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March 31, 2022

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

Attention: Ms. Leigha Worth, Executive Director

Dear Ms. Worth:

Re: FortisBC Inc. (FBC)

2021 Long-Term Electric Resource Plan (LTERP) and Long-Term Demand-Side Management Plan (LT DSM Plan) (Application) – Project No. 1599244

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

On August 4, 2021, FBC filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-24-22 for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

56.0 Reference: Exhibit B-3, BCSSIA 1.10.2.4

Preamble: The response states: "However, FBC is currently undertaking an electrification study, the results of which will inform potential future fuel-switching incentives or special rates that could be offered outside of FBC's DSM program."

56.1 Please confirm that the impact of these potential fuel-switching incentives or special rates has not been factored into either FBC's BAU Load Forecast or its Reference Load Forecast?

Response:

Confirmed. If there are opportunities identified through the study referenced in the preamble that ultimately lead to electrification activities outside of FBC's DSM program, impacts would be addressed in future long-term forecasts.

56.2 Is the impact of these potential fuel-switching incentives or special rates captured in any of the load scenarios set out in Section 4 of the Application?

Response:

The impact of potential fuel-switching incentives or special rates has not been captured in any of the load scenarios set out in Section 4 of the Application. The load scenarios do, however, include varying amounts of gas-to-electric fuel switching based on different percentages of the Conservation Potential Review technical potential.

57.0 Reference: Exhibit B-2, BCUC 1.5.1, and 1.8.6 to 1.8.10

Exhibit B-4, BCOAPO 1.8.4

57.1 With respect to BCUC 1.5.1, please describe the difference between the BAU Load Forecast and the Reference Load Forecast as to the EV-related load growth included in each.

Response:

The BAU forecast does not include any specific EV-related load growth. FBC acknowledges that there is likely some EV charging load embedded in the historical actual residential data, but it is assumed to be immaterial. For example, in 2020 there were approximately 950 EVs in the FBC service area, which serves approximately 125,000 residential customers (i.e., on average less than 1 percent of customers had an EV). The Reference Case annual EV-related load growth is based on the *Zero Emission Vehicles Act* light-duty EV sales targets. As a result, the difference between the EV charging load in the BAU Forecast and that in the Reference Case load forecast is essentially the Reference Case EV load growth, shown in the table below.

Table 1: Reference Case Annual Residential EV Load Growth

Year	EV Annual Load Growth (GWh)
2020	6
2021	10
2022	14
2023	19
2024	24
2025	29
2026	37
2027	47
2028	60
2029	75
2030	92
2031	114
2032	141
2033	172
2034	208
2035	245
2036	287
2037	333
2038	384
2039	440
2040	500

57.2 BCUC 1.8.8 states "New projects included in the BAU forecast have a very high certainty (near 100 percent probability) of materializing because they have progressed past the initial stages of procuring power from FBC". Please outline what is meant by "progressed past the initial stages of procuring power from FBC".

Response:

In FBC's response to BCUC IR1 8.8, "progressed past the initial stages of procuring power from FBC" means that either the customer has already connected to the FBC system and can consume the expected load at any time (i.e., the site is energized), or the customer has paid a deposit for construction to move ahead and is waiting to be energized.

57.3 With respect to BCOAPO 1.8.4 and BCUC 1.8.7, how many additional industrial projects were included in the Reference Load Forecast in addition to those included in the BAU Load Forecast?

Response:

As discussed in the response to BCUC IR1 8.11, four additional industrial projects were included in the Reference Case Load forecast in addition to the new industrial loads included in the BAU forecast.

58.0 Reference: Exhibit B-2, BCUC 1.5.2 and 1.6.2.1

Exhibit B-9, CEC 1.24.1

Preamble: The response to BCUC 1.5.2 states:

"The current model forecasts a UPC decline of 0.24 MWh per year, which FBC considers reasonable in the short-term due to the recent historical declines. The decline may partially be a result of LED lighting adoption as suggested by the 2017 FBC Residential End Use Survey (REUS), where residential lighting declined from 2.2 MWh in 2012 to 1.1 MWh in 2017"

58.1 What does the Residential lighting use reduction of 1.1 MWh translate into in terms of change in the UPC between 2012 and 2017?

Response:

Assuming the decline due to changes in residential lighting happened equally in each year, the annual reduction in the residential UPC from 2012 to 2017 would be approximately 0.18 MWh per year.

FBC notes that this is an estimate and cannot quantify what the residential lighting use reduction of 1.1 MWh translates into in terms of change in the UPC in each year because it only receives aggregate load data, which cannot be further sub-divided into end uses.

58.2 Apart from LED lighting adoption, has there been a reduction in the Residential UPC in the past 10 years due to FBC's DSM programs?

58.2.1 If yes, what is the estimated impact on Residential use over the past 10 years?

Response:

There have been reductions in the residential UPC over the past ten years due to residential DSM programs, which include both lighting (including LED) and non-lighting measures. The estimated cumulative impact on the residential UPC over the last ten years from residential DSM programs is 0.89 MWh per year. DSM lighting programs accounted for 0.38 MWh or 43 percent of the cumulative impact while all other DSM programs accounted for the remaining 0.51 MWh or 57 percent. The table below shows the annual DSM impacts on the Residential UPC from 2011 to 2020.

Residential UPC DSM Impacts from 2011 to 2020 (MWh)

Residential UPC (MWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
DSM Lighting Program	(0.03)	(0.03)	(0.03)	(0.03)	(0.04)	(0.07)	(0.07)	(0.03)	(0.03)	(0.03)	(0.38)
Other DSM Programs	(0.08)	(0.10)	(0.12)	(0.05)	(0.01)	(0.03)	(0.02)	(0.03)	(0.04)	(0.03)	(0.51)
Total DSM	(0.12)	(0.13)	(0.14)	(0.08)	(0.05)	(0.11)	(0.09)	(0.06)	(0.06)	(0.06)	(0.89)

58.3 Are the historic UPC values provided in CEC 1.24.1 weather normalized?

58.3.1 If not, please provide the historic weather normalized values

Response:

FBC confirms the historical UPC values provided in the response to CEC IR1 24.1 are weather normalized.

58.4 Is the 0.23 MWh per year referenced in BCUC 1.5.2 based on the historic trend established by the current regression model and the UPC values set out in CEC 1.24.1 (weather normalized)?

58.4.1 If not, how was the value established?

58.4.2 If yes, how much of the 0.23 MWh annual decrease is attributable to FBC's DSM programs over the past 10 years?

Response:

FBC clarifies that the forecast UPC decline is 0.24 MWh per year as per the response to BCUC IR1 5.2, and not 0.23 MWh as stated in the question.

The 0.24 MWh decline in the residential UPC is based on a historical trend, but is not based on all the UPC values set out in the response to CEC IR1 24.1. The residential UPC was based on a ten-year regression of weather normalized data from 2010 to 2019 (the 2020 data was not available at the time that forecast was produced but was available when CEC IR1 24.1 was responded to). The values from 2010 to 2013 are adjusted in the regression to reflect the inclusion of the City of Kelowna (CoK), which was acquired by FBC in April 2013 by including the CoK customers and load to the regression from 2010 to 2013 (when the CoK was a wholesale customer).

The table below reflects the UPC values used in the regression from 2010 to 2019, which include adjustments for the CoK.

Residential UPC Values from 2010 to 2019 with CoK Adjustment

Residential	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
UPC (MWh)	12.63	12.55	12.28	12.48	11.51	11.41	11.27	11.31	11.03	10.43

58.5 Please provide the weather normalized UPC values for 2011-2020 prior to any reductions for savings from DSM programs implemented by FBC in 2012-2020.

Response:

The annual weather normalized UPC values from 2011 to 2020 prior to any reductions for savings from DSM programs implemented by FBC from 2011 to 2020 are provided in the table below.

Annual Residential UPC Prior to DSM savings from 2011 to 2020 (MWh)

Residential	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
UPC (MWh)	12.82	12.54	12.63	11.59	11.46	11.38	11.40	11.08	10.50	10.94

58.5.1 What does a regression model based on these values indicate is the trend in UPC values?

Response:

A regression model based on the residential before-DSM UPC values from 2011 to 2020 indicates that UPC values are declining at the rate of 0.24 MWh per year.

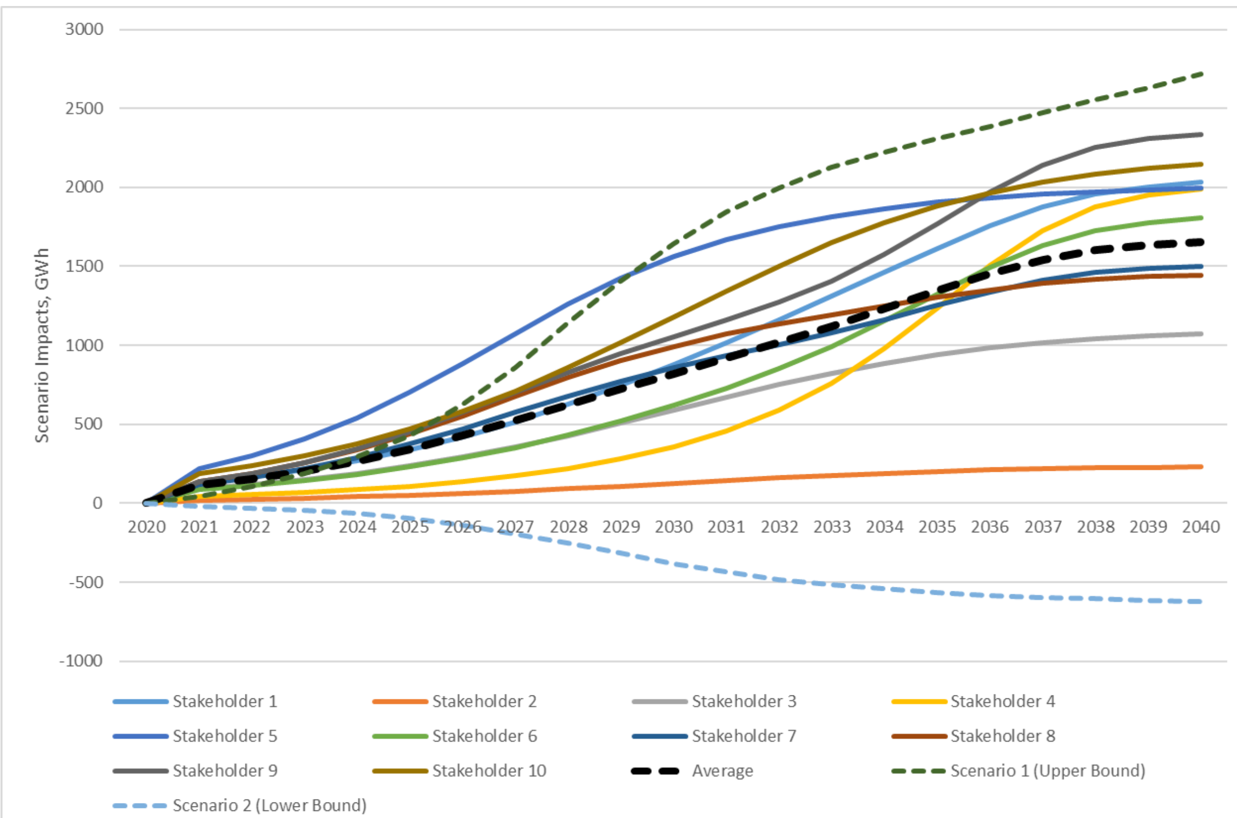
59.0 Reference: Exhibit B-2, BCUC 1.17.2

Preamble: The states: "Furthermore, all of the stakeholder individual scenarios fall within the Upper and Lower Bound scenarios, which were also included in the portfolio analysis".

