for capacity planning purposes.

6.6 Please provide a list of the contingencies FBC can bring to compensate for a year which exceeds the capacity forecast using the 1-in-20 years forecast data, and for each contingency capability please provide the quantity and availability in terms of response time and reliability for each of the contingency capabilities.

Response:

In the Boundary and Similkameen areas, the relevant single contingencies that cause thermal and voltage violations during N-1 conditions are:

- Transformer outage at the ASM Terminal Station;
- 40L/BEN T1 outage; and
- 34L outage.

Please refer to the response to BCUC IR1 2.21 for operational changes that will be performed in the event of an N-1 contingency event.

7. Reference: Exhibit B-1, page 18

Table 3-2: Boundary and Similkameen Areas' Historical Actual Peak Loads, 2017-2022

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

Looking forward, the load forecast for the Boundary and Similkameen areas for summer and winter 2023 through 2027 is shown in Table 3-3 below. Table 3-3 shows the forecasts of peak load based on historical data which are used in power flow simulations to determine compliance with FBC's Transmission Planning Criteria, and also includes forecast load growth related to electric vehicles (EVs)[11] 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.

Table 3-3: Boundary and Similkameen Areas' Peak Load Forecast, 2023-2027

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

7.1 The CEC notes that both the summer and winter peak load forecasts remain below the 2022 actual peak loads. Please explain why this occurs.

Response:

Please refer to the response to BCOAPO IR1 5.2.

7.2 Please explain what the % of load and capacity requirements coming from EVs is historically and forecasted to be in the next 20 years, with year-by-year data.

Response:

The following table relies on data from the 2021 Long Term Electric Resource Plan (LTERP) and provides the forecast to 2040 of the EV impact as a percent for both load and capacity. FBC does not have historical data for EV charging but it is expected to be less than 0.5 percent of both load and capacity.

Year	EV Load Percent	EV Capacity Percent
2021	0.3%	0.4%
2022	0.4%	0.6%
2023	0.5%	0.7%
2024	0.6%	0.9%
2025	0.8%	1.1%
2026	1.0%	1.4%
2027	1.2%	1.8%
2028	1.5%	2.3%
2029	1.9%	2.8%
2030	2.3%	3.4%
2031	2.8%	4.2%
2032	3.5%	5.1%
2033	4.2%	6.2%
2034	5.0%	7.4%
2035	5.9%	8.7%
2036	6.8%	10.1%
2037	7.8%	11.6%
2038	8.9%	13.2%
2039	10.1%	15.0%
2040	11.4%	16.9%

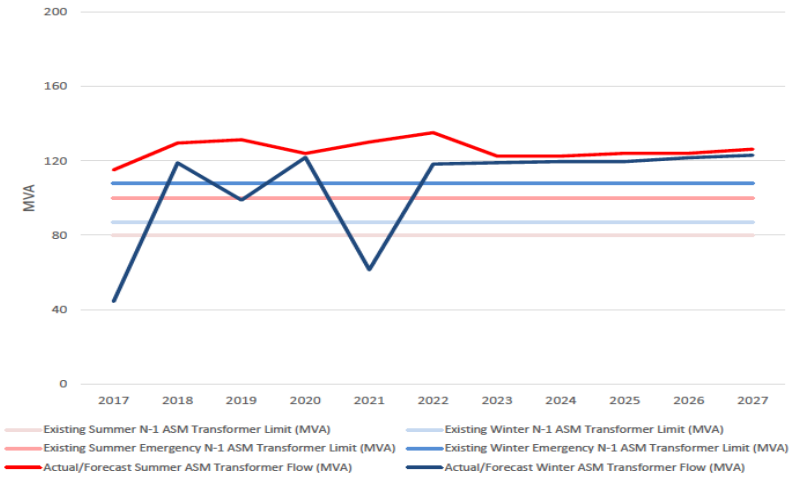
7.3 Given that EV adoption and/or new government policy favouring electrification may drive greater requirements for related load and capacity, which has not necessarily been a factor in historical 20-years data, does FBC anticipate that it may need to modify historical data-based forecasts particularly for capacity based on future forecast related to evolving electricity usages? Please explain

Response:

No. FBC would continue to use historical data-based forecasts as well as develop new methods to add on to or enhance the forecast to capture policies or technological developments not intrinsic in the historical data.

8. Reference: Exhibit B-1, page 19

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



As shown in Figure 3-7, the summer peak load has exceeded both normal and emergency ratings in an N-1 contingency event. FBC notes that winter peak has historically been more variable due to greater fluctuations in system conditions (i.e., configuration and generation) in the winter months. 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.

8.1 Please elaborate on the 'certain new load and generation conditions that have caused FBC to exceed N-1 system planning'.

Response:

Please refer to the response to BCUC IR1 2.20.

8.2 The Actual summer and winter ASM transformer flows have exceeded N-1 limits since 2017 (with the exception of winter 2021). Please explain why FBC has not defined its future forecasts and historical cases in terms of frequency of exceedance and duration of exceedance, which appears to be the necessary granularity for decision making, as opposed to using annual data.

Response:

Figure 3-7 shows the summer and winter peak flows on the ASM transformers, and is not meant to show every instance of load exceeding the transformer limits (or the duration of those events). FBC does not consider it appropriate to change its methodology for its historical data or future forecasts based on a single portion of its system being unable to meet N-1 criteria. The N-1 exceedance under any set of load and generation dispatch scenarios is a violation of the

Transmission Planning Criteria and must be addressed. Therefore, the frequency and duration of exceedance need only occur once in order for it to violate the reliability criteria.

There are a number of factors, including condition of the transformers and the fact that the ASM transformer flows have been experiencing exceedances of the N-1 limits, which have resulted in the need to undertake the Project. Accordingly, and in consideration of all of the factors which form FBC's conclusion that the ASM Terminal Station requires replacement, FBC considers that it has the necessary evidence at the appropriate level of granularity to support the need for the Project.

8.3 Please revise Figure 3-7 to reflect a much more appropriate daily granularity.

Response:

FBC disagrees with the CEC's statement that providing a figure with daily data would be a "much more appropriate" level of granularity. Please refer to the response to CEC IR1 8.2 regarding the purpose of Figure 3-7 and the evidence supporting the need for the Project. FBC respectfully declines to provide a revised Figure 3-7 with daily data for the years included in the existing Figure 3-7, as such an effort would require the collection and dissemination of approximately 55,000 data points.

8.4 What guidelines, if any, does FBC have for when it needs to address capacity issues? Please provide all such written guidelines and criteria.

Response:

FBC's Transmission Planning Criteria provide guidelines for when to address capacity issues and are excerpted below.

General Principles

All equipment will operate within its normal facility ratings and normal voltage limits when the system is operating with all scheduled elements in service, and within its emergency facility ratings and emergency voltage limits immediately after a disturbance involving the loss of single or multiple elements. The system should be capable of such performance at all times including operations during minimum and maximum forecasted load and generation conditions.

In addition to satisfactory performance for normal system conditions and for single contingencies, the system should be able to withstand more severe but less probable multiple contingency outages.

The above outlined principles call for the following three general categories of contingencies with increasing severity:

a) N-1 single contingencies (P1 and P2) exemplified by contingencies such as single line, single transformer or single generator outages.

b) N-1-1 and N-2 multiple contingencies (P3, P4, P5, P6, and P7) exemplified by double contingencies such as loss of both circuits of a double circuit line or two lines connected to the same breaker in a substation.

c) Extreme contingencies exemplified by the loss of all lines on a common right of way, all generators in a plant or all elements connected to the same voltage level in a substation.

Contingencies

The system shall be tested for adequacy by means of steady state (load flow) analysis and for stability using a dynamic simulation program. In addition, the system shall be tested for voltage instability (voltage collapse) and overload cascading using steady state analysis tools.

Contingency tests are defined by the following parameters:

a) Specification of the pre-contingency system condition (base case condition).

b) Specification of the contingency or disturbance.

c) Specification of acceptable system conditions after a contingency or disturbance.

d) Specification of automatic control or operator action that may or must be considered when determining whether criteria for acceptable system conditions are met.

The transmission expansion will be based on the specified acceptable system conditions for normal conditions and for the more probable and less probable contingency conditions. The extreme contingency tests are checks on system resiliency that may have an impact on practices for substation arrangements, protection systems, load shedding systems, concentration of lines on one right of way, and concentration of generation. Results from extreme contingency testing may have an impact on the choice of the most attractive transmission expansion alternative as designed based on normal conditions and the more probable and less probable contingency conditions.

9. Reference: Exhibit B-1, Appendix B, PDF page 90/236

3. Transformer Population Data

The transformer population in the study consists of 2 transformers as listed in **Table 1** below. Included is the relative importance for each transformer that was provided by the customer.

ID No.	Location	Position	Importance	Manufacturer	MVA	Serial Number	YoM
1	ASM	T1	100	CGE	60/80	285738	1965
2	ASM	T2	100	CGE	60/80	287735	1971

Table 1 – Transformers Considered in Fortis BC Transformers Assessment

9.1 Please explain which party determined the Importance level to be 100.

Response:

The "Importance" level of the ASM T1 and T2 transformers was determined by Hitachi based on FBC-provided data.

9.2 Please provide the description, scale and rating methodology for the column entitled 'Importance', and please relate the scale and 100 level to FBCs other Transformers (i.e., what factors create an Importance of 100, and what is the distribution of Transformer Importance in FBC's service territory).

Response:

The Importance of a transformer, determined by Hitachi, is a quantitative value calculated based on:

- The number of customers served;
- The equipment location in the network; and
- The available local or loop redundancy.

