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December 23, 2021

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)

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. 1

On August 4, 2021, FBC filed the Application referenced above. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-314-21 for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, Vol. 1, page ES-1

Preamble: The Application states: "The LTERP includes an action plan that describes the activities that FBC intends to pursue over the next four years."

1.1 Will the "action plan" be formally updated prior to FBC filing its next LTERP? If yes, when and will it be publicly available?

<u>Response:</u>

FBC does not intend to formally update the action plan discussed in Section 13.2 prior to its next LTERP. Consistent with pact practice, FBC intends to provide an update in the next LTERP. Any specific action items related to other FBC applications will be formally updated within those applications. For example, optimizing the PPA and market purchases is updated annually within the FBC Annual Electric Contracting Plan.

2.0 Reference: Exhibit B-1, Vol. 1, page ES-9

Preamble: The Application states: "Third, initiatives to incent and properly manage potential growth in non-traditional high load-factor customer loads, such as hydrogen production, could improve system optimization and help reduce rate increases for all customers, particularly if these loads could be curtailed for short periods during system peaks".

2.1 Given that FBC is in a capacity surplus situation until 2030, is the observation that high load-factor customer loads could "help reduce rate increases" applicable just in the short-term or also in the long term – assuming such loads continue for the entire planning period?

<u>Response:</u>

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.

2.2 Given that FBC is in a capacity surplus situation until 2030, is the observation that high load-factor customer loads could "help reduce rate increases" applicable only if the loads can be curtailed for short term periods during the system peaks? As part of the response, please indicate the extent of the curtailment that would be required (e.g., expected every year or just infrequently and for how long).

<u>Response:</u>

The addition of high load-factor customers provides rate mitigation when the additional revenues that they provide are in excess of the cost of providing service, regardless of whether their loads are curtailed during system peaks. Additional benefits may be achieved if high load-factor customers are able to curtail during system peaks, although the amount of additional benefit will depend on many factors including the frequency, magnitude and duration of the curtailment.

3.0 Reference: Exhibit B-1, Vol. 1, page ES-10

Preamble: With respect to the Transmission and Distribution system, the Application states: "FBC has simulated peak demand scenarios to help determine, at a high-level, the potential system impacts."

3.1 To what extent are the impacts dependent upon where on the transmission and distribution systems the distributed generation or new large loads occur?

Response:

As discussed in Sections 6.5.1 and 6.5.3, the impact of distributed generation or new large loads is highly dependent on their location in FBC's transmission and distribution system.

4.0 Reference: Exhibit B-1, Vol. 1, pages ES-11 and 82

Preamble: The Application states: "Section 7 identifies the load-resource balance (LRB) before incremental demand-side and supply-side resources are included to determine if there are any energy and/or capacity gaps over the planning horizon".

The Application states: "All forecast loads presented in this section are before adjustments for incremental DSM".

4.1 For purposes of Table ES-1 and section 3, what DSM savings (if any) have been included in the load forecasts and what is considered to be incremental DSM (and therefore excluded)?

Response:

Both Table ES-1 and Section 3 have no new DSM savings included in the load forecast for the planning horizon. Incremental DSM is the projected annual savings from FBC DSM programs described in Section 8.

5.0 Reference: Exhibit B-1, Vol. 1, pages 4 and 8-12

Preamble: The Application (page 4) states that one of the objectives of the LTERP is to "Ensure consistency with provincial energy objectives (for example, the applicable objectives in the CEA and the CleanBC Plan)".

At pages 8-12 the Application discusses the CEA objectives applicable to the LTERP.

5.1 Please indicate which, if any, of the CEA objectives FBC viewed as being "musts" as opposed to "considerations" in the development of the LTERP.

Response:

FBC views all of the CEA objectives as being important for meeting provincial energy objectives. However, as discussed in Section 1.4.2, not all of them are directly applicable to FBC, but are rather directed to BC Hydro (as the "authority") and so those objectives are only considerations. These "considerations" include the following objectives, with the remaining CEA objectives in Table 1-3 being directly relevant or "musts" for FBC:

- Achieving electricity self-sufficiency (2a);
- Generating at least 93 percent of the electricity in British Columbia from clean or renewable resources (2c);
- Ensuring the authority's ratepayers receive the benefits of the heritage assets (2e);
- Ensuring the authority's rates remain among the most competitive of rates charged by public utilities in North America (2f);
- To be a net exporter of electricity from clean or renewable resources (2n); and
- To ensure the Commission continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export (2p).

6.0 Reference: Exhibit B-1, Vol. 1, page 18

Preamble: The Application states: "Over the LTERP planning horizon, climate change has the potential to impact FBC's supply in terms of its hydro- electricity generation, how much electricity FBC's customers require, and FBC's transmission and system infrastructure planning."

6.1 Has FBC explicitly factored into the LTERP the impacts on the capability of its hydro-generation facilities due to climate change? If so, what impacts (kWhs and kWs) have been included?

Response:

FBC has not explicitly factored into the LTERP the impacts on the capability of its hydro-generation facilities due to climate change. However, as discussed in Section 5.1.1, FBC has discussed the potential for climate change to have a material impact on water availability for hydroelectricity generation in the Pacific Northwest, thus opening up the possibility of changes to FBC's entitlements relating to its hydro-generation facilities under the Canal Plant Agreement.

6.2 How will climate change impact FBC's transmission and system infrastructure planning?

Response:

As discussed in Section 6.6, depending on the potential risks associated with climate change, adaptation measures could result in installation of new equipment, the use of new technologies, changes to FBC operating procedures, and updates to FBC's design standards.

Further, depending on the specific climate change impacts, including wildfires, flooding, weather events, storms and snow/ice, there may be a need for resiliency measures and additional infrastructure capacity to address higher customer peak demand.

6.2.1 Have any specific impacts been factored into the LTERP and, if so, what are they?

Response:

For the impacts on FBC's hydro-electric generation, please refer to the response to BCOAPO IR1 6.1.

Regarding how much electricity FBC's customers require, FBC has included climate change as a load driver in Section 4 to determine the impacts on customers' requirements based on specific temperature changes over the planning horizon. The results vary by scenario and are provided in Section 3.3 of Appendix H – Load Scenarios Assessment Report.

As far as impacts to FBC's transmission and system infrastructure planning, Section 6.6 discusses FBC's actions and plans regarding system asset resiliency and adaptation measures for climate change-related risks.

6.2.2 How did FBC decide whether to factor certain climate change impacts in its LTERP?

Response:

FBC expects that climate change may have impacts on all of the key aspects of the LTERP, including government policies and FBC's climate goals, supply resources, customer requirements, and system infrastructure over the LTERP planning horizon. Therefore, FBC has included discussion and some analysis for the climate change factors most relevant to these aspects. This analysis and discussion is provided in the following LTERP sections:

- Section 2.2 – impacts on government policies and FBC's climate goals;
- Section 5.1.1 - potential impacts of temperature and precipitation pattern changes on FBC's supply resources;
- Section 4.1 – potential changes to customers' annual energy and peak demand load requirements through load scenarios; and
- Section 6.6 - potential impacts from climate change on its transmission and distribution infrastructure.

6.2.3 If FBC did factor specific impacts into its LTERP, how did it calibrate those impacts and please provide any source materials relied upon to inform its deliberations.

<u>Response:</u>

Please refer to the response to BCOAPO IR1 6.2.1.

7.0 Reference: Exhibit B-1, Vol. 1, pages 39-40 and Appendix F, page 21

Preamble: Appendix F states: "The EV sales percentages, along with the forecast of total new light-duty vehicle sales and the assumed EV charging load, were then used to calculate the EV charging load portion of the Reference Case load forecast."

7.1 How does the forecast of EV sales percentages, total new light-duty vehicle sales, and the assumed EV charging load compare with the forecast used in the preparation of FBC's Application for Approval of Rate Design and Rates for EVCC Fast Charging Stations dated September 20, 2020?

Response:

The same forecast of EV sales percentages and total new light-duty vehicle sales was used in the LTERP and the Application for Approval of Rate Design and Rates for EVCC Fast Charging Stations (EV Rate Design Application). In both cases, the forecast was based on the *ZEV Act* Regulations Intentions Paper.[1] Note that there is a difference in the forecast horizon end years for the two applications: 2030 for the EV Rate Design Application, and 2040 for the LTERP.

Loads calculated in FBC's EV Rate Design Application consider only loads associated with FBC public fast charging stations. Loads calculated in the LTERP include those resulting from a much broader scope of light-duty EV charging, including residential home charging.

7.2 If there are any differences between the values relied upon in this and the FBC Rate Design and Rates for EV Fast Charging Stations process, please explain those differences.

Response:

Please refer to the response to BCOAPO IR1 7.1.

[1] B.C. Zero-Emission Vehicles Act: Regulations Intentions Paper, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/zev_act_regulations_intentions_paper-1-final_-_updated_29oct2019.pdf

8.0 Reference: Exhibit B-1, Vol. 1, pages 82, 89 and 90, Appendix G, page 7 and Appendix H, page 37

FBC's Annual Review for 2022 Rates Submission, page 19 and Appendix A-3, page 5

Preamble: The Application states (page 82): "The BAU is the forecast used for annual rate setting which is then extended out for the 20-year planning horizon. The Reference Case load forecast builds on the BAU forecast by including electric vehicle charging load, and new industrial loads with high confidence of materializing"

The Application states (page 89) the Reference load forecast includes:

- Electric Vehicle charging load forecast based on the ZEV Act light duty EV sales 20 targets (discussed in Section 2.2.3). These loads are included only in the Reference Case load forecast.
- New highly certain industrial customer loads, determined by FBC key account managers, include loads from a waste water treatment facility, a renewable energy facility and long term increases from a current forestry sector customer.

The Application states (page 90): "The BAU forecast includes new projects with near one hundred percent certainty of completion, and in the current forecast includes primarily cannabis production facilities."

Appendix H states: "No incremental EV sales (beyond those embedded in the business-as-usual forecast) are assumed for Scenario 2 (Lower Bound)."

FBC's Annual Review for 2022 Rates Submission states (Appendix A-3, page 5): "FBC assumes no new industrial customers in the current forecast unless there is a confirmed commitment from an industrial customer. FBC works with key account managers to identify new customers and existing customers with expansion plans that have committed contracts that are being added to the system."

8.1 Does the BAU forecast used in the LERTP build on the forecast used for setting 2021 rates or the forecast underpinning the current submission for 2022 rates?

<u>Response:</u>

The BAU forecast used in the LTERP is based on the same 2019 year end actual data that was used in FBC's Annual Review for 2020 and 2021 Rates Application for setting 2021 rates, except that DSM savings were removed.

The following table shows the historical data used in recent forecasts.

Forecast	Historical Data	Completed	DSM Savings included in forecast?
LTERP BAU	2019 Year End	April 2020	No
Annual Review for 2020/2021 Rates	2019 Year End plus 2020 Q3	October 2020 (Evidentiary Update)	Yes
Annual Review for 2022 Rates	2020 Year End	April 2021	Yes

The BAU forecast for the LTERP was completed in April 2020 to allow time for the preparation of the remainder of the LTERP components in order for FBC to be able to file the LTERP application in mid-2021. The forecast contained in the Annual Review for 2022 Rates application forecast was completed in April 2021 and therefore was not available for the LTERP analysis due to timing.

Please also refer to Section 3.3 for further information regarding the load forecast process for the LTERP.

8.2 If the BAU load forecast is based on the forecast used for 2021 rate setting, what adjustments were made to reflect the fact that a number of the new industrial customers (i.e., new cannabis production facilities) included in the forecast did not materialize (per page 19 of the Annual Review for 2022 Rates)?

Response:

As discussed in the response to BCOAPO IR1 8.1, due to time constraints, the timing of preparing the 2021 load forecast used for the LTERP BAU forecast was similar to that filed the Annual Review for 2020 and 2021 Rates Application. As a result the LTERP BAU forecast was not adjusted for industrial loads that did not later materialize.

FBC added the cannabis load to the 2021 industrial forecast because FBC had strong expectations that the loads would materialize based on discussions with potential customers. Some of the customers did commence limited operations in the commercial class, while some did not materialize. 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.

8.3 Does the BAU forecast include any additional new industrial customers apart from those incorporated in the rate setting load forecast?

Response:

The LTERP BAU forecast does not include any additional new industrial customers apart from those included in the 2021 forecast that was included in the Annual Review for 2020 and 2021 Rates application.

8.4 With reference to Appendix G, page 7, Table 2.6, please indicate for each of the forecast years, the new industrial customer load included in the BAU load forecasts

Response:

The new industrial customer load forecast included in the BAU forecast is provided in the following table. The new customers include six cannabis customers and one forestry customer.

BAU New Industrial Customer Loads (MWh)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
BAU Forecast													
2021F	5,482	4,591	4,415	6,404	6,529	6,942	7,468	7,950	6,235	6,568	7,694	9,331	79,610
2022F	10,127	8,178	7,931	7,089	7,251	6,942	7,468	7,950	6,235	6,568	7,694	9,331	92,764
2023F	10,127	8,178	7,931	7,089	7,251	6,942	7,468	7,950	6,235	6,568	7,694	9,331	92,764
2024F	10,127	8,178	7,931	7,089	7,251	6,942	7,468	7,950	6,235	6,568	7,694	9,331	92,764
2025F	10,367	8,360	8,110	7,241	7,413	7,099	7,638	8,131	6,371	6,713	7,866	9,544	94,854
2026F	7,819	7,871	7,971	7,459	7,564	8,449	8,084	8,076	7,715	8,175	8,338	7,952	95,473
2027F	7,880	7,932	8,033	7,517	7,622	8,514	8,147	8,139	7,775	8,238	8,402	8,013	96,212
2028F	7,942	7,995	8,096	7,576	7,683	8,582	8,211	8,203	7,836	8,304	8,469	8,077	96,974
2029F	8,003	8,057	8,159	7,635	7,742	8,648	8,274	8,267	7,897	8,368	8,534	8,139	97,723
2030F	8,058	8,112	8,215	7,687	7,795	8,708	8,331	8,324	7,951	8,425	8,593	8,195	98,394
2031F	8,115	8,169	8,272	7,741	7,850	8,768	8,389	8,382	8,007	8,484	8,653	8,252	99,080
2032F	8,170	8,224	8,328	7,793	7,903	8,828	8,446	8,439	8,061	8,542	8,711	8,308	99,753
2033F	8,224	8,279	8,384	7,845	7,956	8,887	8,503	8,495	8,115	8,599	8,770	8,364	100,419
2034F	8,276	8,331	8,437	7,895	8,006	8,943	8,556	8,548	8,166	8,653	8,825	8,416	101,053
2035F	8,329	8,385	8,491	7,945	8,057	9,000	8,611	8,603	8,218	8,708	8,881	8,470	101,698
2036F	8,379	8,435	8,542	7,993	8,106	9,054	8,663	8,655	8,268	8,761	8,935	8,521	102,314
2037F	8,431	8,488	8,595	8,043	8,156	9,111	8,717	8,709	8,319	8,815	8,990	8,574	102,948
2038F	8,487	8,544	8,652	8,096	8,210	9,171	8,774	8,766	8,374	8,873	9,050	8,631	103,628
2039F	8,542	8,599	8,708	8,148	8,263	9,230	8,831	8,823	8,428	8,930	9,108	8,686	104,294
2040F	8,598	8,656	8,765	8,202	8,317	9,291	8,889	8,881	8,484	8,989	9,168	8,744	104,984

8.5 Is there any EV charging load included in the BAU load forecast?

8.5.1 If yes, please indicate how much.

8.5.2 If yes, please indicate how this load was accounted for in the Reference Case load forecast in order to ensure there was no double counting.

Response:

There is some EV charging loads embedded in the historical loads which are used to forecast the residential and commercial loads. However, FBC is unable to determine the exact amount that is embedded in the historical loads because FBC's billing system cannot identify how customer energy is being allocated. Based on FBC's estimate of historical ZEV registrations in its service area, these EV loads are not material at this time.

The Reference Case EV load forecast is based on the *ZEV Act* targets which require an escalating annual percentage of new light-duty ZEV sales. The *ZEV Act* targets apply to new vehicle sales only, so there is no risk of double counting with the BAU forecast.

8.6 Reference is made (page 90) to FBC using the CBOC composite GDP growth rate to develop the industrial load forecast for the remainder of the planning horizon. How was the industrial load forecast developed (e.g., was the load assumed to grow at the same rates as the forecast GDP?)

Response:

The industrial load forecast is developed by surveying industrial customers for their projected forecasts for the five-year period from 2020 to 2024. If FBC receives no survey response, then the load from the previous year is escalated by the CBOC GDP sector growth rate for that customer for those five years. FBC then includes short-term energy forecasts for any new projects with near 100 percent certainty of completion, which is provided by FBC key account managers. After this, each individual customer load is escalated by an annual composite growth rate, which is an average of the CBOC long-term industrial sector growth rates for industries that are represented in the FBC industrial class.

8.6.1 If a regression analysis or some other form of analysis was used, please provide the equations/analytics employed.

Response:

CBOC GDP growth rates were used to forecast individual customer loads for customers that did not reply to the industrial survey, and for all industrial customers for forecast years 6 through 20. FBC does not use regression analysis to forecast the industrial class loads.

FBC provides the following analysis to demonstrate how the industrial customer load forecast is created. A fictitious customer is used in this hypothetical example, and the following assumptions have been made:

- The customer is in the agriculture sector.
- The customer did not reply to the industrial survey.
- The customer's 2019 actual load was 5,000 MWh.

<u>2020 to 2025</u>

Customers that do not respond to the survey are forecast individually based on their 2019 actual load and the GDP forecast for their sector.

The agriculture sector GDP growth rates (as a percentage) from the CBOC are known for 2020 through 2025 and are shown in the following table.

