Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604)576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
www.fortisbc.com

March 31, 2022

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 2

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. PLANNING ENVIRONMENT

43.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1 (Application), Section 2.4.4, p. 64; Exhibit B-2, BCUC IR 1.2, 1.3, 1.7; Exhibit B-8, RCIA IR 29.1

Regional Market Opportunities and Risks

On page 64 of the Application, FortisBC Inc. (FBC) states:

> Therefore, FBC plans to ensure it has sufficient capacity resources available in place to meet forecast peak demand. The month of June is an exception due to the abundant freshet hydropower available in the market. For the purposes of this LTERP, FBC assumes that it will be able to purchase a limited amount of June capacity from the market, on a forward block basis as opposed to in 'real time', reliably and cost-effectively until 2030. After that time, FBC has assumed capacity self-sufficiency for all months, including June, given the longer-term market risks.

43.1 Please discuss whether there are certain market signals and risks (such as price, availability, etc.) that would cause FBC to change from assuming a certain amount of June capacity could be purchased from the market, to requiring capacity self sufficiency for June.

Response:

Certain market signals and risks could cause FBC to change its assumptions from being able to purchase June capacity from the market to instead requiring self-sufficiency. June is a freshet month and FBC currently expects that market capacity blocks will be available, especially if purchased in advance. A signal or example that this expectation should be revised would be if FBC were to be unsuccessful in procuring the June capacity it required from the forward market on an ongoing basis.

If the PNW region were to experience persistent supply shortages and/or increased load requirements during June of each year, likely resulting in higher market prices, FBC would likely move toward capacity self-sufficiency rather than relying on the market. However, it is unlikely that June market prices alone would be the driving requirement behind a June capacity self-sufficiency requirement by FBC. This is because even if market prices were to become very high, it would still likely be economic to purchase market power at elevated prices for one month of the year, rather than to build a new capacity resource.

Please also refer to the responses to BCUC IR1.1.2 and 1.1.3 for further discussion of market risk related to capacity gaps and the risk of relying on the market for capacity after 2030.

43.2 Please expand on how FBC determined that purchasing a limited amount of June capacity from the market would be cost effective through to 2030.

43.2.1 If possible, please compare the forecasted market prices assumed against other supply side resources.

<u>Response:</u>

As shown in the response to RCIA IR1 1.1, and explained further in the response to RCIA IR1 23.1, FBC has forecast sufficient capacity resources for all months other than June until 2030. If the June surpluses shown in RCIA IR1 1.1 were adjusted to remove the 75 MW of market access, then a deficit would be evident. Therefore, FBC only has a need to meet capacity gaps for one month of the year in the first half of the planning horizon. Purchasing a limited amount of capacity from the market to meet the single-month capacity gap in June is more cost effective for customers than building a new resource.

The following table shows the forecast cost of market capacity in June from 2021 to 2030 compared to other capacity-orientated supply-side resources, expressed in units of dollars per MW-Month.[1] FBC used the Mid-C price forecast adjusted to reflect on-peak prices to represent the cost of market capacity, and multiplied the price by the number of applicable high load hours. The large amount of clean and renewable resources being developed in the Pacific Northwest results in the forecast June market capacity price decreasing over time, although the volatility in prices may increase and is not reflected here.

[1] The comparison supply side resources are drawn from values provided in the response to CEC IR1 5.3, multiplied by (1000/12) to convert from kW-Year to MW-Month.

Year	June Market Capacity ($ per MW-Month)	Battery Storage ($ per MW-Month)	Distributed Battery Storage ($ per MW-Month)	RNG SCGT ($ per MW-Month)
2021	$11,570	$21,572	$18,194	$10,778 to $12,243
2022	$8,328	$20,901	$17,583	$10,759 to $12,224
2023	$7,483	$20,230	$16,971	$10,740 to $12,204
2024	$6,687	$19,559	$16,360	$10,802 to $12,267
2025	$6,400	$18,888	$15,749	$10,883 to $12,348
2026	$5,833	$18,555	$15,446	$10,877 to $12,343
2027	$5,761	$18,222	$15,142	$10,839 to $12,304
2028	$5,019	$17,889	$14,839	$10,845 to $12,310
2029	$4,543	$17,555	$14,535	$10,796 to $12,261
2030	$4,348	$17,222	$14,231	$10,784 to $12,248

43.3 If FBC were to assume capacity self sufficiency for all months prior to 2030, please discuss at a high-level what impacts this would have on FBC's portfolio analysis provided in Section 11 of the Application, including approximate changes in timeframes whereby new resources would be required, if applicable.

Response:

If FBC were to assume capacity self-sufficiency for all months prior to 2030 including the month of June, FBC would require new supply-side resources immediately. As discussed in Section 7.2 and shown in Figure 7-4 of the Application, June capacity gaps start in 2021 based on the Reference Case load forecast and increase over the planning horizon. June is a freshet month and FBC expects June market blocks, especially if purchased in advance, to be available for the foreseeable future. However, in 2030, or at the time when other capacity resources are being acquired to meet capacity requirements in other months, it would be reasonable and prudent to include June within the self-sufficiency requirement at that time as opposed to continuing with the historical practice of treating June as an exception month. The earliest that FBC could realistically target capacity self-sufficiency in all months is 2026, as all new resource options considered within the portfolio analysis have lead times for development and construction. FBC is provided an additional 50 MW of capacity in June after the WAX RCA expires in 2025, reducing the size of the June capacity gap. The RNG SCGT resources in the various portfolio scenarios would need to be accelerated and aligned with remaining gaps in June that emerge prior to 2030, consistent with FBC's contingency plans as outlined in Section 11.3.9.1 of the Application and in the response to CEC IR1 57.1.

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 1.2, FBC stated:

> However, even though there have been no circumstances where FBC has not been able to buy the required power since the CEPSA has been effective, this does not mean there is no risk. Market supplies can be very tight at times. For example, during the recent Heat Dome event in June 2021, supply was extremely uncertain. The fact that Powerex found the supply to meet FBC load does not mean that the market was robust, but rather that FBC was fortunate.

In response to BCUC IR 1.3, FBC stated:

> However, given the extreme load and market power price events in June 2021 and other 'scarcity pricing' events discussed in Section 2.4.4.1, FBC now plans to meet June gaps until 2030 with firm, fixed-price market block purchases, rather than leaving load requirements subject to day ahead or real-time market prices and availability.

In response to BCUC IR 1.7, FBC provided Updated Figure 2-18, the Mid-C Electricity Historical and Forecast Prices.

43.4 Please expand on the price events experienced in June 2021. If possible, please compare to market pricing experienced in June from the previous 5 years, including any 'scarcity pricing' events.

Response:

As stated in the response to CEC IR1 38.1, while there were indications that hot weather and therefore high demand would blanket the region during June 2021, the temperatures and power use far exceeded expectations and operational load forecasts for many utilities in the area. Fortunately, the extreme weather mainly impacted the Pacific Northwest, rather than the entire west coast. Had California also experienced significantly hotter weather as well, that would have put further upward pressure on the western power markets. It was also fortunate that there was sufficient regional hydro generation, in the form of both regulated storage water and snowpack melt, to help keep the regional system balanced. Nevertheless, Mid-C Day Ahead prices reached a peak level of $334 USD per MWh on June 28, 2021. Until then, Mid-C had not seen prices reach this level during the month of June since the Western US energy crisis of 2000/2001. Please see the table below for June Mid-C Day Ahead prices for the years 1996 through 2021.

June Prices 1996 - 2021		
Year	Maximum On Peak Price $USD/MWh	Minimum Off Peak Price $USD/MWh
1996	$ 12.06	$ 3.11
1997	$ 19.37	$ 2.04
1998	$ 20.33	$ 3.78
1999	$ 41.96	$ 3.52
2000	$ 672.88	$ 32.46
2001	$ 148.85	$ 24.39
2002	$ 21.61	$ 1.95
2003	$ 47.77	$ 10.61
2004	$ 47.97	$ 10.21
2005	$ 51.67	$ 15.53
2006	$ 62.03	$ 0.25
2007	$ 60.72	$ 17.00
2008	$ 90.94	$ (7.50)
2009	$ 31.76	$ 0.28
2010	$ 32.75	$ (2.00)
2011	$ 37.47	$ (6.97)
2012	$ 20.34	$ (12.65)
2013	$ 40.90	$ 10.72
2014	$ 41.27	$ (1.02)
2015	$ 68.12	$ 17.24
2016	$ 35.19	$ 10.18
2017	$ 29.46	$ (5.86)
2018	$ 26.55	$ (3.76)
2019	$ 66.27	$ 2.73
2020	$ 20.13	$ (14.55)
2021	$ 334.22	$ 4.13

Please refer to the response to BCUC IR2 43.1 for a discussion that reliability is the primary concern for June capacity gaps, not price.

43.4.1 In light of the market availability and pricing experienced in June 2021, please expand on why FBC considers continuing to rely on the market for June capacity through 2030 to be a reasonable assumption and practice in order to meet forecast peak demand.

Response:

FBC recognizes that during the June 2021 event market supplies were very constrained and pricing was particularly high due to extreme temperatures. However, at this time, FBC has insufficient data to determine whether the June weather event was anomalous or not, at stated in the response to MoveUp IR1 2.1.4. FBC continues to expect market power to be available during June for the foreseeable future, especially if purchased in advance in the form of forward blocks.

As stated in the response to BCUC IR2 43.1, if the region were to experience persistent supply shortages and/or increased load requirements during the month of June, and FBC were unable to procure the required power on an ongoing forward basis, FBC would reconsider its practice of relying on the market for June capacity through 2030.

Residential Consumer Intervener Association (RCIA) IR 29.1 asked FBC to explain why no unit capacity cost (UCC) value is provided for the Market Purchases resource option shown in Table 10-2 of the Application.

In response to RCIA 29.1, FBC stated: "FBC does not consider the market to be a reliable source of capacity over the planning horizon and therefore it is not a long term resource option. Please also refer to the response to BCUC IR1 1.3."

43.5 Please explain why a UCC value for Market Purchases cannot be provided given FBC is proposing to rely on market capacity purchases for June through to 2030. Please elaborate on the anticipated source(s) and timeframe(s) for the "forward block" June capacity contracts

Response:

A market block is a constant amount of energy delivered in all designated[2] hours of the month. A market block provides capacity by creating an obligation to deliver energy during all the heavy load hours. In contrast, the UCC value generally represents the fixed cost portion of a generator and any associated costs to maintain the unit in a ready state for dispatch.

To provide the cost of market capacity in the response to BCUC IR2 43.2, FBC used the units of MW-Months as the comparative value, as opposed to kW-Year units. The cost of a market block varies by month making it difficult to provide a reflective UCC expressed in kW-Year, especially when market capacity purchases are considered available only for the month of June.

[2] Light Load Hours (LLH) include all Sundays and North American Electric Reliability Corporation (NERC) holidays, and hours between 22:00 (Hour Ending 23) and 06:00 (Hour Ending 6) each night. Heavy Load Hours (HLH) include all hours between 06:00 (Hour Ending 7) and 22:00 (Hour Ending 22), Monday to Saturday, excluding NERC holidays.

The anticipated source of market block capacity purchases for June would be through the CEPSA agreement with Powerex, and would be discussed in FBC's Annual Electric Contracting Plan (AECP).

44.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Executive Summary, p. ES-17; North American Electric Reliability Corporation, 2021 Long-term Reliability Assessment (2021 LTRA),[3] p. 120

Energy Self-Sufficiency

On page ES-17 of the Executive Summary, FBC states:

> Should market conditions change such that market energy was no longer a reliable and cost effective resource, portfolio B2 would become the preferred portfolio. This portfolio has slightly higher costs and environmental impacts than portfolio C3, but it has a lower cost and provides higher resiliency and job creation than other portfolios considered for the preferred portfolio. In portfolio B2, FBC has assumed energy self-sufficiency after 2030. However, if market conditions changed prior to that, FBC would seek to implement this portfolio sooner than 2030 so that generation resources are put in place to mitigate this market risk.

On page 120 of the 2021 LTRA, North American Electric Reliability Corporation (NERC) states:

> The U.S. Northwest and Southwest part of WECC (NWPP-US & RMRG and SRSG) have increasingly variable demand and resource profiles, raising the risk of energy shortfalls. Energy analysis indicates the potential for 23 load-loss hours in the Northwest in 2022. The Southwest faces potential load-loss hours in 2024. As resource planners in parts of the Western Interconnection turn increasingly to external transfers for resource adequacy, the need for regional coordination and planning is growing.
>
> …
>
> **WECC-NWPP-BC**
>
> The British Columbia assessment area shows little change from last year's LTRA. This area continues to be a winter-peaking demand area that is served mainly by conventional storage-capable hydro resources. Relying on existing resources only, the assessment area is expected to be short of the calculated reserve margin beginning the winter of 2030; however, plans are in place to increase the hydro capacity by then, and this will be sufficient to meet any demand growth they are expecting. With the storage capable technology, WECC is not concerned with this area's ability to meet variability in demand and or resources. The only potential issue would be on the continuing drought conditions experienced lately, causing less fuel availability for the hydro resources; however, this has not had a significant

3 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

impact to date. WECC will continue monitoring the drought conditions for fuel availability.

44.1 Given the energy constraints anticipated in the US Northwest, please give FBC's view on the risks to FBC of relying on the market. Please discuss if FBC enjoys preferential access to BC energy from Powerex, or if FBC expects to see higher market prices at peak times given the energy shortfall risk in the Northwest in 2022 referenced above.

Response:

Given the resource adequacy constraints anticipated in the Pacific Northwest, FBC has recommended within the 2021 LTERP to be capacity self-sufficient from 2030 onwards, while relying on the market for energy requirements only. In FBC's 2016 LTERP, the BCUC determined that energy self-sufficiency was not in the public interest. Further, as explained in the response to CEC IR1 18.2, FBC does not consider it prudent to rely on the capacity surplus of other utilities or generators to meet its expected demand over the long term, and that doing so would contribute to increased reliability and price risk for the entire region.

FBC expects that market energy will continue to be a reliable and cost-effective resource. Individual utilities are increasingly investing[4] in intermittent renewable resources, and many are overbuilding in order to gain the amount of dependable capacity required to meet their peak demand. Therefore, there is increased potential for large amounts of lower-priced surplus energy to become available in the market when other utilities' own loads are lower than forecast or their energy supplies are higher than forecast.

FBC does not have preferential access to BC energy from Powerex under the CEPSA. However, the CEPSA does provide FBC with improved market access. The source of wholesale market purchases, whether they come from within BC or from a source in the US, is ultimately at the discretion of Powerex.

FBC does not necessarily expect to see higher overall market prices, but does expect increased price volatility as capacity in the region becomes increasingly constrained. This could likely result in higher pricing during peak times.

[4] As illustrated in Appendix D – PNW Electric Utilities IRP Comparison Table of the Application.

B. LONG-TERM LOAD FORECAST

45.0 Reference: LOAD FORECAST

Exhibit B-9, CEC IR 1.2; Exhibit B-2, BCUC IR 5.1

Load Forecast Growth Assumptions

In response to Commercial Energy Consumers Association of BC (CEC) IR 1.2, FBC stated that the "average annual gross load growth rate for the last 10 years was 0.54 percent per year. The average annual gross load growth rate for the BAU is forecast to be 0.90 percent per year. The average annual gross load growth rate for the Reference Case is forecast to be 1.56 percent per year."

FBC confirmed in the response to BCUC IR 5.1 that the only new growth being considered in the Reference Case forecast is due to electric vehicle (EV) charging by residential customers, and new industrial load.

45.1 Please provide FBC's views on the relative risks and possible consequences of either under-estimating or over-estimating the reference load forecast in this LTERP proceeding. Please make reference to FBC's LTERP planning objectives where necessary, and relevant BC energy objectives and policy.

<u>Response:</u>

Section 11.3.9.1 of the Application discusses FBC's contingency portfolio supply plans relating to the risks and possible consequences of customer loads being higher or lower than those in the Reference Case load forecast. This contingency planning enables FBC to effectively manage load changes over time through adjustments to supply resources included in the preferred portfolios as well as through EV charging shifting and DSM programs. As discussed in Section 11.3.9, the resources included in the preferred portfolios meet the LTERP planning objectives, which include cost-effectiveness, reliability, and consideration of BC's energy objectives as well as the inclusion of cost-effective DSM. Programs that shift EV charging outside of peak demand periods help reduce the requirement for additional supply resources, thereby reducing the risk of higher costs for customers.

In the event of load increases greater than those in the Reference Case load forecast, FBC has several options that could be implemented separately or in combination, depending on the specific energy and capacity requirements. These load increases greater than the Reference Case load forecast could be due to, for example, changes in BC energy policies, such as incentives or sales targets for medium- or heavy-duty EVs, or municipal policies regarding fuel switching from natural gas to electricity. FBC's options to address the risks of higher loads include the following:

- Increase market energy purchases;
- Increase PPA energy and capacity (if not already at its maximum);
- Implement other EV charging peak shifting options;

- Ramp up DSM to higher incentive levels; and
- Accelerate new resources from the preferred portfolios which require shorter lead times, such as an SCGT plant using RNG or battery storage units.

In the event of lower loads than expected under the Reference Case load forecast, FBC has several options which include the following:

- Decrease market energy purchases;
- Decrease PPA energy and capacity (if not already at its minimum); and
- Defer implementation of resources identified in the preferred portfolios.

These options provide FBC with flexibility to adjust its resources to match load requirements and avoid the risk of implementing resources that may not be required until much later. This will allow FBC to continue to maintain a cost-effective supply portfolio.

46.0 Reference: INTRODUCTION

Exhibit B-2, BCUC IR 8.7; 8.8, 8.11; Exhibit B-4, BCOAPO IR 8.2, 8.4; BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application Proceeding (F2023-F2025 RRA), Exhibit B-2-3-1, pp. 10-22 – 10-25

Industrial Load Growth

In response to BCOAPO IR 8.4 FBC stated that the new industrial customer load forecast included in the business as usual (BAU) forecast consists of six cannabis customers and one forestry customer.

In response to BCUC IR 8.8 FBC stated to that new projects included in the BAU forecast have a very high certainty (near 100 percent probability) of materializing because they have progressed past the initial stages of procuring power from FBC. Additional projects were added to the Reference Case load forecast that also have a reasonably high probability (at least 75 percent) of materializing, but were still in the initial stages of procuring power from FBC.

In response to BCOAPO IR 8.2, FBC stated:

> 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.

46.1 Please provide an update on whether all of load associated with new industrial customers included in the BAU forecast has materialised, and if not, what proportion has materialized. Where individual customers are not yet operational, please provide an estimate of the financial year in which they are expected to begin production.

Response:

All seven of the loads associated with new industrial customers included in the BAU forecast have materialized at this time. All of the new cannabis customer loads are currently in the commercial class, as they have not yet ramped up production enough to be moved into the industrial class.

In response to BCUC IR 8.11, FBC stated that the additional industrial load in the Reference Case load forecast when compared to the BAU is due solely to four new projects. Two relate to new customers and two relate to existing customers. The range of the projected loads is between approximately 3 GWh and 29 GWh over the planning horizon.

