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December 23, 2021

Residential Consumer Intervener Association
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Mr. Peter Helland, Director

Dear Mr. Helland:

Re: FortisBC Inc. (FBC)

2021 Long-Term Electric Resource Plan (LTERP) and Long-Term Demand-Side Management Plan (LT DSM Plan) (Application)

Response to the Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 1

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference Exhibit B-1, Volume 1, Page ES-1

Executive Summary, Section 1 - Introduction

FortisBC Inc. states:

"The analysis in this LTERP shows that FBC does not require any new supply-side resources until at least 2030, based on the Reference Case load forecast, existing resources and contracts in place, continued access to reliable and cost-effective market energy, and the proposed level of DSM. This is because optimization of market purchases and existing resources, including the power purchase agreement (PPA) with BC Hydro, provide FBC with enough energy and capacity until 2030 to meet customers' requirements in a cost-effective and reliable manner."

1.1. Please describe and quantify the load increase scenarios that could trigger the need for new supply-side resources prior to 2030.

<u>Response:</u>

FBC's LTERP, and corresponding load-resource balance, reflect the Reference Case load forecast. There are multiple potential load scenarios not reflected in the Reference Case load forecast that have the potential to trigger the need for new supply-side resources prior to 2030. These range from defined load scenarios such as increased efforts towards electrification, to a new large load connecting to FBC's system. These load scenarios can impact supply-side resource requirements, including the timing of when resources are required, as shown in Figure 11-4 of Section 11.3.4.

The table below quantifies FBC's projected available capacity, and therefore, the increases in load that would be required to trigger the need for new supply-side resources prior to 2030, regardless of the underlying reason. Projected available capacity is stated based on the Reference Case load forecast, after the base level of DSM, and assuming maximum PPA capacity (200 MW). Furthermore, 75 MW of market access for capacity purposes in June has been included.

Year	June (MW)	Summer (MW)	Winter (MW)
2021	46	35	54
2022	39	26	50
2023	41	29	50
2024	43	30	45
2025	37	23	86
2026	74	63	81
2027	68	57	73
2028	34	10	26

Year	June (MW)	Summer (MW)	Winter (MW)
2029	27	1	17

On a long-term planning basis, FBC has adopted a capacity self-sufficiency requirement. On an operational basis, if small gaps emerged through the years of 2021-2025, prior to the expiry of the RCA which adds approximately 50 MW of capacity in all months, FBC would expect to bridge the gap through market block purchases. Furthermore, the table above assumes the BRX contract is not renewed after 2027, although FBC may explore the viability of this option in the future. Therefore, FBC anticipates a sustained and ongoing increase in load greater than approximately 50 MW beyond the Reference Case load forecast would trigger the need for new resources prior to 2030.

1.2. What level of EV uptake would cause FBC to require new supply-side resources earlier than 2030?

Response:

Please refer to the response to RCIA IR1 1.1 regarding the load level that would cause FBC to require new supply-side resources earlier than 2030.

EV charging is forecasted to have a load impact of 9 MW in all months by the year 2025 and a load impact of 28 MW in all months by the year 2030. The Reference Case load forecast does not include any EV charging mitigation programs, which reduce the capacity impacts of EV charging. Therefore, the EV impacts embedded into the Reference Case forecast likely reflect a value closer to the upper bound of the requirement for new supply-side resources. If EV uptake grows at a faster rate than projected, FBC would correspondingly increase efforts to implement other EV peak shifting options as outlined in Section 2.3.2 of the Application.

2.0 Reference Exhibit B-1, Volume 1, Page ES-7

Executive Summary, Section 3 - Long-Term Load Forecast

FortisBC Inc. states:

"The Reference Case winter and summer peak forecasts do not include any electric vehicle charging peak mitigation (i.e. shifting EV charging loads from peak periods). This is because FBC currently has no EV charging mitigation programs in place and has no certainty, at this point, how much EV charging it will be able to shift off peak periods. The Reference Case load forecast is also presented before any DSM measures – these are discussed in Executive Summary, Section 8"

2.1. Please confirm that FBC plans to implement a residential EV charging peak mitigation pilot program.

2.1.1. If yes, what are the expected or desired outcomes of this pilot program?

Response:

FBC confirms that, as described in Section 2.3.2, it is expected that the EV charging peak mitigation pilot will help inform FBC on the effectiveness of software-based tools for shifting EV load in the long term, as well as how best to engage customers for participation in an EV charging peak mitigation program. The Company is also piloting a load-control pilot as part of the C&EM demand response pilot described in Section 2.3.7.5.

2.2. Has FBC estimated the level of peak shifting that is likely to be achieved by fully implementing an EV charging peak mitigation program?

2.2.1. If yes, please quantify.

Response:

As noted in the Section 2.3.2 of the Application, Guidehouse has estimated that 80 percent of light-duty EV charging will occur at home, and would potentially be eligible for participating in an EV charging peak mitigation program (i.e. 120 MW of the overall 150 MW of estimated peak demand associated with EV charging by 2040). It is estimated that an EV charging peak mitigation program may be able to shift up to 75 percent of this peak demand from EV charging at home, resulting in 90 MW that could potentially be shifted by 2040.

2.2.2. What technology changes or developments must be made to enable implementation of an effective EV peak-shifting program?

Response:

The proposed software-based peak-shifting approach, as described in Section 2.3.2, will generally require only the installation of software by the customer and FBC. In the rare cases where the customer's EV is not compatible with the software, FBC expects that compatible home chargers will be available for purchase by the customer. The Company is also piloting a load-control pilot as part of the C&EM demand response pilot described in Section 2.3.7.5. This pilot will likely require the customer to install a Level 2 charger that can be connected to WiFi and controlled remotely.

2.2.3. Please quantify the anticipated capital and operating costs of fully implementing an effective EV peak-shifting program. Would FBC expect to recover the capital and operating cost of implementing an effective EV peak-shifting program from EV users, or from all its customers (including those who do not own or operate EVs)?

Response:

At this time, FBC does not have comprehensive information on the anticipated capital and operating costs of fully implementing an EV peak-shifting program. However, it is expected that the planned EV charging peak mitigation pilot and the CE&M demand response pilot programs will help further develop these estimated costs. Given that the benefit of load-shifting activities for EV charging accrue to all customers, FBC would expect to recover costs from all customers similar to current cost recovery mechanisms for other DSM measures.

3.0 Reference Exhibit B-1, Volume 1, Page ES-10

Executive Summary, Section 5 - FBC Existing Supply-Side Resources

FortisBC Inc. states:

"FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex on a day-ahead basis, under the terms of the CEPSA, if and when the capacity is not required to meet FBC load requirements. Brilliant Expansion (BRX) entitlement contracts with FBC and BC Hydro expire at the end of 2027 and renewal is not assumed beyond that date. The entire set of capacity and energy entitlements attributed to BRX will be assessed as a future option to meet FBC's resource needs."

3.1. Please describe and quantify any cost or revenue impacts associated with the BRX contract expiry.

Response:

FBC is unable to quantify such costs at this time as it is not yet known if FBC will be able to contract for this power or not in the future. Furthermore, if FBC were to speculate on the nature of these costs, it could disadvantage FBC in any future negotiations to contract for this power.

4.0 Reference Exhibit B-1, Volume 1, Page ES-14

Executive Summary, Section 10 - Supply-Side Resource Options

FortisBC Inc. states:

"The PPA, battery storage and gas-fired power plants using conventional natural gas or renewable natural gas (RNG) as fuel are the lowest cost capacity resources available. Although FBC is currently comfortable with relying on market purchases for some of its energy needs, relying on market purchases for capacity over the long term can be risky in terms of availability. There is no guarantee that FBC will be able to access market capacity supply reliably and cost effectively. The month of June, however, is the exception to FBC requiring capacity self-sufficiency for LTERP planning purposes."

4.1. Why is Fortis not including carbon neutral natural gas (i.e., natural gas with carbon offsets) in its list of available generation fuels?

Response:

Under the BC Government's Carbon Neutral program, legislated under the *Climate Change Accountability Act*,[1] the Province has operated an emissions offset system since 2009 to attain carbon-neutral government operations. Offsets under this regulated program are made in BC, are incremental, and are validated and verified to Provincial standards. This regulated carbon offset program currently does not extend to the private sector, and therefore any use of carbon offsets in BC to create "carbon neutral" gas are voluntary and are at risk of not being recognized by the provincial and federal governments. Until such time that a regulated carbon offset system is in place provincially or federally, FBC cannot rely on carbon offsets to satisfy its CleanBC targets.

Note that this also applies to the use of Renewable Energy Certificates (RECs) in BC to reduce the carbon footprint of electricity, as the Province currently does not officially recognize the use of RECs in BC.

4.1.1. If Fortis is able to secure supplies of carbon-neutral natural gas, how would it change the analysis of fuel costs for the different capacity resources?

Response:

If the Province were to officially recognize carbon offsets used to create abated gas, FEI may include it into the broader RNG portfolio making both the product and tariff the same as RNG from

[1] https://www2.gov.bc.ca/gov/content/environment/climate-change/planning-and-action/legislation#ccaa

a customer perspective. FEI has previously engaged with potential suppliers of abated natural gas to understand various aspects including the regulatory framework, certification process, supply models, and indicative costs. This preliminary market feedback indicated that abated natural gas could be produced in relatively large volumes with low carbon intensity and at a lower cost compared to RNG. As such, if FEI were to include abated natural gas into the broader RNG portfolio, it would serve to lower the overall portfolio price.

5.0 Reference Exhibit B-1, Volume 1, Page ES-16

Executive Summary, Section 11 - Portfolio Analysis

FortisBC Inc. states:

"First, based on the Reference Case load forecast, FBC has no need for incremental generation resources until 2030. If FBC is able to shift some level of EV charging from peak periods, the need for new resources could be pushed out until at least 2031. Under higher load scenarios, FBC may need new resources as early as 2025."

5.1. What are the potential peak shaving mechanisms considered and what are the earliest dates they could be operational?

Response:

In September 2021, FBC began working on a demand-response pilot program for residential electricity customers within the Kelowna area, which includes electric vehicle chargers within its scope. The program uses an automated demand-response signal that will be sent to the EV charger to shift its operation to non-peak times. FBC expects to begin customer recruitment for the pilot in late 2021 with DR events beginning in early 2022.

For a future phase of the demand response program, FBC is also exploring residential EV charging load-shifting through software that will allow the customer to choose when they charge. Under this approach, the software will let customers select when to charge and FBC will only need to receive data validating that the EV load shifting actually occurred. At this time, FBC believes this to be the leading approach for shifting residential EV charging load as it will accommodate the majority of customers regardless of their installed charging station. Ideally, FBC aims to incent residential customers to shift their EV charging behavior without necessarily requiring a demand-response capable EV charger.

FBC is also exploring demand response behavioral "nudges" through email and SMS via FBC's existing *My energy use* portal. No decision on implementation has been made nor has a timeline been determined.

CHAPTER 1: INTRODUCTION

6.0 Reference Exhibit B-1, Volume 1, Page 10

Section 1.4.2 - BC Clean Energy Act Objectives

FortisBC Inc. states in Table 1-3 item 2(c):

"The requirement in section 19 of the CEA to take actions to meet this target applies only to BC Hydro or a prescribed utility. FBC-owned resources and long-term contracts are hydro-based. BC Hydro resources are currently nearly 98 percent clean. FBC alternative and preferred portfolios include clean or renewable resources and the preferred portfolios are at least 99 percent clean."

6.1. Does FBC's "99 percent clean" portfolio include energy purchased from BC Hydro?

Response:

FBC confirms that all portfolios include energy purchased from BC Hydro under the PPA throughout the planning horizon, with the exception of portfolios F4 and F5, which include PPA purchases up to the end of September 2033, when the PPA expires.

6.2. Please confirm that BC Hydro (via its subsidiary PowerEx) trades energy with jurisdictions that have less than "99 percent clean" energy.

Response:

Confirmed.

6.3. How does FBC ensure that energy purchased from BC Hydro remains "99 percent clean" and does not include traded energy from markets with much higher carbon intensity portfolios?

Response:

FBC cannot ensure that energy purchased from the PPA under BC Hydro remains "99 percent clean", as FBC receives a mix of BC Hydro's resources as a whole.[2] As such, FBC has applied

[2] BCUC Decision: PPA RS3808, 3.4 Embedded Cost Power, Page 13-14, May 6, 2014. https://www.bcuc.com/Documents/Proceedings/2014/DOC_41321_05-06-2014_BCH_PPA-RS%203808-TS-No-2-and-3_Decision.pdf

an average grid emission factor reflective of BC Hydro's system as a whole in order to model the emissions associated with energy purchases under the PPA.

However, FBC can work with Powerex to ensure that energy purchased from the wholesale market is clean electricity based on BC requirements. Please also refer to the response to BCUC IR1 1.9.

CHAPTER 2: PLANNING ENVIRONMENT

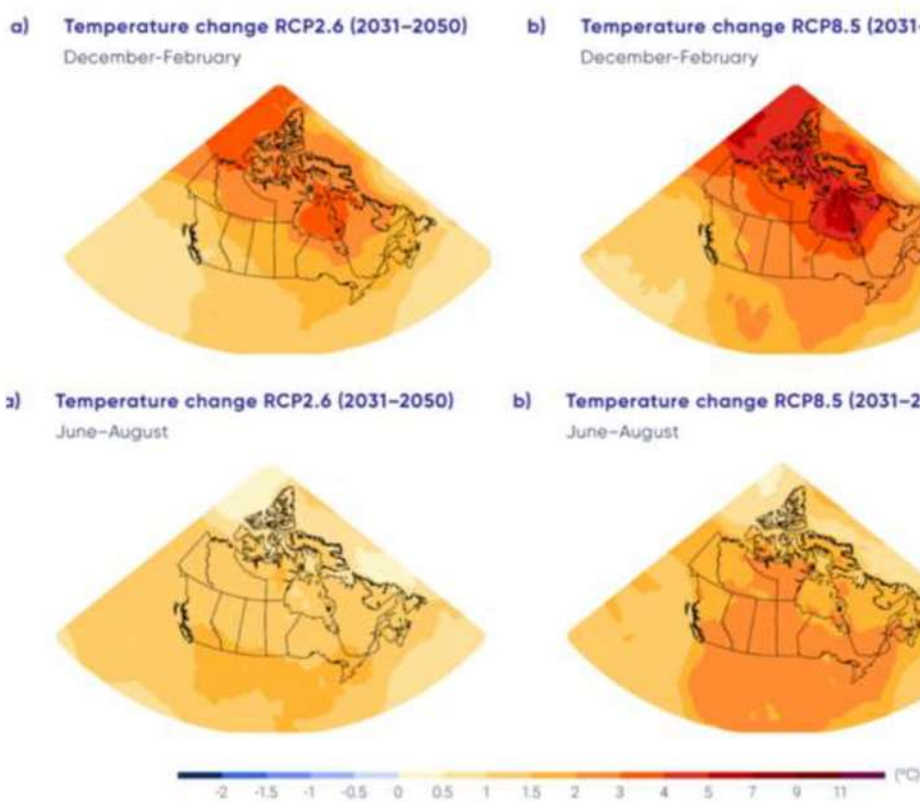
7.0 Reference Exhibit B-1, Volume 1, Page 18 & 19

Section 2.2.1 – Climate Change

FortisBC Inc. stated:

"The following figure shows the projected future average temperature increases for winter and summer months in Canada. The figures with titles including 'RCP2.6' relate to a low GHG emission scenario while those including 'RCP8.5' relate to a high GHG emission scenario. The figures indicate average temperature increases in BC in the order of 1 to 2 degrees Celsius for summer and winter periods from 2031 to 2050. The figures are not specific to the FBC service area but do illustrate possible general trends for Canada and BC in the future and provide a useful range for informing FBC's climate change load driver within its load scenarios (discussed in Section 4).While the figures relate to average warming temperatures over time, they do not capture the increase in the weather and temperature volatility that has occurred in recent years and which is expected to continue in the future."

Figure 2-1: Projected Winter and Summer Temperature Changes[18]



7.1. What are FBC's anticipated winter peak demand and winter energy consumption reductions associated with RCP2.6 and RCP8.5, respectively?

Response:

For clarification, FBC has not explicitly included any winter peak demand and energy consumption reductions within its Reference Case load forecast relating to the temperature changes in the cited figures, but has instead captured potential impacts relating to these temperature changes within its load drivers and load scenarios. As discussed in Section 3.2.6 of Appendix H – Load Scenarios Assessment Report, the assumption relating to the climate change load driver for Scenario 2 (Lower Bound) is that the average temperature on all days of the year increases by 2 degrees Celsius. In this scenario, this load driver decreases both energy and peak winter demand. FBC did not use the impacts associated with the specific temperature changes associated with RCP2.6 and RCP8.5 for this load driver.