59.1 Please provide a revised version of Figure 4-5 that also includes the results from Scenario 1 (Upper Bound) and Scenario 2 (Lower Bound).

<u>Response:</u>

The figure below is a revised version of Figure 4-5 that also includes the results from Scenario 1 (Upper Bound) and Scenario 2 (Lower Bound).

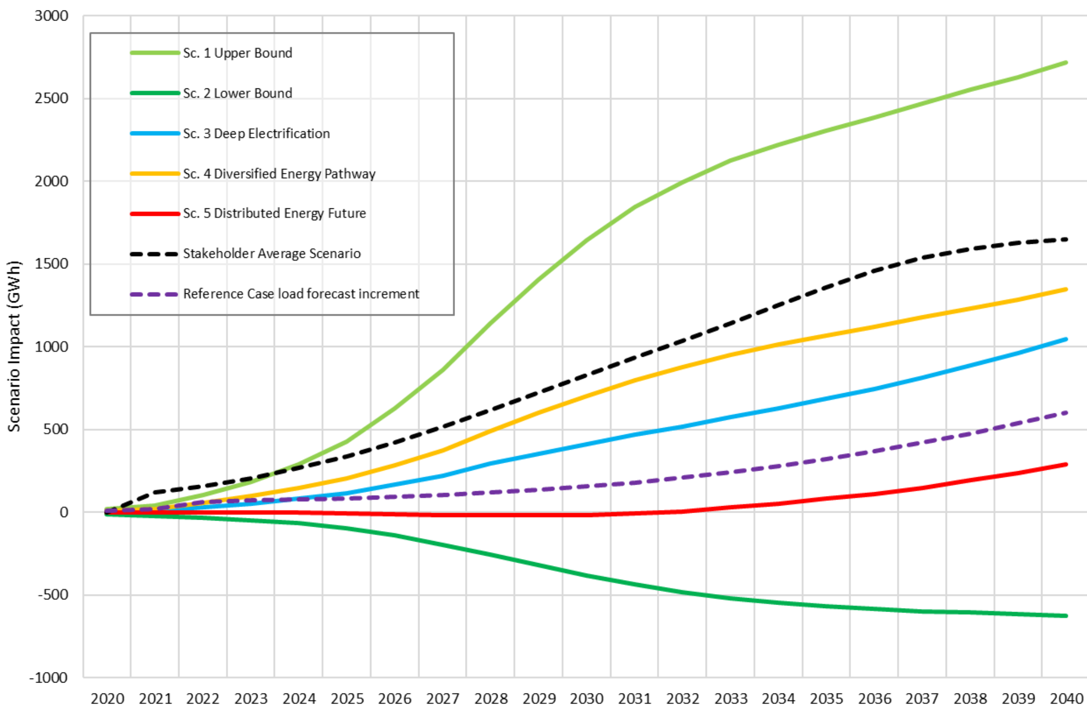


59.2 Please provide revised versions of Figure 4-3 and 4-4 that include the Reference Load Forecast.

Response:

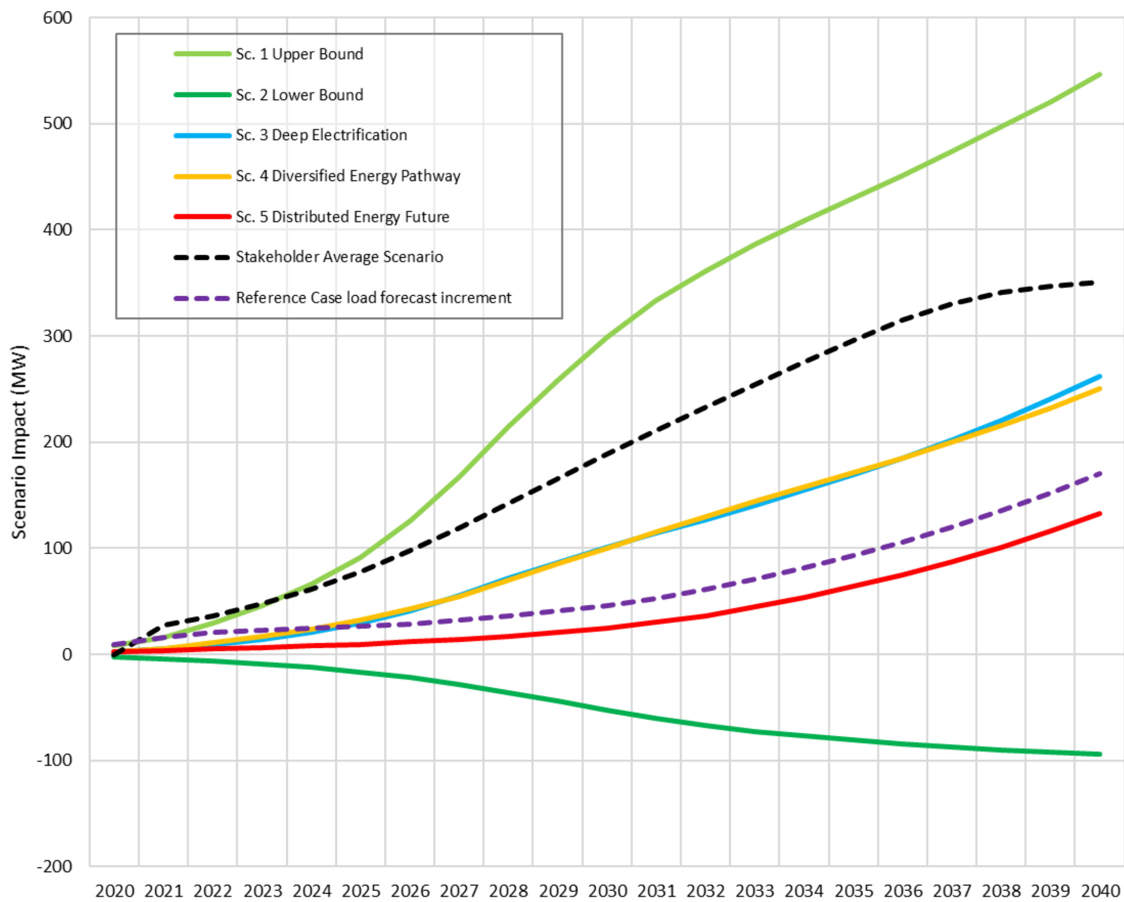
Updated Figure 4-3 below is a revised version of Figure 4-3 that also includes the Reference Case load forecast.

Updated Figure 4-3



Updated Figure 4-4 below is a revised version of Figure 4-4 that also includes the Reference Case load forecast.

Updated Figure 4-4



60. Reference: Exhibit B-8, RCIA 1.19.1

60.1 Please confirm that FBC's EV sales forecast includes the sales of light-duty EVs to both residential and commercial customers.

Response:

Please refer to the response to BCUC IR1 7.1.

60.2 Based on FBC's EV sales forecast and it forecast customer count for Residential and Commercial customers, what percentage of the combined total of Residential and Commercial customers are forecast to have purchased/leased an EV by: i) 2025, ii) 2030 and iii) 2040?

Response:

The following table provides FBC's forecast customer count for residential and commercial customers compared to the estimated number of EVs and the simple ratio (percentage) of EVs relative to customers in the FBC service area in 2025, 2030 and 2040. FBC notes that some customers may purchase multiple EVs, which could affect this calculation.

Year	Customers	EVs	Ratio of EVs per Customer
2025	147,433	8,872	6%
2030	154,646	28,198	18%
2040	166,847	152,648	91%

61.0 Reference: Exhibit B-8, RCIA 1.36.5.1

Preamble: The response states: "FBC does not expect that solar PV installations will reach the level indicated by the survey results and notes that only 0.5 percent of customers have net metering installations (which are <u>required</u> for grid-connected solar installations) today." (emphasis added)

61.1 Please confirm that, as suggested by the response, <u>all</u> residential customers installing solar PV are required to have net metering.

61.1.1. If not confirmed, please explain the circumstances (if any) under which customers installing solar PV would be <u>required</u> to have net metering.

<u>Response:</u>

Not confirmed. The portion of FBC's response to RCIA1 36.5.1 that states "…which are required for grid-connected solar installations" should have indicated that a customer is required to enroll in the Net Metering Program if they wish to take advantage of the program offerings including the kWh Bank and the purchase by FBC of any Net Excess Generation. FBC clarifies that customers may connect customer-owned generation without enrolling in the Net Metering Program in accordance with the FBC Electric Tariff Section 12, *CUSTOMER-OWNED GENERATION.*

62.0 Reference: Exhibit B-6, BCSEA 1.7.2 and 1.9.1

Preamble: The response to BCSEA 1.7.2 states:

"FBC no longer intends to file for approval of a rate for commercial customers related to fleet or employee-charging infrastructure as was contemplated when the LTERP was drafted. Rather, FBC intends to develop a program under the electrification provisions of Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) that will assist in the acquisition, installation or use of charging infrastructure."

62.1 With respect to BCSEA 1.7.2, please explain the reason for the change in approach.

Response:

The alternative approach that FBC is now pursuing is simpler, and will reach the market faster while still incenting the installation of charging infrastructure. This approach also complements existing funding options available from the provincial and federal governments. BC will continue discussions with customers about their needs as related to infrastructure deployment efforts. If customers are experiencing gaps in deploying EV charging infrastructure that are not being filled by third-party providers, FBC will evaluate how to meet their needs.

62.2 Does this change impact the Reference Load Forecast or the DSM savings used in the LTERP?

62.2.1 If yes, how and what it the impact on the Load Resource Balance (after DSM) as set out in Section 9 of the Application?