This Importance value can range from 1 to 100 and is particular to the FBC system. While a score of 100 indicates an essential unit, a score below this could indicate an area or locally important unit.

Since during peak loading neither one of the ASM transformers could fully supply the required load and they are critical to the FBC system, they were assigned the highest score.

1 FBC is not able to provide an Importance ranking for each of its transformers as the Importance
2 methodology is proprietary to Hitachi, who was only retained to provide analysis on ASM T1 and
3 T2.

4

10. Reference: Exhibit B-1, page 21, and page 21 and Appendix B PDF pages 90 and 107/236

> ### *3.3.2* High Risk of Failure due to Condition of Transformers
>
> 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.
>
> Based on the above, ASM T1 and ASM T2 are most likely to fail due to the risk of accessory failure due to their ages.
>
> 11. The CIGRE Technical Brochure 642 on Transformer Failure Statistics shows a low failure rate on units greater than 50 years old for the data compiled. CIGRE Working Group A2.62 is presently performing an update on Transformer Failure Statistics with the goal of receiving wider data (from more countries and applications) and receiving the in-service transformer distribution (by age and application). Early new data shows that the failure rate is flat by age however there is a lower distribution of old in-service units (note - although North America has high distribution of old units, much of the rest of the world has a younger transformer age distribution). The early observation is that the failure rate per in service transformer is higher for older units (> 50 years). Thus, for the 2 transformers in this report which are older than 50 years, they statistically have a higher expected general failure rate.

10.1 Please provide the average service life for the same CGE transformers used for ASM T1 and ASM T2.

Response:

According to FBC's available records, CGE transformers that operated at the transmission level and were previously retired had an average service life of 53 years.

10.2 Please confirm that FBC is able to mitigate deterioration of its equipment with proper ongoing maintenance and explain the appropriate maintenance and its costs.

Response:

Generally speaking, FBC is able to mitigate deterioration of its transformers through on-going maintenance. Please refer to the response in BCUC IR1 3.4 for a description of FBC's on-going maintenance programs. FBC's on-going maintenance programs have ensured that ASM T1 and T2 have both exceeded 50 years of age. Despite this on-going maintenance, ASM T1 and T2 are continuing to age and prolonging asset life through maintenance is no longer effective due to unavailable original equipment manufacturer parts and/or support services.

For example, the ASM T1 and T2 on-load tap-changers (LTC) need refurbishment or replacement. However, refurbishment is not available because the original equipment manufacturer no longer exists. Replacing the LTCs would likely cost approximately $1.2 million per transformer (based on FBC's 2017 costs for LEE T4), but since these transformers are already over 50 years old, this expenditure is not a cost-effective solution.

Furthermore, mitigating ASM T1 and T2 deterioration will not increase the rated capacity of the transformers, and therefore, does not meet the objectives of the Project.

10.3 Please confirm the CEC's interpretation of pp 11 of the Hitachi Energy Conclusion, that there is generally a low risk of failure on units that are greater than 50 years old, even though it may be a higher risk than that for younger units.

Response:

Not confirmed. Item 11 from Appendix B indicates that Hitachi recognizes that the CIGRE Technical Brochure 642 had "…a lower distribution of old-service [power transformers]…" resulting in the "…low failure rate on units greater than 50-years old." Item 11 indicates that CIGRE Working Group A2.62 was working on receiving a wider data set.

Other sources, like CIGRE WG 12-05, *An international survey on failures in large power transformers,* indicates an increasing risk of failure and the probability that 1 in 20 transformers of similar age to ASM T1 and T2 may fail in each calendar year, with no transformer having an in-service life beyond 70 years.

10.4 Please confirm the CEC's interpretation that in North America there are a large number of units more than 50 years old.

Response:

Based on CIGRE Working Group A2.62, FBC confirms that North America has a high distribution of old units when compared with much of the rest of the world.

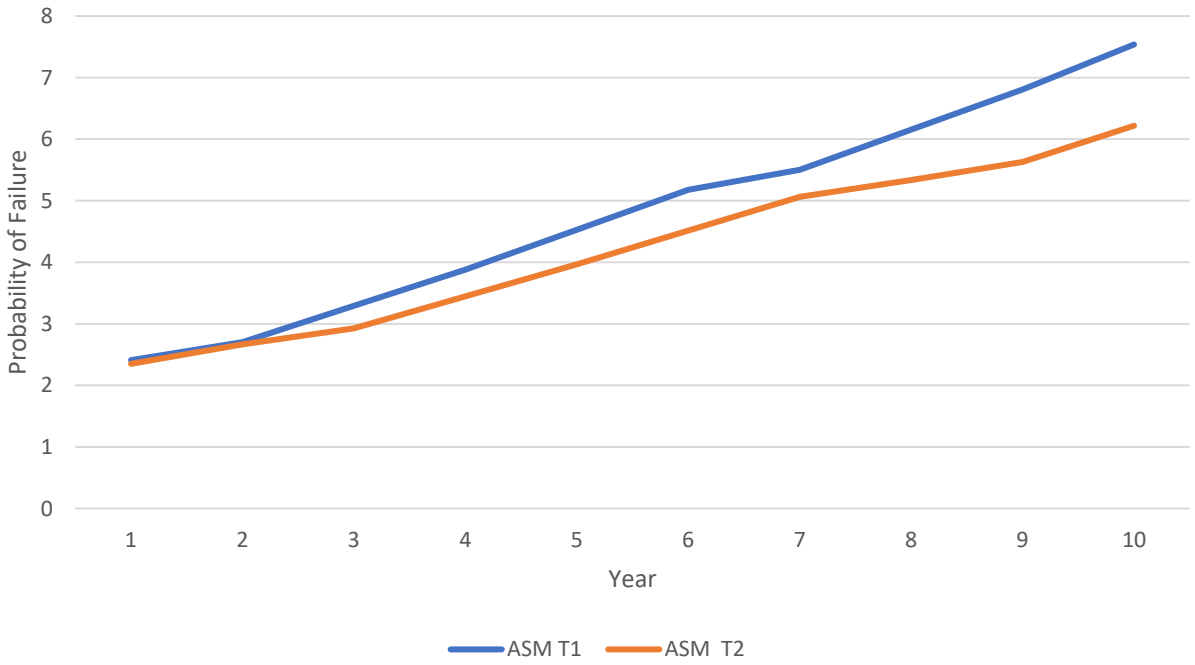
10.5 Please quantify the increasing risk associated with the 'each passing year' in terms of the probability of a transformer failure in a given year for each year going forward for 10 years.

Response:

An exact or approximate quantification of the increasing risk associated with "each passing year" cannot be calculated with the data available for ASM T1 and ASM T2. To provide a probability of failure trajectory, failure data for identical (make and model) power transformers that are aging/deteriorating in the same way would be needed.

However, FBC does not need this analysis to conclude that these transformers are already above the 2 percent Probability of Failure (PoF) threshold, as noted in the response to BCUC IR1 3.5, and are therefore above FBC's accepted risk tolerances.

For the purpose of this request, FBC uses industry available statistics[5] for power transformers to estimate increases in the rate of failure. An example of a potential trajectory of increasing risk through application of Figure 4 in the ABB *Fit at 50* white paper is presented in the figure below. Please also refer to the response to BCOAPO IR1 7.1 for an explanation and table of FBC's interpretation of the PoF thresholds contained in the CEATI report and ABB *Fit at 50* white paper.



[5] ABB *Fit at 50* white paper Figure 4.