	2020	2021	2022	2023	2024	2025
CBOC Agriculture GDP (%)	3.0%	2.7%	2.7%	2.7%	2.7%	2.7%

The forecast load for 2020 through 2025 for this customer can be calculated based on the 2019 actual load (5,000 MWh) and the growth rates as shown in the following table. The calculation for the 2020 and 2021 loads is shown below:

$$2020\ \mathrm{Load} = 5{,}000 \times (1 + 3.0\%) = 5{,}148\ \mathrm{MWh}$$

$$2021\ \mathrm{Load} = 5{,}148 \times (1 + 2.7\%) = 5{,}287\ \mathrm{MWh}$$

The forecast loads for 2020 to 2025 are shown in the following table:

	2019	2020	2021	2022	2023	2024	2025
CBOC Agriculture GDP (%)		3.0%	2.7%	2.7%	2.7%	2.7%	2.7%
Example Customer Load (MWh)	5,000	5,148	5,287	5,430	5,577	5,728	5,883

<u>2026 to 2040</u>

For the period from 2026 through 2040, a weighted composite growth rate is calculated based on the FBC industrial loads in 2019 and the CBOC sector GDP forecasts. The weighted composite growth rate is applied to all industrial customers.

The calculations completed for 2026 are shown below and summarized in the following table:

- The 2019 aggregate load from the industrial sectors is summed in cell B14;
- The load is allocated by sector in column C. For example, the allocation for Agriculture in cell C2 is:

$$Agriculture\ allocation = \frac{16{,}283}{492{,}695} = 3.3\%\ ;$$

- The 2026 CBOC growth rates are shown in column D;
- In column E, the allocation (column C) is multiplied by the sector growth rate (column D);
- The composite growth rate for 2026 is the sum of the weighted growth rates and is shown in cell E14; and
- Remaining years of the forecast are calculated similarly.

	A	B	C	D	E
1	**CBOC List of Industries**	**2019 Load, MWh**	**Load Allocation by Sector (%)**	**2026 CBOC GDP Growth Rate**	**2026 Composite GDP Growth Rate**
2	AGRICULTURE	16,283	3.3%	2.7%	0.09%
3	FORESTRY	163,768	33.2%	-1.1%	-0.37%
4	MANUFACTURING	75,817	15.4%	1.1%	0.17%
5	CONSTRUCTION	3,002	0.6%	0.3%	0.00%
6	UTILITIES	8,450	1.7%	1.4%	0.02%
7	GOODS PRODUCING INDUSTRIES	12,083	2.5%	2.3%	0.06%
8	TRANSPORTATION & WAREHOUSING	647	0.1%	1.2%	0.00%
9	FINANCE, INSURANCE AND REAL ESTATE	5,533	1.1%	2.2%	0.03%
10	COMMERCIAL SERVICES	125,899	25.6%	1.5%	0.39%
11	EDUCATION SERVICES	37,794	7.7%	2.0%	0.15%
12	HEALTH CARE & SOCIAL SERVICES	28,244	5.7%	1.7%	0.10%
13	PUBLIC ADMINISTRATION AND DEFENCE	15,176	3.1%	0.7%	0.02%
14	**Total**	492,695			0.7%

Once the composite growth rate has been calculated for each year, the customer loads can be calculated. The 2026-2040 forecast load for the fictitious customer in this example is shown in the following table.

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
FBC Composite GDP (%)	0.7%	0.8%	0.8%	0.8%	0.7%	0.7%	0.7%	0.7%	0.6%	0.6%	0.6%	0.6%	0.7%	0.6%	0.7%
Example Customer Load (MWh)	5,921	5,967	6,014	6,061	6,102	6,145	6,187	6,228	6,267	6,307	6,346	6,385	6,427	6,468	6,511

Note that the final industrial forecast for 2026-2040 is the annual sum of all the industrial customers.

9.0 Reference: Exhibit B-1, Vol. 1, pages 41 & 89, Appendix F, page 9 and Appendix H, page 37

Preamble: The Application states (page 41): "Second, FBC is developing a rate for commercial customers who wish to install fleet or employee charging infrastructure for light-duty fleet and workplace vehicles."

The Application states (page 89): "GDP forecasts from the CBOC are used to forecast load for both the commercial and industrial classes."

Footnote 132 on page 89 indicates that the COBC GDP forecast was prepared in the first half of 2020.

Appendix F states: "The commercial load is forecast based on a regression analysis using the provincial GDP forecast from the CBOC."

Appendix F states: "The Reference Case forecast does not include any additional commercial loads compared to the BAU, so the BAU and reference case forecasts are identical."

With respect to medium and heavy duty EVs, Appendix H states: "No incremental EV sales (beyond those embedded in the business-as-usual forecast) are assumed for Scenario 2 (Lower Bound)."

9.1 Please provide the GDP forecast used by FBC for purposes of the LTERP.

Response:

The CBOC GDP forecast is provided in the table below. The data for the years 2021 to 2024 are from the *British Columbia, Preliminary Economic Forecast: Spring 2020* dated April 6, 2020 while the data for the years 2025 to 2040 are from the *Provincial Outlook Long-Term Economic Forecast for BC: 2020* dated December 4, 2019. The GDP forecasts used for the preparation of the LTERP are the most current ones available.

CBOC GDP at Basic Prices Forecast

Year	GDP Basic Prices ($2012 millions)
2021	258,884
2022	264,208
2023	267,544
2024	271,587
2025	280,784
2026	285,831
2027	290,941
2028	295,983
2029	301,019
2030	306,286
2031	311,781
2032	317,350
2033	322,693
2034	327,951
2035	333,391
2036	338,809
2037	344,373
2038	350,263
2039	356,249
2040	362,560

9.2 Is there more recent long-term GDP forecast available from the CBOC?

Response:

Please refer to the response to BCOAPO IR1 9.1.

9.2.1 If yes, please provide a schedule that compares the most update forecast available from the CBOC with that CBOC used in the LTERP.

Response:

Please refer to the response to BCOAPO IR1 9.1.

9.2.2 Further, if yes, what impact would using the updated forecast from the CBOC have on the Commercial and Industrial load forecasts and the resulting forecast load-resource balance?

Response:

Please refer to the response to BCOAPO IR1 9.1.

9.3 Please provide the regression equation used to forecast commercial load based on the provincial GDP forecast from the CBOC.

Response:

The expected commercial load in year *t* was forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$Before\ Savings\ Load_t = b_0 + b_1 \times GDP_t + Princeton\ Event_t + CoK\ Event_t$$

The Princeton $Event_t$ is a binary variable for the Princeton Light and Power (PLP) integration in 2007, CoK $Event_t$ is a binary variable for the City of Kelowna integration in 2013 and coefficients b_0 and b_1 are obtained from an ordinary least squares (OLS) regression analysis on the 2005 to 2019 data.

9.4 At page 41 FBC indicates that it is developing a rate for commercial customers who wish to install fleet or employee charging infrastructure for light-duty fleet and workplace vehicles. However, in Appendix F no incremental load for EV charging is added to the BAU forecast in order to derive the Reference Case load forecast. Please reconcile these two points and comment on to what extent the BAU load forecast and the Reference Case load forecast include EV charging load for commercial customers (e.g., medium and heavy duty EVs).

Response:

As discussed in Section 3.4.1, the Reference Case load forecast uses the BAU as the base and then adds EV charging and new highly certain industrial loads. This is because the BAU forecast is based on traditional load drivers inherent in the actual data, which does not contain any significant amounts of commercial fleet EV charging. Therefore, to capture the impacts of these emerging loads, FBC has developed the Reference Case load forecast. The EV charging loads included in the Reference Case load forecast are based on the *ZEV Act* light-duty EV sales targets. FBC assumes that the charging loads from light-duty EV sales targets will be met primarily through residential home charging, as well as commercial customer fleet charging; however, they were included only in the residential portion of the Reference Case load forecast for simplicity (please also refer to the response to BCUC IR1 7.1).

As the *ZEV Act* does not include targets for medium- and heavy-duty EVs, FBC has included these charging impacts in its load scenarios rather than the Reference Case load forecast.

10.0 Reference: Exhibit B-1, Vol. 1, Appendix F, page 11

Preamble: With respect to the Wholesale forecast, the Application states: "FBC's survey requested five years of data from wholesale customers. After that time period, an average of each individual customer's forecasted growth rate is used to project the long-term forecast."

10.1 What were the individual five-year growth rates for the six wholesale customers and what was the average forecast growth rate used for the period after the initial five years?

Response:

Survey respondents each provided five years of load forecast data, from which four annual growth rates were calculated. The growth rates for these four years are shown in the following table for 2020-2021 through 2023-2024.

Wholesale Growth Rates from 2020-2021 to 2024-2025

Wholesaler	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025
Grand Forks	-1.0%	0.8%	0.2%	1.4%	0.4%
Nelson	2.4%	-2.5%	-0.3%	0.9%	0.1%
Penticton	0.4%	0.4%	0.4%	0.4%	0.4%
Summerland	12.7%	11.9%	0.5%	0.5%	6.4%
Lardeau	4.0%	3.8%	3.7%	3.6%	3.8%
Kingsgate	-0.5%	-0.5%	-0.5%	-0.5%	-0.5%

The 2024-2025 growth rate is then calculated independently for each wholesale customer as the average growth rate from 2020-2021 through 2023-2024. The 2024-2025 growth rate is also shown in the above table.

The average forecast growth rate used for the period after the initial five years was developed by calculating the annual growth rates from the aggregate annual load forecast from 2020-2021 to 2024-2025. The average forecast growth rate is considered a weighted average because aggregate loads were used in the calculations. The average of these growth rates was 1.5 percent. The table below shows the aggregate forecast loads and the annual growth rates used to calculate the average growth rate.

Aggregate Wholesale Load Forecast from 2020 to 2025

	2020	2021	2022	2023	2024	2025	Average
Aggregate Wholesale Load Forecast, MWh	574,796	590,359	603,337	605,435	609,027	618,915	
Growth Rate		2.7%	2.2%	0.3%	0.6%	1.6%	1.5%

10.2 Is the average a straight average or is it weighted by the relative load for each wholesale customer?

Response:

Please refer to the response to BCOAPO IR1 10.1.

10.3 After the initial five-year period, what is the average growth rate for FBC's load – excluding the wholesale customers?

Response:

The average annual gross load growth rate from 2026 to 2040, with the wholesale load excluded, is 0.9 percent for the BAU forecast and 1.8 percent for the Reference Case load forecast.

11.0 Reference: Exhibit B-1, Vol. 1, pages 90-91 and Appendix F, page 6 2020 & 2021 Annual Review, Exhibit B-2, Appendix A-3, page 4

2022 Annual Review, Exhibit B-5, BCOAPO 7.3

Preamble: The Application states (page 90): "FBC receives a custom population forecast for its service territory from BC Stats."

The Application states (Appendix F, page 6): "Forecast residential customer counts are determined by a regression analysis of the year-end customer accounts on population in the FBC direct service area."

11.1 It is noted the Residential customer count forecast in the 2020 & 2021 Annual Review was based on 15 years of data (Exhibit B-2, Appendix A-3, page 4) while the customer count forecast in the 2022 Annual Review was based on 3 years of data (Exhibit B-5, BCOAPO 7.3). What was the historical period used in the LTERP to estimate the regression equation relating customer count to population and what was the resulting equation.

Response:

The residential customer count forecast used in the LTERP is the same one used in the 2020 and 2021 Annual Review for Rates application. FBC notes that the residential customer count forecast used twenty-five years of data and not fifteen years of data as noted above. The regression results are as follows:

Results of the Residential Customer Count Regression

Regression	Residential
Start Year	1995
End Year	2019
R^2	0.98
Adjusted R^2	0.98
df	24
Intercept	(23,964)
Slope Population	0.48

11.2 Based on the response to BCOAPO 7.3 from the 2022 Annual Review, is the approach used by FBC and the resulting residential customer count used in the LTERP reasonable?

Response:

The approach and resulting residential customer forecast used in the LTERP is reasonable. The short-term rate-setting forecast discussed in the response to BCOAPO IR1 7.3 from the 2022 Annual Review for Rates only included a forecast for 2022 and is updated annually. As noted in that response, FBC has recently observed higher customer additions than were previously experienced and, for the purposes of developing a reasonable short-term forecast, a shorter historical time frame was used. For the long-term forecast, it is more reasonable to assume the longer term historical trend will prevail, and that the recent increase in customer additions will not persist. As a result, 25 years of historical data was used for the development of the long-term forecast.

12.0 Exhibit B-1, Vol. 1, pages 90-91 and Appendix F, pages 5-9

Preamble: The Application states (page 91): "Customer usage is forecast by applying a ten-year trend to the normalized historical UPCs and then holding the UPC constant after the first five years."

The Application states (Appendix F, page 7): "The before-DSM UPC is forecast to decline from 10.15 MWh in 2021 to 9.44 MWh in 2024."

12.1 The forecast 2021 UPC used in the LTERP (10.15 MWh) does not match either the forecast 2021 UPC used in FBC's 2020 & 2021 Annual Rate Review (10.10 MWh per Exhibit B-2, page 17) or the projected 2021 UPC used in FBC's 2022 Annual Review Submission (10.29 MWh per Exhibit B-2, page 16). Please explain why and, in particular, if/how the population forecast and the regression equation used in the LTERP differs from those used in either of these two Annual Reviews.

<u>Response:</u>

The UPC forecast used in the LTERP is the same as that used for 2021 in the 2020 and 2021 Annual Review for Rates application, with the exception that DSM savings have not been deducted from the LTERP UPC forecast. This results in a difference of 0.05 MWh between the LTERP and 2020 and 2021 Annual Review 2021 UPC values.

The UPC forecast used in the LTERP is different to the one filed in FBC's 2022 Annual Review for Rates because the 2022 Annual Review customer and UPC forecast both used actual data up to and including 2020, whereas the LTERP forecast uses actual data up to and including 2019.

Please also refer to the response to BCOAPO IR1 8.1.

13.0 Exhibit B-1, Vol. 1, pages 87-88 & 126 and Appendix F, page 17

Preamble: The Application states (page 88): "FBC experienced an extended heat event and set a summer peak record of 764 MW on June 29, 2021, which exceeded the levels included in the summer peak forecast above, at least for 2021 through 2032. The data from this event will be captured in FBC's historical data and will be considered in future long-term forecasts."

The Application states (page 126): "The result is a "1 in 20" peak demand forecast which is not the same as the "expected" peak demand forecasts per the Reference Case load forecast shown in Section 3 of this LTERP."

The Application states (Appendix F, page 17): "Peak demand is the largest amount of capacity needed at one point in time on the FBC system due to high customer demand, and is affected by both weather and system growth. The peak demand forecast is calculated by escalating the ten year average (2010-2019) of historic peak data by the gross energy load growth rate."

The Application states (Appendix F, page 17): "Monthly peaks were calculated and then escalated by the annual energy load growth rates for the forecast period to produce forecast monthly peaks. The winter peak is the maximum forecast between the months of November and February and is usually on one of the coldest days of the year."

13.1 It is not clear from the two Appendix F references noted in the preamble precisely how the peak demand forecast is calculated. Please provide a schedule that sets out the derivation of the peak demand forecast.

Response:

The following explanation demonstrates the calculation of the BAU 2021 summer peak demand forecast. In this example, cells are identified based on their row and column. For example, the value "560" in row 2, column 3, will be identified by the following notation: (2,3).

In this example, actual monthly peak values are known up to and including 2019.

All values are in MW.

Figure 1: July Peaks

	1	2	3	4	5	6	7	8	9	10	11	12
1	Year	Gross Load Growth	Jul-10	Jul-11	Jul-12	Jul-13	Jul-14	Jul-15	Jul-16	Jul-17	Jul-18	Jul-19
2	2010		560									
3	2011	3.8%	582	503								
4	2012	-1.1%	575	497	510							
5	2013	2.2%	588	508	521	579						
6	2014	-1.1%	581	503	515	573	596					
7	2015	-1.9%	570	493	506	562	585	597				
8	2016	0.1%	571	494	506	562	585	598	579			
9	2017	6.2%	606	524	537	597	621	635	615	593		
10	2018	-1.8%	595	515	528	586	610	623	604	582	610	
11	2019	2.8%	612	529	543	603	627	641	621	599	627	562
12	2020	-0.1%	611	529	542	602	627	640	620	598	627	561
13	2021	3.0%	630	545	558	620	646	659	639	616	646	578

1. The value 560 in cell (2,3) in Figure 1 is the actual peak demand recorded in July 2010.
2. The peak in July 2010 cannot be used directly for forecasting in 2020, because of growth during the 10 years between 2010 and 2020.
3. The 2010 peak demand must be escalated to reflect the growth.
4. The gross demand load growth rates (column 2) are used to escalate the recorded peak demand values.
5. For example, the value in cell (3,3) is 582 and is calculated as follows:

$$582 = 560 \times (100\% + 3.8\%)$$

6. The value in cell (4,3) is 575 and is calculated as follows:

$$575 = 582 \times (100\% - 1.1\%)$$

7. The value in cell (5,3) is 588 and is calculated as follows:

$$588 = 575 \times (100\% + 2.2\%)$$

8. Finally, in cell (13,3) the escalated value of 630 is calculated.
9. Steps 5-8 are repeated for columns 4-12 to generate the remaining values of row 13 (green) above.
10. Steps 4-9 are repeated for August to produce the following table:

Figure 2: August Peaks

	1	2	3	4	5	6	7	8	9	10	11	12
1	Year	Gross Load Growth	Aug-10	Aug-11	Aug-12	Aug-13	Aug-14	Aug-15	Aug-16	Aug-17	Aug-18	Aug-19
2	2010		545									
3	2011	3.8%	566	519								
4	2012	-1.1%	560	513	540							
5	2013	2.2%	572	524	552	556						
6	2014	-1.1%	566	519	546	550	580					
7	2015	-1.9%	555	509	535	539	569	581				
8	2016	0.1%	555	509	536	540	570	582	590			
9	2017	6.2%	590	541	569	573	605	618	626	588		
10	2018	-1.8%	579	531	559	563	594	606	615	577	624	
11	2019	2.8%	595	546	574	579	611	624	633	594	642	623
12	2020	-0.1%	595	545	574	578	610	623	632	593	641	622
13	2021	3.0%	613	562	591	596	628	642	651	611	661	641

11. The design peak demand is computed by taking the maximum value from July-August for each year.

12. For example, the 2010 peak in July is 630 and is in cell (13,3) in Figure 1. The 2010 August peak is 613 and is in cell (13,3) in Figure 2. As a result, the 2010 July peak is used because it is larger than the August peak.

13. The process of choosing the maximum value from July and August (the summer peak) is repeated for all years, resulting in the following table:

Figure 3: Summer Peaks

	1	2	3	4	5	6	7	8	9	10	11	12
1	Year	Gross Load Growth	Summer 2007	Summer 2008	Summer 2009	Summer 2010	Summer 2011	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016
2	2021	3.0%	630	562	591	620	646	659	651	616	661	641

14. The green and blue cells in row 2 of Figure 3 indicate the month (green=July; blue=August) that the peak demand value was taken from. In five years out of ten, the peak summer consumption occurred in July.

