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October 6, 2022

Industrial Customers Group
c/o #301 – 2298 McBain Avenue
Vancouver, BC V6L 3B1

Attention: Mr. Robert Hobbs

Dear Mr. Hobbs:

Re: FortisBC Inc. (FBC)

Annual Review for 2023 Rates (Application)

Response to the Industrial Customers Group (ICG) Information Request (IR) No. 1

On August 5, 2022, FBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-193-22 for review of the Application, FBC respectfully submits the attached response to ICG IR No. 1.

For convenience and efficiency, FBC has occasionally provided an internet address for referenced reports instead of attaching lengthy 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:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1. Reference: Exhibit B-2, Section 1.4.2, Productivity Initiatives, p. 4

"In 2021, FBC requested its contractor performing condition assessments to incorporate the use of drones for collecting data for certain suspected deficiencies."

1.1 On which transmission lines were drones used for inspection?

Response:

FBC's contractor used drones for all the lines that were inspected in 2021 which included 18L, 32L, 71L, and 6/26L.

1.2 What was the cost of the drone inspections in 2021 and year-to-date in 2022?

Response:

In 2021, FBC's contractor used drones to inspect structures where the ground-based field inspection was insufficient to confirm deficiencies, and further review was required (e.g., pole top condition, insulators, cross arms, woodpecker holes, etc.). Drones were used to inspect approximately 78 structures, representing 7 percent of the 1,119 structures inspected in 2021. The total cost of drone inspections was approximately $7,500, completed at an average cost of $95 per structure inspected.

In 2022, the contractor has used drones for inspecting structures in a similar manner as in 2021 and at similar estimated costs.

1.3 What would have been the cost of the inspections performed by drones if traditional methods had been used instead?

Response:

Drones are an efficient way to avoid the higher costs of bucket truck inspections or pole climb inspections when a closer inspection is required. They also provide more accurate data to build a relevant rehabilitation package from, rather than taking a more conservative approach of just replacing the whole structure. The drone inspection cost of approximately $95 per structure, is less than the cost of approximately $125 for a Powerline Technician to climb the pole or inspect from a bucket truck, which is traditionally what would have been done for a closer inspection.

2. Reference: Exhibit B-2, Section 1.4.2, Productivity Initiatives, p. 5

"The requirements and business case for the necessary information systems infrastructure were completed in 2021. FBC plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings."

2.1 Please provide the business case referenced in the quoted passage.

Response:

The business justification for the Enterprise Data Analytics Solution (EDAS), a joint project between FBC and FEI, is provided below.

Project Description

FortisBC employees currently extract and utilize data from various internal and external software systems using various techniques and tools and with different levels of governance and oversight.

The EDAS addresses key barriers by integrating existing FortisBC data into a single, scalable platform.

Existing problem	EDAS answer
1. **Finding available data is hard.** Today, there is no single place where employees can find a simple description of the data available to them, how it is created (its providence), its sensitivity or quality, or from which they can access data.	**Employees can access a single source of truth for validated enterprise data.** Putting data in the hands of more users and allowing them to create their analyses and reports will remove IT bottlenecks and accelerate efficiencies, creativity and agility. End-user empowerment is critical. Everyone in the company can produce better data visualizations and get access to the data (with no providence) faster.
2. **Relating data from disparate sources requires Information Systems (IS) support.** Combining data from different sources, like outage and customer details, or customer and census or geo-spatial data is complex and time-consuming. Today, each new request is pursued as a separate project, each of which requiring a separate database to support essential analytics.	**Users can easily search, load and relate trusted data from any connected source for analysis.** The EDAS data solution resides above the rest of our data environment. It's like a Data Fabric that stitches together content from multiple data silos to produce a uniform and unified view of essential business data.
3. **The cost of adding new data sources is high and time consuming.** The current method of adding new data sources is time consuming, complex, and variable.	**EDAS streamlines data access and analytics for employees and digital products for customers.** EDAS modernizes our data management strategy and makes connecting to and integrating existing data sources quicker and less expensive.

Existing problem	EDAS answer
4. **Storage and access to historical data is complex.** Although existing systems can handle historical data, the solutions use siloed data stores that have limitations. For example, currently we cannot combine the data from Enterprise Data Warehouse (EDW) and SAP Business Warehouse (BW) to create a report.	**Proposed solution will significantly extend our ability to use historical data.** EDAS addresses current deficiencies. It improves overall historical data availability, dramatically enhances the ability to combine data from different sources, and facilitates more complex modelling.
5. **Governing business use of data is limited.** Once data leaves IS control and is released to business users, how users employ data is largely unseen and ungoverned. In some cases, users can have difficulty accessing data due to the need to talk to multiple departments and negotiate variable internal policies.	**The solution simplifies access to data while improving regulatory compliance, data quality and trustworthiness.** Better, more reliable data facilitates more use cases and ensures accurate and timely analyses. New features improve regulatory compliance to lower organizational risk.

Proposed Solution

The EDAS platform will provide an enterprise platform to "free the data" by providing four key capabilities.

Key platform capabilities
Cheaper, faster software implementations. The EDAS platform will accelerate testing, piloting and implementation of new software solutions. The new ecosystem will allow users to securely retrieve, interact with, explore and visualize any particular data from any connected data source. EDAS will incorporate significant portions of data from 14 internal and five external data sources.
Cheaper, faster, easier access to data and analytics assets. With EDAS, analysts spend 80% of their time analyzing data, rather than gathering it. By instantly combining varied data into a single view as needed, FortisBC can better understand its operations to drive better, faster insights and innovation.
Govern data and analytics assets. The ability to protect data is a core feature of the EDAS platform. It tags data and reports according to their sensitivity. The data catalogue captures and presents data quality scores to users. Each use case implementation ensures that necessary data clean-up and transformation automation occurs to make data fit for purpose (i.e., suitable quality to deliver the use case). The project will establish data quality KPI's and dashboards. When users identify data issues, they can notify data stewards about the problem and initiate an escalation process to correct source system collection or input issues. This process does not exist today. The program will automate processes for requesting and revoking access according to the rules approved by the Data and Analytics Steering Team. The EDAS system also enables automated data retention and destruction policies and procedures.
Develop data and analytics organizational talent. The EDAS platform provide an opportunity to establish an Analytics Centre of Excellence providing support and training for employees working with data. This centralized team will assist departments and users in identifying and using the right analytical tools for their needs. The near-term focus will be on the introduction and adoption of Power BI to a broader user base and increase the analytic skills within FortisBC.

The power and ease-of-implementation of this platform was demonstrated in a Proof of Concept implementation that occurred during 2021. The proposed enterprise system, aside from one component, was set up and connected to internal data sources by CGI and FortisBC in three weeks and resulted in an enhanced Gas Volume Variance report.

Cost and Value

Costs (000s)	2022	2023	2024	2025	Total	Ongoing
Capital (excluding licensing)	$1,195	$2,175			$3,370	
Capital (licensing)	$1,385				$1,385	
Capital Cost	**$2,580**	**$2,175**			**$4,755**	
Project OPEX (change management and training)	$45	$90			$135	
Project O&M (licensing)		$323	$323	$854		$854

The project cost will fund the development and implementation of use cases, which deliver direct, tangible cumulative benefits over eight years of up to $41 million which will indirectly offset the annual operating costs. To achieve O&M savings, the approach will be to use "swarm" strategy. The "swarm" strategy is where we identify a department or function with a complex business problem and embed IS & CGI (outside vendor) data experts in that daily work to help find efficiencies and solve problems. The two initial business groups will be Customer Service and Finance. Other use cases will be reviewed and done based on priority, funding, and availability of resources.