11. Reference: Exhibit B-1, Appendix B, PDF pages 93-97

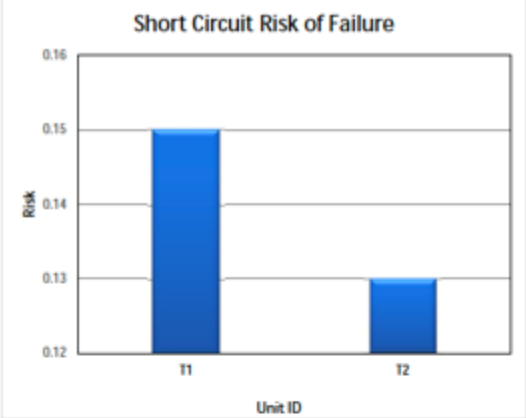


Figure 2 – Relative risk of short circuit failure for the transformers

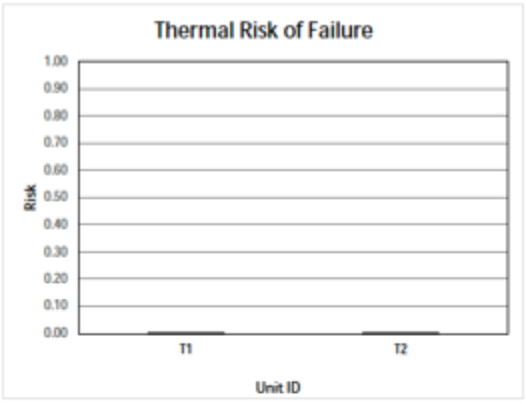


Figure 3 – Relative risk of thermal failure for the transformers

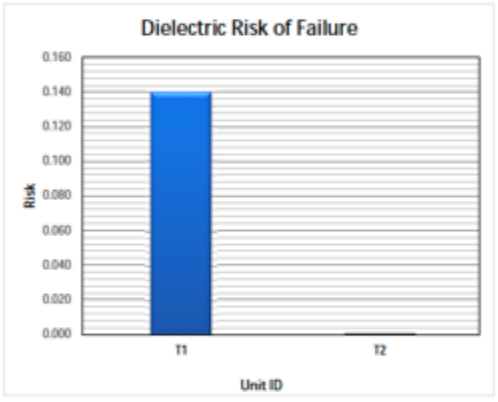


Figure 4 – Relative risk of dielectric failure for the transformers

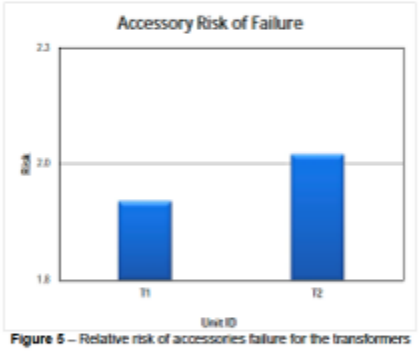


Figure 5 – Relative risk of accessories failure for the transformers

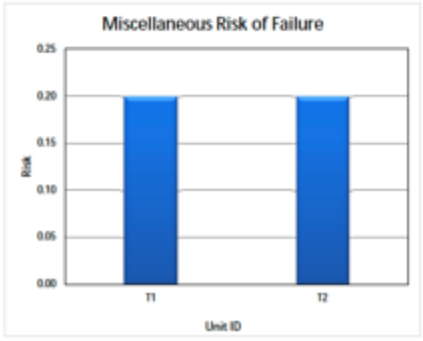


Figure 6 – Relative risk of miscellaneous failure for the transformers

11.1 Please confirm that the risk numbers represent the probability of failure in the year for a single transformer.

Response:

Confirmed. Please refer to the response to BCOAPO IR1 7.1 for further explanation.

11.2 Please provide any historical data for these transformers showing failures and durations of failures.

Response:

Please refer to the response to BCUC IR1 2.4.

11.3 The CEC notes that none of the Figures citing Relative risk provide a total scale or evidence related to interpretation of the Risk values (i.e., what constitutes low, normal, priority or urgent for the given transformers as reasonably interpreted by the industry). Please provide such information for each Figure and provide the source of the information.

Response:

The scale for Relative Risk for all key Risk Factors is 0-100 percent. To provide a meaningful representation, the Y axis was limited at maximum and minimum. Calculations of Relative Risk are proprietary to Hitachi and cannot be provided.

Please refer to the response to BCOAPO IR1 7.1 regarding the priority levels to risk values.

11.4 Please provide an estimate of the range of risk levels for FBC's other transformers, and identify whether or not the transformers at ASM would fall within FBC's typical range of risk.

Response:

FBC is not able to provide an estimate of the range of risk levels specific to each of its transformers. As explained in the response to CEC IR1 9.2, FBC retained Hitachi to provide a condition assessment of ASM T1 and ASM T2 only.

12. Reference: Exhibit B-1, Appendix B, PDF page 96/236 and page 105/236

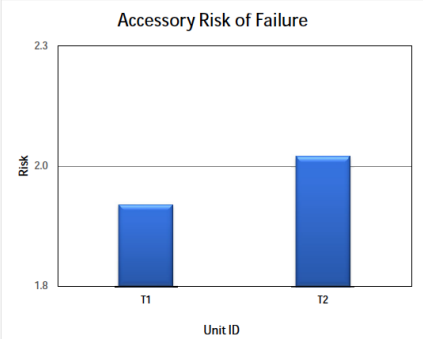


Figure 5 – Relative risk of accessories failure for the transformers

The Condition Assessment Report lists the greatest contributors to risks of failure[19] for ASM T1 and ASM T2 as:

1. Risk of accessory failure due to their age (82.8%);
2. Risk of dielectric failure due to various causes (2.9%);
3. Risk from oil leaks or tank rust and their severity (8.4%);
4. Risk from hot spots or loose connections (0.0%); and
5. Risk of short circuit failure (5.9%).

12.1 The CEC is unable to find the evidence supporting the 82.8% risk associated with the Risk of Accessory failure. Please supply or identify where the calculations may be found in the Application.

Response:

The 82.8 percent risk associated with "Risk of accessory failure due to their age", as provided in Section 9 – Conclusion and Recommendation of the Hitachi report (Appendix B, pdf page 105) represents the weighted contribution of this specific risk towards the Total Risk of Failure (termed by Hitachi as Relative Risk). The calculations performed by Hitachi to determine Relative Risk are proprietary to Hitachi and cannot be provided.

To further clarify, the ASM T1 and T2 transformers do not have a Total Risk of Failure of 82.8 percent; this percentage relates to the weighted contribution of the risk associated with accessory failure due to the transformers' ages to the Total Risk of Failure. As shown in Table 2 of Appendix B, the ASM T1 and T2 Total Risk of Failures are 2.41 percent and 2.35 percent, respectively.

12.2 Please explain why FBC is operating equipment with an 82.8% risk of failure as shown above.

Response:

Please refer to the response to CEC IR1 12.1.

12.3 Please discuss the opportunities that are available to FBC to mitigate risk of accessory and tank leak failures as well as the dielectric and short circuit failures independently of the proposed Project.

Response:

FBC provides the below table setting out each of the relative risks presented in Appendix B (excluding item 4, which presents 0.0 percent risk) and the mitigation options that could be done to extend the life of ASM T1 and T2, if FBC were not proceeding with the ASM Project. FBC notes that while there are actions that could be taken to extend the life of these transformers, many of these options are not viable, as discussed in the table below.

1. Risk of accessory failure due to their age (82.8%)	
Mitigation Action	**Justification**
Repair: Restore to working condition, acceptable to continue operation.	Not all required spare parts are available. OEM support services not available.
Partial or Total Refurbishment: Restore to working condition through replacing some or all worn-out components to improved working condition.	Not all required spare parts are available. OEM support services not available.
Replacement / Overhaul: Accessory is disconnected from operation and replaced with a completely new one.	Not practical. Original manufacturer no longer exists. Equivalent manufacturer would have high costs associated. Prolonged outage to ASM station to execute.
2. Risk of dielectric failure due to various causes (2.9%)	
Mitigation Action	**Justification**
Oil processing, oil replacement, or insulation dry-out.	This action can only mitigate dielectric failure to a certain degree.
Not allowing overloading.	This action will result in reduced system reliability. FBC has limited ability to control system loading; therefore, overloading or loading reductions would require operational changes as described in BCUC IR1 2.21.
Reducing transformer loading below normal ratings.	

3. Risk from oil leaks or tank rust and their severity (8.4%)	
Mitigation Action	**Justification**
Proper design and gasket selection.	Only mitigatable during initial design and manufacture.
Minor field repairs.	Scope is dependent based on necessary parts and required down-time.
Major repairs, specifically leaks between the LTC and main transformer tank.	Not economically viable. Require prolonged transformer down-time.
5. Risk of short circuit failure (5.9%)	
Mitigation Action	**Justification**
Proper design.	Only mitigatable during initial design and manufacture.

12.4 Please discuss the opportunities that are available to FBC to mitigate risk for all of the identified risk and the severity of each risk independently of the proposed Project.

Response:

Please refer to the response to CEC IR1 12.3.

12.5 Please explain how the mitigation of accessory and oil leaks or tank rust would affect the overall risk rating for the two transformers.

Response:

Please refer to the response to CEC IR1 12.3. It would not be feasible to address all the issues related to accessory and oil leaks or tank rust and therefore the ASM T1 and T2 Risk of Failure could not be reduced to a Normal level as per Hitachi's interpretation.

13. Reference: Exhibit B-1, Appendix B PDF pages 105 to 107/236

9. Conclusion and Recommendation

1. For each transformer, a risk of failure was calculated at the relative importance indicated. The results were plotted, grouped, and separated into three distinct categories. Those with high risk of failure, but not so high as to warrant removal from service and those with higher importance and moderate risk of failure or above were categorized into the "Urgent" (Code Red) category, meaning that immediate attention is needed. Those with a significant, but somewhat lower risk of failure or importance were categorized into a middle or "Priority" (Code Yellow) level, meaning that action is needed within about one year. The remaining units, with lower risk of failure and importance were in the "Normal" (code green) category. Both T1 and T2 units were identified in the "Urgent" (Code Red) category.
2. The greatest risks of failure are:
   - [1] Risk of accessory failure due to their age (82.8%),
   - [2] Risk of dielectric failure due to various causes (2.9%),
   - [3] Risk from oil leaks or tank rust and their severity (8.4%),
   - [4] Risk from hot spots or loose connections (0.0%),
   - [5] Risk of short circuit failure (5.9%).
3. A breakdown of all the units' risk of failure with respect to the subcategories is shown below. This helps visualize the major contributor of risk for each unit.

2

4. As a long-term plan, the risk assessment process used in this study should be the process for prioritizing maintenance actions in the future for the two transformers to ensure that the resources used are optimized. The completion of the short-term recommended maintenance actions from this group of transformers will also provide additional diagnostic information, which in turn can be used to refine the estimates from this investigation.
5. The below specific actions are recommended for **both** transformers:
   - Overhaul the LTC's ASAP to lower the risk of failure. The LTC's on both units have signs of arcing, overheating, and copper pitting.
   - Plan for oil quality samples and DGA on the units on a yearly basis.
   - Include oil analysis power factor testing at 100°C in future oil samples. This can distinguish oil contamination vs oil aging if the power factor is high.
   - Oil leaks need to be repaired. Besides the environmental concerns, oil leaks cause oxygen to enter the unit which accelerates insulation aging. Oil leaks can also cause dielectric failure if the leak is big enough and the oil drops below the active part.