Response:

This change does not impact the Reference Case load forecast or the DSM savings used in the LTERP. FBC does not expect any material impact resulting from the change in approach to its support for commercial and fleet charging infrastructure; therefore, the overall EV charging load is not expected to be impacted.

62.3 With respect to BCSEA 1.9.1, why aren't FBC's plans to develop a program under the electrification provisions of Greenhouse Gas Reduction (Clean Energy)

Regulation (GGRR) that will assist in the acquisition, installation or use of charging infrastructure considered a "load building" program.

Response:

FBC agrees that its support for the objectives of the *ZEV Act* could be characterized as a beneficial load-building activity whereby FBC is able to encourage the deployment of EV charging infrastructure in a manner that will benefit all utility customers.

63.0 Reference: Exhibit B-9, CEC 1.9.5

Preamble: The response states:

> "However, over the longer term, FBC expects that payback periods for solar installations will continue to shorten. FBC continues to monitor the development of solar installations in its service area, but expects that the proliferation of PV will not be a significant issue in resource planning."

63.1 In FBC's view, what payback period is required in order to trigger a significant increase in solar installations?

Response:

FBC has not conducted any research that would allow it to quantify demand for solar installations relative to the payback period. Shorter payback periods are expected to increase demand, all else equal.

63.2 In section 4 and Appendix H of the Application, solar installations are a significant contributor to lowering the load forecast in Scenario 2 (Appendix H, page 51) and Scenario 5 (Appendix H, page 85). However, the response to CEC 1.9.5 suggests that a significant penetration of solar is unlikely over the period of the current LTERP. Does this suggest that the lower load growth forecasted in Scenarios 2 and 5 are unlikely to occur?

Response:

There is still significant uncertainty regarding the growth of rooftop solar installations in the FBC service area over the twenty-year planning horizon. As discussed in the response to CEC IR1 9.5, FBC expects that payback periods for solar installations will continue to shorten over the longer term. However, in that IR response, FBC is not suggesting that a significant penetration of rooftop solar is unlikely over the period of the current LTERP, but rather, that the proliferation of rooftop solar will not be a significant issue in resource planning. Therefore, lower load growth associated with increasing penetration of rooftop solar included in Scenarios 2 and 5 is still possible over the long term. As discussed in the response to CEC IR1 2.1, there is too much uncertainty to know which of the scenarios, if any, will occur in the future. As such, FBC is unable to assign any probability estimates to the load scenarios.

64.0 Reference: Exhibit B-9, CEC 1.11.1

Preamble: The response states: "FBC notes that the overall number of charging events recorded at FBC's fast charging stations from July to October 2021 is over double the number of events recorded for the same period in 2020."

64.1 Did the number of charging stations FBC has in-service change between July-October 2020 and July-October 2021?

64.1.1 If yes, how did the number of charging events per station change between the two periods?

Response:

FBC confirms that the number of charging stations in service increased from 25 in the period of July to October 2020 to 32 in the period of July to October 2021. Between July and October 2020, there were 1,858 charging sessions resulting in an average of approximately 74 sessions per station. Between July and October 2021, there were 3,816 charging sessions resulting in an average of 119 sessions per station.

65.0 Reference: Exhibit B-4, BCOAPO 1.2.1

Preamble: The response states: "To the extent that high-load factor loads can be added to the system, thereby increasing overall revenues in a cost-effective manner, any resulting rate mitigation will become embedded in rates and will persist over the long term."

65.1 Is it FBC's view that any high-load factor load that is cost-effective in the short term (i.e. leads to lower rates during a period of surplus) will also be cost-effective in the long term (i.e., rates will be lower if the load continues to exist when there is no surplus and new resources are required to meet increases in load)?

65.1.1 If yes, please fully explain why this is the case.

<u>Response:</u>

Within the context of the referenced statement, cost-effectiveness can be assessed at the time that the load is added with respect to the impact the cost of interconnection has on the fixed costs of the system. Once added, the customer becomes part of the embedded system load. FBC does not revisit the load of any individual customer to make an assessment of long-term cost effectiveness in relation to the cost of marginal resources, since under such a consideration individual existing customers may not be considered cost-effective over the long term.

66.0 Reference: Exhibit B-4, BCOAPO 1.8.1

Preamble: The response states:

"Although the timing is uncertain, due in part to the COVID-19 pandemic, FBC still anticipates these loads will materialize. Therefore, the fact that some cannabis production facilities did not materialize in 2021 should have only a short-term impact as these loads will likely materialize over the longer term.

While FBC saw decreases in the 2020 industrial, wholesale, and lighting loads compared to the 2020 BAU forecast, these decreases were offset by increases in the residential, commercial, and irrigation rate class loads. The end result was that the 2020 actual aggregate gross load was only 0.5 percent higher than the 2020 BAU gross load forecast."

66.1 What is the current status of the cannabis production facilities that were included in the 2020 BAU forecast but did not materialize?

Response:

Please refer to the response to BCUC IR2 46.1 for the current status of the cannabis production facilities.

66.2 What is the 2021 actual (weather normalized) gross load and how does it compare to the 2021 BAU gross load forecast?

Response:

FBC notes that the response cited in the preamble is from FBC's response to BCOAPO IR1 8.2.

The LTERP 2021 BAU gross load forecast before DSM was 3,698 GWh. The after-DSM forecast was 3,664 GWh.

The actual 2021 weather normalized after-DSM gross load was 3,680 GWh, which is 16 GWh (0.4 percent) higher than forecast.

67.0 Reference: Exhibit B-4, BCOAPO 1.13.2

Exhibit B-1, page 125

Preamble: The Application states:

> "In order to ensure that FBC's network infrastructure is sufficient to provide a safe and reliable electricity supply to all customers, the transmission and distribution system must be planned, constructed, and operated to meet peak load requirements during extreme weather conditions. This contrasts with the resource planning requirement to acquire energy resources to meet energy and peak demand requirements under "normal" or "expected" weather conditions as set out in the Reference Case load forecast presented in Section 3".

67.1 Is the Planning Reserve Margin (PRM) that is used when determining future capacity requirements meant, in part, to address the impact of extreme weather conditions?

67.1.1 If not, please explain why it is appropriate to assume "normal" or "expected" weather conditions when doing resource planning.

Response:

FBC confirms that the PRM reliability assessment is used, in part, to determine future generation capacity requirements and address the impact of extreme weather conditions, to the extent extreme weather conditions have occurred historically.

In the event the PRM requirements of a portfolio were not met, the portfolio was re-optimized with additional capacity requirements for PRM purposes, as per the process described in Section 3.2 of Appendix M. The PRM reliability assessment uses monthly uncertainty distributions to represent reasonable variances from the expected forecast based on historical weather variability as well as other external environmental anomalies. The Monte Carlo analysis draws from the monthly uncertainty distributions during each iteration based on historical frequencies, which includes the tail values of the distributions commonly associated with extreme weather events.

68.0 Reference: Exhibit B-4, BCOAPO 1.13.2

68.1 Please confirm that the methodology set out in the response details the approach used for the "1 in 10" peak demand forecast.

Response:

Confirmed. FBC assumes that the question was referring to the response to BCOAPO IR1 13.1 rather than 13.2. The response to BCOAPO IR1 13.2 provides a description of the 1 in 10 peak demand and 1 in 20 system planning peak forecasts.

68.2 Is a similar approach used for the "1 in 20" forecast except that: i) 20 years of historical data are used and ii) at Step #15 rather than using the average the highest value is chosen?

68.2.1 If not, what are the differences between the two methodologies?

Response:

Confirmed.

69.0 Reference: Exhibit B-8, RCIA 1.23.2

Preamble: The response states: "FBC does believe, however, that the CEPSA agreement provides improved market access at comparable or lower cost than could be obtained elsewhere. If Powerex decides not to renew the CEPSA agreement, FBC expects that there could be negative impacts to revenue."

69.1 It is noted that the original information request deals with FBC's revenues under the CEPSA agreement from the sale of capacity. In the referenced portion of the response is FBC referring to the "improved market access" for sales of its surplus capacity and energy (i.e. exports) or is the reference more with respect to improved market access for purchases (i.e., imports to the FBC system)?

Response:

The referenced portion of the response refers to "improved market access" for sales of FBC's surplus capacity and energy (i.e., exports). However, the same consideration is true for imports. FBC believes that the CEPSA results in increased revenue from sales and reduced expenses on imports.

70.0 Reference: Exhibit B-4, BCOAPO 1.20.1

Exhibit B-1, pages 113, 115, 116 and 117

Preamble: With respect to the Brilliant Expansion Agreement, the Application states (page 115): "This agreement expires as of December 31, 2027, and within this Application, renewal is not assumed beyond that date".

70.1 Please explain why in the case of the Brilliant Expansion Agreement, FBC has assumed it will not be renewed whereas both the CPA (page113) and the CESPA (page 116) the agreements are assumed to continue indefinitely and for the BCH PPA (page 117) the agreement is assumed to continue in a similar form past the current expiry date?

<u>Response:</u>

The Brilliant Expansion Agreement (BRX) differs from the other cited contracts because FBC anticipates that it may have to compete with other entities for the power associated with this agreement when it expires. This same risk does not apply for the CPA, the CEPSA, and the PPA. These three agreements govern the long-term relationship between FBC and BC Hydro/Powerex.

71.0 Reference: Exhibit B-2, BCUC 1.20.3 and 1.20.4

Preamble: The response to BCUC 1.20.3 indicates that there was only a 59 MW difference between the summer peak demands in the Kelowna area in 2020 versus 2021.

The response to BCUC 1.20.4 states:

> "If an N-1 event had occurred in the Kelowna area during the June 2021 heat event (such as the loss of either of the two existing LEE terminal transformers), FBC expects that it would have been forced to shed firm load. The load shedding required would have been approximately 65 MW during the peak demand period".

71.1 Does this mean that if an N-1 event had occurred in the Kelowna area during the summer peak in 2020 the load shedding would have been required at that time as well?

71.1.1 If not, why not?

Response:

FBC confirms that if either of the two existing LEE terminal transformers were out of service due to an N-1 event in the summer of 2020, FBC would have been forced to shed approximately 5 MW of load.

72.0 Reference: Exhibit B-2, BCUC 1.23.9

Exhibit B-9, CEC 1.14.2

Preamble: The response to BCUC 1.23.9 states: "For the projects that have been advanced by the load scenarios to within the next four-year timeframe, FBC may be able to redistribute some load to nearby feeders in the short term as required to defer some projects".

The response to CEC 1.14.2 states: "If FBC is able to reduce the amount of incremental EV peak demand and the Kelowna load level remains below 550 MW, then some of the projects in Table 6-6 may not be required before 2040".

72.1 For each of the projects listed in BCUC 1.23.9, what level of demand in the Kelowna area triggers the need for the project?