Section 10.3.3 of BC Hydro's Electrification Plan presented in the BC Hydro F2023-F2025 RRA outlines the Load Attraction component which targets future industrial customers. Load Attraction encompasses BC Hydro's actions to connect new customers to the BC Hydro system and grow its load by promoting B.C.'s clean energy advantage and attracting innovative new industries/operations to B.C. It focuses on potential customers that have flexibility in their choice of jurisdiction and want their operations to be powered by clean electricity. Load Attraction programs are designed to provide incentives to potential customers to connect and stay connected to BC Hydro's system.

46.2 Please discuss, with rationale, whether FBC intends to provide similar incentives to potential Industrial customers in FBC's service territory.

Response:

Please refer to the responses to BCSEA IR1 9.1 and BCUC IR1 37.2.

The 2021 LTERP does not include a formalized incentive structure for attracting new industrial customers; however, FBC continues to seek ways to better support customers, both new and existing. For example, FBC is developing an interruptible rate for large customers and is working with potential customers to find locations with adequate capacity in order to minimize system upgrades.

46.3 Please provide FBC's views on the impact, if any, of BC Hydro's Load Attraction program on FBC's projected industrial load growth over the forecast period in its own service territory.

Response:

FBC's potential new load growth is very likely to be impacted by BC Hydro's Load Attraction program. This has already been seen, with some new large load customers choosing to locate in BC Hydro's territory rather than FBC's territory.

Regarding projected load growth based on existing customers, FBC does not expect that BC Hydro's program will have a significant impact since these customers have existing facilities and infrastructure that will be costly to re-locate.

47.0 Reference: LOAD FORECAST

Exhibit B-1, Section 4.1.4, p. 105; Appendix H, p. 39; Climate Projections for the Okanagan Region February 2020, pp. 20-22; 29[5]; BC Hydro Integrated Resource Plan (IRP) Application, Exhibit B-1, Appendix I, p. 2

Impact of Climate Change on Annual and Peak Loads

On page 39 of Appendix H to the Application, FBC provides the Load Scenario assumptions for the climate change load driver:

> The key assumptions applied to each scenario are:
>
> - Scenario 1 (Upper Bound): The temperature on the ten average hottest days of the year increases by 2.1 degrees Celsius and the temperature on the ten average coldest days of the year decreases by 6.2 degrees Celsius. In this scenario, this driver increases both energy and peak winter demand.
> - Scenario 2 (Lower Bound): The average temperature on all days of the year increases by 2 degrees Celsius. In this scenario, this driver decreases both energy and peak winter demand.
> - All other scenarios: The average temperature on all days of the year increases by 2 degrees Celsius. In these scenarios, this driver decreases both energy and peak winter demand. The temperature on the ten average hottest days of the year increases by 0.7 degrees Celsius, and the temperature on the ten average coldest days of the year decreases by 2.6 degrees Celsius. In these scenarios, this driver increases both energy and peak winter demand.[83]
>
> Footnote 83: Note that the average two degree change is added to all days, even extreme days. This yields a net average increase of 2.7 degrees on the hottest days, and a net average decrease in temperature of 0.6 degrees on the coldest days.

The Regional Districts of the North Okanagan, Central Okanagan and Okanagan-Similkameen partnered with the Pacific Climate Impacts Consortium and Pinna Sustainability and developed a Climate Projections report for the region (Okanagan Climate Projections), identifying climate projections for both the 2050s and the 2080s.

Pages 20 to 22 of the Climate Projections Report discusses the projections for the Hottest Days, 1-20 Hottest Day, and Cooling Degree Day indicators, and Heating Degree Days is discussed on page 29. The summary for the initial 3 indicators is included below:

[5] https://www.rdos.bc.ca/development-services/planning/strategic-projects/climate-projs/

Hottest Days

About this Indicator

Hottest days refers to the hottest daytime high temperature of the season (or year). This measure illustrates how extreme temperature changes are projected to unfold over time.

Projections

- In the past, the hottest summer day in the Okanagan region was about 30°C. By the 2050s, hottest day temperatures are expected to increase by 4.5°C, and by over 7°C by the 2080s.
- The average past hottest day temperature in the valley bottoms was approximately 36°C. These temperatures are also expected to warm by 4.5 degrees by the 2050s, and 7 degrees by the 2080s, resulting in temperatures over 43°C in the populated areas of the Okanagan region by the end of the century.
- Spring temperatures across the Okanagan region are also projected to warm, though the magnitude of the change is smaller than Summer. By the 2050s, the hottest spring day is projected to increase by 3.0°C to 25.7°C, and by 4.7°C to 27.4°C by the 2080s.
- In the future, the annual hottest daytime highs will be as warm as extreme 1-in-20 hottest day temperatures of the past. **This is a remarkable change in that what was once a rare extreme heat event will become commonplace.**

1-in-20 Hottest Day

About this Indicator

1-in-20 hottest day refers to a day so hot that it has only a 1-in-20 chance of occurring in a given year. That is, there is a 5% chance in any year that a daytime high temperature could reach this threshold. This indicator illustrates what extreme heat events will feel like over time, and will be useful to understand impacts related to ecosystems, health, agriculture, and forestry.

Projections

- The past 1-in-20 hottest day in the Okanagan region was 32.8°C. By the 2050s, the region can expect this to increase to 37.8°C, and to 40.1°C by the 2080s.
- In the valley bottoms, the temperatures are projected to be even hotter. The past 1-in-20 hottest day in the north was 38.9°C. By the 2050s, this is expected to increase by 5.1°C to 44°C, and by 7.3°C to 46.2°C by the 2080s. This trend is similar across all Regional Districts. **These changes mark a significant departure from historical temperatures in the Okanagan region.**

Cooling Degree Days

About this Indicator

Cooling degree days refers to the number of degrees that a day's average temperature is above 18°C. To determine the number of cooling degree days in a month, the number of degrees that the daily temperature is over 18°C for each day would be added to give a total value. This measure is used to estimate the use of air conditioning to cool buildings and homes.

Projections

- Historically, there has been moderate demand for cooling in this region by this measure (an average of about 50 cooling degree days). Valley bottoms in all Regional Districts have experienced significantly more cooling degree days than in the past, over three times the regional average.
- The Okanagan can expect an increase of 144 more cooling degree days by the 2050s, and 312 more by the 2080s.
- Valley bottoms are projected to experience nearly double the regional average cooling degree days in the future. As this is a measure of cooling demand, these increases indicate that **significantly more energy will be required to cool homes and buildings in the future.**

On page 2 of Appendix I to BC Hydro IRP Application, BC Hydro states:

> Given the climate-change projections for temperatures, we may also see a shift in the seasonal shape of our load, with reduced heating demand in the winter and increased air-conditioning demand in the summer. Nevertheless, we expect BC Hydro to remain a winter-peaking utility within the 2021 IRP planning horizon, meaning the most demand placed on our integrated system will still be in the winter during the coldest days when space heating is required.

47.1 Please discuss if the results from the Okanagan Climate Projections were used to inform the development of the Load Scenarios. If confirmed, please explain how. If not confirmed, please explain if FBC intends to incorporate these results into future long term resource plans.

Response:

FBC, through Guidehouse, did not consider the results from the Okanagan Climate Projections report in the development of the load scenarios. The report's forecasts are well outside the 20-year planning horizon of the LTERP and, therefore, would not impact the design of any scenario in the LTERP.

In the future, FBC may utilize this or other climate reports in the development of its load scenarios. Decisions on climate change inputs will be made as future modelling is developed for the next LTERP.

47.2 Please provide the current assumptions in the LTERP with respect to Hottest Days, Heating Degree Days, Cooling Degree Days, and extreme heat events.

Response:

Other than the assumptions related to hottest and coldest days (cited in the preamble under "Scenario 1" and "All other scenarios"), FBC did not make any further assumptions about heating degree days, cooling degree days or extreme heat events for the purposes of developing the various load scenarios because these metrics are not elements of, or inputs to, the load scenario forecast model. FBC notes that heating degree days and cooling degree days are simply other ways of describing temperature changes. All climate driver assumptions used in the load scenarios are described on page 39 of Appendix H, as cited in the preamble to this IR.

On page 105 of the Application, FBC states:

> one stakeholder asked if there has there been consideration of the penetration of air conditioning which could increase as climate change temperatures increase and have a non-linear impact on the climate change load driver. FBC noted that the 2017 REUS indicates that FBC customer air conditioning penetration is already at a high level, meaning that climate change warming temperatures are likely to have a linear effect on customer loads. Historical air conditioning load impacts are already taken into account in the BAU load forecast.

47.3 Please provide FBC's assumptions regarding the current and future penetration of cooling equipment in the residential, commercial and industrial sectors.

Response:

FBC's assumptions associated with current penetration of space cooling are taken from the 2017 Residential End Use Study and Commercial End Use Study. The current assumptions for residential and commercial (including warehouses and manufacturing) space cooling are shown in the following tables.

Table 1: Residential Space Cooling Penetration and Saturation

(2017 FBC Residential End Use Survey)

Air Conditioning	Single Family Detached	Semi-Detached	Row / Town-house	Apt / Apt-Style Condo	Mobile & Other
Unweighted base	*1925*	*116*	*142*	*290*	*155*
Central air conditioner					
Penetration (%)	53.4	61.5	54.6	29.0	43.7
Saturation	0.55	0.61	0.56	0.30	0.44
Portable air conditioner					
Penetration (%)	9.5	11.1	10.9	14.3	19.1
Saturation	0.11	0.14	0.13	0.18	0.23
Room window air conditioner					
Penetration (%)	11.5	11.3	14.2	40.8	24.5
Saturation	0.16	0.18	0.17	0.49	0.29
Air conditioning – any type					
Penetration (%)	77.9	84.6	81.1	78.2	81.8
Saturation	0.82	0.94	0.86	0.97	0.95

Table 2: Commercial Space Cooling Penetration (2019 FEI & FBC Commercial End Use Survey)

	Office	Retail	Lodging	Schools, Universities, Colleges, and Hospitals	Food Service	Warehouse/ Manufacturing	Public Assembly	Other	Apartments/ Condos	Total
Unweighted Base	67	114	22	14	42	109	31	99	21	519
Percent with space cooling	88%	75%	77%	93%	88%	66%	68%	69%	76%	75%
Percent of floor space that is cooled:										
Average	89%	72%	74%	100%	90%	56%	67%	80%	52%	75%
Standard deviation	19%	33%	28%	0%	18%	35%	28%	29%	41%	32%

The assumed changes for future residential, commercial, and industrial space cooling end-use intensity (EUI) values by year to 2040 can be found in Appendix B3 of the Conservation Potential Review included as Appendix A of the LT DSM Plan, in the 'ElectricEUI' tab.

C. LOAD SCENARIOS

48.0 Reference: LOAD SCENARIOS

Exhibit B-2, BCUC IR 15.5; 16.4; Exhibit B-1, Appendix H, pp. 35-36; 40-41, ix; Exhibit B-4, BCOAPO IR 17.1; BC Hydro F2023-F2025 RRA, Exhibit B-2-3-1, pp. 10-22 – 10-25

Sensitivity of Load Scenarios to Underlying Assumptions

In response to BCUC IR 16. 4 FBC stated that the sensitivity of the scenario results is highly dependent on the penetrations assumed for the various load drivers.

The following table is an extract from the one provided by FBC in response to BCUC 15.5:

	Scenario 1 (Upper Bound)	Scenario 2 (Lower Bound)	Scenario 3 (Deep Electrification)	Scenario 4 (Diversified Energy Pathway)	Scenario 5 (Distributed Energy Future)
Large Load Sector Transformation – Data centres	An additional 700,000 square feet of data centre floor space	N/A	An additional 150,000 square feet of data centre floor space	An additional 380,000 square feet of data centre floor space	N/A
Large Load Sector Transformation – Cannabis	An additional 3 million square feet of cannabis production floor space	N/A	An additional 250,000 square feet of cannabis production floor space	An additional 370,000 square feet of cannabis production floor space	N/A

On page 40 of Appendix H to the Application, FBC 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.

FBC estimated in response to BCOAPO 17.1 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.

48.1 Please explain why different assumptions are made for large load sector transformation between Scenario 3 and Scenario 4.

Response:

Assumed penetration/uptake values for all load drivers were varied across scenarios to better understand the range of potential impacts for each load driver, within the upper and lower bounds specified. More large load sector transformation (LLST) was assumed for Scenario 4 (Diversified

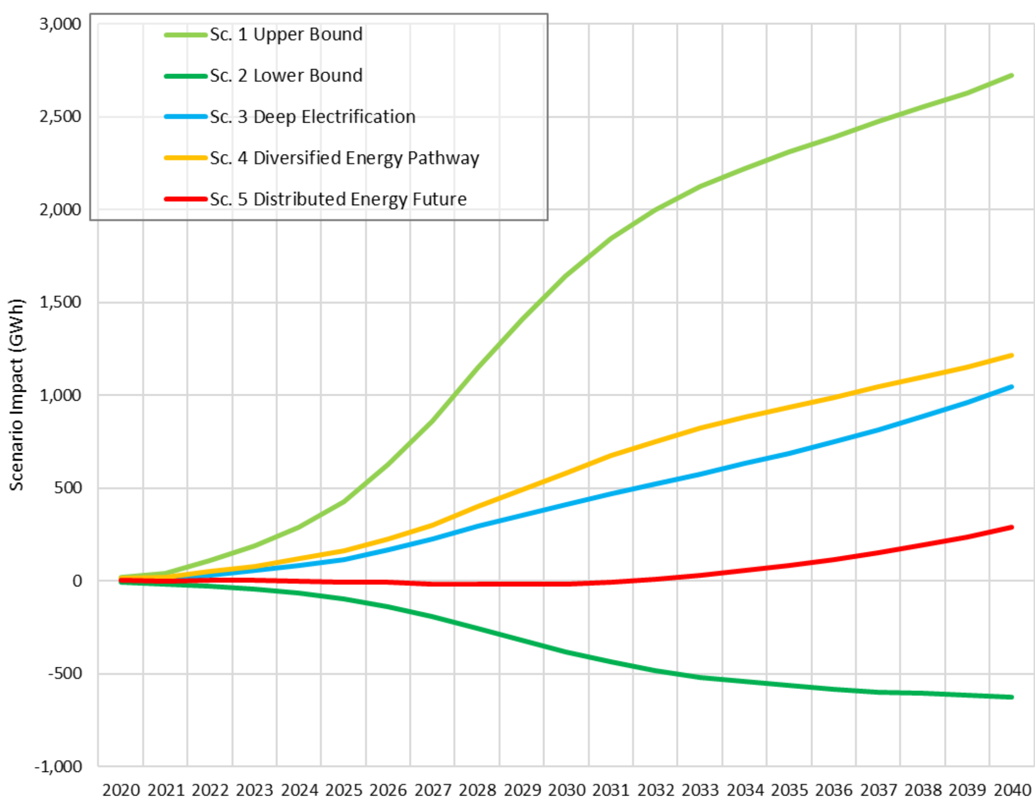
Energy Pathway) than in Scenario 3 (Deep Electrification) on the basis that additional electrification of space and water heating in Scenario 3 would consume excess system capacity, and hence electricity infrastructure would not be able to keep up with the significant incremental electricity requirements. This would therefore reduce the incentive to attract large loads when compared with Scenario 4, in which electric-to-gas fuel switching would increase available capacity for other electricity loads.

48.2 Please provide analysis showing the impact on the scenarios of holding both of these assumptions constant between Scenario 3 and Scenario 4.

Response:

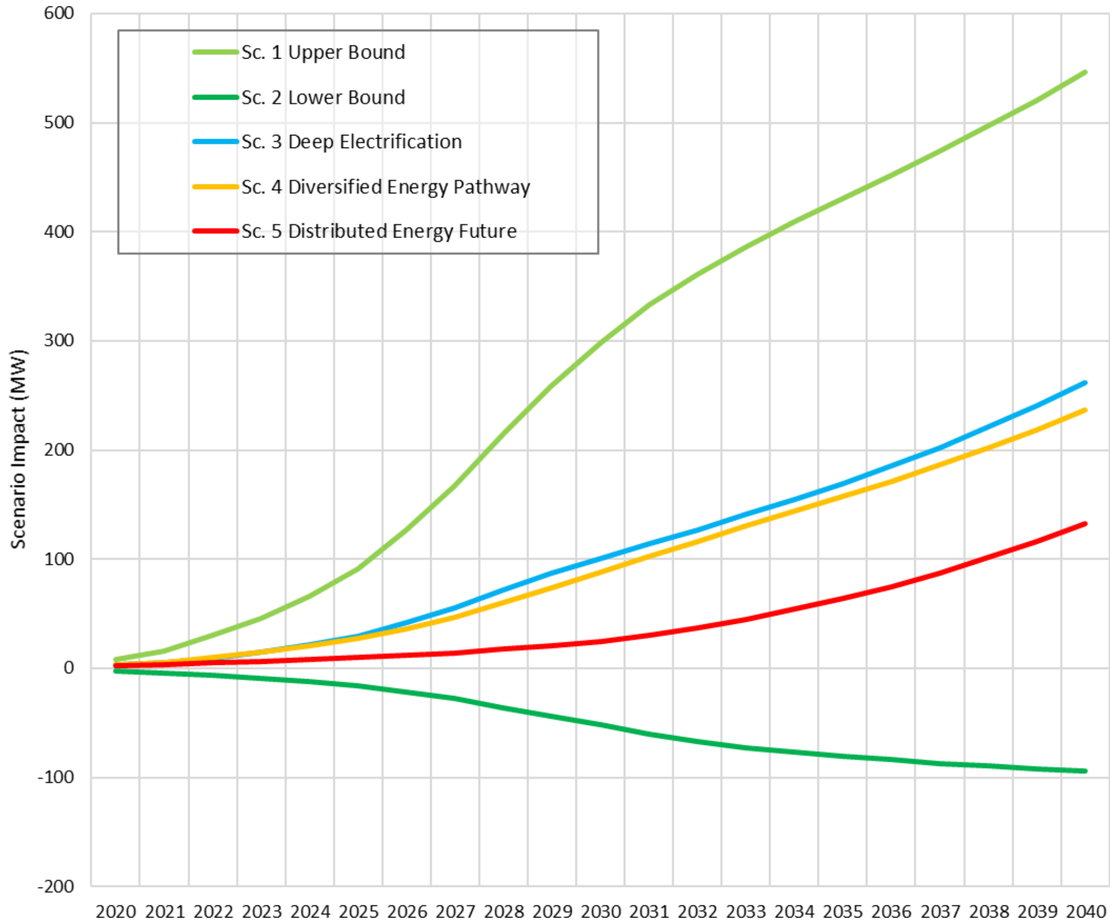
If the same assumptions for Scenario 3 regarding data centre and cannabis production floor space are applied to Scenario 4, the annual energy for Scenario 4 decreases by 133 GWh by 2040 and the winter peak demand decreases by 14 MW by 2040. The following updated Figure 4-1 from Section 4.1.3 (captioned Figure 4-1-A below) shows the resulting impacts of these changes on annual energy for each scenario.