3

   - Ensure the cooling equipment is in good working condition and well maintained.
   - Plan for a bushing power factor testing every 3-5 years.
6. The latest DGA for **T1** main tank shows an increase for H2, C2H4, and CO. Even though the increase does not seem serious at these levels, it should be monitored.
7. The LV bushings of **T2** should be tested for power factor. A bushing DFR test is recommended to be performed if the increased PFs are confirmed.
8. A short-term action plan should be developed to address the risks to the transformers identified in this study and to implement appropriate risk mitigation measures. A recommended short-term action plan is as follows.

Position	ID#	Possible Risk Mitigation Actions [L1] = 6 months, [L2] = 1 - 2 Yrs., [L3] = 2 - 3 Yrs., [L4] = 3 – 5 Yrs							
		DGA & Oil Test	PF and Cap. test	Bushing PF Tests	Bushing DFR Test	Fix Oil Leaks	Clean Rads	LTC Overhaul	Oil Reclaim / Drying
1	T1	[L1]	[L1]	[L1]		[L2]	[L2]	[L1]	
2	T2	[L1]		[L1]	[L2]	[L2]	[L2]	[L1]	

Table 5 – Recommended short term action plan

4

5 13.1 Please confirm or otherwise explain that Hitachi Energy did not identify immediate
6 retirement for either or both of the two transformers.

13.1.1 If not confirmed, please identify where this information may be found in the application.

Response:

Hitachi states on page 4 of the report (Appendix B to the Application):

> Those that fall in the Red Zone are transformers with a combination of high risk of failure and/or higher importance for the system. These are classified as Urgent, or those requiring immediate action. The next transformers are those in the Yellow or Priority zone. Action would normally be taken on these transformers as soon as the Urgent transformers have been taken care of. The transformers in the Normal category would typically not require anything other than normal basic maintenance unless circumstances move either the risk of failure or importance to a higher value (into the Yellow or Red Zone).

As per Figure 7 in the Hitachi report, both ASM T1 and ASM T2 are in the Red Zone and therefore are classified as Urgent or “requiring immediate action”. FBC has determined that the only viable action is to immediately start planning for transformer replacement.

14. Reference: Exhibit B-1, Appendix B, PDF page 98

Figure 7 shows a plot of the risk of failure vs. importance for unit. The Urgent, Priority, and Normal boundaries were also shown on this plot, so that the transformer could be categorized. From **Figure 7** we see that both transformers are in the Urgent (Red) category.

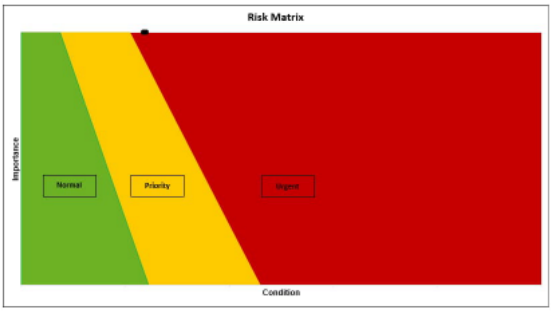


Figure 7 – Risk of Failure vs. Importance

14.1 The Hitachi statement indicates that both transformers are depicted in this Risk Matrix, which the CEC does not find. Please identify the two transformers or modify the matrix such that they can be identified.

Response:

The dot at the top of the risk matrix (as can be seen from Figure 7 provided in the preamble to this IR) represents both ASM T1 and T2 in the Risk Matrix. ASM T1 and ASM T2 have a corresponding Risk of Failure of 2.35 percent and 2.41 percent, respectively, and Hitachi ranked both transformers with an Importance of 100. Since the Risk of Failure and Importance for ASM T1 and T2 are similar, the data points appear to overlap in Figure 7. For further clarity, FBC provides an enlarged Figure 7 below with the dot depicting both transformers circled.

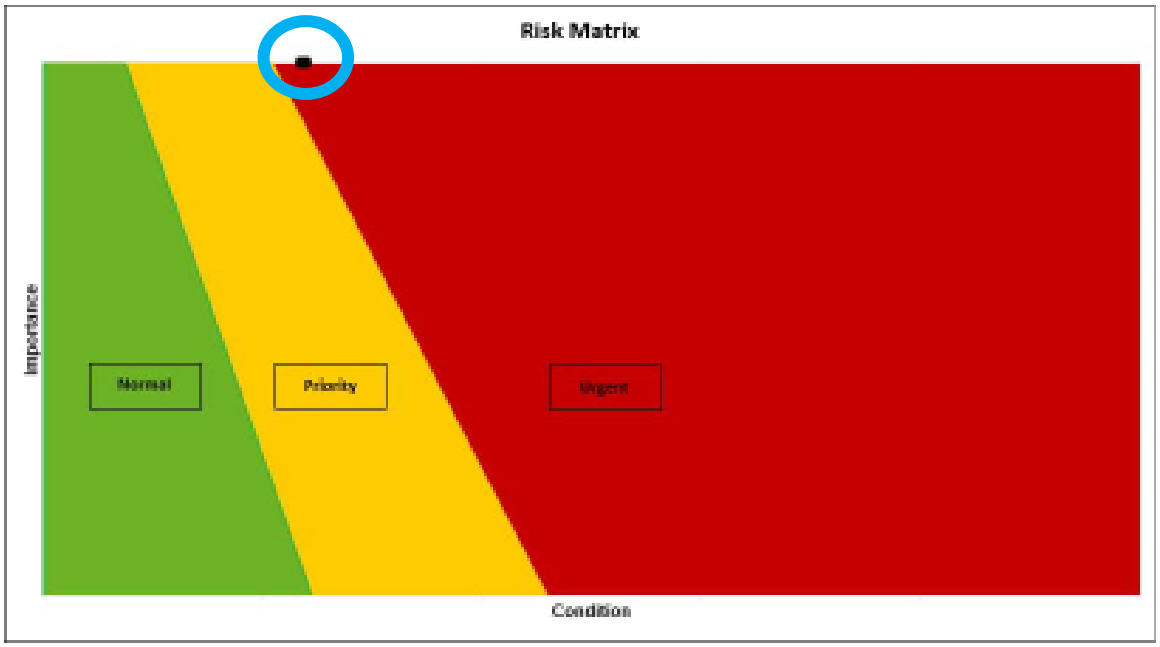


Figure 7 – Risk of Failure vs. Importance

14.2 Please confirm, or otherwise explain, that the dot on the top of the Risk Matrix, representing 100 importance, and barely in the red zone is representative of the overall risk assessment of one or both of the Transformers.

Response:

Please refer to the response to CEC IR1 14.1.

14.3 Please confirm, or otherwise explain, that to the extent that Importance level was reduced by even 20%, the risk would be reduced to the Priority level.

Response:

Not confirmed. Please refer to the response to CEC IR1 9.2.

15. Reference: Exhibit B-1, Appendix B, PDF pages 98 and 99/236

Figure 8 shows a histogram of the failure rate of the transformer, which is a combination of the information from each of the individual risk categories.

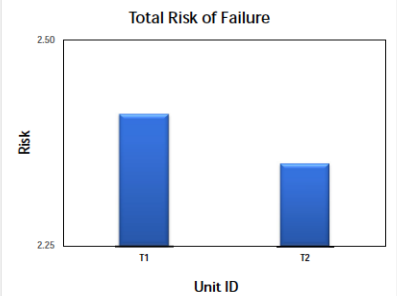


Figure 8 – Total Risk of Failure Histogram

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

15.1 Please confirm, or otherwise explain, that to the extent that the probability of failure is in the range of 2.25% to 2.5% for the year, that the Importance level moves from Priority to Urgent.

15.1.1 Please explain whether or not Urgent would be more or less urgent if the probabilities increased above this range or decreased somewhat from this range.

Response:

Not confirmed. FBC does not have access to the detailed interpretation of Figure 7 in Appendix B of the Application, however, as discussed in the response to BCOAPO IR1 7.1, it is FBC's interpretation that a Probability of Failure (PoF) below 2 percent would downgrade the need for intervention from "Urgent" to "Priority". It is FBC's interpretation that power transformers with a PoF over 2 percent and the same "Importance", regardless of how much over 2 percent, would be classified as "Urgent" as per Figure 7 in the Hitachi report (Appendix B).

15.2 Please explain why risks are not discussed in terms of probabilities and consequences of the risk along with all of the FBC mitigating action potentials.

Response:

As described in Section 1 – Introduction of the Hitachi report (Appendix B), Hitachi was commissioned to identify the conditions of ASM T1 and T2, "… to determine the risk of failure…

and to prioritize them for follow-up corrective actions such as inspection, maintenance, repair, or replacement".

Hitachi chose to use their proprietary methodology of *Total Risk of Failure* and *Importance* (consequence). Hitachi also included mitigating actions in its Conclusions and Recommendations on pages 106-107 of Appendix B.

16. Reference: Exhibit B-1, page 23 and page 31

> 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.

> 1. Infrastructure
>
> 1.1. System Reliability: Considers whether the alternative meets the Single Contingency (N-1) Transmission Planning Criterion, including the long-term ability to continue to serve all load during the outage of a single element (in this case, one of the 63/161 kV transformers). This criterion also considers the long-term amount of incremental capacity added by the alternative, as well as the reliability, availability and sustainability of electrical supply on the transmission and substation facilities in normal and emergency situations.
>
> 1.2. Potential for Future Expansion: Considers the potential for future expansion of a terminal station, such as the ability to add more transmission lines or capacity as needed in the future.

