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December 23, 2021

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Inc. (FBC)

Project No. 1599244

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

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

Treatment of Confidential Material

A portion of the response to BCUC IR1 28.4.1 is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19, consistent with Order E-13-12 because it contains commercially and financially sensitive information of FBC and certain of its affiliates which, if disclosed, could jeopardize FBC's ability to maximize the benefits associated with re-sale of excess capacity under these agreements for customers. As such, only the BCUC will receive a confidential unredacted version of this response under separate cover.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments
cc (email only): Registered Parties

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A. PLANNING ENVIRONMENT

1.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1 (Application), Section 2.4.4, pp. 64–65, Section 2.5.2, p. 72, Section 2.5.7,

p. 80; Section 10.4, p. 170

Regional Market Opportunities and Risks

On page 64 of the FortisBC Inc. 2021 Long-Term Electric Resource Plan (LTERP) and Long-Term Demand-Side Management Plan (LT DSM Plan) (Application) regarding market capacity, FortisBC Inc. (FBC) states:

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

1.1 Please describe FBC's historical reliance on the market as a capacity resource. If possible, please provide the percentage of FBC's peak capacity needs provided by market purchases for winter, summer and June for the past 5 years.

Response:

FBC has not historically relied on the market as a capacity resource over the long-term planning horizon, except for the month of June. Only the month of June has historically had a capacity "planning gap" after the use of the maximum 200 MW of PPA, where the market is expected to be relied upon for capacity purchases.

However, within FBC's optimization strategy, as discussed in Section 5.2.3 of the 2021/2022 Annual Electric Contracting Plan (AECP), FBC can operationally choose to enter into market purchases in the day-ahead market to avoid taking above the minimum billing volume of 100 MW of PPA, when the market cost is economic to displace the total cost of the PPA capacity and energy. Peak capacity needs may only occur for a few hours within a month, and FBC can avoid the incremental PPA capacity cost for the entire month. On an operational basis, FBC has historically purchased a considerable amount of day-ahead and real-time capacity from the wholesale market during the month of June and, to a lesser extent, during other months.

The tables below show the peak capacity load and amounts provided by market purchases for winter, summer, and June for the past five contract years. Please note that the years are based on the PPA contract years, aligned with the AECP, which runs from October 1 to September 30. The Surplus Capacity Available in the tables consists of any remaining PPA not fully utilized up to the maximum 200 MW, as well as any WAX sales to Powerex under the CEPSA. Additionally, if actual peak load is higher than the expected or planned peak load, or unexpected conditions occur within the day, market purchases for capacity needs could be required.

Winter (MW)	2016/17	2017/18	2018/19	2019/20	2020/21
Peak Load	731	663	696	740	733
Surplus Capacity Available	75	155	115	70	100
Peak Market Purchases	45	0	0	65	30
Peak % Supplied by Market	6.2	0	0	8.8	4.1
Summer (MW)	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Peak Load	593	630	623	651	685
Surplus Capacity Available	100	200	205	100	0
Peak Market Purchases	60	20	20	130	45
Peak % Supplied by Market	10.1	3.2	3.2	20.0	6.6
June (MW)	**2016/17**	**2017/18**	**2018/19**	**2019/20**	**2020/21**
Peak Load	536	560	563	503	764
Surplus Capacity Available	100	105	140	100	0
Peak Market Purchases	160	190	170	120	265
Peak % Supplied by Market	29.9	33.9	30.2	23.9	34.7

1.2 Please discuss whether FBC has historically experienced issues with accessing market supply to meet FBC's peak capacity needs.

1.2.1 If yes, please describe the issues experienced.

Response:

Since the CEPSA agreement with Powerex became effective as of May 1, 2015, FBC has been able to purchase the required amounts of power to meet peak capacity needs. Prior to this, that was not always the case with extreme measures such as voltage reductions, public calls for conservation and third-party load buy-downs on rare occasions. One winter, under the previous PPA agreement with BC Hydro, FBC simply stopped attempting to buy from the market and used PPA purchases to cover FBC supply shortfalls. This resulted in PPA purchases well over the current PPA limit of 200 MW. This approach is not possible under the current PPA.

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

On page 170 of the Application, FBC states:

> Due to the availability of freshet[191] power during the month of June and FBC's market import capacity, FBC expects that the June gaps (after DSM) up to the level of 75 MW could be met with market block purchases, contracted prior to the start of each June, rather than acquiring new resources, up until 2030.

1.3 Please expand on how FBC determined that it will be able to rely on market purchases to meet June capacity requirements until 2030 and not after. Please discuss the basis for the 75MW limit.

Response:

FBC previously qualified the small planned June capacity gaps each year within the AECP as being minor, and not expected to affect FBC's ability to maintain reliable supply due to the availability of freshet power in the market. However, given the extreme load and market power price events in June 2021 and other 'scarcity pricing' events discussed in Section 2.4.4.1, FBC now plans to meet June gaps until 2030 with firm, fixed-price market block purchases, rather than leaving load requirements subject to day ahead or real-time market prices and availability.

FBC is comfortable addressing the June gaps through market block purchases until 2030, but after 2030, has assumed capacity self-sufficiency for all months given the long-term uncertainty risks, especially around extreme heating events and water availability, with long-term reliance on the market for capacity purposes.

Previously in the 2016 LTERP, reliable market purchases were limited to 150 MW, on a real-time variable basis, for both capacity and energy purposes. The level of 150 MW was determined due to the FBC's portion of import rights on 71 Line, after Teck Resource Limited's priority over FBC for use of the line.

For the 2021 LTERP, 75 MW was determined as the maximum level due to the need to purchase the energy associated with the June capacity requirements. Purchasing 75 MW of market blocks during all peak hours in the month of June, where there are typically 416 peak hours, results in 31.2 GWh of energy associated with the capacity. In other words, FBC has a very high degree of confidence that it will be able to fully utilize up to a maximum 75 MW peak block within the month of June – both the energy and capacity - associated with such a contract. However, purchasing more than the suggested maximum 75 MW would reduce FBC's flexibility to manage potential low loads that could occur, and increase the likelihood of spilled energy. While FBC is able to store up to 24.5 GWh of excess energy in its storage account under the Canal Plant Agreement (CPA), if the storage limit is exceeded, the energy is deemed under the terms of the CPA to be spilled and delivered to BC Hydro at no cost.

1.4 Please expand on how FBC determined that up to a level of 75 MW, and not more, could be met with market block purchases up until 2030.

Response:

Please refer to the response to BCUC IR1 1.3.

On pages 64-65 of the Application, FBC discusses market energy.

1.5 Please describe FBC's historical reliance on the market as an energy resource.

Response:

On a historical basis, FBC has not planned to rely on the market as an energy resource over and above its firm power purchase contracts in order to meet gross load requirements. In the Application, however, FBC recognizes that its current firm power purchase contracts, including the PPA, will not be sufficient to satisfy energy requirements for the duration of the long-term planning horizon. As such, wholesale market energy purchases will not only be used as an economic alternative to PPA, but will also be needed to meet energy shortfalls over the planning horizon.

However, FBC has used wholesale market energy as an economic tool to displace energy purchases that would have otherwise been made under the PPA. FBC's strategy for optimizing wholesale market energy purchases against the PPA is outlined in Section 5 of the Company's 2021/2022 AECP. Please refer to the table below for the percentage of FBC's energy needs provided by market purchases, on an annual basis, for the past 5 years.

Year	Gross Load (GWh)	Market Purchases (GWh)	% of Gross Load provided by Market
2016	3,387	261	7.7
2017	3,596	417	11.6
2018	3,531	515	14.6
2019	3,618	455	12.6
2020	3,574	370	10.4

1.6 Please provide the percentage of FBC's energy needs provided by market purchases for the past 5 years.

Response:

Please refer to the response to BCUC IR1 1.5.

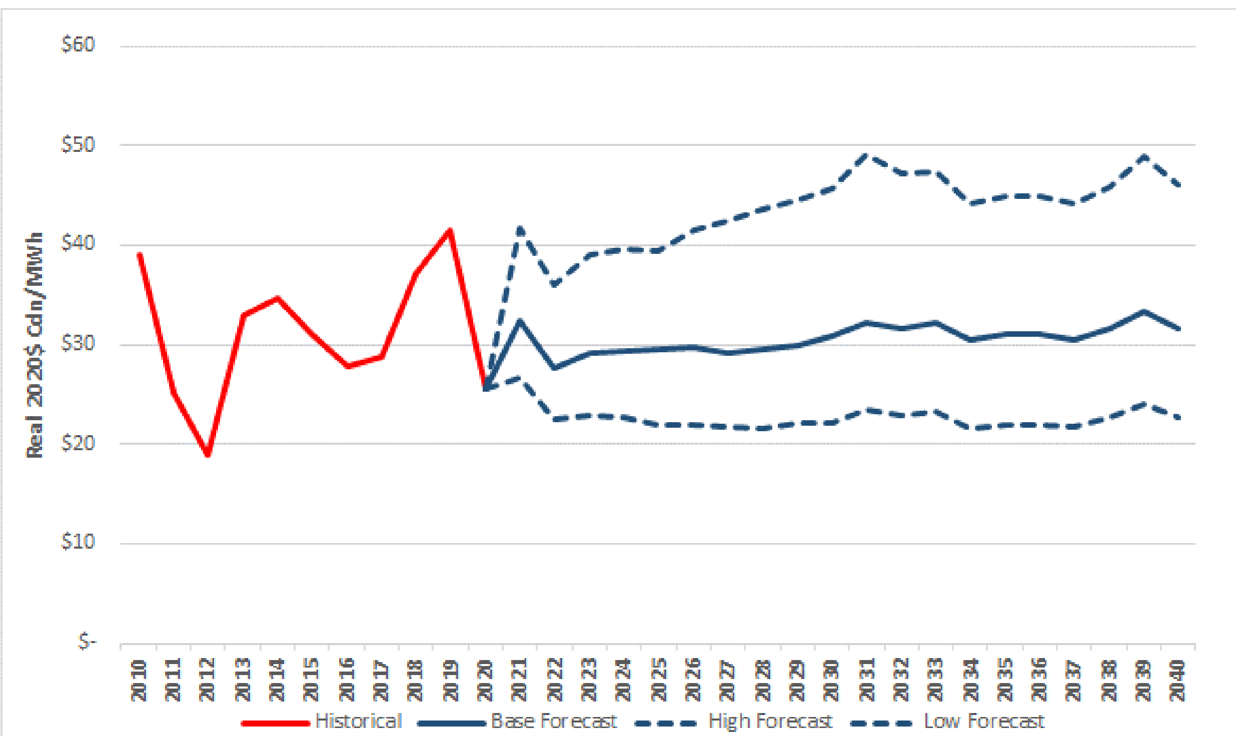
In Figure 2-18, on page 72 of the Application, FBC provides Mid-C Electricity Annual Price Forecasts.

1.7 Please update Figure 2-18 to include historical Mid-C prices from 2010.

Response:

The following figure shows historical Mid-C prices from 2010 to 2020 and the price forecast for Mid-C, including the Base, High and Low forecasts, from 2021 to 2040. The historical and forecast annual prices are in real 2020 Canadian dollars per megawatt-hour (MWh).

Updated Figure 2-18: Mid-C Historical and Forecast Prices



On page 80 of the Application, FBC states:

> A clean market price adder as a proxy for purchasing clean energy is added to the electricity market price forecast and is based on a forecast from IHS. The Mid-C market price forecast is based on current and expected supply in the Pacific Northwest, which includes coal and gas resources, and therefore a clean market adder is used to represent the cost of purchasing only clean market power. The clean market adder forecast from IHS reflects the assumption of a renewable energy credit (REC) oversupply in the Mid-C market, as utilities in the Pacific Northwest are planning to exceed state-mandated renewable portfolio standards. Purchasing a REC certifies that the power is clean electricity and represents the clean energy attributes of renewable electricity. An organized REC market with published prices does not currently exist in the Pacific Northwest and the clean market adder forecast is merely indicative at this time. If states adopt stricter or accelerate decarbonization mandates, the oversupply of renewable generation could decrease closer to 2040 and increase REC costs. The clean market price adder is approximately $2 per MWh.130 Within its portfolio analysis discussed in Section 11, FBC has included these market price forecast adders…

1.8 Please identify the average annual percentage of FBC current market purchases from clean sources, over the past 5 years.

Response:

FBC is unable to calculate the actual average annual percentage of FBC market purchases from clean sources over the past five years. In order to calculate this number, FBC wholesale market imports would need to be purchased directly from a specified clean generation source. Currently, FBC imports its wholesale market energy from unspecified sources, and applies the industry-accepted WCI (Western Climate Initiative) model to estimate a carbon intensity based on the control area from which the power was sourced.

1.9 Please discuss whether there are any differences in how market suppliers outside of BC define clean or renewable resource.

1.9.1 If yes, please describe the differences and discuss how this impacts FBC, if at all, with respect to its market purchases.

Response:

FBC does not have comprehensive knowledge of how market suppliers outside of BC define clean or renewable resources compared to within BC. For example, large hydro is considered clean in BC but may not be classified as such in other jurisdictions. Any clean market purchases that FBC may make would need to come from a source that is recognized in BC as clean or green and to ensure that there is no double-counting of clean energy attributes. If FBC purchases clean market power through the CEPSA agreement, FBC will work with Powerex to ensure that those purchases are consistent with BC requirements.

2.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Appendix E, p. 10

RNG Price Forecast Assumptions

Page 10 of Appendix E shows the price forecast for renewable natural gas (RNG), in real CAD, including a base and low forecast:

- The base forecast ranges from \$22/GJ in 2021, rising to a maximum of \$30 by 2036 with no further growth up to 2040.
- The low forecast ranges from \$22.13 in 2021 to \$20.52 in 2040.

2.1 Please discuss the current prices for RNG, confidentially if necessary.

Response:

When the existing acquisition cost of RNG is combined with future agreement prices expected to come into the portfolio over the next two to three years, the weighted average price of RNG will be approximately \$22 per GJ in 2021 as shown on page 10 of Appendix E.

2.2 Please confirm if FBC developed a high forecast for RNG. If not, please explain why not.

Response:

FBC did not develop a high forecast for RNG because FBC's base RNG price forecast already includes a maximum price consistent with that in the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR) for public utility RNG purchases and production. FBC does not expect RNG prices to be above this level.

2.3 Please provide the source for the price forecast for RNG.

Response:

FEI developed the RNG price forecast for FBC, using the existing FEI agreement pricing to develop a starting point and, for the base case, projected an increase in price based on expected contractual inflation factors for RNG supply agreements. For the low case, FEI assumed economies of scale result in prices dropping by 15 cents per GJ annually to reach close to \$20 per GJ by the end of the forecast period. Please also refer to the responses to BCUC IR1 2.1 and 2.2.

2.4 Please confirm that this is the price for RNG alone, and that it does not include prices for other renewable gases. If not, please discuss.

Response:

Confirmed.

2.5 Please explain where the price of RNG has been used in FBC's portfolio analysis.

Response:

The price of RNG is used as an input into the variable energy costs of dispatching RNG SCGT resource options.

B. LONG-TERM LOAD FORECAST

3.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 3, p. 82

Use of Load Forecast

On page 82 of the Application, FBC states that the Business As Usual (BAU) is the forecast used for annual rate setting which is then extended out for the 20-year planning horizon. The Reference Case load forecast builds on the BAU forecast by including electric vehicle charging load, and new industrial loads with high confidence of materializing. The Reference Case load forecast is the resulting forecast used for planning purposes in this LTERP.

3.1 Please discuss why the BAU forecast is used for annual rate setting, rather than the reference case load forecast.

Response:

The short-term forecast portion of the BAU used for annual rate setting is based only on recent actual data where all the load drivers are “intrinsic” and contained in the data used. On the other hand, the long-term EV charging and industrial load forecasts used to create the Reference Case load forecast are not intrinsic to the historical data and therefore would not be appropriate to include in the rate setting forecast. When FBC next updates its short-term forecast for rate setting, it will have additional actual data available for use that was not available at the time the LTERP Reference Case load forecast was prepared. Thus, the rate setting forecast always reflects the most current data and is the appropriate short term forecasting model to use for that purpose.

4.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Appendix F, pp. 1–2

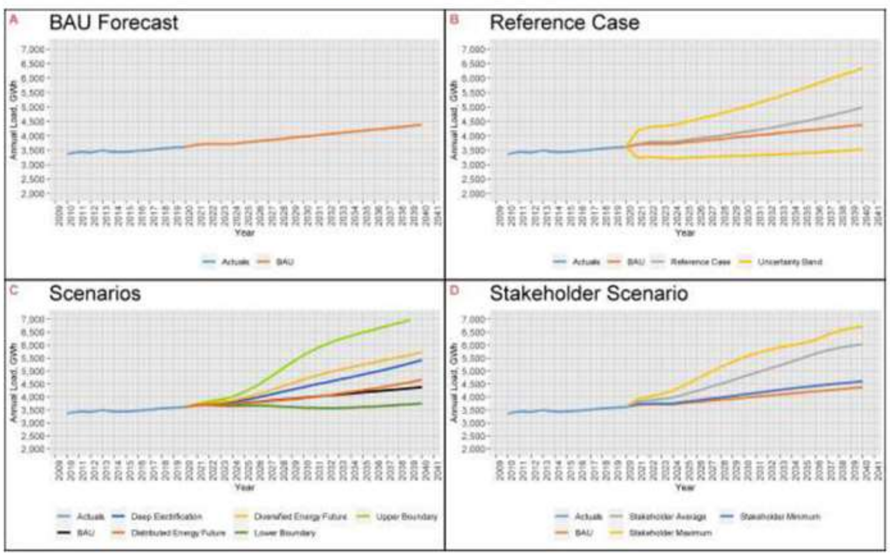
Forecast Levels

The Reference Case forecast is described in Figure F-1: Forecast Levels as follows:

- Starts with BAU
- Adds industrial loads with high confidence, based on discussions with customers
- Adds EV charging loads based on the ZEV Act light-duty sales to the residential load Forecast
- Includes uncertainty band.

Figure F-1 shows the range of different forecasts:

Figure F-1: Forecast Levels



4.1 Please confirm that the forecasts shown above are all before DSM, or explain otherwise.

<u>Response:</u>

Confirmed.

4.1.1 If confirmed, please list any other adjustments, other than for DSM, made subsequently to the above forecasts before using them in the Portfolio Analysis.

Response:

Other than for DSM, FBC made no adjustments to the BAU and Reference Case load forecasts before using them in the Portfolio Analysis.

FEI adjusted the load forecasts used in the load scenarios (graph C in Figure F-1) and the stakeholder scenario (graph D in Figure F-1) for losses before using them in the Portfolio Analysis. The Guidehouse load driver impacts, as provided in Appendix J, are expressed 'at the meter' or point of customer consumption. FBC therefore grossed-up this incremental portion of the load by losses prior to adding the incremental load to the BAU forecast. This was done for the purposes of determining the equivalent generation requirements of the incremental load at the point of interconnection. The BAU and Reference Case load forecasts were already adjusted for losses.

5.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 3.1, p. 82; Appendix F, p. 4

Methodology

On page 82 of the Application, FBC states that the methods used to develop the BAU forecast are consistent with those used to develop the 2016 LTERP.

FBC states on page 4 of Appendix F:

> FBC's Reference Case energy load forecast is composed of individual forecasts for each of the residential, commercial, industrial, wholesale, lighting and irrigation classes as well as system losses. The Reference Case load forecast is presented before any DSM reductions are applied. The residential load forecast also includes electric vehicle charging while the industrial forecast includes highly certain new loads. The method is primarily econometric, while for some rate classes survey data is also employed. Forecasts of service territory population and provincial GDP by sector are primary drivers of customer sales.

5.1 Please confirm, or explain otherwise, that the only new growth being considered in the Reference Case forecast is due to electric vehicle (EV) charging by residential customers, and new industrial load.

Response:

Confirmed.

5.2 Please explain whether any methodological changes have been made to the BAU component of the forecast compared to prior long term resource plans. If applicable, discuss any changes that have been made and the reasons for making those changes.

Response:

The following changes have been made to the BAU forecast for the 2021 LTERP compared to the prior 2016 LTERP.

Residential UPC

The residential UPC method was updated from a three-year average method in the 2016 LTERP, to a ten-year regression model in the 2021 LTERP. FBC tests for trends in the data on an annual basis and found that there is now a usable trend in the historical residential UPC data, and therefore, updated the method. The current model forecasts a UPC decline of 0.24 MWh per year, which FBC considers reasonable in the short-term due to the recent historical declines. The decline may partially be a result of LED lighting adoption as suggested by the 2017 FBC Residential End Use Survey (REUS), where residential lighting declined from 2.2 MWh in 2012 to 1.1 MWh in 2017.

With government policies trending towards increased electrification in the medium to long term, FBC does not believe the current downward trend is sustainable. Therefore, the UPC was held constant after the fifth year of the forecast (2024) at 9.44 MWh. If the UPC was not held constant it would drop to 5.43 MWh by 2041, which would be less than half of the 2020 UPC of 10.89 MWh.

Irrigation Load

The irrigation class was forecast in the 2016 LTERP using a five-year average. Irrigation load has declined in the past five years (2015-2019), decreasing from 46 GWh in 2015 to 36 GWh in 2019. FBC is unable to pinpoint what specific attributes cause historical decreases or increases in the irrigation load in a quantifiable way since it is influenced by many factors, including weather, precipitation, and technology, among others. FBC considered using an average; however, since there has been a decline in the recent past historical data, an average could have resulted in an over-forecast. Therefore, FBC used a one-year forecast in the 2021 LTERP and held it constant for the planning period at 36 GWh. Irrigation load accounts for 1.0 percent of the 2020 normalized gross load.

Lighting Load

The lighting load forecast in the 2016 LTERP was based on a five-year trend that was then held constant at 16 GWh for the planning horizon. In 2018 and 2019, FBC noticed a steep decline in the lighting load, at an average rate of 2 GWh per year. FBC considers the decline to be due to the implementation of LED streetlights. FBC expects the lighting load declines to moderate once the LED exchange programs wrap up and, consequently, FBC held the 2019 load of 11 GWh constant for the planning horizon. Lighting load accounts for 0.3 percent of the 2020 normalized gross load.

6.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Appendix F, pp. 5–7, 20

Residential Methodology

On page 5 of Appendix F, FBC states:

> The residential BAU load growth is driven by the increase in customer count, which itself is determined econometrically as a function of population in the FBC service area. The customer forecast is then combined with the use per customer (UPC) forecast to determine the residential BAU load forecast. The residential Reference Case forecast is calculated by adding the electric vehicle charging load to the BAU forecast.

On page 6 states of Appendix F, FBC states:

> Normalized historical UPCs are obtained by dividing the weather-normalized residential load by the average customer count in each year. The before-DSM UPC is forecast by applying a ten-year trend to the normalized historical UPCs. The before-DSM UPC forecast is then multiplied by the forecast average customer count to derive the before-DSM load forecast.

6.1 Please discuss if there have been any changes to the UPC for residential customers since the previous forecast, and if so, please describe them and the reasons for those changes.

<u>Response:</u>

The residential UPC was 11.41 MWh in 2015 (the final year of actual data used to develop the 2016 LTERP forecast), and 10.43 MWh in 2019 (the final year used to develop the 2021 LTERP forecast). The decline may partially be a result of LED lighting adoption, as suggested by the 2017 FBC Residential End Use Survey (REUS), where the residential lighting UPC declined from 2.2 MWh in 2012 to 1.1 MWh in 2017.

Page 7 of Appendix F states that the before-DSM UPC is forecast to decline from 10.15 MWh in 2021 1 to 9.44 MWh in 2024. With trends towards more electrification of end uses, a continuation of the current downward trend in UPC is not realistic. If the downward trend in UPC were to continue, the before savings UPC by 2041 would be approximately half of the current value, which would be further reduced by DSM. As a result, FBC has held the UPC constant for the remainder of the planning horizon.

6.2 Please explain the basis for the forecast decline in UPC from 2021 to 2024.

6.2.1 If not addressed in response to IR 6.2, please explain the role household size, impacts of changing climate, and electrification may play in residential UPC over the forecast period.

Response:

The forecast change in UPC from 2021 to 2024 could be driven by a combination of numerous factors, which may include household size and energy use, the impacts of climate change and electrification. Some of these factors may contribute to a declining UPC in the near term while others may increase the UPC over the longer term.

Household size may impact the residential UPC over the forecast period. For example, if more multi-family dwellings are built rather than large homes, the UPC would decline over the forecast period since less energy is typically used in multi-family dwellings. Energy usage in terms of household size also varies due to differences in levels of insulation, building codes in effect at the time of construction, and the energy source for heating/cooling. For example, two houses of the same size with different levels of insulation will have different UPCs.

The residential UPC may be impacted by climate change over the forecast period; however, at this time, FBC is unable to speculate on the magnitude of those impacts. If climate change results in increasing winter and summer temperatures, there could be no net effect on residential UPC since less energy would be used for heating in the winter and more energy would be used for cooling in the summer.

Electrification would increase the residential UPC over the forecast period since homes would be using more electricity. Examples include customers using electricity rather than natural gas to heat their homes or an increase in EV growth and home charging. At this time, FBC is not expecting a significant change in household heating appliances and has included EV charging loads in the Reference Case load forecast.

6.3 Please confirm, or explain otherwise, that the current forecast assumes no change in UPC between 2024 and 2040. If confirmed, please provide the basis for the assumption.

Response:

Confirmed. Please also refer to the response to BCUC IR1 5.2.

7.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 2.3.2, p. 37; Section 3.6, p. 91; Section 12.3, p. 203; Appendix F,

p. 8; Appendix N, p. 8

EV Assumptions

Figure F-7 on page 8 of Appendix F shows the projected increase in residential EV charging load, which is forecast to be 9.8 GWh in 2021, growing to 500 GWh in 2040.

On page 91 of the Application, FBC states that the EV charging load portion of the Reference Case load forecast line is based on the ZEV Act sales targets with 100 percent of new light-duty vehicle sales in 2040 being EVs. For the high case, FBC assumed that 100 percent of vehicles sales would be EVs by 2035 instead of 2040. For the low case, FBC assumed that by 2040 only 50 percent of new light-duty vehicle sales were EVs.

Page 8 of Survey findings in Appendix N regarding EVs found that a substantial percentage of residential customers (43%) - and commercial customers (37%) that own or lease vehicles for their business indicate that they are either definitely or somewhat likely to own or lease an EV in the next three years.

On page 203 of the Application, FBC states that it has used the survey results regarding preferences for managing EV charging to help inform its recommended approach.

On page 37 of the Application, FBC states that EV sales, though accelerating, are still at the beginning of the adoption curve. Additionally, EV uptake in the FBC service area lags behind the province as a whole.

7.1 Please confirm that the sales target has been applied only to residential vehicles, and not commercial vehicles. If yes, please explain why. If not confirmed, please discuss how commercial light duty EVs are factored into the reference case.

Response:

The EV sales targets in the *ZEV Act* are based on light-duty EV sales and are not distinguished by residential or commercial vehicles. Therefore, FBC has based its EV uptake impacts in the Reference Case load forecast on the *ZEV Act* targets for light-duty EV sales, which includes both residential and commercial vehicles.

For simplicity, all light-duty EVs were included in the residential class of the Reference Case load forecast (i.e., FBC did not specifically allocate some light-duty EV charging to the residential class and some to the commercial class). On aggregate, the Reference Case still aligns with the *ZEV Act* since its sales targets do not distinguish between residential and commercial sales.

7.2 Please provide the source of information for the number of cars being sold in each year over the forecast.

Response:

Annual car sales estimates over the forecast period were determined by Guidehouse based on data obtained from Statistics Canada and Natural Resources Canada regarding vehicle turnover and growth and the *ZEV Act* for annual sales targets.

Citations and additional relevant details may be found in Section 3.2.3 of Appendix H – Load Scenarios Assessment Report.

7.3 Given the statement that EV uptake in the FBC service area lags behind the province, please explain the basis for the high scenario, which assumes faster implementation than the BC target.

Response:

For clarity, FBC notes that its forecast of EV adoption begins with the current level of EV adoption in the FBC service territory, which lags behind the provincial level. Although different growth factors are applied to this lower starting point, FBC considers they would also likely apply to the entire province. As a result, the high scenario is a scenario where BC EV adoption exceeds current provincial projections.

EV adoption is expected to continue to increase over time and, as discussed in Section 2.3.2, the *ZEV Act* targets are appropriate EV sales levels for FBC to determine the EV charging for the Reference Case load forecast. However, it is possible that EV sales will grow faster than this level and so FBC has assumed 100 percent of vehicle sales being EVs by 2035 for the upper uncertainty band of the Reference Case load forecast. This aligns with the recent announcement by the federal government that it is making 100 per cent ZEV sales mandatory by 2035 to meet Canada's national net-zero targets, as discussed in Section 2.2.2. FBC also notes the recent announcement of the CleanBC Roadmap to 2030 plan that sets a goal of 100 percent ZEV sales in BC by 2035.

8.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 3.4, pp. 86, 89–90; Appendix F, pp. 9–10, 12–14, 16, 22

Forecast Methodology

On page 9 of Appendix F, FBC states that the energy use in the commercial class is well correlated to the provincial real GDP and is forecast on that basis. The Reference Case forecast does not include any additional commercial loads compared to the BAU, so the commercial BAU and reference case forecasts are identical.

The Commercial load is forecast to grow at an average annual rate of 1.3 percent per year over the next 20 years. Growth will be stronger on average in the near term and then will begin to slow due to reduced economic growth.

There is some evidence[1] to suggest that the energy intensity of economies is increasing, and the relationship between GDP growth and the growth in energy consumption has experienced a relative, if not absolute decoupling, resulting in energy demand growing slower than GDP.

8.1 Please confirm, or explain otherwise, that the commercial growth is solely due to provincial GDP growth forecast.

Response:

Confirmed.

8.2 Please clarify what assumptions FBC is making with respect to the relationship between economic growth and energy use for the commercial and other sectors.

Response:

The relationship between economic growth, as measured and forecast by GDP, and commercial load in the FBC service territory remains very strong. The correlation coefficient and R^2 is 99 percent, meaning that 99 percent of any changes in commercial load can be explained by changes in GDP.

As a result, FBC has not made any further assumptions. Given the statistical correlation explained above, the relationship is well defined and appropriate to use for forecasting.

[1] https://www.cesarnet.ca/blog/elephant-room-energy-intensity-canadian-economy; https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/the-decoupling-of-gdp-and-energy-growth-a-ceo-guide; https://iopscience.iop.org/article/10.1088/1748-9326/ab8429

The evidence cited in the preamble from the referenced articles is not specific to the FBC service territory, and includes consideration of other jurisdictions such as China and India. In other economies it could be that GDP is decoupled from energy consumption, but that decoupling is not evident in FBC's service territory.

Pages 9 and 10 of Appendix F describes the wholesale market, of which the three biggest customers are the City of Penticton, Summerland and Nelson Hydro in decreasing order. The forecast for both the BAU and Reference Case is the same for the wholesale class.

Consistent with past practice, the wholesale class is forecast using survey information from each of the individual wholesale customers. FBC believes that individual wholesalers are best able to forecast their future load growth based on their knowledge of their customer mix, load behaviors and development projects with associated energy requirements. FBC's survey requested five years of data from wholesale customers. After that time period, an average of each individual customer's forecasted growth rate is used to project the long-term forecast. All of the wholesale customers responded to the surveys with their forecast growth projections. The wholesale load is forecast to grow at an average annual growth rate of 1.4 percent per year over the next 20 years.

8.3 Please explain whether 5 years of data refers to 5 years historic data, 5 years of forecast data or other.

<u>Response:</u>

FBC requests five years of forecast data from each of its individual wholesale customers.

8.4 Please discuss how FBC provided for changing usage patterns for wholesale customers, such as EV uptake, longer cooling season, or other factors.

<u>Response:</u>

FBC did not provide for changing usage patterns for wholesale customers. Consistent with past practice, the wholesale class is forecast solely using survey information from each of the individual wholesale customers, as the individual wholesale customers are best able to forecast future load growth within their service territory boundaries.

8.4.1 Please explain if FBC makes any adjustment to wholesale forecasts, to account for differing methodologies or assumptions. If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 8.4.

8.5 Please provide a copy of the survey sent to the wholesale customers.

Response:

Please refer to Attachment 8.5 for a copy of the wholesale survey template.

On page 90 of the Application, FBC states that the BAU industrial forecast includes new projects with near one hundred percent certainty of completion, and in the current forecast includes primarily cannabis production facilities.

On page 12 of Appendix F, FBC states:

> Industrial loads are forecast based on survey results provided by individual customers and, where customer information is not available, by forecast GDP growth rates in each industrial sector. In the long term, composite GDP growth rates of industrial sectors are used to escalate the entire industrial load. FBC sends all industrial customers a load survey that requests the customer's anticipated use for the next five years. A survey method is utilized because FBC believes that individual industrial customers have the best understanding of what their future energy usage will be. FBC received a response from 80 percent of the industrial customers. The responding customers represent approximately 92 percent of the total industrial energy load.

8.6 For industrial loads, please describe the methodology that FBC uses to moderate the risk of customers over-estimating future demand.

Response:

Consistent with past practice, the industrial class is forecast using survey information from each of the individual industrial customers, as the industrial customers are best able to forecast their own future load growth. FBC does review each survey and contacts individual customers if there are any anomalies in the survey responses. Other than correcting obvious typographical errors, FBC does not adjust the survey responses provided. Over the past five years (2016 to 2020) there has been an average variance of 1.6 percent between forecast and actuals for the industrial class, indicating that the individual customers are, on an aggregate basis, proficient at forecasting their future demand.