As shown in Table 16 of Appendix H – Load Scenarios Assessment report, the expected annual energy reduction associated with this temperature change is 30 GWh by 2040. For the winter months of January, February and December 2040, the expected energy reduction is 41 GWh. For the summer months of June, July and August 2040, the expected increase in energy is 54 GWh. As shown in Table 17 of Appendix H – Load Scenarios Assessment report, the expected winter peak demand reduction associated with this temperature change is 30 MW by 2040. The expected increase in summer peak demand associated with this temperature change is 34 MW by 2040.

7.2. What are FBC's anticipated summer peak demand and summer energy consumption increases associated with these scenarios?

Response:

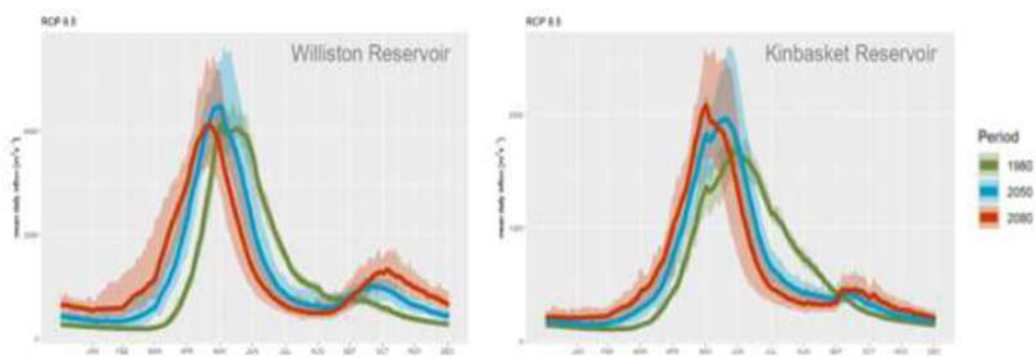
Please refer to the response to RCIA IR1 7.1.

8.0 Reference Exhibit B-1, Volume 1, Page 21

Section 2.2.1 – Climate Change

FortisBC Inc. presented Figure 2-3 which is reproduced below:

Figure 2-3: Projected Winter and Summer Precipitation Pattern Changes[21]



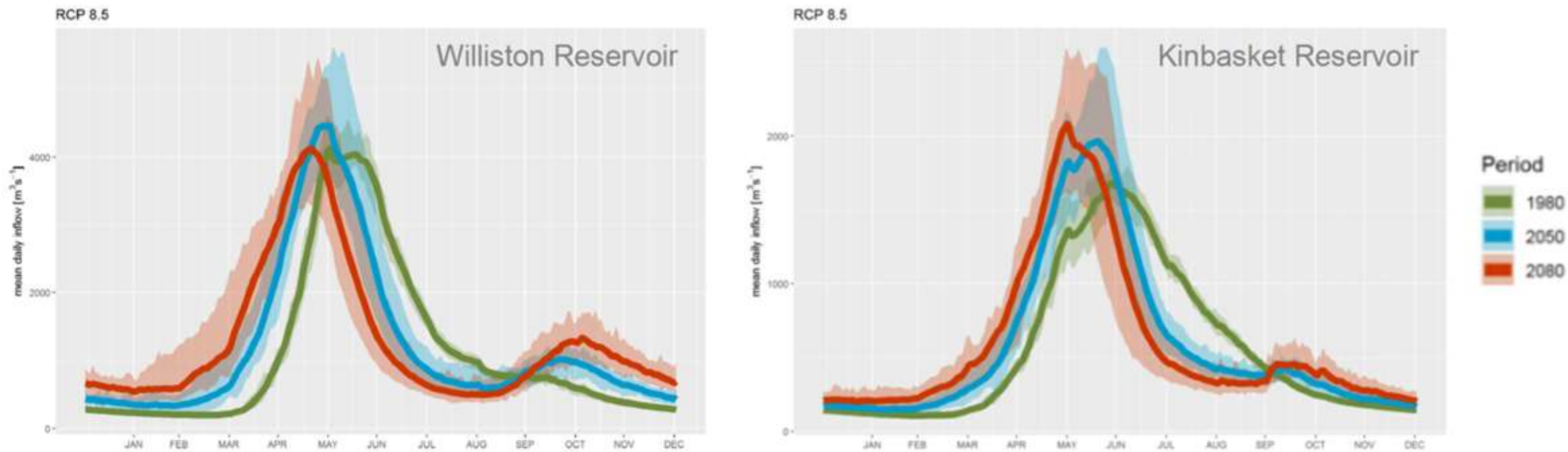
Baseline (1971-2000), 2050s and 2080s mean daily flows averaged over six Global Climate Models (GCMs) for Williston and Mica under the highest global emission scenario. The shaded areas denote the uncertainty bounds between all six GCMs for the respective periods.

8.1. Please provide Figure 2-3 with details that are legible.

<u>Response:</u>

An enlarged, higher-resolution version of Figure 2-3 is provided below.

Figure 2-3 – Projected Winter and Summer Precipitation Pattern Changes



Baseline (1971-2000), 2050s and 2080s mean daily flows averaged over six Global Climate Models (GCMs) for Williston and Mica under the highest global emission scenario. The shaded areas denote the uncertainty bounds between all six GCMs for the respective periods.

9.0 Reference Exhibit B-1, Volume 1, Page 37

Section 2.3.2 – Electric Vehicles

FortisBC Inc. states:

"The growth in EV sales in the FBC service area is expected to play a significant role in the demand for electricity related to EV charging over the planning horizon. BC currently leads the country in EV sales: as of December 30, 2020, EV sales accounted for 9.4 percent of all light-duty vehicle sales in BC."

9.1. Is FBC incurring or planning to incur higher capital and operating costs to encourage EV adoption than is mandated under government policy?

9.1.1. If yes, please explain the business rationale for doing so and quantify the associated capital and operating costs.

Response:

For clarity, there are no mandated investment levels for FBC related to encouraging EV adoption. However, the Province has encouraged public utility investment in public direct current fast charging (DCFC) stations by making such investment a prescribed undertaking under section 18 of the *Clean Energy Act* as set out in the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR).

FBC believes that investments by the Company related to supporting provincial objectives for EV adoption should be paid for by the customers directly receiving the associated benefits to the extent possible. For example, customers using the FBC public DCFC network are charged a rate that is designed to recover all incremental costs from station users over the life of the stations. It is reasonable to expect the costs of DSM measures to shift customer EV charging loads will be recovered from all ratepayers given the distributed nature of the capacity and infrastructure benefits.

9.2. Have FBC's customers asked it to undertake additional spending to encourage EV adoption?

9.2.1. If yes, please provide documentation.

Response:

The feedback received from RPAG stakeholders has generally been focused on encouraging FBC to mitigate EV load impacts and develop measures to shift EV demand, rather than asking FBC to undertake additional spending to encourage EV adoption. It is expected, however, that

EV peak mitigation programs will help support adoption of EVs by providing incentives for customers that are able to shift their EV charging loads.

9.3. Would FBC incur capital and operating costs beyond the level that is mandated under government policy if FBC could not recover those capital and operating costs from ratepayers?

Response:

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

9.4. What are the estimated incremental residential rate impacts in 2025, 2030, and 2040 relative to approved 2021 rates, attributable to FBC's planned volitional (i.e., greater than mandated) incremental capital and operating investments to encourage EV adoption?

Response:

For clarity, there are no mandated investment levels for FBC related to EV adoption. To date, FBC's investments have primarily focused on the deployment and operation of public DCFC stations; RS 96 has been designed to recover the costs of this program from EV drivers. In the response to BCUC IR1 14.1 from the Application for Approval of Rate Design and Rates for EV DCFC Service, FBC provided a sensitivity analysis (Table 3-4) for the rate impacts to all FBC customers if EV usage of the public DCFC stations varies from forecast.

FBC is still developing its plans and related forecasts for investments for other EV-related initiatives, including peak demand mitigation as well as incentive programs for fleet and workplace charging infrastructure. Where possible, EV-related programs will be designed to recover costs from EV drivers (as with FBC public DCFC stations) or will be designed to directly benefit all ratepayers (e.g. EV charging demand reduction programs).

10.0 Reference Exhibit B-1, Volume 1, Page 45

Section 2.3.4 – Small-Scale Distributed Generation

FortisBC Inc. states:

"Small-scale distributed generation technologies present some challenges for FBC both from a technical standpoint and in terms of customer equity. These include the following:

- Safety – potential for back-feeding onto the distribution grid must be properly addressed.
- Grid stability – distribution grid must be able to handle unpredictable distributed generation output without causing power quality problems for other customers.
- Equity – the structure of current rates can lead to net metering customers avoiding the cost of being connected to the FBC system – meaning those costs must be recovered through the rates of non-net metered customers."

10.1. Does providing a net energy rate to energy-metered customers with onsite non-dispatchable renewable generation resources such as rooftop solar (whose output is not coordinated with customer demand) effectively transfer additional costs to customers who have not installed such generation resources? Please explain and quantify the costs under the current residential tariff structures.

Response:

In any Net Metering program where participating customers have the ability to reduce or eliminate electricity billing, and the energy rates normally recover some of the fixed costs of operating the electric system (as is the case with FBC), participating customers will avoid some cost responsibility which will need to be recovered from other customers. In the case of FBC's residential customers, this is demonstrated by the 2017 Cost of Service Analysis filed with the BCUC on December 22, 2017. It can seen in the cost summary that on a cost per kWh basis, energy costs were $0.04185, while the demand (fixed) costs were $0.10255.[3] As an energy-only rate, the Residential rate notionally collects both of these costs in a blended energy rate. A customer that requires little or no energy from FBC still benefits from being connected to the FBC system, but avoids costs related to its operation.

10.2. Please describe and quantify the Equity issues associated with Net-Metering in terms of different residential ratepayer group sub-classifications (e.g., socio-economic indicators, residence type, etc.).

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3 https://docs.bcuc.com/Documents/Proceedings/2018/DOC_50507_B-1_FBC-2017-Rate-Design-Application.pdf pdf page 197.

Response:

In the context of the referenced passage from the Application, FBC intended the customer equity challenge presented by net metering to encompass the shifting of costs from participating to non-participating customers. FBC has no information related to the varying impact that may result from socioeconomic or other factors. However, due to the initial capital outlay and building/property permissions required to install a solar system, it is reasonable to assume that most net metering customers own single-family dwellings and therefore have relatively higher incomes.

10.3. At what net-metering penetration level does FBC believe Equity issues will warrant a re-evaluation of Net-Metering equity transfers between residential ratepayer sub-classes? Please quantify and explain.

Response:

FBC has not set any specific penetration level which would trigger a further examination of net metering. However, FBC does intend to re-evaluate the Net Metering program during the next Cost of Service Analysis expected in the 2024-2025 timeframe. Please also refer to the response to BCUC IR1 11.2.

11.0 Reference Exhibit B-1, Volume 1, Page 46

Section 2.3.4 – Small-Scale Distributed Generation

FortisBC Inc. states:

"Customer participation has been trending upwards from 2012 to 2018 and then additions declined to lower levels in 2019 and 2020. At this point, it is uncertain what the trend for net metering facilities growth going forward will be. FBC's recent customer survey (see Appendix N) shows that 34 percent of residential customers and 49 percent of commercial customers are likely to install rooftop solar panels, with similar percentages for installing battery storage, in the next five years."

11.1. Please discuss and quantify the correlation between customer socioeconomic levels and the adoption of onsite generation such as rooftop solar.

Response:

FBC does not have the customer demographic information required to provide the requested analysis.

11.1.1. Please cite external sources if FBC has not carried out its own analysis for its service area.

Response:

FBC is aware that the California Public Utilities Commission commissioned an extensive demographic study of net metering customers.[4]

Further, a 2020 study by the Lawrence Berkeley National Laboratory found the following annual income distribution of 2018 residential solar adopters (USD): 15 per cent have household income below $50,000; 33 per cent are between $50,000 to $100,000; 24 per cent are between $100,000 to $150,000; and the remaining 28 per cent are above $150,000.[5]

Together, these results indicate that adoption of residential solar generation generally increases with income.

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[4] https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/reports_and_white_papers/nemreportwithappendices.pdf

[5] https://eta-publications.lbl.gov/sites/default/files/solar-adopter_income_trends_report.pdf

11.2. Does FBC response to the above question imply that implementation of non-dispatchable renewable generation by customers with the requisite access to capital imply an expected cross-subsidy from poorer customers to wealthier customers?

11.2.1. If not, please explain why not.

Response:

Given that participating net metering customers will avoid some cost responsibility which will need to be recovered from other customers (as discussed in the response to RCIA IR1 10.1), and that most net metering customers own single-family dwellings and therefore have relatively higher incomes (as discussed in the response to RCIA IR1 10.2), FBC considers there is a potential for cross-subsidy from poorer customers to wealthier customers.

11.3. What will be the total cumulative percentage of residential customers with rooftop solar panels (and/or battery storage) in five (5) years, assuming that the expected new installations are all completed?

Response:

Currently, less than one percent of residential customers have net metering systems. Therefore, if all 34 percent of residential customers cited in the preamble were to install solar panels, the cumulative percentage would be in the 34 to 35 percent range. FBC does not expect that all of the customers surveyed will actually complete installations, but does not have a basis for speculating on the number that can or will.

12.0 Reference Exhibit B-1, Volume 1, Page 47

Section 2.3.5 New Emerging Large Loads

FortisBC Inc. states:

"The prospect of decarbonizing the FEI natural gas system has spurred potential development of green energy projects such as hydrogen and renewable natural gas production. FBC is currently working with customers in these sectors, which could become some of FBC's largest energy consumers in the coming years. Carbon capture and storage may also emerge as technologies that help with the goal of decarbonization in the future and could provide additional electricity demand within the FBC service area."

12.1. What are FBC's and/or FEI's plans to establish carbon capture and storage within FBC's service territory?

Response:

FEI and FBC are currently monitoring carbon capture and storage technology, including the potential for pilot projects; however, neither FEI nor FBC have immediate plans to establish this technology within FBC's service territory. Please also refer to the responses to BCOAPO IR1 16.1 and 16.2.

12.2. What are FBC's and/or FEI's plans to establish renewable natural gas production within FBC's service territory?

Response:

FEI already has an RNG production facility at the Glenmore Landfill in Kelowna, which is within FBC's service territory.[6] FEI is also working with potential suppliers within FBC's service territory, such as REN Energy for example, to establish large-scale RNG production.

With the recent changes to the GGRR, FEI will also be able to invest in the purchase, transportation, and production of green hydrogen produced from clean electricity, in addition to RNG. Therefore, FEI will be in a stronger position to support new RNG and green hydrogen production opportunities and enable development of potentially significant production capacity within FBC's service territory.

FEI's plans to further establish renewable gas supply within FBC's service territory will continue to leverage an ongoing partnership with the University of British Columbia Okanagan Campus to advance technology development in support of new RNG and hydrogen production pathways and

[6] https://www.fortisbc.com/services/sustainable-energy-options/renewable-natural-gas/meet-our-renewable-natural-gas-suppliers#tab-3

also enable the distribution and use of hydrogen in the natural gas system through blending with methane.

On the community side, both FEI and FBC are actively building strong partnerships with Indigenous communities and local governments in FBC's service territory to identify project opportunities.

12.3. What are FBC's and/or FEI's plans to establish hydrogen production within FBC's service territory?

Response:

Please refer to the response to RCIA IR1 12.2.

12.4. What are the competitive advantages of carbon capture and sequestration, hydrogen production and renewable natural gas production projects locating in FBC's service territory rather than BC Hydro's territory (e.g., geotechnical formations, municipal subsidies?)