16.1 Please explain whether or not FBC has prioritized either of these objectives for this Project.

Response:

FBC clarifies that the Project Objectives (outlined in Section 4.1) and the Evaluation Criteria (outlined in Section 4.3) have two separate purposes.

The Project Objectives are the two drivers for the Project and, in order for a project alternative to be considered feasible and to therefore pass the early screening stage, the alternative must meet both objectives. FBC considers both Project Objectives to have equal importance.

The Evaluation Criteria were developed to assess each of the feasible alternatives. FBC notes that the System Reliability criterion assesses the feasible alternatives' abilities to increase capacity to the Boundary and Similkameen areas and to address aging infrastructure issues, both of which are important to maintaining safe and reliable service. Please refer to the response to BCUC IR1 7.1 for a detailed explanation of the rationale for the weights assigned to the Evaluation Criteria and how the Evaluation Criteria were developed.

16.2 Please confirm that the Evaluation Criteria 'System Reliability and Potential for Future Expansion' are the criteria that FBC established for meeting its objective of

maintaining safe and reliable service to customers in the Boundary and Similkameen areas, and please discuss how these parameters were established.

Response:

Please refer to the response to CEC IR1 16.1.

16.3 Please identify any parameters or thresholds that FBC established for 'addressing aging infrastructure', and please discuss how these parameters were established.

Response:

Please refer to the response to CEC IR1 16.1.

17. Reference: Exhibit B-1, page 23 and 24

> **4.2 ALTERNATIVES DESCRIPTION**
>
> Six alternatives were identified and 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
>
> Each of these alternatives is described in this section, including an explanation of the alternatives that were rejected at an early screening stage, as they were not feasible as they either did not meet the required objectives for the Project, or were clearly inferior to other alternatives due to cost and/or complexity.

17.1 Please explain whether or not FBC considered an option of project deferral, potentially with immediate refurbishment of those components most at risk, or a run to failure option.

Response:

FBC did not consider an option to defer the Project. Deferral of the Project, with immediate refurbishment of the components at the ASM Terminal Station that are most at risk, or a run to failure option do not meet either of the Project objectives. Please refer to the response BCUC IR1 3.8.1.1 which explains that FBC is not able to refurbish the most at-risk component, the load tap changer, because the original equipment manufacturer is no longer in business and therefore the necessary equipment cannot be obtained. Please also refer to the response to BCUC IR1 3.10 which describes the assessment that FBC is undertaking to determine what (if any) corrective actions can be undertaken to continue to operate the load-tap changers in the short-term until the Project is complete.

17.2 Please explain why FBC has not included an alternative to replace one transformer now and the other one later, and discuss how this might be done and what the probabilities of failure instances and durations would be for the next 10 years under such a change.

Response:

FBC considered numerous system configurations and approaches when the need to replace the ASM transformers was first identified; however, the only alternatives which warranted a screening-stage level of consideration were the alternatives described in Section 4.2. Of these six alternatives, the closest to the approach suggested by CEC in this IR would be Alternative 6. However, for the reasons described in Section 4.2, this alternative failed the early screening stage assessment.

Beyond Alternative 6, FBC did not investigate in the screening stage an alternative to replace one transformer now and the other one sometime in the future. First, any replacement transformer would need to be larger than the existing ASM transformers in order to accommodate the load growth in the region. As a result, utilizing a staged approach would need to take into consideration the system configuration and site size to accommodate not only one larger new transformer but a second larger new transformer in the future. Second, and most importantly, a staged approach does not meet the Project Objectives and therefore is not a feasible approach.

While not considered, to be responsive, FBC provides the following explanation for why taking a staged approach to Alternative 3 is not reasonable or practical for the following reasons:

- To reliably meet Transmission Planning Criteria, the ASM power transformers must be of the same MVA for the transformer to operate in parallel and be considered redundant. The same size is necessary to ensure both transformers can carry the load if one is out of service. As system load has already exceeded the capacity of the ASM Terminal Station transformers in a single contingency (N-1) event, replacing only one transformer would not address this issue. Replacing only one transformer would leave the ASM Terminal Station without redundancy as the remaining existing unit would not be of suitable size for a single contingency (N-1) event.
- Replacing one transformer now and one transformer later would require the ASM Terminal Station to operate with only one transformer for a significant period (months), overloading the transformer remaining in service or operating with significant system load constraints.
- There are significant construction challenges at the ASM Terminal Station, mostly due to space constraints, and replacing one at a time would mean the station could not meet load requirements for a substantial period of time (months). In addition, the construction activities would compromise the reliability of the one unit in service, which is unacceptable from a loading/reliability perspective

17.3 Are there any options for addressing all or some of the capacity concerns in substations other than WTS or ASM?

17.3.1 If yes, please elaborate on which substations could potentially contribute capacity and how this could be accomplished.

17.3.2 Please advise whether or not FBC has evaluated an alternative using battery capacity to compensate for instances exceeding transformer capacity and failure of one transformer.

Response:

Addressing all or some of the capacity concerns in the Boundary and Similkameen area through other stations would not alleviate the need to increase the capacity of the ASM transformers because they transfer power that is generated in the Kootenays to the Boundary and Similkameen area.

There are no other substations that can perform the ASM transformers' function.

FBC has investigated battery capacity as an alternative supply to support load demand and manage outages. In the case of the ASM Project, battery capacity is not a practical or economical solution. Battery compensation would only reduce system load impacts on the ASM power transformers; it would not reduce the hydro-generation power transformed by the ASM power transformers and would not address the risk of aging transformers at the ASM Terminal Station.

18. Reference: Exhibit B-1, page 29 and 30

> **4.2.6 Alternative 6: Retain the Existing ASM Terminal Station and Add a New Transformer at WTS**
>
> This alternative includes installing a third transformer at WTS (WTS T3) while maintaining ASM T1 and ASM T2 at the existing ASM Terminal Station, resulting in the operation of three transformers in parallel. 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. This alternative would involve expanding WTS to incorporate a 63/161 kV transformer and a 161 kV transmission line connection and would require an extension of 11E Line from the ASM Terminal Station back to WTS. 11E Line would connect to both the ASM Terminal Station and WTS, and the ASM Terminal Station would remain operational with its existing equipment (i.e., the existing ASM T1 and ASM T2 transformers) inside the existing footprint. 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. Installing an additional 161 kV connection between WTS and the ASM Terminal Station, while maintaining the existing 63 kV Line between WTS and the ASM Terminal Station, poses design, construction, and operational risks due to the limited corridor spacing, the terrain, and increasing congestion. 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.

18.1 Please confirm that even if aging infrastructure was not considered, FBC would still reject this alternative on the basis of its impracticality.

Response:

Confirmed. FBC would still reject this alternative for the reasons stated in Section 4.2.6 of the Application.

19. Reference: Exhibit B-1, page 33

Table 4-1: Project Alternatives Evaluation Criteria (Non-Financial)

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%**

19.1 Please explain who developed the Evaluation Criteria and the weightings.

19.2 Please elaborate on how each of the criteria were weighted and the reasons behind the weightings; and please discuss at what stage this set of criteria was developed.

19.3 Please explain why System Reliability has a lower weight than Potential for Future Expansion.

19.4 Please explain why Infrastructure in total is given a fraction of the weighting when this criteria has to do with providing service to customers and the other criteria have to do with qualities related to the service.

Response:

The scoring approach, criteria, and weights given to each criterion were established through engagement and collaboration of FBC's internal stakeholders. The Evaluation Criteria were developed prior to the alternatives analysis during the Class 4 estimate development of the alternatives.

Please refer to the response to BCUC IR1 7.1 for a detailed explanation of how the criteria were developed and the rationale for the weighting of each criterion.

20. Reference: Exhibit B-1, page 33

Table 4-2: Non-Financial Evaluation Scoring Definitions

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

Criteria	Alternative 3 Rebuild ASM Terminal Station	Alternative 5 Expand WTS
Weighted Total[27]	**1.43**	**2.39**

As the table above demonstrates, based on the non-financial criteria, Alternative 5 is superior to Alternative 3.

20.1 Please explain which parties conducted the non-financial analysis.

Response:

The non-financial analysis was conducted by internal stakeholders from the following FBC departments:

- Archaeology
- Asset Management
- Community & Indigenous Relations
- Engineering – Substations & Transmission
- Environment
- Maintenance Planning & Reliability
- Mandatory Reliability Standards
- Operations – Substations & Transmission
- Project Management
- System Operations
- Transmission Planning
- Lands Operations

20.2 The CEC considers that having non-financial Evaluations of 'Best Choice' weighted 3 times as high as 'Acceptable Choice' risks establishing undue parameters for the Project. Please comment on the impacts for the above analysis if FBC used only 'Unacceptable' (0), 'Acceptable' (1) or 'Offers Significant Advantages over Acceptable' (2) analysis for its Non-Financial Alternative assessment.

Response:

If FBC used the evaluation scoring described by CEC in this IR, Alternative 5 would still rank superior to Alternative 3. For instance, Alternative 3 would still receive rankings of "0" for Potential for Future Expansion and Ground Grid Safety, whereas Alternative 5 would continue to receive no "0" rankings. Further, while many of the criteria that are currently ranked as orange or yellow for each alternative would likely be re-categorized as "Acceptable" under CEC's proposed rankings, Alternative 5 has more "green" rankings than Alternative 3 and would therefore accrue more "Offers Significant Advantages over Acceptable" rankings than Alternative 3.