8.7 Please explain how many new cannabis production facilities are included in the BAU forecast.

Response:

Six new cannabis production facilities were included in the BAU industrial load forecast.

8.8 Please explain why some new projects are included in the BAU forecast, and some in the Reference case.

Response:

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

On page 89 of the Application, FBC states that for the Reference case, new highly certain industrial customer loads, determined by FBC key account managers, include loads from a wastewater treatment facility, a renewable energy facility and long term increases from a current forestry sector customer.

On page 12 of Appendix F, FBC states that since these customers' loads do have some uncertainty of materializing, FBC only included seventy-five percent of their projected loads to the Reference Case forecast. Most of the highly certain loads begin in 2022.

8.9 Please provide the basis for including 75 percent of their projected loads.

Response:

The projected loads included in the Reference Case load forecast are still in the initial stages of procuring power and there is still some uncertainty associated with these projects. Therefore, to account for the potential that some of these projects may not proceed, FBC included 75 percent of the projected loads.

8.10 Please clarify if the 75 percent is applied to the group as a whole, or to each individual customer.

Response:

The 75 percent factor is applied to the projected loads of each individual customer, although the same result would have been achieved by applying the 75 percent factor to the group.

On page 22 of Appendix F, FBC states that the uncertainty bands for the industrial load assume 50 percent probability for the low band and 100 percent probability for the high band.

8.11 Please confirm that the additional industrial load is due solely to the three new customers.

Response:

The additional industrial load in the Reference Case load forecast when compared to the BAU is due solely to four new projects. In the course of responding to this IR, FBC identified an error on page 12, lines 18 and 19, of Appendix F – there are four new projects, rather than three new customers. Two of the projects relate to new customers and the other two projects relate to existing customers.

This error has no impact on the load forecast values as all four projects were accounted for in the forecast.

8.11.1 If confirmed, please clarify if the three customers are similar in future load demand

8.11.2 If not confirmed, please provide the range of projected load.

Response:

The four projects described in the response to BCUC IR1 8.11 are not similar in future loads. The range of the projected loads is between approximately 3 GWh and 29 GWh over the planning horizon.

On page 13 of Appendix F, FBC states that due to the variability in the energy load in the recent historic data, FBC has chosen to use the 2019 energy load as the forecast for the irrigation sector. The forecast remains constant over the planning horizon at 36 GWh. The irrigation energy load represents approximately 0.9 percent of the overall gross energy load over the planning horizon.

8.12 Please discuss if FBC expects irrigation energy use to be affected by changing climatic conditions over the planning period.

Response:

At this time, FBC does not have sufficient information to determine whether expected irrigation energy use will be affected by changing climate conditions over the planning period. FBC has considered normalizing the irrigation class load with precipitation and temperature data on an annual basis but at this time has not found a strong correlation between either. FBC will continue to monitor the irrigation class for load changes in the future.

8.13 Please explain if FBC offers DSM measures for irrigation customers.

Response:

Yes, FBC irrigation customers are eligible for FBC performance and prescriptive programs. Irrigation-specific prescriptive measures can be found at:

https://www.fortisbc.com/rebates/business/irrigation-equipment.

On page 14 of Appendix F, FBC states:

> Due to the implementation of light-emitting diode (LED) street lights, the lighting energy load has been declining in recent years. As the LED programs wrap up, FBC expects the energy load trends to level off. As a result, FBC has assumed the lighting energy load is forecast to remain at the 2019 energy loads of 11 GWh for the remainder of the planning horizon.

8.14 Please explain whether all of FBC direct lighting customers have completed the implementation of LED street lights.

<u>Response:</u>

FBC does not know if all of the direct customers in the lighting class have completed the implementation of LED street lights. FBC notes that in 2020 the lighting customer class load decreased by 0.2 GWh while in 2019 and 2018 the reduction was over 2 GWh in both years. This could be an indication that the implementation of LED lighting projects may be nearing completion.

8.15 Please explain whether FBC's wholesale customers have completed the implementation of LED street lights.

<u>Response:</u>

FBC has confirmed with the City of Penticton and the District of Summerland that they both have completed the implementation of LED street light programs. The City of Nelson has replaced approximately 20 percent of their existing street light stock, while the City of Grand Forks has replaced approximately 50 percent. BC Hydro Kingsgate and Lardeau wholesale customers expect to complete their implementation of LED street lights by June 2023, according to the BC Hydro website.[2]

On page 86 of the Application, FBC states that losses are 7.6% of gross energy load, plus company use of 13 GWh a year.

On page 16 of Appendix F, FBC states that the Reference Case total annual losses are forecast to grow at an average annual rate of 1.5 percent per year over the next 20 years, while the BAU forecast losses grow at average rate of 0.9 percent per year.

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[2] https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/accounts-billing/electrical-connections/street-light-project-info-session.pdf

8.16 Please provide the assumptions underlying both the increase in losses, and the differential growth rate between the BAU and reference case forecasts.

Response:

Losses increase over the planning horizon because the gross load increases. Losses are forecast as 7.6 percent of the gross load plus 13 GWh for company use. The BAU gross load increases over the planning horizon due to annual increases in the residential, commercial, wholesale, and industrial loads. The differential in growth rates between the BAU and Reference Case load forecasts is due to EV charging and new industrial projects being added to the Reference Case load forecast. These loads further increase residential and industrial loads, which in turn increases losses, since the gross load has increased.

9.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 3.4.2, pp. 87–88, 94, 217; Appendix F, p. 17

Peak Demand Forecast

On page 87 of the Application, FBC states that the BAU winter peak demand forecast increases from 749 MW in 2021 to 890 MW in 2040, increasing at an average annual growth rate of 0.9 percent, while the Reference Case winter peak is forecast to increase from 766 MW in 2020 to 1,060 MW in 2040, at an average annual growth rate of 1.7 percent.

On page 88 of the Application, FBC 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.

On page 17 of Appendix F, FBC states that the peak demand forecast is calculated by escalating the ten year average (2010-2019) of historic peak data by the gross energy load growth rate. Monthly peaks were calculated and then escalated by the annual energy load growth rates for the forecast period to produce forecast monthly peaks. The winter and summer peaks for the Reference Case forecast grow at an average annual rate of 1.7 percent and 1.9 percent, respectively, over the next 20 years. Both the winter and summer peaks for the BAU forecast grow at an average annual rate of 0.9 percent over the planning horizon.

9.1 Please confirm, or explain otherwise, that the growth rate for the peak BAU forecast of 0.9 percent was based on the gross BAU load growth rate.

Response:

Confirmed.

9.2 In table form, please provide the following information:

- The actual summer and winter peaks over the past 10 years, in MW.
- The actual summer and winter peaks over the 10 years, weather adjusted.
- The estimated annual growth rate of the winter and summer peak over the past 10 years, weather adjusted

Response:

The table below shows both the actual and weather adjusted (normalized) winter and summer peaks and the peak growth rate. Note that the 2020 normalized winter peak of 667 MW (December 2020 normalized peak) reflected in Appendix G, Section 2.10 has been updated to 731 MW (February 2021 normalized peak). The actual winter peak in 2020 has also been updated, from 621 MW to 725 MW. The winter peak occurs between each November and February period and the 2020 winter peak in the Application only reflected values to the end of calendar year 2020. Please note that this does not change the peak forecast presented in the LTERP since only historical data to 2019 was included in the forecast.

Actual and Normalized Peaks from 2011 to 2020

	Actual Peak (MW)		Normalized Peak (MW)		Normalized Growth Rate	
Year	Winter	Summer	Winter	Summer	Winter	Summer
2011	737	519	702	537	-3.3%	-5.2%
2012	623	540	723	589	2.9%	9.8%
2013	699	579	698	600	-3.4%	1.9%
2014	649	596	693	620	-0.8%	3.2%
2015	625	597	685	611	-1.1%	-1.4%
2016	730	590	755	593	10.2%	-2.9%
2017	663	593	714	605	-5.4%	2.0%
2018	691	624	682	631	-4.4%	4.3%
2019	732	623	732	639	7.4%	1.4%
2020	725	648	731	666	-0.2%	4.2%

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

On page 94 of the Application, FBC states that FBC experienced an extended heat event and set a summer peak record of 764 MW on June 29, 2021. This peak demand exceeded the upper confidence band for summer. FBC notes that the Summer Peak BAU prediction interval is based on a 90 percent confidence level and extreme events such as the June 2021 one are expected to exceed the confidence bands.

On page 217 of the Application, FBC states that it expects to submit the next LTERP in 2026, and that if periodic assessment of the LRB indicates the need for new resources sooner than contemplated in this LTERP, FBC would likely submit a LTERP or supplemental update filing sooner.

9.3 Please confirm that FBC expects to submit its next LTERP in 2026.

Response:

As discussed in Section 13.2, FBC expects that it would submit its next LTERP in approximately five years from the submission date of this LTERP (i.e. in 2026). This would provide FBC with enough lead-time to assess the load drivers and load forecast, update the LRB, assess transmission and distribution requirements and DSM and available supply-side resource options and costs before any new resources may be required after 2030. However, if FBC's periodic assessment of the LRB indicates the need for new resources sooner than contemplated in this LTERP or if FBC's access to market energy changes such that it is no longer reliable or cost effective, FBC would likely submit an LTERP or supplemental update filing sooner than five years from the submission of this LTERP in order to meet the LTERP objectives in the interests of its customers.

9.3.1 Please clarify how frequently FBC undertakes periodic assessments of the Load-Resource Balance (LRB).

Response:

FBC expects that it would undertake assessments of the LRB on an annual basis in order to identify any changes in the LRB gaps and potential requirement for new resources.

9.4 Please explain why a 90 percent confidence level is suitable for both annual and peak forecasts.

Response:

For both the annual energy and peak demand forecasts, the prediction interval was calculated based on ten years of actual data. When the sample size is small, it is appropriate to use a lower confidence level, such as 90 percent. Other than using a lower confidence level with small sample sizes, there is no generally accepted method related to the selection of the confidence level.

10.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 3-2, pp. 83–84; Appendix F, p. 18

Load Forecast Uncertainty

On page 18 of Appendix F, FBC states that in order to account for future variability in the Reference Case load forecast, FBC developed uncertainty bands around the reference case forecast composed of three elements:

1. Prediction intervals computed for the BAU forecast at the 90% confidence level;
2. An upper and lower EV forecast, and
3. An upper and lower highly certain industrial energy loads forecast.

10.1 Please explain the basis for selecting a 90% confidence level.

<u>Response:</u>

Please refer to the response to BCUC IR1 9.4.

In Section 3-2 of the Application, FBC discusses the impact of the COVID-19 pandemic, by comparing the 2020 BAU forecast with actual customer loads. FBC states on pages 83-84 that the aggregate actual gross load was approximately 27 GWh, or 0.75 percent, higher than forecast. FBC notes that the average <u>absolute percent error in the six prior annual forecasts was slightly higher at 1.6 percent</u>. FBC concluded that the 2020 long-term forecast, prepared using the 2019 actual data, is appropriate to use for this LTERP. [Emphasis added]

10.2 Given the average absolute percent error in the previous six annual forecasts was 1.6%, and the COVID-19 pandemic was 0.75 percent off BAU, please explain why a 90 percent confidence level is useful for an annual energy demand forecast.

<u>Response:</u>

While the confidence level and forecast variance (absolute percent error) are both expressed as percentages, they measure two different things and therefore are not directly comparable.

A 90 percent confidence level implies that FBC is 90 percent certain that a future forecast value will be greater than the lower prediction interval and less than the upper prediction interval. The confidence level is not used to estimate the forecast variance in any future year.

Historical variances are not used to choose the confidence level for the purposes of prediction interval calculations. The variance simply measures the forecast values versus those actually recorded while the confidence level is used to determine the critical t value, which is then used in the prediction interval formula as a multiplier.

10.3 Please provide an example of years where demand on an annual basis has deviated from forecast by the amount indicated by the uncertainty bands.

Response:

FBC notes that the use of a 90 percent confidence level implies that, on average, the prediction interval may be exceeded approximately once every ten years. While comparing prediction intervals calculated for future forecast years to historical variances is not technically correct, FBC notes that, for example, the residential load forecast prediction interval for 2020 of 83.4 GWh was exceeded in 2015 when the residential load variance was 99 GWh.

11.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Section 2.3.4, p. 45 Appendix N, p. 8; Appendix H, p. 9

Impact of Distributed Generation

According to the survey results quoted on page 9 of Appendix N, one-third of residential customers (34%) and just under half of commercial customers (49%) indicate that they are likely to install rooftop solar panels in the next five years.

On page 45 of the Application, FBC states o that as of mid-June 2021, about 660 customers are enrolled in the Net Metering Program, with the majority generating power using small-scale residential solar photovoltaic installations. The net metering program is available to residential, smaller commercial, and irrigation customers.

Page 9 of Appendix H, FBC states:

> Under FortisBC's current net metering tariff, there is no economic incentive (in fact, due to efficiency losses, a disincentive) to install a storage unit. Customers currently get a storage account from FortisBC and can use this to "store" (as a credit) the additional output from their solar units, then consume from this account once their solar output falls below their use. This is similar to the storage use-case presented above, but without requiring participants acquire any additional equipment or subject them to any efficiency loss during charging.

11.1 Please explain whether FBC collects data on the proportion of net metering customer with storage, and if so, please provide this information.

<u>Response:</u>

FBC does not collect data on the proportion of net metering customers with storage. However, through interactions with customers, FBC does not believe that the installation of storage is common for the reasons outlined in the cited portion of the Application.

11.2 Please provide any information FBC has collected on the impact of distributed generation on load and load factor for residential, commercial and irrigation customers.

<u>Response:</u>

FBC assumes that by "impact", the question relates to what the load and load factor would be in the absence of the customer-owned generation. FBC compiles information on the aggregate capacity of distributed generation connected to its system, but does not collect information on the impact on either load or load factor for customers, or for the FBC system. At the end of Q3 2021, FBC had 6.7 MW of generation installed under the Net Metering program, spread across 743 customer sites, of which 735 were solar based.

In its next Cost of Service Analysis application, which is expected in the 2024-2025 timeframe, FBC intends to segregate and separately examine net metering customers and will be able to discern any differences in load and load factor as compared to customers without distributed generation.

11.3 Please explain the impact on peak loads from customers who have installed rooftop solar, with and without storage.

Response:

Please refer to the response to BCUC IR1 11.2.

11.4 Please discuss if FBC anticipates expanding the net metering program to address demand from medium and large commercial customers.

Response:

The Net Metering program is already currently available to Small Commercial customers (those served under RS 20) and Commercial Customers (those served under RS 21, 22 A, 23 A). FBC considers customers served under RS 21, 22 A, and 23 A, which apply to customers with loads between 45 and 500 kVA, to be "medium"-sized, although FBC notes that the nameplate rating of the generation may not exceed 50 kW to be eligible for the Net Metering program. Customers served under the Large Commercial rate schedules (RS 30 and RS 31) have loads in excess of 500 kVA and 5,000 kVA, respectively, and are not eligible for the Net Metering program. Large Commercial customers have the ability to interconnect self-generation with the FBC system, and to sell generation output that is in excess of load to FBC under financial terms similar to the Net Metering program; however, due to the size and complexity of larger interconnections, the relatively simplistic interconnection standards of the Net Metering program are not appropriate. Large Commercial customers that wish to interconnect self-generation are dealt with on an individual basis. For this reason, FBC does not anticipate that it will extend the Net Metering program to Large Commercial customers.

C. LOAD SCENARIOS

12.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4, p. 96; Section 11, pp. 175, 184

Use of FortisBC Pathways for FBC

On page 96 of the Application, FBC states that Guidehouse was appointed by FBC to identify emerging trends and technologies not reflected in the reference case load forecast and to examine their potential uptake or penetration levels. Guidehouse developed several alternative scenarios based upon these potential load drivers, which may increase or decrease FBC's load requirements relative to the BAU forecast in the future. As there is significant uncertainty in how these scenarios will actually play out in the future, FBC has not assigned any probabilities to them. The scenarios provide examples of what the impacts on FBC's future load requirements might be if specific load drivers occurred at specific growth or penetration levels. They are not alternate load forecasts, but are rather possible future pathways for electricity use.

These Guidehouse and stakeholder load scenarios will help inform FBC's potential future resource requirements and how FBC might adapt its resource portfolio if they were to occur. FBC's portfolio analysis, discussed in Section 11, includes alternative resource portfolios to meet the Reference Case load forecast as well as the alternative load scenarios discussed in this section. This may include, for example, more generation resources to meet higher than Reference Case loads or ensuring flexibility in FBC's resource portfolio to handle decreasing load requirements.

Table 11-1 on page 175 of the Application outlines the Portfolio Analysis Base Characteristics and Sensitivity Cases across 6 different "portfolios."

Section 11.3.4 in the Application shows the modelled effects of the load scenarios provided by Guidehouse and the stakeholder average scenario, (scenarios D2 through D5) compared to the base Reference Case.

12.1 Please confirm, or explain otherwise, that the load scenarios were used primarily to inform the sensitivity cases for the Load Requirements portfolio.

Response:

Confirmed. The load scenarios were used primarily to inform the sensitivity cases for portfolios with varying load requirements as shown in Table 11-1.

12.2 Please explain if the load scenarios were applied in any other portfolios or aspects of the LTERP.

Response:

As discussed in Section 6.5.4, the load scenarios were also used to explore the potential peak demand impacts on FBC's system, in terms of potential infrastructure projects required to meet the additional load and their associated costs.

13.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4.1, p. 98

Guidehouse Load Drivers and Scenarios

On page 98 of the Application, FBC states that the purpose of Guidehouse's Load Scenario Assessment Report was to provide an indication of the magnitude of the impact on FBC's peak demand and annual energy if a given set of circumstances were to arise. It is important to note that the scenarios were developed without determining and measuring the impacts of all of the potential drivers. For example, the impact of a substantial increase in the penetration level of rooftop solar in FBC's territory is quantified; however, determining what might drive increased uptake in rooftop solar, such as the cost of solar panels, related equipment and installation, was beyond the scope of the work.

13.1 Please discuss if FBC intends to replace the current uncertainty bands with the results of the load scenario assessment in future.

<u>Response:</u>

FBC does not intend to replace the current uncertainty bands with the results of the load scenario assessment in future because they serve different purposes. The uncertainty bands were developed in order to account for future variability in load drivers inherent in the Reference Case load forecast, while the load scenarios were developed to identify the impacts of more significant growth in some of the existing load drivers as well as emerging trends and technologies not reflected in the Reference Case load forecast.

13.2 Given that drivers affecting uptake, such as cost, were not taken into account, please discuss how FBC proposes to assess the likelihood of any particular level of penetration, including the presence of asymmetrical probabilities.

<u>Response:</u>

FBC does not propose to assess the likelihood of any particular level of penetration, including the presence of asymmetrical probabilities. As discussed in Section 4.1, the future impact of the load drivers included in these scenarios is, at present, so uncertain that no objective probabilities can be assigned to the scenarios. The scenarios can, however, be refined over time and in future resource plans as better information becomes available.

14.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4.1, pp. 98–100; Canada Energy Regulator, 2017 Report;

The BC Clean Energy Act, objective 2(h)

Load Drivers

On page 98 of the Application, FBC states, "The future impact of the load drivers included in these scenarios is, at present, so uncertain that no objective probabilities can be assigned to the scenarios. It is for this reason that these load drivers are included in this exercise, as opposed to a more formal empirical forecast." [Emphasis added]

FBC and Guidehouse identified the following 9 load drivers on pages 98 to 99 of the Application:

- Residential PV [photovoltaic] solar and storage
- Commercial PV solar and storage
- EVs, including light, medium and heavy duty
- Fuel switching – gas to electricity
- Fuel switching – electricity to gas (Residential fuel switching from electric to gas-fired space and water heating)
- Climate change – increased average annual temperatures, and in averages for the 10 hottest days, and decreases in average temperatures for the 10 coldest days of the year.
- Large load sector transformation – substantial growth in data centre and cannabis cultivation
- "Green" Hydrogen production for injection into the natural gas distribution system
- Carbon capture and storage, and related electricity consumption.

14.1 Please discuss how FBC or Guidehouse considered the experiences of other jurisdictions to guide the estimation of probabilities regarding the possible uptake of the above load drivers.

Response:

As per Section 1 of Appendix H – Load Scenarios Assessment Report, no probabilities have been assigned to the scenarios modeled. The future development of the load drivers included in these scenarios is sufficiently uncertain that no probabilities have been estimated or assigned to the scenarios or the load drivers.

While Guidehouse does provide consulting services relating to load drivers and scenarios for clients across North America and is able to draw on that expertise, the load driver penetration levels developed for the LTERP were primarily developed based on consideration of studies and information most relevant to the FBC service area and its customers. These included, for example, the 2019 CPR, FBC end use studies, the *ZEV Act* and the Guidehouse Pathways Study provided in Appendix O.

14.2 Please discuss, with rationale, if FBC considers utility scale solar PV to be feasible for its service territory,

14.2.1 If yes, please discuss whether FBC has explored the merits of utility scale solar versus customer owned small scale solar and storage.

Response:

FBC considers utility-scale solar PV to be feasible for its service territory and has included utility-scale solar PV within the resource options discussed in Section 10. As discussed in Section 3.3.3 of Appendix K – Supply-Side Resource Options Report, in some areas of FBC's service territory there is significant potential for solar power generation and the cost for solar power has decreased significantly in recent years. As discussed in Section 11.3.8, FBC's preferred resource portfolio includes solar power generation plants.

FBC has explored the merits of customer-owned small scale solar with storage. As discussed in Section 10.7, distributed generation, such as residential or commercial rooftop solar power, can be accounted for as either a supply-side resource or as a variable that reduces customer demand. Since it is ultimately the customer's decision to acquire distributed generation, for the purposes of this LTERP, FBC has treated distributed generation as a load driver that reduces load rather than as a supply-side resource option. Similar to DSM, the adoption of distributed generation in any one location can be greater than or less than anticipated as a result of many factors influencing customer participation such as demographics and socio-economics, or concentrations of customer segments. Therefore, distributed generation in any one location is not certain, but when combined in aggregate at the system level has an impact on the load forecast.

In contrast, the utility controls the marginal decision to acquire supply-side utility solar resources. The utility is able to include utility solar options in the portfolio optimization with considerations for size, cost, and location. In addition, larger utility owned solar output can be scheduled in accordance with industry standards.

The treatment of customer-owned generation as a load driver recognizes the limited control the utility has over customer investment decisions in contrast to other utility supply-side resource options and is consistent with FBC's approach to distributed generation in the 2016 LTERP. On page 26 of Decision and Order G-117-18 regarding FBC's 2016 LTERP, the Panel stated that it was satisfied that FBC had appropriately factored distributed generation into the LTERP planning environment.

14.3 Please explain why FBC included residential EV in both the Reference scenario, and as part of the EV load driver.

Response:

The EV load driver has been included in both the Reference Case load forecast as well as the load scenarios. Therefore, FBC has interpreted this question to ask why FBC included the EV load driver in both the Reference Case load forecast and the load scenarios. FBC has included the EV load driver in the Reference Case load forecast as well as the load scenarios because the *ZEV Act* has mandated specific amounts of EV sales to occur over the next twenty years within BC. Therefore, at this time, FBC has a reasonable expectation that the specified levels of EV sales will occur.

As discussed in Section 4.1.1, because the load scenarios identify potential impacts of light-duty EV charging per the *ZEV Act* that are already included in the Reference Case load forecast, these light-duty EV charging loads should be considered incremental to the Business As Usual (BAU) forecast but not the Reference case forecast in order to avoid any overlap.

14.3.1 Please explain how FBC accounts for any overlap between the residential EV included in the reference case and the EV load driver.

Response:

Please refer to the response to BCUC IR1 14.3.

15.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4.1, pp. 98–99; p. 100; Appendix H, p. 33; Appendix I, Slide 33,

pp. 44, 48

Scenario Descriptions

On page 99 of the Application, FBC states that the assumed uptake, or penetration, of each load driver will vary from scenario to scenario, from zero in some scenarios to a very aggressive level in others.

15.1 Please elaborate on how FBC and Guidehouse determined the assumptions underlying the assumed uptake of each load driver.

Response:

The assumed penetration/uptake rates for each load driver in each scenario were selected by Guidehouse in close collaboration with FBC staff over a period of several months and were based on a number of different factors. The assumed penetration values for the Upper and Lower Bound scenarios were based on a "reasonable extreme" value assumptions. For the other scenarios, the penetration levels were based on other supporting information such as, for example, the *ZEV Act* sales targets for EV growth and charging loads, the Conservation Potential Review for gas-to-electricity fuel switching, and alignment with the Guidehouse Pathways Study analysis for carbon capture and storage. The details of the penetration assumptions for each load driver are provided in Sections 3.2.1 to 3.2.9 of Appendix H – Load Scenarios Assessment Report.

15.2 Pleas discuss what steps FBC took to reduce the level of subjectivity regarding the assumed uptake in the five scenarios.

Response:

Please refer to the response to BCUC IR1 15.1.

On page 100 of the Application FBC states:

Although an infinite number of potential combinations of load drivers into scenarios is possible, the five scenarios selected for this analysis were chosen based on two guiding principles:

1. The analysis should include “boundary” scenarios….
2. The analysis should include scenarios consistent with the FortisBC Pathways analysis provided by Guidehouse….

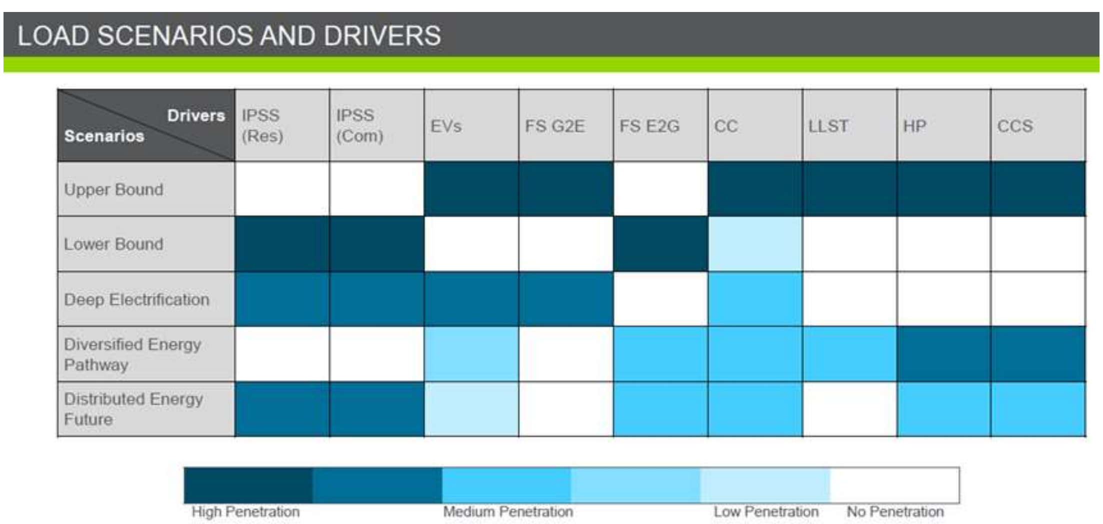
15.3 Please explain whether the Deep Electrification and Diversified energy pathway scenarios are identical to, or informed by, the FortisBC Pathways analysis.

Response:

The following response was provided by Guidehouse.

The Deep Electrification and Diversified Energy Pathway scenarios developed for the LTERP are informed by the Guidehouse Pathways Study analysis provided in Appendix O. The scenarios for the LTERP were designed to be consistent with those of the Guidehouse Pathways study, subject to differences in the applicable geography and the final required granularity of outputs. The Guidehouse Pathways Study scenarios were developed on a province-wide basis and some assumptions were developed to scale within the LTERP Deep Electrification and Diversified Energy Pathway.

The following table in Appendix I (slide 33) shows the overall scenario definition, based on the load drivers.



A similar diagram is presented on page vi of Appendix H:

Figure ES - 2: Qualitative Summary of Load Driver Penetrations by Scenario

Page 44 of Appendix I shows the key assumptions underlying the Deep Electrification scenario. For example, under the HP [Hydrogen Production] driver, it states: Assumes an annual production of 0.7 PJ of hydrogen by 2040.

Page 48 of Appendix I shows the key assumptions for the Diversified Energy Pathway scenario. For the HP driver, it states: Assumes an annual production of 1.8 PJ of hydrogen by 2040.

The load scenario and driver matrix above shows HP as having “no penetration” under the Appendix I version of the Deep electrification scenario.

15.4 Given the differences in Scenarios 3, 4 and 5 between these two graphics, please confirm which of the above graphics defines the main scenarios used by FBC in the LTERP.

Response:

FBC confirms that Figure ES – 2 on page vi of Appendix H – Load Scenarios Assessment Report is the correct version of the Load Driver Penetrations by Scenario matrix.

As noted in footnote 134 on page 97 of the LTERP, some of the figures in the Load Scenarios Presentation dated June 25, 2020 in Appendix I were preliminary (and in this case contained an error), and were updated in the Load Scenario Report dated November 22, 2020.

Page 33 of Appendix H states:

The impacts in each scenario are driven by the assumed “penetration” of each driver by the terminal year of the projection (2040) and the driver-specific assumptions detailed in Section 3.2 below. In the case of this study, “penetration” takes on a very specific definition: it refers to the value taken in the terminal year (2040) of the load-motivating parameter of the load driver. Put simply, the terminal year penetration value is the metric (or that delivers, via some transformation) that is multiplied by the unit impact (described in Section 2, above) to deliver the energy and demand impacts in 2040.

15.5 Please provide a summary of the definition of the possible level of penetration for each of the 9 load drivers, which underlies each of the scenarios.

Response:

The following table provides a summary of the penetration levels for each of the load drivers by scenario in the terminal year 2040, based on the information provided in Section 3.2 of Appendix H – Load Scenarios Assessment Report.

	Scenario 1 (Upper Bound)	Scenario 2 (Lower Bound)	Scenario 3 (Deep Electrification)	Scenario 4 (Diversified Energy Pathway)	Scenario 5 (Distributed Energy Future)
Integrated PV Solar and Storage - residential	N/A	33% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.	15% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.	N/A	25% of all single family homes have rooftop PV. 50% of customers with rooftop PV have storage.
Integrated PV Solar and Storage – commercial	N/A	50% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.	25% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.	N/A	33% of all applicable businesses have rooftop PV. 50% of customers with rooftop PV have storage.
Light-duty (LD) EVs	100% of new LD sales are EVs	N/A	100% of new LD sales are EVs	95% of new LD sales are EVs	90% of new LD sales are EVs
Medium/heavy-duty (MHD) EVs	85% of new MHD sales are EVs	N/A	60% of new MHD sales are EVs	20% of new MHD sales are EVs	10% of new MHD sales are EVs

	Scenario 1 (Upper Bound)	Scenario 2 (Lower Bound)	Scenario 3 (Deep Electrification)	Scenario 4 (Diversified Energy Pathway)	Scenario 5 (Distributed Energy Future)
Fuel switching: Gas-to-electric	30% of 2035 CPR technical potential	N/A	15% of 2035 CPR technical potential	N/A	N/A
Fuel switching: Electric-to-gas	N/A	50% of all residential customers that can, switch	N/A	N/A	35% of all residential customers that can, switch
Climate Change	The temperature on the ten average hottest days of the year increases by 2.1 degrees Celsius and the temperature on the ten average coldest days of the year decreases by 6.2 degrees Celsius	The average temperature on all days of the year increases by 2 degrees Celsius	The average temperature on all days of the year increases by 2 degrees Celsius. The temperature on the ten average hottest days of the year increases by 0.7 degrees Celsius, and the temperature on the ten average coldest days of the year decreases by 2.6 degrees Celsius.	The average temperature on all days of the year increases by 2 degrees Celsius. The temperature on the ten average hottest days of the year increases by 0.7 degrees Celsius, and the temperature on the ten average coldest days of the year decreases by 2.6 degrees Celsius.	The average temperature on all days of the year increases by 2 degrees Celsius. The temperature on the ten average hottest days of the year increases by 0.7 degrees Celsius, and the temperature on the ten average coldest days of the year decreases by 2.6 degrees Celsius.
Large Load Sector Transformation – Data centres	An additional 700,000 square feet of data centre floor space	N/A	An additional 150,000 square feet of data centre floor space	An additional 380,000 square feet of data centre floor space	N/A
Large Load Sector Transformation – Cannabis	An additional 3 million square feet of cannabis production floor space	N/A	An additional 250,000 square feet of cannabis production floor space	An additional 370,000 square feet of cannabis production floor space	N/A

	Scenario 1 (Upper Bound)	Scenario 2 (Lower Bound)	Scenario 3 (Deep Electrification)	Scenario 4 (Diversified Energy Pathway)	Scenario 5 (Distributed Energy Future)
Hydrogen Production	3 PJ of hydrogen produced per year	N/A	0.7 PJ of hydrogen produced per year	1.8 PJ of hydrogen produced per year	0.7 PJ of hydrogen produced per year
Carbon Capture and Storage	Delivers GHG emissions reductions of approximately 240 kT per year	N/A	Delivers GHG emissions reductions of approximately 180 kT per year	Delivers GHG emissions reductions of approximately 180 kT per year	Delivers GHG emissions reductions of approximately 180 kT per year

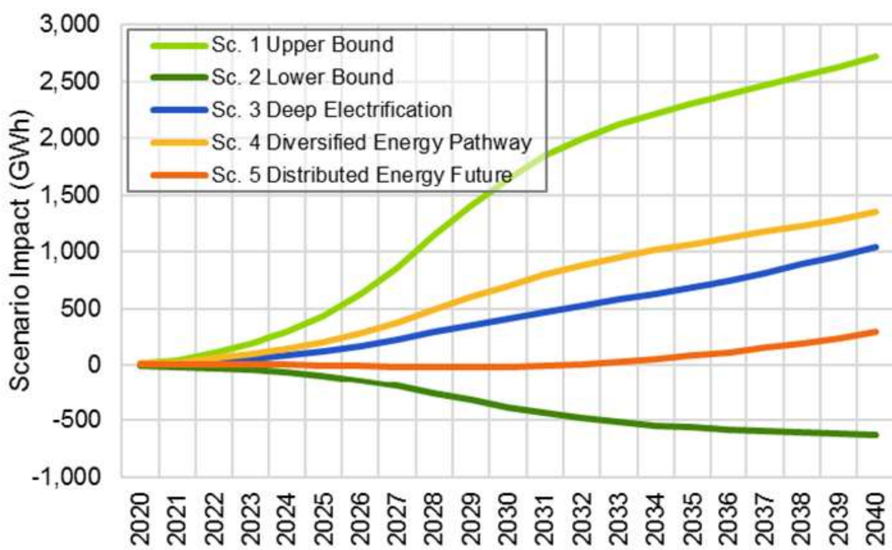
16.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4.1.3, pp. 103–104

Load Scenario Results

Figure 4-1 shows where the overall annual energy consumption impact of each scenario relative to the BAU forecast (at zero on the vertical axis), by year.