Response:

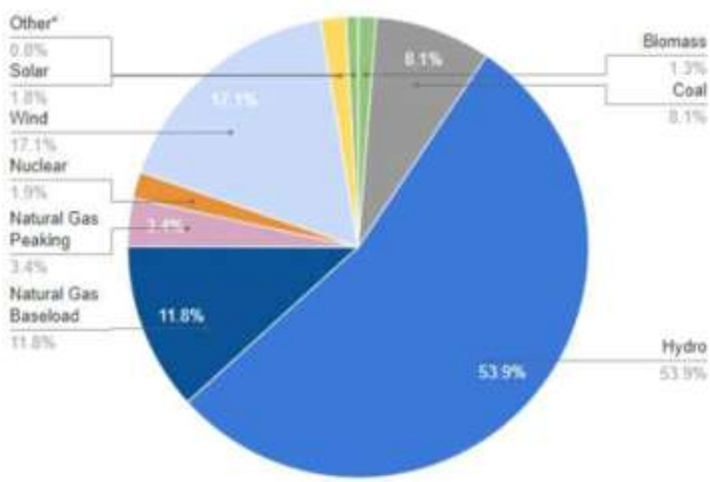
There are no specific competitive advantages for these projects by locating within FBC's service territory. FEI continues to develop multiple RNG projects in BC annually and is actively investigating the feasibility of developing various small-scale and large-scale hydrogen projects in BC. Each project is considered individually and FBC understands that various factors are assessed in order to find high-quality projects that balance socio-economic benefits through investment and jobs in BC while delivering the lowest-cost renewable gas.

13.0 Reference Exhibit B-1, Volume 1, Page 56

Section 2.4.2 – Pacific Northwest Electricity Generation

FortisBC Inc. provided Figure 2-12 which is reproduced below:

Figure 2-12: Pacific Northwest Electricity Generating Capacity[75]

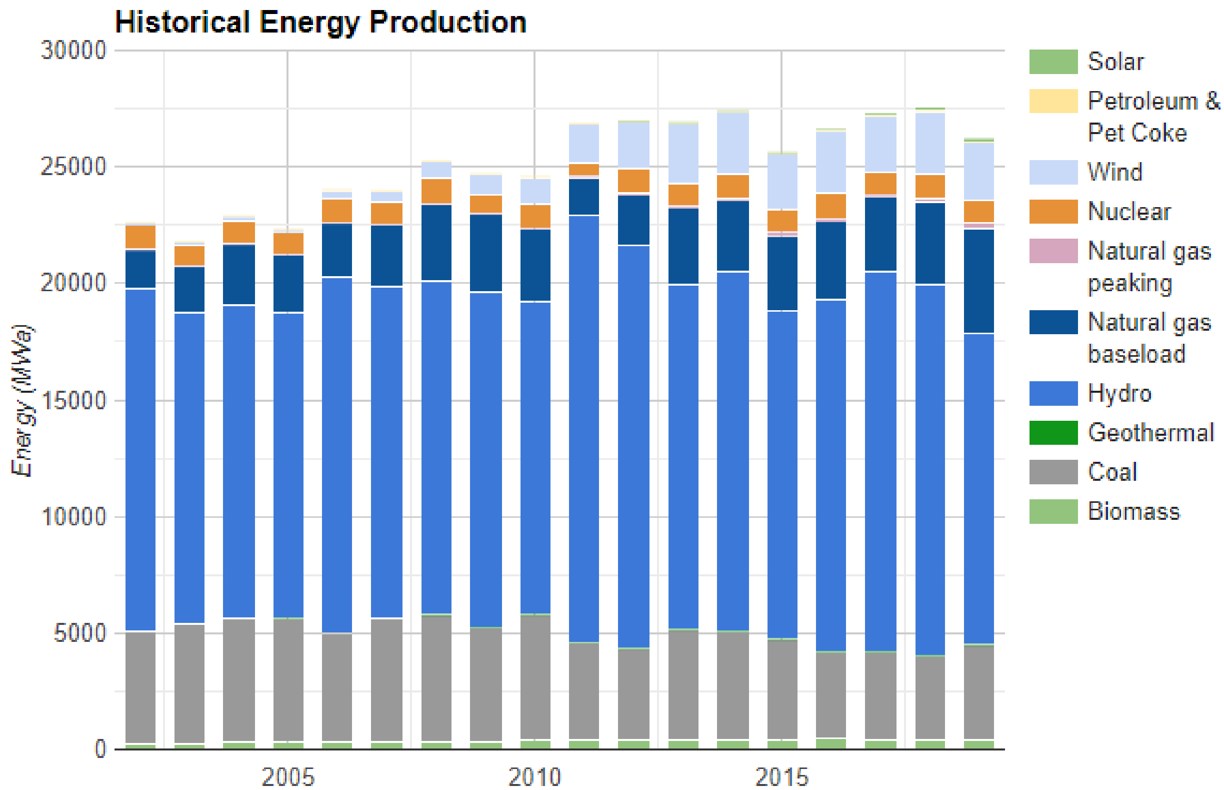


13.1. Please provide a chart showing the annual energy produced by the different resources shown in Figure 2-12.

Response:

Please find the requested chart[7] below from the Northwest Power and Conservation Council.

7 https://www.nwcouncil.org/energy/energy-topics/power-supply.


Historical Energy Production
Energy (MWa)
30000
25000
20000
15000
10000
5000
0
2005
2010
2015
Solar
Petroleum & Pet Coke
Wind
Nuclear
Natural gas peaking
Natural gas baseload
Hydro
Geothermal
Coal
Biomass

14.0 Reference Exhibit B-1, Volume 1, Page 66

Section 2.4.5 – Summary

FortisBC Inc. states:

"Increased renewable penetration across the region may increase the surplus energy available through wind and solar resources, however, declining snowpack levels, persistent drought, and seasonal water shortages due to climate change could decrease the surplus hydropower available during spring freshet and summer periods. FBC will continue to monitor the price and availability of wholesale market energy, as well as any regional developments that would affect the Company's ability to purchase from the wholesale market."

14.1. Has FBC modeled the reliability impacts of a range of penetration scenarios for different renewable generation resources in the Pacific Northwest?

14.1.1. If yes, please provide documentation.

14.1.2. If no, please explain why not, in consideration of the reasonably foreseeable risk of negative reliability and market price and availability consequences associated with increased penetration rates of non-dispatchable electric generation resources.

Response:

FBC has not modeled the reliability impacts for different renewable generation resources in the Pacific Northwest for the following two reasons:

1. FBC has represented the requirement for capacity self-sufficiency within the LTERP, and as a result, selects incremental new resources to meet forecasted capacity gaps. As mentioned in Appendix K – Resource Options Report of the Application, the renewable generation resource options that FBC considered could potentially be available in the FBC service area or within BC. FBC did model the reliability impacts for selected resource options, which is discussed further in Appendix M – Planning Reserve Margin report.
2. FBC has access to the Mid-C market in the Pacific Northwest through the CEPSA agreement with Powerex, effective as of May 1, 2015. The CEPSA provides increased and reliable market access to purchases that are comparable or better than FBC can achieve outside of the CEPSA. While FBC agrees that it is not prudent to rely on market capacity in the long term, market energy should remain available at reasonable prices.

Please also refer to the response to RCIA IR1 17.1, which discusses regional reliability assessments and the external entities that are responsible for ensuring regional resource adequacy.

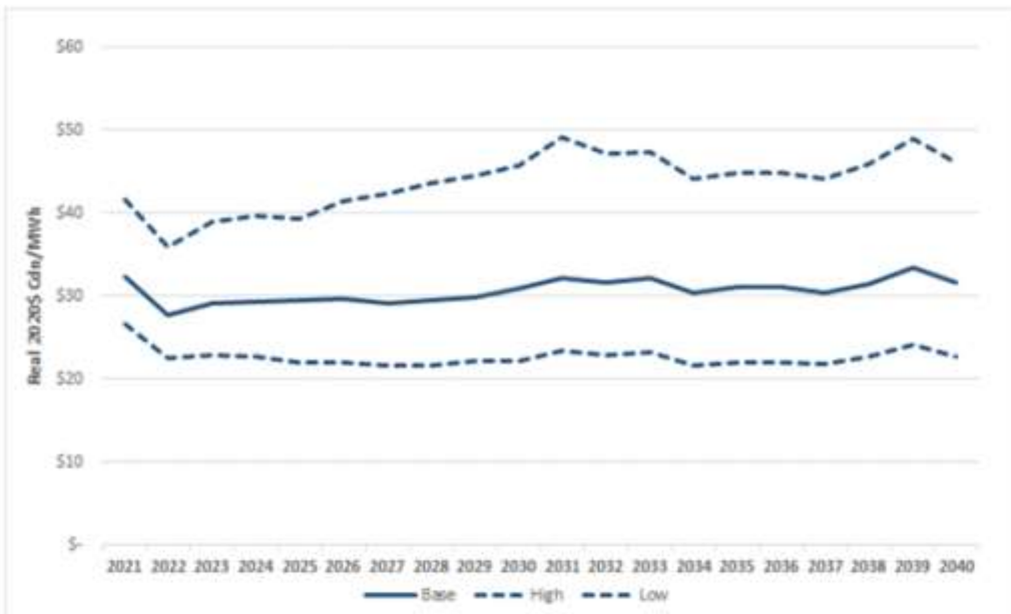
15.0 Reference Exhibit B-1, Volume 1, Page 71 & 72

Section 2.5.2 – Electricity Market Price Forecasts

FortisBC Inc. states:

"The Mid-C market annual price forecasts in real Canadian dollars per megawatt-hour (MWh) are presented in the following figure."

Figure 2-18: Mid-C Electricity Annual Price Forecasts



15.1. Regarding Figure 2-18, please superimpose representative daily, monthly, and seasonal volatility ranges upon the Base, High and Low Mid-C Annual Price Forecast curves, and provide the information in tabular format.

<u>Response:</u>

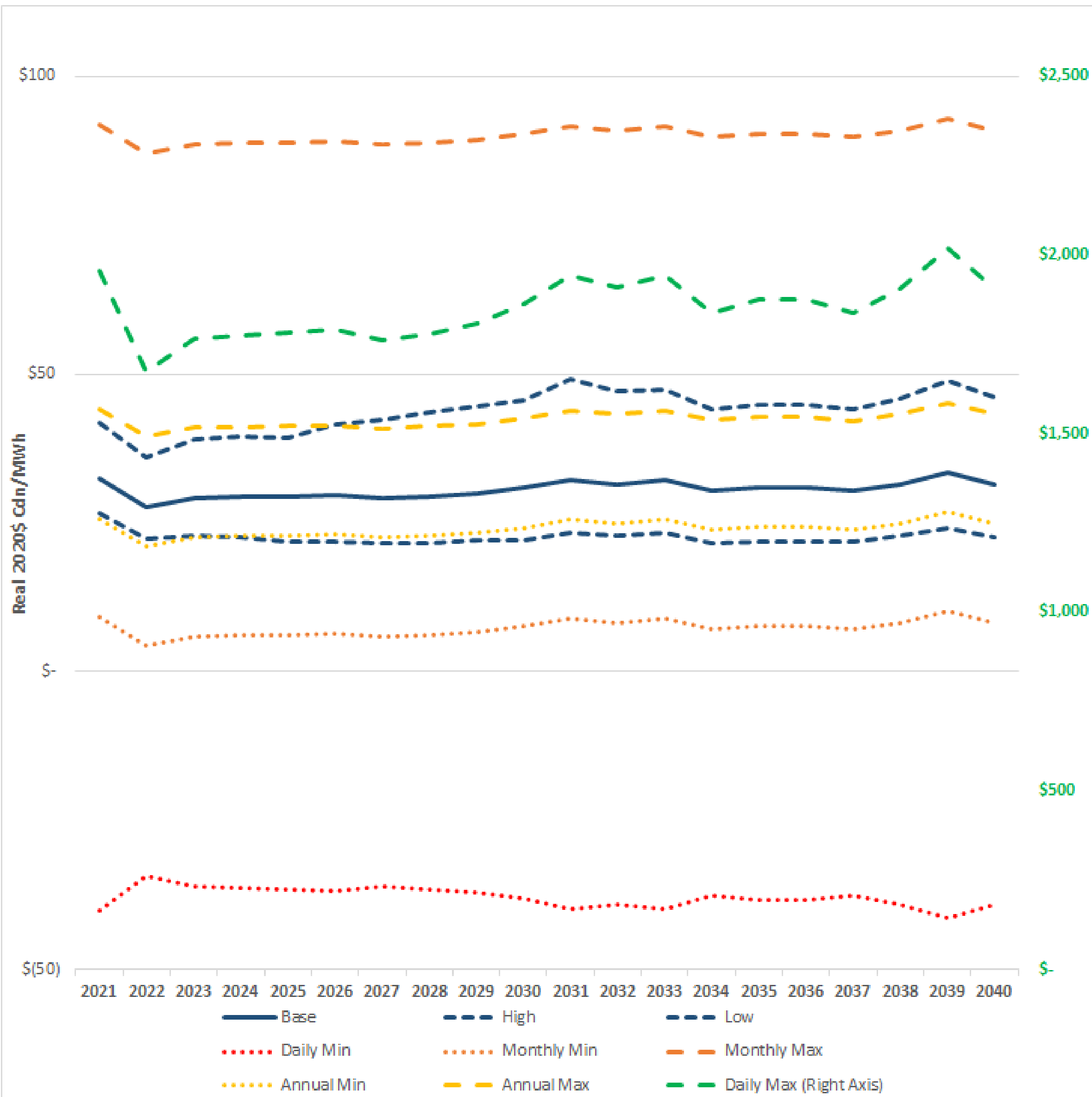
Provided below is an updated Figure 2-18 and the corresponding data in tabular format below. Note that the volatility ranges are shown around the Base forecast only. Each range is shown as a minimum and a maximum. For example, there is a Daily Minimum and a Daily Maximum that represents the lowest as well as the highest daily price from the volatility analysis. Since this is a daily number compared to an annual number, the range will be very large. Monthly volatility is similar in this regard, except that, since this is now a monthly number compared to the annual number, the range is smaller. Finally, the annual volatility number is quite close to the original forecast High and Low values.

Daily volatility is calculated as the average over the years 2016 to 2020 of the standard deviation of the daily price variance from the monthly mean.

Monthly volatility did not use a standard deviation analysis but rather the observed minimum and maximum deviation of monthly prices from 2016 to 2020. The monthly price was calculated as the average daily price in that month.

The seasonal volatility was not calculated, and rather the monthly volatility process was repeated but using the annual values instead.

The ranges are then applied above and below the Base Mid-C price forecast. Note that all the values shown in the table below use the left side axis, with the exception of the Daily Max which uses the right side axis.