21. Reference: Exhibit B-1, page 39 and page 40

> ### 4.3.4 Assessment of Alternatives 3 and 5 based on Financial Criterion
>
> The 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. The 50-year post-project analysis period is based on the Average Service Life (ASL) of the station equipment in the transmission plant category (i.e., asset class 353 Station Equipment)[28].
>
> ### 4.4 *Alternative 5 is the Preferred Project Alternative*
>
> On the basis of FBC's financial and non-financial evaluation framework, the preferred solution is Alternative 5, under which FBC would expand WTS to incorporate a 63/161 kV conversion and convert 34 Line to 161 kV and interconnect it with 11E Line to extend 11E Line back to WTS, then decommission the ASM Terminal Station. Alternative 5 involves the following key components:
>
> - 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 two breaker 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.

21.1 Please confirm that FBC's financial analysis only addressed those aspects of the WTS substation that are expected to change.

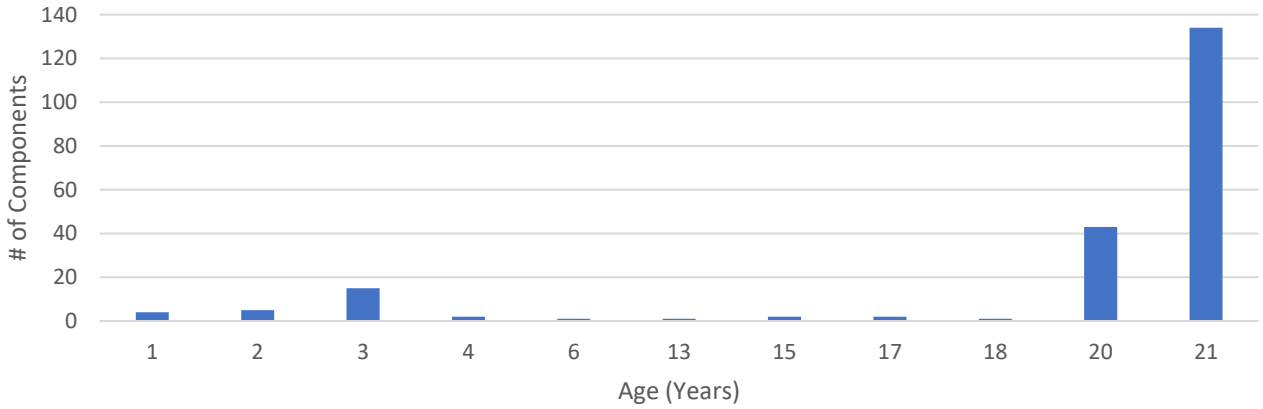
Response:

Confirmed.

21.2 What are the ages of the WTS substation components?

Response:

The following figure provides the ages of the existing WTS substation components.



21.3 Does FBC intend to replace all the equipment in the WTS substation? Please explain.

21.3.1 If no, please describe and provide the remaining life expectancy of those aspects of the WTS substation that will not be replaced.

Response:

FBC does not intend to replace all the equipment at WTS. FBC's scope of work associated with the existing WTS equipment for this Application includes the reconfiguration of and modifications to WTS necessary for expanding the footprint, and the addition of new infrastructure. Based on the Average Service Life (ASL) of 50 years used in the financial analysis, the average remaining life expectancy of those components of WTS that will not be replaced is 33 years.

21.3.2 Please provide an expected future value of the WTS equipment that is not being replaced.

Response:

FBC notes that the existing WTS equipment that is not being removed or replaced is not relevant to the ASM CPCN Application. The scope of Alternative 5 requires the expansion of the WTS footprint to accommodate additional equipment, so there is minimal existing WTS equipment that is expected be replaced or removed as part of the ASM CPCN Application.

However, to be responsive, the Net Book Value (NBV) of the WTS equipment that is not being removed or replaced is estimated to be $10.412 million in 2026.

The WTS equipment that is being removed or replaced as part of the Project includes three A-frame structures and surge arrestors, two 63 kV switches, one 63 kV bus support structure, and fencing along the southern end of the station. By the end of 2026, the NBV of this decommissioned WTS equipment is estimated to be $0.151 million. FBC included the NBV of this decommissioned WTS equipment in the total NBV of all decommissioned assets (including the ASM Terminal Station and existing fibre between WTS and SCC) in the Project analysis. As noted in Section 6.4.3 of the Application, FBC estimates the NBV of all decommissioned assets to be $4.470 million by the end of 2026.

21.3.3 What other analysis period did FBC consider, if any?

Response:

As explained in the Application, FBC used the ASL of the station equipment in the transmission plant category as the analysis period for the Project. This approach correctly reflects the expected life of the new assets as well as the financial lifecycle of the ASM Project; therefore, it is reasonable and appropriate to set the Project's financial analysis to 50 years such that the analysis will cover the expected life of the new assets.

While FBC did not consider using a different analysis period, another approach could be using the depreciation rates to define the length of the analysis period. Depreciation rates and ASL, for the same asset class, often deviate because depreciation rates are set to account for the accumulated gains or losses of all the assets that have been accounted for in the group of assets as well as the net salvage provision. On the other hand, the ASL is the average life expected for any new assets in each individual asset class; it does not account for any accumulated gains or losses within the same asset class, or the net salvage provision. If FBC had used the depreciation rates approach, the financial analysis period would be 42 years instead of 50 years.

FBC used the ASL to define the number of years in the financial analysis because the analysis is intended to evaluate the incremental impact to FBC's revenue requirement due to the ASM Project over the expected life of the assets. Based on the most recently approved depreciation study[6], transmission station equipment, which is the majority of the new assets for the ASM Project, is expected to have an ASL of 50 years (under asset class 353); therefore, it is reasonable and appropriate to set the financial analysis to 50 years such that the analysis will cover the expected life of the new assets.

[6] Approved as part of the 2020-2024 MRP Decision and Order G-166-20.

22. Reference: Exhibit B-1, page 39 and 40, and Appendix C, PDF page 110/236

Table 4-4 below provides a summary of the financial analysis of Alternatives 3 and 5 over the 53-year analysis period at an AACE Class 4 estimate. 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. Please refer to Appendix C for a summary of the capital costs for both Alternatives 3 and 5 at an AACE Class 4 estimate level.

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

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

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

22.1 The CEC understands that the CPCN Guidelines require, and FBC did undertake, an AACE Class 3 Estimate for its Project Cost Analysis. Please explain whether or not FBC typically uses AACE Class 4 estimates for Alternatives analysis.

22.1.1 If this is not typical, please explain why FBC used the Class 4 estimate in this case.

22.1.2 If FBC typically uses a Class 5 Estimate for its Alternatives Analysis, please provide the expected cost difference between the two class estimates, if any.

Response:

FBC typically undertakes an AACE Class 4 level of project definition and design for its analysis of feasible alternatives, consistent with the BCUC's CPCN Guidelines[7]. As stated in the CPCN Guidelines (page 4 of Appendix A to Order G-20-15), "Cost estimates used in the economic comparison should have, at a minimum, a Class 4[8] degree of accuracy as defined in the most recent revision of the applicable AACE International Cost Estimate Classification System Recommended Practices."

Accordingly, FBC would not typically develop its feasible project alternatives to a Class 5 level of accuracy only because this would not be consistent with the CPCN Guidelines. For clarity, a Class 5 estimate would have a wider (i.e., less accurate) cost range than a Class 4 estimate, which is why feasible alternatives are typically developed to a Class 4 accuracy level and the proposed project alternative is developed to a Class 3 level.

[7] British Columbia Utilities Commission. (2015, February). *2015 Certificate of Public Convenience and Necessity Application Guidelines*. DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf

[8] Class 4 estimates are generally prepared based on limited information and subsequently have fairly wide accuracy ranges. They are typically used for project screening, determination of feasibility, concept evaluation, and preliminary budget approval.

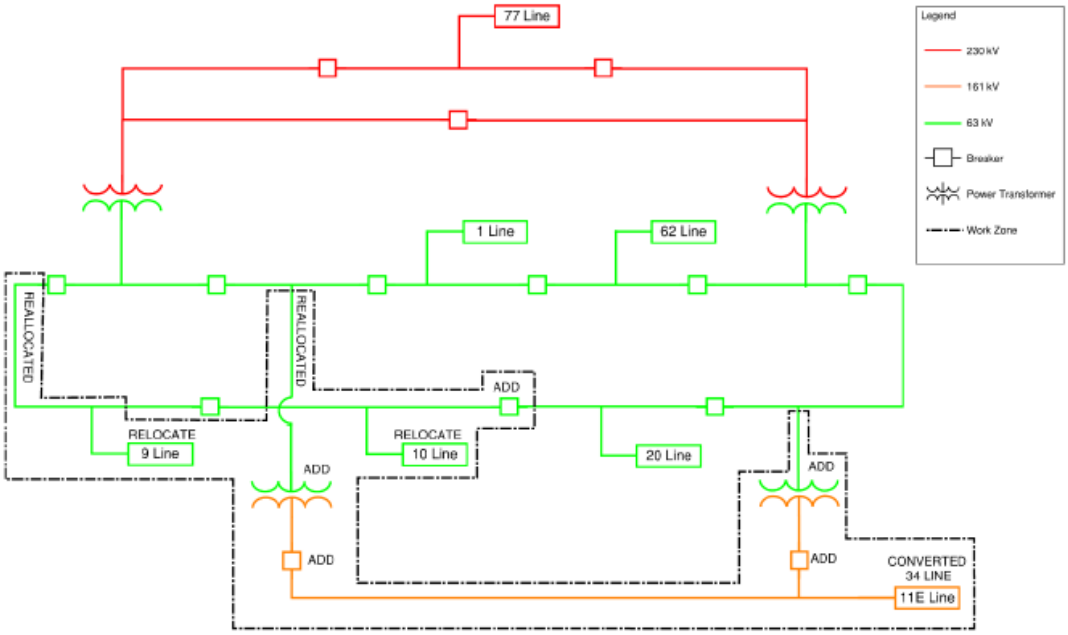
23. Reference: Exhibit B-1, page 42

5.1 PROJECT OVERVIEW

As discussed in Section 4, FBC's recommended alternative requires the installation of two new 150 MVA 63/161 kV transformers at WTS, located in Trail, BC, and the subsequent decommissioning of the existing ASM Terminal Station.