Figure 4-1-A



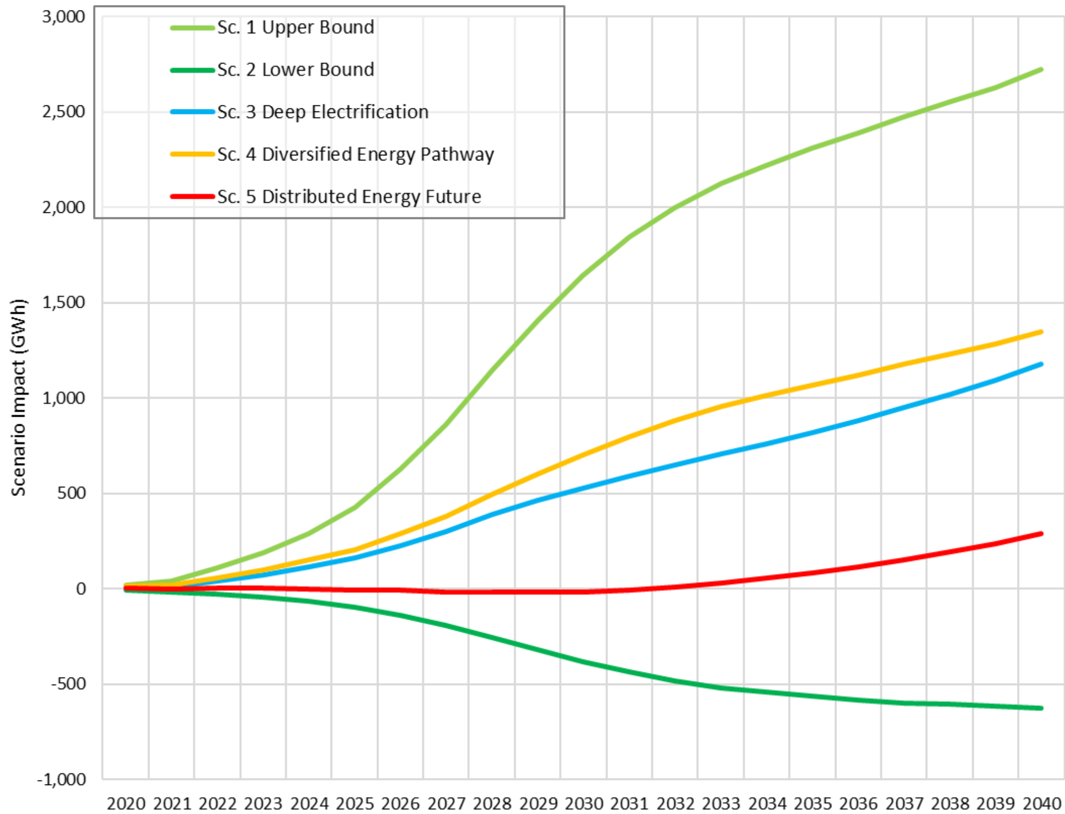
The following updated Figure 4-2 from Section 4.1.3 (captioned Figure 4-2-A below) shows the resulting impacts of these changes on peak winter demand for each scenario.

Figure 4-2-A



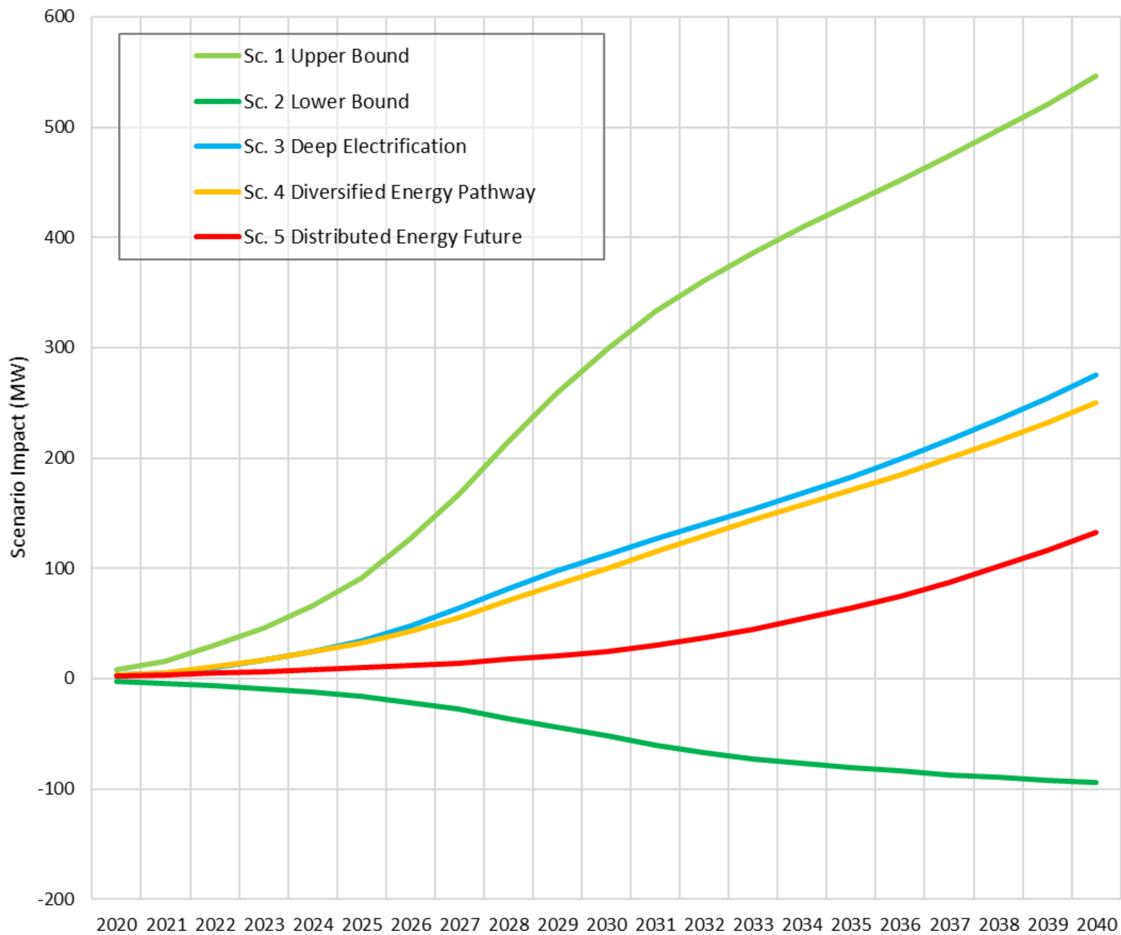
If the same assumptions for Scenario 4 regarding data centre and cannabis production floor space are applied to Scenario 3, the annual energy for Scenario 3 increases by 133 GWh by 2040 and the winter peak demand increases by 14 MW by 2040. The following updated Figure 4-1-B from Section 4.1.3 (captioned Figure 4-1-B below) shows the impacts of these changes on annual energy.

Figure 4-1-B



Similarly, the following updated Figure 4-2-B from Section 4.1.3 (captioned Figure 4-2-B below) shows the impacts of these changes on peak winter demand.

Figure 4-2-B



On page ix of Appendix H to the Application, Guidehouse makes the following recommendation:

> The energy impacts of the growth of hydrogen production and data centres in FortisBC could be considerable. Given the very favourable load profiles of these two drivers and the potential growth of these industries (to support the decarbonization of the natural gas supply, and the ongoing growth in global data storage and processing requirements) FortisBC may wish to consider what ratepayer benefits could exist in developing (or refining any existing) economic development rates that target such industries conditional on where on the system these customers connect.

On page 41 of Appendix H to the Application, FBC states:

In establishing the assumed final penetration values for this load driver, Guidehouse determined that the upper bound amount of hydrogen produced should not exceed approximately 5% of the natural gas energy consumption forecast for the FortisBC electric service territory (sometimes referred to as the shared service territory). To obtain an approximate estimate of total gas consumption in the shared service territory by the end of 2040, Guidehouse identified that:

- The total estimated natural gas use in the shared service territory in 2018 was approximately 40 PJ[84] per year;
- The 2017 long-term gas resource plan (LTGRP) produced by FortisBC Energy Inc. forecast growth in gas consumption of approximately 43% between 2018 and 2036.

Taken together, these suggest natural gas consumption in the shared service territory of approximately 57 PJ per year by 2036. It is based on this value and the upper limit identified above that Guidehouse and FortisBC determined that scenario specific penetration assumptions.

No hydrogen production was assumed in Scenario 2 (Lower Bound). In the remaining scenarios:

- Scenario 1 (Upper Bound), it was assumed that 3 PJ of hydrogen would be produced per year by the end of 2040.
- Scenario 3 (Deep Electrification), it was assumed that 0.7 PJ of hydrogen would be produced per year by the end of 2040.
- Scenario 4 (Diversified Energy Pathway), it was assumed that 1.8 PJ of hydrogen would be produced per year by the end of 2040
- Scenario 5 (Distributed Energy Future), it was assumed, as with Scenario 3, that 0.7 PJ of hydrogen would be produced per year by the end of 2040.

Section 10.3.3 of BC Hydro's Electrification Plan presented in the BC HydroF2023-F2025 RRA outlines the Load Attraction component which targets future industrial customers. Load Attraction encompasses BC Hydro's actions to connect new customers to the BC Hydro system and grow its load by promoting B.C.'s clean energy advantage and attracting innovative new industries/operations to B.C. It focuses on potential customers that have flexibility in their choice of jurisdiction and want their operations to be powered by clean electricity. Load Attraction programs are designed to provide incentives to potential customers to connect and stay connected to BC Hydro's system.

48.3 Please confirm that the above scenarios assume that the volumes of hydrogen will be produced in FBC's service area in the Okanagan, or discuss otherwise. If confirmed, please discuss the likelihood of this occurring given BC Hydro's Load Attraction program.

Response:

The load scenarios do not make any assumptions regarding the specific location of where the hydrogen could be produced within the FBC service area. The specific location will likely depend on access to electricity generation, proximity to power grid for network interconnection, demand/market location requirements, facility costs, and other factors.

As discussed in Section 2.3.6, FBC is monitoring developments in other jurisdictions, including BC Hydro's Load Attraction program, and evaluating new rate structures, such as a large customer interruptible rate, that would allow FBC to attract and connect large baseload customers, including those producing hydrogen. FBC expects that hydrogen producers will consider locating in FBC's service area given this interruptible rate option and other factors that a producer may take into consideration, such as demand/market requirements, location costs, access to labour, etc.

48.4 Please provide an analysis showing the impact of removing the hydrogen load driver from the scenarios.

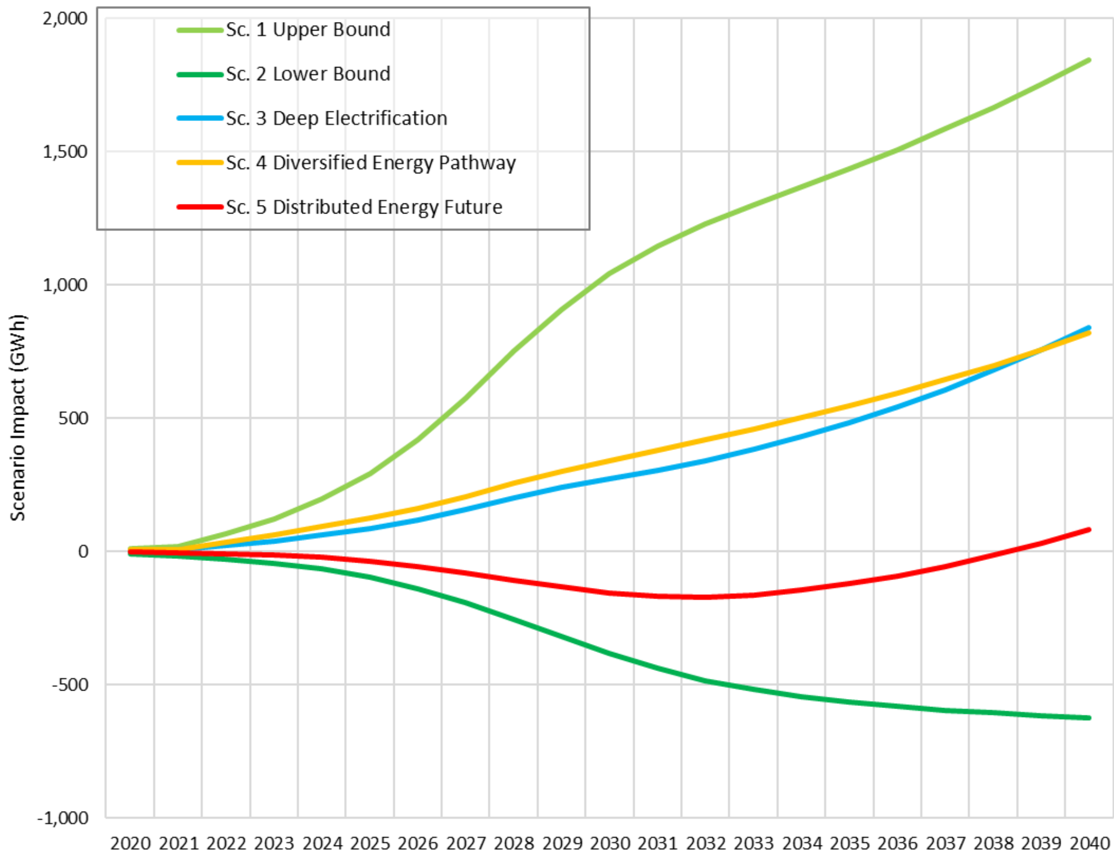
Response:

If the hydrogen production load driver is removed from the scenarios, the annual energy and winter peak demand impacts for Scenarios 1, 3, 4 and 5 decrease by 2040 based on the amounts provided in the following table. There are no changes for Scenario 2 as it does not include any hydrogen production load driver impacts.

Scenario	Annual Energy (GWh)	Winter Peak Demand (MW)
1	877	98
3	205	23
4	526	59
5	205	23

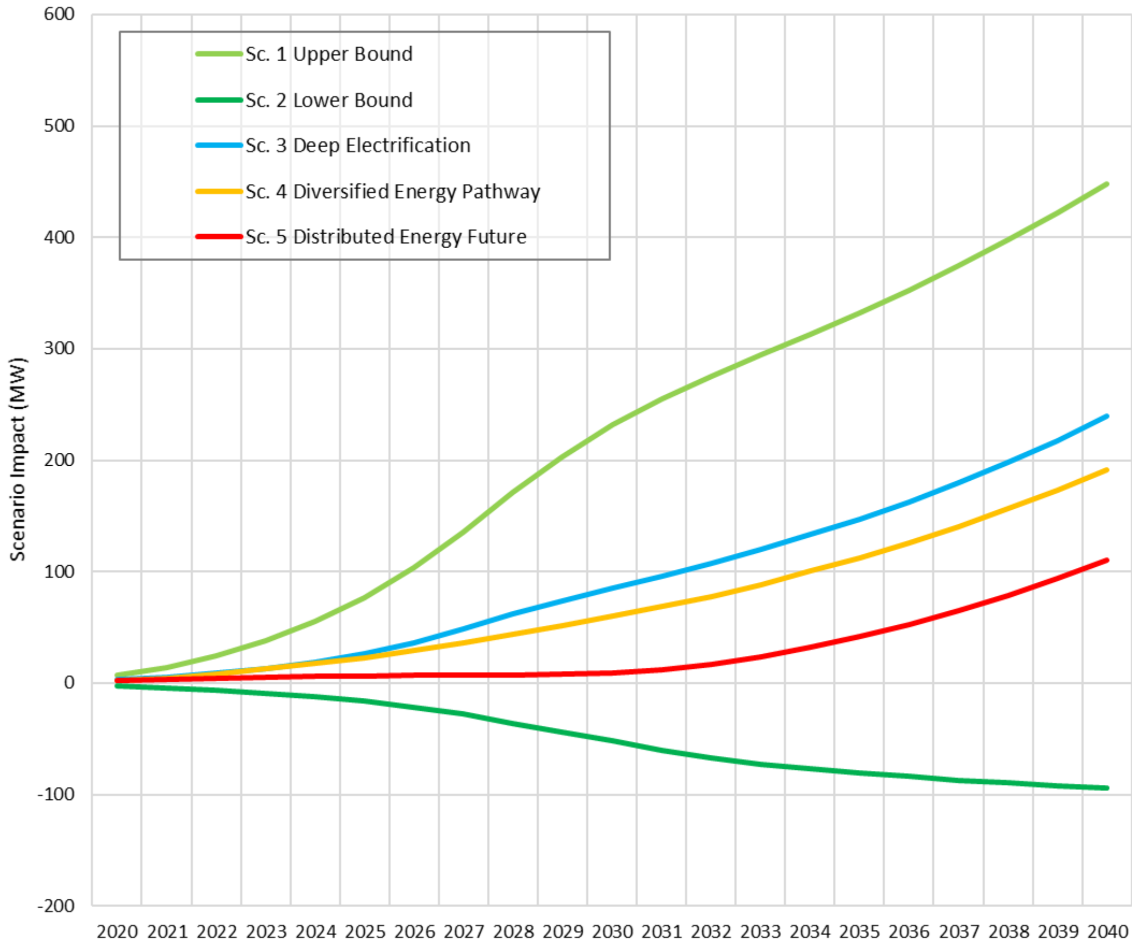
The following updated Figure 4-1 from Section 4.1.3 (captioned Figure 4-1-A) shows the resulting impacts of these changes on annual energy for each scenario.

Figure 4-1-A



The following updated Figure 4-2 from Section 4.1.3 (captioned Figure 4-1-B) shows the resulting impacts of these changes on peak winter demand for each scenario.

Figure 4-1-B



On pages 35 and 36 of Appendix H to the Application, Guidehouse summarizes the methodology for the total number of single-family homes (SFH) which are suitable for residential PV installations.

The following table summarises the assumed levels of penetration for the different Load Scenarios, and is an extract from the one provided by FBC in response to BCUC 15.5:

	Scenario 1 (Upper Bound)	Scenario 2 (Lower Bound)	Scenario 3 (Deep Electrification)	Scenario 4 (Diversified Energy Pathway)	Scenario 5 (Distributed Energy Future)
Integrated PV Solar and Storage - residential	N/A	33% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.	15% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.	N/A	25% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.
Integrated PV Solar and Storage – commercial	N/A	50% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.	25% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.	N/A	33% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.

48.5 Please explain why the Diversified Pathway scenario assumes no incremental residential or commercial PV solar is deployed.

Response:

As discussed in Section 3.3.5 of Appendix H, Scenario 4 (Diversified Energy Pathway) is characterized more by the decarbonization of fuels than by electrification. In this scenario's assumptions, growth in EVs occurs and the addition of this large, peaky EV load results in electricity prices rising, and economic development rates to attract large loads (e.g. data centres and cannabis production) help flatten the utility's load profile and reduce rates for all ratepayers. Therefore, in this scenario, it is assumed there is less incentive for incremental PV solar because of the longer payback periods with rooftop PV solar given the competitive utility rates, and so none is deployed.

48.6 Please explain if the higher PV solar penetration in the Deep Electrification scenario is assumed to be customer driven, utility driven or both, and provide the basis for the penetration figures used in the different scenarios.

Response:

No explicit assumptions were made for the scenarios regarding what share of solar PV uptake is driven by customers compared to what share is driven by utility actions.