Implementation Approach

There are two key components to this project. The first part is to set up the EDAS platform along with the tools required for data catalog, virtualization, governance, and reporting. The second part is conducting two strategic "swarm" activities with Data Experts embedded into Customer Service starting in Q4 2022 and Finance in Q1 2023. There may be opportunity to start with the Finance group earlier. Each "swarm" will be approximately four months in duration which includes identifying opportunities, obtaining the data, and the creation of reports and dashboards.

2.2 Please provide the year-to-date 2022 expenditures on this initiative and describe the specific application.

Response:

This initiative has just recently started and has not incurred any expenditures to-date. The application(s) that will be used to support data analytics will be chosen through a detailed selection process which includes an RFP. These application(s) will support data virtualization, data

cataloging, data governance, and cloud-based data storage, all of which are all required to enable a robust data analytics program.

3. Reference: Exhibit B-2, Section 1.5.1, Customer Growth and Volume Forecast; Section 1.5.2, Power Supply, p. 7

"For 2023, FBC forecasts a net load increase of 170 GWh compared to 2022 Approved, resulting in a decrease in FBC's 2023 revenue deficiency of $12.546 million."

"FBC forecasts an increase in power supply of $20.275 million in 2023 compared to 2022 Approved."

3.1 Please provide the expected 2023 power supply cost increase absent the net load increase of 170 GWh. What are the highest cost blocks of energy or capacity that would be avoided?

Response:

To arrive at an estimate for the expected 2023 power supply cost absent the net load increase of 170 GWh, the current load forecast for 2023 was replaced with the gross load forecast used to develop the 2022 Approved power supply cost. Additionally, it was assumed that the annual PPA nomination for 2023 remained the same at 774 GWh, and that the forecast savings of $7.000 million remained the same.

Based on the above-described assumptions, the 2023 power supply cost in the updated scenario is $165.963 million. In this scenario, the total forecast BC Hydro PPA expense for 2023 is $55.160 million, which is $16.142 million less than the 2023 Forecast contained in the Application. The two components comprising the $16.142 million reduction are further described below.

Using the 2023 Forecast load, FBC estimates 976 GWh of PPA energy use during the 2022/23 contract period, exceeding the nomination by 202 GWh. Using the 2022 Approved load forecast, FBC estimates 793 GWh of PPA use during the 2022/23 contract year, exceeding the nomination by 19 GWh. As a result, FBC avoids 183 GWh of PPA at the 150 percent penalty rate in 2023, representing a cost reduction equal to $13.953 million.

In terms of capacity, the 2023 Forecast total BC Hydro billing capacity is 2,019 MW/month. Using the 2022 Approved load forecast, the total BC Hydro billing capacity in 2023 is 1,765 MW/month, which is a reduction of 254 MW/month. Overall, this results in a reduction to the power supply cost of $2.189 million.

4. Reference: Exhibit B-2, Section 2.2, Inflation, p. 10; Appendix A1, Table A1-2

4.1 Please provide the BC-AWE shown in Appendix A1, Table A1-2 for the "Utilities" category of the Statistics Canada information and provide a percentage difference comparison against the "Industrial Aggregate" category since July 2019.

Response:

A summary comparing the AWE data for the Industrial Aggregate and the Utilities categories is included below.

Month	Industrial Aggregate	12 Month Average	% Change	Utilities	12 Month Average	% Change
Jul-19	995.1			1,920.1		
Aug-19	1,003.4			1,825.8		
Sep-19	1,008.5			1,898.2		
Oct-19	1,017.1			1,966.8		
Nov-19	1,015.0			1,919.9		
Dec-19	1,014.9			1,911.7		
Jan-20	1,024.9			2,044.5		
Feb-20	1,024.1			2,019.1		
Mar-20	1,030.8			1,937.4		
Apr-20	1,106.3			1,906.1		
May-20	1,122.8			2,085.2		
Jun-20	1,096.1	1,038.2		2,167.1	1,966.8	
Jul-20	1,093.7			1,643.0		
Aug-20	1,089.4			1,827.7		
Sep-20	1,093.8			1,778.2		
Oct-20	1,095.3			2,089.2		
Nov-20	1,103.0			1,847.6		
Dec-20	1,110.4			1,817.7		
Jan-21	1,113.2			1,936.3		
Feb-21	1,114.2			1,933.9		
Mar-21	1,107.7			1,750.2		
Apr-21	1,112.0			1,950.1		
May-21	1,118.6			1,825.9		
Jun-21	1,115.4	1,105.5	6.483%	2,093.5	1,874.4	-4.697%
Jul-21	1,140.5			1,824.2		
Aug-21	1,142.4			1,940.2		
Sep-21	1,139.6			1,743.5		
Oct-21	1,136.9			1,969.2		
Nov-21	1,132.3			2,012.3		
Dec-21	1,134.8			1,830.0		
Jan-22	1,157.2			1,950.8		
Feb-22	1,153.9			2,080.1		
Mar-22	1,161.2			1,992.4		
Apr-22	1,164.5			1,930.9		
May-22	1,159.9			1,979.9		
Jun-22	1,165.2	1,149.0	3.933%	2,009.3	1,938.6	3.421%

As can been seen by the data included above, the Utilities category month-by-month trend is quite volatile. FBC considers the AWE-BC data from the Industrial Aggregate category to be a more

accurate representation of the economy-wide labour inflation in BC, as it uses multiple industries and uses a wider sample size of the data than would be used by isolating a specific industry. FBC has consistently used the Industrial Aggregate category of AWE-BC in calculating the inflation factor under both the previous approved 2014-2019 PBR Plan and the current approved MRP.

5. Reference: Exhibit B-2, Section 3.5, Customer Forecast, Table 3-3, p. 28

5.1 The customer growth rates in 2020 (actual), 2021 (actual), 2022 (projected), and 2023 (forecast) over the previous year's ending customer count are, respectively, 1.91% (actual), 1.47% (actual), 2.08% (projected) and 2.11% (forecast). What data does FBC rely upon for the significantly higher customer growth rates in 2022 and 2023 as compared to 2020 and 2021?

Response:

FBC notes that the percentages cited in the question are for the aggregation of all customers in all classes, as follows:

Customers Growth Rate	2020	2021	2022S	2023F
Residential	2.04%	1.37%	2.10%	2.07%
Commercial	1.31%	2.65%	2.42%	2.95%
Wholesale	0.00%	0.00%	0.00%	0.00%
Industrial	-15.69%	-2.33%	0.00%	0.00%
Lighting	-1.64%	-2.49%	-1.99%	-2.18%
Irrigation	0.83%	1.10%	0.00%	0.00%
Total	1.91%	1.47%	2.08%	2.12%

The method and data used to forecast the load in each class is different and is discussed in Section 1.2 of Appendix A3. FBC notes that only the residential customer count is an input to the load forecast – other customer count forecasts are provided for completeness only.

The 2022S and 2023F residential growth rates compare favourably with 2020. The 2021 growth rate is lower and may have been impacted by the COVID-19 pandemic. As shown in Table 6.1 in Appendix A2 of the Application, the six-year residential customer count variance is low at 1.27 percent.

For a detailed description of the data and method underlying the residential customer forecast, please refer to the response to BCOAPO IR1 10.1.

6. Reference: Exhibit B-2, Section 3.4.3, Wholesale Load Forecast, p. 21

"The BCUC Panel further requested that FBC work more closely with wholesale customers to develop more accurate forecasts."

Reference: Annual Review for 2022 Rates, Exhibit B-8, ICG IR 16.8

"A wholesale municipal customer is still considered as a single customer."

6.1 Please describe whether the work FBC and the wholesale municipal have undertaken includes forecasting of the number of residential, commercial and industrial customers and their respective growth rates?