	High	Low	Base	Daily Min	Monthly Min	Annual Min	Daily Max	Monthly Max	Annual Max
2021	$42	$27	$32	-$40	$9	$26	$1,956	$92	$44
2022	$36	$22	$28	-$34	$4	$21	$1,676	$87	$39
2023	$39	$23	$29	-$36	$6	$23	$1,764	$89	$41
2024	$40	$23	$29	-$36	$6	$23	$1,776	$89	$41
2025	$39	$22	$30	-$37	$6	$23	$1,785	$89	$41
2026	$42	$22	$30	-$37	$6	$23	$1,792	$89	$41
2027	$42	$22	$29	-$36	$6	$23	$1,761	$89	$41
2028	$44	$22	$29	-$36	$6	$23	$1,781	$89	$41
2029	$45	$22	$30	-$37	$7	$23	$1,807	$89	$42
2030	$46	$22	$31	-$38	$8	$24	$1,864	$90	$43
2031	$49	$23	$32	-$40	$9	$26	$1,944	$92	$44
2032	$47	$23	$32	-$39	$8	$25	$1,908	$91	$43
2033	$47	$23	$32	-$40	$9	$26	$1,943	$92	$44
2034	$44	$22	$30	-$38	$7	$24	$1,840	$90	$42
2035	$45	$22	$31	-$38	$8	$24	$1,877	$90	$43
2036	$45	$22	$31	-$38	$8	$24	$1,877	$90	$43
2037	$44	$22	$30	-$38	$7	$24	$1,838	$90	$42
2038	$46	$23	$32	-$39	$8	$25	$1,906	$91	$43
2039	$49	$24	$33	-$41	$10	$27	$2,019	$93	$45
2040	$46	$23	$32	-$39	$8	$25	$1,906	$91	$43

16.0 Reference Exhibit B-1, Volume 1, Page 75 & 76

Section 2.5.5 – BC Hydro PPA Rates Scenarios

Exhibit B-1, Volume 1, Page 72

Section 2.5.2 – Electricity Market Price Forecasts

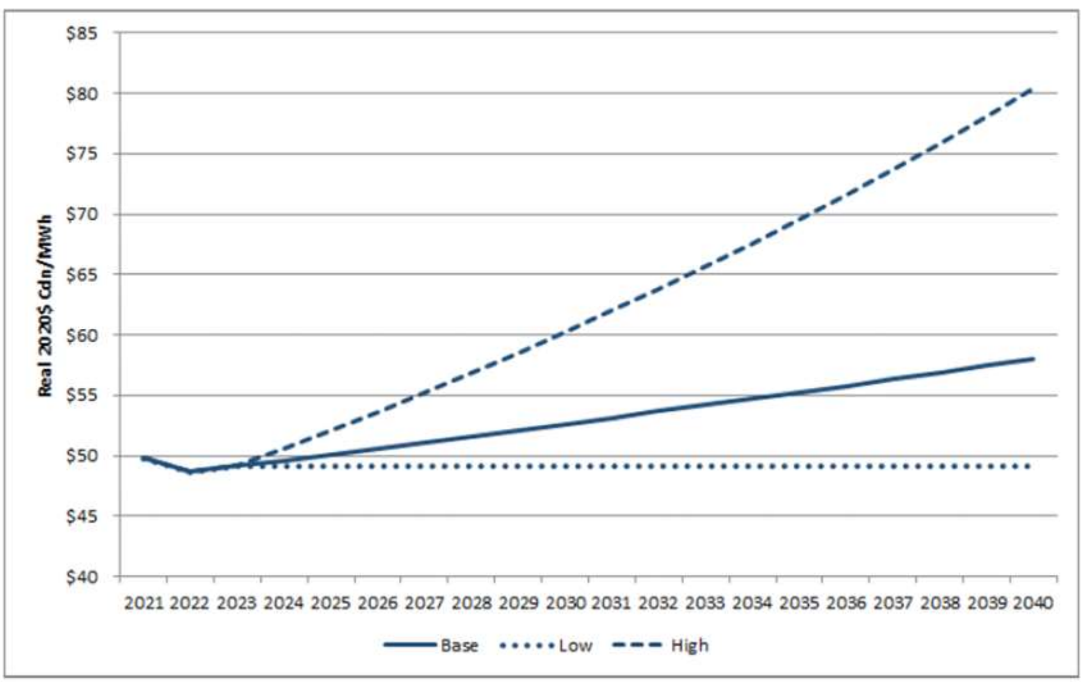
On Pages 75 to 76 FortisBC Inc. states:

"In order to estimate the potential costs for the BC Hydro PPA in the future, FBC has developed PPA scenarios based on annual percentage increases in BC Hydro rates and BC Hydro's LRMC. The percentage increases in the PPA Tranche 1 energy and capacity rates are the same as those applicable to BC Hydro's customers

…

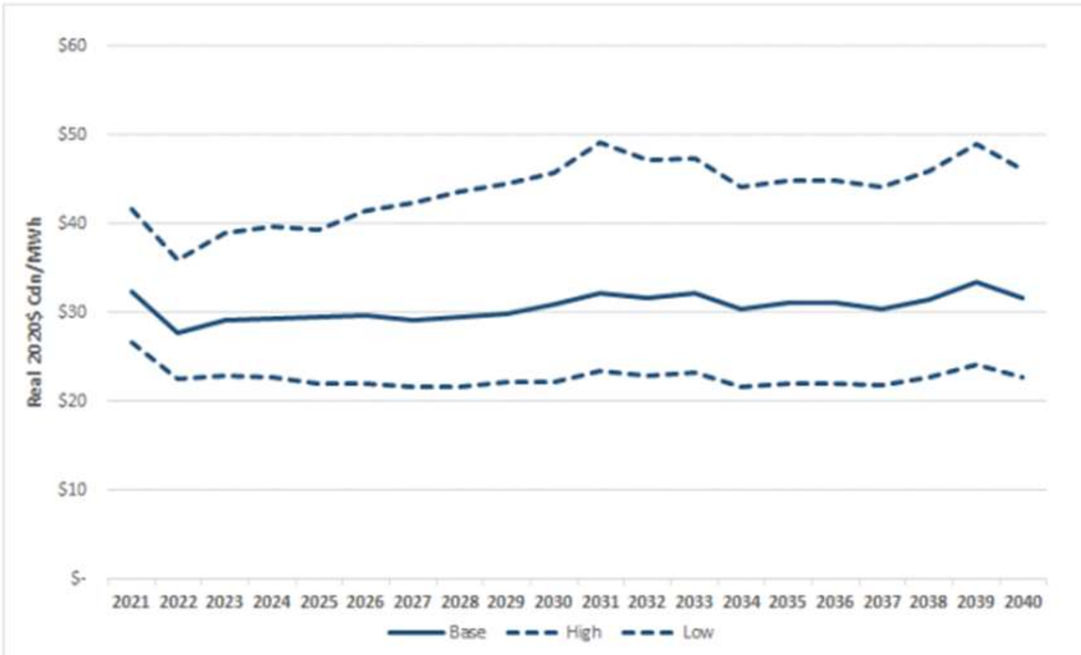
The following figure shows the PPA rate scenarios for Tranche 1 Energy, which is at a rate of $50.73 per MWh as of April 1, 2021.

Figure 2-21: PPA Rate Scenarios for Tranche 1 Energy



On Pages 72 FortisBC Inc. provided Figure 2-18 which is reproduced below:

Figure 2-18: Mid-C Electricity Annual Price Forecasts



16.1. Please explain the business rationale for FBC to continue purchasing power under either Tranche 1 or Tranche 2 of the BC Hydro 3808 PPA, if the Mid C price forecast shown in Figure 2-18 is realistic?

<u>Response:</u>

A one-to-one comparison of the long-term PPA Tranche 1 energy price (as shown in Figure 2-21), and the Mid-C electricity price forecast (as shown in Figure 2-18), does not provide the full picture of the interaction between these two resources or of the potential displacement of PPA energy with market energy. Several other factors must be considered and are discussed further below. At this time, FBC does not currently take, nor does it plan to take, any Tranche 2 energy under the PPA because of its significantly higher cost.

First, the PPA is a bundled product, and as such, when FBC requires PPA capacity in order to meet demand, FBC must also take the corresponding amount of energy.

Second, the long-term Mid-C price forecast is a simplified representation of future prices. As in any long-term market price forecast, certain assumptions about supply and demand factors have been made based on current information. While FBC believes that overall the price forecast is realistic, FBC recognizes that the forecast does not reflect the short/medium-term volatility of the wholesale electricity market.

Finally, the flexibility of the BC Hydro PPA makes it a valuable energy and capacity resource that provides many benefits to FBC. It ensures access to a maximum of 200 MW of capacity and 1,752 GWh of energy on an annual basis; however, there are provisions within the contract that allow FBC to shape and scale up or scale down its usage, along with corresponding costs, based on requirements. This flexibility provides access to firm power when required and the ability to mitigate power purchase expense when the market is favourable or when loads are lower than forecast. The PPA also acts as a price ceiling during times of sustained high market prices.

17.0 Reference Exhibit B-1, Volume 1, Page 80

Section 2.5.7 – Adders to the Market Price Forecast

FortisBC Inc. states:

"Second, the growth of renewable energy will help further diversified electricity generation capacity in the region. This has resulted in low market electricity prices, which are reflected in the market price forecasts. Market purchases, at least in the short to medium term, continue to remain well below the cost of other supply-side resource options, discussed in Section 10.2."

17.1. Please describe and quantify the reliability benefits of increasing the diversity of the regional electricity generation capacity by adding significant volumes of non-dispatchable resources.

Response:

There are at least two external entities in the region that aim to ensure reliable regional power supply, namely the Northwest Power and Conservation Council (NPCC) and the Northwest Power Pool (NWPP). The NPCC issues the Northwest Power Plan, which has the goal of ensuring an adequate, efficient, economic, and reliable power system for the region. The NWPP is in the process of developing a Resource Adequacy Program for the Pacific Northwest[8] to coordinate activities within the region and has performed a comprehensive review of resource adequacy.

FBC has not internally conducted regional studies that investigate or quantify the reliability of the region's generation capacity and changing landscape, rather, FBC has reviewed credible external resources published through the NPCC, NWPP, as well as Energy + Environment Economics (E3).[9]

17.2. What is the optimal proportional penetration of non-dispatchable resources in FBC's system? Please explain and quantify.

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[8] Northwest Power Pool, Exploring a Resource Adequacy Program for the Pacific Northwest, An Energy System in Transition, October 2019. https://www.nwpp.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf

[9] Energy + Environmental Economics (E3), Resource Adequacy in the Pacific Northwest, March 2019. https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf

Response:

The optimal proportional penetration of non-dispatchable resources (also referred to as intermittent resources in the Application) is dependent on the mix of the incremental resources assumed, or more specifically, the correlations among the incremental resources. As increasing amounts of correlated intermittent resources are added into the portfolio, the capacity value for each additional MW installed decreases in a non-linear relationship.

As illustrated in the response to BCUC IR1 30.1, FBC first determines the optimal portfolio, then tests the resulting portfolio for reliability using the Planning Reserve Margin (PRM) model. If the portfolio does not meet the Loss of Load Expectation (LOLE) target of 0.1 days per year, additional capacity requirements are added to all months proportional to the monthly contribution to the LOLE starting in the first year of the planning horizon the LOLE target was not met. The lowest acceptable level of power supply reliability is a portfolio that results in a LOLE value slightly less than 0.1 days per year in the terminal year of the planning horizon.

17.3. What is the maximum penetration of non-dispatchable resources that will provide at least a minimally acceptable level of power supply reliability? Please explain and quantify.

Response:

Please refer to the response to RCIA IR1 17.2.

CHAPTER 3: LONG-TERM LOAD FORECAST

18.0 Reference Exhibit B-1, Volume 1, Page 82

Section 3.1 - Introduction

FortisBC Inc. states:

"The BAU is the forecast used for annual rate setting which is then extended out for the 20-year planning horizon. The Reference Case load forecast builds on the BAU forecast by including electric vehicle charging load, and new industrial loads with high confidence of materializing, which are discussed in detail in Appendix F, Section 3.1.3 and 3.4. The Reference Case load forecast is the resulting forecast used for planning purposes in this LTERP."

18.1. Please confirm that the BAU forecast assumes no incremental EV adoption.

18.1.1. If not confirmed, please explain, and quantify the level of EV adoption assumed in the BAU forecast.

18.1.2. If confirmed, please provide the basis for FBC's expectation that EV adoption will not increase as part of a BAU scenario.

Response:

Confirmed. The first two years of the BAU forecast is used for rate setting purposes which is updated on an annual basis, as explained in the response to BCUC IR1 3.1. The BAU forecast assumes all loads and trends will continue at their current levels. In the case of EV charging, the future load is not intrinsic in the historical actual load, and therefore must be accounted for incrementally in the Reference Case load forecast. If incremental EV charging growth was added to both the BAU forecast and the Reference Case forecast it is possible that double counting would occur. FBC expects that, as EV adoption grows, an increasing amount of EV charging load will be present in the BAU forecasts and the resulting incremental load identified in the Reference Case will be diminished.

19.0 Reference Exhibit B-1, Volume 1, Page 88

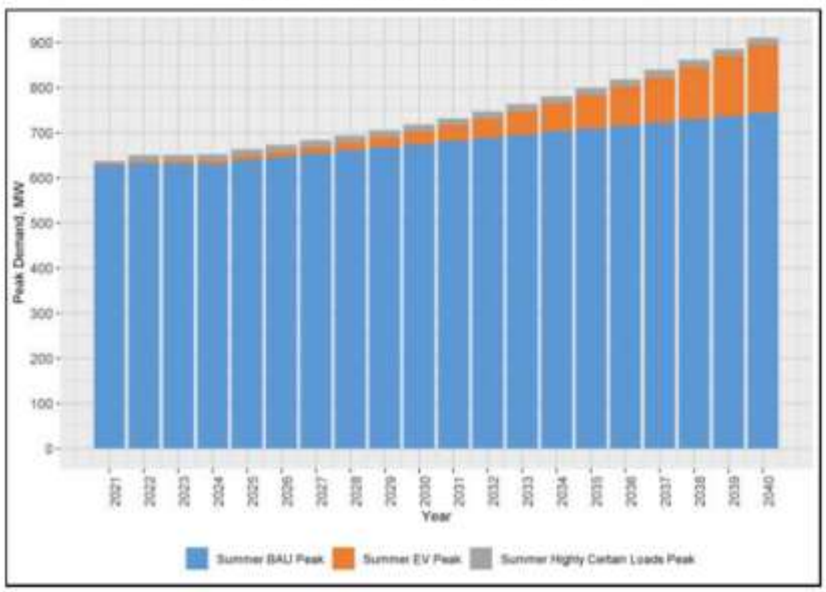
Section 3.4.2 – Peak Demand Forecast

FortisBC Inc. states:

"The BAU forecast summer peak demand forecast increases from 628 MW in 2021 to 744 MW in 2040, increasing at an average annual growth rate of 0.9 percent.

The Reference Case summer peak is forecast to increase from 638 MW in 2021 to 911 MW in 2040, at an average annual growth rate of 1.9 percent.

Figure 3-5: Summer Peak Forecast (MW)



19.1. Regarding Figure 3-5, are reference case system losses included in the annual peak demand bars?

19.1.1. If yes, please provide updated Figures 3-4 and 3-5 with reference case losses shown separately, similar to what was done in Figure 3-3.

19.1.2. If not applicable, please explain why not.

Response:

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

CHAPTER 4: LOAD SCENARIOS

20.0 Reference Exhibit B-1, Volume 1, Page 98 & 99

Section 4.1.1 – Load Drivers

Exhibit B-1, Volume 1, Page 19

Section 2.2.1 – Climate Change

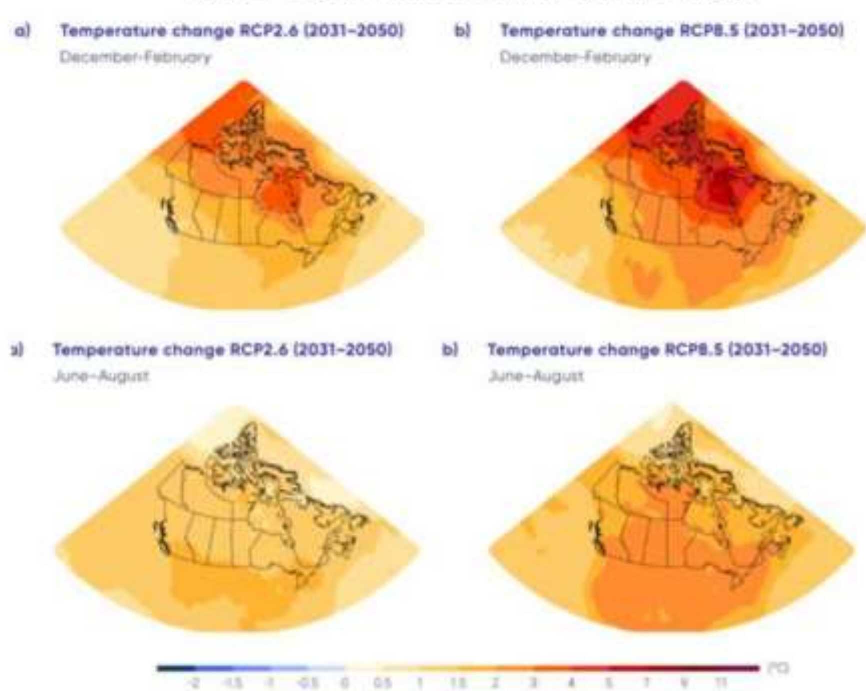
FortisBC Inc. states:

"Nine specific load drivers were included to develop the load scenarios. These drivers are believed to have the potential for the most substantial impact on future loads. The nine load drivers are….:

***6. …Climate Change**: Increasing average annual temperatures, increases in average temperatures during the 10 hottest days of the year, and decreases in average temperatures during the 10 coldest days of the year."*

On Page 19 FortisBC Inc. provided Figure 2-1 which is reproduced below:

Figure 2-1: Projected Winter and Summer Temperature Changes[10]