Figure 5-1 shows a simplified single line drawing of the proposed installation. Preliminary drawings showing the detailed single line diagram and general arrangement are included in Confidential Appendices F.

Figure 5-1: Proposed WTS Simplified Single Line Diagram



The Project's principal elements are modifications to the land, station, transmission line, distribution line, and fibre path, each of which is discussed in more detail below.

23.1 Did FBC hire an external third party to develop the overall Project design, or did FBC design the Project internally?

23.1.1 If FBC hired external assistance in the Project design, please provide the name and qualifications of the third party.

23.1.2 If external assistance was used, what processes did FBC undertake to select the third party?

Response:

FBC determined the need for the Project internally through its Planning department and produced the initial cost estimate, then hired third-party consultants for the Class 4 and 3 estimates and design.

PICA Engineering led the substation Class 4 and 3 effort and received support from BBA Consultants for the site and civil design and estimating, as well as preliminary station grounding design. DBS Energy Services was selected for the lines (transmission, distribution and fibre modification) Class 4 and 3 estimates, and they received support from BBA Consultants on the insulation coordination study for the 34L voltage conversion.

All consultants were selected through FBC's procurement policy and have extensive knowledge from working on many FBC station and transmission projects, as well as other utility experience to draw from. PICA Engineering has designed and estimated many FBC station projects since 2002, as well as providing Project Engineer and technical support to the FBC station team. BBA Consultants is a large engineering firm that specializes in Power System studies and analysis. DBS Energy Services has estimated and designed many FBC transmission lines projects since 2002 and has also been involved in providing technical support to the FBC transmission lines team.

24. Reference: Exhibit B-1, page 46

> **5.2 *PROJECT ENGINEERING AND DESIGN***
>
> Engineering and detailed design is expected to start immediately upon CPCN approval by the BCUC. Activities will encompass all engineering calculations, validations, specifications, and drawings required to cover the Project need. Engineering activities will be organized in order of priority, in relation to the fabrication and procurement lead times and schedule date for each component to be on the work site.
>
> The Engineering packages to be completed include, in no particular order:
>
> - Transformer specification;
> - Circuit breaker specification;
> - 9 Line and 10 Line transmission re-alignment scope (and any associated distribution underbuild);
> - WTS site preparation scope;
>
> Engineering will be completed either by FBC or by an FBC pre-qualified external engineering firm. Each engineering package completed by external resources will be reviewed and accepted by FBC Engineering. Engineering design will occur in stages, anticipated to begin in the first quarter of 2024. The design stage will be concluded by the final design review, prior to issuance of each Issued for Construction package.
>
> - WTS civil scope;
> - WTS electrical scope;
> - 34 Line conversion and re-alignment scope (and any associated distribution underbuild);
> - Fibre modification scope; and
> - ASM Terminal Station demolition scope.

24.1 FBC states that engineering and detailed design is expected to start immediately upon CPCN approval. Has FBC determined whether it will do the engineering internally or use an external engineering firm? Please explain.

Response:

FBC has not determined whether the engineering work will be done internally or with the use of external engineering firms. This decision will be based on the timing of the CPCN approval and other capital projects underway. FBC will endeavor to use internal resources first and supplement these resources with external support where needed.

24.2 Please elaborate on the pre-qualification process and selection processes for engineering, and other aspects of the Project that will be undertaken by third parties.

Response:

To select a consultant for a project, an engineering scope of work and FBC standards are issued to a group of engineering firms in a Request for Proposal (RFP). FBC will then review and award a contract to the successful bidder following a commercial and technical review of the proposals, as well as factoring in the engineering schedule to ensure it meets construction timelines. The successful bidder must be pre-qualified with FBC based on their safety plans and record, technical expertise, and insurance provisions.

25. Reference: Exhibit B-1, page 52

Table 5-1: Risk Register

Type of Risk	Risk Description	Mitigating Actions	Likelihood of Occurrence (Low / Medium / High)
Scope	Scope creep due to existing conditions not reflecting that of existing as-built drawings on record.	FBC will validate existing conditions on site by surveying and reviewing substation drawings to reflect existing infrastructure.	Low
Safety	Contractors not familiar with FBC safe work practices resulting in injury or violation.	FBC will select a contractor with FBC substation experience or train the selected contractor prior to work commencing. FBC will provide a CAT 6 worker[30] to act as a site safety watch for construction work.	Low
Quality	Poor quality installations.	FBC will have dedicated resources monitoring construction activities as scheduled by the Construction Manager. An Inspection & Test plan will be implemented with the installation contractor.	Low
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

25.1 Please explain whether or not the Likelihood of Occurrence represents the risk after mitigation or before mitigation.

25.2 If the likelihood of occurrence represents the initial risk, does FBC expect the risks to be fully mitigated after undertaking the specified Mitigating Actions? Please explain.

25.3 Please quantify the risk's potential consequences for each risk identified and the probability of the risk prior to mitigation and the risk probability and potential consequences after the mitigation.

Response:

The Likelihood of Occurrence represents the risk before mitigation.

By mitigating the initial risk, the Likelihood of Occurrence drops significantly, but does not fully mitigate the risk. Unforeseen risks can still occur during construction, regardless of mitigation efforts or methods.

Quantifying the risk's consequences and probability of risk before and after mitigation is very subjective, and this is why FBC uses the Low, Medium, and High Likelihood scale. If a risk becomes apparent, estimates will be used to capture the costs associated with the specific risk, and costs will be covered by the project contingency.

26. Reference: Exhibit B-1, page 55

- A base capital cost estimate of $25.361 million (excluding contingency) in 2022 dollars developed by FBC in conjunction with PICA Engineering Ltd. (with respect to the station component of the Project) and DBS Energy Services Inc. (with respect to the transmission, distribution and fibre modification components of the Project) using the AACE Class 3 International Recommended Practices 18R-97 and 97R-18 as guides. The 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. Please refer to Section 5.1.2 for details related to the station component of the Project, and Confidential Appendix G-1 for the basis of estimate. With respect to the details of the Project related to transmission, distribution and fibre modifications, please refer to Sections 5.1.3, 5.1.4 and 5.1.5, respectively, as well as Confidential Appendix G-2 for the basis of estimates.

26.1 Please elaborate on the roles of PICA Engineering Ltd. and DBS Energy Services Inc.

Response:

Please refer to the responses to CEC IR1 23.1 and BCOAPO IR1 19.1.

27. Reference: Exhibit B-1, page 55 and 56

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

27.1 Please explain why FBC selected 15% contingency for the station construction and removal costs.

27.2 Please explain why FBC selected 10% for the contingency for the transmission, distribution, and fibre modification components.

27.3 Are there aspects of the Project with no added contingency? Please explain.

27.4 What contingencies does FBC typically apply in capital projects, and why?

Response:

Please refer to the responses to BCUC IR1 15.1, 15.2 and 15.3.

There are two aspects of the Project cost estimate with no contingency:

- Actual CPCN Project Preliminary Engineering costs incurred by FBC prior to January 2023 do not have contingency applied. These costs are actuals and were known at the time of filing the Application.

- As noted in Section 6.2 of the Application, the contingency of 15 percent on Station construction and removal costs excludes the add-on costs that are calculated on top of the base station estimate. These add-on costs include Material Handling costs, Provincial Sales Taxes, and other indirect costs.

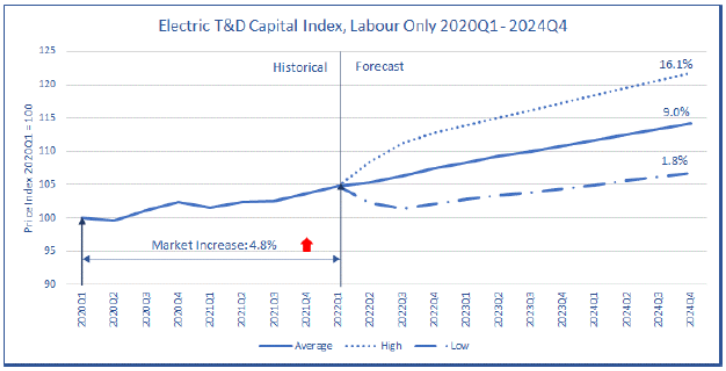
28. Reference: Exhibit B-1, page 56 and Appendix G-3, page 3 of 8

- To convert the base capital cost estimate and contingency from 2022 dollars to as-spent dollars over the period from 2023 to 2026,[31] 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. 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. The Wood Mackenzie Market Report is included in Appendix G-3.

- A forecast of the CPCN Project Preliminary Engineering costs of $0.760 million (includes escalation of $0.009 million) was added, including $0.478 million of actual costs incurred from 2021 and 2022, and a forecast of $0.282 million for 2023. Consistent with the approved treatment[32] for CPCN project preliminary engineering costs, these costs, which are related to the development of the Project and include regulatory costs for the purpose of obtaining approval for the CPCN, are captured in the existing CPCN Project Preliminary Engineering non-rate base deferral account as discussed in Section 6.4.1 below.