Response:

FBC met with the individual wholesale customers to discuss general forecast methods, techniques, and tools as well as their own load forecasts. FBC did not prepare or help prepare any portion of the individual wholesale forecasts - including forecasts of customers and growth rates.

6.2 Please explain why a wholesale municipal customer is considered a single customer for reliability purposes, and provide the specific information that allows that interpretation if referencing external standards, practices or methodologies.

Response:

FBC follows the Electricity Canada (formerly CEA) for reliability reporting. In those definitions, it is stated that "municipal customers buying power from a Provincial utility should not be reported as customers by the Provincial utility". While FBC is not a Provincial utility by definition, the same logic should apply. The full definition of Customers from Electricity Canada is provided below:

> The average number of customers served in the region during the reporting period. A customer is defined as a metered service. Apartments and commercial buildings served by one meter shall be counted as one customer. Street lighting shall not be included. Municipal utilities buying power from Provincial utilities should not be reported as customers by the Provincial utility. Seasonal accounts shall be counted for the equivalent time they are connected. (For example, six months in one year is equal to ½ customer). Inactive accounts for the full year shall not be included.

FBC also notes that it does not have visibility into the number of customers beyond its own metering points to wholesale customers.

7. Reference: Exhibit B-2, Section 3.4.4, Industrial Load Forecast, Figure 3-7, pp. 22-23

"The increased forecast in 2022S and 2023F compared to 2022 Approved is primarily due to projected increases in data centre loads."

7.1 Please provide a more detailed breakdown of the increases in the 2022 forecast industrial load (579 GWh) over the 2021 actual industrial load (472 GWh)?

Response:

FBC assumes the reference in the question to the "2022 forecast" industrial load is referring to the 2022 Seed Year industrial load of 579 GWh. The 107 GWh increase in the 2022 Seed Year load from the 2021 Actual industrial load is due to the following:

- 111 GWh increase in data centre loads;
- 9 GWh DSM savings decrease; and
- Small individual changes from the rest of the industrial customers resulting in an aggregate 5 GWh increase, which is within the normal range of fluctuations for the industrial rate class.

7.2 Please provide the number of new industrial customers and their business sectors added in 2022 and the amount of load attributable to those new customers.

Response:

FBC did not add any new industrial customers in 2022.

7.3 Please explain the information FBC relies upon to forecast that the projected data center loads have a 75% probability of materializing in 2023.

Response:

Please refer to the response to BCUC IR1 7.3.

8. Reference: Exhibit B-2, Section 3.4.8, Peak Demand, Figure 3-11, pp. 26-27

8.1 Please provide a breakdown of winter and summer peak demand by customer class for the period 2020 to 2023 (forecast).

Response:

Peak demand is calculated using FBC's historical actual system peaks and the forecast gross load growth rate. The gross load growth rate includes all customer classes since the gross load is equal to the net load plus losses. FBC is unable to provide peak demand by customer class because the historical peaks are based on the total system demand and are not broken down by customer class. Therefore, peak demand cannot be calculated for individual customer classes.

8.2 What was the actual 2022 summer peak over the months of May to August 2022?

Response:

The FBC summer peaks over the months of May to August 2022 are below.

FBC Summer Peaks from May to August 2022

	May	June	July	August
Summer Peak (MW)	426	565	710	658

9. Reference: Exhibit B-2, Section 4.3, Portfolio Optimization, p. 31

"FBC has contracted to release a 50 MW block of capacity purchased under the WAX CAPA to BC Hydro under the Residual Capacity Agreement (RCA), which was approved by Order G- 161-14. The remaining surplus WAX CAPA will be sold to Powerex Corp. (Powerex) on a day- ahead basis, if and when it is not required to meet FBC load requirements."

9.1 Please confirm the term of the RCA and identify how much of the WAX capacity is likely to be required on a monthly basis for FBC's own load at the end of the term?

Response:

The Residual Capacity Agreement (RCA) provides 50 MW of WAX capacity to BC Hydro in all months and expires September 30, 2025. In this Application, FBC has included a forecast horizon up to 2023 for rate-setting purposes. Assuming that load is equal to the 2023 Forecast and FBC was able use the capacity from the RCA, rather than sell it to BC Hydro, FBC would first use the full 46 MW[1] available in June and up to 13 MW in July to meet its forecast capacity gaps. How FBC would optimize the surplus WAX capacity in the other months is described in Section 5.3.2 of the confidential 2022/23 Annual Electric Contracting Plan (AECP), which discusses the considerations when displacing PPA capacity purchases and maximizing surplus capacity sales.

[1] 46 MW is the full amount of RCA capacity in the month of June, all other months are 50 MW blocks.

10. Reference: Exhibit B-2, Section 5.8, Clean Growth Initiative, Table 5-2, p. 41

"Consistent with the practice from the 2022 Annual Review, FBC does not forecast revenue from the sale of credits that are pending validation; FBC is therefore not forecasting any of these revenues in 2023."

10.1 How many potential carbon credits does FBC have being considered by the BC-LCFS for validation and what would be the value if all potential carbon credits were validated?

Response:

Please refer to the responses to BCUC IR1 10.1 and 10.3.

10.2 Please explain why RS 96 rates should or should not be set to recover all the costs of EV DCFC Stations?

Response:

The inclusion of carbon credits in RS 96 has been the subject of review by the BCUC as part of FBC's Revised EV DCFC Application. Specifically, as part of the Decision and Order G-341-21 regarding FBC's EV DCFC service, the BCUC stated: "the Panel considers that the assumptions and inputs used to derive the $0.26/minute rate for 50 kW stations and $0.54/minute rate for 100 kW stations are reasonable."[2]

FBC also notes that the RS 96 rates were set on a levelized basis with a forecast price of carbon credits at $200 per credit. As shown in Section 5.8 of the Application, the current average market price for carbon credits is above $400 per credit.[3] Since any variances between the forecast price embedded in the RS 96 rates and actual dollar value that FBC is able to monetize for the EV DCFC service will be returned to/recovered from all other customers, the higher market value for the carbon credits at this time is a benefit to all customers.

10.3 Does the cumulative deficiency of $828,000 go into the general revenue requirement and affect all rates? Please explain why this is or is not a direct subsidization of EV charging infrastructure by all ratepayers.

[2] Decision and Order G-341-21, p. 14.
[3] Ministry of Energy, Mines and Low Carbon Innovation, Monthly Credit Market Report – August 2022.

Response:

FBC notes that, as discussed in the response to BCUC IR1 12.1, the cost of energy shown in Table 5-2 of the Application incorrectly included the third-party utility bills (City of Penticton, Grand Forks, Nelson Hydro and BC Hydro) instead of the cost being included in O&M. The cumulative deficiency with the correct cost of energy and O&M is approximately $752 thousand instead of $828 thousand.

FBC confirms the cumulative deficiency of $752 thousand goes into the general revenue requirement and affects all rates. The $752 thousand deficiency is cumulative from 2018-2023 so the impact is not directly felt in 2023 rates alone. The RS 96 rate is set on a levelized basis; thus, it is expected to be under recovering the cost of service of the EV charging infrastructure in the early years, with the expectation that the rate will over-recover the cost of service in the later years over the service life of the stations given the expected growth of electric vehicles on the road. FBC also notes that its EV DCFC stations are prescribed undertakings under section 5 of the GGRR. As the stations are prescribed undertakings, pursuant to section 18 of the *Clean Energy Act*, the BCUC must set rates that allow FBC to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the stations.

11. Reference: Exhibit B-2, Section 6.3, O&M Expense Forecast, Table 6-4, p. 46

"For 2023, FBC has included incremental O&M for the Mandatory Reliability Standards (MRS) Assessment Report No. 13 (AR13), which was approved for exogenous treatment in the 2022 Annual Review."