Figure 4-1: Annual Energy Impacts by Scenario



16.1 Please explain why the deep electrification pathway has a lower impact on annual energy consumption in GWh than the Diversified Energy Pathway, for all years of the forecast.

<u>Response:</u>

The Deep Electrification pathway has a lower impact on annual energy consumption in GWh (the increase in consumption is less) than the Diversified Energy Pathway because of the differing load driver penetrations within each scenario. For example, the Diversified Energy Pathway scenario includes higher levels of hydrogen production and large load sector transformation, which increase annual energy consumption relative to the Deep Electrification scenario. The Deep Electrification scenario includes rooftop solar penetration, which decreases annual energy consumption from FBC, while the Diversified Energy Pathway does not.

On page 104 of the Application, FBC states:

While the energy impacts of Scenario 4 (Diversified Energy Pathway) are higher than those of Scenario 3 (Deep Electrification), Figure 4-2 shows that the two scenarios are roughly the same when considering winter peak demand. This is for the following reasons:

- Integrated Photovoltaic Solar and Storage does not deliver any peak demand reductions in winter – it is dark too early and storage is insufficient (under the behaviours assumed) to shift PV output to peak demand hours later in the day.
- Scenario 4 includes higher penetrations for a number of load drivers that, though they consume a great deal of electricity (hydrogen production and large load sector transformation), also have very flat loads. This is in contrast with Scenario 3 in which loads, in particular, the electrification of transportation and space-heating, are potentially highly peak-coincident.

16.2 Please clarify the level of penetration of residential and commercial solar PV assumed for the Deep Electrification, Diversified and Distributed scenarios.

Response:

As discussed in Sections 3.2.1 and 3.2.2 of Appendix H – Load Scenarios Assessment Report, the penetration levels of residential and commercial solar PV assumed for the scenarios, incremental to the BAU load forecast, are as follows:

Deep Electrification:

- Residential: it is assumed that 15 percent of all single family homes have installed rooftop solar PV by 2040.
- Commercial: it is assumed that 25 percent of applicable businesses have installed rooftop solar PV by 2040.

Diversified Energy Pathway:

- Residential: no incremental rooftop solar PV is assumed to be deployed.
- Commercial: no incremental rooftop solar PV is assumed to be deployed.

Distributed Energy Future:

- Residential: it is assumed that 25 percent of all single family homes have installed rooftop solar PV by 2040.
- Commercial: it is assumed that one third (33 percent) of applicable businesses have installed rooftop solar PV by 2040.

The assumptions regarding the number of applicable residential homes were based on the following assumptions discussed in Section 3.2.1 of Appendix H – Load Scenarios Assessment Report:

Guidehouse assumed that PV (and storage) could be installed only on the rooftops of single-family homes. The total number of single-family homes in each year is derived from:

- FBC's forecast of residential customer counts in its service territory. This grows from approximately 123,000 customers in December of 2019 to approximately 160,000 customers in December 2040.
- The number of residential consumers that are customers of FBC's wholesale customers in 2019, escalated at the same rate of growth as FBC's residential customers. In 2019, there were approximately 23,000 residential consumers served by FBC's wholesale customers, or approximately 16 percent of all residential consumers considered in this study, in that year.
- The provincial proportion of permanent dwellings that are single-family homes. Once mobile homes are excluded, single family homes account for approximately 65 percent of residential dwellings in British Columbia.

The assumptions regarding the number of applicable commercial customers were based on the following assumptions discussed in Section 3.2.2 of Appendix H – Load Scenarios Assessment Report:

Guidehouse assumed that PV (and storage) would be installed only on the rooftops of commercial service customers subject to Rate Schedule 21 (RS 21), with a metered demand of between 40 and 500 kW (or the equivalent indirect customers). The total number of commercial customer is derived from:

- FBC's forecast of commercial customer counts in its service territory. This grows from approximately 16,200 customers in December of 2019 to approximately 22,800 customers in December 2040.
- The number of commercial consumers that are customers of FBC's wholesale customers in 2019, escalated at the same rate of growth as FBC's commercial customers. In 2019, there were approximately 15,000 commercial consumers served by FBC's wholesale customers, or approximately 48 percent of all commercial consumers considered in this study.
- The proportion of FBC's commercial customers that are RS 21 customers in 2019. Approximately 11 percent of FBC's commercial customers in 2019 were RS 21 customers, though these customers accounted for approximately 64 percent of FBC's commercial load in that year.

In all scenarios, it was assumed that the residential and commercial customers, and not FBC, are the owners of the rooftop solar PV.

16.3 Please discuss what assumptions are included in each scenario for the amount, and ownership of, solar PV (utility or customer).

Response:

Please refer to the response to BCUC IR1 16.2.

16.4 Please discuss FBC's view on the sensitivity of the ordering of the scenario results to the level of penetration selected for each of the load drivers.

Response:

The sensitivity of the scenario results is highly dependent on the penetrations assumed for the various load drivers. Some load drivers have more impact on the load scenarios while other load drivers have less. Two examples of higher impact load drivers are EVs and hydrogen production. EVs are more impactful because of the significant number of EV sales forecast by 2040, in accordance with the *ZEV Act* targets, which significantly increases annual energy and peak demand. Hydrogen is also highly impactful because of the significant amount of electricity required to produce a relatively small amount of hydrogen. Other load drivers are less impactful, such as, for example, climate change. The variations in temperature changes assumed for the climate change load driver resulted in only minor changes in energy consumption.

FBC believes that the penetration levels assumed for the various load drivers are reasonable and provide a variety of impacts in the load scenarios. A summary of the penetration levels for each load driver by scenario is provided in the response to BCUC IR1 15.5.

17.0 Reference: LOAD SCENARIOS

Exhibit B-1, Section 4, pp. 105–107, 110

RPAG and Stakeholder Forecast

On page 105 of the Application, FBC states that the load scenarios were discussed with RPAG stakeholders in the June 25, 2020 meeting.

On page 107 of the Application, FBC states that it provided RPAG stakeholders with a crowdsource load scenarios tool to give them the opportunity to model their own load driver penetration levels and scenario impacts. The tool allowed stakeholders to adjust the growth rate of the load drivers based on their own views of the driver growth and penetration levels over time. Ten stakeholders used the tool provided and submitted their results to FBC.

17.1 Please submit a copy of the materials shared with the RPAG group prior, during and after the meeting, providing references to the Application where these have already been submitted.

Response:

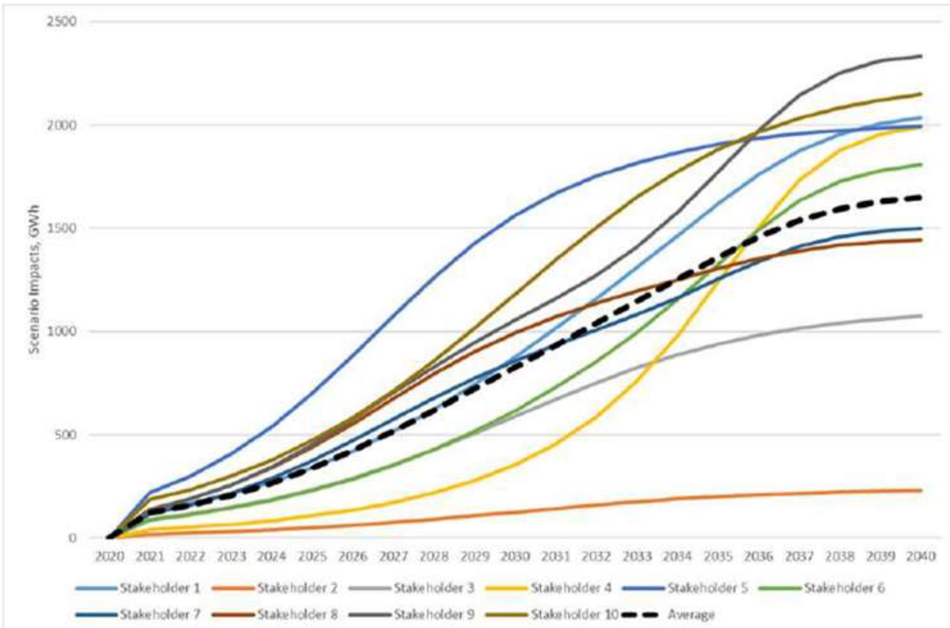
As discussed in Section 12, FBC created an external website for its electricity planning and stakeholder engagement, which includes FBC's presentation materials and meeting notes from its engagement sessions. The URL for the website is as follows: https://www.fortisbc.com/about-us/projects-planning/electricity-projects-planning/electricity-planning-and-stakeholder-engagement.

FBC presented the June 25, 2020 presentation posted on the website prior to and during the meeting and provided the link to the website after the meeting to distribute the meeting notes to the RPAG.

As part of the June 25, 2020 RPAG meeting, Guidehouse presented the Load Scenarios Stakeholder Presentation included in Appendix I of the Application. The RPAG was provided with a link to the crowdsource load scenarios tool after the meeting to give them the opportunity to model their own load driver penetration levels and scenario impacts. The link to the tool is as follows: https://crowdforecast.shinyapps.io/LTERP6/

Figure 4-5 on page 110 of the Application shows Stakeholder Individual vs. Average Load Scenarios

Figure 4-5: Stakeholder Individual vs. Average Load Scenarios – Annual Energy Impacts



FBC draws several conclusions from this analysis on page 110 of the Application including:

- the wide range of scenarios provided by stakeholders indicates a lack of consensus on the likelihood and magnitude ascribed to the load drivers in each case.
- stakeholders believe there is more potential for increased energy and peak capacity requirements above the BAU forecast rather than decreased requirements given that all of the individual scenarios have net positive energy impacts.
- While there are some differences between Guidehouse and the stakeholders in terms of the potential impacts from the individual load drivers, there is some degree of consensus that EV charging, hydrogen production, and large loads will be important load drivers shaping future load requirements.

FBC has included the stakeholder average scenario as well as the Guidehouse scenarios in its 16 portfolio analysis (discussed in Section 11.3.4 of the Application).

17.2 Given the wide range of stakeholder forecasts, please discuss why FBC has used the average in its portfolio analysis.

Response:

FBC has used the stakeholder average, rather than each individual stakeholder scenario, in its portfolio analysis in order to keep the amount of portfolio analysis modelling at a reasonable and appropriate level for this LTERP. Furthermore, all of the stakeholder individual scenarios fall within the Upper and Lower Bound scenarios, which were also included in the portfolio analysis.

17.3 Please discuss if FBC considered using the results more qualitatively, for example through guiding the weighting of criteria, or definition of the different portfolios in Section 11 of the Application. If FBC has used the results more qualitatively, please discuss how.

Response:

FBC has not considered using the stakeholder load scenario results more qualitatively in the manner suggested in the question. The criteria used in the portfolio analysis in Section 11 to determine the preferred portfolios are based on the LTERP objectives rather than the load scenarios. The load scenarios are used to determine what potential energy and capacity resources might be required in the future if a particular load scenario path were to be realized.

D. EXISTING SUPPLY SIDE RESOURCES

18.0 Reference: EXISTING SUPPLY SIDE RESOURCES

Exhibit B-1, Section 2, pp. 17,21, Section 5.1.1, p. 114

Impacts of Climate Change on Water Availability

On page 17 of the Application, FBC states:

> Over the LTERP planning horizon, climate change has the potential to impact FBC's supply in terms of its hydro-electricity generation, how much electricity FBC's customers require, and FBC's transmission and system infrastructure planning. Recent studies indicate that rising temperatures and changes in precipitation patterns will occur over the next century.17

On page 21 of the Application, FBC states:

> Any changes to water availability for hydroelectric generation in the Pacific Northwest could open up the possibility of changes to the entitlements under the Canal Plant Agreement (CPA), thus impacting FBC's existing supply of power.

On page 114 of the Application, FBC states:

> …climate change could have a material impact on water availability for hydroelectricity generation in the Pacific Northwest. The CPA entitlements were originally determined using water inflows prior to 1988 – and climate change may result in more precipitation as rain instead of snowpack during the winter months, which would change the monthly profile and availability of water flow, potentially leading to an earlier freshet period and decreased flows during the summer as well.

Further on page 114 of the Application, FBC states:

> While the LTERP does not directly consider these risks, it is important that any new resources that are acquired be as flexible as possible to assist in meeting any future uncertainties that may occur.

18.1 Please explain why FBC decided not to consider risks associated with water availability due to climate change in this LTERP.

<u>Response:</u>

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

18.2 Please discuss whether FBC considered analyzing any scenarios with respect to water availability over the planning horizon of the LTERP.

18.2.1 If yes, please discuss what was considered and the results of FBC's analysis, if any.

18.2.2 If not, please discuss why not.

Response:

Please refer to the response to BCUC IR1 18.1.

19.0 Reference: EXISTING SUPPLY SIDE RESOURCES

Exhibit B-1, Section 5, pp. 113, 115, 116, 118

Existing Supply Side Resources

On page 116 of the Application, FBC states:

> The BCUC accepted the [Capacity and Energy Purchase and Sale Agreement with Powerex] 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.

19.1 Please discuss why FBC considers it reasonable to assume the CEPSA will continue indefinitely after 2025 in its current form.

Response:

The CEPSA has provided significant benefits to FBC customers by providing reliable market access to purchases and sales that are comparable or better than FBC can achieve outside of the CEPSA. FBC and Powerex have an excellent working relationship and FBC has no reason to believe that this will not continue indefinitely. As such, FBC is actively pursuing ways in which the CEPSA can be extended past the 2025 termination date, and has reflected this intent in its planning assumptions.

On page 116 of the Application, FBC states:

> The amount of residual capacity provided under the [Waneta Expansion Capacity Purchase Agreement (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.

19.2 Please confirm the percentage of FBC's peak capacity needs provided by the WAX CAPA in 2020.

Response:

The WAX CAPA provided approximately 22 percent of the peak capacity needs in 2020.

19.3 Please provide the residual capacity provided by WAX CAPA over the past 5 years, and the proportion sold by FBC as excess.

Response:

The table below provides the residual capacity from the WAX CAPA over the past five years, and the proportion sold by FBC as excess under the RCA contract with BC Hydro and under the CEPSA contract with Powerex. Please note that the total WAX CAPA to FBC is after accounting for reserves and losses.

	2016	2017	2018	2019	2020
Average Hourly WAX CAPA to FBC (MW)	236	237	237	237	236
WAX CAPA sold under the RCA (%)	21	21	21	21	21
WAX CAPA sold under the CEPSA (%)	70	63	64	62	63

On page 118 of the Application, FBC states, "In 2020, market and contracted purchases accounted for 10 percent of FBC's annual energy requirements."

19.4 Please confirm the percentage of FBC's peak capacity needs provided by market purchases in 2020.

Response:

Please refer to the response to BCUC IR1 1.1.

On pages 113, 115 and 116 of the Application, FBC identified that FBC Plants, the Brilliant Plant, the Brilliant Expansion (BRX) Agreement, and the BC Hydro PPA provided 28%, 19%, 4% and 18% of FBC's peak capacity needs.

19.5 If not addressed in the preceding IRs, please identify the supply source of the remaining amount of FBC's peak capacity needs in 2020.

Response:

Please refer to the table below for the supply sources to meet FBC's peak capacity needs in 2020.

Resource	MW % of Peak
FBC CPA Entitlements	28
BPPA	19
BRX	4
PPA Capacity	18
WAX	22
Market	9
Total	100

E. TRANSMISSION AND DISTRIBUTION

20.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6, pp. 121, 127; FBC's Kelowna Bulk Transformer Addition CPCN proceeding, Exhibit B-1, pp. 1, 16-17, 19, Exhibit B-11, Response to ICG IR 2, 6.2

Transmission and Distribution Overview

On page 127 of the Application, FBC states:

> FBC's planning criteria require that the system be planned, designed and operated to serve all customer loads both during normal operations and during contingency operations (i.e. one or more system elements out of service). The most basic criterion is that the system infrastructure must be sufficient to meet all reasonably forecast customer demand with all system components (e.g. transmission lines and transformers) in service. This is referred to as "all elements in service" or N-0156 operation. The next, more limiting, condition is single contingency (N-1)157 operations where FBC's planning criteria state that the transmission system infrastructure must also be sufficient to meet all reasonably forecast customer demand even with the single most limiting transmission component out of service.

On page 121 of the Application, FBC states:

> At the end of June 2021, FBC's service area, the Okanagan in particular, experienced an unprecedented rise in temperature (as discussed in Section 2.2.1). This caused the system to undergo record peak summer demands (with peak demand reaching a record level of 764 MW on June 29) and equipment temperatures well beyond expectations and design conditions. The system was able to meet this peak demand without experiencing any power supply or system reliability issues.

20.1 Please discuss whether any of FBC's critical transmission components were out of service or failed during the June 2021 heat event. If yes, please identify the component.

Response:

During the June 2021 heat event, no FBC critical transmission components were out of service or failed.

20.2 If a critical transmission component failed or had been out of service during the June 2021 heat event, please discuss whether FBC would have been able to provide continued supply to its customers.

20.2.1 If not, please describe the amount of load shedding that may have been required.

Response:

FBC customers would have been exposed to outages if critical system components failed during the June 2021 heat event. The location, number, and duration of the customer outages would have been dependent on the nature and location of the system failure. FBC is unable to speculate further given the large number of possible outage scenarios and outcomes.

On page 16-17 of Exhibit B-1 of FBC's Kelowna Bulk Electricity Transformer (KBTA) CPCN Application, FBC stated:

> The summer peak load is forecast to reach the transformer limit of 315 MW in 2021 and to exceed the limit in 2022 as set out in Table 3-5…

On page 16 of Exhibit B-1 of FBC's KBTA CPCN Application, FBC provided the peak load forecast for the Kelowna Area in Table 3-5 as follows:

Table 3-5: Kelowna Load Area Summer and Winter Peak Load Forecast, 2020-2028

	2020	2021	2022	2023	2024	2025	2026	2027	2028
Summer (MW)	309.5	314.6	319.8	325.5	331.5	336.5	343.3	349.4	355.5
Winter (MW)	340.4	343.9	348.3	352.9	357.0	361.3	365.8	370.3	374.5

On page 19 of Exhibit B-1 of FBC's KBTA CPCN Application, FBC stated:

> Power flow simulation studies were used to analyse single contingency scenarios. When either of the two existing LEE terminal transformers18 is out of service, the loading on the remaining transformer is 191 MVA (91 percent of its emergency limit) when the total Kelowna area load reaches 315 MW, which is just marginally higher than the forecast summer peak load forecast in 202119, as provided in Table 3-5. The loading on the remaining LEE transformer can be lowered by adjusting the load supply configuration in the Kelowna 138 kV system to transfer additional load to DGB. After system reconfiguration, the flow on the remaining LEE transformer is 168 MVA, which is 80 percent of the emergency limit and 100 percent of normal rating.
>
> As Kelowna area load increases, an N-1 event in 2022 and beyond would result in loading above 168 MVA on the remaining LEE transformer, even after the

reconfiguration described above. FBC's operating procedures allow operation above the normal rating for only six hours[20], and plans to reduce the loading must be implemented within this time frame. If loading above the normal rating of 168 MVA is expected to persist for longer than six hours, the facility loading must be reduced below 168 MVA as soon as practicable by shedding customer load during peak load periods. Initially, the requirement for such load shedding would be confined to only part of the peak load period on summer peak days. However, as Kelowna area load increases, the duration and frequency of required load shedding events would increase.

20.3 Please provide the summer peak demand observed for the Kelowna Load area for 2020 and 2021.

Response:

The summer peak demands observed in Kelowna for 2020 and 2021 are shown in the table below:

	2020	2021
Summer (MW)	320	379

20.4 If an N-1 event had occurred concurrent to the peak demand event on June 29, 2021, such as the loss of one of the LEE transformers as contemplated above from page 19 of FBC's KBTA CPCN application, please discuss whether FBC expects it would have had to shed any customer load during the peak period.

Response:

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

On page 1 of Exhibit B-1 of FBC's KBTA CPCN application, FBC stated that "[t]he new transformer is scheduled to be in service by the end of 2022…"

In response to ICG IR 2, 6.2 in Exhibit B-11 of FBC's KBTA CPCN proceeding, FBC identified that if failure of a LEE transformer were to occur, FBC states that "FBC estimates the duration of overloading [of the remaining LEE transformer] to be 5 hours in 2022 and 7 hours in 2023, with the duration increasing as load increases in future."

20.5 Please discuss whether FBC considers there to be any increased risks in summer 2022, at the LEE substation or elsewhere on FBC's system, given the peak demand observed in June 2021.

Response:

Please refer to the response to BCUC IR1 21.3.

On page 121 of the Application, FBC states:

> FBC intends to assess the impacts, if any, on its system infrastructure over the next year to determine if any further actions may be needed to improve system resiliency against these types of events which could be incorporated into FBC's future system capital planning.

20.6 Please expand on the assessments FBC intends to undertake over the next year referred to in the above preamble.

Response:

In its annual assessments, FBC uses the system peak forecast values to analyze the performance of its transmission system. The annual assessments involve the results of the power flow and transient stability analysis carried out to assess the performance of FBC's transmission system in accordance with BC Mandatory Reliability Standards (TPL-001-4). FBC is currently reviewing if the June 2021 heat event should be included in its system peak forecast and therefore in the next annual assessment or not.

FBC is also reviewing its design specifications for future equipment purchases, such as transformers, conductors, and circuit breakers, to operate safely and reliably in higher ambient temperatures.

21.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6, pp. 121, 126–127

System Planning Methodology

On page 126 of the Application, FBC states:

> In order to ensure that FBC's network infrastructure is sufficient to provide a safe and reliable electricity supply to all customers, the transmission and distribution system must be planned, constructed, and operated to meet peak load requirements during extreme weather conditions. This contrasts with the resource planning requirement to acquire energy resources to meet energy and peak demand requirements under "normal" or "expected" weather conditions as set out in the Reference Case load forecast presented in Section 3.153 Consequently, FBC requires and develops load forecasts for two different purposes: system planning (for transmission and distribution infrastructure planning) and resource planning (for capacity and energy resource planning).

And further on page 126, FBC states:

> The result is a "1 in 20" peak demand forecast which is not the same as the "expected" peak demand forecasts per the Reference Case load forecast shown in Section 3 of this LTERP.

Figure 6-2, on page 127 of the Application, provides the Reference 1 Case vs. 1 in 20 Peak Demand Forecast.

On page 121 of the Application, FBC states:

> At the end of June 2021, FBC's service area, the Okanagan in particular, experienced an unprecedented rise in temperature (as discussed in Section 2.2.1). This caused the system to undergo record peak summer demands (with peak demand reaching a record level of 764 MW on June 29) and equipment temperatures well beyond expectations and design conditions. The system was able to meet this peak demand without experiencing any power supply or system reliability issues.

21.1 Please confirm, or explain otherwise, that the "1-in-20" peak demand forecast does not factor in peak demand observed in June 2021.

<u>Response:</u>

FBC confirms that the 1 in 20 peak demand forecast developed for this LTERP was developed and completed prior to the June 2021 extreme heat event.

21.2 Please provide the probability of the peak weather events observed over the summer of 2021.

Response:

FBC estimates the probability of meeting or exceeding the average daily temperature experienced on June 29, 2021 is about 0.00025 percent.

To calculate this probability, FBC used temperature records from the Penticton airport from 1941 to 2021. FBC examined the data and calculated the average daily temperature for the warmest day each summer (referred to as the "maximum mean daily temperature", or MMDT[3]). FBC then used the average and standard deviation to construct a normal distribution of MMDTs to determine the probabilities of experiencing a peak summer temperature at or below any selected MMDT. Based on this calculation, the probability of the peak summer temperature being 33.6 degrees Celsius or lower is 99.99975 percent. Therefore the probability of meeting or exceeding the MMDT experienced in 2021 is (1.0 - 0.9999975) or 0.00025 percent.

FBC notes:

- Many different return periods have been reported in the public discourse.
- The method presented assumes the weather experienced in June 2021 is anomalous. If this event is not anomalous then there is no reliable objective method to calculate the return period based on a single data point.
- Probabilities this small should only be considered as directional as precision cannot be guaranteed and should not be expected.

21.3 Please explain how future "1-in-20" peak demand forecasts will incorporate, if at all, the June 2021 peak demand event.

21.3.1 At a high level, please discuss the expected changes to future forecasts.

21.3.2 Please also discuss whether this may impact the timing of any of the planned transmission reinforcement projects, such as those described in Table 6-3 of the Application.

Response:

FBC is currently assessing data from the June 2021 peak demand event to determine if it is appropriate to include the June 2021 peak demand in future 1 in 20 forecasts. The June 2021

[3] The MMDT can be thought as the "hottest day of the summer".

peak demand was over 200 MW higher than any historical June peak demand and over 100 MW higher than any historical summer peak demand in the last 25 years. FBC is currently collaborating with other regional utilities with regards to the peak demand forecast related to extreme weather conditions, but additional time is required to determine how or if the June 2021 peak demand should be included in future forecasts.

FBC assesses the timing of projects annually based on the updated 1 in 20 peak demand forecasts. As FBC is currently still assessing the June 2021 peak demand, it is too early to determine if this may impact the timing of any of the planned projects.

21.4 Please confirm if the definition of extreme weather conditions used by FBC (one occurrence in 20 years) has been adjusted, if at all, to take account of climate change, and higher frequency of extreme events. If not confirmed, please discuss why such adjustment is not warranted.

<u>Response:</u>

At this time, FBC has not adjusted its definition of extreme weather conditions or its 1 in 20 peak demand forecast explicitly for climate change and higher frequency of extreme weather events. The 1 in 20 peak demand forecast includes actual peak demand for the last 20 years, which implicitly takes into account historical extreme weather conditions. In light of the June 2021 temperature event, FBC is currently reviewing its 1 in 20 peak demand forecast method, including working with a group of regional utilities regarding issues related to climate change to determine if any change in method is warranted at this time.

22.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6, p. 130; FBC 2016 LTERP proceeding, Exhibit B-1, p. 87

Anticipated System Reinforcements

In Table 6-3, on page 130 of the Application, FBC identifies the Transmission Reinforcement projects planned for years 2021 to 2030. Table 6-3 is reproduced below:

Table 6-3: Transmission Reinforcement Projects

Time Frame	Project	Purpose	Primary Driver	
			Capacity	Reliability
2021-2022	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load	X	X
2024-2025	Replace AS Mawdsley (ASM) Transformer T1	To provide adequate transformation capacity during normal and contingency conditions	X	X
2027-2028	52L & 53L Upgrade	To provide adequate capacity during single contingency	X	X
2028-2029	Replace AS Mawdsley (ASM) Transformer T2	To provide adequate transformation capacity during normal and contingency conditions	X	X
2028-2029	60L & 51L Upgrade	To provide required capacity when either LEE T3, T4 or T5 is out of service and there is an outage of another LEE transformer		X
2028-2029	20L Upgrade	To provide adequate capacity during normal and single contingency conditions	X	X

22.1 At a high level, please describe the projects listed in Table 6-3 above and explain why they are needed to serve the forecasted demand and/or reliability criteria.

<u>Response:</u>

A high-level project description and why the projects in Table 6-3 are needed are detailed in the table below. The two projects related to the AS Mawdsley Transformers have been combined into one row in the Table below.

Project	Description	Why this Project is needed
Kelowna Bulk Transformer Capacity Addition	Installation of a new 200 MVA, 230/138kV auto-transformer along with the required station modifications at the FA Lee (LEE) terminal. As part of this project, the existing T3 and T4 tertiary equipment will be salvaged. Further information can be found in the CPCN application which was approved by Order C-4-20.	This project is required in order to maintain adequate transformation capacity in the Kelowna area following the loss of a single system element (an N-1 outage condition). FBC power-flow simulations show that following an outage of either of the two existing LEE Terminal transformers, the loading on the remaining transformer exceeds its normal rating. Current operating procedures allow operation at this level for only six hours, and plans to reduce the loading must be implemented within this time frame. The loading on the remaining LEE transformer can be lowered by adjusting the load supply configuration in the Kelowna 138 kV system. After system reconfiguration, the flow on the remaining transformer is 100 percent of normal rating. Further increase in summer peak demand would result in the ongoing overloading of the remaining transformer at greater than 100 percent of normal rating following a transformer outage and system reconfiguration, thus requiring a capacity increase through additional transformation.
Replace AS Mawdsley (ASM) Transformer T1, and T2	Upgrade the existing ASM T1 and T2 transformers to 150MVA step-up units at 63kV/161kV along with required station modifications. FBC plans to file a CPCN application regarding this project in late 2022.	The primary drivers for this project are: 1. ASM T1 and T2 are protected by a single high-side circuit breaker. As a result, both transformers are disconnected following a fault in one transformer. 2. Following a fault in one ASM transformer, the post-contingency flow through the remaining transformer will exceed its emergency rating. 3. ASM T1 and T2 are 55 and 49 years old, respectively, and are approaching the end of their service life. ASM T1 and T2 asset health is declining each year due to natural aging and operating condition.
52L & 53L Upgrade	Re-conductor the existing 52L and 53L lines between the Huth and RG Anderson substations from 477 AAC Cosmos to 1272 kcmil ASC.	This project is required to increase firm transmission capacity in order to maintain an N-1 level of reliability for customers in the area along Okanagan Lake from Summerland in the north to Skaha Lake in the south. Following an outage of one of the two lines, the post-contingency flow on the remaining line will exceed its emergency limit. Opening 42L at the Huth end will reduce the post-contingency flow, but not sufficiently. Re-conductoring of both 52L and 53L with higher ampacity conductor (1272 kcmil ASC) is required to provide adequate capacity following single contingency outages.

Project	Description	Why this Project is needed
60L & 51L Upgrade	Re-conductor the existing 60L and 51L 138-kV lines between DG Bell and OK Mission substations from 477 AAC Cosmos to 1272 kcmil Narcissus.	When either LEE T2, T3 or T4 is out of service and an outage to another LEE transformer occurs, the flow on the remaining transformer will exceed the emergency rating. Re-configuring the Kelowna loop to reduce the post-contingency transformer flow results in power flow above the emergency rating of lines 60L and 51L requiring their upgrade to a higher ampacity conductor. Upgrading lines 60L and 51L conductor to 1272 kcmil Narcissus conductor will provide the required capacity.
20L Upgrade	Re-conductor the existing 20L 63-kV line between Warfield Terminal Station (WTS) and Salmo substation (SAL). Line 20L consists of a variety of conductor types between WTS and SAL which will be upgraded to 1272 AAC.	The primary drivers for the 20L Upgrade project are: 1. To increase 20L capacity in normal operation to continue supplying new and existing customers; and 2. To increase system reliability during an 18L outage. As load continues to grow on 20L, an outage of 18L will result in post-contingency flows exceeding the rating of 20L downstream of WTS and cause end-of-line voltage violations.

22.1.1 Please also identify whether each project noted is required due to constraints during summer or winter peak loading.

Response:

All the projects identified in Table 6-3 are required due to constraints during the summer peak loads.

22.2 Please confirm, or explain otherwise, whether the 60L & 50L upgrade project shown in Table 6-3 will provide N-2 contingency for the LEE transformers.

22.2.1 If yes, please discuss this in relation to FBC's planning criteria, including in what scenarios FBC plans for double contingency (N-2).

Response:

FBC assumes the question was intended to reference the "60L & 51L Upgrade" project in Table 6-3.

The 60L and 51L upgrade project is required to maintain compliance with Mandatory Reliably Standard TPL-001-4, 2.1.5.[4] FBC does not plan for double contingencies (N-2) other than to fulfill the TPL-001-4 requirement.

When either LEE T2, T3, or T4 is out of service and there is an outage of a second LEE transformer, the flow on the remaining transformer exceeds its emergency rating. The loading on the remaining transformer can be lowered by adjusting the load supply configuration in the Kelowna 138 kV system. This results in more optimal distribution of load between LEE and DGB transformers. After system reconfiguration, the flow on the remaining transformer reduces below the emergency limits but increases the loading on 60L and 51L. The upgrade of 60L and 51L is needed to continue adjusting the load supply configuration in the Kelowna 138kV system without 60L and 51L overloading.