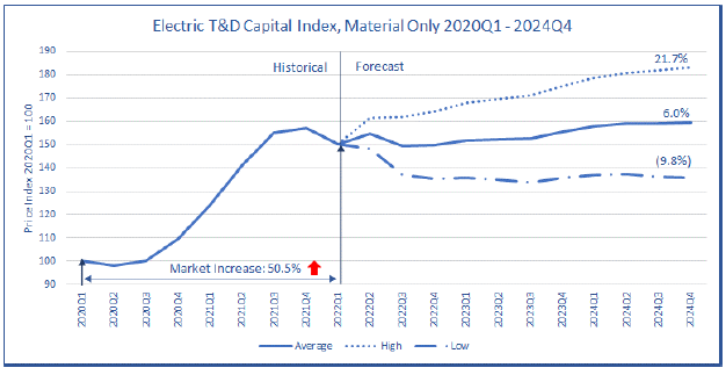
- AFUDC, calculated using FBC's 2023 approved AFUDC rate of 5.73 percent[33], which is equal to FBC's after-tax weighted average cost of capital, and added to the total Project cost.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

28.1 The CEC has reviewed Appendix G-3 and expects that FBC's escalation was based on the above graphs in which materials are forecast to escalate at a lower rate than Labour. Please confirm or identify any other information that was used.

28.2 Please provide the specific calculations that resulted in the escalation values that were applied.

Response:

FBC clarifies it used the first graph on page 2 of the Wood Mackenzie report that forecasts the capital expenditure escalation for all electric Transmission and Distribution costs. FBC did not use the two graphs provided in the preamble that are specific to labor or materials to determine Project escalation.

Please refer to the response to BCUC IR1 16.2 for a calculation of the average cost escalation percentage applied to the total Project cost estimate. FBC confirms no other information was used to determine the Project escalation over the period from 2023 to 2026.

29. Reference: Exhibit B-1, pages 57 and 58

> The financial evaluation of the Project includes the following assumptions:
>
> - **Project Capital and Removal Costs:** Base capital cost estimate of $35.179 million in as-spent dollars as discussed in Section 6.2.
> - **Future Incremental Sustainment Capital:** The financial evaluation over the 53-year period includes the future replacement cost of the poles, towers and fixtures, conductors and devices, and fibre components of the Project. The timing of these replacement costs is based on the ASL of 39 years for the poles, towers and fixtures, and conductors and devices, and an ASL of 14 years for the fibre lines, as detailed in FBC's most recently approved depreciation study (for example, the 50-year post-Project analysis period includes the one-time replacement of the poles, tower and fixtures, as well as the conductors and devices in 2065, and the replacement of the fibre lines three times, in 2040, 2054, and 2068).

29.1 Please explain whether or not the Project capital and incremental sustainment capital included in the Project will result in any reduction to the capital or sustainment capital that would otherwise be required for either the ASM or the WTS substation or the ASM substation in the absence of the Project.

29.1.1 If yes, please explain whether or not FBC has or will incorporate these savings into its financial analyses and/or MRP such that ratepayers are not being charged for services that will no longer be required.

Response:

FBC did not analyze the potential capital or sustainment capital that would be required for either the ASM Terminal Station or WTS in the event that the Project was not undertaken, as FBC determined that the Status Quo alternative was not feasible and it was therefore rejected in the screening stage.

With regard to the impact of the Project on FBC's future sustainment capital requirements, FBC would incorporate these requirements into its sustainment capital plans once the Project is in-service and would file for approval of sustainment capital expenditures as part of its future revenue requirement applications.

30. Reference: Exhibit B-1, page 58

> - **Incremental O&M:** FBC expects that ongoing maintenance spending will be optimized by incorporating the 63 kV/161 kV voltage conversion into WTS. Further, the retirement of the existing ASM Terminal Station will eliminate the O&M 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 as discussed below. 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. The incremental O&M can be found in Confidential Appendix H, Schedule 2.

30.1 Please specifically describe the types of O&M savings that will occur from eliminating those O&M savings associated with the ASM substation, and elaborate on why the additional O&M costs will more than offset those savings.

Response:

FBC expects that ongoing maintenance will be optimized as a result of the Project through the consolidation into one location (i.e., WTS). This consolidation is anticipated to create efficiencies in the following areas:

- Maintenance mobilizing and de-mobilizing;
- Administration;
- Annual inspections, testing, and oil sampling;
- Annual operating costs (snow removal, switching, herbicide); and
- MRS testing requirements due to less electrical apparatus that must be maintained to these requirements.

However, consolidation of the 63 kV/161 kV voltage conversion into WTS also results in increased costs in certain areas, which are expected to offset the above-described O&M savings. The 63 kV/161 kV at WTS would involve different equipment and configuration, resulting in slightly higher O&M costs.

31. Reference: Exhibit B-1, page 58

> - **Property Tax:** 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.
> - **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.

31.1 Please confirm that the property tax calculations reflect the current City of Trail rates.

Response:

Confirmed. The property tax calculations reflect the actual 2022 City of Trail Utility Rates.

31.2 Is FBC's 2% anticipated inflation for the Project the same as that which is reflected in FBC's long range planning? If no, please explain why not.

Response:

FBC used an annual 2 percent inflation as the escalation factor for costs (i.e., incremental O&M, property tax, etc.) expected to occur beyond 2027 over the 50-year post-Project analysis period. FBC relies on the Bank of Canada mid-point inflation target of 2 percent as a proxy for future cost escalation over the 50-year post-Project period. While FBC does not have a standard inflation rate for long-range planning, using 2 percent per year when forecasting long-range costs is consistent with past practice. Please refer to the response to BCUC IR1 16.4 for further discussion.

32. Reference: Exhibit B-1, page 60

Table 6-3: Summary of Project Annual Rate Impact

Line	Particular	2025	2026	2027
1	Incremental Revenue Requirement compared to 2023 Approved ($ millions)	0.290	0.357	2.458
2	*Annual Rate Impact compared to 2023 Approved Rates (%)*	*0.07%*	*0.08%*	*0.58%*

The Project will result in a rate impact of 0.58 percent in 2027 over FBC's 2023 approved rates when all construction and salvage activities are complete, and all capital costs have entered FBC's rate base. This rate impact is equivalent to approximately $0.707 per MWh when compared to FBC's 2023 approved rates, and for an average FBC residential customer consuming 11,000 kWh per year, this would equate to a total bill impact of approximately $7.80 in 2027.

32.1 Please provide the estimated bill impact to FBC's commercial customers.

Response:

Please see Table 1 below for the estimated bill impact to FBC's commercial customers of $37 per customer by 2027 (Line 8 of Table 1 below). The 2023 Forecast Revenue and Energy volumes for Commercial Customers are derived from the Approved[9] FBC Annual Review for 2023 Rates.

Table 1: Estimated Bill Impact to FBC's Commercial Customers by 2027

Line	Particular	Value	Reference
1	2023 Forecast Revenue for Commercial Customers ($000s)	$ 110,490	FBC Annual Review for 2023 Rates, Section 11, Schedule 18, Line 2, Column 5
2	2023 Forecast Energy Volume for Commercial Customers (GWh)	973	FBC Annual Review for 2023 Rates, Section 11, Schedule 18, Line 2, Column 7
3	**2023 Approved Effective Rate for Commercial Customers ($/MWh)**	**$ 113.556**	**Line 1/Line 2**
4	Incremental Rate Impact in 2027 due to ASM compared to 2023 Approved Rates (%)	0.58%	Table 6-3, Line 2, 2027 impact
5	**2027 Forecast Rate Impact for Commercial Customers ($/MWh)**	**$ 0.659**	**Line 3 * Line 4**
6	2023 Average Number of Commercial Customers	17,267	FBC Annual Review for 2023 Rates, Section 11, Schedule 18, Line 2, Column 6
7	**Average Volume for Commercial Customers (MWh/customer)**	**56.350**	**(Line 2 * 1000)/Line 6**
8	**Commercial Bill impact by 2027 due to ASM ($/customer)**	**$ 37**	**Line 5 * Line 7**

[9] Orders G-382-22 and G-87-23.

33. Reference: Exhibit B-1, page 61

> **7.1 *ENVIRONMENTAL IMPACTS***
>
> The WTS is an active FBC substation located within an SRW on a larger parcel owned by Teck Metals Ltd. The substation was developed in the early 2000s with no prior site developments and is located within the City of Trail, though not within the City's designated Development Permit Areas. The WTS is a Contaminated Sites Regulation (CSR) Schedule 2 Activity (electrical transmission or distribution substations) with bulk storage of transformer oil and various electrical infrastructure presenting a metals source.
>
> Environmental investigations can be triggered under the CSR for sites that have a prescribed Schedule 2 Activity if they require a municipal permit, if the Schedule 2 Activity is decommissioned/ceased, or if more than 30 m^3 of soil will be relocated to an unlicensed facility. Municipal permits are not anticipated for the Project, nor will the Schedule 2 Activity be decommissioned/ceased, so only the latter trigger for environmental investigation would apply if more than 30 m^3 of soil was being relocated to an unlicensed facility.

33.1 Section 7.1 appears to relate primarily to the WTS site. Please describe any site remediation and environmental impacts that may occur at the ASM site or identify where this may be found in the Application.

Response:

The Environmental Management Plan addresses the risks and identifies appropriate controls for any environmental issues associated with the Project, including at the ASM Terminal Station site. Please refer to the response to BCUC IR1 12.3 which describes the ASM Terminal Station portion of the Project.