The assumed penetration value of solar PV in Scenario 2 was selected as a “reasonable extreme” boundary value. A less extreme, though still aggressive value, was selected for Scenario 5 (Distributed Energy Future) to better understand the effect of dramatic growth in distributed generation when combined with some off-setting increases in loads (e.g., EVs, hydrogen production, etc.). The assumed penetration value for Scenario 3 (Deep Electrification) was selected to be less aggressive than that assumed for Scenario 5 but to be reflective of the combined effect of assumed falling solar PV costs and increasing energy supply requirements motivated by electrification of space heating, water heating, and transportation.

49.0 Reference: LOAD FORECAST

Exhibit B-2, BCUC IR 7.3; BCUC Resource Planning Guidelines, p. 3; Exhibit

B-8, RCIA IR 21.1.1

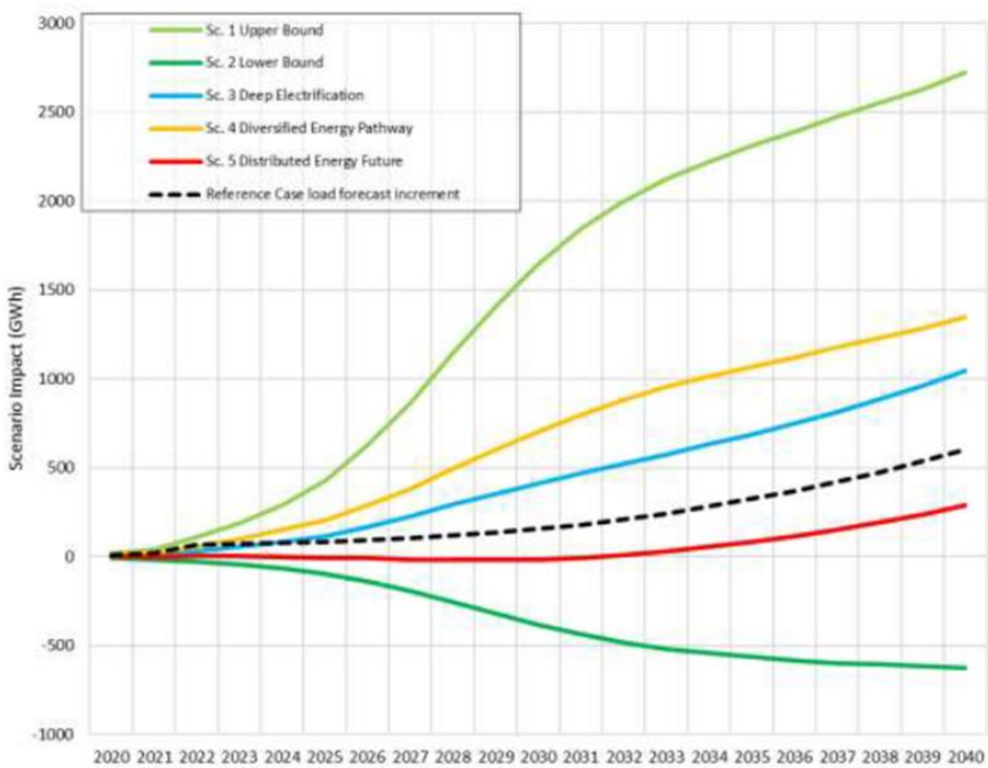
Most Likely Gross Demand Forecast

Section 2 of the BCUC Resource Planning Guidelines states:

> More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. [Emphasis added]

In response to BCUC IR 7.3, FBC stated that FBC has assumed 100 percent of vehicle sales being EVs by 2035 for the upper uncertainty band of the Reference Case load forecast. FBC also notes the recent announcement of the CleanBC Roadmap to 2030 plan that sets a goal of 100 percent ZEV sales in BC by 2035.

FBC provided the following figure in response to RCIA IR 21.1.1, showing the annual energy impacts of the various load scenarios compared to the Reference Case.



49.1 Considering the Roadmap to 2030, please discuss if FBC still considers the Reference Case load forecast to be the most likely gross demand forecast, as opposed any of the other load scenarios presented above.

Response:

As discussed in the response to MoveUP IR1 1.1, the CleanBC Roadmap to 2030 (Roadmap) was released by the BC government on October 25, 2021, after FBC filed its 2021 LTERP on August 4, 2021. The Roadmap includes a number of elements aimed at reducing GHG emissions. The assumptions and results presented in the LTERP, including the Reference Case load forecast, are generally aligned with the Roadmap and as such, FBC still considers the Reference Case load forecast to be the most representative reflection of current policies and market conditions that will impact demand over the planning period. As these Roadmap elements further develop over time, FBC expects that future LTERPs will include the appropriate updates.

With regard to light-duty EVs, the LTERP Reference Case load forecast includes EV charging loads based on the *ZEV Act* sales targets. As cited in the preamble, FBC has included higher EV sales than those included in the *ZEV Act* within its Reference Case load forecast uncertainty bands. For the upper band, FBC has assumed that light-duty EV sales would grow at a faster rate than the *ZEV Act* sales targets with 100 percent of vehicle sales being EVs by 2035 (instead of by 2040 per the *ZEV Act*). As discussed in Section 2.3.3, EV sales within the FBC service area have grown at a slower rate than the BC average and so there is still uncertainty in terms of whether or not EV sales within the FBC service area will meet or exceed the *ZEV Act* sales targets or those outlined in the Roadmap.

With regard to medium- and heavy-duty EVs, the Roadmap discusses new ZEV targets for medium- and heavy-duty vehicles aligned with California. As these targets were not included in the *ZEV Act* nor have they been enacted into any other legislation at this time, there is still uncertainty regarding the potential load impacts from medium- and heavy-duty EV charging. Therefore, it is appropriate that FBC has not included new ZEV sales targets for medium- and heavy-duty vehicles within its Reference Case load forecast. However, as discussed in Section 4, FBC has instead incorporated medium- and heavy-duty EV charging within its load scenarios to determine the impacts of these charging loads on its requirements for new resources.

D. EXISTING SUPPLY SIDE RESOURCES

50.0 Reference: EXISTING SUPPLY SIDE RESOURCES

Exhibit B-2, BCUC IR 18.1

Impacts of Climate Change on Water Availability

In response to BCUC IR 18.1, FBC stated:

> FBC has not directly considered long-term water availability risks in the LTERP (for example, by altering its CPA entitlement amounts) within its portfolio analysis or scenarios because FBC has not observed any material changes in water availability to date. Further, FBC has no information or basis on which to alter its CPA entitlement amounts or develop scenarios with respect to water availability over the planning horizon. However, FBC has discussed and recognized these risks in the LTERP to demonstrate that FBC is monitoring developments in this regard and may undertake or collaborate with other entities in future studies and make adjustments as appropriate in a future LTERP, once there is more information regarding the potential impacts on its supply from climate change.

50.1 Please discuss how FBC monitors developments with respect to long-term water availability. If applicable, please reference any specific organizations, government agencies, or studies that FBC relies upon for this information and/or forecasts.

<u>Response:</u>

FBC monitors developments with respect to long-term water availability by reviewing industry studies and reports, attending industry events and seminars, working closely with other utilities such as BC Hydro, and by keeping apprised of new information and studies as they become available. The response to BCSSIA IR1 12.3 provides a detailed list of reference studies and reports that FBC considered when developing Sections 2.3, 2.4, and 5.0 of the Application, which discuss climate change impacts.

FBC clarifies that any change to CPA entitlements resulting from a change in the water flow set used to calculate entitlements would have to be mutually agreed upon by both FBC and BC Hydro. However, a change in how the available water is used may result in entitlement redetermination depending on the circumstances.[6]

[6] The International Joint Commission is currently considering if a review of the Kootenay Lake order is required or not. If they do reopen the order, it is possible that changes to storage elevations or constraints around the timing of releases could impact the FBC entitlements under the CPA.

50.2 Please expand on what would cause FBC to consider long term water availability risks in a future LTERP, for example as part of scenario analysis.

Response:

FBC expects that it would consider long-term water availability risks in the LTERP, for example, by altering its CPA entitlement amounts within its portfolio analysis, if FBC observed or expected material changes in water availability or if FBC expected any changes to its CPA entitlement amounts. As discussed in Section 5.1.1, any changes to water availability could open the possibility of changes to the entitlements under the CPA. In addition, potential changes to the Columbia River Treaty between Canada and the United States or Kootenay Lake levels as governed by the International Joint Commission order could indirectly impact FBC CPA entitlements.

50.3 Please discuss whether FBC has any current plans to undertake future studies or collaborate with other entities with respect to forecasting water availability.

50.3.1 If yes, please discuss these plans, timeframes for completion and identify the other entities involved, if applicable.

50.3.2 If no, please explain why not.

Response:

FBC currently has no plans to conduct its own studies with respect to forecasting water availability as FBC does not currently have the in-house expertise to do so. However, FBC has contributed funds to ongoing third-party studies, one of which is focused on collecting water quality and quantity data on ten of the Kootenay Lake tributaries. Furthermore, while there are no current plans to collaborate with other entities and/or utilities on such studies, FBC is open to discussing future opportunities to do so.

50.4 If FBC were to see a 10% reduction in its Canal Plant Agreement (CPA) entitlement amounts by 2040, please discuss at a high level the impacts, if any, to FBC, including timing requirements for new supply side resources.

Response:

FBC believes that a 10 percent reduction in both its energy and capacity entitlements due to long-term water availability risks is unlikely to occur.

Plant capacity, and corresponding capacity entitlement, is not determined by water availability. Therefore, FBC does not expect that small to moderate reductions in available water to materially impact capacity entitlement.

Energy entitlement is impacted by long-term water availability. However, FBC's generation on the Kootenay River is undersized compared to the water flows used to calculate energy entitlement for approximately 50 percent of the year. Under the CPA, FBC entitlements are based on pre-Columbia River Treaty conditions,[7] prior to the construction of the Duncan and Libby dams as well as the Kootenay Canal Plant.

Although FBC has not studied the impacts of changing water flows on entitlements, at a high level FBC believes there is a reasonable possibility winter energy entitlement may increase since milder temperatures may support higher natural winter water flows even if natural annual flows are on average reduced. During a significant portion of the year, FBC expects that there would still be sufficient water flow to utilize all the available FBC generation such that there is no impact on energy entitlements for that portion of the year.[8] However, once water flows recede in the summer and fall months, these flows would likely be at lower levels than used in the entitlement calculations so there would be a greater potential for a reduction in summer and fall energy.

Based on the Reference Case load forecast and energy self-sufficiency not being a planning criteria, summer and fall energy requirements are not driving the need for supply side resources within FBC's preferred portfolios. Therefore, it is likely that there would be minimal pressure to advance supply-side resources beyond increasing BC Hydro PPA or market energy purchases over the summer and fall months. These increased purchases may be fully or partially offset by the potential for increasing winter energy entitlement. Winter energy is a critical resource gap so the overall impact on FBC from reduced water availability could even be, counter intuitively, a delay in the requirements for new supply side resources. The monthly timing of the available natural water flows used in calculating entitlements would determine the impact on the need for FBC resources.

For the above reasons, a 10 percent uniform reduction in both energy and capacity is highly unlikely to occur. FBC does not expect material changes in capacity entitlement. The resulting shape of FBC energy entitlements after a redetermination process compared to the forecast monthly load requirements as well as self-sufficiency criteria will determine the impact on supply-side resources.

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7 BC Hydro receives the benefits of the Columbia River Treaty dams and the Kootenay Canal Plant. To the extent that there is a change between the actual generation and the calculated entitlement generation, that is to BC Hydro's benefit or loss.

8 To put it another way, much of the reduced water availability may simply reduce spill down the Kootenay River under the pre-dam conditions which FBC entitlements are calculated by.

E. TRANSMISSION AND DISTRIBUTION

51.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6, pp. 130, 137, 174; 121, 127; Exhibit B-2, BCUC IR 20.4, 20.6, 23.7, 26.1

Transmission and Distribution Overview – June Heat Event

In response to BCUC IR 20.4, FBC stated:

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

51.1 Please identify the approximate duration of outage noted above had an N-1 event occurred during the June 2021 heat event.

Response:

The estimated load shedding durations, had an N-1 event occurred during the 2021 heat event, are shown in the table below:

Date	Duration of Load Shedding (Hours)
6/27/2021	6
6/28/2021	10
6/29/2021	11
6/30/2021	12
7/1/2021	7

The table shows the hours of each day that some level of curtailment would be necessary. The maximum 65 MW of load would only have needed to be shed during the peak hour on June 29.

51.2 Please discuss whether FBC is taking any steps to mitigate risks on its system should similar heat events occur in 2022 or beyond. If yes, please explain the steps planned and associated timeframes and costs for completion. If not, please explain why not.

Response:

The main mitigating step that FBC is taking is to complete the Kelowna Bulk Transformer Addition project which will increase the firm transformer capacity at the LEE substation. This project is currently ongoing with an anticipated completion date before summer 2023.

FBC is currently assessing the June 2021 heat dome event by modelling the 1 in 20 peak load calculations with/without this event. Further, FBC intends to conduct a sensitivity analysis using the results of this modelling to explore the timing impacts for the projects in Table 6-3.

In response to BCUC IR 26.1, FBC stated the following regarding the June 2021 heat event: "FBC's distribution systems did experience localized outages similar to what FBC has seen historically during hot weather."

51.3 Please identify the approximate magnitude and causes of the distribution outages experienced during the June 2021 heat event.

Response:

The June 2021 heat event was most pronounced from June 27 to July 1. During these five days, there were 96 distribution outages, with more than half of the outages affecting ten customers or less. Of the unplanned outages for which FBC is able to identify a specific cause, the most common causes were equipment failure, tree contacts, and adverse weather (likely equipment failures attributed to high ambient temperatures).

The table below provides the approximate number of outages by region during the June 2021 heat dome event.

Region	Number of Outages
Kootenays	37
North Okanagan	31
South Okanagan	22
Boundary	6
Total:	**96**

In response to BCUC IR 20.6, FBC stated: "FBC is currently reviewing if the June 2021 heat event should be included in its system peak forecast and therefore in the next annual assessment or not."

51.4 Please discuss when FBC expects it will determine whether the June 2021 heat event should be included in its system peak forecast or not, and the basis upon which FBC will make such a determination.

Response:

FBC is currently in the initial development of the FBC Annual Review for 2023 Rates and will determine whether the June 2021 heat event should be included in its system peak forecast by May 2022. FBC will make this determination by consulting with internal and external subject matter experts and analysis of the 2021 June event.

On page 130 of the Application, in Table 6-3, FBC provides transmission reinforcement projects planned for 2021 to 2030. On page 137, in Table 6-5 of the Application, FBC provides the list of projects that FBC is currently planning on implementing in the Kelowna area by 2040. In response to BCUC IR 23.7, FBC provided timeframes for the projects identified in Table 6-5 of the Application.

51.5 If FBC were to include the June 2021 heat event in its subsequent peak demand forecast, please discuss at a high-level how the timeframes for the projects identified in Tables 6-3 and 6-5 of the Application would be impacted. Please provide specific changes in project timeframes identified along with an explanation for these changes where possible.

Response:

At a high level, including the June 2021 heat event in subsequent peak demand forecasts would increase the summer peak demand forecasts and therefore require summer demand driven projects and generation resources to be completed sooner. FBC is unable to identify specific changes in project timing at this time as an updated forecast considering the peak demand impacts of the heat dome event has not been finalized.

Please also refer to the response to BCUC IR1 21.4 regarding how FBC is currently reviewing its 1 in 20 peak demand forecast method. While it is too early to determine if this may impact the timing of any of the planned projects, FBC assesses the timing of projects identified in Tables 6-3 and 6-5 annually based on the updated 1 in 20 peak demand forecasts and will adjust the timing of projects as needed based on the results of the demand forecast.

On page 174 of the Application, FBC states:

Based on the portfolio analysis results presented in this section, and assuming the reference case load forecast, proposed DSM level and continued market access, FBC will not require any new generation resources until at least 2030.

51.6 If FBC were to include the June 2021 heat event in its subsequent peak demand forecast, please discuss at a high level how the timeframes for requiring new generation resources would be impacted. Please provide specific changes in timeframes identified along with an explanation for these changes where possible.

Response:

Please refer to the response to BCUC IR2 51.5.

52.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6, p. 140; Exhibit B-2, BCUC IR 24.3, 24.4

Impacts of Climate Change

On page 140 of the Application, FBC states:

> The threat that global climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously. FBC identifies wildfires as the most significant climate-related risk, while others include flooding and extreme weather. FBC has been building climate resiliency using its standards and practices over time, but, as climate change related risks increase, additional adaptation methods may need to be implemented.

52.1 Please summarize the material outages FBC has experienced on its system as a result climate-related events in the last 5 years. Please identify the climate event, outage duration and location, and any significant damage to FBC's infrastructure.

52.1.1 Please discuss at a high level how these experiences have informed FBC's system planning and/or operations moving forward.

Response:

The following tables provide a list of material outages within the last five years that were related to climate events. Table 1 includes material outages that are also considered major events as defined by the SAIDI threshold. Table 2 includes outages that were associated with the Nk'Mip Creek wildfires; these outages did not meet the major event criteria but had a significant impact on the system.

Table 1: Material Outages Related to Climate Events (Major Events)

Outage Date	Event Type	Location	Customer Outage Count	Customer-Hours of Interruption
2016/08/07	Windstorm	Kootenays	7,292	54,157.69
2017/02/06	Snowstorm	Kootenays	6,470	37,264.40
2017/05/24	Windstorm	Kootenays	7,935	48,517.34
2017/12/19	Snowstorm	Kootenays	18,657	94,723.78
2018/04/02	Snowstorm	Kootenays	5,211	47,786.99
2018/06/25	Windstorm	Okanagan, Kootenays	8,070	50,483.32
2019/12/31	Snowstorm	Kootenays	6,123	56,624.14
2020/03/04	Windstorm	Kootenays	13,823	63,967.08
2020/09/07	Windstorm	Kootenays	16,599	213,005.04
2020/12/10	Snowstorm	Okanagan	14,777	60,608.34

Outage Date	Event Type	Location	Customer Outage Count	Customer-Hours of Interruption
2021/01/13	Windstorm	Okanagan, Kootenays	10,866	155,173.19
2021/04/18	Windstorm	Kootenays	19,762	200,815.35
2021/11/15	Windstorm/Flooding (Princeton)	Okanagan, Kootenays	27,498	218,720.37

Table 2: Nk'Mip Creek Wildfire Outages (Excluded from Major Events)

Outage Date	Event Type	Line/Feeder Name	Location	Customer Outage Count	Customer-Hours of Interruption
2022/07/19	Wildfire	66L	South Okanagan	2,333	6,813.7
2022/07/20	Wildfire	48L	South Okanagan	0	0
2021/07/19	Wildfire	PIN2	Oliver	690	877.16
2021/07/19	Wildfire	OSO3	Osoyoos	1,627	1,577.95
2021/07/20	Wildfire	OLI3	Oliver	71	1,362.02
2021/07/21	Wildfire	OLI3	Oliver	71	2,1671.69
2021/07/22	Wildfire	PIN2	Oliver	3	48.40
2021/07/23	Wildfire	PIN2	Oliver	12	392.20

The Nk'Mip wildfire in the South Okanagan area impacted two transmission lines and three distribution feeders. FBC's assessment of the damage found 30 transmission and 13 distribution structures were damaged or destroyed.