In FBC's 2016 LTERP proceeding, FBC provided the following list of transmission reinforcement projects planned for the 20-year planning horizon on that LTERP. Table 6-3 on page 87 of Exhibit B-1 of FBC's 2016 LTERP is reproduced below.

Table 6-3: Transmission Reinforcement Projects

Time Frame	Project	Purpose	Primary Driver	
			Capacity	Reliability
2018-2020	Grand Forks Terminal Transformer Addition	Add a second terminal transformer to maintain adequate single-contingency reliability for load in the Grand Forks area.		X
2019-2020	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load	X	X

22.3 Please discuss why the projects in Table 6-3 of the Application (i.e.: FBC's 2021 LTERP), other than the KBTA, were not included in FBC's 2016 LTERP.

<u>Response:</u>

Given the greater amount of uncertainty regarding the projects for the last ten years of the planning horizon, FBC only included planned projects for 2016 to 2026 in the 2016 LTERP table. The Kelowna Bulk Transformer Capacity Addition and the replacement of AS Mawdsley (ASM) Transformer T1 are the only projects in 2021 LTERP Table 6-3 that fall within the ten-year window of the 2016 LTERP. The timeframe of the last four projects in 2021 LTERP Table 6-3 are beyond 2026, which is why they were not included in the 2016 LTERP Table.

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[4] Order R-27-18A, dated June 28, 2018: https://www.ordersdecisions.bcuc.com/bcuc/orders/en/312044/1/document.do

The replacement of ASM Transformer T1 project was not included in the 2016 LTERP because the ASM transformer loadings were not reaching their limits at the time the 2016 LTERP was prepared. The ASM transformer loadings are now forecast to reach their limits primarily due to two factors. First, since the 2016 LTERP, there has been the addition of a large customer load in the Boundary region of FBC's system which has increased the peak loading on the ASM transformers. Second, the 2021 LTERP uses the Reference Case load forecast instead of the BAU forecast to develop the "1 in 20" forecast for system planning purposes, and the Reference Case load forecast builds on the BAU forecast by including new loads for EV charging and new industrial loads that have a high confidence of materializing.

22.3.1 Please discuss any changes that have resulted in the identification of the projects included in FBC's 2021 LTERP, such as changes in demand forecasts, changes in planning criteria, new customers etc.

Response:

Please refer to the response to BCUC IR1 22.3.

23.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 2.3, p. 39; Section 6, pp. 132–133, 135, 137-138; Section 11,

p. 184

Potential Impacts of Emerging Load/Generation Technologies

On page 132 of the Application, FBC states:

> There have been increasing numbers of [distributed generation] DG interconnections over the past few years, although the growth rate has slowed since 2018 (see Figure 2-9 in Section 2.3.4). Recent studies predict further cost declines in solar PV and associated increases in solar PV penetration rates. Additionally, provincial or federal incentives and/or federal tax credits, CEA or RPS legislation or feed-in tariffs for the purchase of renewable generating capacity from small facilities could make solar PV more cost-effective for customers. Further study of solar PV, and its pairing with battery storage, will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

On page 133 of the Application, FBC states:

> If DG uptake increases significantly in the future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV, alone or paired with batteries, or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

23.1 Please discuss whether FBC is undertaking further study to understand the impacts of distributed generation, including solar PV paired with battery storage, on FBC's system as is contemplated in the above preamble from page 132 of the Application.

23.1.1 If yes, please discuss at a high level what study work is expected and associated timelines.

23.1.2 If not, please explain why not.

<u>Response:</u>

At this time FBC is not undertaking further study to understand the impacts of distributed generation. As described in Section 6.5.1, the near-term impacts of existing DG facilities on transmission and distribution grid operations and reliability are currently relatively low. If DG uptake increases significantly in the future, the scope and timelines of such study work will be defined accordingly.

23.2 Please elaborate on the alternative engineering designs and technology solutions that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

Response:

As explained in the response to BCUC IR1 23.1, FBC has not yet started further study related to the impacts of DG. As described in Section 6.5.1 of the LTERP, additional voltage regulation on distribution feeders is one such measure that may be required due to the intermittent nature of solar PV generation. Additionally, FBC currently uses a number of sophisticated software modeling tools such as LoadSEER and CYMDIST, which enhance its system planning capabilities. FBC is aware of other utilities that are utilizing these tools to evaluate DG impacts, and FBC's utilization of such functionality in these software tools may need to expand in future.

23.3 Please elaborate on the new and updated planning and operations practices that have been implemented in other jurisdictions may be needed for the FBC transmission and distribution system of the future.

Response:

As described in the response to BCUC IR1 23.2, the LoadSEER and CYMDIST software analysis tools are used in other jurisdictions and FBC will consider these tools for planning purposes. FBC will continue to evaluate its system as DG penetration increases and will apply the planning and operations practices that would be relevant to the FBC transmission and distribution system.

On page 135 of the Application, FBC states:

> In each scenario, FBC simulated the impacts of the load scenarios only on the Kelowna area. This is because Kelowna is the area of FBC's system that is experiencing the most significant load growth and would likely have more significant impacts than other parts of the system. FBC did not include the rest of the system in this exercise and assumed that fifty per cent of the scenario loads would materialize in the Kelowna area based on the current proportion of system loads between the Kelowna area and the rest of the FBC system.

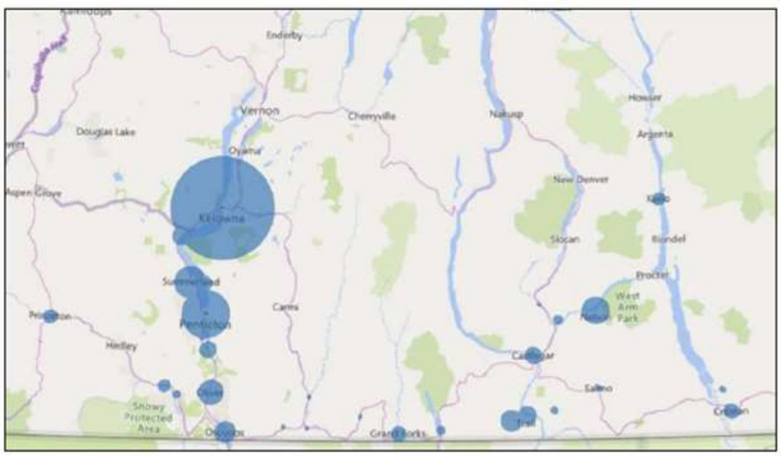
23.4 Please provide the current proportion of system loads between the Kelowna area and the rest of the FBC system.

Response:

The current proportion of system loads between the Kelowna area and the rest of the FBC system is approximately 50/50.

In Section 2.3 of the Application, FBC discusses the customer demand environment. With regards to EVs, FBC provides the following pictorial representation of number of registered EVs in FBC's service area in Figure 2-6, on page 39 of the Application.

Figure 2-6: Number of Registered EVs in FBC Service Area



23.5 Given FBC expects that the impacts of the load scenarios would be experienced mostly in the Kelowna area, please discuss the basis for FBC's assumption that fifty percent of the scenario loads will materialize in the Kelowna area.

Response:

Since the distribution of each load scenario on the FBC system is not known, FBC assumed that 50 percent of the scenario loads would materialize in the Kelowna area based on the current proportion of system loads between the Kelowna area and the rest of the FBC system. FBC did not assume more than 50 percent of load would materialize in Kelowna because there is currently no data to support this load distribution.

On page 135 of the Application, FBC identifies assumptions made "to determine the system impacts from the individual scenario peak-demand forecasts…". One assumption noted is that "[a]dditional peak demand for each scenario has been proportionally allocated to the LEE 138 kV and DGB 138 kV busses in order to simplify the simulations."

23.6 Please explain the reasons for the above noted assumption.

Response:

The additional peak demand for each scenario was proportionally allocated to the LEE 138 kV and DGB 138 kV busses in order to simplify the simulations, as FBC's intention regarding the load scenarios was to assess the adequacy of the high voltage transmission network rather than the Kelowna distribution system. The peak demand loads were allocated at the LEE and DGB busses, as these stations are the sources for serving Kelowna, with the load allocations based on observed previous historical peaks at the LEE and DGB busses.

In Table 6-5 on page 137 of the Application, FBC provides the list of projects that FBC is currently planning on implementing in the Kelowna area. Table 6-5 is reproduced below:

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

23.7 Please confirm, or explain otherwise, that the list of planned projects provided in Table 6-5 above is based on the 1-in-20 load forecast provided in Figure 6-2 of the Application, and not based on the load scenarios.

23.7.1 If yes, please identify the approximate timeframe within which FBC expects each of the above noted projects will be required.

Response:

FBC confirms that the projects in Table 6-5 are based on the 1 in 20 load forecast in Figure 6-2, and not based on the load scenarios. As discussed in Section 6.5.4.4, the majority of these projects are scheduled for completion before the year 2030.

The approximate timeframes for when the projects identified in Table 6-5 will be required are shown in the table below:

Project	Approximate Timeframe
Static VAR Compensator (SVC)	2033-2034
DG Bell 230 kV Ring Bus	2033-2034
Kelowna Bulk Transformer Capacity Addition	2021-2022
Reconductor 51 Line & 60 Line (DG Bell to OK Mission)	2028-2029
Ellison Second Distribution Transformer Addition	2035-2036
Benvoulin Second Transformer Addition	2036-2037
Saucier Second Distribution Transformer Addition	2025-2026
DG Bell 138 kV Breaker and Voltage Transformer Addition	2023
DG Bell Distribution Transformer Addition	2024-2025
FA Lee Distribution Transformer Addition	2028-2029
Duck Lake Second Transformer Addition	2023-2024
Glenmore Third Transformer Addition	2027-2028
Hollywood Third Transformer Addition	2029-2030

The timing of these projects is highly dependent on FBC's peak demand forecast and how it evolves over time.

23.7.2 Please explain why several of the above noted projects in Table 6-5 above are not included in Table 6-3 of the Application, which is FBC's transmission reinforcement projects planned for 2021-2030.

Response:

The majority of the projects listed in Table 6-5 are distribution system projects and therefore are not included in the Table 6-3 Transmission Reinforcement Projects. The two transmission projects in Table 6-5 (the Static VAR Compensator and DG Bell 230 kV Ring Bus), both have an estimated timeframe of 2033-2034 and therefore are not shown in Table 6-3, which only shows projects planned for 2021 to 2030.

In Section 11 of the Application, FBC provides its portfolio analysis.

23.8 Please discuss whether the analysis that resulted in the planned projects described in Table 6-5 of the Application makes any assumptions regarding new generation resources planned for FBC's service area, such as those contemplated in Section 11, Portfolio Analysis, of the Application.

23.8.1 If yes, please describe the assumptions made.

23.8.2 If not, please explain why not.

Response:

FBC assumed there was no new installation of generation resources when completing the load scenario analysis in Section 6.5.4. Instead, 100 percent of the new generation required, regardless of the specific resource, was assumed to come from FBC's transmission interconnections, consistent with the assumptions outlined in Section 6.5.4.1.

The available resource options included in FBC's portfolio analysis represent a wide range of technologies and sizes, located in both BC Hydro's and FBC's service territory. Resource options located in BC Hydro's service territory would result in power wheeling to a point of interconnection with FBC. Resources that are not weather-dependent and dispatchable in nature, such as an RNG SCGT or battery storage, were assumed to be interconnected to areas within FBC's service territory that are likely to be beneficial, but specific site locations have not been explicitly identified or permitted. The LTERP is a high-level planning tool and any project-specific site locations will be subject to availability of land and agreements with various stakeholders and Indigenous groups. The interconnecting location of any new load or generation could significantly affect power flows on the system; therefore, specific site options and the implications on system power flows would have to be studied in detail.

On page 138 of the Application, FBC states:

> Of the projects already identified for the 1-in-20 peak demand forecast, the majority are scheduled for completion before the year 2030. The additional projects would primarily be completed after 2030. This is because the load scenarios have significantly more peak demand being added to the system from years 2031 to 2040 than from years 2021 to 2030. The timing of these additional projects is very dependent on the peak demand forecast and how it materializes over time.

23.9 For each load scenario analyzed, please discuss by which year the projects listed in Table 6-3 and Table 6-5 would be required if load in each scenario materializes.

Response:

The table below provides an estimate of the approximate years in which the projects are required for the 1 in 20 load forecast and each load scenario. Only the timelines for the projects in Kelowna were estimated because this was the area of focus for the load scenarios study discussed in Section 6.5.4. The two applicable projects for the Kelowna area from Table 6-3, which include the "Kelowna Bulk Transformer Capacity Addition" and the "60L & 51L Upgrade", have been included in the Table below (with the 60L & 51L Upgrade shown as "Reconductor 51 Line & 60 Line (DG Bell to OK Mission)") along with the other projects from Table 6-5.

Project	Forecast and Scenarios' Approximate Timeframes				
	1 in 20 Load Forecast	Deep Electrification	Diversified Energy Pathway	Distributed Energy Future	Alternate Scenario
Static VAR Compensator (SVC)	2033-2034	2029-2030	2029-2030	2034-2035	2029-2030
DG Bell 230 kV Ring Bus	2033-2034	2029-2030	2029-2030	2034-2035	2029-2030
Kelowna Bulk Transformer Capacity Addition	2021-2022	2021-2022	2021-2022	2021-2022	2021-2022
Reconductor 51 Line & 60 Line (DG Bell to OK Mission)	2028-2029	2026-2027	2026-2027	2027-2028	2026-2027
Ellison Second Distribution Transformer Addition	2035-2036	2033-2034	2031-2032	2035-2036	2033-2034
Benvoulin Second Transformer Addition	2036-2037	2034-2036	2031-2032	2036-2037	2034-2036
Saucier Second Distribution Transformer Addition	2025-2026	2023-2024	2023-2024	2025-2026	2023-2024
DG Bell 138 kV Breaker and Voltage Transformer Addition	2023	2023	2023	2023	2023
DG Bell Distribution Transformer Addition	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025
FA Lee Distribution Transformer Addition	2028-2029	2028-2029	2028-2029	2028-2029	2028-2029
Duck Lake Second Transformer Addition	2023-2024	2023-2024	2023-2024	2023-2024	2023-2024
Glenmore Third Transformer Addition	2027-2028	2026-2027	2025-2026	2027-2028	2026-2027

Project	Forecast and Scenarios' Approximate Timeframes				
	1 in 20 Load Forecast	Deep Electrification	Diversified Energy Pathway	Distributed Energy Future	Alternate Scenario
Hollywood Third Transformer Addition	2029-2030	2027-2028	2026-2027	2029-2030	2027-2028

Since the load distribution of each scenario is not known, FBC has made assumptions on how the load is distributed between each feeder and substation within Kelowna. For the purposes of this analysis, FBC used a simplified method of distributing each scenario's load to the Kelowna system by evenly allocating load to each feeder. This is not typical practice for FBC's detailed system planning, but it was used for the purposes of the LTERP studies as a simplifying assumption to estimate each scenarios impact on the Kelowna system.

For the projects that have been advanced by the load scenarios to within the next four-year timeframe, FBC may be able to redistribute some load to nearby feeders in the short term as required to defer some projects. For example, the Saucier substation supplies an urban area of Kelowna where there are numerous interconnections to distribution feeders from other stations. On a short-term basis, peak loading on the existing Saucier distribution transformer could be managed by changing normally open points between feeders to transfer some customers and load to other sources.

23.9.1 For those that may need to be advanced to within the next 4-year timeframe, please discuss how FBC is planning and/or preparing for this possibility.

Response:

Please refer to the response to BCUC IR1 23.9.

23.9.2 What is the average lead time in years between the decision to begin work on the projects in Table 6-5, and the in-service date?

Response:

The average lead time between the decision to start planning work and the in-service date can vary significantly depending on the project, but on average would be considered to be about five years.

On page 138 of the Application, FBC states:

> Alternatively, should these scenarios begin to emerge, FBC could implement measures to mitigate the increases in system peak demand requirements. Mitigation measures could include large load curtailment during peak demand periods, shifting EV charging loads off peak periods and installing a large capacity generation resource in the Kelowna area.

In Section 11 of the Application, FBC provides its portfolio analysis. Figure 11-4, on page 184 of the Application, FBC provides portfolios based on the Load Scenarios. Figure 11-4 shows that depending on the load scenario, new resources may be required between 2025-2031.

23.10 Please discuss whether the load scenario analysis provided in Section 6.5.4 of the Application makes any assumptions regarding new generation resources planned for FBC’s service area, such as those contemplated in Section 11, Portfolio Analysis, of the Application.

23.10.1 If yes, please describe the assumptions made.

23.10.2 If not, please explain why not.

<u>Response:</u>

Please refer to the response to BCUC IR1 23.8.

24.0 Reference: TRANSMISSION AND DISTRIBUTION

Exhibit B-1, Section 6.6, p. 140

Impacts of Climate Change

On page 140 of the Application, FBC states:

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

24.1 Please discuss how FBC has been building climate resiliency using its standards and practices over time. Please provide specific examples.

<u>Response:</u>

There are several ways in which FBC has been building climate resiliency using its standards and practices over time.

FBC performs an annual inspection for all transmission and distribution lines, and conducts repairs for any urgent work identified. Condition assessments are completed on an eight-year cycle for transmission and distribution lines and on a six-year cycle for substations. Rehabilitation work to repair the aging infrastructure is completed in the following years.

FBC has also been working to harden the power system to withstand higher wind speeds and other environmental factors through updated designs and material selection. A recent example is the rehabilitation work on the 63kV transmission line 27L to account for increased snow loading as this is a frequent environmental factor that impacts this line.

Substations that fall within a flood zone are redesigned and raised above the flood level when the stations are rebuilt. A recent example includes the Ruckles Substation Upgrade, which raised the site above the 1 in 200-year flood level and successfully avoided flooding damage in 2018.

FBC continues to enhance its system protection by upgrading distribution recloser protection to detect and clear faults faster, as well as providing communications-assisted system automation.

FBC is conducting assessments to analyze the vulnerability of its system to the impacts of climate change. FBC is currently working with an external consultant to develop wildfire risk modeling. The assessment is expected to be complete in 2022. After this project is complete, FBC will begin to further assess the risks related to flooding and extreme weather in more detail.

24.2 Please discuss whether FBC has conducted an assessment analyzing the vulnerability of FBC's system to the impacts of climate change.

24.2.1 If yes, please describe the assessment completed and provide the assessment report, if available.

24.2.2 If not, please discuss why not.

Response:

Please refer to the response to the BCUC IR1 24.1.

Further on page 140 of the Application, FBC states:

> The utility industry, including regulators, continues to discuss the need to be proactive in preparing and taking action to respond to climate change and improve the resiliency of the grid. Industry standards and organizations such as the Institute of Electrical and Electronics Engineers (IEEE) and Canadian Standards Association (CSA) have discussed adopting standards to support utilities in integrating considerations of climate change impacts.

24.3 Please discuss whether FBC is aware of current standards that integrate considerations of the impacts of climate change on electric utilities.

24.3.1 If yes, please identify the standard(s) and whether FBC has considered adoption of the standard(s).

24.3.2 Please discuss whether FBC is aware of other electric utilities that have adopted the standards identified.

Response:

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

Further on page 140 of the Application, FBC states:

> Depending on the climate change related risk, adaptation measures could result in installation of new equipment, the use of new technologies, changes to FBC operating procedures and updates to the FBC distribution, transmission, or station standards.

24.4 Please discuss what progress FBC has made to date in analyzing the need for the above noted adaptation measures in FBC's service territory.

Response:

FBC is in the process of developing a roadmap for climate change adaptation. Wildfires, flooding, and extreme weather events (including windstorms) are considered the highest risks for the FBC service territory.

To mitigate the impacts of flooding, substation construction takes into account floodplain data to ensure that stations are raised to an appropriate height. FBC is also researching and assessing, through pilot programs, the use of alternative materials for poles in areas impacted by flooding.

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

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

Further on page 140 of the Application, FBC states:

> FBC participates in various climate adaptation groups at a national level to share and implement best practices. In collaboration with industry partners, FBC is working to implement strategies to adapt to and mitigate climate risks.

24.5 Please discuss whether there are any specific climate risk adaptation and mitigation strategies FBC is currently implementing or plans to implement within the next 4 years.

24.5.1 If yes, please identify and describe the strategies and provide the associated timelines for implementation.

Response:

Please refer to the response to BCUC IR1 24.4.

F. RESOURCE OPTIONS – DSM

25.0 Reference: RESOURCE OPTIONS – DSM
Exhibit B-1, Section 8.1, p. 149
DSM Levels

On page 149 of the Application, FBC states that the DSM program scenarios considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential. This approach supplants the prior metric of expressing DSM savings targets as a percent of load growth offset. That metric, which originated in the 2007 BC Energy Plan, included targets only to the end of 2020. New load growth forecasts are significantly impacted by electric vehicle growth, which DSM has no energy savings measures thus the existing approach was abandoned in favour of one that aligns with incremental costing, similar to other utility conservation potential reviews, including FEI.

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

25.1 Please discuss on what basis FBC chose the new approach, as opposed to selecting new targets based on a percentage of load growth offset.

Response:

FBC's approach to developing the 2021 DSM portfolio targets and scenarios is detailed on page 7 of the LT DSM Plan. The approach is consistent with the approach detailed on page 6 of the 2016 Long-Term DSM Plan.

However, FBC's illustration of those targets is now different. The difference between the total of the "Low" and "High" Scenarios presented in the 2021 Long-Term DSM plan (421 and 503 GWh, respectively, over the 20-year planning horizon) is relatively small when compared to the estimated load growth before DSM. Thus, if FBC presented the five DSM scenarios in terms of load growth, the percentage difference between each scenario would only be between 1-3 percentage points, losing some of the granularity and distinction between the scenarios.

For clarity, the table below reframes the DSM scenarios as a percentage of the load growth offset:

DSM Scenario	DSM Incentive as Percentage of Measure Incremental Cost	Load Growth Offset 2021 to 2040 (GWh)	Percentage of Load Growth Offset 2021 to 2040
Low	50%	421	33%
Baseline	62%	435	34%
Medium	72%	449	35%
High	84%	468	37%
Maximum	100%	503	40%

25.2 Please provide examples of other utilities that have used a similar approach, namely changing the level of incentive, as opposed to increasing the number of customers receiving the incentive, or expanding the type of measures offered.

Response:

A fundamental principle of DSM strategies is that the primary mechanism for increasing participation in a program is by increasing the incentive offered. The higher the incentive, the more attractive a project will be for the customer's economic decision making, thereby increasing the number of customers willing to participate. While there are other mechanisms that may impact participation (e.g., increasing marketing spend or reducing application barriers), few are as impactful as increasing the incentive.

FBC does not have detailed insight to the DSM planning process of other utilities. However, the BC Hydro 2021 draft Integrated Resource Plan outlines four DSM scenarios that generally follow the same principles employed by FBC:

- No energy efficiency – halt current programs except for those mandated in the Demand-Side Measures Regulation.
- Base energy efficiency – maintain a base level of demand-side measures programs that can readily be scaled up in future years.
- Higher energy efficiency – increased incentives and marketing efforts relative to the Base Energy Efficiency portfolio.
- Higher plus energy efficiency – further increase marketing efforts and incentives, relative to Higher energy efficiency, to cover 100 percent of incremental customer costs.

G. LOAD RESOURCE BALANCE

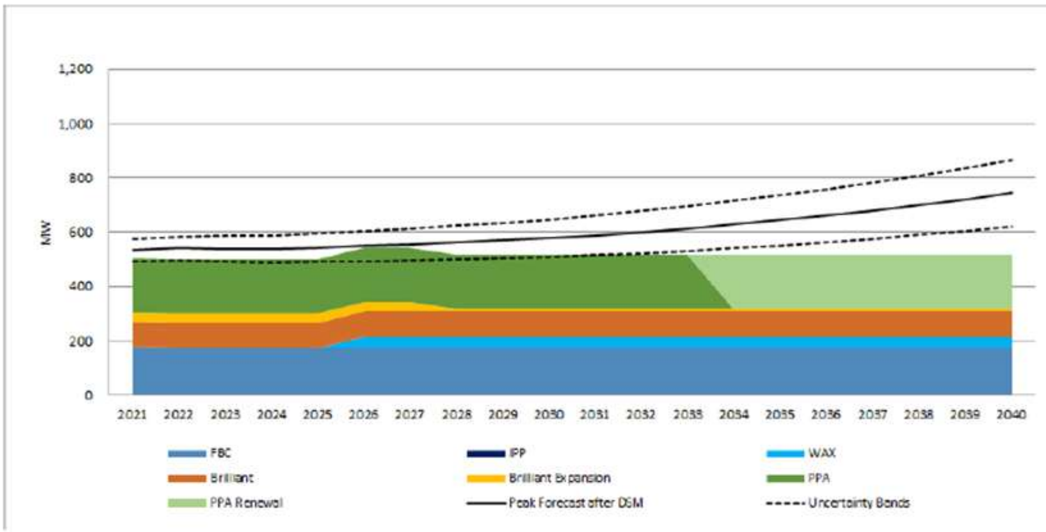
26.0 Reference: LOAD RESOURCE BALANCE

Exhibit B-1, Section 3.7, p. 94; Section 9, p. 158

Peak Load Resource Balance and Uncertainty

Figure 9-6 on page 158 of the Application shows the June Capacity Load Resource Balance (LRB) after DSM, plotting the Reference Case load forecast and the uncertainty bands against current supply resources.

Figure 9-6: June Capacity Load-Resource Balance after DSM



On page 94 of the Application, FBC states that FBC experienced an extended heat event and set a summer peak record of 764 MW on June 29, 2021. This peak demand exceeded the upper confidence band for summer as presented in the figure above. FBC notes that the Summer Peak BAU prediction interval is based on a 90 percent confidence level and extreme events such as the June 2021 one are expected to exceed the confidence bands.

26.1 Please explain how the FBC systems performed during the June extended heat event, and what resources FBC used to meet demand during this period.

<u>Response:</u>

FBC's transmission systems performed without any issues during the June 2021 extended heat event; however, if a critical transmission component failed or had been out of service during this time, FBC customers would have been exposed to outages (please also refer to the response to BCUC IR1 20.2). FBC's distribution systems did experience localized outages similar to what FBC has seen historically during hot weather.

In terms of supply resources, FBC maximized its capacity usage from all existing contracts (defined in Section 5), yet still required 265 MW from the wholesale market during its peak hour.

Please refer to the table below for the resources and corresponding capacity usage (in MW) that FBC used to meet its peak demand on June 29, 2021.

Resource	Peak Usage (MW)*
FBC CPA Entitlements	175
BPPA	121
BRX	29
PPA Capacity	200
WAX (net of RCA)	0
Market and Other Contracted	265
Total	790

* Based on actual dependable capacity during the month of June 2021.

27.0 Reference: LOAD RESOURCE BALANCE

Exhibit B-1, Section 9.3, p. 160

Use of DSM

On page 160 of the Application, FBC states that the average cost of the proposed DSM level is $38 per MWh.

27.1 Please explain how FBC determined $38 per MWh to be an appropriate average cost for DSM.

Response:

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

27.2 Please confirm if this is the average cost, or a recommended cost threshold for selecting DSM measures.

Response:

$38 per MWh represents the average cost of DSM measures under the Base DSM Scenario, discounted over an average 15-year measure life.

H. SUPPLY-SIDE RESOURCE OPTIONS

28.0 Reference: SUPPLY-SIDE RESOURCE OPTIONS
Exhibit B-1, Section 10, pp. 161, 164–168, 171
Supply-Side Resource Options

On page 161 of the Application, FBC states:

> FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. costs), these include operational/ technical characteristics and environmental and socio-economic impacts, which are discussed in the following sections. New to this LTERP is the consideration of power plant footprint in the evaluation of environmental impacts.

28.1 Please discuss why FBC added consideration of power plant footprint in the evaluation of environmental impacts for this LTERP.

Response:

FBC included plant footprint in the 2021 LTERP as this factor is an important consideration in the evaluation of environmental impact. No other new metric for environmental impact was considered for the 2021 LTERP.

The addition of plant footprint did not directly result in a greater consideration of environmental impacts when evaluating portfolio attributes. In the 2016 LTERP, FBC used a balanced set of metrics relating to cost, the environment, economic development and geographic diversity while the 2021 LTERP has used a balanced set of cost, environmental, resiliency and economic metrics based on the objectives of the LTERP.

The inclusion of environmental footprint is intended to recognize some resource options require more land area than others, which can be considered a form of environmental impact alongside GHG emissions. Environmental metrics have been, and will continue to be, an important part of the portfolio evaluation criteria.

28.1.1 Please discuss what other new considerations were contemplated and why they were rejected.

Response:

Please refer to the response to BCUC IR1 28.1.

28.2 Please discuss whether the addition of power plant footprint in the evaluation of environmental impacts results in a greater overall consideration of environmental impacts when evaluating portfolio attributes, as compared to previous LTERPs.

Response:

Please refer to the response to BCUC IR1 28.1.

On page 164 of the Application, FBC states:

> FBC has categorized the socio-economic development attributes for each resource option into low, medium and high impact categories using employment contributions as a proxy for all the socio-economic development benefits.

28.3 Please explain, with rationale, why FBC considers employment contributions a proxy for all socio-economic development benefits.

Response:

FBC used employment contributions as a proxy for all socio-economic development benefits because it was a simplifying assumption that could be derived from the data available from the collaboration with BC Hydro as it updated its Resource Options Inventory.

In Table 10-1, on pages 165-166 of the Application, FBC provides its supply-side resource options type and size summary. In Table 10-2, on pages 166-167 of the Application, FBC provides its supply-side resource options unit cost summary. In Table 10-3 on page 169 of the Application, FBC provided its supply-side resources environmental, socio-economic and lead time attributes summary.

28.4 Please discuss why FBC owned generation facilities, the Brilliant Power purchase agreement (BPPA), the Brilliant Expansion (BRX) entitlement purchases and the Waneta Expansion Capacity Purchase Agreement (WAX CAPA) entitlements are not included in the above noted tables describing the attributes of FBC's supply side resource options.

Response:

Tables 10-1 and 10-2 do not include the BPPA, BRX purchases, or WAX CAPA entitlements because these resources are fully allocated to serving existing loads, and are not available to supply incremental loads. Therefore, they are considered existing resources rather than resource options.

28.4.1 Please provide the data provided in tables 10-1, 10-2 and 10-2 for the above noted plants/agreements.

Response:

A portion of this response is being redacted pursuant to section 18 of the BCUC's Rules of Practice and Procedure as set out in Order G-15-19, consistent with Order E-13-12 because it contains commercially and financially sensitive information of FBC and certain of its affiliates which, if disclosed, could jeopardize FBC's ability to maximize the benefits associated with re-sale of excess capacity under these agreements for customers. As such, only the BCUC will receive a confidential unredacted version of this response under separate cover.

Available energy and dependable capacity is shown in Table 5-1 on page 112. UECs and UCCs of these contracts with third parties are commercially confidential, but have been previously approved by the BCUC.

Please see the table below for the data provided in Tables 10-1, 10-2 and 10-3, with regard to the FBC CPA Entitlements, BPPA, BRX 10 Year Agreement, and WAX CAPA Agreement (net of RCA).

Resource Option	Portfolio Analysis Short Name	Type	Number of Plants in FBC Portfolio Analysis	Average Dependable Capacity (MW)	Annual Energy (GWh)	UEC ($/MWh)*	UCC ($kW-year) *	Clean/ Renewable	GHG Emissions	Plant Footprint	Job Creation	Lead Time (Years)
FBC CPA Entitlements	N/A	Baseload	N/A	208	1596	N/A	N/A	Yes	Low	N/A	N/A	N/A
BPPA	N/A	Baseload	N/A	138	919	$44.31	N/A	Yes	Low	N/A	N/A	N/A
BRX	N/A	Baseload	N/A	45	79	[redacted]	[redacted]	Yes	Low	N/A	N/A	N/A
WAX (net of RCA)	N/A	Baseload	N/A	218	0	[redacted]	[redacted]	Yes	Low	N/A	N/A	N/A

**Based on 2021 RRA Projected Data*

On page 168 of the Application, FBC states that "[t]he unit capacity costs for an SCGT gas plant using conventional natural gas or using RNG as fuel are the same."

28.5 Please explain, with supporting reasons, why the unit capacity costs for an SCGT gas plant using conventional natural gas or using RNG as fuel are the same.

Response:

Whether fueled by RNG or conventional natural gas, the same physical SCGT unit would be connected to the gas system, and therefore would have the same unit capacity cost (UCC). The UCC reflects the total capital cost of the generator, the interconnecting transmission costs, and annual fixed costs associated with maintaining the plant in a state ready for dispatch (i.e., available for capacity purposes).

Although not usually stated, the Unit Energy Cost (UEC) of an SCGT fueled by RNG would be different from an SCGT fueled by conventional natural gas, as this metric includes variable costs of operation such as fuel. FEI's RNG has the same properties as conventional natural gas, but without the carbon footprint. From a modelling perspective, the key difference between the RNG-fueled SCGT compared to a conventionally-fueled SCGT resource option is the variable cost of the fuel when the unit is dispatched.

On page 171 of the Application, FBC discusses expiring energy purchase agreements and states: "There may be opportunities for FBC to acquire power from these expiring EPAs on a cost-effective basis in the future. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities."