Response:

The Static VAR Compensator (SVC) and the DG Bell 230 kV Ring Bus projects are driven by the total Kelowna-area peak load. These projects are needed to avoid voltage collapse in the Kelowna area when the total Kelowna-area demand reaches or exceeds approximately 430 MW.

The Reconductor 51 Line and 60 Line project is required when the Kelowna area demand is forecast to reach or exceed approximately 315 MW. If any of the LEE T2, T3, or T4 230/138 kV transformers are out of service and an outage to another LEE transformer occurs, the flow on the remaining transformer would exceed the emergency rating. Re-configuring the Kelowna transmission system to reduce the post-contingency transformer flow would result in power flows above the emergency ratings of transmission 60 Line and 51 Line requiring their upgrade to a higher ampacity conductor. As such, the 60 Line and 51 Line Upgrade Project is required to maintain compliance with Mandatory Reliably Standard TPL-001-4, 2.1.5.

All but one of the remaining projects[1] identified in the response to BCUC IR1 23.9 are distribution substation transformer upgrade projects (the one project that is not a distribution-level substation project is the Kelowna Bulk Transformer Capacity Addition, which is already under construction). These distribution-level substations supply localized portions of the aggregate Kelowna-area load. Therefore, there is no specific Kelowna-area load that triggers these projects. Instead, it is the individual substation transformer ratings and the load supplied by each station that drives these projects.

[1] FBC also clarifies that the DG Bell 138 kV Breaker and Voltage Transformer Addition project does not have a specific Kelowna load level trigger. This project is driven by reliability requirements and will improve/simplify the protection scheme at the terminal station and increase operational reliability in the Kelowna Area.

72.2 To what extent could EV charging load shifting delay those projects that have been advanced by the load scenarios to within the next four-year timeframe?

Response:

The following projects identified in the response to BCUC IR1 23.9 could possibly be deferred depending on load growth rates (and specifically the growth due to EV charging):

- Saucier Second Distribution Transformer Addition
- DG Bell Distribution Transformer Addition
- Duck Lake Second Transformer Addition
- Glenmore Third Transformer Addition

The timelines for the projects in Table 6-6 are approximations only and the specific timeframe for each project will be determined by the location and amount of future load growth within the Kelowna area.

73.0 Reference: Exhibit B-9, CEC 1.34.1

Preamble: The response states: "At a high level, the forecast peak demand due to EV charging is included in FBC's annual Power Flow and Transient Stability Analysis Report. This report identifies a list of transmission projects that are required to maintain reliable service."

73.1 What load forecast is used in FBC's annual Power Flow and Transient Stability Analysis Report such that it captures the forecast peak demand due to EV charging?

73.1.1 Is this the same forecast peak demand due to EV charging as is reflected in FBC's Reference Load Forecast?

Response:

The 1 in 20 peak demand forecast, described in Section 6.3.1, which includes the forecast peak demand due to EV charging, is used when completing the annual Power Flow and Transient Stability Analysis Report.

74.0 Reference: Exhibit B-4, BCOAPO 1.22.1.1

74.1 Why are the actual summer values used in the regression model? Is it not possible the annual variations in temperature could impact the calculation of the slope/annual change (e.g., if the temperature in the latter years was lower than average then this would reduce the slope)?

Response:

The actual historical values are used in the regression model, as they are the most relevant information FBC has available to develop a historical trend for feeder and transformer loadings. It is true that if the temperatures in the latter years were lower than average, this would reduce the slope since peak load is closely associated with temperature. If the historical values result in a negative slope for feeder growth, the feeder growth is then set to the calculated feeder growth rate percentage of each region (i.e., North Okanagan, South Okanagan, Boundary, Kootenay) to prevent a negative slope (i.e., an apparent load decline) from occurring. A minimum growth rate of 0.5 percent has been established for all regions based on historical load growth data from all regions.

75.0 Reference: Exhibit B-4, BCOAPO 1.22.4

Exhibit B-1, page 126

Preamble: The response to BCOAPO 1.22.4 states: "For transmission infrastructure assessments, the area-level forecasts are used to scale system peak loads to determine the adequacy of the transmission lines and substations". (emphasis added)

The Application states (page 126):

> "This is achieved by forecasting the total system load from the "top down" under extreme (i.e. one occurrence in 20 years) weather conditions, and then rationalizing the two forecasts by uniformly scaling the per-substation peak forecasts such that their total load matches the total winter and total summer peak loads given in the system load forecast".

75.1 Is the scaling referred to in BCOAPO 1.22.4 the same "scaling" described in the Application (page 126)?

75.1.1 If not, what is basis for the scaling referred to in BCOAPO 1.22.4 and why is it different?

Response:

FBC confirms the scaling referred to in the response to BCOAPO IR1 22.4 is the same scaling as described on page 126 of the Application.

76.0 Reference: Exhibit B-4, BCOAPO 1.22.4, 1.23.1 ad 1.23.3

Preamble: BCOAPO 1.22.4 states: "For transmission infrastructure assessments, the area-level forecasts are used to scale system peak loads to determine the adequacy of the transmission lines and substations"

BCOAPO 1.23.1 states: "For distribution substations, the original distribution substation load forecast values are used".

BCOAPO 1.23.3 states: "the total system peak load is scaled to all stations throughout FBC's system to determine adequacy of transmission level facilities".

76.1. Please clarify for what types of Transmission and Distribution facilities the specific line/station forecasts are used and for which facilities the specific line/station asset forecasts scaled to the total system peak are used.

Response:

The feeder/station forecasts are used for distribution-level feeders and stations.

The forecasts that are scaled to the system peak are used for transmission lines and transmission level stations.

77.0 Reference: Exhibit B-4, BCOAPO 1.27.1

77.1 The information request asked how the timeframe required to put these kinds of infrastructure reinforcements in place to serve a new customer compared with the typical timeframe between FBC becoming aware (with a high degree of confidence) that a large load customer will connect to its system and the customer requiring power. The response indicated that the timeframe for the system infrastructure was about 5 years. Does this timeframe generally meet customer's expectations as to when they want/require service?

Response:

The five-year timeframe referenced in the response to BCOAPO IR1 27.1 is a high-level estimate; the actual timeframe could be less than five years, based on a number of factors including location and existing infrastructure.

Different customers have different expectations in regards to the timeframe for receiving service. Some would prefer service as quickly as possible, while others are able to plan their service requests with ample lead-time. FBC strives to be as timely as possible with customer connections; however, due to the time it can take for system improvements, it may not be possible to meet all customer expectations within a given timeframe.

78.0 Reference: Exhibit B-2, BCUC 1.25.1

Exhibit B-4, BCOAPO 1.33.1, 1.33.1.2, 1.33.2 and 1.33.3

Exhibit B-1, page 149

Preamble: The Application states (page 149): "The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs".

BCUC 1.25.1 sets out the percentage of incremental costs used to determine the incentive level for each of the DSM scenarios.

BCOAPO 1.33.1 indicates that using the "percentage of incremental cost" approach to define the DSM scenarios results in the level of incentive being paid varying by customer class in each DSM scenario.

The response to BCOAPO 1.33.2 states: "The dollar-per-NPV-of-savings incentive was used in the determination of the DSM Scenarios."

The response to BOAPO 1.33.3 states: "The DSM scenarios were developed, measure-by-measure, by calculating incentive on a dollar per-NPV-of-kWh basis, not based on a simple percentage of incremental cost".

78.1 With respect to the response to BCOAPO 1.33.1.2, please confirm that the percentages provided for each customer segment represent the incentive payment used in the determination of the Market Potential as a percentage of the incremental costs for the DSM measures in that sector.

<u>Response:</u>

The percentages provided in the response to BCOAPO IR1 33.1.2 represent the average incentive payment used in the determination of the Market Potential as a percentage of the incremental costs across all cost-effective DSM measures in that sector.

78.1.1 Please explain why the percentage varies by customer segment.

<u>Response:</u>

The percentages vary by sector as the incentives are also limited by a payback period threshold and maximum incentive per kWh saved. Measures in the commercial and industrial sector tend to have shorter payback periods while measures in the residential sector have longer payback periods.

78.2 The Application and BCUC 1.25.1 indicate that the DSM scenarios were determined using a different incentive level for each based on a percentage of the incremental cost of the DSM measures. However, the responses to BCOAPO 1.33.2 and 1.33.3 suggest that the incentive as a percentage of incremental costs for each DSM scenario is a derived value as opposed to being the basis for each scenario and that the basis for the incentives used in each scenario was established by varying the incentive on a dollar per-NPV-of-kWh basis. Please clarify precisely how the incentive levels used in the various DSM Scenarios were established.

78.2.1 With respect to the Table provided in BCOAPO 1.33.3, if the incentive is based on a dollar per-NPV-of-kWh basis, why isn't the upper end of the incentive range for each customer segment in a given DSM Scenario the same?

78.2.2 With respect to BCOAPO 1.33.2, if the incentive is based on a percentage of incremental costs, why does the response refer to the 50, 62, 72, 84 and 100 percent values as being the <u>average</u> incentive level as a percentage of incremental costs, which were derived from the applied levelized incentives across all measures and sectors?

<u>Response:</u>

Please refer to the Incentive Methodology memo by Lumidyne Consulting LLC provided as Attachment 33.1 to FBC's response to BCOAPO IR1 33.1, which explains how incentives were developed in the 2020 FBC CPR.

In summary, incentives were developed on a measure-by-measure basis, for each portfolio area, based on targeted levelized incentives rates bounded by a minimum and maximum incentive. The exception to this is the Max DSM scenario that uses 100 percent incremental cost as the driver of incentive and does not rely on targeted levelized incentive rates.

Incentive ranges are not the same between customer segments, as higher incentives are needed for some measures in some customer segments to promote measure adoption.

DSM Scenarios were reported as a percentage of incremental cost as a useful way to compare the savings and expenditure impacts of increasing incentives between the minimum scenario having an average incentive of 50 percent of incremental cost, and the maximum scenario incentives being 100 percent of incremental cost.

79.0 Reference: Exhibit B-2, BCUC 1.39.1

Exhibit B-1, Volume 2, page 13

Preamble: The LT DSM Plan states (page 13): "The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential".

The response to BCUC 1.39.1 states:

> "No known cost-effective measures were excluded from the Medium, High and Maximum scenarios, as each DSM scenario already includes a comprehensive list of known cost-effective measures for each customer type".

79.1 Were any known cost-effective measures excluded from the Low or Base DSM scenarios?

79.1.1 If yes, what were they?

79.1.2 If yes, please reconcile this exclusion with the statement in the Application that "the same DSM measures were included in all scenarios" (per page 13).

Response:

The cost-effective measures included are identical across all DSM Scenarios; no cost-effective measures were excluded from the Low or Base DSM scenarios.