15. The summer peak demand forecast is the simple average of row 2 from Figure 3. The forecast is 628 MW in cell (2,13) the table below.

Figure 4: Summer Peak

	1	2	3	4	5	6	7	8	9	10	11	12	13
1	Year	Gross Load Growth	Summer 2007	Summer 2008	Summer 2009	Summer 2010	Summer 2011	Summer 2012	Summer 2013	Summer 2014	Summer 2015	Summer 2016	Average
2	2021	3.0%	630	562	591	620	646	659	651	616	661	641	628

16. The winter peak is calculated by following the same procedure as shown above.

13.2 The reference from page 126 suggests that the peak demand forecast is meant to reflect "weather normal" (i.e., expected) conditions. However, the second reference from Appendix F suggests is based on actual historic peak data and captures extreme weather events. If not addressed in the previous question, please clarify what weather conditions the peak forecast is meant to reflect.

Response:

FBC prepares both a 1 in 10 and a 1 in 20 peak forecast for the LTERP. The 1 in 10 forecast uses normal or expected weather while the 1 in 20 forecast captures extreme weather events. Each forecast is described below.

1 in 10 Peak Demand Forecast:

The 1 in 10 peak demand forecast presented in Appendix F is the Reference Case peak demand forecast used for the LTERP to determine the peak demand requirements of FBC's customers under "normal" or "expected" weather conditions. The forecast monthly peak demand values are based on the actual historical peak demand averaged over a ten-year period, which normalizes for extreme weather events.

1 in 20 System Planning Peak Forecast:

The method for developing the 1 in 20 system planning peak forecast is the same as the 1 in 10 peak forecast method except the forecast monthly peak demand values are based on the maximum actual historical peak demand over a twenty-year period, which does not normalize for extreme weather events.

13.3 How would the forecast change if the data for 2020 and the first part of 2021 were also used in the calculation?

Response:

If the data from 2020 and particularly 2021 were used in the peak demand forecast calculation then the peak demand forecast would likely be higher. However, if the peak experienced in the summer of 2021 is determined to be an outlier then it would be improper to include it in the calculations and the results would be similar to those filed using data up to and including 2019.

To determine the outlier status, FBC has recently established a working group to investigate the 2021 summer heat impact. The working group is liaising with other utilities, including BC Hydro, to potentially learn about approaches being considered by others. The 2021 Heat Dome event is without precedent and the working group will attempt to determine whether this is an outlier or represents a potential ongoing trend.

13.4 Is the energy load forecast meant to reflect "weather normal" conditions?

Response:

FBC confirms the energy load forecast reflects normal weather conditions.

14.0 Reference: Exhibit B-1, Vol. 1, Appendix H, pages 5 and 11

14.1 Is the nameplate capacity of the residential solar PV installation assumed to be the same (i.e., 8 kW) when combined with storage? If yes, why?

Response:

The following response has been provided by Guidehouse.

Yes, the nameplate capacity of the residential solar PV installation is assumed to be the same (i.e., 8 kW) when combined with storage. Guidehouse used 8 kW as the nameplate capacity for residential PV both connected to storage and not connected to storage because the data summarizing average installed nameplate capacity in FBC's service territory does not distinguish between installations that are storage-enabled and those that are not.

14.2 Is the nameplate capacity of the commercial solar PV installation assumed to be the same (i.e., 20 kW) when combined with storage? If yes, why?

Response:

The following response has been provided by Guidehouse.

Yes, the nameplate capacity of the commercial solar PV installation is assumed to be the same (i.e., 20 kW) when combined with storage. Guidehouse used 20 kW as the nameplate capacity for commercial PV both connected to storage and not connected to storage because the data summarizing average installed nameplate capacity in FBC's service territory does not distinguish between installations that are storage-enabled and those that are not.

15.0 Reference: Exhibit B-1, Vol. 1, Appendix H, pages 27

Preamble: The Application states: "FBC examined peak hour data from the ten coldest and ten warmest days from 1997 forward. The peak hour as a percentage of peak day was determined to be approximately 5.4% of the peak day. The peak hour factor can be applied to the peak day from both the Normal or Scenario load duration curves to determine the peak impact from the scenario."

15.1 Has FBC or Guidehouse undertaken any analysis to determine if the peak hour hourly demand as a percentage of daily use changes with the average temperature for the day (i.e., is it reasonable to use 5.4% for Scenarios where higher/lower peak day temperatures are assumed)?

Response:

When considering the warmest and coldest ten days of each year from 1997 through 2019, the original analysis method determined that the peak hour was approximately 5.4 percent of the peak day.

To respond to this IR, the analysis was changed to use twenty random days each year instead of the ten warmest and ten coldest days. The remainder of the method was unchanged and the analysis was repeated ten times. In the random sample case, the peak hour was determined to be approximately 5.3 percent of the daily total load.

As a result, FBC believes that using 5.4 percent for all scenarios is reasonable.

16.0 Reference: Exhibit B-1, Vol. 1, Appendix H, pages 31 and 42

Preamble: The Application states: "This load driver quantifies the electricity consumption driven by the power requirements of CCS technologies used to capture carbon emissions from industrial processes."

The Application states (page 31): "The distribution of demand from CCS across the year is determined by the distribution of industrial CO2 emissions across the year".

The Application states (page 42): "Specifically, it assumed that FortisBC's electric service territory would account for approximately 10% of all provincial CCS deployment."

16.1 For what industries and types of industrial process are CSS technologies most likely to be applicable?

<u>Response:</u>

CCS technologies exist that are mature and market ready, as well as technologies that are currently in development. Mature and market ready CCS technologies are applicable to a range of industries. In BC, some of the most likely candidates for mature CCS technologies include mining, upstream gas production, pulp and paper, cement production, and renewable gas production. This list should not be considered exhaustive and will change as technology develops.

Newer CCS technologies that are in development or early commercialization may further expand the range of emission sources that can be addressed with CCS. These technologies include:

1. Direct Air Capture (DAC): Direct air capture removes CO_2 directly from the atmosphere. It offers an alternative to current point-source capture methods. DAC can be used to capture the emissions from many small sources of emissions such as residential home heating systems. Note that the proposed Huron Clean Energy Project[2] in Merritt, BC is projected to require up to 315 MW at peak demand. Similar technologies could be introduced within the FBC service territory to capture distributed emissions from both within and outside of the FBC territory.
2. Customer-scale carbon capture: CleanO2[3] has developed a carbon capture unit capable of capturing the GHG emissions from flue gases at a scale more in line with a commercial building. With further development this technology may be ready for deployment at sites such as hospitals, hotels, multifamily buildings, and recreation/aquatic centres.
3. Carbon mineralization in the mining sector: Ultramafic rocks commonly found in the tailings of mining processes in central BC have a natural affinity for CO_2. With further

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[2] https://www.huroncleanenergy.com/news/engineering-begins-on-large-scale-commercial-facility-in-canada-to-produce-fuel-from-air

[3] https://cleano2.ca/

technology development, rock from mine tailings may be used to capture CO_2 either from the mining processes themselves or from the atmosphere.

4. Bioenergy with carbon capture and storage (BECCS): Renewable Gas facilities, such as the existing Kelowna Biogas Plant, produce an exhaust stream of high purity, biogenic carbon dioxide. As CCS technologies mature, they can be integrated in biogas upgrading facilities. The deployment of BECCS allows Renewable Gas facilities to increase their GHG reduction benefits.

5. Integration with hydrogen production: hydrogen can be produced by reforming natural gas and capturing the CO_2 emissions (blue hydrogen with CCS) or by methane pyrolysis (turquoise hydrogen), which captures carbon in the form of carbon black. With improvements in the technology and the ability to avoid increasing carbon tax charges, this form of hydrogen production is expected to become a cost effective solution for reducing emissions.

The assumption that the FBC service territory will account for 10 percent of provincial CCS deployment was based on the percentage of the annual natural gas consumption in FBC's service territory when compared to the overall provincial annual consumption. The economics and effectiveness of CCS technologies are dependent on the concentration of CO_2 in the exhaust stream; therefore, not all natural gas end users in the FBC service territory will have the opportunity to use CCS at the point of combustion.

16.2 How prevalent are these industries/industrial processes in FBC's service territory?

Response:

There are currently no CCS industries or processes in the FBC service territory.

Industries with the potential for CCS include cement production, pulp and paper, and renewable gas (RG) production. Based on the number and size of facilities, as well as current production levels, the cement production and pulp and paper facilities represent only a small opportunity for CCS in the FBC service territory. In contrast, RG production has significant potential for CCS. There is currently one RG facility operating in the FBC territory and it is anticipated that more will be added in the near future.

16.3 How does the output from these industries/industrial process located in FBC's service territory compare with the total output in BC from these industries/industrial processes? In particular, is the proportion close to 10%?

Response:

As Guidehouse stated in footnote 88 on page 42 of Appendix H, the 10 percent value is "derived from the observation that FortisBC's shared service territory consumed approximately 40 PJ of natural gas in 2018, while the province as a whole, per the Canadian Energy Regulator's Canada's Energy Futures 2019 database, consumed approximately 396 PJ of natural gas in the same year." However, FBC does not have the data to verify such a comparison for the specific industries in question.

17.0 Reference: Exhibit B-1, Vol. 1, Appendix H, page 40
2022 Annual Review, Exhibit B-2, page 19

Preamble: With respect to Large Load Sector Transformation, Appendix H states: "The scenario-specific assumptions were informed by Guidehouse's estimates of current existing, or 100% confidence connection request- driven, floorspace in these two sub-sectors."

Appendix H also states: "Guidehouse estimates that there are currently approximately 200,000 square feet of data centre floorspace, and (based on existing and 100% confidence connection requests) that by 2021 there will be approximately one million square feet of commercial floorspace dedicated to cannabis production."

The 2022 Annual Review submission stated: "FBC's 2021 Approved included 68 GWh of additional cannabis load; however, at this time, none of those customers have taken service in the industrial class. As a result, those loads have been removed from the current forecast."

17.1 What is FBC's current estimate as to square feet of commercial floor space dedicated to cannabis production that will be connected to its system by the end of 2021?

Response:

FBC estimates that there is currently 800,000 square feet of commercial floor space dedicated to cannabis production in the FBC service territory at the end of 2021.

17.1.1 To the extent this differs from the assumption used by Guidehouse, how does this affect results of the five scenarios?

Response:

FBC does not expect that the difference between FBC's estimate (800 thousand square feet) and the Guidehouse estimate (one million square feet) at the end of 2021 will affect the results of the five load scenarios as FBC expects that some of the delayed cannabis facilities will instead come online in the coming years, thus achieving a result close to the one million square foot estimate, albeit slightly delayed. Regardless, as the load scenarios are based on high-level estimates for cannabis facility floor space by 2040, FBC does not expect that this somewhat lower 2021 starting floor space estimate would have altered the 2040 penetration assumptions.

17.1.2 If this differs from the assumptions used by Guidehouse, please explain the reason for the difference.

Response:

The difference between FBC's estimate (800 thousand square feet) and the Guidehouse estimate (one million square feet) is likely due to a number of factors, including market fluctuations (e.g., legalized cannabis is a new market, which comes with uncertainty in product demand), licensing delays, and other construction/implementation delays related to the COVID-19 pandemic. FBC expects that some of the delayed facilities may come online in the next few years.

17.2 What is the load impact (GWh and MW) associated with the "100% confidence connection requests that have not yet connected" referred to in Appendix H?

Response:

The forecast energy load (GWh) impacts for the 100 percent confidence connection requests that are not yet connected and that were included in the BAU and Reference Case load forecast are provided in the table below. FBC cannot provide the capacity (MW) impacts since the peak forecast is based on the gross load forecast and is not broken down by class.

100% Confident Connection Request Load Impacts

Year	Load Impact (GWh)
2021	80
2022	93
2023	93
2024	93
2025	95
2026	95
2027	96
2028	97
2029	98
2030	98

Year	Load Impact (GWh)
2031	99
2032	100
2033	100
2034	101
2035	97
2036	98
2037	98
2038	99
2039	100
2040	100

17.3 Appendix H also states that "the impacts presented below are derived only from the incremental floor space assumed for the modeling (i.e., the results do not include the impacts of the 100% confidence connection requests that have not yet connected)." Are the impacts of the 100% confidence connection requests included in either: i) the BAU load forecast or ii) the Reference Case load forecast?

Response:

The impacts of the 100 percent confidence connection requests that have not been connected are included in the industrial class of the BAU forecast and are therefore also included in the Reference Case load forecast.

18.0 Reference: Exhibit B-1, Vol. 1, pages 112 - 113

Preamble: Table 5.1 sets out FBC's 2021 available energy and dependable capacity resources.

The Application states (page 113): "In exchange for permitting BC Hydro to determine the output of these facilities, the Entitlement Parties are contractually entitled to their respective "entitlements" of energy and capacity from BC Hydro. The Entitlement Parties receive their entitlements irrespective of actual water flows to the relevant generating plants and are thus insulated from the annual hydrology risk of water availability."

18.1 Is FBC's contractual entitlement to capacity and energy from the four hydraulic generating stations it owns the same regardless of the actual water flows and available generation from the plants?

Response:

FBC confirms the dependable capacity and available energy for FBC CPA Entitlement resources are equal to the associated entitlements under the Canal Plant Agreement. The entitlements, both capacity and energy, are fixed, regardless of the actual water flows. However, entitlement capacity and energy is subject to reductions based on unit outages.

18.1.1 If yes, is the dependable capacity from FBC-owned generating plants and the associated entitlements under the Canal Plant Agreement (per Table 5.1) equivalent to FBC's contractual capacity entitlement?

Response:

Please refer to the response to BCOAPO IR1 18.1.

18.1.2 If the FBC contractual capacity entitlement varies with the available water flows/generation, then how is FBC's dependable capacity from these plants (as set out in Table 5.1) determined?

Response:

Please refer to the response to BCOAPO IR1 18.1.

18.2 What is the basis for Available Energy associated with the FBC-owned generating plant (per Table 5.1)?

Response:

Please refer to the response to BCOAPO IR1 18.1.

19.0 Reference: Exhibit B-1, Vol. 1, pages 112 and 115

Preamble: Table 5.1 sets out FBC's 2021 available energy and dependable capacity resources.

The Application states (page 115): "Under the BPPA, which expires in 2056, FBC has agreed to purchase (a) the energy and capacity entitlement allocated to the Brilliant Plant pursuant to the CPA and (b) after the termination, if any, of the CPA, the actual electrical output generated by the Brilliant Plant."

19.1 Is FBC's contractual entitlement to capacity and energy under the BPPA the same regardless of the actual water flows and available generation from the Brilliant plant?

Response:

FBC confirms the dependable capacity and available energy for BPPA resources are the associated entitlements under the Canal Plant Agreement, contracted by FBC through the BPPA. These entitlements, both capacity and energy, are fixed, regardless of the actual water flows. However, entitlement capacity and energy is subject to reductions based on unit outages.

19.1.1 If yes, is the dependable capacity from the BBPA (per Table 5.1) equivalent to FBC's contractual capacity entitlement?

Response:

Please refer to the response to BCOAPO IR1 19.1.

19.1.2 If the FBC's contractual capacity entitlement varies with the available water flows/generation, then how is the BBPA's dependable capacity (as set out in Table 5.1) determined?

Response:

Please refer to the response to BCOAPO IR1 19.1.

19.2 What is the basis for Available Energy associated the BBPA (per Table 5.1)?

Response:

Please refer to the response to BCOAPO IR1 19.1.

20.0 Reference: Exhibit B-1, Vol. 1, page 112 and 115

Preamble: Table 5.1 sets out FBC's 2021 available energy and dependable capacity resources.

The Application states (page 115): "FBC has entered into a ten-year power purchase agreement with Columbia Power Corporation (CPC), as of June 10, 2017. Under this agreement, FBC has agreed to purchase a portion of the capacity and energy entitlements attributed to BRX from Brilliant Power Corporation. This agreement expires as of December 31, 2027, and within this Application, renewal is not assumed beyond that date."

20.1 Is FBC's contractual entitlement to capacity and energy under the BRX agreement the same regardless of the actual water flows and available generation?

<u>Response:</u>

FBC confirms the dependable capacity and available energy for the BRX resource is a portion of the associated entitlements under the Canal Plant Agreement, contracted by FBC through the ten-year power purchase agreement with CPC. These entitlements, both capacity and energy, are the same regardless of the actual water flows. However, entitlement capacity and energy is subject to reductions in the case of unit outages.

20.1.1 If yes, is the dependable capacity from the BRX agreement (per Table 5.1) equivalent to FBC's contractual capacity entitlement?

<u>Response:</u>

Please refer to the response to BCOAPO IR1 20.1.

20.1.2 If the FBC's contractual capacity entitlement varies with the available water flows/generation, then how is the BRX agreement's dependable capacity (as set out in Table 5.1) determined?

<u>Response:</u>

Please refer to the response to BCOAPO IR1 20.1.

20.2 What is the basis for Available Energy associated the BRX agreement (per Table 5.1)?

Response:

Please refer to the response to BCOAPO IR1 20.1.

21.0 Reference: Exhibit B-1, Vol. 1, page 112 and 115-116

Preamble: Table 5.1 sets out FBC's 2021 available energy and dependable capacity resources.

The Application states (page 116): "Under the WAX CAPA, FBC has agreed to purchase from the Waneta Expansion Power Corporation all unused WAX-related capacity (residual capacity) that remains after BC Hydro has acquired the energy entitlements associated with the plant (as defined by the CPA). FBC began receiving power under the WAX CAPA on April 2, 2015, and the agreement is for a 40 year term that expires on April 2, 2055. The capacity entitlements obtained by FBC under the WAX CAPA vary by month and are suitably shaped to meet FBC's winter and summer peak demand requirements when capacity is needed the most and provides less capacity during the three freshet months when it is needed the least."

21.1 Is FBC's contractual entitlement to capacity and energy under the WAX CAPA the same regardless of the actual water flows and available generation?