28.6 Please confirm, or explain otherwise, that FBC has not assumed that any existing BC Hydro EPAs will be acquired in its portfolio analysis in Section 11 of the Application.

Response:

Confirmed.

29.0 Reference: SUPPLY-SIDE RESOURCE OPTIONS

Exhibit B-1, Section 11, pp. 193, 195; Appendix K, pp. 5–6, 9, 28–29, 31, 48

Supply-Side Resource Options Report

Appendix K to the Application provides FBC's Supply Side Resource Options Report (ROR).

On page 5 of the ROR, FBC states:

> Base load resources operate at a high capacity utilization factor[3] generating significant amounts of electrical energy over the entire year. Such resources can be evaluated for both energy and capacity attributes. Examples include:
>
> - Hydro generation with some storage reservoir;
> - Combined cycle gas turbine (CCGT) plants;
> - Biomass wood-waste thermal generation; and
> - Geothermal generation.
>
> [3] Capacity utilization factor is the ratio of the actual output from a plant over the year to the maximum possible output from it for a year under ideal conditions.

29.1 Please provide the capacity utilization factors assumed for each of the above noted base load resources.

Response:

FBC has applied the formula below to calculate the resource capacity factors:

$$\frac{Annual\ Reliable\ Energy\ (MWh)}{Installed\ Capacity\ (MW) * 8760\ Hours}$$

Annual reliable energy refers to the maximum amount of energy anticipated to be available in a year after considering the capabilities of the generating unit and availability of fuel, which also includes environmental factors (e.g. amount of sunlight available for solar PV generation).

Capacity factors in the portfolio model are resource specific. The table below shows the average annual capacity factor by resource type for resource options included in the portfolio analysis. There is a capacity factor range for those resources with varying sizes. The names and ordering of resource types align with Table 10-1: Resource Options Type and Size Summary.

Resource Type	Range of Annual Average Capacity Factors
Wood Waste Biomass	0.91
Geothermal	0.65 to 0.76
Gas- Fired Generation: Combined Cycle Gas Turbine (CCGT)	0.90
Small Hydro with Storage	0.43 to 0.76
Gas- Fired Generation: Simple Cycle Gas Turbine (SCGT) – NG	0.18
Gas- Fired Generation: Simple Cycle Gas Turbine (SCGT) - RNG	0.18
Pumped Hydro Storage	N/A
Onshore Wind	0.38 to 0.53
Run of River Hydro	0.37 to 0.39
Utility Scale Solar	0.18 to 0.21
Distributed Solar	0.19
Battery Storage	N/A
Distributed Battery Storage	N/A

It is critical to note that these values are not modeled dispatched amounts but the maximum amount available to the model to dispatch. Resources that are dispatchable may not be dispatched up to the full amount of annual reliable energy available, which would result in a lower capacity factor for the particular resource in a specific scenario. Resources that are intermittent in nature are assumed to produce volumes of energy equal to the amount of annual reliable energy available as these resources are driven by environmental factors outside the utility's control.

The annual capacity factor may not be constant among all months, especially in the case of intermittent resources. For example, solar will produce the majority of the annual reliable energy during the summer months, which would result in a monthly capacity factor greater than the annual average capacity factor during the summer season and a lower than annual average capacity factor during the winter season.

Pumped storage hydro and batteries do not produce net energy, and therefore do not have a capacity factor. After accounting for losses associated with charging cycling and pumping water up an elevation, both batteries and pumped storage hydro are resources which consume energy on an annual basis. The storage capabilities and installed capacity of these resource types determine the duration and capacity contribution available to serve monthly peak hours. In contrast, SCGT peaking resources do not store energy but rather generate energy up to their rated capacity and therefore are not limited in duration the same way; however they are expected to operate for a smaller number of hours in the year, hence the lower capacity factor than a CCGT resource.

On page 6 of the ROR, FBC states:

> Peaking resources can be dispatched to provide capacity but are expected to operate at a low capacity utilization factor, generating electricity when it is needed. Peaking resources typically have a low cost to construct per unit of capacity, but high per unit energy costs. These resources can also act as planning reserve margin assets which can be brought into service quickly following a contingency event (e.g. loss of a base load facility), meet sudden changes in customer load requirements or help firm up intermittent resources. Although these resources produce energy when generating, they are primarily evaluated for their capacity attributes. Examples include:
>
> - Simple cycle gas turbine (SCGT) plants;
> - Pumped storage hydro; and
> - Batteries.

29.2 Please provide the capacity utilization factors assumed for each of the above noted peaking resources.

Response:

Please refer to the response to BCUC IR1 29.1.

On page 6 of the ROR, FBC states:

> Variable/intermittent resources provide little dependable capacity and typically operate at lower capacity utilization rates than base load resources.
>
> …
>
> Examples include:
>
> - Onshore wind turbine generation;
> - Run-of-river hydro generation;
> - Utility-scale PV solar; and

- Distributed Solar.

29.3 Please provide the capacity utilization factors assumed for each of the above noted variable/intermittent resources.

Response:

Please refer to the response to BCUC IR1 29.1.

29.4 Please discuss whether FBC's portfolio optimization routine and analysis pair variable/intermittent resources with storage resources, such as battery storage. Please explain why or why not.

Response:

FBC confirms that its portfolio optimization routine considers the pairing of intermittent resources with storage resources, although not as a single integrated resource option. Intermittent resources provide both reliable monthly energy and dependable capacity based on resource specific profiles. Battery storage is able to contribute to monthly capacity requirements up to the dependable capacity of the battery, which includes taking into account the battery duration as discussed in response to CEC IR1 44.2. FBC is also able to store energy in its flexible operational accounts and pair it with existing capacity resources such as WAX. The optimization routine was able to select a combination of intermittent resources and lithium ion batteries working together with existing resources to meet monthly capacity requirements.

On page 9 of the ROR, FBC states:

> Implementing projects within Indigenous communities' traditional territories has a cost, whether it be accommodation in the form of an impact benefit agreement or in the form of partnership with equity participation. FBC has included a 2.5 percent adder as a proxy for Indigenous Communities Participation Cost related to new generation projects. The cost used in FBC's portfolio analysis is a 2.5 percent adder to the UEC values for energy projects, or an adder of 2.5 percent to the UCC values for capacity projects.

29.5 Please explain the basis for using a 2.5 percent adder as a proxy for Indigenous Communities Participation Cost related to new generation projects.

Response:

The 2.5 percent adder is a simplifying assumption used as a proxy for the cost of Indigenous participation in renewable projects. The actual cost will be project specific.

The basis of the 2.5 percent adder is the 2015 BC Hydro wind cost update as part of FBC's ongoing collaboration with BC Hydro as it updated its Resource Options Inventory. In that update, a 2.5 percent onshore wind adder for Indigenous participation was included in the analysis. For the 2021 LTERP resource options, FBC continues to apply the 2.5 percent adder to wind resources and extended it to all resource options in recognition that there will be Indigenous participation in any resource development project going forward.

On page 48 of the ROR, with regards to biogas, FBC states:

> FBC has excluded baseload biogas generation from this analysis as it is assumed that most available biogas in BC would be required for decarbonization of the FEI natural gas system going forward, with minimal amounts possibly providing fuel for SCGT plants.

29.6 Please expand on the basis for this assumption, such as supply and demand forecasts for biogas.

Response:

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

These strategies also align with the Province's CleanBC Plan targets for blending RNG and hydrogen in the natural gas system, which will increase the need for RNG and hydrogen in the existing gas system. As a result, it was assumed that FEI would allocate the majority of its RNG to its own programs rather than specifically allocating to FBC.

On pages 28-29 of the ROR, FBC discusses Gas Fired Generation – Simple Cycle Gas Turbine (SCGT) and identifies that "Given their low utilization rate, SSGT gas plants can use RNG rather than conventional natural gas as fuel to offset their carbon footprint."

FBC identifies RNG fueled SCGT plants in many of the portfolios considered in Section 11 of the Application.

On page 195 of the Application, FBC identifies Portfolio C3 as the preferred portfolio. On page 193 of the Application, Portfolio C3 is identified to have a resource mix including 2 RNG fueled SCGT plants.

29.7 Please discuss whether FBC has prepared a forecast of demand for RNG for the LTERP horizon associated with any of its evaluated resource portfolios, including FBC's preferred portfolio C3.

29.7.1 If yes, please provide the forecast of RNG demand in gigajoule (GJs) for FBC's 3 preferred portfolios included in Figure 11-7 of the Application.

29.7.2 If not, please explain why not.

<u>Response:</u>

Yes, FBC has prepared a forecast for the demand of RNG over the LTERP planning horizon based on the modelled dispatch of RNG Resources contained in the portfolios. Portfolio C4 does not include any RNG resources; therefore, the RNG demand for portfolio C4 is zero. The following table shows the RNG demand for the preferred portfolios C3 and B2. The dispatched annual energy from RNG SCGT resources is provided for context. The RNG SCGTs are providing energy in peak hours at the very top of the Load Duration Curve and are not being dispatched as a primary source of energy in the portfolio. The RNG demand forecasts have been rounded to the nearest 100 GJ.

	Portfolio [C3]: Clean w/RNG		Portfolio [B2]: Self-Sufficiency (Capacity 2021; Energy 2030)	
Year	Modelled Energy from RNG SCGT Resources (GWh)	Estimated Total RNG (GJ)	Modelled Energy from RNG SCGT Resources (GWh)	Estimated Total RNG (GJ)
2021	-	-	-	-
2022	-	-	-	-
2023	-	-	-	-
2024	-	-	-	-
2025	-	-	-	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-

	Portfolio [C3]: Clean w/RNG		Portfolio [B2]: Self-Sufficiency (Capacity 2021; Energy 2030)	
Year	Modelled Energy from RNG SCGT Resources (GWh)	Estimated Total RNG (GJ)	Modelled Energy from RNG SCGT Resources (GWh)	Estimated Total RNG (GJ)
2030	-	-	1.0	9,900
2031	4.5	42,300	1.1	10,300
2032	4.9	46,500	1.1	10,600
2033	5.0	47,700	1.1	10,300
2034	5.2	48,900	1.1	10,700
2035	9.8	92,300	1.0	9,700
2036	9.8	92,800	1.1	10,600
2037	9.7	91,600	1.1	10,500
2038	9.8	92,400	1.1	10,300
2039	10.4	98,700	1.1	10,100
2040	10.1	95,700	1.1	10,000

Although FBC has not specifically secured any quantity of gas from FEI, the volumes likely required to support FBC's proposed peaking resources, even if the dispatch is significantly greater than modelled, are anticipated to be a small percentage of the total RNG available. FEI is on track to have approximately 30 PJ (30 million GJ) of RNG supply available by 2030.

29.8 Please discuss the risks associated with availability of RNG supply in relation to FBC's expected RNG demand.

Response:

FBC does not foresee any risk associated with securing this future supply of RNG. The potential demand for the use of RNG in the portfolios is not material compared to its projected availability over the planning horizon.

29.8.1 For each risk identified, please discuss how FBC is preparing for and mitigating these risks.

Response:

Please refer to the response to BCUC IR1 29.8.

29.9 Please provide the assumptions made by FBC regarding the geographic location of RNG (provincial; Canadian; other), including any assumptions regarding the use of RNG credits over the forecast period.

Response:

FBC is agnostic to the geographic location of the RNG supply. For the 2021 LTERP, FBC assumes it would acquire RNG from FEI, who is acquiring RNG from both inside of BC, across Canada, and from the US. However, irrespective of the geographic location, this RNG supply would have the same associated environmental attributes. As a result, FBC considers RNG supplied from inside of BC to be the same at RNG supplied from outside of BC.

FBC does not use the term "RNG credits", so it is assumed that the question refers to the carbon intensity of RNG as an input to generation and FBC's ability to declare that the electricity it generates is low carbon electricity, approximately equivalent to hydroelectricity (in terms of carbon intensity). In this case, FBC considers all RNG to be equivalent irrespective of geographic location.

It is also possible that the RNG generation could be located at the SCGT plant site, providing a dedicated supply of fuel.

On page 31 of the ROR, FBC discuses Battery Storage and Distributed Batteries. FBC states:

> Batteries in the portfolio model were classified either as Battery Storage, which is defined for the purpose of the model as a 50 MW Lithium-ion battery connected to the transmission system, or Distributed Batteries, which is defined as a 25 MW Lithium-Ion battery connected to the distribution system. Each battery is able to sustain a 4-hour duration. One of each battery was utilized in the portfolio model.

FBC identifies battery storage in many of the portfolios considered in Section 11 of the Application. On page 195 of the Application, FBC identifies Portfolio C3 as the preferred portfolio. On page 193 of the Application, Portfolio C3 is identified to have a resource mix including a distribution battery storage system.

29.10 Please discuss whether FBC considered there to be any risks associated with availability of supply for batteries and associated materials in relation to FBC's expected demand for battery systems.

Response:

FBC has not explicitly considered the risks associated with availability of supply for batteries and associated materials in the LTERP. For the preferred portfolio, the need for batteries is identified by the year 2030. Given this timeframe, and the relatively small scale battery storage resource needed (i.e., 25 MW), FBC is not actively preparing for or mitigating supply risks relating to battery systems at this time. FBC anticipates any concerns regarding supply for batteries and associated materials would be discussed in the next LTERP or in a CPCN application, as required.

29.10.1 Please discuss how FBC is preparing for and mitigating these risks.

Response:

Please refer to the response to BCUC IR1 29.10.

29.11 At a high level, please discuss whether FBC expects any technical feasibility issues with respect to connecting a 25MW battery system to its distribution system.

Response:

The technical feasibility of connecting a 25 MW battery system to the FBC distribution system will depend on the location of the battery storage, availability of land, the system configuration and the surrounding infrastructure where it is connected. Although still a relatively new technology, grid-scale batteries are seeing increasing deployment by electric utilities around the world. Although FBC would be required to conduct feasibility studies and engineering evaluations, it does not anticipate any technical impediment to the execution of such a project at this time.

I. PORTFOLIO ANALYSIS

30.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Section 11, pp. 175–176, 183

Portfolio Analysis Methodology

On page 175 of the Application, FBC states:

> FBC's portfolio model incorporates an optimization routine to find the lowest power supply revenue requirement of satisfying the forecast load requirements given a set of constraints, which lead to what new resources should be acquired and when.

30.1 At a high level, please expand on how FBC's portfolio optimization routine functions.

30.1.1 Please identify FBC's key inputs and/or constraints.

Response:

The resource portfolio optimization routine addresses the following questions in meeting the lowest cost power supply portfolio:

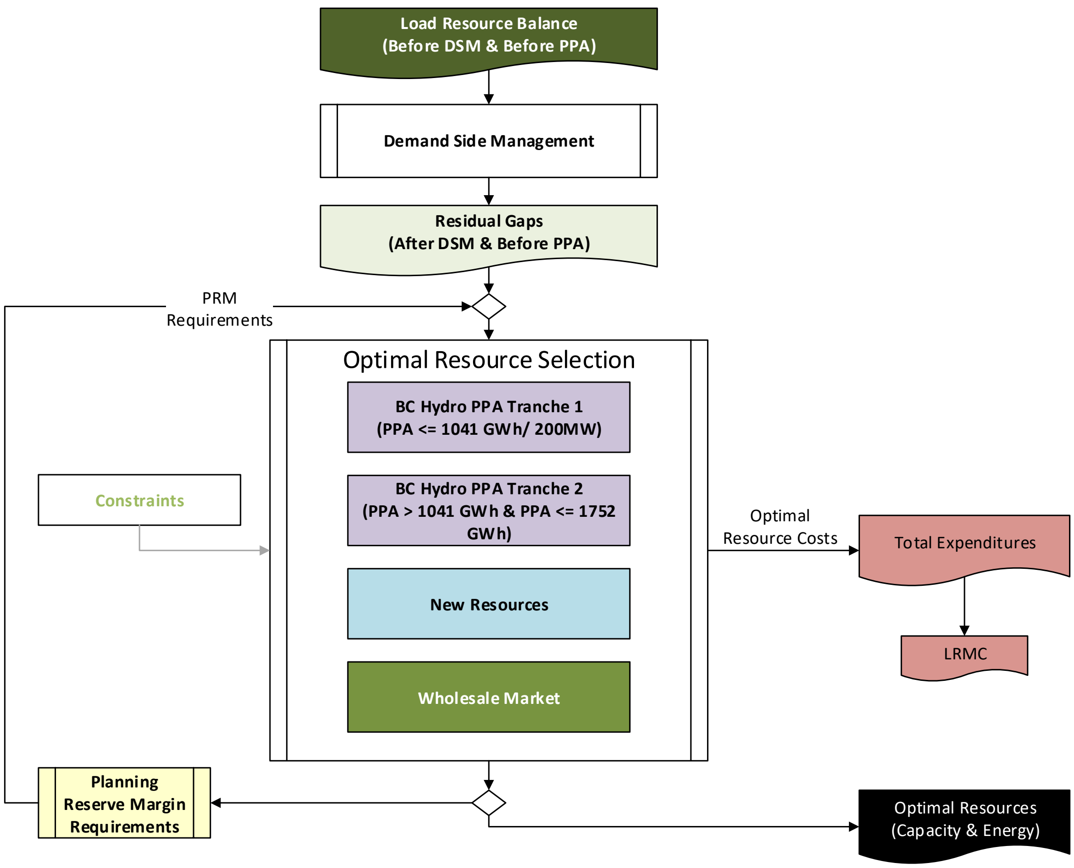
- What is the optimal utilization of the BC Hydro PPA?
- When and which new resources should be acquired?
- Once a new resource is acquired, if dispatchable, how much energy should it generate?
- What is the optimal utilization of market purchases?

The fundamental purpose of each portfolio is to meet the load forecast scenario, which specifies the energy and capacity requirements that are needed to be met in each month for all years throughout the planning horizon.

The model first considers FBC's existing and committed resources, which include FBC Entitlement Generation, existing Brilliant and Brilliant Expansion agreements, the Waneta Expansion agreement, and other resources such as energy from existing IPPs or any existing and committed market block purchases. These existing resources are netted against the load requirements to determine the remaining incremental load requirements (if any) that need to be satisfied with marginal resources.

FBC views both DSM measures and "behind the meter" customer generation (e.g., rooftop solar energy generated by the customer) to be demand-side variables, rather than supply-side resources, as the utility can incent action, but ultimately the customer decides whether to participate in DSM programs or install behind the meter generation, and if so, how much. In contrast, the utility makes decisions to acquire supply-side resources with considerations for size, cost, location, and shape of the monthly energy and capacity in the selection process relative to any anticipated monthly residual gaps. Furthermore, the energy output of utility supply-side resources can be scheduled in accordance with industry standards.

To summarize, the resource portfolio routine determines the optimal selection of marginal resources to meet the monthly load residual gaps after existing resources and DSM and with consideration for any scenario load drivers (including behind the meter generation). The following diagram illustrates the broad components of the optimization routine:



Depending on the scenario being investigated, one of the DSM portfolios is incorporated into the resource stack as a preferred resource. The DSM portfolio further reduces the load requirements that need to be satisfied with the BC Hydro PPA, new resources, and/or market power purchases. The supply-side resource options available as inputs to the resource optimization routine were selected from the resource options report completed in collaboration with BC Hydro as discussed in Appendix J of the LTERP and shown in Table 10-1: Resource Options Types and Size Summary.

The resource portfolio model incorporates an optimization routine to find the lowest net present value cost of satisfying the forecast load requirements given a set of constraints. Specifically, FBC uses a Mixed Integer Linear Programming model.[5] To determine the optimal mix of resources,

[5] Gurobi Optimization. Mixed-Integer Programming – A Primer on the Basics.
URL: https://www.gurobi.com/resource/mip-basics

the optimization routine includes constraints for the solution to be practical and reflective of the desired portfolio attributes. High-level categories of these constraints include parameters of the PPA, practical limitations on new resource options, considerations for *Clean Energy Act* objectives, rules around market activity, and logic that ties energy and capacity requirements together.

The optimization routine considers the decisions simultaneously as the selected resources depend on the existing energy and capacity residual gaps, but also considers the interaction with existing resources and other marginal resources within the portfolio. For example, as illustrated in the diagram above, the optimal level of PPA and wholesale market will depend on whether the optimization routine selects new resources for inclusion in a specific load scenario. When the optimization routine selects a resource option, the average monthly dependable capacity and reliable energy is then added to the total available monthly capacity and energy in the resource portfolio for future years past the selected resource in-service date.

In summary, the optimal resource portfolio that results in the lowest power supply revenue requirement, while meeting both the forecast energy and capacity load scenario, is simultaneously selected with consideration for the scenario constraints. The reliability of each portfolio is then evaluated by ensuring that it meets Planning Reserve Margin (PRM) requirements. In the event that PRM requirements are not met, the portfolio is re-optimized with additional capacity requirements for PRM purposes as per the process described in Section 3.2 of Appendix M of the LTERP.

30.2 Please discuss whether there are any key changes to FBC's portfolio optimization routine since FBC's 2016 LTERP.

30.2.1 If yes, provide the rationale for these key changes.

Response:

The 2021 LTERP portfolio model is an evolutionary improvement on the 2016 LTERP portfolio model. While the two models are fundamentally structured the same, the following is a high-level summary of the changes since the 2016 LTERP and their rationale:

- Minimize the power supply revenue requirement rather than power purchase expense. This better reflects the actual costs to customers by taking capital related costs (such as depreciation) into account as part of the cost minimization.
- Require the model to take all energy produced by intermittent resources such as wind and solar. This is more realistic and properly reflects the true volumes of energy that must be incorporated into utility operations.

- Update FBC's portfolio resource options to reflect the updated Supply Side Resource Options Report (Appendix K).
- Add the ability to use a resource option cost curve rather than a constant value over the planning horizon to account for changes in technology costs over the planning horizon.
- Change the market access rules for both energy and capacity:
  - Energy self-sufficiency is not required in accordance with the BCUC decision regarding FBC's 2016 LTERP.
  - If market capacity is used to meet load (up to 2030), it must be a monthly block rather than hourly. This greatly increases the market energy that must be purchased to obtain market capacity and this extra energy must be incorporated into utility operations.
  - The CEPSA agreement allows for greater certainly of market energy access and as such the amount of market energy allowed to be purchased to meet load requirements was increased.

In Table 11-1, on pages 175-176 of the Application, FBC provides its portfolio analysis base characteristics and sensitivity cases. The Base Case scenario is identified as portfolio A1 in Figures 11-1, 11-2, 11-3, 11-4, 11-5 and 11-6. Figure 11-2 is reproduced below, which shows that for portfolio A1, a distribution battery system will be required in 2030, an SCGT plant in 2031, etc.

Figure 11-2: Portfolios with Market Access versus Self-Sufficiency

30.3 Using the base case portfolio A1 as an example, please discuss, at a high level, how FBC's optimization routine determines which resources should be acquired and when.

<u>Response:</u>

As discussed in the response to BCUC IR1 30.1, the optimization routine minimizes the net present value of the power supply revenue requirement while meeting the energy and capacity requirements in each month of each year of the planning horizon. The optimal portfolios are a function of the available resources, the costs of those resources, and the portfolio constraints.

The first residual energy gaps in portfolio A1 occur in the winter of 2028-2029, which the optimization routine is able to address with cost effective wholesale market energy purchases.

The first residual capacity gap, after DSM, maximum PPA, and maximum market access permitted (which is 0 MW for capacity purposes over the planning horizon, with the exception of June, where 75 MW is permitted up to 2030), occurs in July 2030 for 8 MW. Therefore, the optimization routine must begin to meet this capacity requirement through new resources, while simultaneously considering other new resources required over the entire planning horizon as well as the impacts to PPA and market requirements. In addition, any portfolio constraints must also be met. As this initial capacity gap is relatively small, and only occurs in one month in 2030, the optimization routine determined that the lowest power supply cost decision is to build the DistBattery6 resource.

The next capacity gaps then occur in June, July, and December 2031, with the highest monthly capacity gap being 67 MW in June as market access for capacity purposes is no longer permitted after 2030. As these capacity gaps are larger, grow over the planning horizon and begin to occur in multiple months, the optimization routine determined that the SCGT3 is required, which is capable of providing dependable capacity year round. The model selects resources while simultaneously considering the interaction with existing resources. For example, the inclusion of SCGT3 results in a decreased use of PPA capacity, which has a take or pay ratchet in months where there are no or minimal residual capacity gaps. SCGT3 is the largest SCGT resource option available in the portfolio at 100 MW of installed capacity, allowing for some growth in capacity requirements later in the planning horizon, but only dispatches small amounts of energy. The optimization routine used the wholesale market as the most cost-effective way to meet general energy requirements but relied on the energy from the SCGT units during peak hours. The next capacity gaps, after the new resources as discussed above, occur in 2035, and the optimization routine determined, based on the size and shape of the incremental gaps remaining over the rest of the planning horizon, that SCGT1 and RNG_SCGT1 are the lowest cost decisions. Lastly, the remaining capacity gaps at the end of the horizon are relatively minor and occur in June, and thus the smaller DistSolar1 and Solar2 resources are selected. If FBC included larger SCGT units as an available resource in the portfolio, a larger unit may be selected over a combination of smaller SCGT units. Larger SCGT units were not included as larger capacity-orientated units, relative to FBC's load, create challenges with planned and unplanned outages as well as the limited interconnection locations on FBC's transmission system.

30.3.1 Please also discuss, at a high level, how the optimization routine determines what size of each resource is required.

Response:

The optimization routine considers the residual capacity and energy gaps over the planning horizon, and simultaneously optimizes the size of new resources that fit within the portfolio and the constraints. The portfolio model selects from a set of resource options that range in size. The optimization routine is able to select one or more combinations of resource options to meet the forecast load. Both the selection of the appropriate size of a specific resource type, and the timing of the build, are considered in minimizing the costs over the planning horizon.

Figure 11-3, on page 183 of the Application, FBC provides portfolios with varying levels of clean or renewable resources. Figure 11-3 is reproduced below.

Figure 11-3: Portfolios with varying levels of Clean or Renewable Resources

30.4 Using Figure 11-3 as an example, please discuss how the optimization routine determines which resources should be acquired and when. For example, please explain, at a high level, why a distribution battery is the selected resource in 2030 for portfolios A1, C2 and C3, whereas a transmission battery is the selected resource in 2030 for portfolios C4 and C5.

Response:

The monthly capacity gaps in 2031, as discussed in the response to BCUC IR1 30.3, resulted in SCGTs being selected as new resources in portfolios A1, C2 and C3, and therefore, only a smaller DistBattery6 (24 MW of dependable capacity) is first being acquired in 2030.

In contrast, portfolios C4 and C5 are restricted such that they are not permitted to select SCGTs of any kind as new resources. Therefore, the optimization routine determined the larger Battery4 (39 MW of dependable capacity) is a better fit in 2030. A portfolio of complementary renewable resources is then required in the subsequent years to meet the future monthly capacity gaps over the different seasons.

In other words, portfolios A1, C2 and C3 primarily purchase clean market energy and then meet capacity self-sufficiency requirements with SCGT peaking resources. Portfolios C4 and C5 are restricted from using SCGT peaking resources, and instead build a large collection of renewable resources that collectively meet the monthly capacity self-sufficiency requirements, but displace the market energy and portfolio flexibility in the process. The cost to achieve capacity self-sufficiency through a larger collection of intermittent resources is greater than a smaller number of year-round dispatchable resources.

31.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Section 10.4, p. 169Section 11, pp. 175–176, 183, 189–193

Portfolio Analysis Results

In Table 11-1, on pages 175-176 of the Application, FBC provides its portfolio analysis base characteristics and sensitivity cases.

On page 4 of the Application, FBC provides its long-term resource planning objectives. FBC states:

> FBC's resource planning objectives form the basis for meeting any potential load-resource balance gaps in the future and for identifying and evaluating potential resource options and portfolios in the LTERP. These objectives reflect the Company's commitment to deliver quality service to customers, manage resources prudently, and operate a safe and reliable electricity system. The objectives of the LTERP are as follows:
>
> - Ensure cost-effective, secure and reliable power for customers;
> - Provide cost-effective demand side management and cleaner customer solutions, and
> - Ensure consistency with provincial energy objectives (for example, the applicable objectives in the CEA and the CleanBC Plan).

31.1 Please discuss how a portfolio with base characteristics as described by Table 11-1 meets FBC's LTERP Objectives as stated above.

Response:

A portfolio with base characteristics as described in Table 11-1 is represented by portfolio A1, which is used as a common point of reference in Section 11.3. This portfolio meets the LTERP objectives because it is:

- cost effective (given its relatively low LRMC value);
- includes the recommended base level of DSM;
- includes SCGT plants to provide dependable capacity while meeting the current regulations of at least 93 percent clean;
- has low environmental impacts;
- provides some economic development; and
- meets FBC's planning reserve margin requirements.

However, as discussed in Section 11.3.8, this portfolio was not considered in FBC's set of preferred portfolios as FBC believes that portfolios including only clean or renewable resources best reflect the energy priorities of its customers, stakeholders, and Indigenous communities based on their feedback discussed in Section 12.

31.2 Please explain, with rationale, whether the base case portfolio (A1) considers 100 percent of its market purchases are from clean resources.

Response:

FBC confirms the base case portfolio (A1) has the clean market adder applied to the cost of its market purchases, and therefore 100 percent of the market purchases in this portfolio are considered from clean resources. All portfolios presented, with the exception of portfolios B3 and B4, have the clean market adder applied.

FBC included the clean market adder as a base case as this reflects some stakeholders' desires for clean energy in the portfolio and, since the 2016 LTERP, Powerex has become open to offering this type of product to FBC. FBC intends to transition to clean market purchases as stated in the action items outlined in Section 13.2.

31.3 Please discuss whether FBC considered any sensitivity analysis with respect to utilization factor of its supply side resources to, for example, evaluate conditions where actual energy produced many be less or more than expected.

31.3.1 If yes, please describe what was considered.

31.3.2 If not, please explain why not.

Response:

FBC's modelling does not include any sensitivity analysis with respect to utilization factor of its supply-side resources to evaluate conditions where energy cumulatively produced over the year (as opposed to on peak hours) may be less or more than expected energy. The primary reasons why this is not a material limitation are: the capabilities of FBC's existing supply-side resources and storage accounts under the CPA, the reliability as well as flexibility of the PPA, and FBC's access to market.

FBC-owned generation as well as the BPPA and BRX contracts provide firm energy under the CPA that is only subject to unit outage risk. The PPA contract with BC Hydro is even less risky in that it is completely flexible and reliable except in the exceedingly unlikely situation where FBC is isolated from BC Hydro or BC Hydro itself has insufficient supply such that all customers, including FBC, must reduce energy use. Therefore, FBC's existing supply-side resources carry little to no energy risk and the small amount of risk that remains is well within FBC's operational flexibility to ensure reliable supply.

The CPA provides a storage account that allows for storage of up to a maximum of 24.5 GWh.[6] This flexibility can either temporarily replace energy that was expected to be received or store energy that is surplus until it can be used. If energy from existing or new resources varies beyond the capabilities of the CPA storage account, FBC can also vary purchases under the PPA or adjust market purchases, whichever has the lowest total cost.

However, FBC does account for sensitivity analysis with respect to the capacity variation of its supply-side resources. PRM is a component of the portfolio analysis process and a means to explore uncertainty around the availability of capacity (energy during peak hours). The PRM model investigates the possibility that capacity available during peak load can vary from the average monthly profile. The resource options were grouped into two broad categories, namely dispatchable and intermittent. Dispatchable resources were assigned a forced outage rate that was used to simulate outages resulting in the unavailability of the unit. Intermittent resources used a distribution of possible generation on peak hours to simulate varying resource output. Therefore, varying operational conditions, which includes if actual energy produced by resources varied more or less than expected in peak hours, was considered through FBC's modelling of PRM.

Figure 11-3, on page 183 of the Application, FBC provides portfolios with varying levels of clean or renewable resources. FBC identifies that portfolio C3 includes only clean and renewable resourcing including SCGT plants using RNG and portfolio C4 includes only clean and renewable resources and excludes SCGT plants using RNG.