11.1 Given that Mandatory Reliability Standards (MRS) have been in effect in British Columbia since 2009, does FBC anticipate a time when costs associated with MRS will cease to be considered "exogenous"?

Response:

While the MRS framework has been in place for many years, the MRS themselves continue to evolve and new MRS adopted in BC continue to meet the criteria for exogenous factor treatment as approved by the BCUC. FBC considers that flow-through treatment, as opposed to exogenous factor treatment, would be more appropriate for incremental costs to comply with the MRS program. FBC requested this change in treatment (from exogenous factor to flow-through) as part of the MRP Application. However, the BCUC disagreed and directed that FBC continue to file for exogenous factor treatment of incremental MRS costs, stating that "continuing with exogenous factor treatment for costs associated with future policy changes will still allow the Utilities to recover costs that have been reviewed and approved by the BCUC, subject now to a reduced materiality threshold"[4].

Therefore, for the duration of the MRP, FBC will continue to apply for exogenous factor treatment for incremental MRS costs that exceed the exogenous factor threshold and meet the other four exogenous factor criteria, consistent with FBC's approach during the 2014-2019 PBR Plan term.

[4] MRP Decision and Order G-166-20, p. 75.

12. Reference: Exhibit B-2, Section 7.2.1, Updated 2023 and 2024 Forecast Regular Capital Expenditures, Table 7-2 and Table 7-3, p. 53

12.1 The updated forecasts for 2023 and 2024 Regular Capital Expenditures are 10% greater than the original forecasts. Please explain whether FBC has considered postponing or cancelling capital projects in order to decrease expenditures to original forecast amounts, and if so, which projects?

Response:

Please refer to the response to BCUC IR1 14.1 for a description of how FBC prioritizes its projects through the Asset Investment Planning (AIP) process. As described in response to BCUC IR1 14.1, based on this risk-informed prioritization process, FBC determined which growth, sustainment and other capital projects could reasonably and safely be deferred to future years (i.e., to 2025 and beyond) and these adjustments have already been reflected in the Updated Forecasts for 2023 and 2024. For instance, as explained in the response to BCUC IR1 14.4, FBC has deferred the planned installation of dam safety instrumentation at Corra Linn (COR) until after the current MRP term. Additionally, individual transmission line work has been prioritized and staged across multiple years within the Transmission Line Rehabilitation program. This has resulted in some carry over beyond 2024.

Please also refer to Appendix C2 of the Application for a list and description of FBC's projects over $1 million which were planned to be undertaken during the MRP term and which have now been deferred.

13. Reference: Exhibit B-2, Section 7.2.1.1.3, Capital Forecasts, p. 57

"Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized."

13.1 Please identify those projects that have been delayed or cancelled, and the new projects that have been identified and prioritized and the costs associated with each such project.

Response:

With regard to specific projects that have been deferred and new projects that have been identified, FBC provided a list and description of its projects over $1 million which were planned to be undertaken during the MRP term and which have been undertaken or are planned to be undertaken in the remainder of the MRP term in Appendix C2 to the Application.

Please also refer to the responses to the BCOAPO IR1 29 series for further explanations of growth capital variances and the BCOAPO IR1 30 series for further explanations of sustainment capital variances.

FBC did not defer any projects within the other capital category. The main project that has been added in the other capital category is the Kelowna Space Project, which was described in detail in the Application. Please also refer to the response to BCOAPO IR1 31.2 for a discussion of the increased spending in Information Systems other capital in 2022.

14. Reference: Exhibit B-2, Section 7.2.1.2.2, Facilities Capital, pp. 59-62

14.1 Please describe the consequences of delaying or cancelling the Kelowna Space Project. What incremental costs would be experienced by FBC and FEI should the Kelowna Space Project be cancelled.

Response:

The consequences of delaying or cancelling the Kelowna Space Project would be significant to both organizations. Currently, the Kelowna office buildings are full and oversubscribed. As such, the Company is unable to accommodate additions to headcount in the present facilities or address the ongoing functional challenges of these spaces.

FortisBC considered multiple options to address the space constraints faced by both FEI and FBC in the Kelowna region. The options developed considered the needs of each utility separately as well as the two utilities combined. Upon completion of each area's space program requirements in 2020 (i.e., Gas Operations, Electric Operations and the Shared Services Department), it became clear the office growth for all groups had impacted the ability for the Shared Services Department to remain combined with Operations at one of the existing facilities.

FortisBC has been employing a number of short-term measures to address the space constraints experienced in Kelowna. These measures include removing collaborative spaces like meeting and lunchrooms, and removing closets and storage rooms to create space for workstations. In addition, some employees were relocated to other facilities where possible and appropriate.

These measures are now exhausted as there are no further spaces which can be reallocated to workstations required for further growth. Moreover, the space which has been reallocated is both temporary and suboptimal with regard to working conditions. There is little or no access to natural light and a complete lack of collaborative workspaces critical to employees working on multi-faceted projects. This situation is substandard and is not beneficial to the Company or to customers as it promotes inefficiency, hinders collaborative work, negatively impacts the work culture, and can be challenging for employee recruitment and retention.

Both FBC and FEI are committed to a new lease agreement for the Shared Service Departments and the project is under way. FBC does not have an estimate of the incremental costs that would be experienced if the Kelowna Space Project were to be cancelled because such an outcome is not reasonable or expected.

14.2 Please provide the business case for the Kelowna Space Project.

Response:

Please refer to the response to BCOAPO IR1 32.3.

14.3 Please explain whether the capital expenditures to support energy efficiency and GHG reductions are mandatory or other required by legislation, or are the expenditures voluntary? What would be the consequences of delaying or cancelling the identified expenditures in 2023 and 2024?

Response:

The capital expenditures in 2023 and 2024 to support energy efficiency and GHG emissions reductions are not mandatory or required by legislation. The capital expenditures align with federal, provincial and local government climate action direction for buildings. As climate action policy evolves for the built environment, capital expenditures will be necessary to support new requirements, such as the BC Energy Step Code and performance standards under the Province's Energy Efficiency Standards regulation.

Delaying or cancelling expenditures in 2023 and 2024 will negatively impact the Company's ability to take the necessary steps to increase energy efficiency in FBC's buildings. Progress towards the Company's and ultimately the Provincial climate action initiatives and strategies will be delayed.

15. Reference: Exhibit B-2, Section 7.2.2.1, EV DCFC Stations, pp. 63-64

"At this time, FBC is not expecting to construct any additional stations or sites beyond the two additional DCFC stations noted above; however, station utilization will continue to be monitored to determine if any additional stations are warranted to meet customer demand."

15.1 Please provide the utilization data for each of FBC's DCFC sites. Please describe how the utilization data being summarized and expressed, and provide a comparison of forecast versus actual utilization levels.

Response:

Please refer to Attachment 15.1 for the utilization data of FBC's 50 kW and 100 kW stations, respectively. A comparison of utilization from 2018 to 2022 between actual/projected and forecast is also included. FBC notes the forecasts provided for comparison were based on the growth rates included in the rate design of RS 96 from the Revised EV DCFC Application, which was filed with the BCUC in 2020 and approved by Order G-314-21. As discussed in Section 5.8 of the Application, FBC is directed to file an assessment report on the EV DCFC Service by no later than December 31, 2022, or within six months of Measurement Canada's approval of DCFC energy-based metering for FBC, whichever is earlier. The assessment report will include an update to the financial models with actuals and forecast information and also a review of the RS 96 rate design.