Based on the information provided above and the occurrence of climate change impacts in FBC's service territory, FBC recognizes the need for infrastructure storm hardening, updated design standards, and evaluation of alternative materials.

FBC reviews 200-year event floodplain data during the design for upgrades of existing or new infrastructure, such as substations or lines. FBC is also considering wildfire mitigation and adaptation for areas at risk.

52.2 If not addressed in the preceding IR, please discuss the impacts, if any, to FBC's system resulting from BC's November 2021 flooding event, including outages experienced, significant damage to infrastructure, etc.

52.2.1 Please discuss at a high level how this event, and/or other flooding events have informed FBC's system planning and/or operations moving forward.

Response:

Please refer to the response to BCUC IR2 52.1.

In response to BCUC IR 24.3, FBC stated:

> FBC follows industry practices, and IEEE and CSA standards (including CSA C22.3 No. 1 Overhead Systems, CSA C22.3 No. 7 Underground Systems, and CSA C22.3 No. 60826 Design Criteria of Overhead Transmission Lines). FBC is aware that these organizations are working on updating the standards related to integrating considerations of climate change impacts. Once completed, FBC intends to consider, and adopt if appropriate, the updated standards as guidelines. However, FBC intends to be proactive regarding the resiliency of its system in light of climate change impacts regardless of the timing of standards development.

52.3 Please discuss whether FBC is aware of when the updates to the standards, as referred to in the above preamble, may be published.

Response:

The newest updates to the CSA C22.3 No. 1:20, *Overhead systems*[9] standard was published to the CSA store on January 31, 2022. At this time, FBC is not aware of when the other two standards will be published.

In response to BCUC IR 24.4, FBC stated:

> FBC is in the process of developing a roadmap for climate change adaptation. Wildfires, flooding, and extreme weather events (including windstorms) are considered the highest risks for the FBC service territory.
>
> To mitigate the impacts of flooding, substation construction takes into account floodplain data to ensure that stations are raised to an appropriate height. FBC is

[9] https://www.csagroup.org/store/product/CSA%20C22.3%20NO.%201:20/.

also researching and assessing, through pilot programs, the use of alternative materials for poles in areas impacted by flooding.

FBC is developing an internal business case to assess various mitigation strategies for wildfires. Some of these solutions will be dependent on the results of the wildfire risk modeling currently under development with an external consultant. These strategies include, but are not limited to, application of fire-retardant gel to wood poles, current-limiting fuses, fire-protection mesh, and updates to FBC's reclosing policy.

Similar business cases will be developed for flooding and extreme weather events (including windstorms) once similar assessments for these climate change impacts are completed.

52.4 Please identify the timeframes by which FBC expects the following items to be complete: (i) FBC's roadmap for climate change adaptation; (ii) the use of alternative materials for poles in areas impacted by flooding pilot programs; (iii) FBC's business case relating to wildfire mitigation strategies; (iv) FBC's business cases for mitigating flooding and extreme weather events.

Response:

Following are responses to each sub-item in this IR:

(i) FBC's roadmap on climate change adaptation is under development and FBC expects that it will be completed in Q4 2022;

(ii) The alternative material pole type pilot program was completed for the Creston wetlands areas in November 2021;

(iii) FBC's business case relating to wildfire mitigation and adaptation strategies will be completed in Q2 2022;

(iv) The flooding business case will be completed in 2023/2024, followed by the extreme weather business case in 2025 to 2027.

52.5 Please expand on the materials being considered for poles in areas impacted by flooding. Please also identify where this pilot program is being conducted.

Response:

FBC completed a pilot program to evaluate the installation of composite pole in wetland areas in Creston, BC in November 2021. The pilot helped FBC to gain internal experience with the installation, operation, and maintenance of the composite poles in a wetland area. FBC is considering use of composite materials for poles impacted by flooding as, generally, composite poles will not experience rot or corrosion in standing water. The installation of composite material poles in flooding areas would be considered on a case-by-case basis.

52.6 Please discuss to what extent, if any, FBC is considering selective undergrounding of its system as part of its strategy relating to climate resiliency.

52.6.1 If yes, please provide a high level overview of FBC's plans and the expected reliability and/or resiliency improvements. Please also discuss the cost effectiveness of this strategy.

52.6.2 If not, please explain why not.

Response:

FBC confirms it is considering selective underground distribution as a potential option on a case-by-case basis in high-risk areas. This analysis will be completed during the development of the extreme weather business case.

F. SUPPLY-SIDE RESOURCE OPTIONS

53.0 Reference: SUPPLY-SIDE RESOURCE OPTIONS

Exhibit B-1, Section 5, p. 112; Section 10, p. 166

Supply-Side Resource Options

On page 112 of the Application, FBC provides Table 5-1 as follows:

Table 5-1: FBC's 2021 Available Energy and Dependable Capacity Resources[141]

FBC Existing Resources (2021)	Available Energy (GWh)	Dependable Capacity (MW)
FBC CPA Entitlements	1,596	208
BPPA	919	138
BRX	79	45
PPA (Tranche 1 Energy)	1,041	-
PPA (Tranche 2 Energy)	711	-
IPP	1	-
Market and Other Contracted	302	-
PPA Capacity	-	200
WAX (net of RCA)	-	218
Total Resources	4,648	810

On page 166 of the Application, FBC provides Table 10-2, Supply-Side Resource Options Unit Cost Summary as follows:

Table 10-2: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Low DSM	$33	N/A
Base DSM	$38	N/A
Med DSM	$40	N/A
High DSM	$45	N/A
Max DSM	$58	N/A
PPA Tranche 1 Energy	$49 - $60	N/A
PPA Tranche 2 Energy	$80 - $95	N/A
PPA Capacity	N/A	$101 - $123
Market Purchases	$28 - $49	N/A
Wood-Based Biomass	$121 - $173	$682 - $719

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Geothermal	$114 - $176	$863 - $1,377
Gas-Fired Generation (CCGT) - NG	$90 - $109	$150 - $287
Gas Fired Generation (SCGT) - NG	N/A	$131 - $148
Gas Fired Generation (SCGT) - RNG	N/A	$131 - $148
Small Hydro with Storage	$101 - $163	$687 - $1,271
Pumped Hydro Storage	N/A	$102 - $540
Onshore Wind	$68 - $91	$509 - $734
Run-of-River Hydro	$111 - $173	$817 - $1,330
Utility Scale Solar	$99 - $134	$686 - $863
Distributed Solar	$137 - $141	$829 - $882
Battery Storage	N/A	$267
Distributed Battery Storage	N/A	$226

53.1 Please discuss why Table 10-2 of the Application does not include all the unit energy cost (UEC) and UCC values for all of FBC's existing resources, such as the Brilliant Power Purchase Agreement (BPPA) entitlements, Brilliant Expansion (BRX) entitlement purchases, etc.

Response:

The resources listed in Table 10-2 reflect the marginal resource options that are available to FBC and included in the portfolio analysis. Many of FBC's existing resources, such as the Brilliant Power Purchase Agreement and Brilliant Expansion entitlement purchases, are not considered resource options for FBC as the monthly entitlements are set per the contract agreements. The existing resources that FBC has the ability to increase or decrease on a marginal basis over the planning horizon such as PPA, market purchases, and DSM, have all been included in Table 10-2 and reflect forward looking levelized prices.

53.1.1 If possible, please provide the UEC and UCC values for all of FBC's existing resources. If not possible, please explain why not.

Response:

Please refer to the response to BCUC IR1 28.4.1 which provides the UEC and UCC values of FBC's existing resources not included in Table 10-2, including the FBC CPA Entitlements, BPPA, BRX 10 Year Agreement, and WAX CAPA Agreement (net of RCA), where applicable.

G. PORTFOLIO ANALYSIS

54.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Section 11, p. 175; Exhibit B-8, RCIA IR 25.1

Portfolio Analysis – Impacts of Project Deferrals

In response to RCIA IR 25.1, FBC confirmed that "some transmission-level projects [listed in Table 6-5 and Table 6-6 of the Application] could potentially be deferred by resources contained in FBC's proposed LTERP solutions."

54.1 Please confirm, or explain otherwise, that the projects listed in Table 6-5 and Table 6-6 of the Application do not consider the potential for project deferral by resources contained in FBC's proposed LTERP solutions.

54.1.1 If confirmed, please discuss why FBC considers this approach to be reasonable. Please also discuss whether this approach would be reasonable in future LTERPs where new resources may be needed in a shorter time horizon.

Response:

FBC confirms that the projects listed in Table 6-5 and Table 6-6 in the Application do not consider project deferrals as a result of specific generation projects. This approach is reasonable due to the uncertainty regarding the siting of generation, region specific load growth, and corresponding changes in the future configuration of the Okanagan system, all of which can make material differences in the timing of prospective transmission and distribution projects and, therefore, materially change the value of any deferral benefits. There are many possible scenarios created through various combinations of generation location, areas of concentrated load growth or new large customers, and corresponding system configurations. As a result, FBC made reasonable assumptions as explained in Section 6.5.4.1 to recognize the impacts if certain load scenarios were to occur in the future.

While specific site locations have not been identified at this time, the dispatchable resources contained in FBC's proposed LTERP solutions, such as RNG SCGT units and battery storage, are assumed to connect to FBC's 138 kV system somewhere in the North Okanagan (Kelowna area). However, any proposed location would be subject to consultation and engagement with Indigenous groups as well as a variety of other stakeholders, and would consider public impacts, environmental requirements, and community consultation. Generation located in the Kelowna area would have a materially different impact on the projects contained in Tables 6-5 and Table 6-6 than if that same generation were to be located in the South Okanagan.

For purposes of responding to RCIA IR1 25.1, FBC assumed the generation would be located in the Kelowna area connected in a location that is highly favourable to the transmission system, thereby demonstrating that some LTERP solutions could *potentially* defer projects. In the event FBC was unable to successfully site an RNG SCGT unit, battery storage, or other generation in the Kelowna area, FBC may still opt to recommend building the same generation resource in other viable locations on the system as the identified projects meet power supply requirements at the system level.

Further, for purposes of responding to RCIA IR1 25.1, FBC assumed that 50 percent of the growth in system peak would occur in the North Okanagan region (Kelowna) as this is where FBC is currently experiencing the most significant growth. Load growth after the planning horizon (post 2040) needed to approximate a deferral value was forecast using a simple annual average MW per year growth factor rather than the formal methodologies outlined in Appendix F. In the event that region-specific growth shifts to the South Okanagan, or a new large customer were to connect to the system that materially changed the system power flows, then the timing of when projects are needed could vary and substantially change the value of deferral.

The conclusion that should be drawn from the response to RCIA IR1 25.1 is that projects listed in Table 6-5 and Table 6-6 are required at specific load levels and could *potentially* be deferred or eliminated through LTERP solutions if those solutions were located favourably on system. However, locations most favorable from the utility's perspective are not the only consideration and may not ultimately determine where generation is sited on the system.

FBC will address the deferral value of generation projects in future LTERPs when new resources are needed in a shorter time horizon, and if specific site locations for resources are known with greater certainty. FBC expects the ability of a new resource to defer transmission and distribution projects would be an important component of a resource-specific CPCN application.

On page 175 of the Application, FBC states:

> FBC's portfolio model incorporates an optimization routine to find the lowest power supply revenue requirement of satisfying the forecast load requirements given a set of constraints, which lead to what new resources should be acquired and when. The portfolio analysis takes into consideration BC energy and environmental policies, as discussed in Section 2.2, such as the objective of at least 93 percent of generation from BC clean or renewable resources in the CEA and the Bill 17 proposed amendment to the CEA for a 100 percent clean energy standard for BC electricity and the removal of the self-sufficiency requirement. It also includes constraints on the amount of wholesale market purchases FBC is able to import based on transmission limitations. The costs and the LRMC values of the various portfolios FBC evaluated are based on the Average Incremental Cost (AIC) approach as discussed below in Section 11.2 and in Appendix L regarding the LRMC.

54.2 Please explain whether FBC's portfolio analysis and/or optimization routine considers cost savings associated with project deferrals, such those described above in response to RCIA IR 25.1. If not, please discuss why FBC considers this approach to be reasonable. Please also discuss whether this approach would be reasonable in future LTERPs where new resources may be needed in a shorter time horizon.

Response:

FBC's portfolio optimization routine does not explicitly assign or include a transmission and distribution deferral credit to the various resource options. In addition to the challenges highlighted in the response to BCUC IR2 54.1, FBC does not have an established approach for determining a transmission and distribution deferral credit for all resource types such as intermittent resources. Without an established approach to objectively assign a deferral credit to all resource types, it is difficult to justify assigning a deferral credit to specific resources types.

A further complication is that the deferral value of any particular resource option has the potential to change depending on the specific combination of resources selected in the portfolio and the specific load resource balance in the areas of the system where those resources are connected. At this time, it is not clear whether this complication will allow a deferral credit to be assigned to each resource option prior to resource selection, as opposed to being considered after the portfolio is formed, as done in the response to RCIA IR1 25.1. The size of the resources relative to FBC's existing load influences the deferral value. Given that FBC is a smaller utility than BC Hydro, adding generation into one of FBC's sub-regions may have a substantially greater impact compared to the same resource being added into one of BC Hydro's sub regions, as the generation may represent a significantly greater proportion of the sub-region's load resource balance. This makes developing and assigning a generic deferral credit in the optimization routine more difficult.

Regardless of whether a transmission and distribution deferral credit is included or not, the most cost-effective capacity orientated resources are the PPA, RNG SCGT, and Battery Storage as shown in Figure 10-2. These resources are regularly selected among the portfolios without a deferral credit, which can only increase the attractiveness of these resources if a deferral credit was included.

FBC will address the deferral value of generation projects in future LTERPs when new resources are needed in a shorter time horizon, and if specific site locations for resources are known with greater certainty. The appropriate approach for FBC to overcome the listed challenged and represent the value of deferred transmission and distribution within the portfolio analysis has not yet been determined.

Further in response to RCIA IR 25.1, FBC states:

> The LRMC of portfolio C3, as stated in Table 11-2, is $81 per MWh. With the inclusion of the deferral credits from the table above, the LRMC of portfolio C3 would decrease to $72 per MWh. Portfolio C3 has more impact on transmission and distribution deferrals than portfolio B2 as RNG_SCGT2 is not included in portfolio B2.

54.3 Please confirm, or explain otherwise, that none of the LRMC amounts shown for portfolios identified in sections 11.3.2 through 11.3.6 of the Application include deferral credits as contemplated in response to RCIA IR 25.1. If yes, please discuss why FBC considers this approach to be reasonable.

Response:

FBC confirms the LRMC is a byproduct of the portfolio analysis. As a deferral credit is not included in the portfolio analysis, it is therefore not reflected in the LRMC.

FBC acknowledges the potential merits of reflecting the avoided transmission and distribution costs associated with generation in some form. For the next resource plan, FBC will give further consideration to the interacting effects between the DCE[10] and the LRMC values, and how avoided transmission costs can be reflected at a high level, while being cognizant that underlying assumptions can materially change the value of deferral credits, as discussed in the responses to BCUC IR2 54.1 and 54.2.

54.4 Please discuss whether any of the other portfolios identified in sections 11.3.2 through 11.3.6 of the Application would have more impact than portfolio C3 on on transmission and distribution deferrals. If possible, please compare the LRMC of the other portfolios with the inclusion of deferral credits to that of portfolio C3.

Response:

FBC is a dual peaking utility with forecast summer gaps starting in 2030 and winter gaps starting in 2031, after taking into account the proposed level of DSM as shown in Section 9.2. Portfolios with greater amounts of dispatchable resources that provide year-round dependable capacity, as well as voltage support, have the greatest potential for transmission deferral. As discussed in the responses to BCUC IR2 54.1 and BCUC IR2 54.2, the degree of impact that generation can have on long-term transmission planning is highly dependent on the location where the generation interconnects on the system, the combination of resources contained in the portfolio, the region-specific load growth, and the corresponding system configurations.

[10] The Deferred Capital Expenditure (DCE) value which represents the marginal cost of transmission and distribution.

As FBC does not have an established approach to assign a transmission and distribution deferral credit objectively to all resources, FBC is unable to compare the LRMC of the other portfolios with the inclusion of deferral credits to that of portfolio C3. Based on the composition of portfolio C3, which predominately includes dispatchable capacity oriented resources, portfolio C3 is very likely to be one of the portfolios with the greatest <u>potential</u> to defer transmission and distribution projects relative to other portfolios identified in Sections 11.3.2 through 11.3.6. Portfolio C3 is the only portfolio among the preferred portfolios that is ranked as having “High” operational flexibility and “High” geographic diversity, which reflects the dispatchable nature of the resources contained and the flexibility to site those resources in favourable locations.

55.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Section 11, p. 193; Exhibit B-8, RCIA IR 25.1

Portfolio Analysis – Resource Locations

In response to RCIA IR 25.1, FBC states:

> The solar resources in portfolio C3 located in FBC's service territory provide zero dependable capacity during the winter peak. The wind resource contained in portfolio C3 is located in BC Hydro's service area and, therefore, power would be delivered over existing interties to the FBC system.

On page 193 of the Application, in Table 11-2, FBC provides the resource mix of portfolios C3, B2 and C4.

55.1 For each of the new resources proposed as part of portfolios C3, B2 and C4, please identify whether the resource is expected to be located inside or outside of FBC's service territory, or whether that is known at this stage.

Response:

The following table is reproduced from the response to BCUC IR1 31.5 with the additional requested information included in the last column.

Resource ID	Installed Capacity (MW)	Portfolio C3	Portfolio B2	Portfolio C4	Located inside FBC's service territory
DistBattery6	25	√	√		√
RNG_SCGT2	100	√			√
RNG_SCGT1	48	√	√		√
Solar2	39	√	√	√	√
Solar3	47	√	√	√	√
DistSolar3	9	√	√	√	* note
Solar1	17	√		√	
Wind1	45	√	√		
Wind5	140		√	√	
Solar7	110		√	√	√
RoR3	16		√	√	
Battery4	50			√	√
DistSolar2	4			√	* note
Wind3	65			√	
Biomass1	9			√	
DistSolar1	1			√	* note

Resource ID	Installed Capacity (MW)	Portfolio C3	Portfolio B2	Portfolio C4	Located inside FBC's service territory
RoR2	11			√	

Table Note:

* DistSolar1, 2 and 3 are located in the BC Hydro service territory. However, FBC believes that it is likely that alternate project sites within the FBC service territory exist that were not identified in the Resource Options Report. If this resource type is constructed, FBC would first seek to identify and then consider sites within the FBC service territory.

55.2 Please summarize the advantages and disadvantages of having supply resources located within FBC's service territory as compared to outside of FBC's service territory.

55.2.1 Please discuss whether FBC's portfolio analysis balances these advantages and disadvantages when optimizing its portfolios. If yes, please discuss how and cite specific examples. If not, please discuss why not.

Response:

A shared provincial pool of resource options provides FBC ratepayers with the advantage of including resources located both inside and outside FBC's territory, thereby allowing access to the best available resources in BC to meet forecast resource gaps, as well as providing the portfolio analysis with a greater diversity of resource types and sizes to determine the optimal fit. FBC's optimization routine can freely select options in BC Hydro's service area, but those resource options include a price premium for wheeling, as explained further below.