31.4 Please explain the purpose of including scenario analysis with and without SCGT plants using RNG.

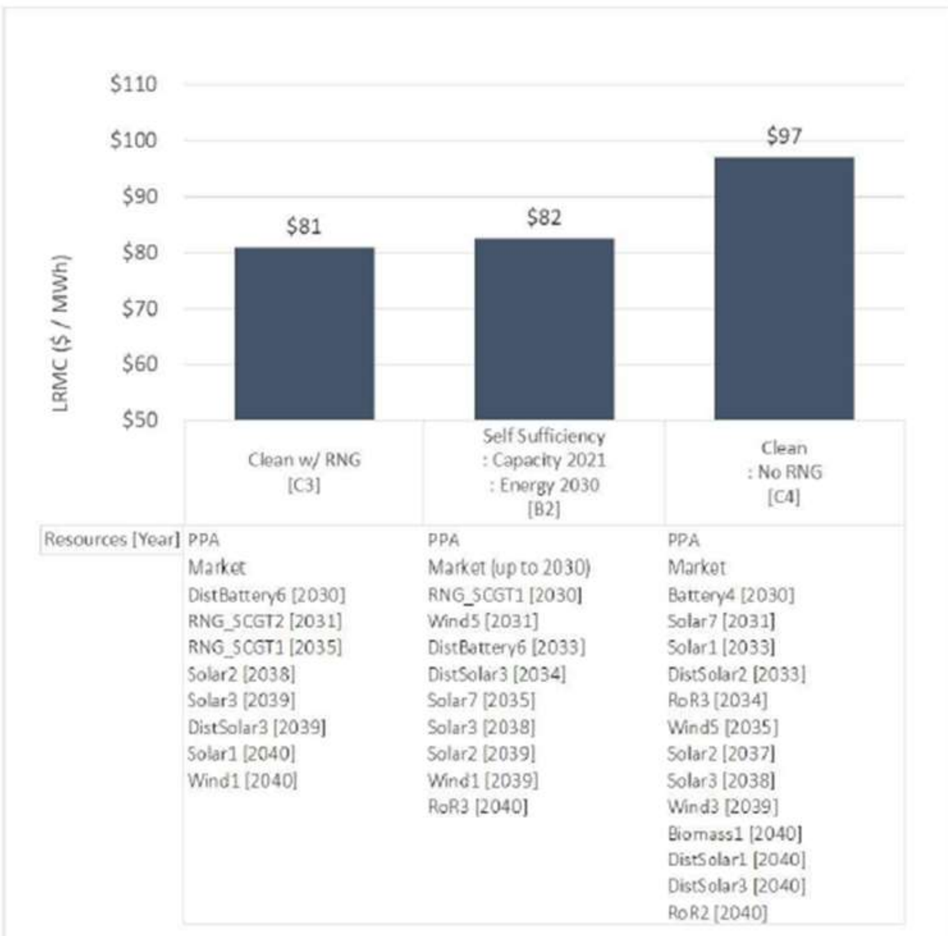
Response:

Based on the feedback provided during FBC's RPAG meetings, FBC anticipated that stakeholders would be interested in comparing the costs, environmental, resiliency, and economic attributes of a portfolio that includes RNG SCGT resources to a portfolio that does not include any RNG SCGT resources. Comparing portfolios C3 and C4 illustrates that a collection of seasonally complementary intermittent resources is required to replace the dependable year-round capacity provided by RNG SCGT resources.

[6] FBC's share of the CPA joint account of 49 GWh.

Figures 11-7, on page 190 of the Application provides the portfolios considered for preferred portfolios. Figure 11-7 is reproduced below.

Figure 11-7: Portfolios Considered for Preferred Portfolios



31.5 For each of the 3 preferred portfolios, please identify the size of resource specified (i.e.: for portfolio C3, what size of SCGT is specified in 2031, what size of SCGT plant is specified in 2035, etc.)

Response:

Please refer to the below table for the sizes of each resource selected in the preferred portfolios:

Resource ID	Installed Capacity (MW)	Portfolio C3	Portfolio B2	Portfolio C4
DistBattery6	25	√	√	
RNG_SCGT2	100	√		
RNG_SCGT1	48	√	√	
Solar2	39	√	√	√
Solar3	47	√	√	√
DistSolar3	9	√	√	√
Solar1	17	√		√
Wind1	45	√	√	
Wind5	140		√	√
Solar7	110		√	√
RoR3	16		√	√
Battery4	50			√
DistSolar2	4			√
Wind3	65			√
Biomass1	9			√
DistSolar1	1			√
RoR2	11			√

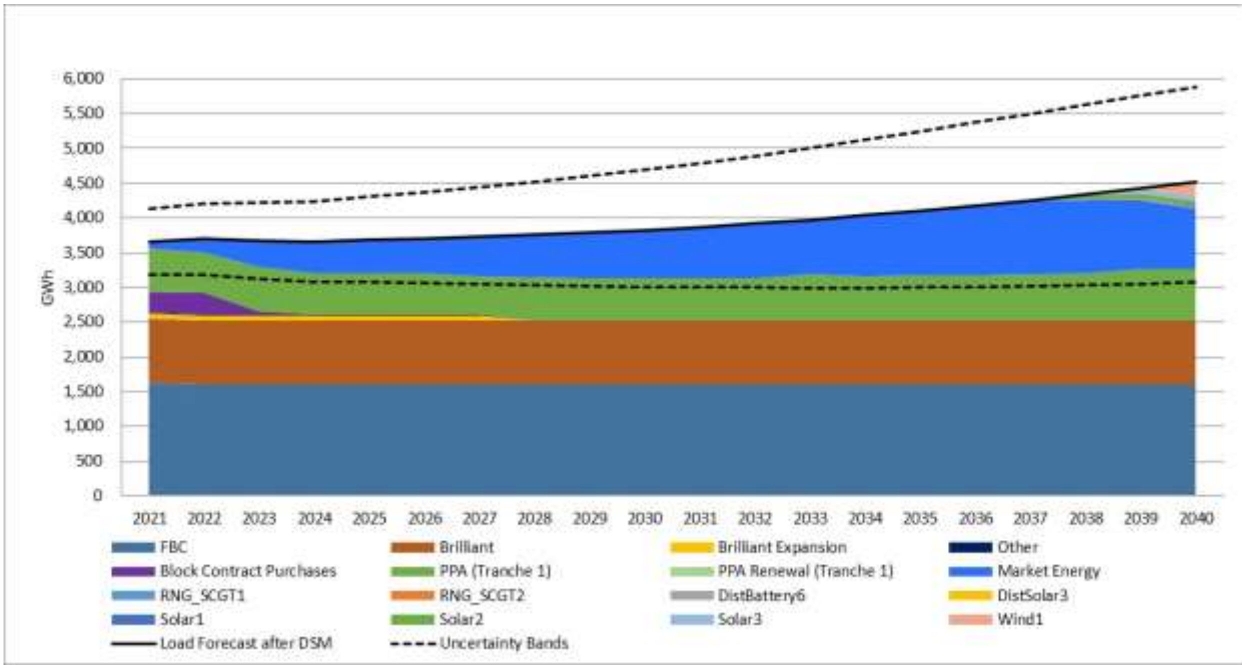
31.6 Please overlay the proposed resources for the portfolios shown in Figure 11-7 on each of the load-resource balance (LRB) gap figures provided in Section 9 of the Application to show how each portfolio meets the LRB gaps identified (for energy and winter, summer and June capacity).

Response:

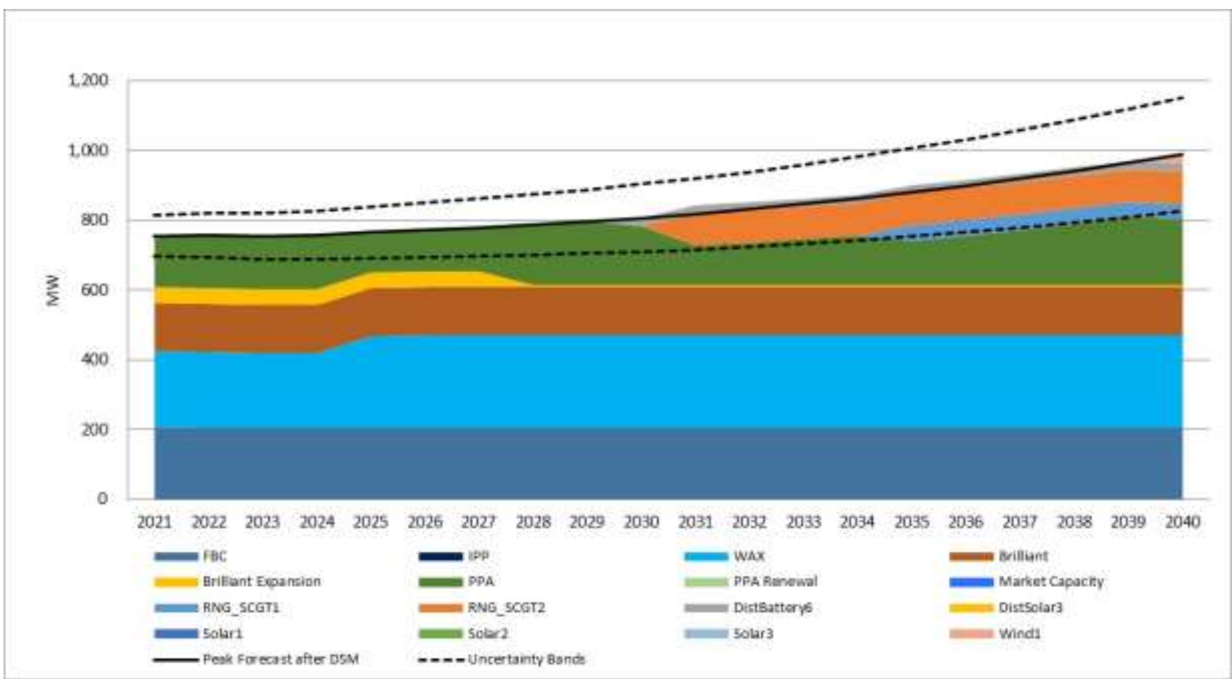
The figures below are updates of Figures 9-1, 9-2, 9-4, and 9-6 for the preferred portfolios shown in Figure 11-7. Note that the June graphs illustrate market capacity blocks in increments of 25 MW, not variable market capacity, as discussed in Section 2.4.4.1 of the Application.

Clean w/ RNG [C3]

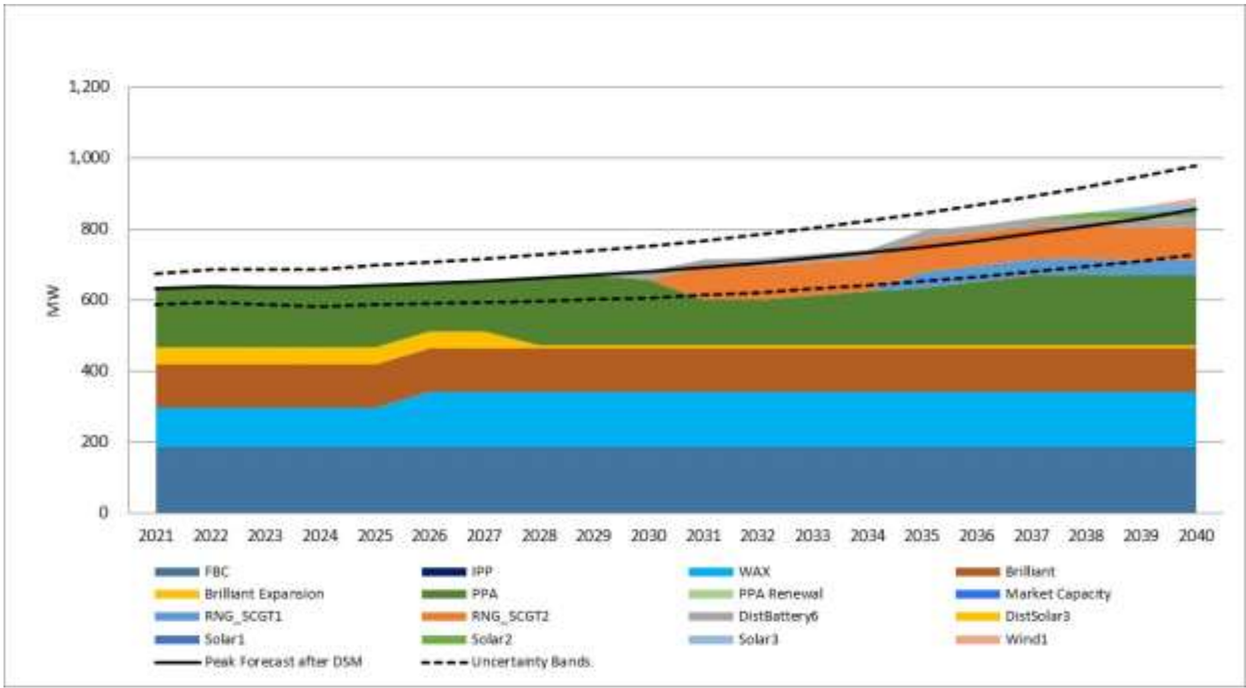
Updated Figure 9-1 – Energy Load-Resource Balance after DSM



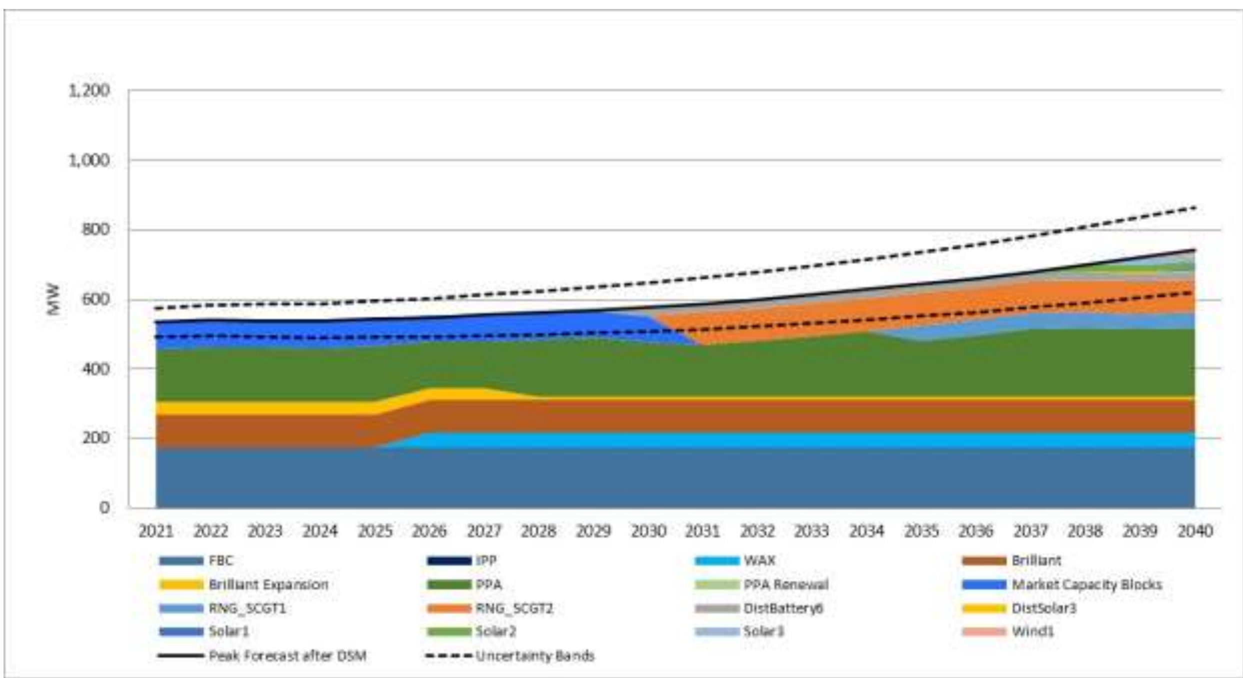
Updated Figure 9-2 – Winter Capacity Load-Resource Balance after DSM



Updated Figure 9-4 – Summer Capacity Load-Resource Balance after DSM

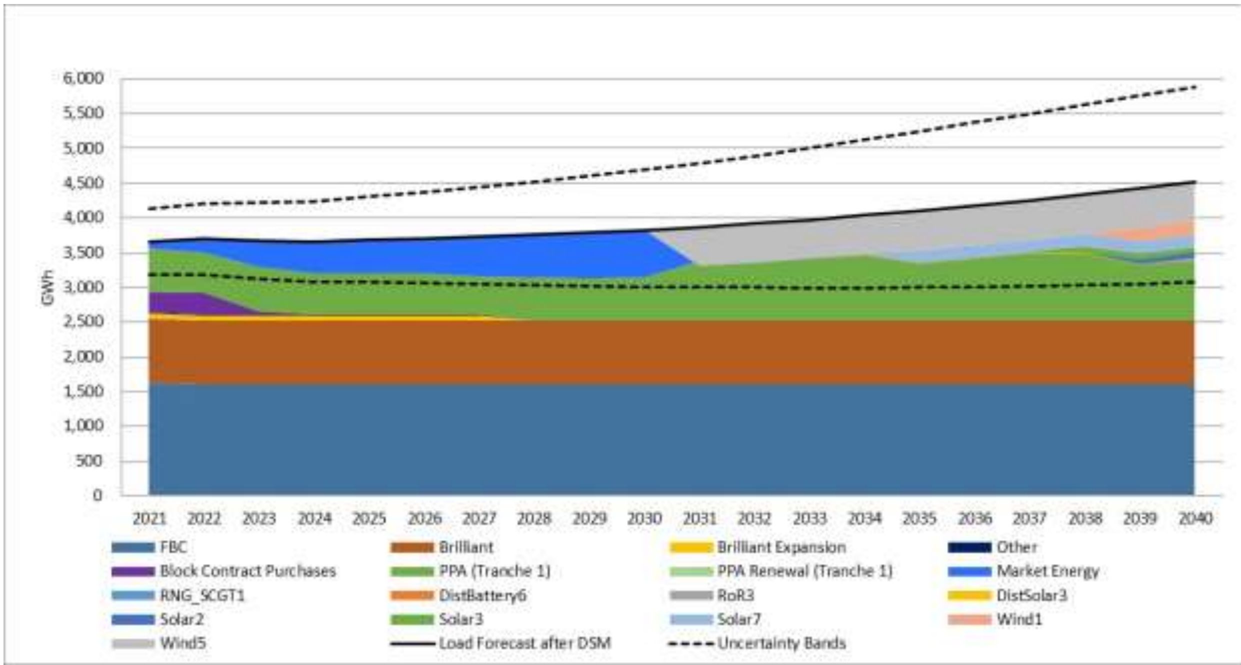


Updated Figure 9-6 – June Capacity Load-Resource Balance after DSM

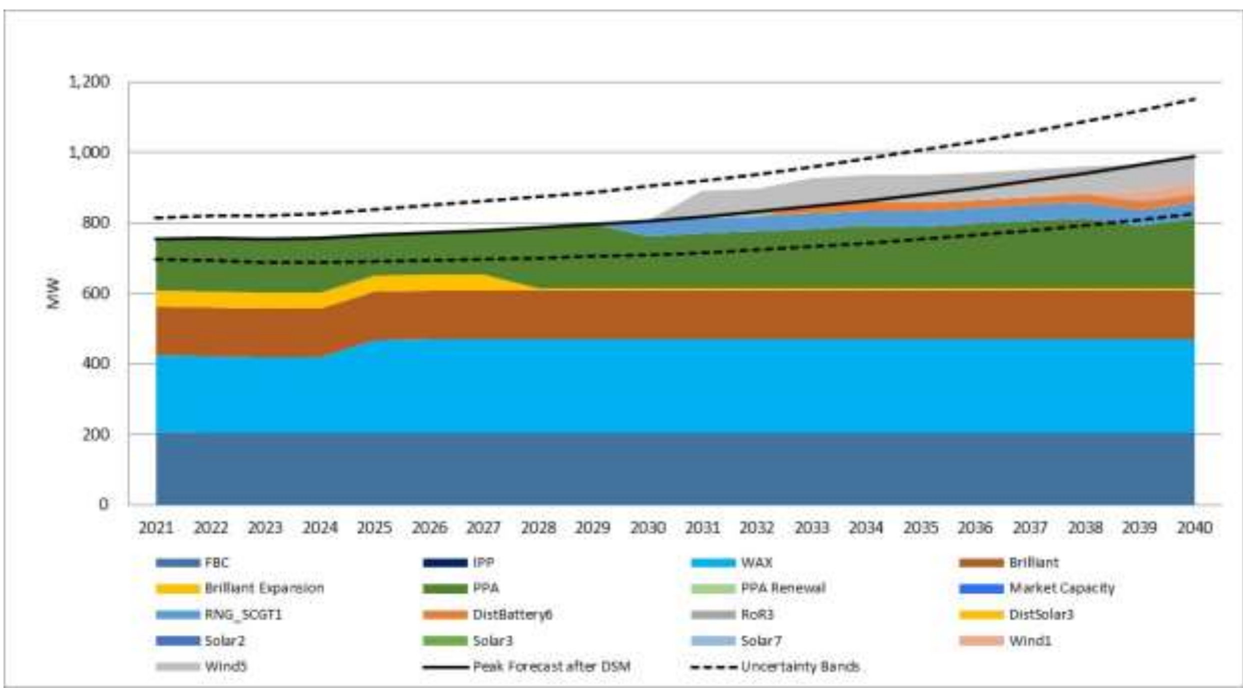


Self Sufficiency: Capacity 2021: Energy 2030 [B2]

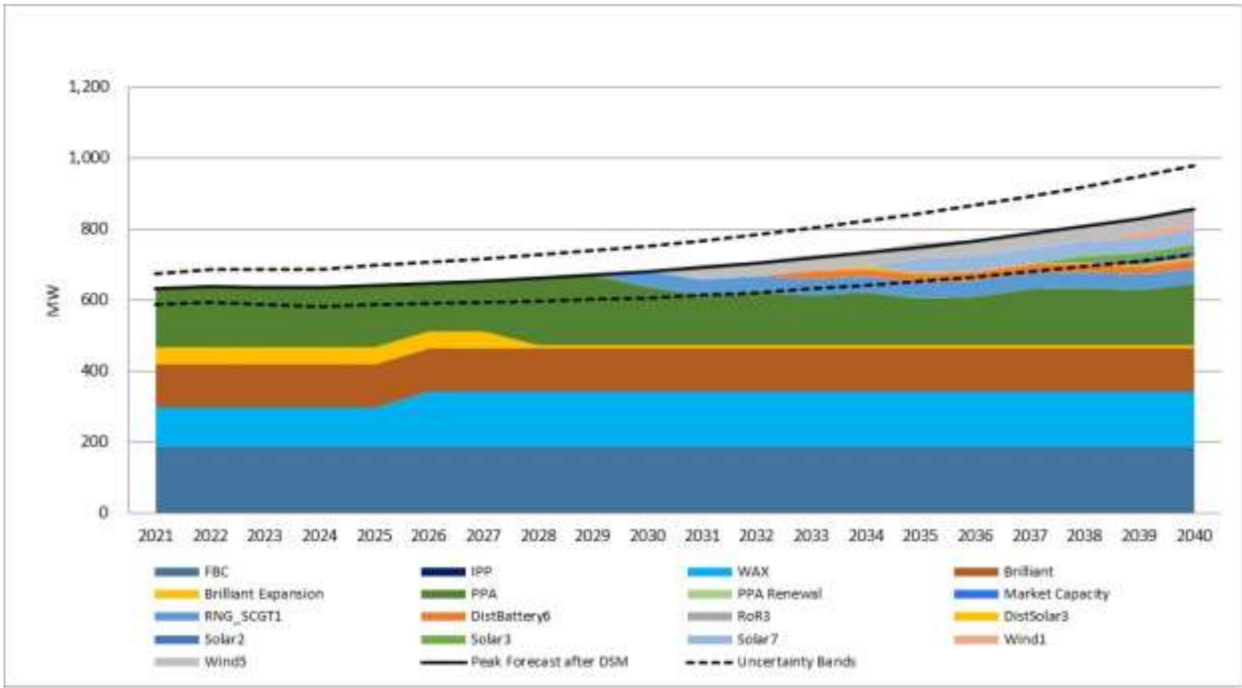
Updated Figure 9-1 – Energy Load-Resource Balance after DSM



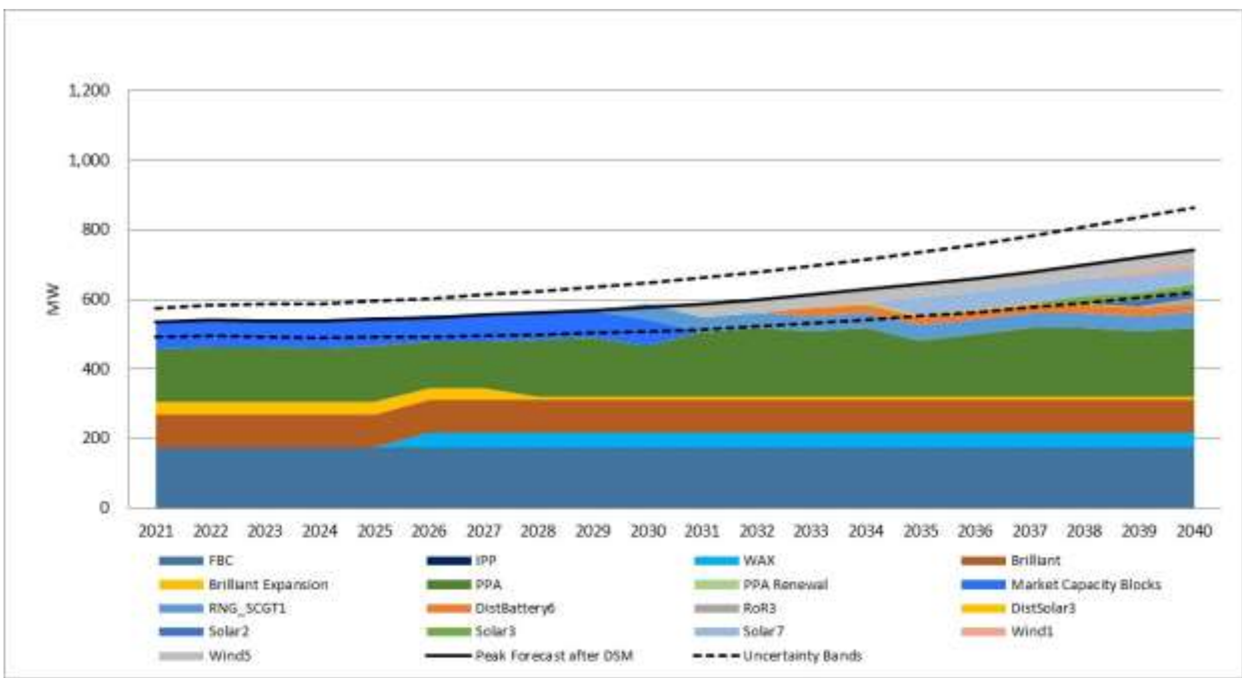
Updated Figure 9-2 – Winter Capacity Load-Resource Balance after DSM



Updated Figure 9-4 – Summer Capacity Load-Resource Balance after DSM

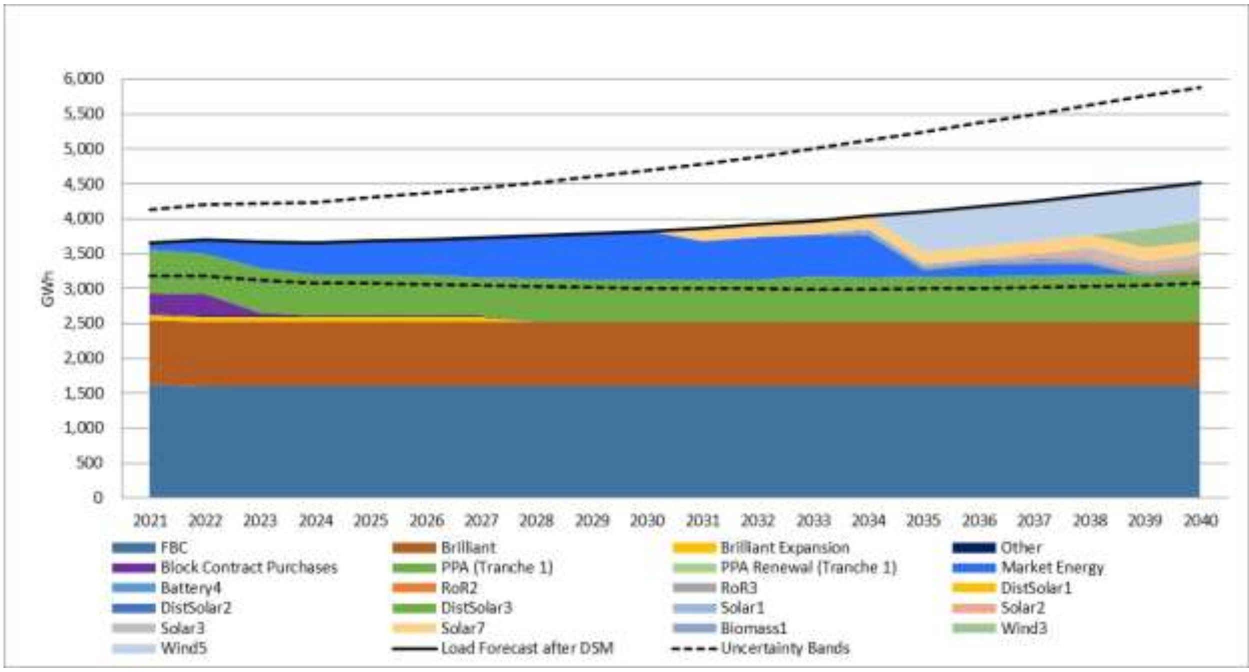


Updated Figure 9-6 – June Capacity Load-Resource Balance after DSM

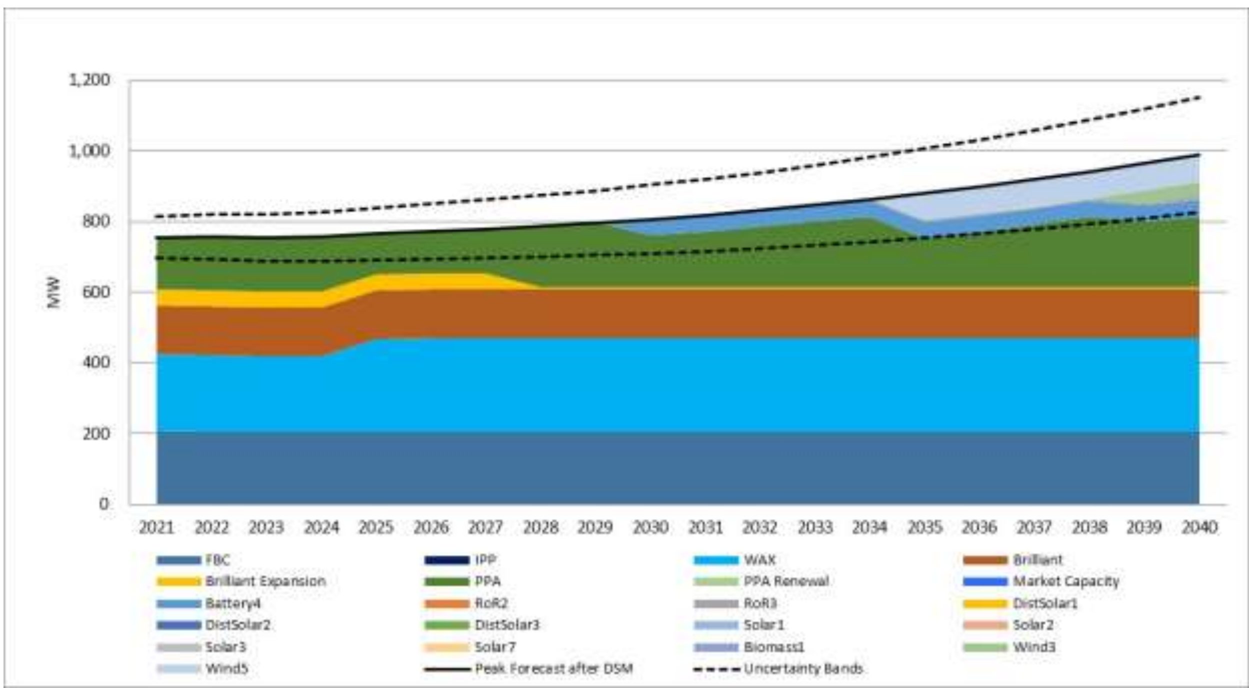


Clean: No RNG [C4]

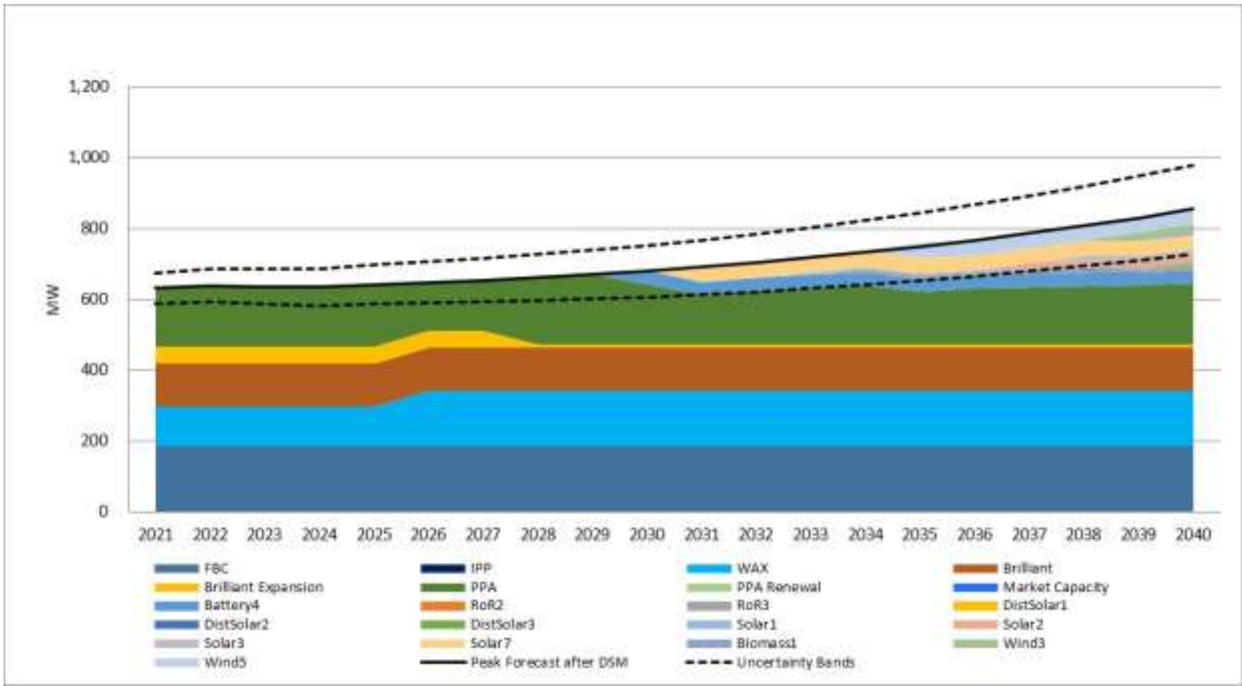
Updated Figure 9-1 – Energy Load-Resource Balance after DSM



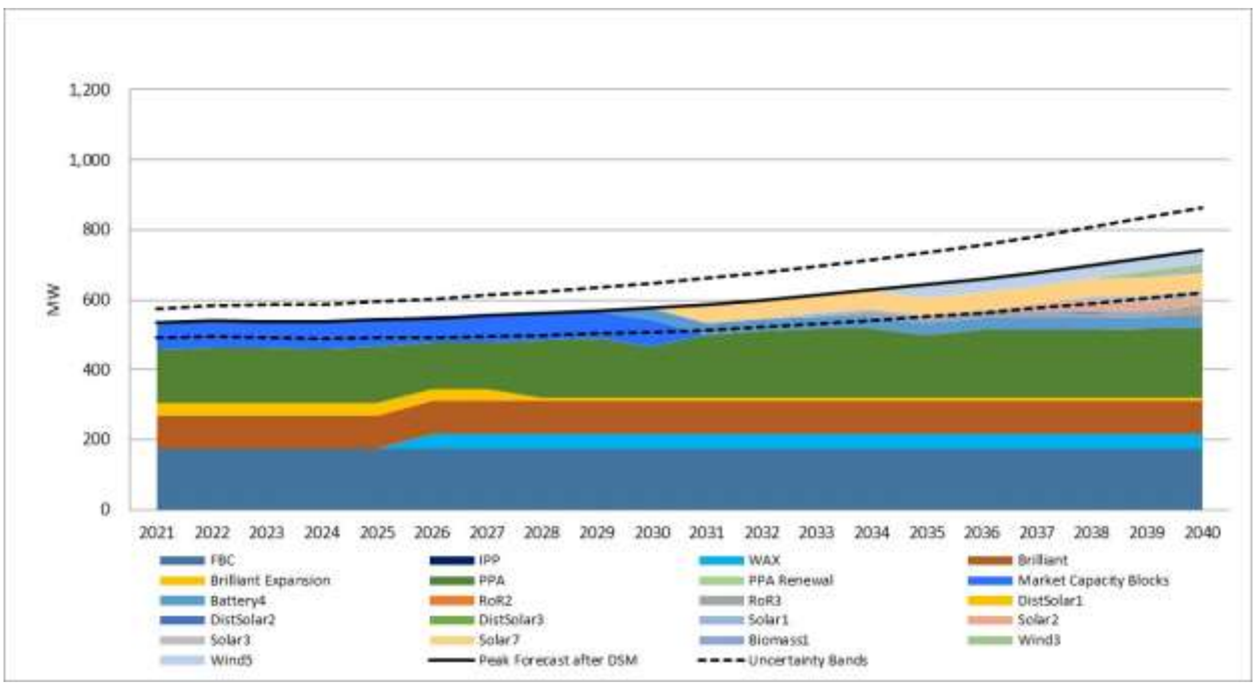
Updated Figure 9-2 – Winter Capacity Load-Resource Balance after DSM



Updated Figure 9-4 – Summer Capacity Load-Resource Balance after DSM



Updated Figure 9-6 – June Capacity Load-Resource Balance after DSM



On page 189 of the Application, FBC states:

> Based on the portfolio analysis presented in the previous sections, FBC has determined a set of portfolios that are considered for the preferred resource portfolios. The preferred portfolios are those that meet the LRB gaps based on the Reference Case load forecast, includes cost effective DSM, and best meet the LTERP objectives of cost-effectiveness, reliability, and consideration of BC's energy objectives. The preferred portfolios are selected from the discussion and figures in the previous sections and are presented in the following summary figure.