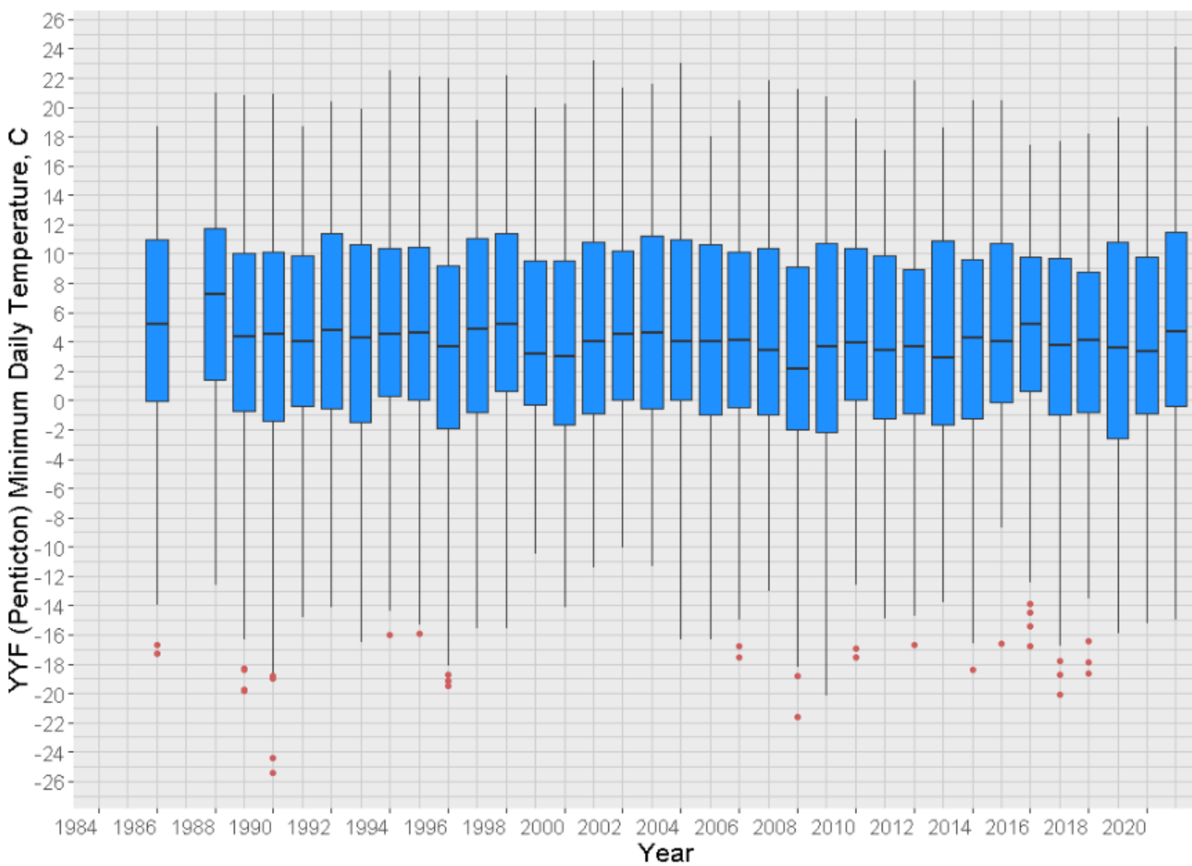


20.1. Please explain and quantify why increasingly high average winter temperatures as per Figure 2-1 which show RCP2.6 and RCP8.5 winter temperature anomalies will produce decreasing average temperatures during the ten (10) coldest days of the year? Please provide the longest possible historical climate records for FBC's service area that demonstrate statistically significant low temperature anomalies over the "10 coldest days of the year".

Response:

As discussed in Section 2.2.1, while the figures relate to average warming temperatures over time, they do not capture the increase in the weather and temperature volatility that has occurred in recent years and which is expected to continue in the future. Therefore, while overall annual warming of average temperatures is expected, there is also the possibility for colder cold snaps and warmer hot spells due to the volatility associated with climate change.

Environment Canada data for Penticton airport (YYF) includes minimum temperatures from 1986 to present day.[10] The plot below shows the minimum temperatures by year.



The plot shows:

- The median minimum daily temperature for each year as the black horizontal line in each box;

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10 Minimum temperature data for 1987 is not available.

- The 25th and 75th percentiles define the size of the shaded box;
- The "whiskers" cover data that is up to 1.5 times warmer or colder than the shaded region; and
- The minimum temperature outliers are shown as discrete data points by the red dots.

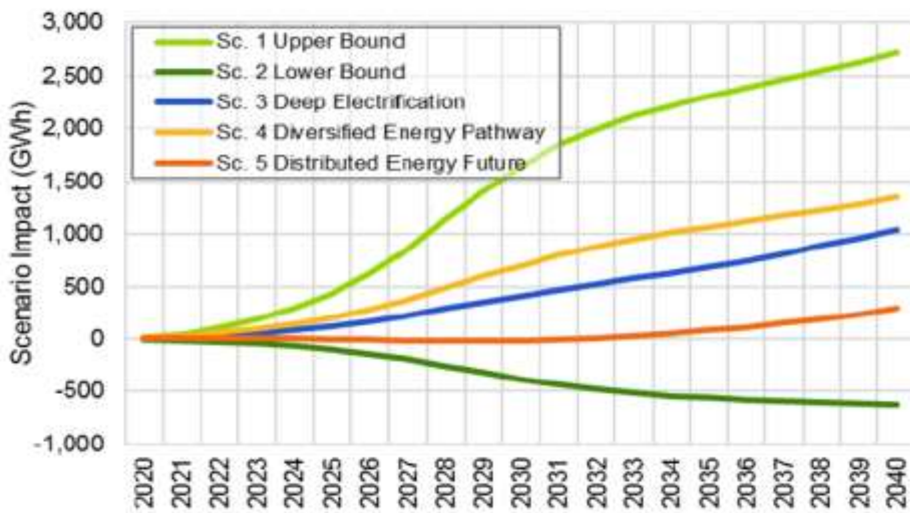
For this IR response, the minimum temperature outliers are most relevant. FBC notes in the 20-year period from 1985 through 2005 that 13 outliers were recorded (i.e., an average 0.65 outliers per year). In the 14-year period from 2006 through 2020, 19 outliers were recorded (i.e., an average 1.4 outliers per year). While FBC does not have any specific data in this regard relating to the 10 coldest days of the year, the increased frequency of temperature outliers per year provides some evidence that low temperature anomalies have increased in recent years.

21.0 Reference Exhibit B-1, Volume 1, Page 103

Section 4.1.3 - Load Scenarios Results

FortisBC Inc. presents the following:

Figure 4-1: Annual Energy Impacts by Scenario

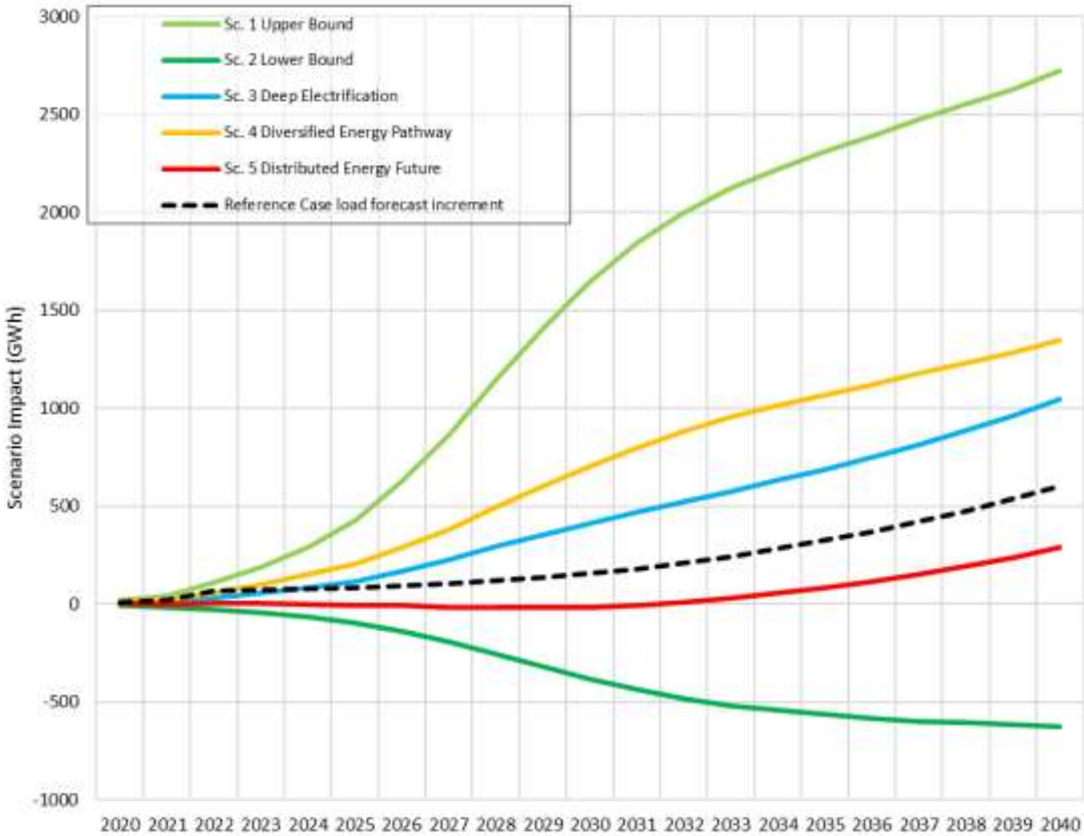


21.1. Please confirm that the Reference Case has a 0 GWh scenario impact for all years.

21.1.1. If not, please restate Figure 4-1 with the Reference Case added and explain why FBC did not include the Reference Case.

Response:

Not confirmed. As discussed in Section 4.1.1, the load scenarios developed by Guidehouse should be considered incremental to the BAU forecast but not the Reference case forecast. Therefore, in Figure 4-1, the BAU load forecast has a 0 GWh impact for all years. The figure below includes the annual energy included in the Reference Case load forecast which is incremental to the BAU forecast. As shown in Figure 3-3, this incremental annual energy is primarily related to EV charging.



Sc. 1 Upper Bound
Sc. 2 Lower Bound
Sc. 3 Deep Electrification
Sc. 4 Diversified Energy Pathway
Sc. 5 Distributed Energy Future
Reference Case load forecast increment
Scenario Impact (GWh)
3000
2500
2000
1500
1000
500
0
-500
-1000
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040

1

2

22.0 Reference Exhibit B-1, Volume 1, Page 111

Section 4.3 - Conclusion

FortisBC Inc. states:

"As part of its load scenario analysis, FBC explored two boundary scenarios and three intermediate scenarios as well as stakeholder scenarios. Load driver penetrations in the boundary scenarios help FBC understand the potential impact that each of these load drivers could have under extreme, but plausible, penetration scenarios, providing upper and lower limits for the other intermediate scenarios. The intermediate scenarios, which include combinations of load drivers that increase and decrease load, may be more reasonable potential future pathways. However, at this point in time, there is too much uncertainty to know which of the scenarios, if any, will occur in the future."

22.1. Please comment upon the impact the two boundary scenarios have on the FBC recommendations.

Response:

The two boundary scenarios include load drivers that only increase or only decrease load and do not include load drivers that might offset each other in terms of their load impacts. Therefore, these boundary scenarios provide 'bookends' or reasonable limits that FBC expects the other, more reasonable potential future pathways, represented by the intermediate scenarios, will fall within. As such, they do not directly impact the recommendations discussed in Section 4.3.

22.1.1. If the boundary scenarios informed the FBC recommendations, please enumerate and quantify the impacts, along with a rationale as to why scenarios with "too much uncertainty to know which of the scenarios, if any, will occur in the future" are impactful.

Response:

Please refer to the response to RCIA IR1 22.1.

CHAPTER 5: EXISTING SUPPLY-SIDE RESOURCES

23.0 Reference Exhibit B-1, Volume 1, Page 116

Section 5.4 - Waneta Expansion Capacity Purchase Agreement

FortisBC Inc. states:

"The amount of residual capacity provided under the WAX CAPA is greater than FBC's current capacity requirements in most months and, as a result, FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to sell a 50 MW block of WAX CAPA residual capacity to BC Hydro under the Residual Capacity Agreement (RCA), entered into as of July 15, 2013. The BCUC approved the RCA in Order G-161-14. The RCA expires September 30, 2025, and for the purposes of the 2021 LTERP, FBC is assuming that it is not renewed. FBC will sell the remaining surplus WAX CAPA residual capacity to Powerex Corp. (Powerex) on a day-ahead basis, under the terms of the Capacity and Energy Purchase and Sale Agreement (CEPSA), dated February 17, 2015, if and when the capacity is not required to meet FBC load requirements. The BCUC accepted the CEPSA for filing in Order E-10-15. The CEPSA currently expires on September 30, 2022, but can be renewed on an annual basis through September 30, 2025 by mutual agreement. For the purposes of the 2021 LTERP, FBC is assuming that the CEPSA will continue indefinitely after 2025 in its current form."

23.1. Are FBC's expected winter and summer capacity surpluses until 2030 largely dependent upon expiry of the RCA in September 2025?

Response:

FBC has sufficient capacity resources with or without the WAX RCA contract, in non-June months, from 2021 through 2027. With the WAX RCA expiring in September 2025, the first non-June capacity gap based on the Reference Case load forecast occurs in July 2030. If the WAX RCA were to be extended through the planning horizon (in other words, the 50 MW block of WAX CAPA residual capacity were continued to be sold to BC Hydro), the first non-June capacity gaps would occur beginning in July 2028. Therefore, FBC's expected winter and summer capacity surpluses are largely dependent upon FBC's overall portfolio of resources, and the WAX RCA accelerates the capacity gap by two years.

23.1.1. Please quantify the impact the continuing RCA beyond September 2025 would have on FBCs resource capacity deficiency.

Response:

Please refer to the response to RCIA IR1 23.1.

23.2. What are the lost revenue implications if Powerex decides to not renew the CEPSA after Sept 30, 2022? Please quantify.

Response:

The terms of the CEPSA agreement between FBC and Powerex are confidential, and as such, FBC cannot disclose revenue calculations under this contract. FBC does believe, however, that the CEPSA agreement provides improved market access at comparable or lower cost than could be obtained elsewhere. If Powerex decides not to renew the CEPSA agreement, FBC expects that there could be negative impacts to revenue.

23.3. Does FBC expect any other impacts if the CEPSA is not renewed? Please explain and quantify.

Response:

If the CEPSA is not renewed, in addition to the potential negative impact on revenue, FBC expects that there is the potential for the cost of power to increase and its availability could decrease, requiring higher PPA purchases to obtain the required amount of energy. FBC would also have to reconsider its position on the security of market access depending on what new arrangements, if any, could be put into place. FBC would also have to consider if there are any implications to the PRM calculations that rely on market capacity access through the CEPSA. However, even in the absence of the CEPSA agreement, FBC expects that Powerex would remain a valued supplier.

In addition, FBC would also have more onerous operational requirements in the absence of the CEPSA. The commercial arrangements under the CEPSA allow FBC to schedule deliveries prior to the Preschedule deadline, which reduces the burden on FBC's real-time system operators. FBC is able to optimize its system on a day-ahead basis, while still maintaining the ability to purchase energy hourly in real-time to address changes in load or resources.

Finally, in absence of the CEPSA, FBC would face increased scheduling and contract risk. Interchange schedules require complex management and they do not always succeed due to time pressures to manage the process or due to the loss of the transmission path. Schedules from

Powerex are very reliable due to the increased percentage of FBC market purchases being scheduled on a day-ahead basis. The risk of contract disputes also increases in the absence of the CEPSA due to the notification requirements under the CPA that FBC would have to make to BC Hydro, which are outside of industry standard scheduling practice. With FBC's market needs purchased and scheduled through Powerex, the risk for disputes around scheduling rights with BC Hydro under the CPA is lessened. It is likely that FBC would require additional staff, or even implement a dedicated trading group to manage the increased complexities.

24.0 Reference Exhibit B-1, Volume 1, Page 116

Section 5.5 BC Hydro Power Purchase Agreement

FortisBC Inc. states:

"Under the PPA, FBC's customers have access to BC Hydro supply up to a maximum of 200 MW and 1,752 GWh of annual energy. The term of the PPA continues through to September 30, 2033. In 2020, the PPA supplied 18 percent of FBC's energy requirement and 18 percent of the Company's peak capacity needs.

"FBC's access to BC Hydro's embedded cost energy (at a rate of $50.73 per MWh as of April 1, 2021) under the PPA is limited to 1,041 GWh (Tranche 1 Energy). Above 1,041 GWh and up to the maximum of 1,752 GWh, the energy cost increases to $95.09 per MWh (Tranche 2 Energy), which is tied to BC Hydro's proxy for long run marginal cost for firm energy and is equal to BC Hydro's RS 1823 Tier 2 rate."

24.1. Please provide comments on how (if at all) Site C coming into service in 2025 may impact the renegotiation of the BCH PPA.