16. Reference: Exhibit B-2, Section 7.6.2.1, COVID-19 Customer Recovery Fund Deferral Account, p. 73

"The unrecovered revenue recorded in the deferral account includes:

- **any remaining balances associated with the bill payment deferral program, described in 11 section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and**
- **any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above)."**

16.1 Please provide the unrecovered revenue recorded by customer class that is to be included in the Covid-19 Customer Recovery Fund Deferral Account?

Response:

Please refer to the table below for a breakdown of the 2020 and 2021 Actual, 2022 Projected and 2023 Forecast unrecoverable revenues by customer class.

As described on page 73 of the Application, the "additions" shown below are any unrecovered revenue from all customer classes due to the COVID-19 pandemic including industrial and large commercial customers and those residential and small commercial customers that did not participate in the bill payment deferral or bill credit relief offerings, while the "transfers" shown below are any remaining balances associated with the bill payment deferral program that resulted from customers' inability to pay.

Table 1 – Unrecovered Revenue by Customer Class ($millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast	Total
Residential Customer Additions	0.001	0.050	0.293	-	0.344
Residential Customer Transfers	-	0.110	0.004	-	0.114
Subtotal – Residential	**0.001**	**0.160**	**0.297**	**-**	**0.458**
Small Commercial Customer Additions	0.014	0.004	0.032	-	0.050
Small Commercial Customer Transfers	-	0.004	0.001	-	0.005
Subtotal – Small Commercial	**0.014**	**0.008**	**0.033**	**-**	**0.055**

17. Reference: Exhibit B-2, Section 12.2.1.3.1, Increased O&M expenditures due to the COVID-19 pandemic, p. 120

"The Other category of approximately $0.25 million includes miscellaneous items such as different support group costs (e.g., Information Systems and TELUS Babylon health service)."

17.1 Please explain the services FBC was receiving from Telus Babylon.

Response:

TELUS Babylon Health service have provided FBC employees access to a suite of health services and wellness support during the COVID-19 pandemic, including:

- Health and wellness video consultations that can be accessed remotely, avoiding in-person visits to clinics or the emergency room;
- Mental health support through one-on-one counselling sessions with highly qualified mental health counsellors to develop skills and tools in managing anxiety or stress; and
- Nutrition guidance from registered dietitians through one-on-one sessions to maintain good health.

18. Reference: Exhibit B-2, Section 13.2, Service Quality Indicators, Table 13-1, p.131; Annual Review for 2022 Rates, Exhibit B-2, Table 13-1, p. 118

18.1 Comparing the actual 2021 SAIDI and SAIFI results from Table 13-1 in this Application with the June 2021 YTD SAIDI and SAIFI results from Table 13-1 in last year's application, please explain the reasons behind the increases in SAIDI (from 2.90 to 4.27) and SAIFI (from 1.64 to 2.08). Can similar increases be anticipated in 2022 actual results?

Response:

The reasons for the higher 2021 SAIDI and SAIFI year-end results compared to the June 2021 SAIDI and SAIFI results included in the 2022 Annual Review are discussed in Sections 13.2.3.1 and 13.2.3.2 of the current Application.

FBC is forecasting a 2022 SAIDI result of 2.72 which is better than the benchmark of 3.22. This is based on actual SAIDI performance year-to-date as of August 2022 of 1.58 and adding on the three-year average performance from September to December.

FBC is forecasting a 2022 SAIFI result of 1.68, just above the benchmark of 1.57. This is based on actual SAIFI performance year-to-date as of August 2022 of 1.06 and adding on the three-year average performance from September to December.

18.2 Please provide the running hours of each generator in the FBC fleet in 2020, 2021 and YTD 2022.

Response:

Please refer to the table below for the generator running hours for 2020, 2021 and to the end of June 2022.

	Unit Run Times		
Generator	2020	2021	2022 (Jan to Jun)
LBO-G1	8608	8496	4344
LBO-G2	4005	5551	3902
LBO-G3	8675	6123	4340
UBO-G1	2425	2120	2421
UBO-G2	10	2341	4343
UBO-G3	3216	2273	2421
UBO-G4	3149	2162	2421
UBO-G5	7276	4446	4053

	Unit Run Times		
Generator	2020	2021	2022 (Jan to Jun)
UBO-G6	4959	7685	4330
SLC-G1	5579	5691	4344
SLC-G2	8245	8475	4053
SLC-G3	7185	6594	4344
COR-G1	8653	8051	4340
COR-G2	8677	8750	4340
COR-G3	3379	3685	4031

1

19. Reference: Exhibit B-2, Appendix A3, Load Forecast Methods, Section 1.2.4, Industrial, p. 5

"FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer."

19.1 Please describe what constitutes a "confirmed commitment"?

Response:

FBC considers a new industrial customer to have made a confirmed commitment when they sign a Facilities Interconnection Agreement, as outlined in FBC's Facility Connection Requirements.[5]

19.2 Have any new industrial customers met the "confirmed commitment" threshold for either 2022 or 2023?

Response:

No new industrial customers have met the "confirmed commitment" threshold for 2022 or 2023 at the time of filing.

[5] https://www.cdn.fortisbc.com/libraries/docs/default-source/services-documents/fortisbc-facility-connection-requirements.pdf?sfvrsn=140b7bb4_4.

20. Reference: Exhibit B-2, Appendix B2, UBO Refurbishment Project Final Report, Section 3.1, Project Cost Summary, p. 5

"Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 10 percent or approximately $2.4 million over the control budget. This is well within the typical accuracy range of an AACE Class 4 cost estimate as stated in AACE Recommended Practice 69R-12, Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry."

20.1 Given that an AACE Class 4 cost estimate has an accuracy range of -30% to +50%, please explain why final project costs within this accuracy range are acceptable given the amount originally approved by the Commission.

Response:

Please refer to the response to BCUC IR1 16.3. However, FBC notes that the reference to 10 percent over the control budget in the preamble is not correct. The correct number is 7 percent. FBC states in Appendix B2 of the Application, page 5, lines 8-10: "Final Project costs (including $1.174 million of AFUDC and $1.840 million of removal costs) are $34.151 million, which is 7 percent or approximately $2.4 million over the control budget."

20.2 Please provide the final levelized cost of energy and capacity for electricity from the UBO refurbishment project with supporting calculations.

Response:

The levelized cost of energy and capacity from the Project is estimated to be approximately $33 per MWh and $131 per kW-Year, respectively. The following image shows how these numbers are calculated.

	Annual	NPV (2022$)	Calculation
Discount Rate (After-Tax WACC)		5.73%	r
Annual Inflation		2.00%	g
Estimated Project Life		20	n
Annuity Factor		13.74	[A]= (1 - ((1 + g)/(1 + r))^n)/(r - g)
UBO Final Project Costs		$ 34,151,000	[B]
Estimated Annual O&M	$ 490,000	$ 6,731,627	[C] = $490K * [A]
Estimated Allocated Water Fee	$ 830,000	$ 11,402,553	[D] = ~$12M*115GWh/1663GWh Entitlement*[A]
Energy (MWh)	115,000	1,579,872	[E] = 115GWh*1000MWh/GWh*[A]
Capacity (MW-Months)	273.6	3,759	[F] = 4 Units*5.7MW each*12 months per Year*[A]
NPV Total Costs		$ 52,285,180	[G] = [B] + [C] + [D]
NPV Fixed Costs		$ 40,882,627	[H] = [B] + [C]
Levelized Cost of Energy (LCOE)		$ 33	per MWh ([G]/[E])
Levelized Cost of Capacity (LCOC)		$ 10,877	per MW-Month ([H]/[F])
		$ 131	per kW-Year ([H]/[F]*12/1000)

21. Reference: Exhibit B-2, Appendix C2, Section 2.1, Beaver Park Substation Upgrade, pp. 2-3

21.1 Please provide a detailed comparison of the estimates for the Beaver Park Substation Upgrade for the amount in Table C2-1 compared with the amount in Table C2-2.