Please also refer to the response to BCUC IR2 57.1 for further discussion.

80.0 Reference: Exhibit B-8, RCIA 1.2.1.1 and 1.5.1

Exhibit B-1, pages 42-43

80.1 The response to RCIA 1.5.1 describes two EV-related demand response pilots: the first where DR events are expected to begin in early 2022 and the second which will be undertaken at a future phase. Please explain how these two projects are related to the EV-related load shifting pilots described in Sections 2.3.2 and 2.3.7.5 of the Application.

Response:

Both Sections 2.3.2 (beginning at page 43, line 13) and 2.3.7.5 (beginning at page 51, line 22) describe the scope of the residential demand response pilot currently in market that includes a hardware-approach to control EV charging.

The future phase of the residential demand response pilot that would evaluate a software-approach to control EV charging was not described in detail in either section, but would correspond to the software-based approach presented in Table 2-1 of the Application.

80.2 The response to RCIA 1.5.1 suggests that the EV load shifting pilot it plans to test sometime in the future is "the leading approach for shifting residential EV charging load". If this is the case, why isn't it being tested/piloted first?

Response:

The software-based approach to EV charging demand response was not tested/piloted first as the charging software demand response protocols are just beginning to be integrated into the platforms for utility demand response implementers, including the vendor FBC retained in its current demand response pilot phase.

As discussed in the response to BCOAPO IR2 80.1, FBC is exploring both hardware- and software-based approaches to mitigate the impacts of EV charging so that it is able to determine which approach, or combination, may be most effective in the future.

While the software-based approach to demand response is still an emerging approach, it is already seen as the leading approach to manage EV charging demand by electric utilities as it requires minimal investment from the customer. FBC anticipates that by late 2022 or early 2023, software charging protocol integration will be mature enough to test using the same vendor demand response platform used in the current demand response pilot phase.

81.0 Reference: Exhibit B-8, RCIA 1.9.3 and 1.9.4

Preamble: The response to RCIA 1.9.3 states:

> "For clarity, there are no mandated investment levels for FBC related to EV adoption. FBC does not expect to incur capital and operating costs at a level for which it would not be afforded a reasonable opportunity to recover those costs from ratepayers."

The response to RCIA 1.9.4 states:

> "To date, FBC's investments have primarily focused on the deployment and operation of public DCFC stations; RS 96 has been designed to recover the costs of this program from EV drivers."

81.1 With respect to the response to RCIA 1.9.3, does FBC anticipate that any future investments related to EV will be recovered from EV drivers"?

81.1.1 If not, why not?

Response:

Where possible, FBC intends to design EV-related rates and programs such that costs will be recovered from EV drivers over time. While the principle of cost-causation remains a cornerstone of FBC's approach to rate design, FEI recognizes that it may become necessary to accept some cross-subsidization in the future in response to changing market conditions, government policies and programs, asset utilization, or other factors.

82.0 Reference: Exhibit B-8, RCIA 1.39.1

Exhibit B-4, BCOAPO 1.33.3

82.1 With respect to RCIA 1.39.1, please explain why the average per annum savings (2021-2040) for the Residential sector are the same under the Medium, High and Maximum DSM scenarios even though the incentives being offered increase for the High and Maximum DSM scenarios (per BCOAPO 1.33.3).

Response:

In order to reasonably align with the historical and projected residential incentive spending for the market potential (detailed on page 37 of Appendix A), which corresponds best with the Base DSM scenario, a relatively high levelized incentive value was used for residential measures. This led to most residential measures being incentivized at 100 percent of incremental costs. Even though the high end of the $ per kWh incentive range increased for the Medium, High, and Maximum DSM scenarios, the difference in actual measure $ per kWh incentive only impacted measure adoption on a small number of measures. The impacted measures did not make a notable change to the overall residential per annum savings.

Thus, in the higher incentive DSM Scenarios, there was little room to increase the residential incentive levels and thus increase program potential over the Base Scenario.

83.0 Reference: Exhibit B-4, BCOAPO 1.31.3 and 1.31.4

Preamble: The response to BCOAPO 1.31.3 states: "The DCE value is presented and used as a blended transmission and distribution value."

The response to BCOAPO 1.31.4 states: "There was no distinction made for DSM program evaluation purposes between transmission and distribution losses. All analyses were performed using the common system losses value."

83.1 Please provide the DCE values for Transmission and Distribution along with the derivation of the weighted values of $51.22 / kW-year used in the Application. As part of the derivation please show the value for common system losses and how it is related to the values for transmission vs. distribution losses.

Response:

FBC's DCE value for transmission is $43.64 per kW-year and the DCE value for distribution is $7.58 per kW-year. The sum of these two components results in the total of $51.22 per kW-year.

The transmission and distribution components of the DCE value both use the system planning 1 in 20 year peak demand forecast as a denominator. The NPV costs of planned transmission growth projects and the NPV costs for planned distribution growth projects required to meet the 1 in 20 year peak demand forecast are the numerators of the transmission and distribution components, respectively. The 1 in 20 year forecast is stated at point of power supply and therefore is inherently inclusive of both transmission and distribution losses as well as company-use electricity. System losses are estimated to be 7.6 percent.[2] The methodology for creating the 1 in 20 year forecast is described in the response to BCOAPO IR1 23.2.

Additional information about the DCE methodology can be found in the EES Consulting Deferred Capital Expenditure Report provided as Attachment 38.1 to the response to BCUC IR1 38.1. Note that the values shown in the EES Consulting report reflect values filed in the 2016 LTERP. As stated in the response to BCUC IR1 38.1, the 2021 DCE value has been updated using the same methodology.

[2] FBC 2020-2024 MRP Application. Appendix B3 – FBC Losses Study (page 65 of the PDF).

84.0 Reference: Exhibit B-4, BCOAPO 1.38.6 and 1.38.7

Exhibit B-1, Volume 2, Appendix A, pages 31-32

Preamble: The response to BCOAPO 1.38.6 states:

> "The customer uptake of DSM measures in the Conservation Potential Review relies on payback acceptance curves to estimate the percentage of customers who would be willing to adopt a high efficiency measure based entirely on economic payback. Higher incentives drive faster economic 30 paybacks which increase uptake".

The response to BCOAPO 1.38.7 states:

> "No, the incentive for each measure in the Base DSM Scenario is the same as the incentive for the same measures in the 2021 Conservation Potential Review".

The Application (Volume 2, Appendix A, page 31) states:

> "Market potential is a subset of economic potential, and its intent is to capture real-world dynamics influencing measure adoption. For example, equipment turnover of replace-on-burnout measures constrains the market potential by limiting the opportunities for replacing failed inefficient equipment with efficient equipment. Market potential requires customer awareness and familiarity with efficient measures before adoption occurs. Lastly, relative economic attractiveness—after considering utility bill savings, incremental costs, operation and maintenance costs, and <u>incentives</u>—among high- and low-efficiency measures influences customers' purchasing decisions that drive market potential". (emphasis added)

84.1 The reference from Appendix A indicates that market potential is influenced/affected by the level of incentive offered to customers and the response to BCOAPO 1.38.7 indicates that the level of incentives used to determine market potential in the 2021 CPR was the same that used for the Base DSM Scenario. Please confirm that these two observations are correct.

84.1.1 If not correct, please explain/correct the response provide to BCOAPO 1.38.7.

<u>Response:</u>

FBC confirms that the two observations are correct.

84.2 BCOAPO 1.38.7 asked: "Are there DSM scenarios in which the assumed incentive payment for some/all of the measures exceeded the incentive payment used in the Market Potential study". The response provided stated – No. Please explain how this can be the case when (per the response to BOAPO 1.38.7 the incentive levels used in the CPR were the same as those used in the Base DSM scenario and higher levels of incentives were assumed for the Medium, High and Max DSM scenarios,

Response:

The incentive levels of the Base DSM Scenario in the LT DSM Plan are the same as in the Market Potential study (per the Conservation Potential Review).

The response to BCOAPO IR1 38.7 did not consider scenarios other than the Base DSM Scenario. The incentive levels for measures in the Med, High and Max DSM Scenarios exceed the incentive levels for the Market Potential study. Please refer to response to BCOAPO IR1 33.3.1 which tabulates ranges of incentives by customer segment and DSM Scenario.

84.3 Would the 2021 CPR's determination of the market potential for various the DSM measures have resulted in higher savings if the incentive levels used had aligned with those assumed in the Medium, High or Max DSM scenarios?

84.3.1 If not, why not

84.3.2 If yes, why wasn't a higher incentive level used in the CPR?

Response:

FBC confirms that if the incentive levels in the 2021 CPR were increased to match any of the Medium, High or Max scenarios, the study would have resulted in higher savings.

FBC chose the Base Scenario over the Med, High, or Max DSM Scenarios in the CPR (and ultimately, the LT DSM Plan) as the achievable savings amount of the Base Scenario was within 14 percent of the Max DSM Scenario while having an average resource cost ($ per MWh) that was 41 percent lower than the Max DSM Scenario. While the Med, High, and Max DSM Scenarios are still cost effective, FBC considered the added costs would not result in significant enough benefits to justify significantly expanding the size of FBC's DSM programs and incentives.

FBC has begun initial program planning as a part of the next DSM expenditures schedule. As described in the response to BCUC IR2 57.2, additional opportunities and measures have been identified that impact the expenditures, energy savings, and incentive levels as compared to the Base Scenario. These additional identified opportunities and measures do not materially impact the Base DSM Scenario and its impact on LTERP resource planning.

85.0 Reference: Exhibit B-4, BCOAPO 1.39.1

Preamble: The response states: "The average cost in Table 3-1 represents the average non-levelized cost for all cost-effective DSM at the incentive of the particular DSM Scenario over the planning horizon".

85.1 Please explain more fully what FBC means by "the average non-levelized cost" (e.g., how is it calculated?).

Response:

Average non-levelized costs ignore the time-value of expenditures and savings achieved across proposed measures, while average levelized costs discount future expenditures and savings achieved across proposed measures by FBC's discount rate. The average levelized cost of DSM is calculated by conducting a net present value calculation (using FBC's discount rate) that considers all the measure incentive and administration expenditures over the planning horizon and then dividing this by the achievable savings.

86.0 Exhibit B-4, BCOAPO 1.38.7 and 1.39.4

86.1 With respect to BCOAPO 1.39.4, please explain why the annual savings associated with the Market Potential are higher than those for the Base DSM scenario when according to the Application (Volume 2, page 13) the same DSM measures were included in all scenarios and according to BCOAPO 1.38.7 the incentive levels used in the determination of the market potential are the same as those used in the Base DSM scenario.