Figure 11-7, on page 190 of the Application provides the portfolios considered for preferred portfolios.

31.7 Please confirm, or explain otherwise, that all the portfolios identified in Sections 11.3.1 through 11.3.6 of the Application meet the LRB gaps based on the reference case load forecast.

31.7.1 If not, please identify which portfolios do not.

Response:

The portfolios in Sections 11.3.1 through 11.3.6 of the Application meet the LRB gaps of their corresponding scenarios.

Portfolios A1 in Section 11.3.1, D1 in Section 11.3.4, E1 in Section 11.3.5, and all the portfolios in Sections 11.3.2, 11.3.2, 11.3.3 and 11.3.6, meet the LRB gaps based on the Reference Case load forecast.

The other portfolios meet LRB gaps based on scenarios that are different from the Reference Case load forecast as follows:

- In Section 11.3.1, portfolios A2 to A6 contain different DSM portfolios (or no DSM in the case of portfolio A2). Therefore, these portfolios contain different LRB energy and capacity gaps after DSM, but do contain the same LRB energy and capacity gaps as the Reference Case load forecast before DSM.
- In Section 11.3.4, portfolios D2 to D5 are based on the load scenarios provided by Guidehouse as well as the stakeholder average scenario. Therefore, these portfolios contain different LRB energy and capacity gaps than the Reference Case load forecast.
- In Section 11.3.5, portfolios E2 to E5 are based on the same LRB energy gaps as the Reference Case load forecast; however, each portfolio contains varying levels of EV charging shifting and therefore incrementally less LRB capacity gaps than the Reference Case load forecast.

31.8 Please expand on how FBC evaluated the portfolios identified in Sections 11.3.1 through 11.3.6 of the Application to determine which portfolios are the preferred portfolios.

Response:

As discussed in Section 11.3.8, FBC recommends portfolios C3, B2 and C4 for consideration as the preferred portfolios. These portfolios were selected based on their ability to meet the LTERP objectives under different conditions. FBC also considered the energy priorities as indicated by stakeholders, Indigenous communities, and customers through FBC's LTERP engagement processes.

As discussed in Section 12, FBC's community and Indigenous engagement revealed their priorities are related to cost-effectiveness, reliability, and protecting the environment. One Indigenous group also indicated that economic growth and partnership opportunities help community development and therefore indirectly help to address affordability.

The customer survey indicates priorities of cost-effective and reliable power rank above reducing GHG emissions, conservation and energy management solutions, and job creation. Some of FBC's RPAG members have indicated a preference for cost-effective and reliable resources with some prioritizing protecting the environment.

Based on these considerations, the table below shows how the portfolios considered for the preferred portfolios were determined, with reference to the various portfolios presented in the figures in Sections 11.3.1 to 11.3.6.

Portfolio Figure/Attributes	Portfolio(s) Considered for Preferred Portfolios	Reason
Figure 11-1: Varying DSM Levels	A1	Base DSM level is considered optimal per LT DSM Plan
Figure 11-2: Market Access vs. Self-Sufficiency	A1, B2	Least-cost and include clean market adder
Figure 11-3: Clean vs. Non-Clean	C3, C4	Least-cost clean portfolios
Figure 11-4: Load Scenarios	A1	Reference Case load forecast is expected planning forecast
Figure 11-5: EV Charging Shifting	A1	FBC does not yet have a program in place for shifting EV charging
Figure 11-6: PPA Renewal	A1	Least-cost with PPA renewal

As the table above indicates, portfolios A1, B2, C3 and C4 were the resulting portfolios considered for the preferred portfolios. FBC did not include A1 in the preferred portfolios as it includes an SCGT plant using conventional natural gas and so is not a clean and renewable portfolio.

Therefore, portfolios B2, C3 and C4 were considered for the preferred portfolios, as shown in Figure 11-7.

Portfolio C3 has the lowest LRMC of the portfolios including only clean or renewable resources and so ranks favourably in terms of cost effectiveness and environmental attributes. As shown in Table 11-2, this portfolio also rates 'high' in terms of resiliency and provides some economic development in terms of BC employment. It includes market energy throughout the planning horizon but maintains a capacity self-sufficiency requirement.

Portfolio B2 also includes only clean or renewable resources, maintains a capacity self-sufficiency requirement throughout the planning horizon, but additionally includes an energy self-sufficiency requirement starting in 2030. This portfolio has relatively low environmental impacts, provides some operational flexibility and geographic resource diversity, and contributes to economic development. Although the LRMC of portfolio B2 is relatively low, the average cost of this portfolio is comparably higher as full energy self-sufficiency would impact FBC's ability to utilize the market to meet current load in addition to the incremental load. Portfolio B2 would likely be a preferred option for FBC in the event that market conditions changed such that market energy was no longer a reliable or cost-effective option in the future. FBC discusses the regional energy market in Section 2.4.4 and notes the potential risks with relying on market energy and capacity. Therefore, portfolio B2 is considered a preferred portfolio as it also meets the LTERP objectives while also including both capacity and energy self-sufficiency over the long term.

Portfolio C4 also includes only clean or renewable resources but excludes SCGT plants, even those using RNG as fuel. Portfolio C4 maintains a capacity self-sufficiency requirement, but allows market energy throughout the planning horizon. This portfolio requires a collection of resource options that are more costly than SCGT plants to maintain capacity self-sufficiency. This portfolio has higher cost attributes and lower operational flexibility than the other two preferred portfolios but has low environmental impacts, high geographic diversity and a higher contribution to economic development. FBC has included portfolio C4 in the preferred portfolios as FBC recognizes that there may be social licensing issues with the permitting and construction of an SCGT plant in its service area, even if the plant were to use a renewable fuel like RNG.

FBC has not included portfolios with SCGT plants using conventional natural gas as fuel, such as portfolio A1, in its set of preferred portfolios based on the feedback received during the June 2021 RPAG meeting. FBC believes that portfolios only including clean or renewable resources best reflect the energy priorities of its customers, stakeholders and Indigenous communities based on their feedback discussed in Section 12.

31.8.1 Please discuss whether FBC used any weightings or other quantifiable evaluation strategy in determining which portfolios identified in Sections 11.3.1 through 11.3.6 of the Application are the preferred portfolios.

31.8.1.1 If yes, please describe the evaluation strategy used and how each portfolio was scored or weighted.

31.8.1.2 If not, please explain why not.

Response:

FBC did not use any weightings or other quantifiable evaluation strategy in determining which portfolios are the preferred portfolios. As discussed in Section 11.3.8 and the response to BCUC IR1 31.8, the preferred portfolios were based on their ability to meet the LTERP objectives under different conditions (e.g., access or no access to market energy and capacity or exclusion of RNG SCGT plants). FBC's selection of preferred portfolios was based on considerations of the energy market dynamics as well as stakeholder feedback, and so weightings or other quantifiable evaluation strategies were not necessary. As discussed in Section 2.4.4, the regional resource mix is changing and there are longer term risks with relying on market energy and capacity. Therefore, FBC believes that a portfolio with both energy and capacity self-sufficiency should be among the preferred portfolios. As discussed in Section 11.3.9, some members of the RPAG have indicated their support for SCGT plants using RNG fuel as a cost-effective and environmental alternative to SCGT plants using traditional natural gas. FBC does note that it may be difficult to permit and construct RNG SCGT plants from a social license perspective. Therefore, based on this feedback, FBC has included in the preferred portfolios a portfolio which excludes SCGT plants altogether.

31.9 Please discuss how FBC evaluated the portfolios identified in Sections 11.3.1 through 11.3.6 of the Application to determine which portfolios best meet the LTERP objectives of cost-effectiveness, reliability, and consideration of BC's energy objectives.

Response:

Please refer to the response to BCUC IR1 31.8.

31.9.1 Please discuss whether FBC used any weightings or other quantifiable evaluation strategy in determining which portfolios identified in Sections 11.3.1 through 11.3.6 of the Application best meet the LTERP objectives of cost-effectiveness, reliability, and consideration of BC's energy objectives.

31.9.1.1 If yes, please describe the evaluation strategy used and how each portfolio was scored or weighted.

31.9.1.2 If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 31.8.1.

31.10 Please discuss whether other criteria, in addition to the above LTERP objectives, were used to select the preferred portfolios.

Response:

Please refer to the response to BCUC IR1 31.8.

On page 191 of the Application, FBC states:

> FBC has not included portfolios with SCGT plants using conventional natural gas as fuel, such as portfolio A1, in its set of preferred portfolios based on the feedback received during the June 2021 RPAG meeting.

31.11 Please discuss how FBC used stakeholder feedback in evaluating the portfolios identified in Sections 11.3.1 through 11.3.6 of the Application to determine which portfolios are the preferred portfolios.

Response:

Please refer to the response to BCUC IR1 31.8.

31.12 Please discuss whether there are any other factors, in addition to negative stakeholder feedback, that would have eliminated portfolio A1 from being a preferred portfolio.

Response:

No other factors besides the negative stakeholder feedback would have eliminated portfolio A1 from being a preferred portfolio.

31.13 Please discuss how each of the preferred portfolios identified in Figure 11-7 meets FBC's LTERP objectives.

Response:

Please refer to the response to BCUC IR1 31.8.

On page 192 of the Application, FBC states:

> FBC received stakeholder feedback at the RPAG meetings to include an Indigenous community development attribute in the portfolio evaluation criteria. FBC considered this but since the benefits of Indigenous participation are common to all portfolios, it is not required as an independent measure. It is FBC's view that the BC employment provides a similar measure. As discussed in Section 10.9, FBC will consider partnerships with local and Indigenous communities when new supply-side resources are developed in the future.

31.14 Please explain, with rationale, how Indigenous community development is common to all portfolios.

Response:

As discussed in Section 12 of the Application, FBC engaged with Indigenous communities throughout the development of the LTERP to better understand their energy priorities, energy plans for the future, and to receive feedback on key aspects of the LTERP. Through these discussions, Indigenous community representatives provided input and feedback on key aspects of the LTERP that was consistent with the final portfolio attributes identified in Table 11-2 of the Application. Indigenous community representatives engaged during the LTERP process identified key energy priorities, including but not limited to, affordability, energy efficiency, reliable energy service, low carbon and renewable energy, and economic development. This feedback was factored into the Preferred Portfolio development within the Application, and FBC considers the final version of the portfolio attributes to be consistent with the feedback provided by Indigenous community representatives during the LTERP process. On this basis, Indigenous community development has been factored into the portfolio attributes within the Application.

As discussed in Section 10.9 of the Application, FBC will continue to engage with local and Indigenous communities when new supply-side resources are developed to ensure these resources are developed in a manner consistent with FBC's portfolio attributes and the key energy priorities identified by Indigenous community representatives during the LTERP process. FBC will continue to evolve its LTERP development and engagement process to ensure long-term utility planning meaningfully incorporates and reflects Indigenous energy priorities, such as those identified during this LTERP process, in future resource planning processes.

In Table 11-2, on page 193 of the Application, FBC provides the four key attributes of portfolios considered for preferred portfolios, namely cost, environment, resiliency, and economic.

31.15 Please discuss whether these attributes were assigned weightings for use in the evaluation process.

31.15.1 If yes, please identify the weightings and why FEI considers them reasonable.

31.15.2 If not, please discuss why not.

Response:

These attributes were not assigned weightings for use in the evaluation process. FBC considers all attributes to be important in the evaluation of the portfolios as they are generally reflective of the LTERP objectives and stakeholders' energy priorities. FBC has taken a balanced approach in its portfolio evaluation in order to meet all the LTERP objectives.

In Table 11-2, on page 193 of the Application, FBC provides GHG emissions for each portfolio.

31.16 Please confirm the units associated with the scope 1 and scope 3 emissions listed.

Response:

The scope 1 and 3 emissions reflect the total emissions over the planning horizon, stated in tonnes CO2e. As projected emissions can vary year to year depending on the dispatch of the various existing and new resources, the total emissions are expressed on a net present value basis.

On page 192 of the Application, FBC states:

> Operational flexibility refers to the ability of the portfolio to manage higher than expected energy and capacity loads. These loads may occur over a short period of time such as occurred this past June 2021 with record setting daily loads or over a longer period of time due to unexpected load growth. A portfolio with a 'high' rating means that it has more flexibility to meet higher than expected loads than a portfolio with a 'low' rating.

In Table 11-2, on page 193 of the Application, FBC provides scoring for operational flexibility for each portfolio.

31.17 Please explain the scoring of "High", "Medium" and "Low" for operational flexibility for portfolios C3, B2 and C4, respectively.

Response:

Portfolio C3 contains two RNG SCGTs, which are highly flexible and dispatchable resources that can quickly ramp up or down to meet changing demand. The RNG SCGT plants are used minimally in this portfolio, and therefore could be utilized more frequently to meet higher demand requirements if needed. This portfolio also contains the least amount of intermittent resources within the preferred portfolios, and therefore has the "High" rating for operational flexibility.

Portfolio B2 only contains one RNG SCGT, and also contains more intermittent resources than portfolio C3, and therefore has the "Medium" rating for operational flexibility.

Portfolio C4 contains no RNG SCGTs, and the largest number of intermittent resources. These intermittent resources provide less dependable capacity, and generation from these resources cannot be increased or decreased on demand in response to changing loads, leading to possible times of energy surplus or deficiency that must be managed in the portfolio. Therefore, this portfolio has the "Low" rating as it has the least amount of flexibility to meet higher or lower than expected loads.

On page 189 of the Application, FBC states the following as portfolio analysis key finding:

> No new generation resources are required before 2030 except for portfolios based on higher load scenarios, which require new resources in 2025 or 2028;

On page 184 of the Application, Figure 11-4 provides the portfolios based on load scenarios. Figure 11-4 is reproduced below.

Figure 11-4: Portfolios based on Load Scenarios

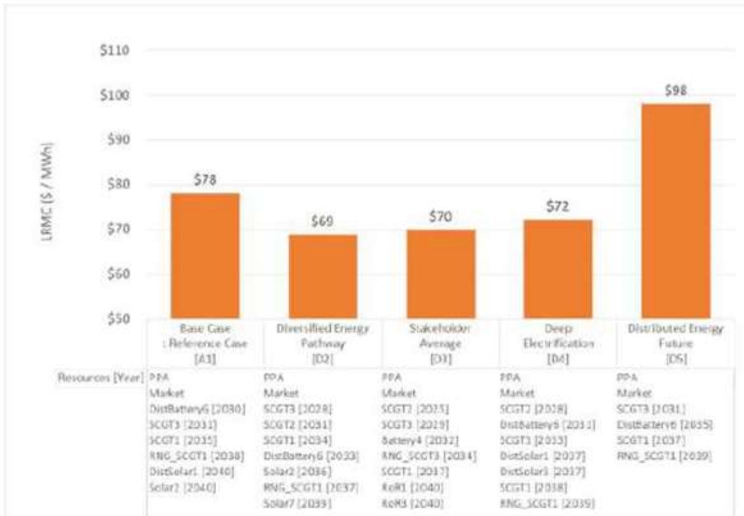


Table 10-3, on page 169 of the Application, provides a summary of the supply-side resource environmental, socio-economic and lead time attributes, including lead time in years. SCGT is identified as having a 4-year lead time.

31.18 If the load associated with any of the following scenarios materializes, namely the diversified energy pathway, the stakeholder average, or the deep electrification load scenario, please discuss the feasibility of an SCGT plant being operational by either 2025 or 2028.

<u>Response:</u>

An SCGT plant could be operational by either 2025 or 2028 given the four-year lead time. However, to have a plant operational by 2025 would require that FBC submit an expedited application for a CPCN to the BCUC for review, and the project design and the permitting of the site would likely have to proceed prior to the CPCN review process being completed. Given this risk, FBC contemplates accelerating the development of the selected generation resource, starting in 2022. FBC expects to initiate project development work, including land acquisition, front-end engineering design (FEED), permitting, and stakeholder and Indigenous consultation in the near future.

31.18.1 Please discuss whether there are any specific actions FBC is undertaking now or in the near term to prepare for this possibility.

Response:

As the portfolio analysis for higher load scenarios in Section 11.3.4 indicates, new generation resources or power supply contracts may be required sooner than is contemplated in this LTERP based on the Reference Case load forecast. As discussed in Section 11.3.9.1, FBC's has developed contingency plans to help manage the potential additional load requirements. These contingency plans include the following options for the near term, which could be implemented separately or in combination, depending on the specific energy and capacity requirements:

- Increase market energy purchases;
- Monitor potentially expiring BC Hydro EPAs;
- Increase PPA energy and capacity (if not already at its maximum);
- Implement other EV peak shifting options discussed in Section 2.3.2;
- Ramp up DSM to higher incentive levels; and
- Accelerate new resources from the preferred portfolios which require shorter lead times, such as a SCGT plant using RNG or battery storage units.

As discussed in Section 13.2, FBC intends to explore its potential resource options identified in this LTERP in more detail in the near-term, so that FBC is ready, if required, to bring forward an application for a new resource to the BCUC for approval prior to the development of the next LTERP. FBC expects that exploring its potential resource options in more detail would involve discussions with developers and/or consultants with expertise in this area so that FBC could obtain more specific information regarding resource options' costs, energy and capacity profiles and other relevant data. In summary, FBC recognizes the criticality of additional resources, and plans to move forward more definitively on its development plans in 2022.

J. STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

32.0 Reference: STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

Exhibit B-1, Section 12.1, pp. 203, 205–206

FBC and FEI Resource Planning Integration

On page 203 of the Application, FBC states that feedback from the RPAG group included the "Degree of integration between FBC LTERP and FEI LTGRP development process;"

32.1 Please detail the feedback regarding the degree of integration between FBC LTERP and FEI LTGRP development process.

<u>Response:</u>

During the November 26, 2019 RPAG meeting, an RPAG member asked if the gas and electric utility load scenarios were at odds with each other. FBC's response was that it expected there to be some degree of alignment in the load scenarios as both would present an electrification scenario and a diversified scenario. An RPAG member also asked if the FBC and FEI resource plans are going to be filed together. FBC's response was that the plans are not going to be filed together given FBC and FEI are two separate utilities, but that there would be some degree of collaboration on the planning environment sections.

On pages 205 to 206 of the Application, FBC states:

> Three community engagement workshops were held in person within the FBC electricity service area in the fall of 2019 and two online workshops were held in the fall of 2020, involving a total of 48 registered participants. These meetings were conducted in collaboration with the FEI gas resource planning group and therefore included presentations and discussions regarding FBC electricity resource planning as well as FEI gas resource planning. This made for the most efficient use of stakeholders' and Indigenous groups' time for those within the combined gas and electric service area and also reduced costs related to the workshops.
>
> …
>
> Some key themes and areas of interest that were identified as important to stakeholders and Indigenous groups included, among others:
>
> …
>
> - Fuel switching potential, challenges and opportunities between natural gas and electricity for space and water heating as well as transportation;
>
> …

Overall, the community engagement workshops facilitated the sharing of valuable long term planning information between stakeholders, Indigenous groups and FBC and FEI. In particular, the meetings assisted FBC in identifying energy issues or planning opportunities in municipalities throughout B.C.

32.2 Please explain how FEI and FBC balance the preparation and presentation of material and discussion at the community engagement workshops between the two utilities.

Response:

FEI and FBC share in the preparation and presentation of the material and discussion at the community engagement workshops. Some aspects of the presentation material are relevant for both utilities and so both FEI and FBC staff help in the preparation and presentation of that material. This includes, for example, information about each utility's energy planning environment and resource planning objectives. The nature of the resource planning process is such that for both FEI and FBC consideration of alternate energy resources is considered as part of the analysis. This allows FBC to present a balanced and objective view in its LTERP of any inter-relationship between the planning environments in which both utilities operate. Material more specific to each utility is prepared, presented, and discussed separately by FEI and FBC staff. This includes, for example, the supply-side resource options available to FEI, such as renewable gases, which differ from those available to FBC, such as solar or wind generation.

32.3 Where fuel switching or other opportunities that would result in customer demand shifting from FEI to FBC or vice versa, please explain how FBC and FEI address any potential conflicts in the community engagement workshops.

Response:

FBC and FEI do not believe there were any potential conflicts that needed to be addressed in the workshops or the individual resource plans relating to the topic of fuel switching. Rather, FBC and FEI believe that the best approach to long-term planning for energy needs is to use the right fuel for the right use at the right time, and considers the community engagement workshops as an opportunity to show how gas and electric utilities can work together to plan for a diverse and resilient energy future in a changing planning environment.

The load forecasts to which FEI and FBC are planning within their respective resource plans do not include an amount of fuel switching or other considerations that would result in significant shifts in customer demand from FEI to FBC or vice versa. Instead, to inform the respective resource plans, the two utilities explore the potential for more significant levels of fuel switching to result in some shifting in customer demand between the two utilities within the alternative future scenarios each utility has examined. For FEI, future increases in renewable gas supply play a far more prominent role in reaching provincial GHG emission reduction targets than does gas-to-electric fuel switching.

Furthermore, fuel switching which does not result in shifting customer demand between the two utilities was also explored within the forecasts and scenarios and presented in the workshops. For example, FBC's load forecast and scenarios explore various levels of light-duty EV growth while FEI's explore the use of natural gas as fuel for heavier-duty transportation. FBC's load scenarios also include electricity demand from hydrogen production, which would provide fuel for FEI in its future decarbonization efforts. Therefore, while a certain amount of fuel switching may occur in the future, it was not viewed as a "conflict" during the engagement workshops.

33.0 Reference: STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

Exhibit B-1, Section 12.1, p. 203

RPAG Feedback

On page 203 of the Application, FBC summarizes additional feedback provided through the RPAG sessions, including the following:

- Inclusion of Indigenous collaboration/opportunities as a portfolio attribute in the portfolio evaluation rating framework;
- Impacts of climate change on FBC's current supply resources;
- Consideration of rate design, demand management and customer-owned rooftop solar as resource options;
- Consideration of using percentage of Conservation Potential Review (CPR) achievable potential to determine DSM portfolios;

33.1 Please explain how FBC uses the inputs from the RPAG sessions.

Response:

FBC has considered the feedback provided through the RPAG sessions during the development of various aspects of the LTERP.

As discussed in Section 11.3.8, FBC received stakeholder feedback at the RPAG meetings that it should include an Indigenous community development attribute in the portfolio evaluation criteria. FBC considered this but since the benefits of Indigenous participation are common to all portfolios, it is not required as an independent measure. In FBC's view, BC employment provides a similar measure. As discussed in Section 10.9, FBC will consider partnerships with local and Indigenous communities when new supply-side resources are developed in the future.

Based on the feedback regarding the impacts of climate change on FBC's resources, FBC has included discussion of this topic in Section 5.1.1. This helps to provide stakeholders with an idea of the potential impacts of changes in seasonal precipitation on FBC's resources and other relevant agreements.

FBC has provided discussion of rate design and demand management considerations in Section 2.3.6. One example includes the potential to provide large baseload customers an interruptible rate offering that may be used to allow load curtailment when FBC system loads are at their peak, thereby enabling FBC to avoid incremental peaking resources or system upgrades, further mitigating costs and rate increases for all customers. As discussed in Section 2.3.4, customer-owned rooftop solar installations continue to grow in the FBC service area. However, as discussed in Section 10.7, FBC has no assurances that the customer-generated electricity will be available on its system when needed, or in the appropriate location. Furthermore, distributed rooftop solar generation provides little to no capacity during winter peak-demand periods unless paired with appropriate levels of battery storage. At this time, FBC plans to continue to monitor developments in distributed energy storage, including the use of EV batteries as distributed energy resources and consider formalizing an approach to leveraging such resources for system benefit.

With regard to the feedback regarding the determination of the DSM scenarios, FBC based its DSM Scenarios on incenting ever larger proportions of the DSM measures' incremental costs, which effectively results in each scenario having a different percentage of the CPR achievable potential.

33.2 Please confirm if FBC provides participants with underlying assumptions and documentation prior to the sessions, to allow for more considered input.

Response:

As part of informing the RPAG, FBC continuously updated its external resource planning website (discussed in Section 12) with meeting materials, including presentations and meeting notes, after each session so that RPAG members could have access to the relevant information. Prior to each session, FBC attached the latest presentation to the meeting invitation so that the RPAG could review the underlying assumptions and documentation prior to each session.

33.3 Given the limited time available, and the complexity of the material, please discuss the weight that FBC places or should place on RPAG preferences with regards to portfolio selection.

Response:

FBC does not agree with the characterization that there was "limited time available". The RPAG sessions were held over a period of 20 months, from November 2019 to June 2021 and covered a variety of resource planning topics. While one focus of the last RPAG session in June 2021 was the portfolio analysis, the RPAG was able to provide input and feedback on topics such as the LTERP objectives, resource options, and portfolio analysis in the other RPAG sessions leading up to the final session. Therefore, FBC feels that there was ample time available for the RPAG to understand the material and provide their opinions on their views regarding the portfolios, at least at a high level appropriate for long-term resource planning. As discussed in Section 5.1.1, the Resource Planning Guidelines include soliciting stakeholder input during the planning process. FBC believes that consideration should be given to the views of its stakeholders, as represented by the RPAG, customers, communities, and Indigenous groups with regards to portfolio selection and FBC has done so for this LTERP.

34.0 Reference: STAKEHOLDER, INDIGENOUS AND CUSTOMER ENGAGEMENT

Exhibit B-1, Section 12.4.2, p. 208

On page 208 of the Application, FBC states:

> As the Declaration for the Rights of Indigenous Peoples [DRIPA] continues to be implemented across government through the development of action plans, FBC will continue to evolve its planning and business practises in alignment with this implementation.

34.1 Please discuss how DRIPA has been considered in the development of the LTERP.

<u>Response:</u>

As discussed in Section 12.4.3 of the Application, the United Nations Declaration on the Rights of Indigenous Peoples (UN Declaration) has been considered in the development of the LTERP through FBC's engagement with Indigenous groups. FBC sees the overarching principles of the UN Declaration as aligned with the key values of FBC's Statement of Indigenous Principles. Input and feedback received during the LTERP engagement process identified the importance for utilities, including FBC, to analyze the long-term energy planning process through the lens of the UN Declaration. FBC will continue to assess and evolve its resource planning process to ensure that Indigenous energy objectives and the UN Declaration are considered in FBC's future project plans. If system considerations identified in the LTERP progress towards planned system upgrade projects, FBC will engage meaningfully with Indigenous groups through future regulatory processes, and will seek free, prior and informed consent of Indigenous communities whose territories may be impacted by the execution of such system upgrade projects.

FBC commits to continue to work collaboratively with Indigenous groups on long-term energy planning initiatives, such as the LTERP. FBC will continue to engage Indigenous groups through community workshops, the RPAG and will work closely with Indigenous groups to identify additional engagement opportunities that can support further integration of Indigenous energy objectives into future long-term resource plans. FBC looks forward to continued dialogue with the province of BC and Indigenous groups regarding the UN Declaration and commits to continue evolving its business practises to align with the UN Declaration action plans, as these are developed across various levels of government in the coming weeks and months.

K. ACTION PLAN

35.0 Reference: ACTION PLAN

Exhibit B-1, Section 13.1, p. 214

2016 LTERP Action Plan

On page 214 of the Application, FBC states that the BC CPR was completed in May 2019.

35.1 Please explain what period the 2019 BC CPR covered and why FBC required the preparation of a new CPR for the purposes of the current LTERP.

<u>Response:</u>

The previous 2019 BC CPR covered the period of 2016 to 2035 and the final FBC Market Study report was completed in January 2018. For the purposes of the current LTERP, FBC prepared a new CPR to update its forecast DSM program savings with the current 2021 to 2040 planning horizon.

36.0 Reference: ACTION PLAN

Exhibit B-1, Section 13.2, p. 215

Action Plan

On page 215 of the Application, FBC states:

> FBC intends to explore its potential resource options identified in this LTERP in more detail in the next few years so that FBC is ready, if required, to bring forward an application for a new resource to the BCUC for approval prior to the development of the next LTERP.

36.1 Please specify how FBC intends to explore its potential resource options further.

Response:

Please refer to the response to BCUC IR1 31.18.1.

36.2 Please specify what circumstances would require FBC to bring forward an application to the BCUC for a new resource prior to the next LTERP.

Response:

As discussed in the response to BCUC IR1 31.18.1, the portfolio analysis for higher load scenarios in Section 11.3.4 creates a scenario where new generation resources or power supply contracts may be required sooner than is contemplated in the Reference Case load forecast. Also, as discussed in Section 11.3.9, if FBC's access to market energy no longer remains cost effective and reliable, new resources may be needed sooner than expected. Given the long development timelines for new generation, FBC will likely make a determination to initiate project development work numerous years in advance of physically needing the assets. These circumstances may require FBC to bring forward an application to the BCUC for a new resource prior to the next LTERP. Finally, if an opportunity to obtain power supply that meets the LTERP objectives arises, FBC may choose to bring an application forward to the BCUC in order to take advantage of the opportunity while it exists.

37.0 Reference: ACTION PLAN

Exhibit B-1, Section 4.2, p. 107; Section 13, pp. 205, 215, 107

Guidehouse Recommendations

Action 4 identified by FBC on page 215 of the Application states: Implement program to help shift home EV charging

> …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.

37.1 Please discuss what role time of use rates could play in encouraging shifting of home EV charging to off-peak periods, and if FBC intends to investigate this option further.

Response:

FBC is currently pursuing a software-based approach as its leading approach to encourage the shifting of home EV charging to off-peak periods. Should this approach prove ineffective or unfeasible, FBC will revisit other approaches, including time of use (TOU) rates.