Response:

Please refer to the response to BCUC IR1 14.2.

21.2 Please describe the archaeological requirements associated with Beaver Park Substation Upgrade and the costs associated with those requirements.

Response:

The Beaver Park Substation (BEP) is located within a registered archaeological site.

In British Columbia, the *Heritage Conservation Act* (HCA) is the legislation responsible for the protection and management of heritage sites, including archaeological sites. As such, any activity at BEP that might result in an alteration to the archaeological site requires authorization provided through the issuance of an HCA Site Alteration Permit.

In order to assess the impact to the archaeological site as a result of the BEP upgrade, FBC engaged a qualified archaeological consultant to conduct an archaeological impact assessment (AIA) in 2021. The results of the AIA informed archaeological site impact management recommendations which included acquiring an HCA Site Alteration Permit and conducting concurrent archaeological monitoring of project-related ground disturbing activities.

Based on these recommendations, FBC engaged a qualified archaeological consultant to apply for an HCA Site Alteration Permit on behalf of FBC for the project. The HCA Site Alteration Permit was issued in May 2022. Concurrent archaeological monitoring of project-related ground disturbing activities is a requirement of the HCA Site Alteration Permit.

To maintain compliance with this permit requirement, the archaeological consultant has been monitoring all excavation work at BEP in the current year and will continue to do so in 2023. Indigenous monitors are on site sifting material and collecting artifacts. All excavated material is remaining within the registered arch site.

The archaeological excavation is still underway, so costs will not be finalized until next year; however, FBC is forecasting to spend $420 thousand in 2022 and $170 thousand in 2023.

21.3 Please provide the load growth data for the Trail area served by the Beaver Park Substation for the period 2012 to 2022.

Response:

The historical seasonal peak load data for the Beaver Park (BEP) substation between 2012 and 2022 is provided below in Table 1. The winter 2022 season has not occurred and is not yet available.

Table 1: BEP T1 Historical Seasonal Peak Load Data 2012 to 2022

Unit	Season	Historical Load (MVA)										
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
BEP T1	Summer	7.3	6.7	7.5	6.2	7.9	6.3	6.3	6.2	5.9	6.9	6.3
BEP T1	Winter	7.8	7.3	6.8	6.4	7.4	6.9	6.7	6.6	6.3	6.0	N/A

Although the historical load has not shown growth, FBC is anticipating a significant capacity request in the future. Also, the Beaver Park Substation Upgrade is required due to equipment condition issues at the BEP station. The BEP T1 transformer and switchgear were manufactured in 1965. The BEP T1 transformer load tap changer cannot be adequately maintained as spare parts are no longer available from the manufacturer. If the load tap changer were to fail, the transformer would lose its ability to regulate voltage, impacting FBC's ability to supply acceptable voltage to customers.

21.4 Please describe the other sources of supply in the Trail area to serve the distribution load normally served by the Beaver Park Substation.

Response:

Beaver Park is interconnected with the Fruitvale and Glenmerry substations in the Trail area. Load supplied by the Beaver Park substation cannot be entirely transferred to the neighbouring stations during summer and winter seasons. Approximately 60 percent of Beaver Park load can be transferred to the neighboring substations in the summer, and 50 percent can be transferred in the winter.

22. Reference: Exhibit B-2, Appendix C2, Section 3.1, Generation Sustainment, pp. 4-7

22.1 Please provide the details for the UBO Unit 6 turbine runner replacement project. How old is the existing turbine runner, and what was its expected life when first installed? What are the consequences of delaying the project?

Response:

The UBO Unit 6 turbine runner replacement project scope of work includes the replacement of the existing turbine runner which is original equipment (1935) and will be 89 years old at the time of its anticipated replacement in 2024.

FBC does not have any information on the expected service life of this runner from the manufacturer. The runner was designed based on manual calculations and is made of cast steel, which has an expected life of 75 years based on industry experience.

The runner is subject to increased rates of cavitation damage due to its age, and currently requires repairs on a two-year cycle. The runner has reached the end of its useful life and needs to be replaced. If the runner fails in operation, it could damage other turbine components and would result in a forced outage duration of at least three years due to the time it takes to design and receive a replacement.

22.2 Please provide a detailed information for the Generation Excitation System and Control System Replacement Project. How old are the systems that are being replaced and describe the probability and consequences of equipment failure, including time to repair the existing systems. Can the project be delayed?

Response:

FBC provides the following information on the Excitation System and Control System Replacement projects.

Excitation System Replacement Project

FBC currently has eight ABB Unitrol F digital excitation systems in service at its generating facilities which are between 16 to 24 years old. The installation dates for the excitation systems are shown in Table 1 below.

Table 1: Excitation Systems' Installation Dates

Plant	Unit	Exciter Control	Installation Date	Years in Service
P1 - LBO	**2**	ABB - Unitrol F	Apr-1998	24
P4 - COR	**3**	ABB - Unitrol F	Feb-2000	22
P3 - SLC	**2**	ABB - Unitrol F	Sep-2000	22
P2 - UBO	**5**	ABB - Unitrol F	Oct-2001	21
P3 - SLC	**3**	ABB - Unitrol F	Nov-2001	21
P2 - UBO	**6**	ABB - Unitrol F	May-2004	18
P1 - LBO	**1**	ABB - Unitrol F	Jun-2005	17
P1 - LBO	**3**	ABB - Unitrol F	Sep-2006	16

The expected life cycle of digital excitation systems is estimated at 15 years (IEEE paper 2017-PPIC-0234 "*Digital Excitation Systems – Growing Obsolescence of Aging Systems*").

FBC has already experienced excitation system failures including circuit board failures, field flashing contactor failure, and thyristor bridge failure.

At the start of 2017, ABB announced that the Unitrol F excitation system platform has been moved into the limited phase of its lifecycle, resulting in decreased spare parts availability and technical support. Starting with 2022, ABB will move the Unitrol F platform into full obsolescence.

Deferral of this project will pose several risks to the reliable and safe operation of FBC's generating facilities. As these systems continue to age, the rate of equipment failures is expected to increase and spare parts will become more difficult to procure. A failure that would require a complete replacement or rebuild would have an estimated 8 to 12 month lead-time and result in a loss of FBC generation capacity.

Control System Replacement Project

The control systems include individual programmable logic controllers (PLCs) for control of FBC generation. These systems are on the Schneider Quantum PLCs for control, communication, and alarm/trip protection.

FBC currently has 15 Schneider Quantum PLCs in service which are between 10 and 19 years old. The installation dates for the control systems are shown in Table 2 below.

Table 2: Control System Installation Dates

Plant	Unit	Installation Date	Years In Service
P2 - UBO	**5**	Sep-2003	19
P2 - UBO	**6**	May-2004	18
P1 - LBO	**1**	Feb-2005	17
P1 - LBO	**2**	Aug-2006	16
P1 - LBO	**3**	Sep-2006	16
P3 - SLC	**3**	Dec-2007	15
P3 - SLC	**1**	Dec-2008	14
P3 - SLC	**2**	Dec-2008	14
P4 - COR	**1**	Oct-2010	12
P4 - COR	**2**	Apr-2011	11
P4 - COR	**3**	Feb-2012	10
P4 - COR	**Plant**	Jan-2005	17
P1 - LBO	**Plant**	Feb-2005	17
P2 - UBO	**Plant**	Feb-2005	17
P3 - SLC	**Plant**	Jul-2007	15

CEATI hydroAMP Guide – Hydropower Asset Condition Assessments Rev2.0 estimates that the service life for an electronic control system varies from 15 to 20 years.