Response:

The Market Potential is not a DSM Scenario. The DSM Scenarios refer to the Low, Base, Med, High, and Max DSM Scenarios. Please refer to the response to BCUC IR2 61.1 which discusses the difference between the Market Potential and the DSM Scenarios. The only difference between the DSM Scenarios are a greater level of incentive and administration costs for the same selection of measures.

86.2 With respect to BCOAPO 1.39.4, please explain why the annual savings associated with the Market Potential are higher than those for the Medium, High and Max DSM scenarios when according to the Application (Volume 2, page 13) the same DSM measures were included in all scenarios and according to BCOAPO 1.38.7 the incentive levels used in the determination of the market potential was the same as those used in the Base DSM scenario and therefore lower than that assumed in the Medium, High or Max DSM scenarios.

Response:

Please refer to FBC's response to BCUC IR2 61.1. The annual energy savings associated with the Market Potential are higher than those for the DSM scenarios because the Market Potential included measures that were excluded from the DSM scenarios.

86.3 With respect to BCOAPO 1.39.4, please explain why the average costs associated with the Market Potential are higher than those for the Base DSM scenario when according to the Application (Volume 2, page 13) the same DSM measures were included in all scenarios and according to BCOAPO 1.38.7 the incentive levels used in the determination of the market potential are the same as those used in the Base DSM scenario.

Response:

Please refer to the response to BCUC IR2 61.1. The average costs associated with the Market Potential are higher than those for the Base DSM scenario because the Market Potential included some measures that were excluded from the DSM scenarios.

87.0 Reference: Exhibit B-4, BCOAPO 1.41.2

Preamble: The response states:

"DSM cost-effectiveness is evaluated from the customer perspective. For many DSM measures, the utility only pays a portion of the costs as a rebate and the remaining balance of the costs is directly borne by the customer. Customers are required to pay their share of the measure cost without the benefits of tax deductions at the utility tax rate. In contrast, utility investments in new resources are capital expenditures, and interest expense incurred for capital investment purposes is tax deductible".

87.1 If DSM is to be evaluated from the customer perspective why is it appropriate to use FBC's pre-tax discount rate as opposed to a discount rate reflective of customers' (as opposed to FBC's) time value of money?

Response:

DSM programs are utility investments that encourage customers to adopt energy efficient solutions which are beneficial to all rate payers. The Total Resource Cost (TRC) test is a reflection of two different customer perspectives, with the numerator reflecting avoided costs of new resources that would otherwise be borne by all rate payers, and the denominator reflecting an individual customer's choice to accept the incremental costs associated with a more efficient technology.

It is not possible to derive a discount rate that is reflective of every customer's time value of money. Adopting the utility's pre-tax WACC is a simplifying assumption that provides a degree of consistency with other aspects of the LTERP and LT DSM Plan. Customers purchasing a fridge, range, heat pump, or some other DSM measure generally pay their portion of the cost without the advantage of being able to deduct any interest that may have incurred as a result of their purchase. Moreover, some cash flows going into the TRC, such as O&M savings, do not reflect invested capital eligible for tax deductions. In contrast, new supply-side resources and system infrastructure upgrades are generally large utility capital investments. The use of the pre-tax WACC in the TRC calculation is consistent with historical practices.

88.0 Reference: Exhibit B-2, BCUC 1.27.1 and 1.27.2

Exhibit B-4, BCOAPO 1.41.2

Exhibit B-1, Volume 1, pages 151-152 and 160

Preamble: The response to BCUC 1.27.1 states:

> "FBC has determined $38 per MWh to be the appropriate average cost for the proposed base level of DSM. This average cost was based on a calculation that included the total costs for this level of DSM, as determined by the CPR, divided by the total energy savings discounted over an average 15-year measure life. This is consistent with FBC's past practice and is the method used in FBC's 2016 Long-Term DSM Plan that was accepted by the BCUC in its Decision and Order G-117-18".

88.1 The response to BCUC 1.27.1 indicates that $38 per MWh is the average cost for the proposed level of DSM. Similarly, at page 160 the Application states: "The average cost of the proposed DSM level is $38 per MWh". However, the Application indicates that "FBC selected the Base DSM scenario as its preferred scenario in the LT DSM Plan" (page 152) and the average cost for the Base DSM scenario is $44 per MWh (Table 8-1). Please reconcile.

Response:

The $38 per MWh average cost for proposed DSM detailed in the response to BCUC IR1 27.1 is the levelized cost of DSM. The $44 per MWh average cost for proposed DSM detailed in Table 8-1 of the Application is the non-levelized cost of DSM.

88.2 With respect to Table 8-1 was is included in the determination of the average cost of each DSM scenario and is the cost calculation done from the utility/FBC's perspective, the customer's perspective or from a societal perspective?

Response:

The cost calculations shown in Table 8-1 are from the perspective of the utility (i.e., FBC). The costs include incentive and administrative costs for both the program and portfolio.

88.2.1 What discount rate is used to determine this average cost value? In responding please demonstrate that the discount rate used is consistent with the response provided to BCOAPO 1.41.2

Response:

FBC used a pre-tax discount rate of 7.9 percent,[3] rounded up from 7.89 percent, as calculated in the response to BCOAPO IR1 41.1 and referenced in the response to BCOAPO IR1 41.2.

[3] 2021 LTERP, Volume 2: Long-Term Demand Side Management Plan, Appendix A: 2021 Conservation Potential Review Report, Table 1, Page 10.

89.0 Reference: Exhibit B-2, BCUC 1.29.1

Exhibit B-1, Volume 1, Appendix K, page 5

Preamble: The Application (Appendix K) states: "Base load resources operate at a high capacity utilization factor, generating significant amounts of electrical energy over the entire year"

89.1 BCUC 1.29.1 requested the capacity factors of the supply-side options FBC had identified as being base load resources. The response provided capacity factors for a number of resources not identified in the Application as being "base load resources" and also indicated fairly low capacity utilization factors for some of the resources the Application had identified as being base load resources. Please indicate which of the resource options listed in BCUC 1.29.1 FBC considers to be baseload.

89.1.1 Furthermore, if any of the resource options identified as "baseload" have relatively low capacity utilization factors, please explain why they are considered to be base load resources.

Response:

The table of capacity factors provided in the response to BCUC IR1 29.1 also included peaking resources and intermittent resources, in addition to baseload resources, to address BCUC IR1 29.2 and 29.3.

The following table identifies the resource types that FBC considers to be baseload within the Application. For clarity, the table includes the names of the resource types as labelled in BCUC IR1 29.1 and as well as the equivalent resource type as bulleted in the cited reference, Exhibit B-1, Volume 1, Appendix K, page 5.

BCUC IR1 29.1	Appendix K, Page 5	Annual Average Capacity Factors
Wood Waste Biomass	Biomass wood-waste thermal generation	0.91
Geothermal	Geothermal generation	0.65 to 0.76
Gas-Fired Generation: Combined Cycle Gas Turbine (CCGT)	Combined cycle gas turbine (CCGT) plants	0.90
Small Hydro with Storage	Hydro generation with some storage reservoir	0.43 to 0.76

FBC does not consider any of the baseload resource types listed above to have a "relatively low capacity utilization factor".

90.0 Reference: Exhibit B-2, BCUC 1.29.6

Application, Volume 1, page 190

Preamble: The response states:

"Providing upgraded biogas (i.e., renewable natural gas (RNG)) to FEI gas customers in support of FortisBC's Clean Growth Pathway to 2050 and its 30BY30 targets is a better use for RNG than generating baseload electricity. RNG used in the natural gas system will displace conventional natural gas, but electricity generation using RNG would displace electricity primarily produced by hydroelectric dams. Given that FEI's targets are emissions-related, it is reasonable to expect that displacing conventional gas to reduce customer GHG emissions is a better use for RNG than displacing electricity generation".

90.1 Two of the three preferred portfolios include RNG-SCGT plants (C3 and B2). For each of these portfolios please provide the average annual capacity utilization factor for each of the RNG-SCGT plants included in the portfolio (calculated for years the plant is in-service).

Response:

The table below shows the modelled average annual capacity factors for each of the RNG SCGT plants included in Portfolios C3 and B2 for each year the plants are in service over the planning horizon. In addition to providing capacity during times of forecast peak load, dispatchable RNG SCGT plants could also run as contingency resources in the event that load or other operating conditions require their capacity. The capacity factors listed do not include any provisions for generation that may occur as a result of contingency conditions.

Year	Portfolio C3 RNG SCGT1 Capacity Factor Percentage (%)	Portfolio C3 RNG SCGT2 Capacity Factor Percentage (%)	Portfolio B2 RNG SCGT1 Capacity Factor Percentage (%)
2030	N/A	N/A	0.3%
2031	N/A	0.5%	0.3%
2032	N/A	0.6%	0.3%
2033	N/A	0.6%	0.3%
2034	N/A	0.6%	0.3%
2035	2.0%	0.2%	0.2%
2036	2.0%	0.2%	0.3%
2037	1.9%	0.2%	0.3%
2038	2.0%	0.2%	0.3%
2039	2.1%	0.2%	0.3%
2040	2.0%	0.2%	0.3%

90.1.1 Based on these values can any of these RNG-SCGT plants be considered as generating baseload electricity?

Response:

FBC does not consider an RNG SCGT plant to be a baseload resource, but instead considers it a peaking resource as discussed in Section 10.2.1 of the Application.

91.0 Reference: Exhibit B-9, CEC 1.36.1 and 1.37.1

Exhibit B-1, Volume 1, pages 118 and 170

Preamble: The response to CEC 1.36.1 states:

> "Note that FBC cannot currently purchase 3,241 GWh annually from the market due to the following non-exhaustive list of reasons: commitments to existing supply-side resources, contractual limitations, and insufficient customer load".

The Application states (page 118):

> "FBC access to the market is mainly through its transmission rights on the Teck-owned 71 Line, which provides transmission from across the BC/US border to the FBC system. For long-term planning purposes such as the 2021 LTERP, this access is treated as firm but it must be recognized that the Company does not own this transmission line. FBC retains access to the wholesale market on Teck's 71 Line for a 20-year period at minimum."

The Application (page 170) states:

> "FBC relies on Line 71 to access US market supply, and there can be transmission constraints both on Line 71 and on the US transmission south of the border that can interrupt that supply when FBC needs it for capacity purposes, as discussed in Section 5.5. Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option".

91.1 With respect to CEC 1.36.1, please outline the contractual limitations that restrict FBC's ability to purchase power from the market.