FBC and BC Hydro are intertwined in significant ways, including multiple geographic points of interconnection, BC Hydro being party to the Canal Plant Agreement (CPA) as well as other significant power supply related agreements, and BC Hydro being the balancing authority in the province. The multiple points of interconnection allow FBC to schedule the delivery of power to different areas of FBC's system via BC Hydro's higher voltage bulk transmission system. The CPA allows FBC to use entitlement resources within its service territory to virtually balance resources located in BC Hydro's service territory. Any resource development in BC Hydro's service area would need to consider BC Hydro's balancing obligations and continue to be in the spirit that coordination of resources across the province should provide value to both parties.

The disadvantage of resources located outside of FBC's service territory is the need to include both resource interconnection costs as well as the cost to wheel power over BC Hydro's system to FBC's system. FBC has included BC Hydro's interconnection cost assumptions and simplified wheeling costs[11], as stated in Appendix K, Section 2.2.2.1, for all resources located within BC Hydro's service area. These wheeling costs notably increase the UEC of resources located in BC Hydro's service area. The resource optimization routine considers these costs in the selection of resources.

In contrast, resources located within FBC's service territory reflect interconnection costs on FBC's system and do not include wheeling costs. Resource options located in FBC's service territory located near the North Okanagan load centre potentially provide resiliency benefits as well as the ability to defer future transmission and distribution projects depending on the specific location of interconnection and the performance attributes of the particular resource.

55.3 Assuming portfolio C3 is implemented as proposed, please compare the percentage of available energy and dependable capacity resources located within FBC's service territory by 2040 to the current (2021) percentage of available energy and dependable capacity resources located within FBC's service territory.

55.3.1 Please explain why FBC considers this resource mix to be reasonable.

Response:

FBC has interpreted "available energy and dependable capacity" to be consistent with how resources are presented in Table 5-1 of the Application, meaning the *maximum amounts available for dispatch*[12] divided by the total resources available in FBC's portfolio. The stated proportions of dependable capacity resources are based on the month of December, and provided below in Table 1. Both the PPA and the market are considered to originate outside of FBC's service territory.

Table 3: Portion of Resources in FBC's Service Territory based on Maximum amounts Available for Dispatch

Percentage (%) located inside FBC's service territory	Portfolio C3 [2021]	Portfolio C3 [2040]
Available Energy Resources	56	50
Dependable Capacity Resources	75	77

However, FBC also provides Table 2 below for the interpretation of "assuming portfolio C3 is implemented as proposed", meaning that the proportions are provided in the context of what the portfolio optimization routine *dispatched* in portfolio C3 divided by the forecast load requirements.

[11] The actual costs of wheeling for a FBC resource in BC Hydro's service territory would likely be a point of negotiation.
[12] RNG SCGT1 and RNG SCGT2 have 75 GWh and 158 GWh of energy available for dispatch in the portfolio analysis, respectively. This is considerably more energy than modelled dispatch as shown in the response to BCUC IR2 29.7.

In other words, the stated proportions of energy and capacity reflect resources used to meet the annual energy and system peak demand forecast over the planning horizon.[13]

Table 4: Portion of Resources in FBC's Service Territory based on Modelled Dispatch

Percentage (%) located inside FBC's service territory	Portfolio C3 [2021]	Portfolio C3 [2040]
Available Energy Resources	73	63
Dependable Capacity Resources	81	80

Portfolio C3, along with many other portfolios[14], includes large amounts of market and PPA energy to meet annual forecast energy requirements over the planning horizon. As load grows over the planning horizon, a larger portion of the incremental energy is met through resources not located within FBC's service territory, which is the result of comparatively lower forecast PPA and market energy prices relative to new resources and is consistent with the BCUC's determination that energy self-sufficiency is not in the interest of the ratepayer.[15] In 2021, approximately 10 percent of FBC's energy requirements are met with market energy compared to 17 percent in 2040. In 2040, for some months the volume of market energy used to meet load cannot be fully covered by alternatively using PPA energy if market prices were to increase or market access was to become unavailable.

In regards to capacity, FBC maintains a capacity self-sufficiency requirement. This requirement permits the use of PPA and resources within BC Hydro's service territory to meet system peak demand, but will not permit the use of market capacity to meet peak demand after 2030. This resource mix is reasonable as it provides capacity self-sufficiency through available provincial resources, reflects FBC's agreements with BC Hydro, and uses the most cost-effective energy resources available in line with BCUC's guidance from the 2016 LTERP decision.

13 Appendix G states the load forecast before DSM. The proposed level of DSM activity is treated as a dispatched resource in this response and is reflected in the proportions of resources located inside FBC's service territory.

14 FBC illustrated the energy and capacity resources used to meet load requirements in graphical format in the response to BCUC IR1 31.6, which includes graphs for Portfolio C3.

15 2016 LTERP Decision, Order G-117-18, page 7 of 27.

56.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Section 6, p. 140; Section 11

Impacts of Climate Change on Portfolio Analysis

On page 140 of the Application, FBC states:

> The threat that global climate change presents to FBC infrastructure and operations is a continuing reality that FBC is taking seriously. FBC identifies wildfires as the most significant climate-related risk, while others include flooding and extreme weather. FBC has been building climate resiliency using its standards and practices over time, but, as climate change related risks increase, additional adaptation methods may need to be implemented.

In Section 11 of the Application, FBC provides its Portfolio Analysis.

56.1 Please discuss whether FBC considers the impacts of climate change when planning for new supply-side resources and developing portfolios in this LTERP, such as giving preference to certain types of resources over others, preference to resources in certain locations etc. If yes, please discuss how and cite specific examples. If not, please discuss why not.

Response:

The portfolios presented in Section 11 of the Application are an outcome of the portfolio optimization routine as outlined in the response to BCUC IR1 30.1. Within the portfolio evaluation matrix shown in Table 11-2, FBC recognizes both operational flexibility and geographic diversity as criteria when considering the tradeoffs among the preferred portfolios. Portfolios ranked “High” in these categories reflect diversity. FBC believes that diversification in terms of both resource type and geographic location are important considerations in developing resiliency to climate change. Portfolios with “High” operational flexibility ratings generally contain dispatchable resources, such as a RNG SCGT, which can be used to help to mitigate some of the risk associated with integrating renewable energy.

However, there are no specific constraints in the optimization routine that give preference to certain resource types due to potential impacts of climate change. FBC acknowledges that climate change and extreme weather events have the potential to impact intermittent renewable generation over the next 20 years. Please refer to the response to BCUC IR1 31.1 for discussion on how FBC can accommodate conditions where actual energy produced from intermittent resources may be more or less than expected. It is difficult to know with any degree of confidence, however, which future resource options will be impacted and to what degree those will impact future energy output. FBC has aligned the energy and capacity profiles of intermittent renewable resource options contained in the portfolio model with data collected within the Resource Options Report that was developed in collaboration with BC Hydro. FBC does not have any new or additional information that can be used to make further objective adjustments to the resource options dataset. In future resource plans and/or within other future proceeding that involve the evaluation of specific resource options, FBC will incorporate the best information available at that time.

H. VOLUME 2 – LONG-TERM DSM PLAN

57.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, Volume 2 (LT DSM Plan), Section 3, p. 15; Exhibit B-1, Volume 2, Appendix A, p.31; Exhibit B-4, BCOAPO IR 40.3

Cost Effectiveness of DSM Programs vs. DSM Measures

On page 15 of FBC's 2021 Long-Term Demand Side Management Plan (LT DSM Plan), FBC states: "FBC also clarified that all DSM Scenarios included the same selection of cost effective DSM measures."

In response to BCOAPO IR1 40.3, FBC states:

> The [Conservation Potential Review] 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.

On page 31 of Appendix A to the LT DSM Plan, Lumidyne states:

> The economic screening used cost tests that excluded program administrative costs because measure specific administrative costs are difficult to assess. It is generally more insightful to include administrative costs when evaluating aggregate cost effectiveness for an entire program or sector, as is done in Section 3.3, rather than burdening measure-level cost effectiveness with uncertain administrative costs. Additionally, measure-specific administrative costs are highly dependent on program implementation, which is outside the scope of this study.

57.1 Please discuss whether any measures were excluded from consideration in the LT DSM Plan because they failed the cost-effectiveness test at the measure level, but could have been included if cost-effectiveness was calculated at the program, sector or portfolio level. If yes, please provide additional details on the excluded measures.

<u>Response:</u>

Residential measures that have an mTRC less than 1.0 and commercial and industrial measures that have a TRC less than 1.0 were excluded from the market and program potential. Per the DSM Regulation, measures that were excluded from consideration in the LT DSM Plan could be included if screening was calculated at the program, sector, or portfolio level. However, the potential inclusion of non cost-effective measures as part of CPR and LT DSM planning would make it a complex and iterative exercise, as the cost-effectiveness of a program, sector, or portfolio level would be dependent on which non cost-effective measures are bundled with which cost-effective measures. Their inclusion could result in an exponential increase in the number of DSM Scenarios that would need to be evaluated and compared with each other.

FBC does consider bundling of some non cost-effective measures with cost-effective measures as part of program design during DSM Expenditure Planning. An example is FBC's Custom Efficiency Program, where customers implementing both cost-effective and non cost-effective measures in the same project can obtain incentives from FBC provided that overall program cost-effectiveness is maintained. However, inclusion of non cost-effective measures is generally considered to be an exception, rather than a rule. Therefore, as part of LT DSM planning, FBC excludes non cost-effective measures from all DSM Scenarios.

There are 167 non cost-effective measures screened in the CPR. The cost effectiveness of all measures screened in the CPR (including non cost-effective measures) is included in the "Net Benefit-Cost Ratios" tab of Appendix B1 of the Conservation Potential Review, included as Appendix A of the LT DSM Plan.

57.1.1 Please confirm, or explain otherwise, that the Maximum DSM scenario does not represent the maximum level of energy savings that FBC could achieve, while being considered cost-effective as defined in the DSM Regulation.

Response:

FBC confirms the Maximum DSM Scenario represents the maximum modeled energy savings that FBC could potentially achieve if incentives for cost-effective measures were set at a maximum of 100 percent of the incremental cost, at the measure level, using the methodology detailed in the response to BCOAPO IR1 33.1. Note that the LT DSM Plan DSM Scenarios are prepared for planning purposes and do not include the detail of DSM program design developed in the DSM Expenditures Plan.

57.2 Please discuss whether FBC intends any future DSM expenditure schedules, based upon the LT DSM Plan, to be limited to including the same measures that were selected for the DSM scenarios in the LT DSM Plan. If not, please further explain how the LT DSM Plan forms the basis for informing FBC's DSM program design.

Response:

The majority of measures in future DSM expenditure schedules will be based upon the LT DSM Plan, but not necessarily all measures. The LT DSM Plan serves as a guide for future DSM expenditure planning, but does not necessarily consider factors such as market readiness and emerging measures. Thus, DSM expenditure schedules should be consistent with the resource planning goals of the LT DSM Plan and LTERP, but not identical with respect to both total expenditures, total savings, and relative allocation of expenditures and savings between program areas.

Measures proposed for incentives as part of DSM program design reflect additional considerations, including, but not limited to:

- Interactive effects or spillover potential with other DSM measures;
- Variation of savings and costs based on a more limited application of the DSM measures (e.g., only providing packaged terminal heat pumps to hotels and motels versus other building types);
- Revised savings and cost assumptions provided after the LT DSM planning process;
- Supporting measures on a project-by-project basis through the Performance Program; and
- Customer and industry demand and feedback.

For example, some additional opportunities have been identified in FBC's upcoming DSM Expenditures Plan to improve cost-effective energy savings compared to the Base DSM Scenario that was included in the LT DSM Plan, reflecting the above considerations. Additional measures have also been identified that were not identified as part of the LT DSM planning process. These additional identified opportunities and measures do not materially impact the Base DSM Scenario.

57.3 Please discuss the key factors that may affect the overall cost-effectiveness of a DSM portfolio when FBC undertakes its DSM program design, compared to the aggregate cost-effectiveness of the individual DSM measures comprising the LT DSM Plan.

Response:

Key factors that may affect the overall cost-effectiveness of a DSM portfolio or program when comparing to the individual measures in the LT DSM Plan include:

- The qualifying criteria for the measures that may impact the equipment baseline, measure life, incremental cost and savings as compared the LT DSM Plan assumptions;
- Interactions between measures installed at the same time that may result in incremental cost and savings as compared the LT DSM Plan assumptions; and

- Labour, administration, and marketing costs that may exceed or be below the universal administration adder in the LT DSM Plan assumptions.

57.3.1 Please explain whether the assumed customer adoption of a specific DSM measure would be expected change when it is bundled together with other measures in a DSM program, as opposed to if it were provided separately. Please include any relevant examples from FBC's existing DSM programs.

Response:

FBC confirms that customer adoption of a specific measure may change when it is bundled together with other measures. Several examples include:

- FBC's Home Renovation Rebate program provides a bonus incentive for customers who adopt multiple measures together. This bonus incentive combined with the regular incentive helps reduce the customer's total incremental cost of the project compared to implementing measures separately.
- FBC's Continuous Optimization Program looks at providing an incentive to target multiple building control optimization projects. If FBC supported the measures individually, the savings may not be significant, but when implemented together, the overall package has much greater savings and, thus, attracts more customers to participate in the offer.
- FBC's Custom Efficiency Program provides incentives for bespoke commercial and industrial energy efficiency projects. Each project may range from including just a few to dozens of measures. If implemented on their own, some measures may have less savings and may not even be cost-effective. However, when measures are combined into a larger project, the overall savings are greater and the incentive is more attractive, encouraging the customer to advance the project as a whole.

58.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Section 4, p. 26; Exhibit B-2, BCUC IR 41.1,

Demand Response Pilots

On page 26 of the LT DSM Plan, FBC states:

> The Company currently has a residential DR [Demand-Response] pilot phase out to tender. It will seek to control and shift key household end-uses such as: space cooling, hot water and possibly other devices such as pool pumps. Importantly, the scope includes controls of residential home EV charging, which has been identified as the largest demand growth factor in this LTERP.
>
> The current DR pilots are intended to provide proof of concept, i.e. magnitude of load shifted and propensity of customers to participate. The results are expected to inform a business case for an ongoing DSM program to scale up DR capacity over time, the benefits of which may include deferral of T&D infrastructure upgrades and power supply operational flexibility.

In response to BCUC IR 41.1, FBC stated:

> The commercial DR pilot was completed in December 2020 and evaluated in 2021. The pilot consisted of two parts:
>
> 1) an assessment study for DR potential within the Kelowna area; and
>
> 2) the pilot itself where commercial customers were recruited to participate in DR events. The pilot identified a number of limitations in the approach used, including:
>
>   1. Challenges in customer recruitment using the key account targeted customer approach;
>   2. Challenges using manual dispatch to implement DR events; and
>   3. The methods of communication leading up to, and during, a DR event to ensure all parties are aware of the timing and expectations.
>
> The overall results did not conclusively show that commercial DR using the approach advanced in the pilot could have a notable impact on commercial customer demand. FBC will re-assess the approach to commercial DR for a potential future pilot, as the assessment expected a notable DR potential in the region despite the pilot results.
>
> The residential DR pilot is planned to launch in winter 2021/22. Initial performance indicators are expected in mid-2022.

58.1 Please summarize the scope of the commercial DR pilot, and discuss whether it was based on a customer controlled voluntary response or utility-controlled demand response with customer override capabilities.

Response:

FBC's goal with the commercial DR pilot was to test out commercial DR on a small scale and study the effectiveness of commercial DR as a potential future system resource. The season consisted of an abbreviated summer (four dispatched events across three sites) and a winter (eight dispatched events across seven sites) season. FBC then extended the pilot for a second, full summer season in 2020, which increased the participant count to 10 sites and was dispatched a total of 20 times. FBC tested two different incentive mechanisms during the pilot.

The method of demand response was customer-controlled, voluntary (manual) response. Prior to a DR event, FBC would contact the participant to dispatch the event.

58.2 Please provide additional details on the outcomes of the commercial DR pilot, including customer participation and response data, lessons learned, value of the DR potential, and any metrics used by FBC to determine the level of success of the pilot.

Response:

A total of ten participants were enrolled by the completion of the DR Pilot. FBC benefitted the most from DR capacity during both the coldest days in winter and the hottest days in summer, when it was most needed by the system, suggesting that DR may be considered a reliable resource. As a result of the pilot, the system benefitted from a maximum of 1.33 MW of DR capacity and 619 kW average DR capacity in the summer of 2020, and maximum DR capacity of 696 kW and average of 524 kW of DR in the winter. Some lower-performing days reduced the summer 2020 average savings, due to participant technical issues and changes in participant operation creating more variability and less reliability, along with other customer staffing and operational issues.

The criteria that FBC used to measure the success of the commercial DR pilot included:

- the magnitude of DR capacity available (compared to the potential estimate);
- operational characteristics such as: dispatchability, reliability, and timeliness of the DR event responses;
- customer engagement and satisfaction, including retention;
- DR potential scalability;

- reliability as a resource option;
- DR use-cases, for example infrastructure deferral, generation deferral, wholesale market price mitigation; and
- cost effectiveness.

FBC obtained several key insights and findings as an outcome to the commercial DR pilot:

- **Dispatch and Metering Infrastructure** - The manual DR program dispatch and metering infrastructure was effective operationally and cost-effective. The dispatch and metering of manual DR could be improved with three changes: increased planning and vetting of sites for hardware installation, avoiding client-supplied data configurations, and upgrading data loggers with additional memory to minimize short-term data loss. FBC did not explore auto DR in this pilot; this could be considered in future pilot phases.
- **Key Participation Factors -** Expanding the target area, as well as increasing the incentive amount also had positive effects on attracting more participation, and from a more diverse set of participants. Both financial and non-financial motivations proved to be important to participants. Non-financial factors, such as energy conservation and emission reductions, were cited as major motivators for participants in the pilot. Participants also found the voluntary system attractive as it provided operational flexibility.
- **Recruitment Length -** Recruitment for the commercial DR pilot and for any future DR pilots or programs benefit from lengthy lead times ahead of participation to allow ample time for educational, decision-making, legal, and technical questions to be answered. This pilot was the first experience many of the participants had with DR and additional support for devising curtailment plans and evaluating participation potential proved to be very helpful.
- **Satisfaction -** All surveyed contributors were satisfied with their experience and indicated interest in future participation. Some clients expressed interest in enrolling additional sites to increase economy of scale and share benefits with other sites. Future improvements or considerations should consider event timing, duration, and frequency, which may impact contributors' facilities operations, priorities, and ultimately, participation. Participants felt the frequency and duration of events was acceptable as dispatched. Additional support and training at the onset of the pilot would be beneficial, as well as more timely reporting and feedback on event performance.

58.3 Please discuss when FBC plans to re-assess and test the future commercial DR pilot, and how, if at all, FBC's pilot aligns with the DR practices of other Canadian utilities.

Response:

FBC plans to test and assess automated DR for commercial and industrial customers in 2023, subject to BCUC approval of this in its upcoming DSM Expenditure Plan.