Response:

As discussed in the response to RCIA IR1 24.3, the renegotiation of the BCH PPA will consider if the current PPA energy and capacity available to FBC from BC Hydro, based on its portfolio of resources, including Site C, is still the appropriate amount.

24.2. Will Site C potentially enable FBC to access a larger Tranche 1 or Tranche 2 if it chooses?

24.2.1. If so, please quantify the potential impact on Tranche 1 and Tranche 2 sizing.

Response:

Please refer to the response to RCIA IR1 24.1.

24.3. Has FBC requested its ratepayers' "fair share" of BC Hydro's $50.73/MWh embedded cost energy (and the associated capacity), given that FortisBC's customers are BC taxpayers and in consideration of the critical role that BC/BC

Treasury has played in financing development of BC Hydro's generating resources?

Response:

FBC is satisfied that at this time FBC ratepayers are receiving their "fair share" of BC Hydro's embedded cost of energy and the associated capacity. This was the subject of significant discussion in the May 6, 2014 BCUC decision approving the current PPA with BC Hydro.[11] The discussion begins at Section 7.2.1.1 on page 42 and concludes on page 54.

The BCUC determined on page 49 that, "…the Panel finds it would have been fair under the Bonbright Principles evaluation, all else being equal, for the capacity limit and associated energy to increase to 232 MW…" However, the BCUC then goes on to state that, "This finding does not mean that the New PPA, when considered in its entirety, is unfair to FortisBC… As FortisBC notes, the 'flexibility of the PPA is …very valuable.' "

Further, the BCUC states on page 51, "The Commission Panel determines it is reasonable that the maximum amount of associated energy that should be available at embedded costs rates (Tranche 1 cap) ought to be approximately 60 percent of the total available associated energy." Then on page 52, "The Commission Panel finds that based on 200 MW of capacity, the Tranche 1 cap of 1,041 GWh/year appears to be appropriate as it represents approximately 60 percent of associated energy."

The current PPA is approaching the half way point of its 20-year life. FBC expects that the question of the appropriate PPA capacity available as well as the Tranche 1 energy cap (if any) will once again require careful consideration in the negotiation of the future renewal of the PPA.

[11] https://www.ordersdecisions.bcuc.com/bcuc/decisions/en/111742/1/document.do

CHAPTER 6: TRANSMISSION AND DISTRIBUTION SYSTEM

25.0 Reference Exhibit B-1, Volume 1, Page 136 & 137

Section 6.5.4.3 - Potential System Impacts

FortisBC Inc. states:

"The values in the table below are high-level estimates and may change as more detailed analysis for each of the projects is conducted in the future."

Table 6-5: Planned Projects (1-in-20 Peak Demand Forecast by 2040)

Project	Cost ($ Millions)
Static VAR Compensator (SVC)	30
DG Bell 230 kV Ring Bus	10
Kelowna Bulk Transformer Capacity Addition	21
Re-conductor 51L & 60L (DG Bell-OK Mission)	9
Ellison Second Distribution Transformer Addition	8
Benvoulin Second Transformer Addition	8
Saucier Second Distribution Transformer Addition	7
DG Bell 138 kV Breaker and Voltage Transformer Addition	1
DG Bell Second Distribution Transformer Addition	6
FA Lee Distribution Transformer Addition	8
Duck Lake Second Transformer Addition	6
Glenmore Third Transformer Addition	6
Hollywood Third Transformer Addition	8
Total	128

"Table 6-6 includes additional projects required to meet the additional peak demand requirements of the Kelowna area at the 550 MW level."

Table 6-6: Additional Projects Required to meet 550 MW Peak Demand by 2040 ($ millions)

Project	Cost ($millions)
New Distribution Stations	60
New Distribution feeders	40
Meshing Kelowna 138 kV Transmission System	20
138kV Transmission Line Re-conductor	40
138kV Transmission Line Addition	30

Project	Cost ($millions)
Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV Transmission Line	500
DG Bell Second 230/138 kV Transformer Addition	20
Total	710

25.1. Can any of the projects listed in Table 6-5 and Table 6-6 be deferred or eliminated by any of the proposed LTERP solutions?

25.1.1. If yes, please identify the impacted T&D project(s), the expected length of the spending deferral and the net impact on the LCOE and LCOC of the relevant proposed LTERP resources if credited with the T&D deferral.

Response:

FBC confirms some transmission-level projects could potentially be deferred by resources contained in FBC's proposed LTERP solutions. FBC performed the following high-level analysis using the winter peak demand forecast and portfolio C3 to estimate the potential deferral opportunities for the applicable projects in Table 6-5 and 6-6. In this instance, FBC selected portfolio C3 as it is the most likely portfolio to have the greatest impact on these projects given its larger amounts of dispatchable resources relative to the other portfolios. For clarity, the North Okanagan (NOK) region in the second table below refers to Kelowna and immediate surrounding areas.

The following table includes the resources contained in portfolio C3 that were considered in the analysis. 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.

Resource ID	Installed Capacity (MW)	Dependable Winter Capacity (MW)	Modelled In-Service Year
DistBattery6	25	25.0	2030
RNG_SCGT2	100	100.4	2031
RNG_SCGT1	48	47.6	2035

FBC assumed the generation resources would be connected to the transmission system; therefore, no distribution level projects are affected. The projects in Table 6-5 and Table 6-6 that could be deferred are shown in the table below. The “Meshing Kelowna 138kV Transmission System” project is not included in the table as it is required for reliability purposes and therefore cannot be deferred by adding generation resources. Also, both “138kV Transmission Line Re-conductor” and “138kV Transmission Line Addition” projects are required to support growth and, given the uncertainty as to where load growth will occur, these projects were not included in the deferral calculation.

Project	NOK Load Level (MW)	Base In-Service Year	Deferred In-Service Year	Project Cost ($000s) 2020$	NPV Base[12] ($000s)	NPV Deferred[13] ($000s)	T&D Deferral Credit[14] ($000s)
Static VAR Compensator	430	2034	2054	30,000	18,064	8,751	9,312
DG Bell 230 kV Ring Bus	430	2034	2054	10,000	6,021	2,917	3,104
Ashton Creek to Vaseux Lake (ACK-VAS) 500kV Transmission Line	550	2047	2070	500,000	187,964	81,682	106,282
DG Bell 230/138 kV Second Transformer Addition	550	2047	2070	20,000	7,519	3,267	4,251

The total transmission and distribution deferral credit based on the four projects in the table above is approximately $123 million. This deferral credit was allocated to the resources in portfolio C3 based on the proportion of the total dependable winter capacity provided. The UCCs of these

[12] Equation: Project Cost * (1 + 3.69%)^(2020 – Base In Service Year)

[13] Equation: Project Cost * (1 + 3.69%)^(2020 – Deferred In Service Year)

[14] Assumed Credit = NPV Deferred - NPV Base

capacity resources are restated in the table below. The UECs were not stated as they are considered not applicable for capacity-oriented resources.

Resource ID	Dependable Winter Capacity (MW)	Portion of Dependable Winter Capacity (%)	Allocated Deferral Credit ($000s)	UCC without Deferral Credit ($/kW-Year)	UCC with Deferral Credit ($/kW-Year)
DistBattery6	25.0	14	17,767	226	171
RNG_SCGT2	100.4	58	71,353	148	90
RNG_SCGT1	47.6	28	33,829	131	108
Total	173.0	100	122,949		

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.

CHAPTER 10: SUPPLY-SIDE RESOURCE OPTIONS

26.0 Reference Exhibit B-1, Volume 1, Page 162 & 163

Section 10.2.1 - Technical Attributes

FortisBC Inc. states:

"In this way, battery storage is similar to pumped hydro storage, which has a limited capacity generation period before the reservoir must be re-filled to provide capacity again. This is in contrast to some other peaking resources, such as a Simple Cycle Gas Turbine (SCGT) plant. An SCGT plant can provide capacity for any peak demand duration period as long as the fuel source, including conventional natural gas or RNG, is consistently available. Therefore, capacity duration is an important factor when assessing peaking resource options."

26.1. Please confirm that storage technologies are net energy loads rather than net energy supply resources, and that storage devices act as both capacity supply resources and net energy loads.

26.1.1. If not confirmed, please explain.

Response:

Confirmed.

26.2. What are the expected and best-case round-trip energy efficiencies for the storage technologies included in this application?

Response:

The expected round-trip energy efficiencies for pumped hydro storage and battery storage resources are assumed to be 75 percent and 90 percent, respectively.

27.0 Reference Exhibit B-1, Volume 1, Page 164

Environmental Attributes

FortisBC Inc. states:

"Environmental considerations are an important objective of the CEA and energy policy in BC. Environmental attributes describe the estimated environmental impact of the various resource options. While DSM resources are assumed to have no negative environmental impacts, some supply-side resources can. For the purposes of this LTERP and the portfolio analysis in Section 11, FBC has characterized resource options as either clean or renewable, or not, according to what the CEA defines as clean or renewable resources generated in BC. The CEA defines clean or renewable resources as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. An SCGT plant using RNG as fuel is considered a clean resource option as biogas and biomass are considered clean or renewable per the CEA definition. For the purposes of this LTERP, FBC also considers energy and capacity under the PPA to be clean and renewable, although there is a carbon footprint associated with the PPA as the resource is 98 percent clean. For non-renewable resources, FBC has considered both direct GHG emissions from burning fossil fuels (i.e. scope 1 emissions) and indirect GHG emissions associated with the production of the fossil fuel (i.e. scope 3 emissions). Other environmental attributes, such as plant land or water footprint, have also been considered. Based on the regional electricity generation source mix as discussed in Section 2.4.2, market purchases could include a mix of clean or renewable and non-clean or renewable resources. For the purposes of this LTERP, as discussed in Section 2.5.7, FBC has applied a clean adder to its market purchase prices to serve as a proxy for the purchase of only clean and renewable power from the market."

27.1. Please confirm that FBC considers any natural gas purchased with a clean adder to be clean?

27.1.1. If no, please explain why not, and describe what would have to change for FBC to consider such resources to be clean.

Response:

Not confirmed. The 'clean market adder' in the portfolio scenarios applies to electricity purchases, rather than natural gas fuel for a resource option. In order for FBC to consider natural gas to be carbon neutral, and therefore having zero reportable GHG emissions in the portfolio, the portfolio scenario needed to assume RNG was used as fuel for the SCGT plants.

27.2. What is the forecast cost of clean adders by year over the planning period?

Response:

The clean market adder for electricity purchases was developed by IHS Markit. IHS Markit has requested that FBC not disclose the yearly forecasted values publicly due to the commercial sensitivity. The clean market adder was estimated by IHS Markit to be approximately $2 per MWh on a levelized basis over the planning horizon. The actual cost of a clean market adder will be a point of negotiation between FBC and Powerex or a third party.

The implied premium for renewable natural gas is the difference between the forecast prices of renewable natural gas and conventional natural gas in Appendix E.

28.0 Reference Exhibit B-1, Volume 1, Page 165 & 166

Section 10.3 - Resource Options Evaluation

FortisBC Inc. states:

Table 10-1: Resource Options Type and Size Summary

Resource Option[179]	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)
PPA Tranche 1 Energy	PPA	Baseload	N/A	N/A	Up to 1,041
PPA Tranche 2 Energy	PPA	Baseload	N/A	N/A	Up to 711
PPA Capacity	PPA	Baseload	N/A	Up to 200	N/A
Market Purchases	Market	Baseload	N/A	Up to 75	Up to 3,241
Wood-Based Biomass	Biomass	Baseload	3	9 – 30	73-237
Geothermal	Geothermal	Baseload	4	15 – 75	130 - 657
Gas-Fired Generation (CCGT)	CCGT	Baseload	3	67 – 279	528 – 2,201
Small hydro with storage	Hydro	Baseload	4	8 - 50	77 - 443
Gas-Fired Generation (SCGT) - NG	SCGT	Peaking	3	48 – 100	75 – 158
Gas-Fired Generation (SCGT) - RNG	RNG_SCGT	Peaking	3	48 - 100	75 - 158
Pumped Hydro Storage	PSH	Peaking	2	100 – 1,000	N/A
Onshore Wind[180]	Wind	Intermittent	13	21 – 133	196 – 1,239

Resource Option[179]	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)
Run-of-River Hydro	RoR	Intermittent	3	2 – 6	16 - 52
Utility Scale Solar	Solar	Intermittent	11	4 - 107	28 - 754
Distributed Solar[181]	DistSolar	Intermittent	3	0 - 2	2 - 15
Battery Storage[182]	Battery	Peaking	1	39	N/A
Distributed Battery Storage[183]	DistBattery	Peaking	1	24	N/A

28.1. How was the dependable capacity limit for market purchases determined?

<u>Response:</u>

Please refer to the response to BCUC IR1 1.3.

28.2. Has FBC evaluated an option to purchase additional market capacity access?

28.2.1. If yes, please provide documentation.

28.2.2. If no, explain why not.

Response:

Please refer to the response to RCIA IR1 30.1 which discusses whether or not FBC has investigated the availability and cost of acquiring long-term firm transmission, which would be needed for additional market capacity access.

28.3. Why hasn't FBC evaluated RNG-Fired CCGT as a resource option?

Response:

FBC did not consider RNG-Fired CCGTs as a resource option given that the cost of RNG fuel would make a baseload gas plant less favourable relative to other energy-oriented resource options available.

28.3.1. What are the practical technical limitations (if any) to using RNG in a CCGT facility?

Response:

Given that RNG is indistinguishable from conventional natural gas from a combustion perspective, FBC does not expect any technical limitations associated with using RNG in a CCGT facility.

29.0 Reference Exhibit B-1, Volume 1, Page 166

Section 10.3 - Resource Options Evaluation

FortisBC Inc. states:

"Table 10-2 shows the unit energy and capacity costs for the resource options (in real \$2020). The range of unit costs reflects the different plant sizes available for some of the resource options. No UEC is presented for capacity resources including SCGT gas-fired generation, Pumped Hydro Storage or battery storage because these resources are primarily used for providing capacity and not energy. There is no UCC value for market purchases as FBC has assumed capacity self-sufficiency for the purposes of this LTERP for the reasons discussed in Section 2.4.4."

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

29.1. Table 10-1 (see above) shows that Market Purchases provide up to 75 MW of capacity. Please explain why no UCC value is provided for the Market Purchases resource option shown in Table 10-2.

Response:

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.

29.2. Why has FBC not included the UEC for SCGT-NG and SCGT-RNG?

Response:

FBC does not consider RNG SCGT or NG SCGT resources to be a practical source of large volumes of energy over the planning horizon. SCGT plants are capacity-oriented resources intended to serve the energy at the top of the load duration curve representing the peak hours only, rather than across all hours in the months. Furthermore, the UEC of a SCGT resource can vary greatly depending on the capacity factor assumed.

The value of an SCGT resource is the dispatchable capacity reliably available during peak hours. In other words, an SCGT is better suited to responding to unexpected system events, or when scheduled energy is curtailed, rather than continually generating large volumes of energy. In the event of a cold snap or heat wave, when several hours in a row are peak hours of the month or even year, a SCGT unit is able to run continuously. An SCGT plant can also provide power to localized load centres thereby supporting system transmission in contingency events if sited in a favourable location.

29.3. Please provide the UEC and UCC for SCGT-NG with Clean Adders.

Response:

The following table provides the UEC and UCC ranges for NG-SCGT and RNG-SCGT resources. As discussed in the response to RCIA IR1 27.1, the clean adder is not applicable for fuel used in SCGT plants but rather to purchased market energy. An RNG-SCGT unit is assumed to run exclusively on RNG, whereas the SCGT unit (or SCGT-NG as identified in the question) is assumed to run exclusively on conventional natural gas.

Resource	Capacity Factor (%)	Size (MW)	UEC ($2020/MWh)	UCC ($2020/kW-Year)
RNG-SCGT	18	48 - 100	$356 - $367	$131 - $148
NG-SCGT	18	48 - 100	$173 - $184	$131 - $148

The UEC has been calculated based on the average annual energy available from these resource types. Depending on the portfolio scenario, the dispatch of the SCGT units varies. In all scenarios investigated, the effective capacity factor (based on the modelled dispatch) is much lower than 18 percent. Although the price of RNG is considerably greater than conventional natural gas, the UECs are comprised of both fixed and variable costs that do not change with the price of fuel, such as the cost of the turbine/generator unit as well as interconnection, operations, and maintenance costs. Furthermore, the fuel costs of SCGT-NG units include the cost of carbon (based on the carbon price forecast), which decreases the differential between the two UECs.