FBC has already experienced PLC controller failures and digital input/output cards failures and has been able to repair these failures with the available spare parts. However, in 2015, Schneider designated the Quantum platform as “End of Commercialization” (EoC) and have stopped selling Concept PLC processors.

Deferral of this project will pose several risks to the reliable and safe operation of FBC’s generating facilities, which are critical to the power generation at these facilities.

FBC is planning to implement a staged replacement strategy for control systems as part of this project. FBC will increase its stock of available spare parts by replacing a plant controller and two unit controllers in 2023 and 2024. These replaced systems will be retained as spare parts to support the remaining in-service systems.

Once the remaining PLC controllers start to experience a decrease in reliability, the replacement program will be re-started.

22.3 Please discuss the consequences of delaying or cancelling the Dewatering and Drainage Systems Rehabilitation Project, the Station Service Upgrade Project and the Corra Linn Annex Building Replacement Project.

Response:

FBC provides further information on the need for the three projects identified in this IR below.

Dewatering and Drainage Systems Rehabilitation Project

This project is a continuation of the program started in 2011 and involves the rehabilitation of pipes, valves and other components of the dewatering and drainage systems, which are original to the plants, having service lives of over 79 years. The systems have begun to fail due to their service age and corrosion.

Drainage system equipment is used for personal safety isolation, and any failures could result in an inability to perform maintenance on critical equipment or plant flooding.

Station Service Upgrade Project

This project includes upgrading the protection system of station services that have reached the end of their service life and other small station service improvement projects.

The station service system provides the power supply to all critical systems installed in the generating plants such as: lighting, protection/control systems, pumps and generator cooling systems. Failure of station service equipment can result in a complete loss of power to critical components of the generating units and as such result in a unit forced outage.

Delaying or cancelling the Station Service Upgrade project could result in equipment failures and forced outages.

Corra Linn Annex Building Replacement Project

This project includes the replacement of the 91-year-old Corra Linn Annex building, which has structural damage due to foundation settlement. The Annex Building is part of the powerhouse and is composed of a fire pump room, a battery room, a washroom, and an office and houses critical infrastructure for emergency operations.

The Annex Building's structure has visible signs of concrete damage and cracking at critical structural locations. FBC has implemented temporary mitigation measures for these structural issues; however, delaying or cancelling the Corra Linn Annex Building Replacement project will pose a risk to FBC generation capacity and personnel.

23. Reference: Exhibit B-2, Appendix C2, Section 3.3, Stations Sustainment, pp. 8-10

23.1 Please describe the options considered for the Keremeos Second Transformer Addition Project, and the estimated total cost of those options compared to the proposed project?

Response:

The name of this project was incorrectly entered in the filing and should have read: "Keremeos Transformer Replacement". As per the description that followed, this project is the replacement of the existing Keremeos transformer rather than the addition of a second transformer. This transformer is 48 years old and is not properly regulating voltage due to a failed Load Tap Changer. The only project option that was considered is the replacement of the existing transformer based on its age and condition.

23.2 Please describe the options considered for the Fruitvale Station Upgrade Project, and the estimated total cost of those options compared to the proposed project? Please provide the load profile served by the Hearns and Fruitvale substations for the period 2012-2022.

Response:

FBC notes that the Fruitvale Station Upgrade project is not a new project. The project was contemplated in the MRP Application and included in the Original 2024 Forecast with a project cost of $10.6 million which has now been increased to $12.5 million spread over three years. In the MRP Application, FBC explained that it was proposing to rebuild the Fruitvale station, decommission the Hearns station and transfer the Hearns station load to Fruitvale, and add a second transformer at Fruitvale. The scope of the project generally remains the same as that contemplated in the MRP Application. The key difference and drivers of the increased forecast cost are land acquisition requirements and increases in engineering, material, and construction costs.

The following two alternatives were considered for the Fruitvale Station Upgrade project:

1. Rebuild the station with two new distribution transformers and associated station equipment. The AACE Class 5 level cost estimate including direct overhead is $12.5 million.

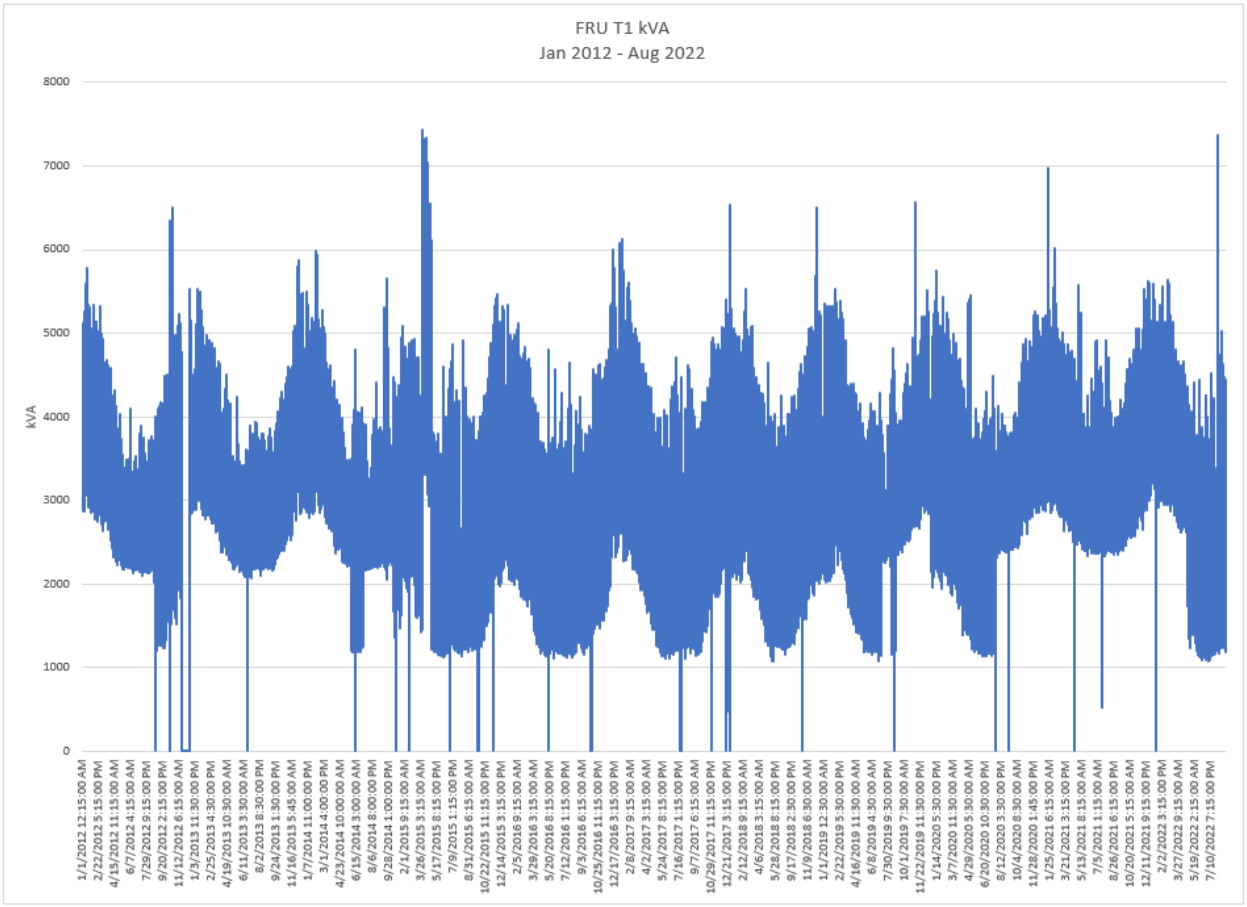
2. Rebuild the station with a single new distribution transformer and associated station equipment. The AACE Class 5 level cost estimate including direct overhead is $10.8 million.