Response:

FBC confirms the dependable capacity for the WAX CAPA resource is a portion, or all residual capacity, of the associated entitlement under the Canal Plant Agreement, contracted by FBC through the WAX CAPA agreement with WEPC. This entitlement, which is for capacity only (i.e., no energy is included) is the same regardless of the actual water flows. However, entitlement capacity is subject to reductions based on unit outages.

21.1.1 If yes, is the dependable capacity from the WAX CAPA (per Table 5.1) equivalent to FBC's contractual capacity entitlement?

Response:

Please refer to the response to BCOAPO IR1 21.1.

21.1.2 If the FBC's contractual capacity entitlement varies with the available water flows/generation, then how is the WAX CAPA dependable capacity (as set out in Table 5.1) determined?

Response:

Please refer to the response to BCOAPO IR1 21.1.

21.2 What is the basis for Available Energy associated the WAX CAPA (per Table 5.1)?

Response:

Please refer to the response to BCOAPO IR1 21.1.

22.0 Reference: Exhibit B-1, Vol. 1, pages 121, 124 and 126

Preamble: The Application states (page 126):

"The system planning forecast is a per-substation forecast that is developed from the "bottom up" using historical per-feeder peak demand data. The per-feeder data is aggregated to the substation level and then by area for use in transmission and distribution infrastructure project identification and planning. The feeder and substation forecasts are based on actual demand peaks, which are typically recorded during weather extremes in the summer (June through August) and in the winter (November through February). The substation forecast forms the basis for the expected future winter and summer peak loads and is used to determine the adequacy of the transmission, substation, and distribution infrastructure required to supply FBC's customers during peak demand periods."

22.1 Are forecasts prepared for each individual feeder and then aggregated to obtain a forecast for each substation?

Response:

FBC confirms each individual feeder's demand is forecast using seasonal peaks and the substation or transformer forecast is the sum of the feeder's seasonal peak demand attached to the substation or transformer. Additionally, for the transformers, the peak demand is then multiplied by the corresponding diversity factor.

The purpose of the diversity factors is to calculate the seasonal diversity factor for each transformer based on historical load profiles. The diversity factor is calculated as transformer peak divided by the sum of the connected feeder peaks.

The forecast diversity factors are based on the average of the past five years.

22.1.1 If yes, please describe how the feeder level forecasts are calculated and provide an illustrative example.

Response:

The forecasting method includes calculations based on the summer and winter peaks over the last five years. FBC calculates the slope of regression for the seasonal peak values from the last five years and then applies that slope to the maximum seasonal peak values from the last five years to forecast future years' peak values. This method works well to identify slowly or rapidly growing loads on specific feeders. The forecast also takes into consideration regional growth rates, large load developments, and planned load transfers.

The following table shows an illustrative example of the calculation for the KRE3 feeder forecast. The table shows historical actuals from 2016 to 2020 and forecast values from 2021 to 2026 (all in kVA).

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1					Actuals					Forecast					
2	Region	Feeder	Capacity	Season	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
3	NOK	KRE3	13262	Summer	4388	4411	4353	4524	4670	4938	5078	5103	5183	5232	5347
4	NOK	KRE3	13262	Winter	4295	4202	4061	4559	4235	4783	4809	4844	4872	4936	5007

- The following steps show how the summer 2021 forecast value is calculated:
- Maximum summer actual value from 2016 to 2020 = 4,670
- Slope of the regression of summer actual values for 2016 to 2020 = 68
- Planned load developments for 2021 = 200
- Sum of the above components to determine 2021 summer forecast = 4,938

Next, the forecast values for years after 2021 are calculated based on the following formula:

- Following year's forecast = previous year's forecast x forecast regional growth rate +/- highly probable load developments +/- known feeder switching

As an example, the following steps shows how the summer 2022 forecast value is calculated:

- Previous year (2021) summer forecast value = 4,938
- Regional growth rate = 1.0284
- No adjustments for highly probable loads or feeder switching for 2022 were required
- Applying the formula to the components above determined the 2022 summer forecast = 5,078

22.1.2 If yes, is there any allowance made for diversity when summing the individual feeder forecasts to derive a substation forecast?

Response:

Please refer to the response to the BCOAPO IR1 22.1.

22.1.3 If yes, how is the quantum of this "allowance" determined?

Response:

Please refer to the response to the BCOAPO IR1 22.1.

22.1.4 If not, please describe how the substation forecasts are calculated and provide an example.

Response:

Please refer to the response to BCOAPO IR1 22.1.

22.2 The Application indicates that substation forecasts are aggregated by "area". What are the "areas" over which the substation forecasts are aggregated (e.g. are they the "regions" referenced in Table 6.1 or the two broad areas consisting of the Kootenay area and Okanagan area as discussed on page 124)?

Response:

The areas are the same as the regions referenced in Table 6-1.

22.3 When substation forecasts are aggregated by area, is there any allowance made for diversity when summing the individual substation forecasts to derive an area forecast?

22.3.1 If yes, how is this "allowance" determined?

Response:

Please refer to the response to the BCOAPO IR1 22.1.

22.4 For what specific transmission facilities are the "area" forecasts used to determine the adequacy?

Response:

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. These assessments are used to determine whether any infrastructure upgrades are required (i.e., if additional transformation, re-conductoring of existing transmission lines, or construction of new transmission lines or stations, is needed).

23.0 Reference: Exhibit B-1, Vol. 1, page 126

Preamble: The Application states:

"Recognizing that these per-substation forecasts represent load peaks that may or may not occur at the same time, it is necessary when aggregating the per-substation forecasts to account for customer load diversity within the system. 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."

23.1 For purposes of assessing the adequacy of individual substations, is the original substation load forecast used or the "scaled" forecast? If the scaled forecasts are used, please explain why this is considered to appropriate for planning the substation level?

Response:

For distribution substations, the original distribution substation load forecast values are used.

23.2 Please explain more fully how the forecasting the total system load from the "top down" under extreme (i.e. one occurrence in 20 years) weather conditions is forecasted and provide an illustrative example.

Response:

The following explanation demonstrates the calculation of the BAU 2021 summer peak demand 1 in 20 forecast. In this example, cells are identified based on their row and column. For example, the value "445" in row 2, column 3, is identified by the following notation: (2,3).

In this example, actual monthly peak values are known up to and including 2019.

All values are in MW.

Figure 1: July Peaks

JULY	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1	Year	Gross Load Growth	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2	2000		445																			
3	2001	1.1%	450	471																		
4	2002	3.3%	465	486	485																	
5	2003	1.8%	473	495	494	505																
6	2004	1.5%	480	502	501	512	478															
7	2005	3.6%	498	521	519	531	495	516														
8	2006	1.7%	506	530	528	540	504	525	558													
9	2007	0.1%	507	531	529	541	505	525	559	562												
10	2008	-0.3%	506	529	528	540	503	524	558	560	528											
11	2009	2.3%	517	541	540	552	515	536	570	573	540	561										
12	2010	-4.4%	494	517	516	528	492	512	545	548	516	536	552									
13	2011	3.8%	513	537	536	548	511	532	566	569	536	557	573	493								
14	2012	-1.1%	508	531	530	542	505	526	560	563	530	551	567	487	503							
15	2013	2.2%	519	543	541	554	516	537	572	575	542	563	579	498	514	572						
16	2014	-1.1%	513	537	535	547	511	532	566	569	536	556	573	493	508	566	587					
17	2015	-1.9%	503	527	525	537	501	521	555	558	525	546	562	483	499	555	576	587				
18	2016	0.1%	504	527	526	538	502	522	555	558	526	546	562	484	499	555	576	588	569			
19	2017	6.2%	535	560	558	571	532	554	590	593	558	580	597	514	530	590	612	624	604	585		
20	2018	-1.8%	525	550	548	560	523	544	579	582	548	570	586	504	520	579	601	613	593	574	604	
21	2019	2.8%	540	565	563	576	538	560	595	599	564	586	603	519	535	596	618	630	610	591	621	553
22	2020	-0.1%	540	565	563	576	537	559	595	598	563	585	602	518	535	595	617	629	609	590	621	552
23	2021	3.0%	556	582	580	593	553	576	613	616	580	603	621	534	551	613	636	648	628	608	639	569

1. The value 445 in cell (2,3) in Figure 1 is the actual peak recorded in July 2000.
2. The peak in July 2000 cannot be used directly for forecasting in 2020, because of growth during the 20 years between 2000 and 2020.
3. The 2000 peak demand must be escalated to reflect the growth.
4. The gross load growth rates (column 2) are used to escalate the recorded peak demand values.
5. For example, the value in cell (3,3) is 450 and is calculated as follows:

$$450 = 445 \times (100\% + 1.1\%)$$

6. The value in cell (4,3) is 465 and is calculated as follows:

$$465 = 445 \times (100\% + 3.3\%)$$

7. The value in cell (5,3) is 473 and is calculated as follows:

$$473 = 465 \times (100\% + 1.8\%)$$

8. Finally, in cell (23,3) the escalated value of 556 is calculated.

9. Steps 5-8 are repeated for columns 4 to 22 to generate the remaining values of row 23 (green) above.

10. Steps 4-9 are repeated for August to produce the following table:

Figure 2: August Peaks

AUGUST	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1	Year	Gross Load Growth	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2	2000		463																			
3	2001	1.1%	468	453																		
4	2002	3.3%	484	468	436																	
5	2003	1.8%	492	476	444	491																
6	2004	1.5%	500	483	450	498	512															
7	2005	3.6%	518	501	467	516	531	506														
8	2006	1.7%	527	510	475	525	540	515	435													
9	2007	0.1%	528	510	476	526	541	515	435	527												
10	2008	-0.3%	526	509	474	525	539	514	434	526	541											
11	2009	2.3%	538	521	485	537	552	526	444	538	553	534										
12	2010	-4.4%	514	498	464	513	527	502	424	514	529	510	539									
13	2011	3.8%	534	517	482	533	547	522	441	534	549	530	560	514								
14	2012	-1.1%	528	511	476	527	541	516	436	528	543	524	553	508	530							
15	2013	2.2%	540	522	487	538	553	527	445	539	555	536	566	519	542	549						
16	2014	-1.1%	534	516	481	532	547	521	440	533	549	530	559	514	536	543	570					
17	2015	-1.9%	524	506	472	522	537	511	432	523	538	520	549	504	525	533	559	574				
18	2016	0.1%	524	507	472	523	537	512	432	524	539	520	549	504	526	533	560	575	583			
19	2017	6.2%	556	538	502	555	570	544	459	556	572	552	583	535	558	566	594	610	619	577		
20	2018	-1.8%	546	529	493	545	560	534	451	546	562	542	573	526	548	556	583	599	608	567	614	
21	2019	2.8%	562	544	507	560	576	549	464	561	578	558	589	541	564	572	600	616	625	583	631	614
22	2020	-0.1%	561	543	506	560	575	548	463	561	577	557	588	540	563	571	600	615	624	582	631	613
23	2021	3.0%	578	559	521	577	593	565	477	578	595	574	613	557	580	588	618	642	643	600	650	632

11. The design peak is computed by taking the maximum value from July-August for each year.

12. For example, the 2000 peak in July is 556 and is in cell (23,3) in Figure 1. The 2000 August peak is 578 and is in cell (23,3) in Figure 2. As a result, the 2000 August peak is used because it is larger than the July peak.

13. The process of choosing the maximum value from July and August (the summer peak) is repeated for all years, resulting in the following table:

Figure 3: Summer Peaks

Summer	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
1	Year	Gross Load Growth	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
2	2021	3.0%	578	582	580	593	593	576	613	616	595	603	621	557	580	613	636	648	643	608	650	632

14. The green and blue cells in row 2 of Figure 3 indicate the month (green=July; blue=August) that the peak demand value was taken from. In 12 years out of 20, the peak summer consumption occurred in July.

15. The summer peak forecast is the maximum value of row 2 from Figure 3. The forecast is 650 MW in cell (2,13) the table below.

Figure 4: Summer Peak

Summer	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	Year	Gross Load Growth	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Max
2	2021	3.0%	578	582	580	593	593	576	613	616	595	603	621	557	580	613	636	648	643	608	650	632	650

16. The winter peak is calculated by following the same procedure as shown above.

23.3 Are there any specific transmission facilities for which the total system peak load forecast is used to assess adequacy?

<u>Response:</u>

No, the total system peak load is scaled to all stations throughout FBC's system to determine adequacy of transmission level facilities.

24.0 Reference: Exhibit B-1, Vol. 1, page 130

24.1 With respect to Table 6-3, please explain the difference in the circumstances under which "capacity" vs. "reliability" is the driver. In doing so please explain how each is related to the (N-0) and the (N-1) planning criteria?

Response:

In general terms, projects that are required to meet N-0 planning criteria are considered "capacity" projects, whereas projects that are required to meet N-1 planning criteria area considered "reliability" projects. The projects listed in Table 6-3 are all primarily driven by reliability needs. Capacity was also identified as a driver for most projects in this table since load exceeding a given threshold is the trigger for the required project timing.

24.2 Which of the projects in Table 6-3 are driven by the peak load forecast at the substation level, the area level versus the overall system level?

Response:

All of the projects in Table 6-3 are driven by the overall system peak load forecast as scaled to the area impacted by each proposed project.

25.0 Reference: Exhibit B-1, Vol. 1, page 131

2022 Annual Review, Exhibit B-2, page 19

Preamble: The Application states (page 131):

"As shown in Table 6-3 above, recent system studies indicate that the 20L Upgrade project will not be required until the late-2020s based on recent load forecasts. However, due to recent transmission interconnection requests and interest from new large load customers in 2021, this project may be required sooner. FBC is currently considering options and may bring forward a CPCN application to the BCUC if necessary."

The 2022 Annual Review submission stated: "FBC's 2021 Approved included 68 GWh of additional cannabis load; however, at this time, none of those customers have taken service in the industrial class. As a result, those loads have been removed from the current forecast."

25.1 Does the change in expectations regarding new industrial load referenced in the 2022 Annual Review submission impact the timing of the 20L Upgrade project?

Response:

The change in expectations for cannabis load discussed in the 2022 Annual Review for Rates application does not impact the timing of the 20L upgrade project. The timing of the requirement to upgrade sections of 20L is based on the request of a separate, large customer unrelated to cannabis production.

25.2 Does the change in expectations regarding new industrial load referenced in the 2022 Annual Review submission impact the timing of any of the other projects set out in Table 6-3?

Response:

The rest of the projects listed in Table 6-3 are required based on FBC's 2021 Power Flow and Transient Stability Analysis Report and the respective load forecast. The projects are not impacted by the referenced additional cannabis load not yet materializing. FBC's timing for projects changes as annual studies are completed with updated information. Longer-term projects are subject to further review as load growth trends become more certain in the future.

26.0 Reference: Exhibit B-1, Vol. 1, page 133

Preamble: The Application states:

"Notwithstanding the limited impacts at current adoption rates, the potential future impacts on transmission and distribution system planning and operations are more complex. Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation. Distributed solar PV increases the complexity of managing voltage regulation on distribution feeders due to its intermittent nature. These facilities will have increasing impacts on the distribution system first and then the transmission system later as DG growth continues."

26.1 Can DG impose additional costs on the transmission or distribution systems (relative to the circumstances where they are not installed) that are not covered by customer contributions? If so, what circumstances would give rise to such "costs"?

Response:

FBC confirms that DG can impose additional costs on the transmission or distribution systems (relative to the circumstances where they are not installed) that are not covered by customer contributions.

In the context of small distributed systems (like net-metered PV), which is the focus of Section 6.5.1 of the Application, in the event that work is required on the distribution and transmission systems to manage the proliferation of DG, associated costs are not likely to be offset by customer contributions. This would be the case regardless of what circumstances gave rise to the additional costs because the incremental nature of the small DG additions will result in the system upgrade costs being recovered through the rates of all customers.

27.0 Reference: Exhibit B-1, Vol. 1, page 134

Preamble: With respect to large scale customers, the Application states:

"To accommodate these service requests and depending on the site selected by the customer, infrastructure reinforcements may be required to meet planning criteria during normal or contingency operations. These infrastructure reinforcements may include, but are not limited to, upgrading substation capacity or upgrading transmission lines."

27.1 Please comment on the timeframe required to put these kinds of infrastructure reinforcements in place as compared to 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 connection actually occurring/the customer requiring power.

Response:

The average lead time between the decision to start planning and the in-service date for infrastructure reinforcements is about five years.

28.0 Reference: Exhibit B-1, Vol. 1, page 137

Preamble: The Application states:

"Table 6-6 includes additional projects required to meet the additional peak demand requirements of the Kelowna area at the 550 MW level. The Deep Electrification, Diversified Energy Pathway and Alternate scenarios each exceed 550 MW by 2040, before mitigation, and so would have an additional estimated project cost of $710 million in order to meet the additional peak demand by 2040."

28.1 Table 6-6 set out a number of projects totaling $710 M in costs. The title for Table 6-6 is "Additional Projects Required to meet 550 MW Peak Demand by 2040 ($ millions)". However, the later part of the text cited in the preamble suggests that $710 M is the additional costs required if peak demand in the Kelowna area exceeds 550 MW. Please clarify.

Response:

The projects in Table 6-6 are required when the Kelowna peak demand meets or exceeds 550 MW.

28.1.1 What level of demand requirements in the Kelowna area can be met with the projects set out in Table 6-5?

Response:

The projects listed in Table 6-5 will allow FBC to meet Kelowna area peak demand requirements up to 430 MW.

28.1.2 If Table 6-6 is the cost of projects required to meet a Kelowna area demand of 550 MW what are the additional costs that would need to be incurred under those scenarios (i.e., the Deep Electrification, Diversified Energy Pathway and Alternate scenarios) where demand exceeds 550 MW?

Response:

FBC has not identified any additional transmission projects or costs in order to serve the Kelowna area for the Deep Electrification, Diversified Energy Pathway, or Alternate scenarios where demand exceeds 550 MW. Please also refer to the response to BCOAPO IR1 28.1.

29.0 Reference: Exhibit B-1, Vol. 1, page 145

Preamble: The Application states: "The capacity LRB figures assume that 200 MW of capacity is available to FBC from the PPA, but can be reduced if not required to meet the load forecast."

29.1 Under the current PPA does FBC only pay for the capacity it actually "takes" from BCH (up to 200 MW) or does it pay for 200 MW regardless of whether or not the full 200 MW is "taken"?