Response:

FBC's market purchases are restricted by contractual limitations under circumstances where FBC needs the power but is unable to purchase from the market due to the following contractual terms:

1. 71 Line transmission is not available. If 71 Line is out of service, then FBC's ability to purchase from the market under the CEPSA agreement with Powerex is not as strong as it is with 71 Line in service. In addition, if Teck requires use of 71 Line for their own purposes, the transmission capacity available to FBC for imports may also be restricted.
2. Limitations in the BC Hydro PPA agreement that restrict how quickly FBC can ramp up cost effective PPA purchases in the event market power is not cost effective or is not available. Under the PPA, FBC submits an annual energy nomination for each contract

year as outlined in the confidential Annual Electric Contracting Plan. Based on a current year's PPA nomination, FBC can only increase or decrease the energy nomination in the subsequent contract year by +/- 20 percent. This in turn, limits the amount of energy that FBC can bring in from other sources, such as the wholesale market. While FBC could ignore these PPA limitations and buy the market power anyway, that would mean that the PPA nomination would be so low that FBC would have to purchase PPA power above the nominated energy amount in future years if, in the future market, power was not cost effective.

91.2 Do FBC's transmission rights on the Teck-owned 71 Line guarantee it access to the line? Based on this access how much power could be purchased and imported?

Response:

FBC confirms that its transmission rights on 71 Line guarantee it access for a 20-year period at minimum, conditional on FBC's use not interfering with Teck's requirements.

For the maximum amount of market purchases that could theoretically be imported on 71 Line, please refer to the responses to CEC IR1 36.1 and 36.2.

91.3 What are sources of the transmission constraints on the 71 Line referred to on page 170 of the Application? How, are they expected to impact the amount of power that FBC can purchase and import over the 71 Line?

Response:

Please refer to the response to BCSSIA IR1 14.1 for the sources of transmission constraints.

Transmission constraints are not expected to substantially impact the amount of power that FBC can import over 71 Line over the long-term planning horizon. However, on an operational basis, there is always the possibility that unforeseen congestion or transmission line outages could impact market imports, although, to date, this has been an infrequent occurrence.

92.0 Reference: Exhibit B-3, BCSSIA 1.3.7

BC Hydro's 2021 IRP, Exhibit B-1, Appendix L, page 13

92.1 What is the updated cost for BC Hydro Tranche 2 energy based on the LRMC estimates in BC Hydro's 2021 IRP Application?

Response:

The updated LRMC of energy in BC Hydro's 2021 IRP Application is $65 per MWh (in 2022 dollars).[4] As set out in the PPA, the Tranche 2 energy price reflects BC Hydro's most recent proxy for the LRMC for firm energy as determined by BC Hydro and accepted by the BCUC for ratemaking purposes. FBC's current Tranche 2 energy price is $95.09 per MWh, as stated in BC Hydro's tariff dated July 29, 2021 (per BCUC Order G-187-21). FBC will update the PPA Tranche 2 energy price after BCUC acceptance of any BC Hydro proposed changes to Rate Schedule 3808.

92.2 Would this updated cost impact FBC's choice as to its "preferred portfolios"?

Response:

BC Hydro's updated LRMC of energy would not impact FBC's choice of preferred portfolios for the following reasons:

1. New resources in the preferred portfolios are required to meet monthly capacity gaps and the resulting energy also serves to reduce any energy requirements;
2. A BC Hydro PPA rate of $65 per MWh is still higher than the market price forecast;
3. Even if the average market price exceeds $65 per MWh, it is likely there will still be months when FBC can purchase cost-effective market energy with the result that it is likely FBC will remain below the 1,041 GWh of BC Hydro PPA purchases allowed under Tranche 1 pricing; and
4. FBC is limited in how much PPA energy can be purchased by the 200 MW cap. This results in non-PPA resources being required in certain months even if the PPA energy rate is cheaper.

The following expands upon each of these points.

[4] BC Hydro's 2021 IRP, Exhibit B-1, Appendix L: Reference Price and Long Run Marginal Costs, Page 13.

Assuming an updated BC Hydro LRMC of energy of $65 per MWh, the optimization routine still would not select PPA Tranche 2 as an energy resource because it is still not cost effective relative to other available energy resources, specifically, market energy. An updated PPA Tranche 2 Energy price, even at $65 per MWh, is greater than the market forecast prices of $28 to $49 per MWh as supported by the Mid-C Electricity Price Forecast tables in Appendix E. As energy self-sufficiency is not a planning criteria consideration, the optimization routine will favor market energy over PPA Tranche 2 energy.

If the price of market energy were to rise and exceed the price of PPA energy, then FBC would opt to consume more PPA energy, but not necessarily in quantities that exceed the PPA Tranche 1 limit. This is because FBC's energy gaps and market prices both vary on a monthly basis, and therefore even if FBC scheduled higher amounts of PPA energy during higher load winter months, there would likely still be other months throughout the year that market energy would be more economic to schedule. Additionally, the PPA is a bundled product, meaning FBC must schedule PPA capacity to receive PPA energy. FBC has access to a maximum of 200 MW of capacity in any hour, which creates a physical limitation of 148.8 GWh of energy that can be scheduled at most in any month[5] even if FBC would like to take more energy in specific months, regardless of the energy unit cost per MWh rate or remaining available energy within the contract year.

For preferred Portfolios C3 and C4 that have no energy self-sufficiency requirements, the energy gaps are primarily met with market energy, and therefore are not impacted by the updated Tranche 2 price. In contrast, preferred Portfolio B3, which does have an energy self-sufficiency requirement, is also not impacted since the new resources selected in the portfolio have associated energy that must be delivered and utilized before any PPA energy at the Tranche 2 rate.

5 Assuming 31 days * 200 MW * 24 hours per day = 148.8 GWh.

93.0 Reference: Exhibit B-2, BCUC 1.31.8 and 1.31.16

Preamble: The response to BCUC 1.31.16 states: "As projected emissions can vary year to year depending on the dispatch of the various existing and new resources, the total emissions are expressed on a net present value basis".

The response to BCUC 1.31.8 states:

> "FBC did not include A1 in the preferred portfolios as it includes an SCGT plant using conventional natural gas and so is not a clean and renewable portfolio."

93.1 Please explain more fully why it is important to consider projected emissions on a net present value basis (i.e., why does it matter what year the emissions occur in?).

Response:

Total GHG emissions are presented in net present value (NPV) terms for purposes of consistency with other values in the Application. Further, emissions occurring later in the planning horizon are less certain than emissions in early years.

The GHG intensity values shown in Table 11-2, and expressed in the units of tonnes per GWh, are levelized values calculated as the NPV of GHG emissions divided by the NPV of energy within the portfolio. Calculating the average tonne per GWh intensity values by taking the total GHG emissions divided by the total energy within the portfolio *decreases* the GHG emission intensity factor even though total GHG emissions is a larger value. The GHG emissions grow at a slower rate than the energy within the portfolio over the planning horizon and these larger volumes of energy at the end of the planning horizon are more influential without discounting.

Regardless of whether GHG emissions are expressed on an NPV basis or without discounting, the majority of reportable GHG emissions in the preferred portfolios are attributed to indirect (Scope 3) emissions associated with energy purchases from BC Hydro under the PPA. As discussed in the response to RCIA IR1 6.3, FBC receives a mix of BC Hydro's resources as a whole and has applied a constant average grid emission factor[6] reflective of BC Hydro's system to estimate reportable emissions from energy purchases under the PPA. FBC considers a constant emissions factor to be conservative, as FBC anticipates BC Hydro's overall system grid factor will decrease over time as remote service components of the grid powered by baseload thermal generation, such as Fort Nelson, adopt cleaner forms of fuel, alternate forms of generation, or through offsetting technology such as carbon capture.

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[6] BC Government, Electricity emission intensity factors for grid-connected entities, Grid factors, 3 year average of the integrated grid GHG Emission Intensity factor (2017-2019). https://www2.gov.bc.ca/gov/content/environment/climate-change/industry/reporting/quantify/electricity.

93.2 With respect to Table 11-2, please restate the GHG Emissions for each of the preferred alternatives without any "discounting".

Response:

Please refer to the response to BCOAPO IR2 93.4.

93.3 With respect to the response to BCUC 1.31.8, please provide the average annual capacity utilization factor for each of the SCGT plants included in the A1 portfolio (calculated for years the plant is in-service).

Response:

The table below provides the projected average annual capacity factor for each of the SCGT plants included in Portfolio A1, calculated for years that the resources are in service.

Year	Portfolio A1 SCGT1 Capacity Factor Percentage (%)	Portfolio A1 SCGT3 Capacity Factor Percentage (%)	Portfolio A1 RNG SCGT1 Capacity Factor Percentage (%)
2030	N/A	N/A	N/A
2031	N/A	0.5	N/A
2032	N/A	0.6	N/A
2033	N/A	0.6	N/A
2034	N/A	0.7	N/A
2035	2.8	0.2	N/A
2036	3.4	0.2	N/A
2037	3.5	0.2	N/A
2038	5.2	0.3	0.2
2039	7.0	0.3	0.2
2040	6.6	0.3	0.2

93.4 With respect to Table 11-2 please provide a revised version that also includes portfolio A1 and that includes a column where the GHG Emissions for each of the alternatives is restated without any "discounting".

Response:

The table below is a revised version of Table 11-2 that also includes Portfolio A1 and includes a column where the GHG emissions are restated without any "discounting".

Portfolios	Resource Mix	Portfolio Attributes									
		Cost			Environment				Resiliency		Economic
		LRMC ($/MWh)	Average Cost ($/MWh)	Rate Impacts (CAGR)	% Clean Resources	GHG Emissions	GHG Emissions without Discounting	Footprint (Hectares)	Operational Flexibility	Geographic Diversity	BC Employment (Job Persons)
Clean [C3]	PPA Market DistBattery6 [2030] RNG_SCGT2 [2031] RNG_SCGT1 [2035] Solar2 [2038] Solar3 [2039] DistSolar3 [2039] Solar1 [2040] Wind1 [2040]	$81	$76	1.58%	99%	6.5 CO2e tonne/GWh Scope 1: 122 Scope 3: 355,480	6.0 CO2e tonne/GWh Scope 1: 219 Scope 3: 474,603	292	High	High	1346
Energy Self Sufficiency 2030 [B2]	PPA Market (up to 2030) RNG_SCGT1 [2030] Wind5 [2031] DistBattery6 [2033] DistSolar3 [2034] Solar7 [2035] Solar3 [2038] Solar2 [2039] Wind1 [2039] RoR3 [2040]	$82	$79	2.01%	99%	7.4 CO2e tonne/GWh Scope 1: 19 Scope 3: 404,297	7.0 CO2e tonne/GWh Scope 1: 33 Scope 3: 559,934	597	Medium	High	1915
Clean No RNG SCGT [C4]	PPA Market Battery4 [2030] Solar7 [2031] Solar1 [2033] DistSolar2 [2033] RoR3 [2034] Wind5 [2035] Solar2 [2037] Solar3 [2038] Wind3 [2039] Biomass1 [2040] DistSolar1 [2040] DistSolar3 [2040] RoR2 [2040]	$97	$78	2.10%	99%	6.4 CO2e tonne/GWh Scope 1: 0 Scope 3: 353,609	5.9 CO2e tonne/GWh Scope 1: 0 Scope 3: 470,972	723	Low	High	2504
Reference Portfolio [A1]	PPA Market DistBattery6 [2030] SCGT3 [2031] SCGT1 [2035] RNG_SCGT1 [2038] DistSolar1 [2040] Solar2 [2040]	$78	$76	1.47%	99%	7.4 CO2e tonne/GWh Scope 1: 45,459 Scope 3: 355,576	7.1 CO2e tonne/GWh Scope 1: 84,713 Scope 3: 474,803	123	High	High	727

94.0 Reference: Exhibit B-2, BCUC 1.31.18

Exhibit B-6, BCSEA 1.5.1

Exhibit B-1, Volume 1, pages 214-217

Preamble: The response to BCUC 1.31.18 states:

> "Given this risk, FBC contemplates accelerating the development of the selected generation resource, starting in 2022. FBC expects to initiate project development work, including land acquisition, front-end engineering design (FEED), permitting, and stakeholder and Indigenous consultation in the near future."