30.0 Reference Exhibit B-1, Volume 1, Page 170

Section 10.4 - Market Purchases

FortisBC Inc. states:

"There is also no guarantee that FBC will be able to access market capacity supply reliably, especially if there is no access to long-term firm transmission. FBC relies on Line 71 to access US market supply, and there can be transmission constraints both on Line 71 and on the US transmission south of the border that can interrupt that supply when FBC needs it for capacity purposes, as discussed in Section 5.5. Therefore, FBC does not believe that market supply can be relied on as a long-term capacity resource option."

30.1. Has FBC investigated the availability and cost of acquiring long-term firm transmission?

30.1.1. If yes, please provide documentation.

30.1.2. If no, please explain why not.

<u>Response:</u>

It is FBC's understanding that firm transmission rights to cross the BC/US border (i.e., WECC transmission Path 3) are fully subscribed. FBC has not investigated the cost and availability of acquiring any of this long-term firm transmission. FBC's confidential preliminary work on the feasibility of building additional transmission facilities determined that there were no feasible independent solutions at this time. Any new transmission facilities would require a very long lead time with no guarantee of successful approval or completion.

CHAPTER 11: PORTFOLIO ANALYSIS

31.0 Reference Exhibit B-1, Volume 1, Page 178

Section 11.2 - Long Run Marginal Cost

FortisBC Inc. states:

"The LRMC values represent the cost to FBC of incremental resources needed to meet incremental load requirements over the planning horizon. The LRMC includes both energy and capacity generation components. FBC's LRMC values are outcomes of the portfolio analysis and are dependent upon which demand-side and supply-side resource options are included within a particular portfolio."

31.1. Please explain how a $/MWh value captures the impact of FBC's forecast capacity requirements, especially considering that capacity deficiencies are identified as the primary driver of new FBC resource additions.

Response:

A portfolio approach in determining the LRMC recognizes multiple resources collectively meeting the energy and capacity requirements over the planning horizon, rather than any one individual resource. The LRMC should be viewed as a price signal and not considered in isolation from other planning considerations, such as energy and capacity profiles of the other resources contained in the portfolio.

The LRMC has traditionally been stated on a unit energy cost basis as energy is what is ultimately sold and consumed by the customer. It is not possible to have available energy without capacity generating it, but it is possible to have available capacity that is not producing energy. Capacity is the ability to reliably deliver energy in peak hours of need. FBC agrees with the observation that generation capacity requirements are an important cost driver in the portfolio.

32.0 Reference Exhibit B-1, Volume 1, Page 182

Section 11.3.2 Market Access versus Self-Sufficiency

FortisBC Inc. states:

"FBC did explore a portfolio that did not have a self-sufficiency requirement for both energy and capacity. However, since accessing market capacity to meet expected load utilizes the same resource (i.e. transmission to the US market) that is used to provide reliability to ensure planning reserve margin targets are met (discussed in Section 11.3.10), it is not an appropriate portfolio in FBC's view. Furthermore, relying on capacity from the US market for long-term planning is not appropriate given the risks FBC has identified in Section 2.4.4. FBC recognizes that market capacity may be available from within B.C., thereby avoiding this issue. However, FBC has no information at this time about what, if any, B.C.-based market capacity resources may be available."

32.1. Has FBC attempted to initiate or held discussions with BCH to either purchase electricity from Site C, or to co-invest in Site C?

32.1.1. If yes, please describe the results or status of these discussions

32.1.2. If no, please explain why such discussions were not investigated.

Response:

FBC has not directly asked to participate in Site C either through an ownership or power purchase agreement. In FBC's view, the best way to potentially participate in any increased resources BC Hydro may have available is either through a revised PPA agreement or an additional agreement to purchase power. These potential agreements would not be tied directly to any one project.

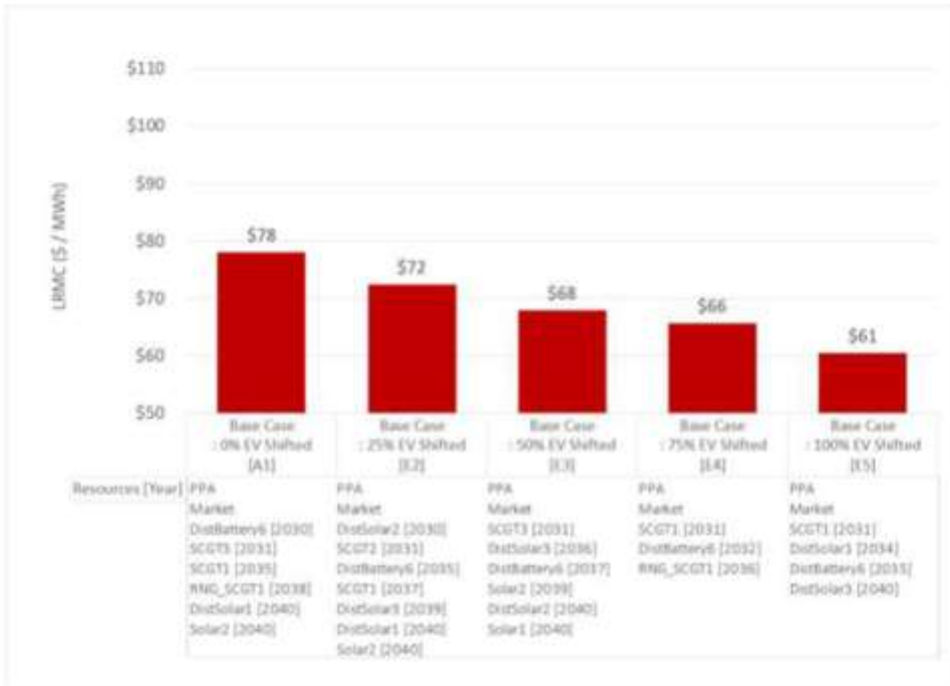
FBC has had high-level discussions with BC Hydro in regards to purchasing increased amounts of power from BC Hydro as a resource option. However, no detailed discussions have yet been held. FBC expects that it will have had preliminary discussions with BC Hydro in regards to either renewing and potentially expanding the PPA or entering into additional contracts with BC Hydro prior to the next expected FBC LTERP in 2026. These are reasonable topics to consider as part of the half-way mark review of the PPA which FBC intends to undertake in 2023. By that time, FBC believes the 2021 LTERP and BC Hydro 2021 IRP processes will be concluded and BC Hydro will also have additional certainly as to their available resources.

33.0 Reference Exhibit B-1, Volume 1, Page 186

Section 11.3.5 – EV Charging Shifting

FortisBC Inc. provides Figure 11-5 which is reproduced below:

Figure 11-5: Portfolios based on Different Percentages of EV Charging Shifting



33.1. What is the estimated probability that FBC will achieve 50% EV Charging Shifting by 2030?

Response:

EV drivers are not generally expected to be concerned about starting charging later in the day in non-peak periods provided their vehicles are charged before they need them the next day. Given this anticipated load flexibility, FBC believes there is a high probability of shifting at least 50 percent of EV charging load off-peak by 2030.

33.2. What is the most likely level of EV Charging Shifting that FBC expects to achieve by 2030, if other than 50%?

Response:

As shown in the response to RCIA IR1 33.3, there is significant opportunity to shift EV charging to a non-peak period. FBC expects that EV users will not generally be concerned about starting charging later in the day during non-peak periods, provided their vehicles are charged before they need them the next day. As such, FBC considers 50 percent a reasonable minimum level of peak demand shifting related to residential EV charging to be achieved by 2030, with a potential maximum of 75 percent as discussed in Section 2.3.2.

33.3. Please provide a daily chart showing the expected charging load shape for a household with a typical EV (i.e., Tesla 3 or equivalent), with and without EV charging shifting.

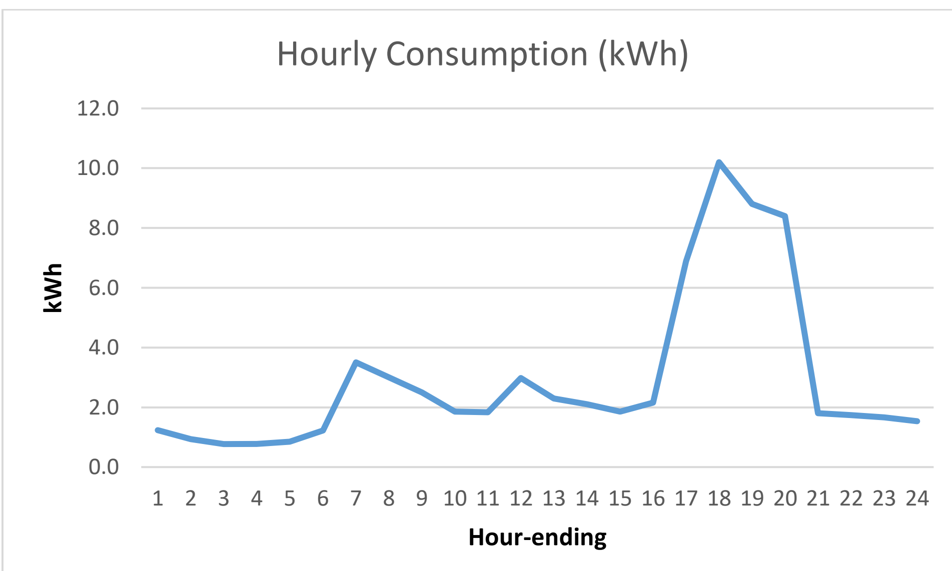
Response:

The following figures show representative household load profiles with a typical light-duty EV charge session requirement of approximately 20 kWh using a 6 kW Level 2 charger.

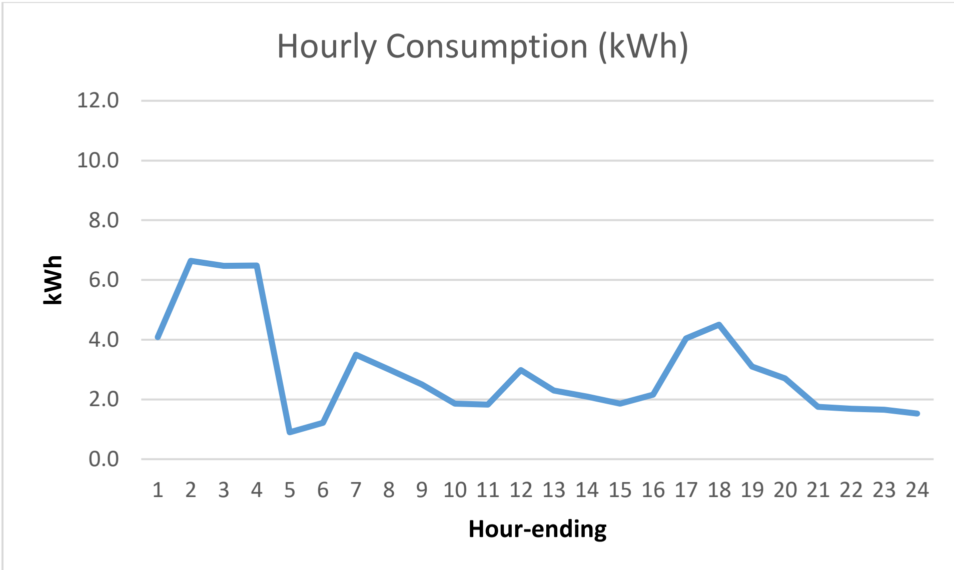
In the first figure, there is no EV charging shifting, the charge session begins at 5:30 pm and ends shortly after 8 pm. In the second figure, 100 percent of the EV charging is shifted from the evening to the early morning hours (12:30 am to shortly after 4 am).

As noted in the response to RCIA IR1 33.2, FBC expects to shift 50 percent of the EV charging load through its software-based incentive approach.

Figure 1: Typical Daily Charging Profile – No EV Load Shift



1 **Figure 2: Typical Daily Charging Profile – EV Load Shifted**



2

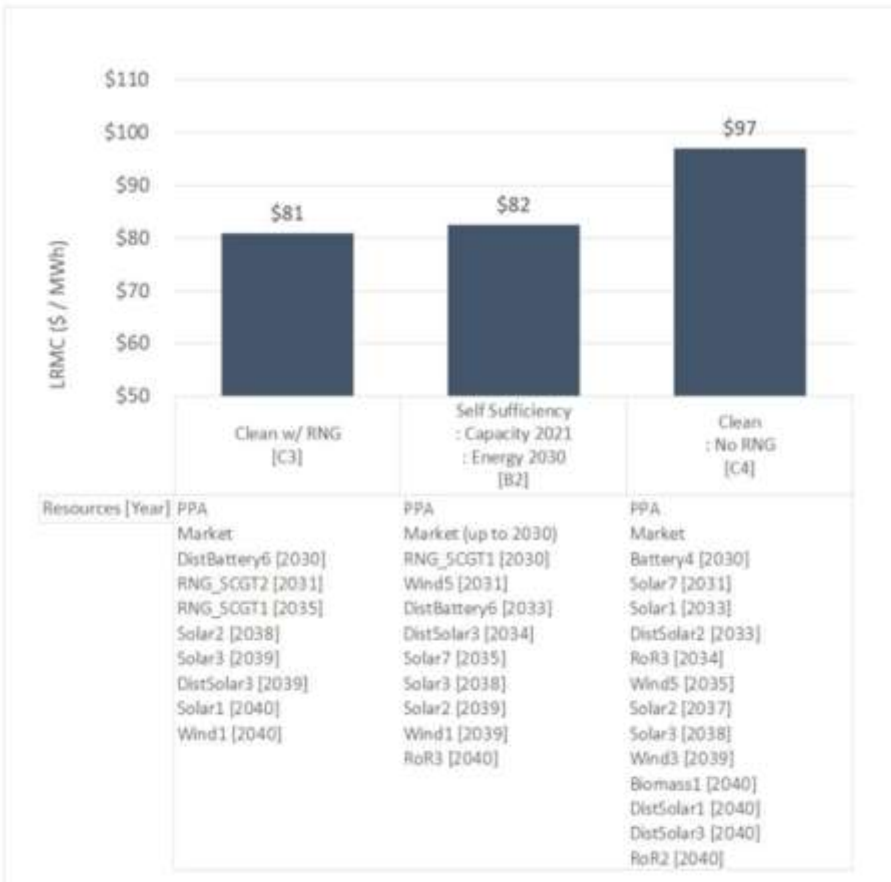
3

34.0 Reference Exhibit B-1, Volume 1, Page 190

Section 11.3.8 - Portfolios Considered for Preferred Portfolios

FortisBC Inc. states:

Figure 11-7: Portfolios Considered for Preferred Portfolios



34.1. Could the SCGT portfolio elements in C3 and B2 potentially offset or defer the need for the ACK-VAS 500 kV TL Project if advantageously sited?

34.1.1. If yes, please restate the LRMC values in figure 11-7 with a capital credit corresponding to the elimination or deferral of the TL project.

34.1.2. If no, please explain why not.

Response:

Please refer to the response to RCIA IR1 25.1.

CHAPTER 12: STAKEHOLDER, INDIGENOUS, AND CUSTOMER ENGAGEMENT

35.0 Reference Exhibit B-1, Volume 1, Page 203

Section 12.1 Resource Planning Advisory Group

FortisBC Inc. states:

"More specifically, some of the feedback and areas of stakeholder and rights holder interest in the workshops included the following items:

…

- Inclusion of Indigenous collaboration/opportunities as a portfolio attribute in the portfolio evaluation rating framework;
- Consideration of potential changes to the CEA and a clean energy requirement for customers resulting in a clean portfolio option;

…

- Consideration of using percentage of Conservation Potential Review (CPR) achievable potential to determine DSM portfolios;"

35.1. Please confirm that RPAG members provided differing viewpoints and feedback on the issues discussed during the RPAG sessions.

35.1.1. If confirmed, please explain how FBC balances differing feedback and viewpoints to avoid bias when incorporating RPAG feedback into FBC's planning decisions.

35.1.2. If not confirmed, please explain why FBC did not select RPAG members with a diverse set of viewpoints and feedback.

<u>Response:</u>

Confirmed. FBC balances differing feedback and viewpoints provided by the RPAG through its LTERP objectives, which ultimately guide FBC in its long-term resource planning decisions. FBC gives higher priority to feedback that is aligned with the LTERP objectives as set out in section 1.2, as compared to feedback that is not.