Response:

As outlined in the Billing Demand section of BC Hydro's Rate Schedule 3808 from BC Hydro's Electric Tariff, the Billing Demand in any Billing Month will be the greatest of:

a) The maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement, for any hour of the Billing Month;

b) 75 percent of the maximum amount of Electricity (in kW) scheduled under the Power Purchase Agreement in any hour in the 11 months of the Term immediately prior to the Billing Month (or less than 11 months, if the Effective Date is less than 11 months prior to the month); and

c) 50 percent of the Contract Demand (in kW) for the Billing Month.

30.0 Reference: Exhibit B-1, Vol. 2, page 7 and Appendix A, pages 18 and 22

Preamble: The Application states (page 7):

"After calibrating the 2019 base year to actual utility energy sales, Lumidyne generated a reference case forecast that estimates the electricity demand over the CPR period absent incremental DSM activities. The technical and economic potential scenarios were then calculated against the reference case forecast. Lumidyne used two key inputs to construct the reference case forecast for each customer sector: stock growth rates and energy use intensity trends."

The Application states (Appendix A, page 18):

"In brief, the Reference Case stems from actual 2019 consumption captured by the Base Year, follows FortisBC's 2021 Long Term Electric Resource Plan's (LTERP's) sector-level consumption forecast, and includes observed trends in EUIs from multiple data sources."

The Application states (Appendix A, page 22):

"To conclude this section on the Reference Case, it is worth noting that there was less than 1 percent difference in total 2040 consumption between the CPR and the LTERP—when normalized for self-generation, losses, electric vehicle consumption and planned DSM savings. However, the CPR's consumption forecasts were not perfectly aligned with the LTERP at the sector level."

30.1 Is Lumidyne's reference case forecast meant to be comparable to the BAU load forecast in the LTERP? If not, why not?

Response:

Due to timing differences between completion of the studies, Lumidyne's reference case is similar but not exactly the same as the BAU load forecast in the LTERP. However, the two forecasts are comparable.

30.2 Please provide a schedule that compares Lumidyne's reference case forecast for total energy with the BAU load forecast for total energy described in Vol. 1. In the same schedule please set out the "normalizing" adjustments required to make the two comparable.

Response:

Please refer to the table below which compares the Direct and Indirect At-the-Meter Load Totals (without EVs & Self-Gen) between the LTERP BAU load forecast and the CPR reference case forecast:

Direct and Indirect At-the-Meter Load Totals without EVs & Self-Gen (MWh/year)			
Year	**LTERP**	**CPR**	**% Difference**
2020	3,305,155	3,320,920	0.48
2021	3,413,000	3,448,147	1.03
2022	3,473,835	3,527,865	1.56
2023	3,468,512	3,551,509	2.39
2024	3,469,882	3,582,609	3.25
2025	3,520,561	3,629,338	3.09
2026	3,558,357	3,662,262	2.92
2027	3,597,004	3,696,279	2.76
2028	3,635,516	3,730,302	2.61
2029	3,673,781	3,764,098	2.46
2030	3,711,939	3,797,883	2.32
2031	3,750,605	3,832,238	2.18
2032	3,789,187	3,866,490	2.04
2033	3,826,956	3,899,734	1.90
2034	3,864,106	3,932,176	1.76
2035	3,901,620	3,964,935	1.62
2036	3,938,709	3,997,077	1.48
2037	3,976,129	4,029,478	1.34
2038	4,014,574	4,062,895	1.20
2039	4,053,079	4,096,241	1.06
2040	4,092,522	4,130,532	0.93

There are no "normalizing factors" to convert one forecast to the other. Instead, a comparison of the two forecasts and their differences is described in the CPR on page 22:

> *[…] the CPR's consumption forecasts were not perfectly aligned with the LTERP at the sector level. The key drivers for sector-level differences were as follows:*

- *The LTERP data did not specify the sector for indirect customers' consumption, so the CPR allocated 2019 indirect consumption to each sector—based on wholesale utilities'* *actual sector-specific consumption—and grew it according to each sector and segment's respective growth trajectory.*

- *The CPR intentionally allowed the residential forecast to differ from the LTERP because reliable end use intensity and housing stock data were available at a granular level.*
- *The CPR removed commercial-like customers on large power electric rates from the industrial sector and added them to the commercial sector.*

31.0 Exhibit B-1, Vol. 1, page 178 and Vol. 2, page 8

Preamble: The Application states (Vol. 2, page 8):

"The TRC test was done at the measure level in the CPR modelling tool. The benefits are FBC's "avoided costs", calculated as the measures' present value over the effective measure life of:

- energy savings, valued at the LRMC of $90 per MWh; and
- demand savings, valued at the DCE of $51.22 per kW-yr.

The measures' energy and demand savings are grossed up by the avoided transmission and distribution energy losses (line losses) value of 7.6 percent, before the benefits are calculated. A 7.9 percent pre-tax nominal discount rate was used to calculate the present value of the benefits."

The Application states (Vol. 1, page 178):

"The LRMC values represent the cost to FBC of incremental resources needed to meet incremental load requirements over the planning horizon. The LRMC includes both energy and capacity generation components.

FBC's LRMC values are outcomes of the portfolio analysis and are dependent upon which demand-side and supply-side resource options are included within a particular portfolio.

The LRMC is distinct and calculated separately from the long run avoided cost of transmission and distribution infrastructure, referred to as the Deferred Capital Expenditure (DCE) value. The DCE value is discussed in Section 2.4 of the LT DSM Plan. The DCE is a measure of avoided system infrastructure while the LRMC is a measure of energy and capacity generation."

31.1 What is the basis for a DCE of $51.22 per kW-yr? As part of the response, please confirm that it consists of the avoided costs for transmission and distribution and, if so, how each is determined.

Response:

FBC confirms the DCE value is based on the avoided cost of both transmission and distribution projects. The value is calculated using the methodology developed by EES Consulting[4] which was filed as Appendix C of the 2017 DSM Application and included as Attachment 38.1 in response to BCUC IR1 38.1. The same 2016 LTERP methodology was used with updated transmission and distribution forecasts for the 2021 LTERP.

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[4] EES Consulting, Deferred Capital Expenditure Study, July 2016.

31.2 What is the basis for the 7.9% pre-tax nominal discount rate?

Response:

The 7.9 percent pre-tax nominal discount rate represents FBC's Weighted Average Cost of Capital (WACC) based on values filed in July 2020 as part FBC's Annual Review for 2020 and 2021 Rates and calculations as shown in the response to BCOAPO IR1 41.1.

31.3 In determining the value of demand savings for various DSM measures was any distinction made between transmission-connected (e.g. large industrial customers) and distribution-connected (e.g. residential customers)? If not, why not?

Response:

The DCE value is presented and used as a blended transmission and distribution value. The DCE is intended to be a price signal based on system-wide capital projects and the system annual Coincident Peak load level. The DCE value can be broken into transmission and distribution components if needed as per the developed methodology discussed in the response to BCOAPO IR1 31.1. The DCE value represents a weighted-average value across all customer types, in all geographical areas of the FBC service territory and therefore is appropriate to use for broad DSM programs. Therefore, a distinction between transmission-connected and distribution-connected customers is not made in determining the value of demand savings for various DSM measures.

31.4 In applying adjustments for losses was any distinction made between transmission-connected (e.g. large industrial customers) and distribution-connected (e.g. residential customers)? If not, why not?

Response:

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. This was done for simplicity.

32.0 Reference: Exhibit B-1, Vol. 2, Appendix A, page 30

Preamble: The Application states:

"Commercial and industrial economic potential used a total resource cost (TRC) benefit-cost ratio for economic screening, while residential potential used a modified total resource cost (mTRC) benefit-cost ratio. The mTRC is similar to the TRC, except that it includes a 15 percent increase to avoided costs. The 15 percent increase in avoided costs captures non-energy benefits, as allowed by British Columbia DSM Regulation."

32.1 Please explain why, based on the DSM Regulation, the 15% adder for non- energy benefits is applied to all Residential measures but not to Commercial or Industrial measures?

Response:

In the 2021 Conservation Potential Review, residential measures were screened using the Modified Total Resource Cost Test (mTRC), while commercial and industrial measures were screened using the Total Resource Cost Test (TRC). FBC screened residential measures using the mTRC as, per the *Demand Side Measures Regulation*, an electric utility's portfolio can only have 10 percent of the portfolio reflect the mTRC instead of TRC and residential measures tend to have lower TRC cost-effectiveness. In addition, measures in the low-income portfolio are subject to the mTRC instead of the TRC and are predominantly residential measures.

In the Guide to the Demand-Side Measures Regulation[5] (2014) published by the BC Ministry of Energy and Mines (now Ministry of Energy, Mines, and Low Carbon Innovation), a table is presented in Section 3.3 that details the difference between TRC and mTRC:

Requirement to…	**TRC**	**MTRC**
…use the zero-emission energy alternative for the avoided cost of natural gas?		✓
…use the long-run marginal cost of clean BC electricity for the avoided cost of electricity?	✓	✓
…adjust the calculations for non-energy benefits?		✓

5 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/energy-efficiency/guide_to_the_dsm_regulation_july_2014_c2.pdf

The table outlines that, as per 4(1.1)(c) of the *Demand Side Measures Regulation*, non-energy benefits are only to increase the benefits of measures subject to the mTRC. Thus, for the Conservation Potential Review screen of cost-effective measures, only residential measures had the mTRC reflect the 15 percent adder for non-energy benefits.

33.0 Reference: Exhibit B-1, Vol. 2, page 13 and Appendix A, pages 35-36

Preamble: The Application states (Appendix A):

"Incentive levels played a role in the market potential forecasts by improving the customer payback times and increasing customers' willingness to adopt CPR measures. Consistent with the 2016 CPR, the team specified incentive levels as dollars per net present value (NPV) of energy savings (e.g., $/kWh), where the NPV accounts for a measure's savings across its expected useful lifetime. Compared with an incentive approach based on first year savings or a percentage of incremental costs, the advantage of using a dollar-per-NPV-of-savings incentive is that it favours measures with greater lifetime savings"

The Application states (page 13):

"The DSM program scenarios represent FBC paying levelized incentives to cover 50, 62, 72, 84 and 100 percent of incremental measure costs respectively."

33.1 In the determination of Market Potential (per the CPR-Appendix A), what level of incentive (i.e., $/NPV of energy savings) was included in the assessment of each measures market potential?

<u>Response:</u>

The target levelized incentives used in the determination of the Market Potential and DSM Scenarios are shown in the table below.

Scenario	Percentage of Average Incremental Cost	Target Levelized Incentive Rates (2020 dollars/NPV of Energy Savings)		
		Commercial	Industrial	Residential
Low Scenario	50%	$0.007	$0.015	$0.074
Base Scenario (Market Potential)	62%	$0.011	$0.025	$0.124
Med Scenario	72%	$0.020	$0.046	$0.229
High Scenario	84%	$0.038	$0.086	$0.428
Max Scenario[6]	100%	N/A	N/A	N/A

However, there are other variables that may impact the incentive assigned for each measure in the model. A complete explanation of the methodology and associated variables is presented in the CPR Incentive Methodology provided as Attachment 33.1.

6 The "Program Potential – 100% Scenario" applied incentives that were 100% of the incremental measure costs, and thus did not rely on targeted levelized incentive rates.

33.1.1 If the incentive level was not constant over all measures, please provide the incentive level used for each measure eventually included in FBC's 2021 LT DSM Plan.

Response:

The incentive level was not constant over all measures. Although FBC has the information on a per-measure basis, the spreadsheet contains over 9000 combinations of measures and variables that may impact the incentive assigned for each measure in the model. In addition, the CPR incentive model is meant to be looked at by sector rather than by the individual combinations of measures and variables. The incentive calculations for each combination of measures and variables will typically not match the incentives assigned for a measure within a program included in the DSM Plans. However, the CPR results at the sectoral level propose a level of savings, incentive expenditure, and participation for future DSM Plans.

Please also refer to the response to BCOAPO IR1 33.1.

33.1.2 For each measure included in FBC's LT DSM Plan please express the level of the incentive payment included in the Market Potential calculation as a percentage of the measures incremental cost (as used on the derivation of the DSM program scenarios).

Response:

Please refer to the responses to BCOAPO IR1 33.1 and 33.1.1 for an explanation of the incentive rates and for why FBC cannot provide the requested information as asked.

FBC is able to provide summarized results below, expressed as the weighted level of incentive as a percentage of incremental cost for each sector across the plan years:

- Residential: 98.2% of incremental cost
- Commercial: 44.3% of incremental cost
- Industrial: 64.3% of incremental cost

33.2 If the use of a dollar-per-NPV-of-savings incentive approach is preferable for determining the market potential then why wasn't a similar approach used to define the DSM scenarios?

Response:

The dollar-per-NPV-of-savings incentive was used in the determination of the DSM Scenarios. DSM Scenarios use 50, 62, 72, 84 and 100 percent as a shorthand identification to indicate the average incentive level as a percentage of incremental costs, which were derived from the applied levelized incentives across all measures and sectors.

33.3 Does defining the DSM scenarios based on the percentage of incremental measure costs paid mean that the cost per kWh saved will vary across the measures in any given scenario?

Response:

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. The cost per kWh saved will vary between measures depending on the customer segment and year. The incentive for a measure typically varies between scenarios, up to a maximum incentive level at which no additional incentive will result in additional measure uptake. The DSM scenarios were reported in the LT DSM Plan based on the percentage of incremental costs for portfolio comparative purposes only.

33.3.1 If yes, what is the range of costs per kWh saved in each of the five DSM scenarios? For each scenario, please provide the result for each sector (Residential, Commercial and Industrial).

Response:

The range of levelized incentives for each scenario, by sector, is provided in the table below. This range of levelized incentives represents the costs per kWh saved in each of the five DSM scenarios.

	Levelized Incentive Range ($/NPV of kWh) by DSM Scenario				
Scenario	**Low**	**Base**	**Med**	**High**	**Max**
% of incremental cost	50%	62%	72%	84%	100%
Residential	0.000 - 0.111	0.000 - 0.184	0.000 - 0.341	0.000 - 0.636	0.000 - 0.764
Commercial	0.000 - 0.010	0.000 - 0.016	0.000 - 0.030	0.000 - 0.056	0.000 - 1.063
Industrial	0.011 - 0.022	0.011 - 0.037	0.011 - 0.069	0.011 - 0.128	0.011 - 0.430

Across all scenarios, the minimum levelized incentive (in $/NPV of kWh) is $0.00 for the residential and commercial sectors. This is because some measures have incremental costs that gradually decrease to zero.

33.4 Which of the five DSM scenarios does the level of incentive included in the Market Potential study most closely align with? Please indicate if the response varies by sector (Residential, Commercial and Industrial).

Response:

The Conservation Potential Review's market potential is represented by the Base scenario (average incentive of 62 percent of incremental cost) in the LT DSM Plan. The response does not vary by sector.

34.0 Reference: Exhibit B-1, Vol. 2, Appendix A, pages 40 and 42

34.1 With respect to Figures 13 and 15, do "Traditional Program Measures" represent measures that are included in FBC's current DSM plan whereas "Non-Traditional Measures" and "Kraft Pulp and Paper" represent measures that are not included in the current CDM plan? If not, please explain the differences?

Response:

The "Traditional Program Measures" represent measures that are included in FBC's current DSM plan in the residential, commercial and industrial sectors, excluding the kraft pulp and paper sector. "Non-Traditional Measures" represent measures that are not included in FBC's current DSM plan in the residential, commercial and industrial sectors, excluding the kraft pulp and paper sector. "Kraft Pulp and Paper" represent measures applicable in the kraft pulp and paper sector.

34.2 Please provide a schedule that for each of the three sources of DSM savings, sets out the incremental kWh savings in each year consistent with Figure 13.

Response:

The table below provides the incremental savings in each year consistent with Figure 13 for each of the three sources of DSM savings.

Incremental Energy Savings Potential by Source (GWh/year)				
Year	Traditional Program Measures	Non-Traditional Measures	Kraft Pulp & Paper	Total
2020	25.7	9.2	3.1	38
2021	27.8	8.2	3.5	40
2022	27.4	7.5	3.6	38
2023	21.6	6.1	4	32
2024	23.5	6	4.1	33
2025	25.7	5.9	4.2	36
2026	25.4	5.5	4.4	35
2027	24.9	4.3	4.4	34
2028	24.2	4.2	4.4	33
2029	23.3	4	4.4	32
2030	22.2	3.8	4.3	30

Incremental Energy Savings Potential by Source (GWh/year)				
2031	20.5	3.7	4.1	28
2032	18.5	3.5	3.8	26
2033	16.8	3.3	3.5	24
2034	15.2	3.2	3.3	21
2035	14.3	3	3	21
2036	13.6	3	2.7	19
2037	11.9	2.8	2.5	17
2038	11.3	2.7	2.1	16
2039	10.8	2.6	2	15
2040	10.3	2.5	1.6	15

34.3 Please provide a schedule that, for each of the three sources of DSM savings, sets out the incremental kW savings in each year consistent with Figure 15.

Response:

The table below provides the incremental demand savings potential in each year consistent with Figure 15 for each of the three sources of DSM savings (Commercial, Industrial and Residential).

Market Potential Electric Demand Savings by Sector (MW)						
Year	Commercial (winter)	Commercial (summer)	Industrial (winter)	Industrial (summer)	Residential (winter)	Residential (summer)
2020	2.3	2.4	0.8	0.9	2.8	1.8
2021	2.4	2.5	1.4	1.5	1.9	1.2
2022	2.4	2.4	1.3	1.5	1.8	1.2
2023	2.3	2.4	0.8	0.8	1.4	0.9
2024	2.6	2.7	0.8	0.8	1.3	0.9
2025	2.9	2.8	0.9	1.0	1.3	0.8
2026	2.7	2.7	0.9	1.0	1.3	0.8
2027	2.5	2.5	0.9	1.0	1.3	0.8
2028	2.3	2.4	0.9	1.0	1.3	0.7
2029	2.2	2.2	0.9	1.0	1.4	0.8
2030	2.0	2.0	0.9	1.0	1.4	0.7

Market Potential Electric Demand Savings by Sector (MW)						
Year	Commercial (winter)	Commercial (summer)	Industrial (winter)	Industrial (summer)	Residential (winter)	Residential (summer)
2031	1.8	1.7	0.8	0.9	1.3	0.7
2032	1.5	1.6	0.8	0.9	1.3	0.7
2033	1.4	1.4	0.8	0.8	1.3	0.5
2034	1.2	1.1	0.7	0.8	1.2	0.6
2035	1.0	1.1	0.6	0.7	1.3	0.5
2036	0.9	0.9	0.6	0.7	1.3	0.6
2037	0.9	0.9	0.6	0.6	1.1	0.4
2038	0.8	0.8	0.5	0.6	1.0	0.4
2039	0.8	0.8	0.5	0.5	1.1	0.3
2040	0.8	0.8	0.4	0.5	1.0	0.4

35.0 Reference: Exhibit B-1, Vol. 2, Appendix A, pages 50-52

Preamble: With respect to Figures 21, 22 and 23 the Application states:

"The following figures show energy and summer/winter demand savings by measure. In some instances, the measure names consist of groups of similar measures. For example, the "Com | LED" measure group includes interior LED, interior LED MR/PAR, LED luminaire and troffer LED."