Fruitvale has limited offloading capability, making it challenging to support all customer load during a single transformer outage. Therefore, Alternative 1 is preferred as a second distribution transformer provides additional operational flexibility and improves contingency options.

FBC is still in the process of selecting and acquiring lands for the Fruitvale Station Upgrade project. Once land is acquired, an AACE Class 3 level estimate will be developed to further refine the project cost.

The Hearns (HER) station does not have metering. The HER T1 transformer has a normal rating of 1.875 MVA. Historical load data between 2012 and 2022 for the Hearns station is not available.

The historical load data for the Fruitvale station for the period of January 2012 to August 2022 is provided in the figure below.



24. Reference: Exhibit B-2, Appendix C2, Section 3.5, Telecommunications Sustainment, pp. 11-12

24.1 Please describe the consequences of further delaying each of the telecommunications sustainment projects.

Response:

Please refer to the response to BCUC IR1 14.7.

Attachment 15.1a

Number of Charging Minutes Per 50 kW Station - Actual Compared to Forecast

Station	2018 Actual	2018 Forecast	Difference
Castlegar	3,196	3,062	134
Christina Lake	3,194	3,062	132
Creston	2,079	3,062	(983)
Greenwood	4,551	3,062	1,490
Salmo	2,478	3,062	(584)
Total	15,498	15,309	190

Station	2019 Actual	2019 Forecast	Difference
Castlegar	8,684	7,866	818
Christina Lake	6,870	7,866	(995)
Creston	6,037	7,866	(1,829)
Greenwood	13,243	7,866	5,377
Salmo	4,856	7,866	(3,010)
Kelowna Airport	3,817	4,588	(771)
Kelowna Airport # 2	3,817	4,588	(771)
Kelowna Museum	2,292	655	1,637
Beaverdell	329	655	(326)
Oliver	185	-	185
Osoyoos	371	-	371
Rutland	960	655	305
Total	51,462	50,470	991

Station	2020 Actual	2020 Forecast	Difference
Castlegar	6,609	17,125	(10,516)
Christina Lake	8,665	17,125	(8,460)
Creston	5,789	17,125	(11,336)
Greenwood	12,071	17,125	(5,054)
Salmo	3,270	17,125	(13,856)
Kelowna Airport	3,040	17,125	(14,085)
Kelowna Airport # 2	3,040	17,125	(14,085)
Kelowna Museum	11,496	17,125	(5,629)
Kelowna Museum # 2	4,734	9,990	(5,256)
Beaverdell	1,922	17,125	(15,203)
Beaverdell # 2	792	9,990	(9,198)
Nelson	8,903	17,125	(8,222)
Nelson #2	3,666	9,990	(6,324)
Oliver	3,381	17,125	(13,744)
Oliver # 2	1,392	9,990	(8,597)
Osoyoos	11,068	17,125	(6,057)
Rutland	3,187	17,125	(13,938)
Rutland # 2	1,312	9,990	(8,677)
Kaslo	2,121	15,698	(13,577)
Nakusp	4,003	14,271	(10,268)
New Denver	1,739	14,271	(12,532)
Rossland	3,601	17,125	(13,524)
Rossland # 2	1,483	9,990	(8,507)
Pentiction	7,519	4,281	3,238
Total	114,804	348,213	(236,648)

Station	2021 Actual	2021 Forecast	Difference
Castlegar	11,491	22,421	(10,931)
Christina Lake	15,555	22,421	(6,866)
Creston	10,135	22,421	(12,287)
Greenwood	14,109	22,421	(8,312)
Salmo	6,088	22,421	(16,333)
Kelowna Airport	7,276	22,421	(15,145)
Kelowna Airport # 2	2,425	11,211	(8,785)
Kelowna Museum	19,253	22,421	(3,169)
Kelowna Museum # 2	19,253	22,421	(3,169)
Beaverdell	1,320	22,421	(21,101)
Beaverdell # 2	1,320	22,421	(21,101)
Nelson	10,206	22,421	(12,215)
Nelson #2	10,206	22,421	(12,215)
Oliver	3,945	22,421	(18,476)
Oliver # 2	3,945	22,421	(18,476)
Osoyoos	12,048	22,421	(10,373)
Rutland	6,810	22,421	(15,612)
Rutland # 2	6,810	22,421	(15,612)
Kaslo	4,461	22,421	(17,961)
Nakusp	7,423	22,421	(14,999)
New Denver	3,457	22,421	(18,964)
Rossland	4,175	22,421	(18,246)
Rossland # 2	4,175	22,421	(18,246)
Grand Forks	19	-	19
Kootenay Bay	112	3,737	(3,625)
Kootenay Bay # 2	112	3,737	(3,625)
Naramata	82	-	82
Penticton	32,955	22,421	10,534
Rock Creek	7,228	20,553	(13,325)
Trail	3,005	22,421	(19,417)
Trail # 2	2,542	20,553	(18,011)
Total	231,942	597,904	(365,962)

Station	2022 Projected	2022 Forecast	Difference
Castlegar	19,769	29,927	(10,159)
Christina Lake	14,308	29,927	(15,619)
Creston	12,618	29,927	(17,310)
Creston # 2	14,921	29,927	(15,007)
Greenwood	17,616	29,927	(12,311)
Salmo	17,147	29,927	(12,780)
Kelowna Airport	19,056	29,927	(10,872)
Kelowna Museum	63,361	29,927	33,434
Kelowna Museum # 2	36,507	29,927	6,580
Beaverdell	3,279	29,927	(26,648)
Beaverdell # 2	4,006	29,927	(25,921)
Nelson	28,794	29,927	(1,134)
Nelson # 2	29,243	29,927	(684)
Oliver	7,860	29,927	(22,067)
Oliver # 2	12,405	29,927	(17,522)
Osoyoos	12,386	29,927	(17,541)
Rutland	34,261	29,927	4,334
Rutland # 2	11,033	29,927	(18,894)
Kaslo	4,785	29,927	(25,142)
Nakusp	19,543	29,927	(10,384)
New Denver	9,471	29,927	(20,457)
Rossland	11,313	29,927	(18,614)
Rossland # 2	6,578	29,927	(23,350)
Grand Forks	22,650	29,927	(7,278)
Grand Forks # 2	13,237	24,940	(11,703)
Kootenay Bay	952	29,927	(28,976)
Kootenay Bay # 2	1,711	29,927	(28,217)
Naramata	4,650	19,952	(15,301)
Naramata # 2	2,148	29,927	(27,780)
Penticton	35,240	29,927	5,313
Pentiction # 2	26,585	29,927	(3,343)
Rock Creek	13,512	29,927	(16,415)
Trail	19,814	29,927	(10,114)
Trail # 2	11,098	29,927	(18,830)
Total	561,859	1,002,571	(440,712)

Attachment 15.1b

Number of Charging Minutes Per 100 kW Station - Actual Compared to Forecast

Station	2021 Actual	2021 Forecast	Difference
Castlegar	66	-	66
Christina Lake	160	-	160
Greenwood	378	-	378
Kelowna Airport	4,840	4,997	(157)
Osoyoos	8,060	6,995	1,064
Rock Creek	3,035	4,997	(1,962)
Total	16,539	16,989	1,511

Station	2022 Projected	2022 Forecast	Difference
Castlegar	22,119	17,399	4,720
Christina Lake	7,137	17,399	(10,262)
Greenwood	7,173	17,399	(10,225)
Kelowna Airport	9,655	17,399	(7,743)
Osoyoos	8,021	17,399	(9,377)
Rock Creek	10,142	17,399	(7,257)
Total	64,248	104,393	(40,145)