36.0 Reference Exhibit B-1, Volume 1, Page 207

Section 12.3 Direct Customer Surveys

Exhibit B-1, Volume 1, Page 215

Section 13.2 2021 LTERP Action Plan

FortisBC Inc. states on pg. 207:

"In terms of EV ownership, 43 percent of residential and 37 percent of commercial customers indicated that they are likely to purchase or lease an EV within the next three years. The preferred approaches for managing EV charging by those indicating they are likely to buy or lease an EV include incentives for charging during off-peak times and rebates to customers who buy EV chargers that automatically charge during off-peak times. The survey also indicates that 34 percent of residential and 49 percent of commercial customers are likely to install rooftop solar panels on their home or business in the next five years, with similar percentages indicating a likelihood of also installing battery storage. Preferred incentives include rebates for installation of equipment and FBC purchasing surplus energy from solar panel owners."

FortisBC Inc. states on pg. 215:

"As discussed in Section 2.3.2, EV growth is continuing within the FBC service area and EV charging, if left unmitigated, could significantly increase peak demand on the system. This could lead to the requirement for additional capacity generation resources and/or transmission and distribution infrastructure, increasing rates for customers. FBC's preference is to implement a software-based incentive program in order to encourage shifting home EV charging from peak demand periods while requiring minimal customer involvement. As part of this initiative, FBC intends to implement an EV charging pilot project as part of a wider residential demand-response pilot. Section 4.6.3 of the LT DSM Plan discusses this further."

36.1. Does FBC expect that 43 percent of residential customers will purchase or lease an EV in the next three years?

36.1.1. If no, what percentage of customers does FBC expect will purchase or lease an EV in the next three years, and what is that determination based upon?

Response:

It is likely that the actual number of residential customers purchasing or leasing an EV in the next three years will be less than 43 percent, as intent indicated through a survey does not always translate to action. FBC's expectation of annual EV sales aligns with the current legislated *ZEV Act* sales targets discussed in Section 2.3.2.

36.2. Please confirm that "43 percent of residential … customers indicated that they are likely to purchase or lease an EV with the next three years" means that FBC considers EV ownership mainstream and part of baseline planning conditions (i.e., although the uptake magnitude has uncertainty, uptake is considered a baseline condition).

36.2.1. If not confirmed, at what residential EV ownership threshold does EV ownership become part of FBC's baseline planning conditions?

Response:

Confirmed.

36.3. Given that "43 percent of residential … customers indicated that they are likely to purchase or lease an EV with the next three years" explain why the pilot project represents an adequate plan to evaluate expected EV uptake.

Response:

Although the survey results are useful for assessing customer sentiment, FBC believes actual adoption rates will be lower than 43 percent due to barriers related to both cost and availability of vehicles. FBC is actively monitoring EV uptake through annual ICBC EV registration data, charging volumes on FBC's public charging network, as well as through rebates administered under the CleanBC program for FBC customers.

Regardless of the percentage of customers indicating that they are likely to purchase or lease an EV within the next three years, the appropriate first step in the implementation of any new program is a pilot project, which can later be scaled up based on effectiveness and need.

Please also refer to the response to RCIA IR1 36.1.

36.4. Does FBC expect that 34 percent of residential customers will install rooftop solar panels on their home or business in the next five years?"

36.4.1. If no, what percentage of customers does FBC expect will install rooftop solar panels in the next three years, and what is the basis for that determination?

Response:

Please refer to the response to RCIA IR1 11.3.

36.5. Please confirm that “34 percent of residential … customers are likely to install rooftop solar panels on their home or business in the next five years, with similar percentages indicating a likelihood of also installing battery storage” means that FBC considers residential rooftop solar panel installations to be mainstream and part of baseline planning conditions (i.e., although the uptake magnitude has uncertainty, uptake is considered a baseline condition).

36.5.1. If not confirmed, at what threshold does residential solar panel installation become part of FBC’s baseline planning conditions?

Response:

Not confirmed. FBC does not expect that solar PV installations will reach the level indicated by the survey results and notes that only 0.5 percent of customers have net metering installations (which are required for grid-connected solar installations) today. Many customers aspire to install solar, but clearly barriers (primarily economic) exist to actual implementation.

Customers on the Net Metering tariff are part of the residential and commercial classes and, therefore, their load impacts are naturally embedded into the LTERP BAU load forecast. In the next resource plan, FBC will re-evaluate the residential (IPSS-RES) and commercial (IPSS-COM) rooftop solar and storage load drivers, included in the load scenarios rather than the Reference Case load forecast, as presented in Section 2.1 and Section 2.2 of Appendix H. The decision to include a customer-based rooftop solar load driver in the Reference Case forecast in the future will depend on clear signals from the operating environment that future adoption rates will be significantly higher than historical rates. For example, the decision to include EV charging load in the Reference Case load forecast was based on regulatory requirements, specifically the *ZEV Act* legislated light-duty EV sales targets (as discussed in Section 2.3.2). No equivalent signal has been provided to indicate customer net metering rooftop solar should be included in the Reference Case load forecast at this time.

37.0 Reference Exhibit B-1, Volume 1, Page 210

Section 12.4.3 Engagement Sessions

FortisBC Inc. states:

"Community representatives also raised concerns about past grievances relating to the construction of existing hydroelectric generation facilities in the province. Representatives in the meeting expressed that communities were not properly reimbursed for the lands and culturally significant sites impacted or disrupted through the construction of these facilities. It was raised to FBC that the inability to resolve these grievances makes it challenging for communities to discuss energy planning issues and opportunities for the future. Later in the meeting, another representative identified the need for FBC to continue discussions with the communities on beneficial opportunities and how future benefits can be paired to reconcile past grievances."

37.1. Please describe FBC's plans to reconcile past grievances, or the plan to develop a plan to reconcile past grievances.

Response:

As stated in Section 12.4.3, key concerns were raised by Indigenous community representatives during LTERP engagement sessions about past grievances relating to the construction of hydroelectric generation facilities in the province. These comments were directed broadly at historic grievances pertaining to all hydroelectric generation facilities constructed in the province of BC, not exclusively FBC-owned and operated hydroelectric generation facilities. FBC is committed to reconciliation with Indigenous peoples and continually engages with Indigenous groups to strengthen relationships and to identify actions necessary to work towards reconciliation. As additional supply-side resources are considered for future utility planning, FBC will continue to engage with Indigenous groups to minimize impacts of FBC operations and to identify how beneficial opportunities can be paired to reconcile past grievances, such as those identified by community representatives during the LTERP engagement sessions.

37.2. Please describe which, if any, of the recommended 2021 LTERP Action Plan items, or sub-items therein, require reconciliation of past First Nation grievances to reach completion within the planning period.

Response:

Action Plan items 9 and 10 in Section 13.2 of the Application outline the importance of community engagement and input into the ongoing resource planning process and in monitoring potential available power supply opportunities moving forward. Reconciliation is directly applicable to these

Action Plan items and actions toward reconciliation broadly apply to the entire LTERP Action Plan and FBC energy planning process.

With respect to RCIA IR1 37.2.1, various risks are posed by unreconciled grievances with Indigenous communities. As discussed above, feedback and input provided by Indigenous community representatives is an integral part of the LTERP development process. To the extent that unreconciled grievances create challenges for Indigenous community representatives to engage with FBC on energy planning and to share community energy plans or priorities, FBC's ability to accurately capture community feedback and integrate this information into FBC's energy planning process will be limited. Unreconciled grievances may also pose implementation risks for future FBC infrastructure projects or other supply-side resource considerations identified in the LTERP. Given the importance of community input and feedback in the LTERP process as described in Section 13.2 of the Application, FBC commits to continued engagement with Indigenous groups, including identifying actions necessary to work towards reconciliation, and to identify beneficial opportunities associated with supply-side resource options, planned infrastructure projects, and future FBC operations and programs.

37.2.1. For any Action Plan items identified, please describe the risk posed by unreconciled grievances.

Response:

Please refer to the response to RCIA IR1 37.2.

38.0 Reference Exhibit B-1, Volume 1, Page 215

Section 13.2 2021 LTERP Action Plan

Exhibit B-1, Volume 1, Appendix N, Page 8

Customer Survey - Highlights

FortisBC Inc. states on pg. 215:

"EV growth is continuing within the FBC service area and EV charging, if left unmitigated, could significantly increase peak demand on the system. This could lead to the requirement for additional capacity generation resources and/or transmission and distribution infrastructure, increasing rates for customers. FBC's preference is to implement a software-based incentive program in order to encourage shifting home EV charging from peak demand periods while requiring minimal customer involvement. As part of this initiative, FBC intends to implement an EV charging pilot project as part of a wider residential demand-response pilot. Section 4.6.3 of the LT DSM Plan discusses this further."

FortisBC Inc. states in Appendix N:

"Many customers view this – and things like giving their utility some control of their thermostat – as a form of surveillance. A significant amount of customer education is probably still needed to allay customer concerns in this regard."

FortisBC Inc. states in Volume 2, pg. 26:

"The Company currently has a residential DR 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."

38.1. What percentage of its customers does FBC expect will see utility control of, and visibility into, EV charging as "surveillance"?

<u>Response:</u>

FBC demand response programs are expected to be implemented on a voluntary basis. A leading approach to shifting EV charging load involves providing a phone app that allows the customer to control charging times on their own. If the customer opts-in to the incentive program, FBC would receive information about when charging occurs in order to provide an incentive for charging during off-peak periods. Customers that see this program as "surveillance" will presumably not participate. FBC expects that most customers will realize that the program must verify results in order to provide incentives.

38.2. Why has FBC chosen control of residential home EV charging as the preferred approach to shifting home EV charging from peak demand periods?

Response:

FBC has not finalized an approach to EV demand response; however, demand response via control of residential home EV charging is one approach to residential EV peak load shifting, as described in Section 2.3.2.

As described in the response to RCIA IR 1.5.1, FBC believes that a leading alternative at this time for residential EV charging load-shifting is to use a software-based approach that will allow customers to choose when to charge their vehicles and to receive an incentive when charging occurs outside of peak periods.

38.3. Are there other methods of shifting charging from peak demand periods and if yes, why were those options not chosen for advancement?

Response:

Aside from the hardware-based approach discussed in Section 8.2, there are other methods not included in the FBC demand response pilot that could shift EV charging from peak demand periods. These methods include:

- Behavioral nudges: Utilities can either send incentivized or non-incentivized behavior nudges through email, text message, or smart home appliance notifications to encourage customers to displace peak load. Participation is voluntary.
    - FBC did not evaluate this method as it would likely need integration into FBC's *My energy use* portal, which has only recently come online. FBC may look to explore this intervention in a future pilot or program.
- Vehicle software-based demand response: Instead of having a demand-response program that sends signals to the vehicle charger, most electric vehicles have internal software that can control the period of charging or provide validation of when charging occurred.
    - As discussed in the response to RCIA IR1 5.1, this approach for shifting residential EV charging loads offers a number of advantages, and will be further investigated in 2022 for a potential pilot.

- Time-of-use rates: Utilities can set a time-of-use rate to encourage customers to displace peak load through price signals
    - Rate design is not a DSM intervention, so FBC did not evaluate this as part of the pilot. Any consideration of time-of-use rates would be as a part of a broader rate design exercise.

38.4. Given that customers see utility control of residential home functions “as a form of surveillance”, what are the primary barriers FBC foresees to the wider adoption of direct control of residential home EV charging?

Response:

FBC is aware of the following main barriers to the wider adoption of automated demand response:

- **Incentive** – The demand-response incentive must be high enough to offset the customer’s inconvenience.
- **Inconvenience –** Customers that have currently adopted electric vehicles disproportionally come from a demographic with higher incomes. Thus, for some customers no amount of reasonable incentive will change charging behaviour.
- **Vehicle Charging Protocols for Demand Response** – There are many different EV charging protocols (for example Open Intercharge Protocol, Open Automated Demand Response, Open Smart Charging Protocol) that makes integration with demand-response platforms challenging. FBC is not aware of a demand-response platform that can integrate with all demand-response protocols at this time.
- **Awareness –** The concept of demand-response programs is still relatively new to the British Columbia market. Educational and marketing campaigns will be necessary to educate customers on how demand response works, how it helps the utility, and how it may impact them as a customer.

As a result, FBC’s leading approach to residential EV charging load-shifting is through software that will allow the customer to choose when they charge. Although this approach does not require direct load control, it still requires FBC to receive data regarding when the charging actually occurred in order to validate and provide appropriate incentives. FBC believes this approach addresses both the inconvenience and available DR protocol concerns noted above. A software-based approach for leveraging both available EV original equipment manufacturer (OEM) application programming interfaces (APIs) as well as any already customer-installed smart chargers for validating EV load-shifting will allow FBC to implement a program that ensures as many customers as possible can participate without requiring additional hardware.

38.5. How will "customer education" mitigate the concerns that underpin customer perceptions of direct control being "surveillance"?

Response:

Customer education will inform customers how demand response works, how it helps the utility, and how it may impact them as a customer. As part of customer education, it will be important to explain the limits of utility intervention to hopefully allay some potential concerns associated with utility control of select devices. With better awareness of demand response, the customer will have the opportunity to make an informed decision whether to voluntarily participate in the program or not.

38.5.1. Are there any lessons FBC learned when implementing the Advanced Metering Infrastructure that can be applied to direct control of residential home EV charging?

Response:

The role of customer education was an important consideration prior to the FBC Advanced Metering Infrastructure implementation and is applicable to future programs like direct control of residential home EV charging.

VOLUME 2, CHAPTER 4: DEMAND-SIDE MANAGEMENT PROGRAMS

39.0 Reference Exhibit B-1, Volume 2, Pages 14-15

Section 3 DSM Scenario Development

Exhibit B-1 Volume 2, Pages 19-21

Section 4.1 Residential Sector

Section 4.2 Low-Income Household Programs

FortisBC Inc. presents the following on pg. 14 & 15:

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per annum ('21 - '40)	21.0	21.8	22.4	23.4	25.2
Average per annum ('21 - '29)	26.8	28.0	29.4	31.4	34.5
Total (2021 to 2040)	421	435	449	468	503

Category	DSM Scenario				
	Low	Base	Med	High	Max
Capacity Savings, MW					
Total (2021 to 2040)	61.6	64.0	65.6	68.1	72.7
Resource Cost, 2020 ($000s)					
Average Cost ($/MWh)	$38	$44	$49	$57	$75
Incremental cost compared to base case ($/MWh)	N/A	-	$183	$190	$234

FortisBC Inc. states on pg. 19 – 21, the following Residential Sector Programs:

1) *Residential Sector Programs:*
    a. *Home Renovation Rebates*
    b. *Retail Rebates*
    c. *Now Home Rebates*
    d. *Rental Apartment Program*
2) *Low-Income Household Programs:*
    a. *Self-Install*
    b. *Direct Install*
    c. *Other Initiatives*

39.1. Please provide an enhanced Table 3-1 for the Low, Base and Med DSM Scenarios that shows the Energy Savings, Capacity Savings, Average Cost, and Incremental Cost Compared to the Base Case for each of the Residential Sector Programs and each of the Low-Income Household Programs.

Response:

Programs are identified, at a high-level, to include cost-effective measures identified in the 2021 Conservation Potential Review. The LT DSM Plan does not include the granularity of program design, participation or budgeting at a program-level.

Within the 2021 Conservation Potential Review, Low-Income Residential customers are considered part of the Residential sector. The following table presents energy and capacity savings for cost-effective measures for the five DSM Scenarios in the Residential sector.

Category	DSM Scenario (Residential sector only)				
	Low	Base	Med	High	Max
Energy Savings, GWh					
Average per Annum (2021 to 2040)	4.8	5.3	5.3	5.3	5.3
Average per Annum (2021 to 2029)	5.6	6.0	6.1	6.1	6.1
Total (2021 to 2040)	95	105	107	107	107
Capacity Savings, MW					
Total (2021 to 2040)	20.7	22.7	23.0	23.0	23.0

The average and incremental costs compared to the base case was not analyzed at a sector level. Individual measure assumptions are included in Appendix A of the LT DSM Plan, Appendices B1 and B2.

39.2. Given that BC Hydro is trying to increase its electrical load, what discussions has FBC had with BC Hydro to supply additional load to BC Hydro rather than to continue pursuing DSM?

Response:

FBC has not met with BC Hydro to discuss supplying more power to FBC in place of FBC pursuing DSM programs. The *Clean Energy Act* emphasizes the deployment of demand-side measures to meet growing electricity demand in British Columbia. FBC's objective for DSM activities is to offer customers in its service area a range of programs, within a cost-effective portfolio of measures, which address the majority of end uses for each major customer sector. The rebate, or level of incentive, FBC is willing to offer customers gives consideration to the avoided costs of electricity, which includes power from BC Hydro under the PPA.