35.1 For each of Figures 21, 22 and 23 please indicate which of the measures set out in the Figure are: i) fully included in FBC's current DSM Plan, ii) partially included in FBC's current DSM Plan (i.e., the CPR measure consists of a group of similar measures only some of which are included in FBC's current DSM Plan) and iii) not included in FBC's current DSM Plan.

Response:

The table below lists the measures included in Figures 21, 22 and 23, as well as their status within FBC's current DSM plan. In the table, 'Included' means the measure is fully included.

Measure Name	Status	Rationale for Not Including
Com | LED	Included	N/A
Res | LED	Included	N/A
Ind | Pump Equipment Upgrade	Included	N/A
Com | Building Automation Controls	Included	N/A
Ind | Improved Fan Systems	Included	N/A
Res | Energy Star Television	Not included	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact
Ind | Efficient Lighting High Bay	Included	N/A
Com | VSD on Pumps	Included	N/A
Com | NC measure 30 %>code	Included	N/A
Ind | Process Control	Included	N/A
Com | Interior LED High Bay	Included	N/A
Com | HVAC Control Upgrades	Included	N/A
Com | NC measure 45 %>code	Included	N/A
Com | Photocell	Included	N/A
Res | Home Energy Reports	Included	N/A
Ind | Pump Off Controllers	Included	N/A
Res | Smart Thermostats	Included	N/A
Com | VSD on Fans	Included	N/A

Measure Name	Status	Rationale for Not Including
Com | Interior Lighting Controls	Included	N/A
Com | NC Step Code 2	Included	N/A
Ind | Efficient Air Compressor	Included	N/A
Ind | Cannabis LED	Included	N/A
Com | Comprehensive Retrocomissioning	Included	N/A
Res | Adv Power Strips	Not included	Difficult to implement properly without a direct install program
Res | Energy Star Desktop PC	Not included	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact
Res | Clothes Dryer	Included	N/A
Ind | Lighting Controls	Included	N/A
Res | Air Source Heat Pumps	Included	N/A
Ind | Energy Management	Included	N/A
Res | NC Apt Step Code 2	Included	N/A
Res | Ceiling Insulation	Included	N/A
Res | New Home Step Code 4	Included	N/A
Res | Energy Star Windows	Included	N/A
Ind | Cannabis HVAC	Included	N/A
Com | CAC Tune-up	Not Included	Under consideration, but not implemented to date

35.2 If any of the measures set out in the figures are not fully or partially included in FBC's current DSM plan, please explain why.

Response:

Please refer to the response to BCOAPO IR1 35.1.

36.0 Reference: Exhibit B-1, Vol. 2, Appendix A, pages 50-52 & 54 and Appendix B1

Preamble: The Application states (Appendix A, page 54):

"The benefit-cost ratios were favourable for all costs tests and sectors, except for the Rate Impact Measure Test (RIM)."

36.1 Are the results set out for each sector in Tables 24 and 25 and in Appendix B1 (Net Benefit Cost Ratios Tab) for the Utility Cost test, the Participant cost test and the Rate Impact Measure test impacted by the level of incentive payments included for each measure? If not, why not?

Response:

The formula for Total Resource Cost does not include incentive payments, therefore incentives do not impact the Total Resource Cost Test. The Utility Cost Test, Participant Cost Test, and Rate Impact Measure are all impacted by incentive payments.

36.2 For the top 30 measures identified in Figures 21, 22, and 23 please indicate: i) the result if the Utility Cost Test and ii) the level of incentive included in the determination of the Market Potential.

Response:

For each measure, the utility cost test (UCT) and level of incentive vary based on installation by building type or sector, and implementation decision point (new construction, replacement on burn-out, early replacement). For the measures identified in Figures 21, 22, and 23:

i. The result of the UCT may be seen in the LT DSM Plan, Appendix B1 of Appendix A, in the "Net Benefit-Cost Ratios" sheet. An average for each measure for the 2020 year is shown in the table below.

ii. The level of incentive included in the determination of the Market Potential is the same as the level of incentive for the Base Scenario. An average for each measure for the 2020 year is shown in the table below.

Measure	Average Net Utility Cost Test for 2020	Average Levelized Incentive ($/NPV of kWh, 2020)
Com | Building Automation Controls	8.43	0.017
Com | Comprehensive Retrocomissioning	2.10	0.056
Com | Exterior LED	2.26	0.035
Com | High Efficiency Fans	3.69	0.031
Com | HVAC Control Upgrades	7.73	0.019
Com | Interior LED High Bay	5.60	0.029
Com | LED	8.13	0.035
Com | NC measure 30 %>code	5.05	0.024
Com | NC measure 45 %>code	5.61	0.022
Com | NC Step Code 2	6.12	0.015
Com | NC Step Code 3	5.02	0.023
Com | NC Step Code 4	3.13	0.042
Com | Photocell	9.38	0.015
Com | VSD on Fans	10.28	0.014
Com | VSD on Pumps	10.20	0.014
Ind | Cannabis LED	4.30	0.032
Ind | Efficient Air Compressor	4.40	0.031
Ind | Efficient Lighting High Bay	7.72	0.021
Ind | Energy Management	6.15	0.020
Ind | Improved Fan Systems	4.40	0.031
Ind | Process Control	4.77	0.028
Ind | Pump Equipment Upgrade	4.41	0.031
Ind | Pump Off Controllers	16.13	0.030
Res | Adv Power Strips	2.44	0.020
Res | Ceiling Insulation	5.06	0.037

Measure	Average Net Utility Cost Test for 2020	Average Levelized Incentive ($/NPV of kWh, 2020)
Res | Clothes Dryer	2.91	0.080
Res | Ductless Mini Split Heat Pump	1.85	0.105
Res | Electric Tankless Water Heater	7.69	0.021
Res | Energy Star Television	65,535.00[7]	0.000
Res | Heat Pump Water Heater 2.0 EF	2.56	0.088
Res | Home Energy Reports	5.15	0.029
Res | LED	13.57	0.013
Res | Low Flow Showerheads	3.98	0.021
Res | NC Apt Step Code 3	2.40	0.023
Res | NC Apt Step Code 4	2.61	0.042
Res | New Apt 45% > code	2.26	0.042
Res | New Home Step Code 3	2.17	0.061
Res | New Home Step Code 4	3.01	0.049
Res | New Home Step Code 5	1.70	0.097
Res | Smart Thermostats	3.51	0.051

[7] Note that the very high UCT for RES | Energy Star Television is a result of the measure's zero incremental costs, requiring minimal incentive to achieve savings.

37.0 Reference: Exhibit B-1, Vol. 2, pages 11-12

37.1 For each of Figures 2-4, 2-5 and 2-6 please indicate which of the measures set out in the Figure are: i) fully included in FBC's current DSM Plan, ii) partially included in FBC's current DSM Plan (i.e., the CPR measure consists of a group of similar measures only some of which are included in FBC's current DSM Plan) and iii) not included in FBC's current DSM Plan.

Response:

All measures listed in Figures 2-4, 2-5, and 2-6 are included in the current DSM Plan.

37.2 If any of the measures set out in the figures are not fully or partially included in FBC's current DSM plan, please explain why.

Response:

Please refer to the response to BCOAPO IR1 37.1.

37.3 For each of the measures identified in Figures 2-4, 2-5 and 2-6, please indicate:

i) the result if the Utility Cost Test and

ii) the level of incentive included in the determination of the Market Potential.

Response:

For each measure, the UCT and level of incentive vary based on installation by building type or sector, and implementation decision point (new construction, replacement on burn-out, early replacement). For the measures identified in Figures 2-4, 2-5, and 2-6:

1. The result of the utility cost test may be seen in the LT DSM Plan, Appendix B1 of Appendix A, in the "Net Benefit-Cost Ratios" sheet. An average for each measure for the 2020 year is shown in the table below.

2. The level of incentive included in the determination of the Market Potential is the same as the level of incentive for the Base Scenario. An average for each measure for the 2020 year is shown in the table below.

Measure	Average Net Utility Cost Test for 2020	Average Levelized Incentive ($/NPV of kWh, 2020)
Res | LED	13.57	0.013
Res | Smart Thermostats	3.51	0.051
Res | Heat Pump Water Heater 2.0 EF	2.56	0.088
Res | Ceiling Insulation	5.06	0.037
Res | Home Energy Reports	5.15	0.029
Res | Clothes Dryer	2.91	0.080
Res | New Home Step Code 5	1.70	0.097
Res | Air Source Heat Pumps	2.32	0.105
Res | New Home Step Code 4	3.01	0.042
Res | Residential Occupancy Sensors	14.96	0.010
Res | Energy Star Windows	2.20	0.152
Res | Attic Insulation	2.34	0.077
Com | LED	8.13	0.035
Com | NC measure 45 %>code	5.61	0.042
Com | Building Automation Controls	8.43	0.017
Com | NC measure 30 %>code	5.05	0.023
Com | VSD on Pumps	10.20	0.014
Com | HVAC Control Upgrades	7.73	0.019
Com | Interior LED High Bay	3.70	0.029
Com | Photocell	9.38	0.015
Com | VSD on Fans	10.28	0.014
Com | Interior Lighting Controls	9.58	0.014
Com | Solid Door Freezer	8.17	0.016
Com | Comprehensive Retrocomissioning	2.10	0.056
Ind | Efficient Lighting High Bay	7.72	0.021
Ind | Improved Fan Systems	4.40	0.031
Ind | Process Control	4.77	0.028
Ind | Efficient Air Compressor	4.40	0.031
Ind | Pump Equipment Upgrade	4.41	0.031
Ind | Lighting Controls	5.95	0.024
Ind | Optimize Compressed Air Dryer	4.59	0.031
Ind | Cannabis LED	4.30	0.032
Ind | Efficient Lighting Low Bay	7.02	0.022

Measure	Average Net Utility Cost Test for 2020	Average Levelized Incentive ($/NPV of kWh, 2020)
Ind | Cannabis HVAC	6.23	0.022
Ind | Energy Management	6.15	0.020
Ind | Cannabis Dehumidifier	4.45	0.031

38.0 Reference: Exhibit B-1, Vol. 2, pages 11-13 & 15 and Appendix A, pages 50-52

Preamble: The Application states (page 13):

"The same DSM measures were included in all scenarios, and the uptake was based on the market potential."

The Application states (page 15):

"FBC also clarified that all DSM Scenarios included the same selection of cost effective DSM measures. However, the difference between DSM Scenarios was the percentage of incremental cost that would be covered by DSM incentives"

38.1 Please confirm that for all scenarios the only assumption varied was the incentive paid. If not confirmed, please explain how else the DSM scenarios differ.

Response:

Confirmed.

38.2 Please indicate how the measures included in the DSM scenarios were determined and what those measures were.

Response:

The DSM measures that were identified for inclusion in the 2021 Conservation Potential Review and DSM Scenarios are based on measures incented in past and current DSM Plans, input from Lumidyne, and consultation with FBC's DSM program team. The measures included in the DSM Scenarios represent the cost-effective measures identified in the Conservation Potential Review. The measures included in the DSM Scenarios are presented in Appendix B2 of the LT DSM Plan Appendix A – 2021 Conservation Potential Review Report.

38.3 Please indicate which of the measures included in the DSM Scenarios were: i) fully included in FBC's current DSM Plan, ii) partially included in FBC's current DSM Plan (i.e., the CPR measure consists of a group of similar measures only some of which are included in FBC's current DSM Plan) and iii) not included in FBC's current DSM Plan.

1 **Response:**

2 The following cost-effective measures were included in the DSM Scenarios, but do not exist in
3 the current DSM Plan.

Sector	Measure	Rationale
Commercial	CAC Tune-up	Under consideration, but not implemented to date
Commercial	CFL	LED measures available with better savings
Commercial	Duct Insulation, Electric	Limited number of electrically heated commercial buildings where measure would apply
Commercial	Interior High bay T5 HO fixtures	LED measures available with better savings
Commercial	New ECM Fan Motor System (ROB)	Limited applicability
Commercial	Roof Deck Insulation	Limited number of electrically heated commercial buildings where measure would apply
Commercial	Tankless Electric Hot Water Heater, RET	Heat pump water heater measure available with better savings
Commercial	Tankless Electric Hot Water Heater, ROB	Heat pump water heater measure available with better savings
Commercial	Server Virtualization	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact
Industrial	Refrigerated Storage Tuneup	Limited number of refrigerated storage facilities to warrant a program
Residential	Adv Power Strips	Difficult to implement properly without a direct install program
Residential	CFL	LED measures available with better savings
Residential	Cooking Convection Ovens	Limited suppliers and demand for electric kitchen appliances
Residential	Electric Storage Water Heater	Heat pump water heater measure available with better savings
Residential	Electric Tankless Water Heater	Heat pump water heater measure available with better savings
Residential	MURB Roof Deck Insulation Elec	Limited number of electrically heated commercial buildings where measure would apply
Residential	Energy Star Desktop PC	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact

Sector	Measure	Rationale
Residential	Energy Star Display	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact
Residential	Energy Star Freezer	Minimal savings for relatively high incentive required
Residential	Energy Star Television	Incremental cost is very low compared to total cost, thus incentive will likely have minimal impact
Residential	Refrigerator Buy Back	Limited savings compared to program effort-FBC does offer a new refrigerator rebate incentive

FBC does not have any measures that are partially included. Measures are either included in a DSM program or they are not included, with the rationale noted in above table.

38.3.1 If any of the measures set out in the DSM Scenarios are not fully or partially included in FBC's current DSM plan, please explain why.

Response:

Please refer to the response to BCOAPO IR1 38.3.

38.4 Please indicate which of the measures identified in Figures 2-4, 2-5 and 2-6 (pages 11-13) were included in the DSM scenarios.

Response:

All measures identified in Figures 2-4, 2-5, and 2-6 were included in the DSM Scenarios.

38.4.1 If any of the measures were excluded or, where the measure per the CPR represented a group of measures, only some were included in the DSM scenarios, please explain why?

Response:

Please refer to the response to BCOAPO IR1.38.4.

38.5 Please indicate which of the measures identified in Figures 21, 22 and 23 (pages 50-52) were included in the DSM scenarios.

Response:

All measures identified in Figures 21, 22, and 23 were included in the DSM Scenarios.

38.5.1 If any of the measures were excluded or where the measures per the CPR represented a group of measures, or where only some were included in the DSM scenarios, please explain why.

Response:

Please refer to the response to BCOAPO IR1 38.5.

38.6 Please explain how the uptake in each scenario was "based on the market potential".

Response:

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 paybacks which increase uptake. The analysis then uses a Bass diffusion model that observes the uptake relationship changes over time based on the established S-shape of technology adoption, which also reflects how many non-DSM products are adopted, including computers, cellphones, and electric vehicles.

A more detailed explanation for how participation was determined based on the market potential is included in Section 2.5.3.1 of the 2021 Conservation Potential Review.

38.7 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 (Appendix A)? If yes, please identify the scenarios, the specific measures and the associated differences between the incentive payments.

Response:

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.

39.0 Reference: Exhibit B-1, Vol. 2, pages 14-15

39.1 With respect to Table 3-1, does the "Average Cost" value for each scenario represent the average cost of all DSM implemented over the planning period? If not, what does it represent?

Response:

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.

39.2 With respect to Table 3-1, does the "Incremental cost compared to base case" value represent the increase in cost of DSM (over the base case) divided by the increasing savings (over the base case)? If not, what does it represent?

Response:

FBC confirms the "Incremental cost compared to base case" value represents the increase in cost of DSM (over the base case) divided by the increasing savings (over the base case).

39.3 What is the incremental cost of the Base Scenario as compared to the Low Scenario?

Response:

The incremental cost of the Base Scenario compared to the Low Scenario is $196 per MWh.

39.4 Please revise Table 3-1 so as to include an additional column based on the Market Potential as determined in the CPR (Appendix A).

Response:

An additional column for Table 3-1 is shown below.

Category	DSM Scenario					Market Potential
	Low	Base	Med	High	Max	
Energy Savings, GWh						
Average per annum (2021 to 2040)	21.0	21.8	22.4	23.4	25.2	29.1
Average per annum (2021 to 2029)	26.8	28.0	29.4	31.4	34.5	38.9
Total (2021 to 2040)	421	435	449	468	503	583
Capacity Savings, MW						
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7	83.5
Resource Cost, 2020 ($000s)						
Average Cost ($/MWh)	$38	$44	$49	$57	$75	$40
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234	$25

Note that the Market Potential is a maximum levelized incentive approach for traditional, non-traditional, and kraft pulp & paper measures, at the Base Scenario's incentive levels. The DSM scenarios do not include non-traditional or kraft pulp & paper measures.

40.0 Reference: Exhibit B-1, Vol. 1, pages 152 and 154-155

Preamble: The Application states (page 152):

"FBC selected the Base DSM scenario as its preferred scenario in the LT DSM Plan. The Base DSM Scenario can be characterized as a continuation of the 2016 LT DSM Plan's "High" scenario, in which the target savings increased from 26.4 to 30.4 GWh by 2022 and which used a constant 32 GWh per year as a placeholder thereafter. As shown in Figure 8-2, the energy savings achieved to date and forecast in 2021 align with the Base scenario."

40.1 Please explain more fully why FBC characterizes the Base DSM Scenario as a continuation of the 2016 LT DSM Plan's "High" scenario when the annual savings for the Base Scenario appear to be less than 30 GWh/year for every year after 2022 and the 2016 LT DSM Plan's "High" scenario assumed annual DSM savings in excess of 30 GWh/year for 2022 and after.