FBC is aware of the following commercial and industrial DR programs in Canada:

- Ontario's Independent Electricity System Operator (IESO) operates a DR auction[16] that includes both manual and automated DR solutions advanced by several contracted proponents.[17]
- Alberta's Electric System Operator (AESO) operates an automated DR program[18] for large load customers through its Load Shed Service for Imports.[19]
- Quebec has a manual DR program under its Demand Response Option.[20]

FBC's completed commercial DR pilot is generally aligned with the other manual DR programs noted above. A future phase of the DR pilot focusing on automated DR generally aligns with other automated DR programs noted above.

58.4 Please explain what FBC means by "key account targeted customer approach."

Response:

In lieu of having pilot participants express interest in response to general marketing (such as the FBC website, email subscription, or bill inserts), FBC key account staff directly contacted potential participants they believed would be successful under the pilot program. Those customers contacted by FBC key account staff either elected to participate in the pilot or declined.

58.5 In addition to the residential DR pilot program scheduled for 2022, please provide information on any other DR pilots which may be implemented over the next 5 years, and how FBC defines success. Please discuss what factors FBC takes into account when determining which pilots become DSM program offerings.

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[16] https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Demand-Response-Auction.

[17] https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Demand-Response-Pilot.

[18] https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/.

[19] https://www.aeso.ca/market/ancillary-services/load-shed-service-for-imports/.

[20] https://www.hydroquebec.com/business/customer-space/rates/demand-response-option.html.

Response:

Currently, FBC has no additional BCUC-approved DR pilot programs scheduled over the next five years. FBC intends to include an additional automated commercial DR pilot in the upcoming DSM Plan and is currently considering if additional pilots are need to assess automated DR of electric vehicle charging.

Please refer to the response to BCUC IR2 58.2 for the criteria FBC uses to measure the success of the commercial DR pilot. These same criteria will be used to determine which DR pilots become DSM program offerings.

58.6 Please discuss the main factors that will contribute to whether, and the extent to which, FBC will be able to utilize DR as a future resource for deferral of T&D infrastructure upgrades and power supply operational flexibility.

Response:

The main factors that will contribute to whether, and the extent to which, FBC will be able to utilize DR as a future resource for deferral of transmission and distribution infrastructure upgrades and power supply operational flexibility are as follows:

- the magnitude of DR capacity available (compared to the potential estimate);
- operational characteristics such as: dispatchability, reliability, and timeliness of the DR event responses;
- customer engagement and satisfaction, including retention;
- DR potential scalability;
- the market potential of the proposed DR offerings (i.e. based on pilot information, what percentage of customers will voluntarily enroll in the program);
- the cost-effectiveness of the DR resource using the Total Resource Cost; and
- the suitability of the DR technology to control emerging demand challenges (electric vehicle challenges, space cooling, connected appliances, etc.).

59.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, Volume 2, Section 3, p. 28; Exhibit B-3, BCSSIA IR 10.2.4; Greenhouse Gas Reduction Regulation, Section 4

Electrification

On page 28 of the LT DSM Plan, FBC states:

> This LT DSM Plan relies on the LTERP Load Scenarios (section 4 of Volume 1) to explore the impacts of Deep Electrification, and other less intense variants thereof, on FBC's LRB.
>
> The 2016 BC CPR estimated 36 GWh of fuel-switching potential, primarily commercial space heating and a small 1 GWh portion of residential space heating. Using the provincially prescribed cost test, only the commercial space heating measure achieved unity – after rounding – on the base measure only. Once program administration costs were included all the measures failed at the program level.
>
> In light of anticipated fuel cost increases, e.g. the federally announced carbon tax escalation to $170/tonne by 2030, the Company is updating its electrification potential as part of its 2021 CPR scope of work. Those results are not ready at the time of this filing."

In response to BC Solar & Storage Industries Association (BCSSIA) IR1 10.2.4, FBC stated:

> FBC provides incentives for residential and commercial customers to replace less-efficient electric resistive heating systems, such as electric baseboards, with retrofitted electric heat pumps. FBC does not currently provide incentives or special rates to convert other heating equipment to electric heat pumps or to supplement gas-fired heating with heat pumps (fuel-switching incentives). However, FBC administers the provincial government's CleanBC fuel-switching incentives for FBC customers and the municipal electricity customers of Summerland, Penticton, Grand Forks, and Nelson Hydro. FBC has focused on providing energy efficiency incentives and has not offered fuel-switching incentives as they are not cost-effective (per the Total Resource Cost test) under the Demand-Side Measures Regulation. However, FBC is currently undertaking an electrification study, the results of which will inform potential future fuel-switching incentives or special rates that could be offered outside of FBC's DSM program.

Section 4 of the Greenhouse Gas Reduction Regulation (GGRR) provides the following definition of cost-effective:

> "cost-effective" means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection (3) (a) or (b) exceeds

the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year;

(4) An undertaking is within a class of undertakings defined in paragraph (a) or (b) of subsection (3) only if, at the time the public utility decides to carry out the undertaking, the public utility reasonably expects the undertaking to be cost-effective.

59.1 Please confirm when the results of FBC's electrification potential analysis will be available. Please confirm if the electrification potential and/or future load forecasts will incorporate CleanBC Roadmap to 2030 policy commitments and federal initiatives such as the Canada Greener Homes Grant. If not, please explain why not.

Response:

FBC expects that the electrification potential study will be complete in Q2 2022. The study focusses on evaluating the cost effectiveness of individual electrification measures, both including and excluding demand mitigation measures. Should FBC offer future electrification incentives, those initiatives would be aligned with the CleanBC Roadmap to 2030 policy commitments.

FBC confirms the study did not consider incentives from the Canada Greener Homes Grant (or other funding bodies), as those incentives may be transitory.

59.2 Please provide the methodology used by FBC, including all benefits and costs considered, to inform the analysis of the cost-effectiveness of fuel-switching incentives discussed above.

Response:

FBC is using the benefit-cost test stipulated in Section 4 of the BC *Greenhouse Gas Reduction Regulation* (GGRR). The benefits are being calculated by reviewing, by measure, the incremental revenues that would have been earned from the supply of undertaking electricity to export markets. The costs are calculated to reflect costs FBC would reasonably expect to incur to implement the undertaking – in this case, the estimated incremental energy supply, capacity, transmission and distribution costs. The cost effectiveness would be the ratio between the costs and benefits, calculated using FBC's discount rate.

FBC is performing this calculation for all electrification measures within the scope of the study. Prior to FBC preparing a submission for an electrification plan under the GGRR, FBC would assemble the included electrification measures into discrete programs. This would follow a similar methodology to DSM Program design, evaluating estimated participation, qualifying criteria, and administration costs on a program-by-program basis.

59.3 Given the current GGRR definition of cost-effectiveness, please discuss FBC's view on the appropriate definition of cost-effectiveness to be used when assessing fuel-switching measures, and if FBC intends to re-assess the cost-effectiveness of these measures in its electrification potential analysis.

Response:

Please refer to the response to BCUC IR2 59.2.

60.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, Volume 2, p. 6; Exhibit B-2, BCUC IR 40.1, 40.2; Exhibit B-4, BCOAPO IR 32.1; Exhibit B-1, Volume 2, Appendix A, p. 54

Cost-effectiveness

On page 6 of the LT DSM Plan, FBC states that one of the guiding principles used to develop the plan included:

> Cost effective by including only those measures, with the exception of adequacy measures, that have a Total Resource Cost (TRC) Benefit/Cost (B/C) ratio greater than unity on a portfolio basis (see Section 2.4)

In response to BCOAPO IR 32.1, FBC stated:

> 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.

On page 54 of Appendix A to the LT DSM, FBC states: "Though the analysis applied an mTRC test to residential measures, more than 96 percent of residential market potential passed the more restrictive TRC test."

60.1 Please provide a table showing the total forecast DSM program expenditures that require the mTRC, and showing the estimated share of portfolio expenditure.

<u>Response:</u>

The table below shows the total forecast DSM program expenditures that are cost effective using the mTRC screening versus total forecast DSM program expenditures that are cost effective using the TRC screening. The table also presents the percent share of portfolio expenditures that are only cost effective using the mTRC screening.

	Total Program Spending (Administration + Incentive)			
	Including mTRC Measures	TRC Measures Only	Difference	mTRC % of Spending
2020	$10,565,071	$10,160,354	$404,717	3.80%
2021	$10,900,776	$10,706,951	$193,825	1.80%
2022	$10,825,061	$10,223,146	$601,916	5.60%
2023	$9,850,737	$9,428,796	$421,941	4.30%
2024	$10,829,615	$10,409,049	$420,566	3.90%
2025	$11,933,285	$11,518,131	$415,153	3.50%
2026	$11,524,178	$11,122,843	$401,336	3.50%
2027	$12,166,036	$11,760,071	$405,965	3.30%
2028	$12,112,795	$11,705,436	$407,359	3.40%

	Total Program Spending (Administration + Incentive)			
	Including mTRC Measures	TRC Measures Only	Difference	mTRC % of Spending
2029	$12,005,063	$11,595,158	$409,904	3.40%
2030	$11,782,095	$11,368,678	$413,417	3.50%
2031	$10,486,166	$10,068,510	$417,656	4.00%
2032	$10,923,984	$10,501,416	$422,568	3.90%
2033	$10,455,125	$10,027,771	$427,354	4.10%
2034	$9,636,621	$9,204,825	$431,796	4.50%
2035	$9,797,764	$9,362,316	$435,448	4.40%
2036	$8,205,017	$7,766,639	$438,378	5.30%
2037	$7,836,790	$7,397,542	$439,248	5.60%
2038	$7,740,567	$7,302,643	$437,924	5.70%
2039	$7,611,998	$7,177,750	$434,248	5.70%
2040	$7,492,683	$7,064,648	$428,035	5.70%
Total	**$214,681,425**	**$205,872,674**	**$8,808,751**	**4.10%**
NPV	**$111,501,268**	**$107,167,656**	**$4,333,612**	**3.90%**

In response to BCUC IR 40.1 requesting a high-level summary of the projected expenditures and cost effectiveness indicators (specifically, mTRC and the UCT values) for each of the programs outlined by FBC in the 2021 Long Term DSM Plan, FBC states that:

> In the CPR, the TRC and mTRC are calculated at the measure level. Programs are identified at a high-level to include the cost-effective measures identified in the CPR. The LT DSM Plan does not go into the granularity of program design or budgeting at a program-level. As cost effectiveness is determined based on program design inputs, the cost-effectiveness indicators at the program level will be included in a future DSM Plan.

In response to BCUC IR 40.2, FBC stated that the CPR model did not include assumptions for free-ridership, spillover, and rebound at the measure-level as those are influenced at the program level (i.e. the net-to-gross was assigned a value of 1.0). Thus, zero percent was assumed for all three factors.

60.2 Please discuss FBC's views on the relevance of gross to net adjustments when assessing potential DSM savings, and the impact on TRC when this adjustment factor is excluded.

Response:

The gross to net adjustments reflect the impact of FBC programs on customer savings from program free ridership and spill over, which FBC assesses through its evaluation, measurement, and verification activities. In 2021, FBC's DSM programs have a relatively high average portfolio net to gross ratio of 0.93. While customers do realize savings regardless of free-ridership and spill-over, FBC cannot rely on DSM as a resource option without a gross to net adjustment.

Gross to net adjustments are typically a factor of program design and not inherent to a measure. Thus, for LT DSM planning purposes, the savings potential of a measure is not discounted, allowing for a complete assessment of all potentially cost-effective measures at this stage. Gross to net adjustments are considered when preparing programs as part of DSM expenditure planning.

The TRC for electric measures is calculated as the ratio of avoided energy benefits over the sum of incremental measure costs and program administrative costs. In the TRC equation, gross to net adjustments discount the avoided energy benefits and the incremental measure costs, but do not impact the program administration costs. Lower net to gross ratios will reduce the TRC, but not proportionally.

60.3 Please provide the formula used by FBC when calculating the TRC and mTRC for DSM purposes, and a summary of the key assumptions used to calculate the TRC.

Response:

The formula used by FBC when calculating the TRC and mTRC is listed as Equation 1 on page 30 of the Conservation Potential Review, included as Appendix A of the LT DSM Plan. A copy of the relevant section has been included below.

Equation 1. Benefit-Cost Tests for Economic Measure Screening

Sector	Benefit-Cost Ratio
Commercial* & Industrial	$TRC = \frac{NPV(DiscountRate,\ AvoidedCost_{year} + OMSavings_{year})}{NPV(DiscountRate,\ IncrementalCost_{year})}$
Residential	$mTRC = \frac{NPV(DiscountRate,\ AvoidedCost_{year} * 115\% + O\&MSavings_{year})}{NPV(DiscountRate,\ IncrementalCost_{year})}$

**MURBs were treated as commercial customer segments.*

Where…

TRC: the benefit-cost ratio for the Total Resource Cost test

$mTRC$: the benefit cost ratio for the modified Total Resource Cost test

$NPV(\,)$: the net present value formula that sums discounted cash flows over time

$DiscountRate$: the discount rate applied to future cash flows

$AvoidedCost$: FortisBC's avoided energy and demand costs generated through conservation

$O\&MSavings$: operating and maintenance cost savings from installation of efficient measures

$IncrementalCost$: the efficient measure's incremental equipment cost relative to the baseline measure

$year$: each year of the measure's expected useful life

The key assumptions used to calculate the TRC are listed in Table 1 on page 10 of the Conservation Potential Review, included as Appendix A of the LT DSM Plan. A copy of the table is included below.

Table 1. Comparison of Economic Assumptions

Economic Assumption	2016 CPR (2016 nominal values)	2021 CPR (2020 nominal values)
Long-Run Marginal Cost	\$100/MWh	\$89/MWh
Deferred Capital Expenditures	\$80/kW-year	\$51/kW-year
Discount Rate	8.12%	7.90%
Electric Rates	Residential: 13.3 cents/kWh Commercial: 9.7 cents/kWh Industrial: 8.1 cents/kWh	Residential: 13.9 cents/kWh Commercial: 10.2 cents/kWh Industrial: 8.2 cents/kWh
Gas Rates	Residential: \$7.7/GJ Commercial: \$5.2/GJ Industrial: \$4.3/GJ	Residential: \$8.5/GJ Commercial: \$7.4/GJ Industrial: \$6.8/GJ

61.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, Volume 2, p. 1; 13; Table 3-1, p. 14; Appendix A, Table 31, p. 56; Table 34, p. 57; Table 42, p. 63

DSM Potential Savings Included in the LTERP

On page 57, Table 34, of Appendix A to the LT DSM Plan shows the Cumulative Energy Savings Potential by Sector, which totals 582 GWh/year in 2040 across the commercial, industrial and residential sectors.

On page 63, Table 42, of Appendix A to the LT DSM Plan compares the Cumulative Energy Savings Potential After Natural Change, which reduces the Market Potential from 583GWh to 522 GWh/year by 2040 after natural change.

On page 1 of the LT DSM Plan, FBC states: "The proposed DSM Scenario target is to acquire 435 GWh of cost effective savings over the 20 year period."

On page 14, Table 3-1, of the LT DSM Plan shows the range of savings from DSM scenarios, ranging from a low of 421GWh to a high of 503 GWh for the Max DSM scenario.

61.1 Please explain all adjustments and exclusions that were made between the identification of the market potential of 583 GWh/year by 2040, and the Max DSM scenario.

Response:

Between the identification of the market potential and the DSM Scenarios, several traditional measures were excluded, including the following:

Sector	Measure Name
Commercial	Interior CFL
Commercial	Interior High Bay T5 HO fixtures
Commercial	Interior LED MR/PAR lamps
Commercial	Interior T5 New Fluorescent Fixture w/ Electronic Ballast
Commercial	New Construction 45% > Code - Accommodation
Commercial	New Construction 45% > Code - Office
Commercial	New Construction 45% > Code - Retail
Commercial	New Construction Step Code 2 - Accommodation
Commercial	New Construction Step Code 2 - Office
Commercial	New Construction Step Code 2 - Retail
Commercial	Storage Tanks for Load/No Load Screw Compressors
Industrial	Efficient Conveyor
Industrial	Improved Fan Systems
Industrial	Electric Ventilation Optimization
Residential	Advanced Power Strips

Sector	Measure Name
Residential	Electrically Heated Building - Attic Duct Insulation
Residential	ENERGY STAR CFL Bulbs (Reflector)
Residential	ENERGY STAR CFL Bulbs (Spec)
Residential	Home Energy Reports
Residential	Indoor Fluorescents T8
Residential	New Construction 45% > Code - Apartments <= 4 storeys
Residential	New Construction 45% > Code - Apartments > 4 storeys
Residential	New Construction Step Code 2 - Apartments <= 4 storeys
Residential	New Construction Step Code 2 - Apartments > 4 storeys
Residential	New Home Step Code 2 - Single Family Attached
Residential	New Home Step Code 2 - Single Family Detached
Residential	Plug Lighting Controls

These measures were excluded for several reasons, including:

- There were multiple similar measures that filled the same market niche (e.g., new construction measures, which were covered by New Construction Step Code 3, 4, and 5 measures that were included in DSM scenarios);
- Measures with very low energy savings potential (e.g., advanced power strips); and
- There are more efficient measures in market (e.g., it is preferable to incent LEDs than CFLs).

Following these measure exclusions, FBC then set the incentive levels for each measure for the given DSM Scenario, as discussed in the response to BCOAPO IR1 33.1. Next, the market adoption model was run with these new incentive values to achieve new adoption rates which drive the energy savings reported for the given DSM Scenario. In the Max DSM Scenario, the incentive level is equal to 100 percent of incremental measure cost.

61.2 Please comment on the process required to achieve the Max DSM scenario, over and above the assertion of paying an increased incentive.

Response:

The LT DSM Plan is developed using an economic model that relates the incentive paid to participants and the corresponding savings. In the model, incentive level is the only input that can be altered to increase the savings. Thus, to achieve the Max DSM scenario, there are no mechanisms in the model to achieve the Max DSM Scenario other than incentive level.

The LT DSM Plan should be considered a planning exercise that informs, but does not supplant, the detailed planning that is undertaken to develop programs in the DSM Expenditures Plan. DSM expenditure planning considers mechanisms beyond changing the incentives to affect participation and levelized cost of savings, which would be true for all DSM Scenarios, including the Max and Base DSM Scenarios. These mechanisms may include:

- Customer and trade ally marketing;
- Delivery channel (e.g., customer application vs. point-of-sale);
- Qualifying criteria;
- Complexity of customer application; and
- Coordination with other incentive programs (e.g. CleanBC, Canada Greener Homes Grant).

61.3 Please discuss the feasibility of other ways by which FBC would be able to achieve the Max DSM scenario at a lower cost than noted in the LTERP.

<u>Response:</u>

Please refer to the response to BCUC IR2 61.2.

On page 56, Table 31, of Appendix A to the LT DSM Plan shows the cumulative energy savings potential by source, totaling 583 GWh by 2040 for the traditional, non-traditional and Kraft pulp and paper sources (415 GWh, 95 GWh and 73 GWh/year respectively).

61.4 Please provide a table showing how the proposed DSM Scenario target of 435 GWh/year is allocated between the traditional, non-traditional and Kraft pulp and paper sources.