The response to BCSEA 1.5.1 states:

> "If the BCUC accepts FBC's 2021 LTERP including its recommended preferred portfolio, FBC would further plan to implement the resources in this portfolio to meet customers' load requirements, assuming the Reference Case load forecast, proposed DSM level and resource options costs, and energy and capacity profiles remain as presented in the LTERP."

94.1 With respect to BCUC 1.31.18, what is the "selected generation resource" that FBC is contemplating accelerating the development of?

Response:

With respect to the response to BCUC IR1 31.18, FBC is contemplating accelerating development of the RNG SCGT plant as the selected generation resource.

94.2 Please indicate where the activities described in BCUC 1.31.18 and BCSEA 1.5.1 have been reflected in the Action Plan set out in section 13.2 of the Application.

Response:

The activities described in the responses to BCUC IR1 31.18 and BCSEA IR1 5.1 relate to the development of new generation resources that may be needed in the future, as per the requirements in preferred Portfolio C3 or other portfolios that require new resources sooner. Action item #3 in Section 13.2, contingency resource(s) assessment, reflects these development activities and describes FBC's intent, as part of a prudent approach to manage future system loads, to explore the potential resource options identified in this LTERP in the short term. FBC must undertake this work so that it will be ready to bring forward an application for a new resource to the BCUC for approval prior to the development of the next LTERP. This is particularly important given the long development timelines of major projects in British Columbia, including the time for land acquisition, front-end engineering design (FEED), permitting, environmental assessment, and stakeholder and Indigenous consultation.

95.0 Reference: Exhibit B-8, RCIA 1.33.1 and 1.33.2

Exhibit B-9, CEC 1.55.2 and 1.56.2

Exhibit B-1, Volume 1, pages 185-187

95.1 Portfolios E2, E3, E4 and E5 include the different levels of EV load shifting. Did the portfolios include any costs (e.g., software or hardware costs or incentive costs) related to achieving the indicated levels of EV load shifting?

95.1.1 If yes, are these costs reflected in the reported LRMC values for each portfolio?

95.1.2 If yes, what was the cost/kWh shifted included in each portfolio and how was it determined? (Note: While the savings from such shifting are capacity-related, these savings will be achieved by encouraging customer to shift their charging activity and the associated kWh required from peak to off-peak)

95.1.3 If not, why not?

95.1.4 If not, for each of the portfolios E2, E3, E4 and E5, what cost per kWh for the EV load shifted would equate the portfolio's LRMC value to LRMC value for portfolio A1 ($78 / MWh)?

Response:

Portfolios E2, E3, E4, and E5 (which include various levels of EV charging shifting) do not include any software, hardware, or incentive costs required to achieve the indicated level of EV load shifting. The conclusion to be drawn from the EV charging shifting portfolios is that an EV program designed to encourage and shift charging from the evening peak hours to non-peak hours, such as the middle of the night, will help to improve the efficiency of the system.

FBC did not include specific shifting program costs for EV charging within the LTERP portfolios or Long-Term DSM Plan as the pilot program is not complete and outcomes from this pilot will be used as a basis to inform program costs. FBC has not yet requested and received approval for any large-scale deployment of EV mitigation programs that can achieve the volume of capacity savings represented in any of the EV charging shifting portfolios. The target capacity savings and corresponding costs of an EV mitigation program will be informed by the pilot initiatives as discussed in the response to BCSEA IR1 4.2. A broader discussion of FBC's Demand Response pilot programs can be found in the responses to the BCUC IR2 58 series. Projected capacity savings associated with EV mitigation programs will be treated similar to other DSM programs and deducted from the load forecast rather than modelled as a supply-side resource. The LRMC is stated after DSM, therefore, these costs would not be reflected in future portfolio LRMC values.

EV charging programs shift energy from peak times to provide capacity savings, as opposed to energy savings. As a result, there is no change in the energy between the portfolio A1 and the

EV charging shifting portfolios, which is the denominator for the LRMC calculation. However, it is possible to calculate the value of the EV savings associated with the EV charging shifting portfolios relative to portfolio A1 in the units of $ per kW-Year, which are shown in the table below. This value can be interpreted as the change in capacity requirements due to the shifting of the EV charging. To yield a $ per kW-Year value, the difference in the total portfolio costs between a specific EV charging shifting scenario and portfolio A1 is divided by the corresponding reduction in capacity requirements.

Portfolio	Percent of EV Capacity Requirements Shifted	Value in $ per kW-year Relative to Portfolio A1
E2	25	$179
E3	50	$159
E4	75	$130
E5	100	$138

96.0 Reference: Exhibit B-6, BCSEA 1.14.1 and 1.14.3

Exhibit B-1, Volume 1, page 181

96.1 Please clarify/confirm that FBC: i) assumes capacity self-sufficiency after 2030 for all of the portfolios assessed but ii) assumes for all portfolios assessed that it can continue to rely the market for capacity purchases to meet PRM requirements if needed.

<u>Response:</u>

Confirmed. Please also refer to Section 2.1.3 of Appendix M of the Application for further information and FBC's view on the difference between relying on market capacity purchases to meet expected load on a planning basis versus using the market as a supplemental resource to meet system requirements under unexpected conditions.

97.0 Reference: Exhibit B-9, CEC 1.56.1

Preamble: The response states: "The LRMC reflects only the incremental cost to serve incremental load, after netting-out changes in the cost to serve existing load."

97.1 Please clarify what is meant by the statement "after netting-out changes in the cost to serve existing load". Does this mean that changes in the cost of serving existing load are factored into the calculation of the LRMC?

97.1.1 If yes, why doesn't the calculation of the LRMC already account for the impact the self-sufficiency assumption in B2 has on the cost of serving existing load?

Response:

The statement "after netting-out changes in the cost to serve existing load" means that any changes in the cost to serve existing load are not factored in the calculation of the LRMC, but are reflected in average costs. Please also refer to the response to BCOAPO IR1 54.1 and Appendix L, Section 5.1.1.

97.2 The response explains why the LRMC for B2 is not comparable to the LRMC values for the other two portfolios. However, it is portfolio C4 where the difference between the LRMC value and the average cost for the portfolio differs the most from the other two (e.g., the differences are: $5 for C3, $3 for B2 and $19 for C4). Please explain why the difference between LRMC and average portfolio cost is so much higher for C4 than C3 when both rely on the market for energy after 2030.

Response:

In Portfolio C3, the RNG SCGT plants provide dependable capacity in all months of the year. In Portfolio C4, a larger portfolio of seasonally complementary energy-oriented resources are required to meet the same monthly capacity requirements. This significantly increases the cost of the portfolio.

As shown in Table 10-2, the RNG SCGT resource contained in portfolio C3 has a UCC cost in the range of $131 to $148 per kW-Year. Within portfolio C4, those same capacity requirements are primarily met with solar, wind, and battery resources. As shown in Table 10-2, solar UCCs range from $686 to $882 per kW-Year, wind UCCs range from $509 to $734 per kW-Year, and batteries storage UCCs range from $226 to $267 per kW-Year.

Although both portfolios have access to market, portfolio C4 foregoes the use of the market to use the take-or-pay energy from the intermittent resources that were developed for capacity purposes. Both portfolios C3 and C4 have the same cost of meeting existing load, the difference is how the incremental capacity gaps are met.

98.0 Reference: Exhibit B-9, CEC 1.56.1

Exhibit B-1, pages 188-189

Preamble: The Application sets out to the following key findings from the portfolio analyses:

"• Higher levels of DSM than the base DSM level are less cost effective than other resource options;

• Based on current price forecasts, market energy is more cost effective than other resource options;

• Clean or renewable resource portfolios that include SCGT plants using RNG are more 33 cost effective than portfolios that exclude SCGT plants;

• Shifting EV charging loads from peak periods reduces the need for capacity resources and lowers portfolio costs;

• Renewing the PPA is a more cost effective and flexible option than replacing it with other resource options;

• No new generation resources are required before 2030 except for portfolios based on lection as the preferred portfolios".

CEC 1.56.1 states: "Therefore, the LRMC of portfolio B2 cannot be directly compared with the other portfolios without also considering other cost metrics. Instead, the average cost must be examined to take into account the impact of how existing load is met in addition to incremental load."

98.1 The key findings set out in the Application are based, in part, on comparing the LRMC values for the various portfolios. Would the findings change if the average cost of each portfolio (per CEC 1.56.1) was used as the basis for comparing the costs of the portfolios

Response:

The high-level conclusions drawn from the portfolio analysis would be the same if the average cost of the portfolios were used as the cost comparison metric rather than the LRMC. The use of LRMC places emphasis on the incremental costs associated with incremental changes in load. The use of average cost as a comparison metric would make the cost differences among the portfolios much more subtle and would only add additional information in scenarios where changes in self-sufficiency or existing resources influence how the current load is met.

The portfolio scenarios investigated that have the greatest effect on how FBC manages existing load are Portfolio B2, which achieves energy self-sufficiency in 2030, and Portfolios F4 and F5, which both investigate if the PPA were not renewed. FBC does not have control over market conditions, market prices, or PPA prices from BC Hydro. Portfolio B2 would likely be a preferred option for FBC in the event that market conditions changed such that market energy was no longer a reliable or cost-effective option in the future. Portfolios F4 and F5 would likely only be considered in the event that FBC was unable to successfully renew the PPA agreement or the cost of PPA became more expensive relative to other resource options. The use of average cost versus marginal cost would not change these conclusions.