Response:

The actual incremental energy savings achieved to date for 2019, 2020, and forecast for 2021, align closely with the 2016 LT DSM Plan's "High" scenario, as can be seen in the table below.

Source	Annual Incremental Energy Savings (GWh per year)			
	2019	**2020**	**2021**	**2022**
2016 LT DSM Plan "High" Scenario	26.4	26.4	28.4	30.4
2021 LT DSM Plan Base Scenario	-	-	29.0	33.1
Actual Energy Savings to Date	25.8	26.2	29.8[8]	33.1[9]

The DSM scenario development took these actual DSM energy savings as data points. The resulting "Base" scenario was found to have values that aligned very closely to near-term planned values in the 2019-22 DSM Plan, which was based on the 2016 LT DSM Plan's "High" scenario.

The energy savings for 2023 and later in the Base DSM Scenario are less than the 2016 LT DSM Plan's "High" scenario due to a difference in methodology while creating the scenarios. The 2016 LT DSM Plan assumed that, for the "High" scenario, new measures would come in during the plan life to give consistent 32 GWh per year energy savings. In the 2021 LT DSM Plan, FBC took a different approach and did not assume that measures beyond what were identified in the 2021 Conservation Potential Review would appear during the plan life. This is a more conservative assumption, as it is possible that there will be energy savings opportunities for measures not yet identified that will become known over the plan duration.

[8] Forecast.

[9] As per FBC 2019-22 DSM Plan.

40.2 Please explain more fully why the energy savings achieved to date are considered to align with the Base Scenario.

Response:

Please refer to the response to BCOAPO IR1 40.1.

40.3 Are there any measures included in the Base Scenario where the level of incentive to be provided exceeds that in the current 2019-2022 DSM Plan?

Response:

FBC confirms there are some measures where the level of incentive in the Base Scenario exceeds that in the current 2019-2022 DSM Plan; however, it is challenging to do a side-by-side comparison as the LT DSM Plan is a directional economic model that reflects 172 energy conservation measures which vary in ways that include:

- Installation by building type or sector;
- Implementation decision point (new construction, replacement on burn-out, early replacement); and
- Climate zone.

Thus, each DSM Scenario models a total of 985 discrete measures-configuration combinations, each having a unique calculated incentive based on $/kWh savings. Making the comparison even more difficult, each measure in the Conservation Potential Review may be included in different programs in the 2019-2022 DSM Plan. For instance, the "Com | Interior LED" measure would exist in the Commercial Prescriptive Program, Rental Apartment, and Low Income Program.

Thus, it is more relevant to compare the level of incentives between the LT DSM Plan and current 2019-2022 DSM Plan based on average $/kWh by sector. The table below compares the average $/kWh incentive in the Conservation Potential Review to the average $/kWh in the 2019-2022 DSM Plan. In the table below, as the 2019-2022 DSM Plan includes additional detail that is not available in the base scenario, the Residential, Commercial and Industrial totals are directly comparable.

	Average incentive expenditure per first year kWh	
	Base Scenario (2020)	2019-2022 DSM Plan
Residential	**0.418**	**0.313**
Home Renovation	-	0.324
New Home	-	0.482
Lighting	-	0.093
Rental Apartment	-	0.210
Low Income	-	0.480
Commercial	**0.137**	**0.131**
Custom	-	0.155
Prescriptive	-	0.118
Industrial	**0.149**	**0.145**
Custom	-	0.150
Prescriptive	-	0.122

Note that the Base Scenario costs are in 2020 dollars, while the 2019-2022 DSM Plan costs are in 2019 dollars.

40.3.1 If yes, please identify the measures and the level of incentives included in the current DSM Plan (i.e., percentage of incremental costs paid).

Response:

Please refer to the response to BCOAPO IR1 40.3.

40.3.2 If yes, please create a new DSM scenario, where for these measures the level of incentive is assumed to be the same as in the current DSM Plan and revise Table 3-1 to include the summary results. Please also report the incremental cost of the Base Scenario as compared to this updated Scenario.

Response:

The following response was provided by Lumidyne.

It is not practical to create a new DSM scenario where the level of incentive is assumed to be the same as the current DSM plan. The model that generated the DSM scenarios determines the per-measure incentive based on the measure's net present value of kWh savings and a targeted $/kWh incentive rate. The targeted $/kWh incentive rate is only differentiated by sector and does not allow for measure-level customization. The reason for this is that program potential scenarios from the model are typically simulated prior to knowledge about each program's decisions about measure-level incentives and administration costs, so generalized incentive rates are applied instead.

The CPR model evaluates measure potential by customer segment and replacement type, which differs from how FBC evaluates measures. It is not equitable for FBC to exclude certain customer segments from rebate applications if both customers are on the same rate codes. The CPR model is meant to compare a measure's potential from one customer segment to the next, and is not intended to replicate or supplant FBC program design.

Moreover, the model is meant to inform program design, not model program design. Tools that model program design have the ability to specify measure-level participation targets, incentives, and administrative costs. Those tools also rely on a less disaggregated characterization of measures to reflect averages across all targeted building types or customer segments. Because they are less disaggregated, it's practical to replicate the DSM plan without estimating thousands of measure-level assumptions. In contrast, the model used for DSM program potential scenarios would require thousands of measure-level updates.

40.3.3 If yes, please revise Figures 9-1 and 9-2 to include the results of this new DSM scenario instead of the Base DSM Scenario.

Response:

Please refer to the response to BCOAPO IR1 40.3.2 for an explanation of why the requested DSM scenario cannot be created.

41.0 Reference: Exhibit B-1, Vol. 1, page 163 & Appendix K, page 8 and Vol. 2, page 8

Preamble: The Application states (page 163):

"The UCC and UEC values are based on a levelized net present value (NPV) cost basis in order to enable comparison between the different resources with different cost structures and energy and capacity values. The UECs and UCCs are presented in real 2020 dollars. FBC has assumed a WACC of 3.69 percent after tax (in real terms) as the discount rate in determining the UECs and UCCs."

The Application states (Vol. 2, page 8):

"The measures' energy and demand savings are grossed up by the avoided transmission and distribution energy losses (line losses) value of 7.6 percent, before the benefits are calculated. A 7.9 percent pre-tax nominal discount rate was used to calculate the present value of the benefits."

41.1 Is the discount rated used in determining the UCC and UEC values for resource options equivalent to that used in the evaluation of DSM measures?

41.1.1 If yes, please demonstrate that this is the case.

41.1.2 If no, why not?

<u>Response:</u>

A 7.9 percent pre-tax nominal discount rate is used for DSM measures. A 3.69 percent after-tax real discount rate is used in determining the UECs and UCCs. The two are equivalent, considering the context of how they are applied.

The table below shows the calculation of the two discount rates (shown in bold text) used in the LTERP analysis. The highlighted values are 2021 Ratios and Average Embedded Costs sourced from the FBC Annual Review for 2020 and 2021 Rates as filed in July 2020.[10]

[10] FBC Annual Review for 2020 and 2021 Rates, Exhibit B2, Schedule 26 & Schedule 24, July 20, 2020. https://www.bcuc.com/Documents/Proceedings/2020/DOC_58993_B-2-FBC-Annual-Review-for-2020-and-2021-Rates-Materials.pdf

Weighted Average Cost of Capital (WACC)			
	Weight	Pre-Tax Rate	After-Tax Rate
Short Term Debt	2.84%	2.22%	1.62%
Long Term Debt	57.16%	4.93%	3.60%
Common Equity	40.00%	12.53%	9.15%
WACC (Nominal)	100.00%	**7.89%**	5.76%
WACC (Real)		5.78%	**3.69%**
FBC Tax Rate	27.00%		
Inflation (CGAR)	2.0%		

The Conservation Potential Review (CPR) model includes an inflation variable and therefore requires the use of a nominal WACC value. The WACC is natively expressed in nominal terms, but the resource portfolio model expresses costs in 2020 real dollars. To convert between a nominal discount rate and a real discount rate, the following relationship was used:

- (1 + Nominal rate) = (1 + Real rate) * (1 + Inflation rate)
- Real rate = ((1 + Nominal rate) / (1 + Inflation rate)) - 1

The inflation assumptions used in the CPR model and resource portfolio model are consistent. To adjust between pre-tax and after-tax, the following relationship was used:

- After-Tax rate = Pre-Tax rate * (1 - Tax rate)

41.2 Why is an after-tax discount rate used for resources options but a pre-tax discount rate used for DSM?

Response:

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 expenses incurred for capital investment purposes is tax deductible.

42.0 Reference: Exhibit B-1, Vol. 1, page 170

Preamble: The Application states:

"Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option."

42.1 What does FBC consider to be "long-term" (i.e., after what date)?

Response:

As presented in Table 11-3, in this context FBC considers the "long-term" to cover the period from 2031 to 2040. As discussed in Section 10.4, the month of June is the exception to FBC requiring capacity self-sufficiency for LTERP planning purposes. FBC expects that June gaps (after DSM) up to the level of 75 MW could be met with market block purchases, contracted prior to the start of each June, rather than acquiring new resources, up until 2030. After 2030, FBC is assuming capacity self-sufficiency given the risks with longer term reliance on market capacity.

42.2 Please confirm that FBC believes market supply can be relied on as a long-term energy resource option (as opposed to a capacity resource option).

Response:

Confirmed. However, as discussed in Section 11.3.9, in the event that market conditions change such that accessing market energy is no longer a reliable and cost effective option, FBC has determined that portfolio B2 would be the preferred portfolio, which assumes energy self-sufficiency after 2030.

43.0 Reference: Exhibit B-1, Vol. 1, pages 170-171

43.1 With respect to FBC's reliance on market supply as a capacity resource for the month of June, please explain the basis for the proposed level of 75 MW and the 2030 date.

Response:

FBC is proposing to purchase capacity blocks[11] for June, entered into before the month begins. On an expected basis, June is a freshet month and FBC expects these blocks to be available for the foreseeable future due to the expected availability of water, even beyond 2030. However, in 2030, other months begin to require additional capacity resources and as FBC obtains additional resources to meet these requirements, it is reasonable and prudent to include a self-sufficiency capacity requirement in June as well. Please also refer to the response to BCUC IR1 1.3 for a discussion of the 75 MW level.

[11] Most likely this will be a standard Heavy Load Hour monthly block.

44.0 Reference: Exhibit B-1, Vol. 1, page 171

Preamble: The Application states:

"As of February 2020, BC Hydro had a total of 127 electricity purchase agreements with independent power producers. About 70 of these agreements are expiring over the next 20 years, representing approximately 9,100 GWh of firm energy and 1,300 MW of dependable capacity."

44.1 Of the 70 expiring EPAs, are any of the associated facilities located in FBC's service area? If yes, how many and what is their total associated energy and dependable capacity?

Response:

FBC does not have access to the confidential terms of the BC Hydro EPAs, so cannot speak to which EPAs are expiring. However, BC Hydro did publish a list of IPP projects in operation[12] as of October 1, 2021, and from that list, five are located in FBC's service area. FBC believes that of the projects within FBC's service territory, power from the Brilliant Expansion project (1 and 2) will become available.

Project Name	BC Hydro Call	Capacity (MW)	Energy (GWh/year)
Brilliant Expansion 1	2003 Green Power Generation	120	202.7
Brilliant Expansion 2	2006 Open Call	< 1	226
Celgar Green Energy	2019 Biomass Energy Program	100	127.9
Arrow Lakes Hydro	1998 Negotiated EPA	185	767
Waneta Expansion	2010 Clean Power Call	335	627.4

44.2 For those not located in FBC's service area, are there any anticipated transmission limitations on being able to deliver the power to FBC's service area?

[12] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/independent-power-producers/ipp-supply-list-in-operation.pdf

Response:

FBC has not undertaken any technical evaluations of the BC Hydro transmission system to determine if there are transmission limitations to deliver to FBC's service area for any of the 70 expiring EPAs.

However, in general, FBC does not expect transmission limitations to be an issue for most projects to deliver to the FBC service territory.

45.0 Reference: Exhibit B-1, Vol. 1, pages 171-173

45.1 In the discussion on Distributed Generation, FBC raises the issue that distributed generation is not within FBC's control and is not a reliable resource option for long-term planning purposes. Does a similar issue exist with purchases from self-generators (as described in section 10.8)?

Response:

In Section 10.7 of the Application, the discussion is focused on residential or commercial rooftop solar distributed generation which, as noted, FBC does not consider a reliable resource option for long-term planning purposes. Self-generation from larger, industrial customers (the focus of Section 10.8) may or may not be a reliable source of supply depending on the characteristics of the generation and the nature of the agreement that FBC would have in place with the self-generator. For example, all of the industrial self-generation that FBC currently receives is delivered on a net-of-load, ad hoc basis over which the Company has no control with respect to timing or amount. Were the Company able to structure these purchases such that the power could be called upon when and in the amount required, it would become a better fit for long-term planning.

46.0 Reference: Exhibit B-1, Vol. 1, pages 178-179 and Appendix L, page 19

Preamble: The Application states (page 178):

"The LRMC values for the portfolios that include DSM serve as a point of reference reflecting the general level and trend of future costs. Power supply options with costs below the LRMC values could be considered viable resource options for FBC provided that they also meet FBC's monthly and annual energy and capacity requirements and LTERP objectives."

The Application states (page 179):

"FBC has adopted the Average Incremental Cost (AIC) approach to estimating the LRMC values. The AIC approach takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the additional load expected to be served within the same period."

The Application states (Appendix L):
"Figure 5 shows a visual of the AIC approach. Utilizing this approach, the term additional demand served (the full area highlighted in blue in Figure 5) refers to demand over and above that which is currently being supplied, rather than which could be supplied with existing capacity (NERA, 2011).

This distinction is particularly important when calculating the LRMC of a system that is not capacity constrained."

46.1 Please confirm that the LRMC value for any portfolio will include a number of resource options, some of which will have a cost (i.e., a UEC) that is less than the portfolio's LRMC while other options will have a cost that is greater than the portfolio's LRMC. If not confirmed, please explain why not.

Response:

FBC confirms a portfolio can include a number of incremental resource options, some of which may have a cost (as represented by a UEC) that is less than the portfolio's LRMC, while other resource options may have a cost that is greater than the portfolio's LRMC. For example, capacity-oriented resources generally have a much higher UEC value than an energy-orientated resource, but a lower UCC value. The LRMC reflects the change in total portfolio costs required to serve load above the existing load over the planning horizon. The changes in FBC's portfolio costs are a function of an increase in PPA rates and/or quantity used, selected incremental resources, changes in market prices and/or quantity of energy purchased, and reductions in WAX surplus sales.

The portfolio model accounts for these broad LRMC components in the optimization routine as shown in the response to BCUC IR1 30.1. The value of a resource to the utility depends on the alignment, or fit, between the time of delivery of energy and the forecasted utility resource gaps, as well as the resources' complementary nature to existing resources and other incremental resources over the planning horizon. Therefore, it is entirely possible that a particular resource that appears to be lower in cost compared to the overall LRMC may actually drive costs up if it is included. This is since it may displace an even more economic resource or, if the fit is bad, it may displace nothing at all and just add cost. Likewise, what appears to be an expensive resource may decrease overall costs if it is the right size and fit to meet the resource gap.

46.2 If the response to part 1 is confirmed (and in reference to the quote from page 178), would it be the case that Power supply options with costs "above" the LRMC value could also be considered viable resource options if they were used in in place of a resource option that was included in the portfolio but had a higher cost?

46.2.1 If not, why not?

46.2.2 If yes, how does FBC's portfolio analysis take this into account?

Response:

Please refer to the response to BCOAPO IR1 46.1.

46.3 If the response to part 1 is confirmed (and in reference to the quote from page 178), would it be the case that Power supply options with costs "below" the LRMC value would not be considered viable resource options if they were used in in place of a resource option that was included in the portfolio but had a lower cost?

46.3.1 If not, why not?

46.3.2 If yes, how does FBC's portfolio analysis take this into account?

Response:

Please refer to the response to BCOAPO IR1 46.1.

47.0 Reference: Exhibit B-1, Vol. 1, page 180

Preamble: The Application states:

"Portfolio A2 includes the PPA and only clean or renewable resources without any DSM, which, as described above, is used to determine the LRMC for the purposes of evaluating cost effective DSM (per the DSM Regulation). The LRMC for this portfolio is $90 per MWh and is a higher cost than portfolio A1 due to no market access, no DSM and more costly generation resources."

47.1 Please explain why the portfolio used to determine the LRMC for the purposes of evaluating cost effective DSM assumes (apart from the caveat noted in the footnotes) no market access.

Response:

As per the *Demand-Side Measure Regulation*, FBC is required to undertake an amount of DSM activity that the BCUC is satisfied represents the LRMC of acquiring energy from clean and renewable resources located within British Columbia.[13] Therefore, since there is no BC market, market access is excluded from the analysis for this particular portfolio.

[13] Demand-Side Measures Regulation, Cost Effectiveness, Section 4(1.1)(b)(i). https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10_326_2008

48.0 Reference: Exhibit B-1, Vol. 1, pages 189-190

Preamble: The Application states (page 189):

"The preferred portfolios are those that meet the LRB gaps based on the

Reference Case load forecast, includes cost effective DSM, and best meet the LTERP objectives of cost-effectiveness, reliability, and consideration of BC's energy objectives."

The Application states (page 190):

"The recommended portfolios considered for selection as the preferred portfolios are portfolios C3, B2 and C4."

48.1 Please provide a schedule that, with reference to the considerations set out on page 189, identifies the key reason(s) why each of the other portfolios discussed in sections 11.3.1, 11.3.2 and 11.3.3 were not included as one of the "the recommended portfolios considered for selection as the preferred portfolios".

Response:

Please refer to the response to BCUC IR1 31.8.

49.0 Reference: Exhibit B-1, Vol. 1, page 195

Preamble: The Application states:

"In addition, the two SCGT plants using RNG fuel included in Portfolio C3 provide significant dependable capacity that could help to defer more costly transmission and distribution infrastructure in the event that loads increase significantly beyond the Reference Case load forecast in the future, as discussed in Section 6.4."

49.1 Is the statement referenced in the preamble based on the premise that the SCGT plants would be located close to the new loads and, thereby reduce the need for additional transmission and distribution infrastructure?

Response:

The statement referenced in the preamble is based on the premise that the RNG SCGT plants would be located in a favourable location on the system close to a large load centre, such as in the Kelowna area, thereby potentially deferring the need for a larger transmission infrastructure project later into the future.