<u>Response:</u>

FBC notes that in Appendix A to the LT DSM Plan, all results (including the referenced 583 GWh) reflect cumulative at-the-meter savings, which exclude savings from avoided line losses. This is in contrast to the DSM Scenario target 435 GWh figure, which does include line losses adjustment. In the table below, FBC first shows the allocation of the savings before the losses adjustment (the 583 GWh), the savings after the losses adjustment (totaling 631 GWh), and that, after adjusting for some traditional measures that were removed after the CPR was completed (total of 14 GWh), the total comes to 435 GWh, which is exclusively from traditional measures.

Source	Savings before Losses Adjustment	Savings after Losses Adjustment[21]	Percent included in DSM Scenario Target	DSM Scenario Target
Traditional	415 GWh	449 GWh	97%	435 GWh
Non-traditional	95 GWh	103 GWh	0%	0 GWh
Kraft pulp and paper	73 GWh	79 GWh	0%	0 GWh
Total	**583 GWh**	**631 GWh**	**-**	**435 GWh**

FBC notes that the DSM Scenario target does not include all traditional measures that were investigated. Please also refer to the response to BCUC IR2 61.1 for an explanation of how the traditional measures in the Conservation Potential Review compare with the measures included in the LT DSM Plan DSM scenarios and the rationale for exclusion.

Non-traditional measures were excluded from the DSM Scenario target as there were other market and adoption barriers that did not make these measures reliable for DSM programs, even in consideration of economic factors.

Measures in the kraft pulp and paper sector were excluded from the DSM Scenario target as the kraft pulp and paper facility in FBC's service territory primarily self-generates its own electricity; thus, the savings in the facility do not result in significant savings realized by FBC.

61.5 Please discuss what criteria were used to identify and select non-traditional measures.

Response:

Measures identified for inclusion in the CPR and LT DSM Plan evaluation were identified by Lumidyne based on a broad assembly of known measures from a variety of sources, including technical resource manuals, other utility DSM potential studies, and other utility past and current DSM programs. The criteria for a measure to be a "Traditional Program Measure" in the LT DSM Plan is that it is supported in FBC's current DSM plan in the residential, commercial and industrial sectors, excluding the kraft pulp and paper sector.[22] The criteria for a measure to be a "Non-Traditional Measure" in the LT DSM Plan is that the measure is not supported in FBC's current

[21] (*Savings after losses adjustment*) = (*Savings before losses adjustment*)/(*1-losses percent*). Losses are 7.6 percent, as noted on Page 86 of the Application.

[22] "Kraft Pulp and Paper" represent measures applicable in the kraft pulp and paper sector.

DSM plan in the residential, commercial and industrial sectors, excluding the kraft pulp and paper sector.

Examples of non-traditional measures include:

- Residential refrigerator buy back;
- Residential ENERGY STAR desktop personal computers; and
- Commercial server virtualization.

On page 13 of the LT DSM Plan, FBC states:

> The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential. This approach supplants the prior metric of expressing DSM savings targets as a percent of load growth offset. That metric, which originated in the 2007 BC Energy Plan, included targets only to the end of 2020. New load growth forecasts are significantly impacted by electric vehicle growth, which DSM has no energy savings measures thus the existing approach was abandoned in favour of one that aligns with incremental costing, similar to other utility conservation potential reviews, including FEI.

61.6 Please confirm, or explain otherwise, that the sole basis for the earlier methodology was the targets in the 2007 BC Energy Plan.

<u>Response:</u>

The basis for the methodology of representing DSM savings targets as a percent of load growth offset was a combination of the 2007 BC Energy Plan and the BC *Clean Energy Act*, both of which express DSM targets as a percentage of load growth offset.

61.7 Please provide additional information on the other utility CPRs that use the incremental costing approach to establish the target amount of DSM, other than FEI.

<u>Response:</u>

FBC did not use an incremental cost approach to establish the target amount of DSM. FBC noted in the response to BCSEA IR1 15.3 that the "Average Cost ($/MWh)" metric in Table 3-1 of the

LT DSM Plan was the primary metric used to compare DSM scenarios and is consistent with the direction in Order G-117-18. Describing the DSM scenarios in terms of incentive as an average percentage of incremental cost was a useful metric to compare and communicate the DSM Scenarios. A detailed description of the incentive methodology is outlined in the response to BCOAPO IR1 33.1.

The DSM scenarios as a percentage of load growth offset from 2021 to 2040 is tabulated in the response to BCUC IR1 25.1, and ranges from 33 percent in the Low DSM scenario to 40 percent in the Max DSM scenario. Given the low variation of load growth offset, the DSM scenarios were instead based on varying incentive levels ($ per MWh).

FBC was able to identify and evaluate the following utilities' CPRs (or similar study):

- **BC Hydro**: The Draft 2021 Integrated Resource Plan[23] discusses energy efficiency resource options in Section 5.2.1, and notes that "Several different portfolios of energy efficiency resource options have been defined which reflect differing scales of marketing and education efforts and incentive levels."

  The response to BCUC IR1 25.2 discusses the similarities between FBC and BC Hydro, with respect to the principles followed when developing DSM scenarios.

- **Efficiency One**: A 2019 Potential Study Update[24] notes that five scenarios were developed: Base, Maximum Achievable, Low, Mid, and PAC (Program Administrator) screening. The Base scenario is calibrated to historical achievements, and the PAC screening scenario uses the PAC measure screening instead of TRC test measure screening. The remaining three scenarios vary both incentive and marketing factors relative to the Base scenario.

- **Ontario Energy Board**: A 2016 Natural Gas Conservation Potential Study[25] analyzed three achievable potential scenarios: unconstrained (which assumed no budget constraints or policy restrictions), semi-constrained (using budgets initially set at the levels approved by the Ontario Energy Board for 2015-2017, then gradually increased so they doubled by 2020 and remained at that level until 2030), and constrained (in which budgets from 2015-2020 are the Ontario Energy Board-approved budget levels and remain at 2020 levels through to 2030).

- **Yukon**: The 2012 Conservation Potential[26] noted that the achievable potential will vary based on the level of financial incentives, information, and other measures put into place

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23 BC Hydro and Power Authority, DRAFT 2021 Integrated Resource Plan, Page 16. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/draft-integrated-resource-plan.pdf.

24 EfficiencyOne 2019 Potential Study Update, Page 22. https://irp.nspower.ca/files/key-documents/E1-Potential-Study-Presentation_June28.pdf.

25 Natural Gas Conservation Potential Study, Ontario Energy Board, 2016. https://www.oeb.ca/sites/default/files/uploads/ICF_Report_Gas_Conservation_Potential_Study.pdf.

26 Review of Yukon's Conservation Potential, 2012, Page 83. https://yukonenergy.ca/media/site_documents/1141_Conservation%20Potential%20Review%20Final%20Report%202012%20-%20Residential%20Chapter1.pdf.

by stakeholders in the region. Within the achievable potential, two scenarios were analyzed: a lower and upper scenario. The lower scenario that assumed market conditions, customers' awareness and motivation levels, and technology and energy performance standards continue along at historic rates. The upper scenario assumed that Yukon market conditions aggressively support investment in energy efficiency, for example, assuming that electricity prices increase over the study period.

- **Energy Efficiency Alberta**: A 2018 presentation[27] shows a high level view of the inputs and general approach used in the Potential Study; however, it lacks the context to definitively state the methodology.

A trend across these studies is that the DSM scenarios were developed based on varying the marketing and education efforts, as well as the incentive levels. The model used for FBC's scenario development enabled only incentive level variation rather than allowing multiple inputs to vary. None of the other utilities' studies target their DSM scenarios as a percentage of incremental costs.

[27] Navigant, Alberta Energy Efficiency Potential, May 16, 2018. https://static1.squarespace.com/static/5c13eb6896d455789a8b64f9/t/5c4e4fce4d7a9c9ad44c51a1/1548636113441/180516_Alberta+Energy+Efficiency+Potential_Maoz%2C+Karen.pdf.

62.0 Reference: LONG-TERM DSM PLAN

Exhibit B-1, p. 166; Volume 2, pp. 4, 6; Exhibit B-2, BCUC IR 38.1; BC HydroF2023-F2025 RRA,

Exhibit B-10, Attachment 1, p. 5

LRMC for DSM Purposes

On page 4 of the LT DSM Plan, FBC states:

> Accordingly, the Company has developed a long-run marginal cost (LRMC) for DSM purposes, based on BC clean and renewable resources, of $90 per MWh, which reflects the cost of firm energy i.e. inclusive of generation capacity. Additionally, FBC is using a Deferred Capital Expenditure (DCE) value of $51.22 per kW-yr as its avoided capacity cost of deferred infrastructure, consistent with the methodology presented in Appendix C of FBC's 2017 DSM Expenditure Plan Application, accepted by the BCUC in its Decision and Order G-9-17.

When discussing cost-effectiveness in its DSM Expenditure Schedules, BC Hydro states on page 5 of Attachment 1 to Exhibit B-10 of its F2023-F2025 RRA that:

> For the purposes of assessing the Total Resource Cost Test under the Demand-Side Measures Regulation, BC Hydro used an energy LRMC of $65 per MWh3,4 and a capacity LRMC of $109 per kW-year based on the updated values presented in Appendix L of the 2021 Integrated Resource Plan Application.

62.1 Please provide FBC's views on the implications and relevance, if any, of BC Hydro's LRMC costs in its 2021 Integrated Resource Plan, for FBC's own LRMC costs for DSM purposes. Please discuss whether FBC anticipates a need to update these costs for its upcoming DSM Expenditure Schedule applications as a result. Why or why not?

<u>Response:</u>

DSM programs offered by FBC are evaluated for cost effectiveness based on FBC's avoided costs as represented by portfolio A2, rather than BC Hydro's avoided costs.

BC Hydro's LRMC of energy for ratemaking purposes does impact the cost of PPA Tranche 2 energy which is currently set at $95.09 per MWh.[28] Therefore, BC Hydro's LRMC of energy can potentially have minor impacts on FBC's own LRMC for DSM Purposes. As also discussed in the response to BCOAPO IR2 92.2, the bundled nature of the PPA product creates a physical limitation that prevents FBC from using large volumes of PPA energy in the months where FBC has the greatest energy requirements, therefore limiting the use of Tranche 2 energy.

[28] BC Hydro Tariff. Rate Schedule 3808 – Revision 10. Effective April 1, 2021. BCUC Order G-187-21.

FBC does not anticipate a need to update these costs for its upcoming DSM Expenditure Schedule applications. At this time, FBC plans to use the avoided costs stated in the response to BCUC IR1 38.1 for its upcoming DSM Expenditure Schedule application. FBC will continue to monitor BC Hydro's future proceedings to determine how BC Hydro's LRMC of Energy is reflected in RS 3808 rates. FBC's LRMC for DSM purposes reflects a portfolio of resources. FBC plans to next update the LRMC for DSM purposes in its next LTERP application, and will reflect updated costs of PPA energy along with all other resource costs at that time.

Please also refer to the response to BCOAPO IR2 92.1.

On page 166 in Table 10-2 of the Application, FBC outlines a summary of unit energy costs (UEC) and unit capacity costs (UCC) of different resources:

Table 10-2: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
Low DSM	$33	N/A
Base DSM	$38	N/A
Med DSM	$40	N/A
High DSM	$45	N/A
Max DSM	$58	N/A
PPA Tranche 1 Energy	$49 - $60	N/A
PPA Tranche 2 Energy	$80 - $95	N/A
PPA Capacity	N/A	$101 - $123
Market Purchases	$28 - $49	N/A
Wood-Based Biomass	$121 - $173	$682 - $719

On page 6 of the LT DSM Plan, FBC states:

> 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: a. energy savings, valued at the LRMC of $90 per MWh; and 9 b. demand savings, valued at the DCE of $51.22 per kW-yr.

In response to BCUC IR 38.1, FBC stated:

> The LRMC of $90 per MWh for DSM is inclusive of both energy and generation capacity… For targeted demand response programs, the capacity-only value per kW of the LRMC would be more appropriate to use. The LRMC for DSM purposes can be split into energy and capacity components using the approach outlined in Section 5.2.3 of Appendix L.

Components of LRMC	Unit Costs
Blended Energy and Capacity	$90 per MWh
Energy Only	$63 per MWh
Capacity Only	$145 per kW-Year

FBC uses a Deferred Capital Expenditure (DCE) value of $51.22 per kW-Year for DSM purposes to estimate the avoided transmission and distribution (T&D) costs (i.e., benefits from avoided infrastructure), resulting from the implementation of DSM programs.

62.2 Please explain why FBC does not assign a UCC to the DSM scenarios.

Response:

In the 2020 CPR, FBC targeted DSM measures that primarily result in energy savings, but also have corresponding capacity savings. Thus, in the calculation of cost-effectiveness, FBC utilized a LRMC that reflects the blended cost of energy and capacity. As the measures are primarily considered energy resources, the UEC value is a more appropriate metric for the unit costs.

62.3 Please explain whether FBC assumes the DSM measures contained in the DSM scenarios provide firm capacity savings for planning purposes.

62.3.1 If so, please discuss any key uncertainties associated with estimating the capacity savings from DSM.

62.3.2 If not, please discuss why FBC applies a value for generation capacity and DCE as avoided cost “benefits” in the calculation of the TRC.

Response:

FBC considers DSM a reliable resource for purposes of generation capacity planning as a result of diversification. DSM programs include a variety of cost-effective measures to address key end-uses offered to the major customer sectors across the FBC service territory. The DSM savings realized by any one measure, or in any one location, may be greater or less than anticipated as a result of factors influencing customer participation, such as demographics and socio-economics, or concentrations of customer segments. Therefore, the DSM measure savings realized in any one specific location is less certain, but, when aggregated at the system level, DSM measure savings are considered reliable.

FBC’s detailed network planning is based on the actual load growth trajectory for specific lines, feeders, and substation equipment, which may have been tempered by DSM activities to date. When there is significant concentrated new development in localized areas, the resulting increases in load generally outpace the impact of DSM savings in that same area. Once a planning criteria threshold has been crossed, a system upgrade is planned for the infrastructure in question in order to continue to meet service quality and reliability standard requirements.

Therefore, DSM savings are considered reliable for purposes of generation planning, but not firm capacity in any specific location on the system at the current time. FBC applies a value for generation capacity and DCE as avoided cost benefits in the calculation of the TRC because, despite the uncertainty in localized impact, DSM savings reliably provide capacity benefits at the system level and contribute to decreasing the system coincident peak. At a high level, reductions in the system coincident peak are in turn reflected in the 1 in 20 year forecast. As such, DSM also helps to defer future system upgrades.

62.4 Please also provide the TRC ratios of the DSM scenarios if the “Energy Only” value was applied as the avoided cost.

Response:

The table below shows a comparison of the TRC between the Base DSM Scenario with a LRMC of $89 per MWh plus DCE of $51.22 per kW-year, with a scenario having an energy LRMC of $63 per MWh and no DCE.

Year	**Residential** (mTRC)[29]		**Commercial** (TRC)		**Industrial** (TRC)		**Portfolio** (TRC)	
	LRMC 89	LRMC 63	LRMC 89	LRMC 63	LRMC 89	LRMC 63	LRMC 89	LRMC 63
2020	2.06	1.88	2.20	1.74	2.78	2.52	1.85	1.52
2021	1.92	1.80	2.18	1.73	2.14	2.59	1.77	1.52
2022	1.95	1.89	2.31	1.79	3.22	2.77	1.96	1.59
2023	1.76	1.65	2.42	1.82	3.29	2.52	1.87	1.45
2024	1.81	1.74	2.41	1.84	3.30	2.52	1.90	1.49
2025	1.86	1.80	2.33	1.84	3.24	2.56	1.91	1.52
2026	1.82	1.73	2.59	1.86	3.33	2.55	1.98	1.50
2027	1.82	1.72	2.60	1.87	3.33	2.55	1.98	1.51
2028	1.81	1.71	2.57	1.86	3.32	2.55	1.97	1.51
2029	1.87	1.76	2.52	1.84	3.31	2.55	1.96	1.51
2030	1.91	1.81	2.45	1.81	3.29	2.54	1.93	1.51
2031	1.84	1.75	2.38	1.77	3.27	2.54	1.88	1.46

[29] Note that it was assumed that the majority of Modified Total Resource Cost (mTRC) allowance under the Demand Side Measure regulation would be utilized to support the residential sector (including income qualified customers). Therefore, in the LT DSM Plan, residential measures were screening using the mTRC instead of the Total Resource Cost Test.

Year	Residential (mTRC)[29]		Commercial (TRC)		Industrial (TRC)		Portfolio (TRC)	
	LRMC 89	LRMC 63	LRMC 89	LRMC 63	LRMC 89	LRMC 63	LRMC 89	LRMC 63
2032	1.74	1.62	2.30	1.73	3.24	2.53	1.80	1.43
2033	1.75	1.63	2.22	1.69	3.21	2.53	1.77	1.41
2034	1.80	1.69	2.10	1.56	3.18	2.52	1.73	1.39
2035	1.79	1.67	2.03	1.54	3.14	2.52	1.70	1.38
2036	2.04	1.95	1.99	1.52	3.10	2.52	1.72	1.40
2037	2.16	2.10	1.96	1.50	3.07	2.52	1.74	1.43
2038	2.18	2.12	1.93	1.49	3.05	2.52	1.73	1.43
2039	2.19	2.13	1.91	1.49	3.02	2.53	1.71	1.42
2040	2.22	2.16	1.89	1.48	3.00	2.54	1.70	1.41
2020-2040	1.90	1.79	2.33	1.77	2.97	2.57	1.87	1.49

The LRMC value of $89 per MWh was used in the Conservation Potential Review, as the reference forecast calibration was completed before the $90 per MWh value for LRMC was finalized. Lumidyne performed a sensitivity analysis and found that the $89 per MWh value resulted in a difference of less than one percent, so it was decided to continue the Conservation Potential Review report using an LRMC value of $89 per MWh rather than re-calibrate the reference forecast in both the LT DSM Plan and CPR. The economic assumptions that influenced the cost effectiveness test are further described on Page 10 of the Conservation Potential Review report, included as Appendix A of the LT DSM Plan.

Note that the reference forecast was calibrated based on the LRMC value of $89 per MWh plus the DCE value of $51.22 per kW-year. When considering the above scenario where the “energy only” LRMC value is applied as the avoided cost, the Base DSM Scenario that aligns with the market potential is no longer a valid estimate of a reference forecast. The impact of this is the 2020 energy savings dropped by 9.4 percent, however the first-year program spending (in dollars per kWh) and proportion of incentive and administrative cost percentages remained relatively consistent. In order to prepare a complete comparison, the reference forecast would need to be recalibrated using the lower avoided costs. Re-running the reference forecast would take substantial effort, and was not possible to accomplish within the time frame allotted for these information requests.

Given the amount of time associated with running the model, it was not possible to re-run all DSM scenarios using the adjusted LRMC. The Base DSM scenario showed a 20 percent drop in the 2020-2040 portfolio-level TRC ratio, while the Max DSM scenario showed a 14 percent drop. FBC believes the remaining DSM scenarios’ percentage drops would be between that range, with the exception of the Low DSM scenario which would likely see a drop of greater than 20 percent.