49.2 If yes, doesn't this assume that all of the new load will occur in just one or two general areas and that FBC will be able to located new SCGT plants in the proximity? How likely is this to be the case?

Response:

The statement assumes load growth will continue to occur in the Okanagan load centres and the RNG SCGT plant can be connected to one of the 138 kV stations in the Kelowna area. It is reasonable to assume load growth will continue to occur in the Okanagan in the future.

50.0 Reference: Exhibit B-1, Vol. 1, page 198

Preamble: The Application states:

"FBC has assumed capacity self sufficiency over the planning horizon due to the risks with relying on market capacity."

50.1 Do the preferred scenarios C3 and B2 assume capacity self-sufficiency over the entire planning horizon or just after a certain date?

Response:

Both preferred portfolios C3 and B2 assume capacity self-sufficiency over the entire planning horizon, except for the month of June, which is capacity self-sufficient after 2030. The key difference is the assumed need for energy self-sufficiency in portfolio B2 in the event the market becomes a less reliable source of energy in the future as discussed in Section 2.4.4.2. Although the LRMC values are similar, the average costs of these two portfolios differ as shown in Table 11-2, with portfolio B2 being notably more costly than portfolio C3. Please also refer to the response to BCOAPO IR1 54.1.

51.0 Reference: Exhibit B-1, Vol. 1, pages 214-217

51.1 Based on the 2021 LTERP Action Plan set out in Section 13.2 and assuming the Reference load forecast, are there any O&M expenses or capital expenses that FBC would anticipate incurring prior to 2027 (i.e., 2026 or earlier) that would not be considered as being included in FBC's Base O&M expenditures, its Regular Capital Expenditures or the Major Capital Projects expenditures identified in FBC's Annual Review for its 2022 Rates?

Response:

The majority of the twelve Action Plan items included in Section 13.2 of the LTERP would be considered normal course of business activities that would be performed by the appropriate FBC personnel as part of their regular work and would therefore be included in what is currently defined as Base O&M expenditures or Regular capital expenditures under the MRP[14].

Notwithstanding this, a number of the action items are beyond the scope of normal work and would require separate BCUC approvals. These include: Contingency resource(s) assessment, Implement program to help shift home EV charging, Consider initiatives to manage large loads (which may include specific rate or program development), and Prepare Submission of next LTERP. Initiatives related to managing large loads and EV charging are likely to occur in 2022-2023, while the preparation of the next LTERP will occur later, prior to the next submission in 2026.

51.1.1 If yes, what are they and what is their expected timing?

Response:

Please refer to the response to BCOAPO IR1 51.1.

14 FBC notes that the MRP is in place until the end of 2024 and the regulatory treatment of O&M beyond that time is not yet determined.

52.0 Reference: Exhibit B-1, Vol. 1, Appendix M, pages 2 and 13

Preamble: The Application states (page 2):

"PRM's role is to ensure resource adequacy when dealing with unforeseen increases in demand and forced outages in the system. It serves the utilities' ultimate goal of "keeping the lights on" by confirming that power supply will remain adequate over the planning horizon."

The Application states (page 13):

"FBC accounted for the potential of variance from the scenario load forecast to test the robustness of the prospective portfolios. To create a distribution of potential load variances, FBC used a classic multiplicative decomposition model29 to decompose historic peak loads into trend, seasonal, and irregular (random) components. FBC then used the portfolio scenario specific peak forecast after DSM savings as the average expected load in combination with a distribution representing load variance created using the components of the decomposition model."

52.1 To what extent is the PRM meant to deal with unforeseen increases in demand? In responding please indicate whether the PRM: i) Just deals with the unforeseen increases in demand associated with weather variability, ii) Deals with some of load forecast uncertainty discussed in Section 3.2 and, if so, to what extent, and iii) Deals with the load forecast uncertainty identified in the load scenarios set out in Section 4.0 and, if so, to what extent.

Response:

The PRM adequacy assessment addresses reasonable variances from the expected forecast based on historical weather variability, as well as other external environment irregularities such as the COVID-19 pandemic as discussed in Section 3.2, assuming that the gross load impacts of the COVID-19 pandemic remain within historically observed variation. The COVID-19 pandemic impacted the usage of the load classes in different and offsetting ways, resulting in minimal variances to the load at the point of power supply. The PRM assessment does not address resource adequacy when the variances are step changes in load or fundamental changes in the operating environment such as the load drivers and load scenarios discussed in Section 4.

53.0 Reference: Exhibit B-1, Vol. 1, page 183 and Appendix M, pages 16-17

Preamble: The Application states:

"Table 3-1 below shows the LOLE of the preferred portfolio (C3) over the planning horizon, and demonstrates that the PRM requirement of LOLE equal to or less than 0.1 days per year has been met over the planning horizon."

53.1 Based on Table 3-1, the LOLE for the preferred portfolio (C3) is 0.04 or less for all of the years considered which is well below the target of 0.1. Does this mean that the assumed in-service dates for the new resources identified in portfolio C3 could be "pushed out" relative to the dates identified in Figure 11-3 (page 183)?

53.1.1 If yes, what later dates would still meet the 0.1 target?

53.1.2 If not, why not?

<u>Response:</u>

Each portfolio must first meet the energy and capacity requirements of the load scenario under expected conditions. Then the portfolio outcome is tested to confirm reliability as described in the response to BCUC IR1 30.1. The lower LOLE value of 0.04 is largely the outcome of FBC recognizing the full 370 MW of market access available on 71L for contingency purposes as a result of FBC's improved market access through the CEPSA. As per section 6.9 of the CEPSA agreement, FBC has the ability to make real-time nominations to overcome unexpected conditions. The 370 MW of market access available for unexpected conditions is large enough to overcome many contingency scenarios, resulting in a lower LOLE value. If the conditions of FBC's market access were to change, FBC could have materially less than 370 MW of market access to support contingency events in the future, and the LOLE would increase. It is not prudent to rely on the market as both a base and back-up resource in the long run. Therefore, the new resources identified in portfolio C3 cannot be pushed out relative to the dates identified in figure 11-3.

54.0 Reference: Exhibit B-1, Vol. 1, Appendix L, pages 18-19

54.1 In applying the AIC method, is the value used for "current load requirement" per Step 4 of the description on page 18 based on: i) the current load requirements per the base year of the analysis or ii) the load requirements that can be met by existing resources? The discussion on page 19 suggests it is the former.

Response:

In applying the AIC method, the value used for "current load requirement", per Step 4 of the description on page 18, is based on the current load requirements per the base year of the analysis, rather than what could be met by existing resources. The existing load needs to be served regardless of incremental load growth, and existing resources can change over the planning horizon. Furthermore, there are additional costs to further utilize existing resources.

In the hypothetical numerical example on page 20 of Appendix L, the Energy in Year_0 is shown as constant, but the Total Costs to serve Year_0 load vary. The costs to meet the existing load over the planning horizon can vary with changes in environmental costs (such as negotiating for a clean market adder), changes in existing resource costs (such as increases in the PPA rates and ratchet costs of capacity), as well as portfolio policies (such as introducing energy self-sufficiency requirements in portfolio B2).

The LRMC reflects only the incremental costs associated with incremental load, after netting out changes in the cost to serve existing load. The concept of marginal cost relates to the idea of opportunity cost, where the value of something is calibrated in terms of lost alternatives or opportunities. The incremental load over the planning horizon is what can change. The variables in the portfolio that impact existing load as well as future load are reflected in the average costs, as opposed to marginal costs, as these costs will be incurred regardless of the incremental load.

54.2 Please confirm that the description on page 18 sets out the approach used by FBC in the 2021 LTREP for all of the LRMC values presented in Section 11.3 of the Application.

Response:

Confirmed.

54.2.1 If not confirmed, please note the exceptions, explain the approach used and explain why.

Response:

Please refer to the response to BCOAPO IR1 54.2.

55.0 Reference: Exhibit B-1, Vol. 1, Appendix L, Section 5

55.1 This section discusses the appropriateness of using of the AIC approach versus the Perturbation Approach in a number of different circumstances. One circumstance that is not addressed is how the LRMC should be determined for purposes of use in rate design (e.g. stepped rates). In such circumstances, which approach should be used and why?

Response:

Appendix L recognizes the potential for the LRMC to be a component of rate design. The context in how marginal costs are applied will determine whether the AIC or Perturbation approach is correct, as discussed in Section 6.3 of Appendix L. As acknowledged by Bonbright,[15] there are limitations of marginal costs as a basis for optimal pricing and the application of the LRMC in rate design can be a point of debate. The LRMC is not a replacement for looking at various cost components resulting from an embedded cost of service study.

15 Bonbright, Principles of Public Utility Rates, Chapter 17: Marginal Costs and Optimal Pricing.

Attachment 33.1

Lumidyne Consulting LLC

Incentive Methodology

This document outlines the incentivization approach taken in FortisBC's 2020 Conservation Potential Review (CPR) and the demand side management (DSM) program potential scenario analyses. The goal of the document is to present the methodology that stakeholders can use to calculate measure-level incentives using data provided in the appendix attachments to the CPR and the supplemental data provided in this report.

To calculate measure-level incentives, we can use the data sources listed in Table 1.

Table 1. Data Sources for Calculating Measure-Level Incentives

Data Type	Data Source
Measure Characterization • Sector • Unit Basis • Lifetime • Increm. Energy Savings • Incremental Cost • Increm. Cost Proration Factor • O&M Savings	Appendix B2 of 2020 CPR Report
Targeted Levelized Incentive Rates	Table 2 of this document
Lower/Upper Bounds on Incentive Percentages	Table 3 of this document
Discount Rates	Appendix B3 of 2020 CPR Report

Targeted levelized incentives are the incentive rates—applied to the net present value of energy savings over a measure's lifetime—that are used to find an initial unbounded incentive amount for each measure. The targeted levelized incentives rates varied by analysis and sector, as shown in Table 2. The rationale for using levelized incentive rates is described in Section 2.5.3.3 of the 2020 CPR report.

Table 2. Targeted Levelized Incentive Rates by Scenario (2020$/kWh)[1]

Scenario	Commercial	Industrial	Residential
CPR Market Potential	$0.011	$0.025	$0.124
Program Potential - 50% Scenario	$0.007	$0.015	$0.074
Program Potential - 62% Scenario	$0.011	$0.025	$0.124
Program Potential - 72% Scenario	$0.020	$0.046	$0.229
Program Potential - 84% Scenario	$0.038	$0.086	$0.428
Program Potential – 100% Scenario[2]	NA	NA	NA

The program potential scenarios' naming conventions (e.g., 50%, 62%, etc.) correspond to the adoption-weighted average incentive as a percentage of incremental costs across all measures contributing to the forecast program potential. Mathematically, the naming conventions were derived using Equation 1, where incentive spending and incremental equipment costs are totals across all measure adoption contributing to program potential. Note that this metric incorporates cost discounting over time.

[1] Since the analysis used nominal dollars, the targeted levelized incentives were escalated at a 2%/year inflation rate over the forecast horizon, which is analogous to staying constant in real 2020 dollars.
[2] The "Program Potential – 100% Scenario" applied incentives that were 100% of the incremental measure costs, and thus did not rely on targeted levelized incentive rates.

Equation 1. Weighted-Average Incentive as a Percentage of Incremental Costs

$$WtdAvgIncentivePct = \frac{NPV(DiscountRate,\ IncentiveSpending_{year})}{NPV(DiscountRate,\ ProratedIncremCosts_{year})}$$

In addition to the targeted levelized incentive rates, the analysis imposed minimum and maximum bounds, expressed as a percentage of incremental equipment costs, on measure-level incentives. The maximum incentive percentage is meant to ensure that ratepayers aren't paying more than is required to cover the incremental cost of the efficient measure. The minimum incentive percentage ensures that incentives are a large enough percentage of incremental costs to promote an increase in customers who adopt efficient measures. Experience has shown that incentives that are too small of a percentage of incremental costs generally lead to little adoption above what would have occurred in absence of the incentive, leading to an undesirable share of incentives being spent unproductively on customers who would have adopted efficient measures regardless of the incentive level. Table 3 shows the upper and lower bounds on measure-level incentives applied in these analyses.

Table 3. Upper and Lower Bounds on Incentives as a Percentage of Incremental Costs

Incentive Bounds	Value
Minimum Incentive as % of Incremental Cost (%)	25%
Maximum Incentive as % of Incremental Cost (%)	100%

Illustrative Example

To demonstrate how a measure's incentives are calculated, this section provides a step-by-step example. To begin, let's consider the ENERGY STAR windows measure in the single-family detached homes customer segment.

Table 4. Illustrative Measure Characteristics

Measure Characteristic	Value
Sector	Residential
Unit Basis (unit basis)	per Home
Efficient Measure Lifetime (years)	20
Incremental Cost ($/unit basis)	$1,646
Incremental Cost Proration Factor (%)	100%
O&M Savings ($/year-unit basis)	$0
Incremental Energy Savings (kWh/year-unit basis)	1,174

Additionally, we'll use the following assumptions:

Table 5. Illustrative Auxiliary Assumptions

Assumption	Value
Discount Rate (%/year)	7.9%
Targeted Levelized Incentive ($/kWh)	$0.124
Minimum Incentive as % of Incremental Cost (%)	25%
Maximum Incentive as % of Incremental Cost (%)	100%

The first step is to find the participant's cost of lifetime electric energy savings (prior to incentives), which is often called the levelized cost of savings. This formula uses the prorated incremental cost, which is simply the incremental cost multiplied by the proration factor.[3]

Equation 2. Cost of Participant Savings over Measure Lifetime

$$ParticipantSavingsCost = \frac{NPV(DiscountRate,\ ProratedIncremCost_{year} - OMSavings_{year})}{NPV\left(DiscountRate,\ Savings_{year}\right)}$$

Since the incremental costs are only incurred at the beginning of year 1 and operation and maintenance costs are zero, the numerator becomes $1,646. For this measure, we're assuming that annual energy savings are constant over the measure lifetime, so we can replace the NPV (net present value) function with the PV (present value) function for the denominator:

Equation 3. Present Value of Lifetime Savings

$$LifetimeSavings = PV(DiscountRate, Lifetime, -Savings) = PV(7.9\%, 20, -1{,}174) = 11{,}613\ kWh/home$$[4]

Next, we finalize the calculation for the participant's cost of lifetime energy savings:

Equation 4. Cost of Energy Savings over Measure Lifetime

$$ParticipantSavingsCost = \frac{\$1{,}646}{11{,}613 kWh} = \$0.142/kWh$$

Although we're targeting an incentive per NPV of savings of $0.124/kWh, we also want to respect the minimum and maximum bounds on the incentive as a percentage of incremental cost. As such, we must first find the unbounded incentive for this measure:

Equation 5. Unbounded Measure Incentive

$$UnboundedIncentive = TargetedIncentive * LifetimeSavings = \$0.124 * 11{,}613 = \$1{,}440/home$$

To determine whether the unbounded incentive falls within the bounds, we must compare it to the incremental costs:

Equation 6. Unbounded Measure Incentive as Percentage of Incremental Cost

$$UnboundedIncentivePct = \frac{UnboundedIncentive}{ProratedIncremCost} = \frac{\$1{,}440}{\$1{,}646} = 87\%$$

[3] Incremental cost proration factors that are less than 100% correspond to measures that materially impact both gas and electric end uses, and therefore the cost of incentivizing the measure is likely to be shared between FortisBC's gas and electric businesses. The electric-focused analysis accounts for cost sharing by applying a prorated incremental cost to the calculation of incentives, instead of using the full incremental cost.

[4] Savings generally occur throughout each operating year, and not solely at the end of each year of operation. To account for this nuance, the DSMSim™ model applies a half-year compounding factor, which approximates the net present value across multiple periods (e.g., months) in the year. As such, the model's calculation multiplies the present value of savings by *(1+DiscountRate)^0.5* before finding the final *LifetimeSavings*. This small adjustment is omitted from the calculations above to facilitate comprehension, but the adjustment is required to match the calculations performed in the savings potential analyses.

Since the unbounded incentive falls within the 25%-100% lower-to-upper bounds, we can treat the unbounded incentive as equivalent to the bounded incentive. If this were not true, we would find a bounded incentive as follows:

Equation 7. Bounded Measure Incentive as Percentage of Incremental Cost

$$BoundedIncentivePct = Min\big(100\%, Max(25\%, UnboundedIncentivePct)\big) = Min\big(100\%, Max(25\%, 87\%)\big) = 87\%$$

Equation 8. Bounded Measure Incentive

$$BoundedIncentive = BoundedIncentivePct * ProratedIncremCost = 87\% * \$1{,}646 = \$1{,}440/home$$

The bounded incentive amount can be converted back to a realized incentive rate per NPV of savings as follows:

Equation 9. Bounded Levelized Incentive Rate

$$BoundedLevelizedIncentive = \frac{BoundedIncentive}{LifetimeSavings} = \frac{\$1{,}440}{11{,}613} = \$0.124/kWh$$

Alternatively, we can convert the bounded incentive to a realized incentive rate per first-year savings:

Equation 10. Bounded First-Year Incentive Rate

$$BoundedFirstYrIncentive = \frac{BoundedIncentive}{FirstYearSavings} = \frac{\$1{,}440}{1{,}174} = \$1.23/kWh$$

Adhering to the equations above, we can explore the outcomes of various targeted levelized incentive scenarios:

Table 6. Illustrative Incentive Outcomes by Scenario

	Scenario				
	A	B	C	D	E (100%)
Targeted Levelized Incentive ($/kWh)	$0.074	$0.124	$0.229	$0.428	NA
Unbounded Incentive ($/home)	$864	$1,440	$2,664	$4,968	NA
Unbounded Incentive % of Increm. Cost	52%	87%	162%	302%	NA
Bounded Incentive % of Increm. Cost	52%	87%	100%	100%	100%
Bounded Incentive ($/home)	$864	$1,440	$1,646	$1,646	$1,646
Bounded Levelized Incentive ($/kWh)	$0.074	$0.124	$0.142	$0.142	$0.142
Bounded First-Year Incentive ($/kWh)	$0.74	$1.23	$1.40	$1.40	$1.40

Using the appropriate measure characterization assumptions and targeted levelized incentives, these steps can be replicated for all measures assessed in the 2020 CPR's market potential and the DSM program potential scenarios.