During FBC's initial investigation of TOU rates, the following concerns were identified:

- TOU rates implemented on a whole-home basis (i.e., for the meter serving a premises) may not be favourably received by customers as the timing and customer ability to shift discretionary loads likely varies depending on the end-use and customer preferences;
- TOU rates that are EV-specific and require a separate meter for EV charging may not be favourably received by customers due to the added cost of the additional hardware and billing complexity driven by two residential rates at one premise;
- The use of TOU rates for shifting EV home charging to off-peak periods may have the inadvertent effect of driving the creation of a second load peak for certain areas of FBC's system depending on customer uptake and response to TOU price signals; and
- Customers may be more receptive to an approach that only incents the shifting of EV loads as opposed to whole-home TOU rates.

For the above reasons, FBC opted to pursue a software-based approach that uses the remote-connectivity abilities that many EVs now include, as well as the potential use of a customer's smart phone to schedule and monitor when a customer charges their EV. This approach may offer a cost-effective and scalable program for incenting customers to shift EV charging loads as required.

Guidehouse notes on page 107 of the Application that the energy impacts of the growth of hydrogen production and data centres for FBC could be considerable. Given the very favourable load profiles of these two drivers and the potential growth of these industries (to support the decarbonization of the natural gas supply, and the ongoing growth in global data storage and processing requirements), FBC may wish to consider what ratepayer benefits could exist in developing (or refining any existing) economic development rates that target such industries conditional on where on the system these customers connect.

FBC's Action 5 on page 215 of the Application states, "Consider initiatives to manage large loads."

37.2 Please discuss what specific actions FBC intends to pursue to manage future large loads.

Response:

FBC is in the planning and consultation phase to develop and implement an interruptible rate for larger customers. An interruptible rate is seen as attractive to some customers and also provides a benefit to FBC in the management of large load customers. An interruptible rate will allow FBC to curtail a customer's usage during peak hours, reducing system capacity impacts during peak periods. As a result, there would be more potential to add new interruptible loads to the FBC system without triggering the level of system upgrades typically required for firm load additions.

For large loads not on an interruptible rate, FBC is exploring the use of a demand response program to manage their load.

Lastly, as new large customers seek to attach to the system, FBC works with the customer to locate in areas that have the capacity to serve the customer with fewer system upgrades.

37.3 Please discuss if FBC has begun to identify any locations which would be well suited to these types of customers.

Response:

FBC is undertaking to identify potential areas where there is capacity available for new large loads. To support this, FBC's regional engineers have developed maps that identify general areas that are more favourable for addition of large loads.

Additionally, FBC responds to customer requests for large loads at specific locations. FBC conducts a series of studies to assess the system impact and feasibility of the requested load at that particular location.

L. VOLUME 2: LONG TERM DSM PLAN

38.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Section 2.4, p. 6

The TRC and FBC Avoided Costs

In Section 2.4 of the Application, FBC states that: "The TRC test was done at the measure level in the CPR modelling tool. The benefits are FBC's "avoided costs", calculated as the measures' present value over the effective measure life of:

a. energy savings, valued at the LRMC of $90 per MWh; and

b. demand savings, valued at the DCE of $51.22 per kW-yr."

38.1 Please explain how FBC computes the value of the demand savings.

Response:

FBC's LRMC of $90 per MWh for DSM purposes is an outcome of Portfolio A2. To calculate the LRMC for DSM purposes, the gross load forecast (before any DSM savings) is used as the load requirement for which an optimal portfolio of supply-side resources is required to meet. Clean energy requirements are applied as constraints within the optimization routine such that the characteristics of the portfolio represents the avoided costs of serving the gross load using only regulation defined 'clean resources' from BC. The LRMC of $90 per MWh for DSM is inclusive of both energy and generation capacity. The utility's LRMC calculated using the Average Incremental Cost (AIC) approach is appropriate for programs that are designed primarily to conserve energy and are offered broadly across the utility's service area.

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

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

FBC uses a Deferred Capital Expenditure (DCE) value of $51.22 per kW-Year for DSM purposes to estimate the avoided transmission and distribution (T&D) costs (i.e., benefits from avoided infrastructure), resulting from the implementation of DSM programs. The 2021 DCE value has been calculated using the methodology created by EES Consulting and filed with the 2017 DSM Application[7] which considered the present value of planned future T&D upgrades divided by the growth in the coincident system peak. The EES Consulting report is included as Attachment 38.1.

[7] FBC 2017 DSM Application. Appendix C: Deferred Capital Expenditure Study (EES Consulting). Exhibit B-1.

38.2 Please discuss if FBC has considered capacity-based DSM, and if it plans to include capacity DSM measures in future, including over the forecast period.

Response:

FBC confirms that it is currently completing demand response pilots to assess the potential for capacity-based DSM. If the pilots are successful, FBC would plan to include capacity-based DSM measures in the next DSM Plan.

39.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Section 3, pp. 13, 17

DSM Scenario Development

On page 13 of the Application, FBC states o:

> FBC developed five different DSM scenarios including Low, Base, Medium (Med), High and Maximum (Max) cases that were subsequently tested with various supply-side resource options in the Resource Planning portfolio analyses.
>
> The DSM program scenarios FBC considered are based on incenting ever larger proportions of the DSM measures' incremental costs. The same DSM measures were included in all scenarios, and the uptake was based on the market potential.

39.1 Please discuss if FBC considered alternative scenarios where FBC would also increase the range of programs and total number and types of customers that are being incentivised under the Medium, High and Maximum scenarios, as opposed to adjusting the incentive dollars for the existing programs.

Response:

FBC identifies programs, at a high-level, to include cost-effective measures identified in the CPR. The LT DSM Plan does not explore the granularity of program design or budgeting at a program level. Programs identified are generally consistent with those previously presented in the 2019-2022 DSM Plan, with some new additions (e.g., Industrial Strategic Energy Management).

Customer participation is an outcome from the model and estimated by a simple payback demand curve reflecting cost, estimated operational savings, and DSM incentives. The CPR model does not account for other external factors that could influence participation such as marketing and/or program design.

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

39.1.1 Please describe if FBC has identified any additional programs and/or broader customer participation that could be added under the Low, Medium, High and Maximum scenarios.

Response:

FBC has not identified any additional programs and/or broader customer participation that could be added under the Low, Medium, High and Maximum scenarios.

39.1.2 If possible, please provide an updated scenario analysis considering any additional programs that could be added in the modelling for the Med, High and Max scenarios.

Response:

Please refer to the response to BCUC IR1 39.1.1.

On page 17 of the Application, FBC concludes that while the Low DSM scenario was more cost effective than the Base scenario, it was not chosen, because:

- The Base scenario maintains consistency with the previous DSM plan, which had support from customers and stakeholders;
- Transitioning to the Low scenario may require FBC to remove existing program offerings or reduce program incentives, potentially resulting in a reputational impact with customers and trade allies;
- The Low scenario requires pullback of program offerings which limits FBC's ability to scale up programs in the future if new cost-effective measures are identified. Selecting the Base scenario provides flexibility to meet future market demands; and
- The Base scenario includes additional budget to further investigate DR programs that have the potential to cost-effectively defer capacity costs.

39.2 Please discuss if FBC considered alternative scenarios where FBC would remove DSM programs with little future potential when modelling the Low scenario.

Response:

FBC did not consider alternative scenarios where FBC would remove DSM programs or measures with little future potential when modeling the Low scenario.

39.2.1 If possible, please provide an updated Low scenario analysis where lower potential programs have been removed.

Response:

Please refer to the response to BCUC IR1 39.2.

The 2021 CPR uses a “measure-up” approach to develop DSM Scenarios. Program design to incorporate those measures into DSM programs is out of scope for both the CPR and LT DSM Plan. Program design, including estimation of participation, is completed during the DSM planning process. At this point, FBC is unable to attribute any program to having a “lower potential” and thus FBC cannot remove lower potential programs from the CPR DSM Scenario analysis.

40.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Section 2.4, p. 8; Section 4, p. 19

DSM Programs

On page 19 of the Application FBC states:

> The LT DSM Plan portfolio includes programs for the Residential, Commercial, and Industrial customer classes and is intended to capture market potential savings over the long term, as identified in the FBC CPR. There are also low-income programs, portfolio-level supporting initiatives, and planning and evaluation activities required to support the DSM Plan.

On page 8 of the Application FBC states that the TRC test was done at the measure level in the CPR modelling tool.

40.1 Please provide a high-level summary of the projected expenditures and cost effectiveness indicators (specifically, mTRC and the UCT values) for each of the programs outlined by FBC in Section 4 of the 2021 Long Term DSM Plan.

Response:

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

40.2 Please provide the assumptions used to calculate the cost-effectiveness indicators, including any adjustments made for free-ridership, spillover and rebound between the different DSM scenarios as incentive levels increase between scenarios. Please include references to the CPR Appendices where applicable.

Response:

The assumptions used to calculate the measure-level TRC and mTRC are presented in CPR Appendix B3 included with the Application.

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

Free-ridership, spillover, and rebound factors will be developed, as necessary, at the program-level in the next DSM Plan and will be based on values derived from past program and pilot evaluation results.

41.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Section 4.6.3, p. 26

Demand Response Pilots

On page 26 of the Application FBC states:

> FBC's 2019-2022 DSM Expenditure Plan includes funding to conduct Demand-Response (DR) pilot projects to test the opportunity, and customer willingness, to undertake load shifting during peak demand periods. In 2019-2020 the Company undertook the first phase of DR pilot with commercial & industrial customers that focused on, but was not limited to, offsetting summer loads in the Kelowna area, the results of which are summarized in the 2019 and 2020 DSM Annual reports.

41.1 Please describe how the DR pilot programs have performed since the filing of the DSM Expenditure Plan.

<u>Response:</u>

The commercial DR pilot was completed in December 2020 and evaluated in 2021. The pilot consisted of two parts: 1) an assessment study for DR potential within the Kelowna area; and 2) the pilot itself where commercial customers were recruited to participate in DR events. The pilot identified a number of limitations in the approach used, including:

1. Challenges in customer recruitment using the key account targeted customer approach;
2. Challenges using manual dispatch to implement DR events; and
3. The methods of communication leading up to, and during, a DR event to ensure all parties are aware of the timing and expectations.

The overall results did not conclusively show that commercial DR using the approach advanced in the pilot could have a notable impact on commercial customer demand. FBC will re-assess the approach to commercial DR for a potential future pilot, as the assessment expected a notable DR potential in the region despite the pilot results.

The residential DR pilot is planned to launch in winter 2021/22. Initial performance indicators are expected in mid-2022.

41.2 Please discuss if FBC considers that the DR pilot programs could be considered a resource option in the future and why or why not.

Response:

FBC considers that both residential and commercial DR pilot programs could be resource options in the future. FBC's research on DR programs suggests the programs will cost between $70 and $120 per kW-year which is lower than the capacity-only component of the LRMC presented in BCUC IR1.38.1.

42.0 Reference: LONG TERM DSM PLAN

Exhibit B-1, Volume 2, Appendix A, p. 1

2021 Conservation Potential Review (CPR) Report

Page 1 of Appendix A states that "FBC engaged Lumidyne in 2020 to prepare the CPR Report that estimates electric energy and demand savings potential from a broad collection of energy-saving measures in FortisBC's electric service territory."

42.1 Please describe in detail how FBC has used (or is planning to use) the Lumidyne Report results to inform the DSM Scenarios discuss in Section 3.2 of the Application.

Response:

FEI based all of the DSM scenarios in Section 3.2 of the Application on the market potential scenarios developed as part of the Conservation Potential Review completed by Lumidyne. The Conservation Potential Review report outlines the market potential of the Base DSM Scenario.

Sections 2.2 and 2.3 of the 2021 LT DSM Plan describe how the Lumidyne Conservation Potential Review informs the DSM Scenarios discussed in Section 3.2 of the LTERP.

A brief summary of how the CPR is used is as follows:

1. The program level energy savings potential available over the LTERP planning horizon was developed (see LT DSM Plan Section 2.2 and Appendix A Section 3);
2. The range of DSM scenarios (Low, Base, Medium, High, and Maximum) were developed to be part of the resource portfolios analyzed in the LTERP process, each reflecting a distinct incentive level as a percent of incremental cost (see LT DSM Plan Section 3);
3. The CPR and DSM scenarios were presented to stakeholders through the LTERP engagement process (see LT DSM Plan Section 3.1); and
4. The DSM scenario was selected that is the preferred option for the LT DSM Plan and the LTERP (see LT DSM Plan Section 3.2).

42.2 Please discuss whether Lumidyne considered the development or addition of new programs and/or broadened customer base for the DSM scenario development.

42.2.1 If not, please explain why not.

Response:

The scope of the CPR was to evaluate the technical, economic, and market potential of individual cost-effective energy efficiency measures. Program development was not included in the scope of the CPR or LT DSM Plan. Program development is conducted as part of the DSM planning process.

No customer base was excluded from CPR or DSM scenario development.

Attachment 8.5

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 38.1

FortisBC, Inc.

Deferred Capital Expenditure Study

July 2016

Prepared by:

EES Consulting

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EES Consulting

July 5, 2016

Mr. Keith Veerman
FortisBC, Inc.
1975 Springfield Road, Suite 100
Kelowna, BC V1Y 7V7

SUBJECT: Deferred Capital Expenditure Report

Dear Mr. Veerman:

EES Consulting, Inc. (EES) is pleased to submit a final report for the Deferred Capital Expenditure (DCE) on behalf of FortisBC. We would like to acknowledge and thank you and your staff for the excellent support in developing and providing the data for this project.

Very truly yours,

Anne Falcon
Senior Associate

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offices in Kirkland, WA and Portland, OR

Contents

Introduction

EES Consulting (EES) is pleased to provide you with a final draft report summarizing the results of our research and calculation of the Deferred Capital Expenditure (DCE) factor. FortisBC plans to use this DCE factor to estimate the "avoided" transmission and distribution (T&D) costs due to the implementation of demand-side management (DSM) programs. The recommended Marginal Cost methodology was selected based on the literature review of the common methodologies used to determine avoidable T&D expenditures due to DSM program implementation. Based on FortisBC's forecast growth-related capital T&D expenditure schedules and annualizing factors obtained from FortisBC, this study found the levelized T&D DCE values to be $67.03 and $12.83 respectively in 2015 dollars.

As part of the evaluation of the cost-effectiveness of demand-side management resources, utilities are including the avoided infrastructure costs for deferred transmission and distribution costs. Based on a recent survey[1] by the (ACEEE) 82 percent of the states surveyed include avoided T&D costs in the benefit-cost analysis of DSM programs.

According to the Regulatory Assistance Project's 2011 report *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*: "The capital cost of augmenting transmission capacity is typically estimated at $200 to $1,000 per kilowatt, and the cost of augmenting distribution capacity ranges between $100 and $500 per kilowatt. Annualized values (the average rate of return multiplied by the investment over the life of the investment) are about 10 percent of these figures, or $20 to $100 per kilowatt-year for transmission and $10 to $50 per kilowatt-year for distribution. There are also marginal operation and maintenance costs for transmission and distribution capacity, but these are modest in comparison to the capital costs."[2]

This report explores the methodologies available when assessing the deferred, or avoided, transmission and distribution costs, provide an overview of methodologies and values used by several utilities in the U.S. and Canada, and recommend a calculation and value to be used going forward for FortisBC DSM assessments.

Estimating Avoided Transmission and Distribution (T&D) Costs

DSM has the potential to reduce or delay infrastructure investments in a utility's transmission and distribution systems. In particular, DSM can defer T&D investments that are driven by economic conditions and growing peak loads.

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[1] "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs" http://aceee.org/research-report/u122

[2] Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements RAP, p. 6.

In the context of DSM, avoided costs are the costs that are avoided by the implementation of an DSM measure, program, or practice. Such costs are used in benefit-cost analyses of DSM measures and programs. Different elements of the T&D system can experience peak demand at different times of the day and even in different seasons. Thus, the extent to which an efficiency program can help defer T&D investment will depend on the hour and season of peak and the hourly and seasonal profile of the efficiency program's savings. In order for DSM programs to defer T&D investments, the DSM programs would need to impact loads during the peak hour on the transmission or distribution system. NV Energy, for example, assumes that 25 percent of the annual growth-related T&D costs can be avoided due to DSM programs.

The calculation of distribution avoided cost is particularly complicated because the distribution grid has been built for all existing customers and the main purpose is to provide reliability to customers. As a result, the maximum avoided cost may only be realized in areas of grid expansion due to load growth. Even in areas of growth, distribution system costs can be avoided only when the DSM programs are included in the design process, and the utility is planning to rely on these programs as a resource. Considerable avoided costs may also be realized where utilities can avoid replacing or upgrading aging equipment needed to support load growth.

In order to maximize the avoided T&D cost, targeted DSM programs can be implemented in specific locations due to constraints or the need for significant infrastructure investments.[3] However, these non-wires solutions[4] to T&D investments are specifically designed programs, rather than general DSM programs for the residential, commercial or industrial end-user. They will generally result in much higher avoided costs than are used for overall DSM cost-effectiveness evaluations.

This paper does not examine the avoided T&D costs by DSM program or for targeted distribution programs specific for the FortisBC system. Instead, it explores the different methods used by various jurisdictions in the U.S. and Canada to determine the avoided T&D costs when evaluating overall DSM programs.

Based on the survey of methodology and DCE results, the following best practices can be concluded:

---

[3] See for example *Energy Efficiency as a T&D resource: Lessons from recent US efforts to use geographically targeted efficiency programs to defer T&D investments*, Northeast Energy Efficiency Partnership January 9, 2015.

[4] Non-wires solutions can include for example energy efficiency, demand reduction initiatives, pricing strategies and distributed generation solutions.

- Use methodology based on specific utility data available. Estimated deferred T&D investments can vary considerably depending on the region and the utility system. Therefore, the best option for FortisBC is to estimate T&D DCE based on FortisBC data.
- Separate the calculation of transmission and distribution capital deferred expenditures and provide a DCE for each function if data is available.

- For each function (transmission and distribution) evaluate the potential on-peak impact of the potential conservation programs.

- While benchmarking may be indicative, benchmarking DCE results for FortisBC outside Western Electricity Coordinating Council (WECC) does not appear to be appropriate[5].

- Using a marginal costing approach appears to be the most common calculation methodology.

[5] Customer usage patterns, energy efficiency programs and transmission and distribution system constraints are different outside WECC than what is faced by FortisBC.

Avoided T&D Cost Estimation Methodologies

This section of the report provides more information on each of the methodologies commonly used to value avoided T&D expenditures.

Overview

In general, there are five different methods used to estimate the avoided T&D costs to be included in the benefit calculation of DSM programs. Many utilities calculate the avoided costs for transmission and distribution separately as the investment in these systems are different over time. The most common calculation methods are the following:

- Marginal avoided costing: estimates avoided capital costs based on the cost of adding one additional MW. This method can be performed based on a regression or based on an average of forecasted investments.
- Average investment: estimates the average amount of capital investment deferred based on the reduction of peak load and average transmission and distribution expansion costs.
- Market value: for utilities that rely on a market for transmission capacity, the market price can be used to determine the avoided transmission cost.
- Scenario-based estimation: estimates infrastructure investments with and without the DSM program. This methodology is very data intensive and the results are highly dependent on the DSM programs evaluated.
- Benchmarking: estimates are based on results from other utilities.

Each of these methods is further described below.

Marginal Cost Method

The marginal cost reflects the savings associated with a decrease of one MW either permanently or as a deferral in costs. There are two methods that can be used to estimate the marginal cost: average forecasted value or a regression technique.

The average forecasted value relies on the utility's forecast of transmission and distribution system upgrades and expansions, and the projected peak loads increases over the same time period (typically 5-10 years). The total investments over the analysis period is then divided by the total peak increases over the same period. This calculation results in a $/kW for the analysis period. This value is then annualized by applying a carrying cost factor based on the utility's cost of capital and the length of the analysis period. Some utilities only include the investment cost in the avoided cost estimate while other utilities also include associated avoided operation and maintenance (O&M) costs. The marginal cost method, however, is not responsive to the timing of investments or load growth, rather it considers only their cumulative effect over the planning period.

A marginal unit capital cost can also be determined by regressing the cumulative changes in investment with cumulative changes in load. The marginal unit capital cost is then annualized by using a carrying cost factor and may be grossed up for marginal expenses. Although the regression method is accurate for calculating historical marginal costs, it is predicated on the assumption that the future will resemble the past. Because of this reliance on historical data, many have found that the regression methods are unsuitable for DSM cost-effectiveness evaluations.

Average Investment Method

The average investment method computes an arithmetic average by dividing the historical investment by the load growth during the same period. The resulting unit marginal cost is then annualized using a carrying charge factor. The carrying charge factor annualizes the marginal cost by calculating the weighted return on investment for the utility after taxes. Similar to the marginal cost method using regression analysis, the issue with this methodology is that it assumes that the historic average will reflect necessary investments in the future.

Market Value

For some utilities, it is possible to determine the avoided cost of transmission based on a market proxy. This is particularly relevant for utilities that do not own their own transmission system, but rather they purchase transmission services from other parties. For example, FortisBC wheels power over BC Hydro's transmission system using Rate Schedule 3817. The annual wheeling rate ranges between $13,734.87 and $56,199.12 per MW of nominated wheeling demand. This translates to approximately $13.73 - $56.20 per kW-yr in transmission wheeling costs. DSM capacity savings on peak would therefore avoid between $13.73 and $56.20 per kW-yr based on BC Hydro's transmission tariff.[6]

Scenario Method

In practice, the impact of DSM on the transmission and distribution system will vary considerably based on the location, type of program, customer mix, and other factors. Initially, the impact of these factors suggest a need to conduct in-depth studies of the transmission and distribution system. The optimum analysis would develop feeder level forecasts of the change or delay in investments and peak growth from specific DSM programs. Corresponding avoided costs can then be computed in a bottom-up manner using actual component costs or location specific planning costs.

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[6] BC Hydro Transmission tariff. https://www.bchydro.com/about/planning_regulatory/tariff_filings/oatt/general-wheeling.html

However, this type of analysis is very time consuming and requires a combination of engineering judgment and multiple software simulations to examine the potential changes in the transmission and distribution systems due to DSM programs. This method is, therefore, not a viable option unless the utility is implementing a targeted program specifically used to address localized transmission or distribution limitations.

Benchmarking

The final option that has been used by many jurisdictions is benchmarking. Because the estimation of avoided transmission and distribution costs is difficult, many utilities use data from existing studies and often average the results. The reasoning behind this methodology is that avoided costs are likely to be similar in magnitude across utilities. Of course, the different studies show that there are a wide range of estimates depending on utility load growth, the constraints on the transmission and distribution system, and the methodology used to estimate the avoided costs.

Calculation Considerations

Within each methodology there are several variations and assumptions about the specific data. For example, the utility must consider if only the investment cost should be included in the marginal cost estimate or if an overhead adder or avoided O&M expenses should be included as well.

In addition, the utility must consider if the avoided T&D costs need to be de-rated. Some energy efficiency programs will not result in capacity savings in locations where the transmission and distribution systems are constrained. Therefore, T&D costs will only be reduced if a significant amount of load reduction is attained in an area where the utility expansion plans can be altered. Using a deration approach helps mitigate the risk of overvaluing DSM program peak reduction potential.

It should also be noted that, in some cases, the reduction in loads resulting from past DSM, rate structures, or natural changes in consumer loads lead to a case where there is surplus transmission and/or distribution capacity on the system. In this case there would not be any incremental savings in T&D costs associated with new DSM programs.

Estimated deferred T&D investments can vary considerably depending on the system condition, projected growth, and other factors the utility considers when determining how much of the investment is deferrable. At the most general level, estimates of avoided T&D costs are typically developed by dividing the portion of forecast T&D capital investments that are associated with load growth by the forecast growth in system load. As part of the analysis, T&D capital investments should exclude investments associated with replacement due to time-related deterioration or other factors that are independent of load.

Based on the review of methodologies, the following methodology best practices should be followed:

- Use methodology based on specific utility data available. Estimated deferred T&D investments can vary considerably depending on the utility system.
- Separate the calculation of transmission and distribution capital deferred expenditures and provide a DCE for each function if data is available.
- For each function (transmission and distribution) evaluate the potential on-peak impact of the potential conservation programs.

Literature Review

As part of this project, EES performed a literature search and examined the best practices for the methodology and resulting DCE factor used by a range of utilities in the U.S and Canada. The following sources were reviewed:

- BC Hydro's Integrated Resource Plan
- Ontario Power Authority (OPA)
- Hydro One
- Northwest Power and Planning Council, 7th Power Plan Methodology
- California Public Utility Commission Standard Practice
- Avoided Energy Supply Component (AESC) Study Group Report for New England
- Regulatory Assistance Project (RAP) Reports on Valuing Avoided Costs
- Regulatory filings and proceedings by several utilities

The findings related to the methodology used to determine T&D avoided costs for DSM evaluation and the resulting values are described below.

BC Hydro

BC Hydro is in the process of updating its conservation potential assessment. In the 2008 LTAP study performed, BC Hydro used the following values for avoided costs:[7]

- *Bulk transmission capacity:* $5 per kW-year between the Lower Mainland and Vancouver Island based on British Columbia Transmission Corporation (BCTC) estimates of the cost of incremental firm bulk transmission. Zero between the Interior and Lower Mainland because this cost is reflected in the avoided generation capacity cost. Zero between other regions because DSM is not expected to generate sufficient capacity savings in those regions to defer bulk transmission capacity investments.
- *Regional transmission capacity:* $30 per kW-year based on BCTC estimates of the cost of incremental regional transmission.
- *Distribution capacity:* $17-28 per kW-year, based on BC Hydro estimates of the cost of incremental distribution capacity in different regions of the province.

These values have been updated since then in the Amended F2012 to F2014 Revenue Requirements Application Updated DSM Plan,[8] the following assumptions were listed:

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[7] Appendix K to BC Hydro's 2008 LTAP.

[8] BC Hydro Amended F12/F14 RRA – Amended New Appendix II, Attachment 6, p. 191 of 271.

- *Bulk transmission capacity:* $0 per kW-year ($ F2011) based on BC Hydro estimate because there are no bulk transmission capacity investments expected to be deferred by the Updated DSM Plan.
- *Regional transmission and substation capacity:* $11 per kW-year ($ F2011) based on BC Hydro estimate of the cost of the regional and substation capacity costs avoided by the Updated DSM Plan.
- *Distribution capacity:* $1 per kW-year ($ F2011), based on BC Hydro estimates of the distribution capacity cost avoided by the updated DSM Plan.

The methodology used to determine these avoided costs was not described.

Ontario Power Authority

The Ontario Power Authority has developed a cost effectiveness guide and model for Conservation and Demand Side Management (CDM) resources for use by Ontario's Local Distribution Companies (LDC). This model includes avoided transmission costs of $3.83 per kW-yr ($2014) and avoided distribution costs of $4.73 per kW-yr ($2014).[9]

Hydro One, Ontario

In the 2011 Integrated Power System Plan (IPSP), Hydro One used avoided costs to evaluate the cost effectiveness of the conservation resources proposed in the IPSP. The avoided costs were determined by using an incremental cost estimation method.[10] This methodology determined the transmission and distribution investments that could be avoided or deferred by CDM measures. The avoided transmission costs were estimated based on the magnitude of capital expenditures deferred, the deferral period, the cost of capital, the avoided annual operations and maintenance (O&M) costs, estimated at 1% of capital costs.

The annual avoided cost of transmission including both capital and operating costs were estimated at $5.40 ($2007) per kW of incremental demand at the time of the system peak load. Similarly, the avoided cost of distribution was estimated at $6.70 ($2007) per kW of incremental demand at the time of the system peak load. These incremental costs were re-evaluated, at a 4% real discount rate to be $3.40 per year for transmission and $4.20 per kW per year for Distribution.[11]

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[9] Ontario Power Authority, "Conservation and Demand Management Energy Efficiency Cost Effectiveness Guide" Final v1 - October 2014. P. 58.

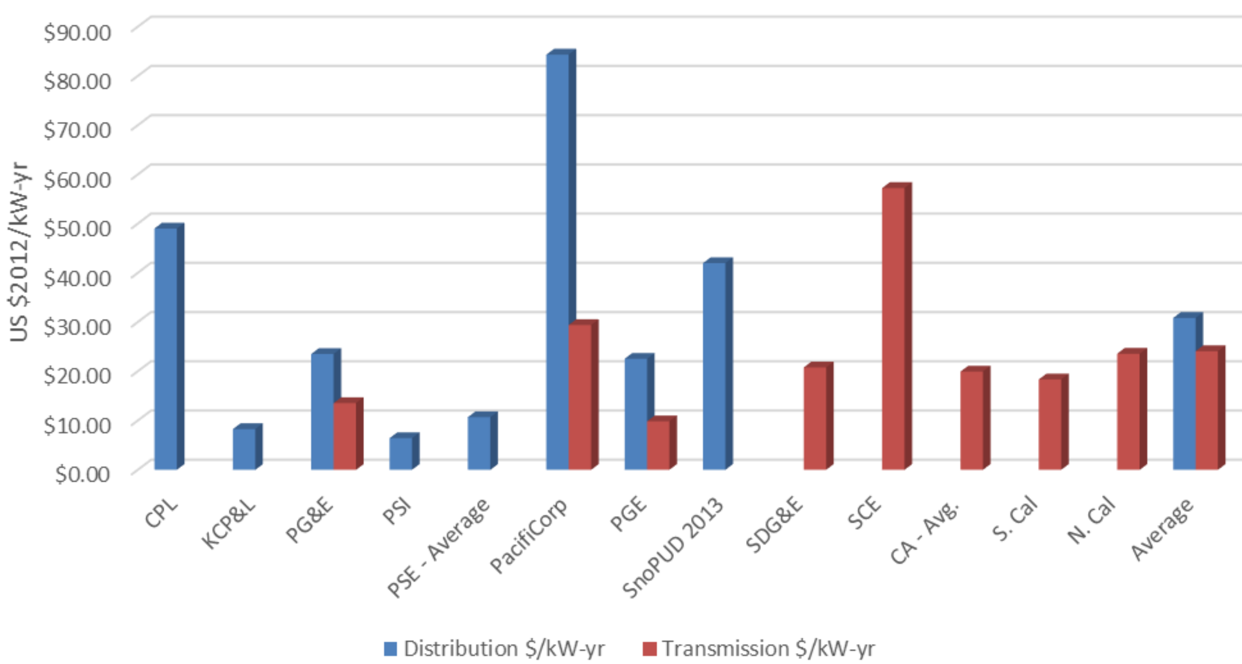
[10] Refer to EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 15.

[11] Refer to EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 3, p. 5 of 37.

Northwest Power and Planning Council, 7th Power Plan Methodology

The Northwest Power and Planning Council (Power Council) develops a power plan every five years to examine the power supply and cost-effective DSM potential in the States of Washington, Oregon, Idaho and Montana. Potential T&D avoided costs from investment in DSM is included in the determination of cost-effective DSM programs. The methodology used by the Power Council includes a benchmarking survey of the avoided T&D costs used by utilities from the Northwest and California, as well as benchmarking with data from outside the WECC region. Figure 1 provides the data from the Power Council survey escalated to 2012 dollars.[12]

Figure 1
Value of Deferred Capital Expenditure Survey – Pacific Northwest



The Power Council relied on the California data described below, as well as reported data from Northwest utilities. In addition, the distribution avoided costs were compared to regional data provided in the report "*Avoided Energy Supply Costs in New England: 2013 Report.*"[13] The majority of the distribution cost information is based on 2006 data and then escalated. However, the estimate from Snohomish PUD was updated more recently.

[12] Costing Methodology for Electric Distribution System Planning.
[13] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.

In the recent update, Snohomish PUD developed their deferred distribution costs by determining the major upgrades and major expansion costs over a forecasted 7-year period. Next, the total value of forecasted distribution investments was divided by the forecasted peak growth. After annualizing using 5% borrowing rate over a 35-year life of assets, this methodology resulted in a $42/kW-yr deferred value.

The resulting survey shows significant differences in transmission and distribution deferred value across utilities. The standard deviations for the sample data is $26.59 (86%) for distribution and $14.65 (61%) for transmission.

California Public Utilities Commission (CPUC) Standard Practice

The CPUC has adopted a calculator for use by the Investor Owned Utilities (IOUs) in California to report on the cost-effectiveness of DSM programs. This model takes the marginal T&D cost determined in the IOUs' cost of service studies and uses these values to determine the avoided costs for DSM program evaluations.

The general methodology used by the utilities to develop the marginal T&D costs for the Cost of Service studies is based on forecasted investment data, forecasted load increases, and the addition of any general plant loading factor plus an avoided O&M adder. Because the avoided costs depend upon area-specific capacity conditions, the Pacific Gas & Electric (PG&E) model forecasts electric T&D avoided costs by climate zone and is based on the hours of the year that are the most likely drivers of the local peak demand. Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) calculate the utility average T&D marginal cost.

Figure 2 displays the weighted average annual T&D avoided costs for SCE, PG&E and SDG&E from the most recent study.

Figure 2
Value of Deferred Capital Expenditure - California

New England AESC Study

The Avoided Energy Supply Component (AESC) Study Group released the Avoided Energy Supply Cost in New England: 2015 Report.[14] The AESC provides estimates of avoided costs for program administrators throughout New England to support their internal decision-making and regulatory filings for DSM program cost-effectiveness analysis. As part of the avoided cost calculation, the AESC provides estimates of avoided T&D costs for several utilities in the region.

In 2013, the utility estimates of avoided T&D costs ranged from about $30 per kW-year (Connecticut Light & Power (CL&P)) to about $200 per kW-year (National Grid –Massachusetts) USD.[15] Figure 3 provides the estimated T&D Deferred Capital Expenditures from the 2013 Study.

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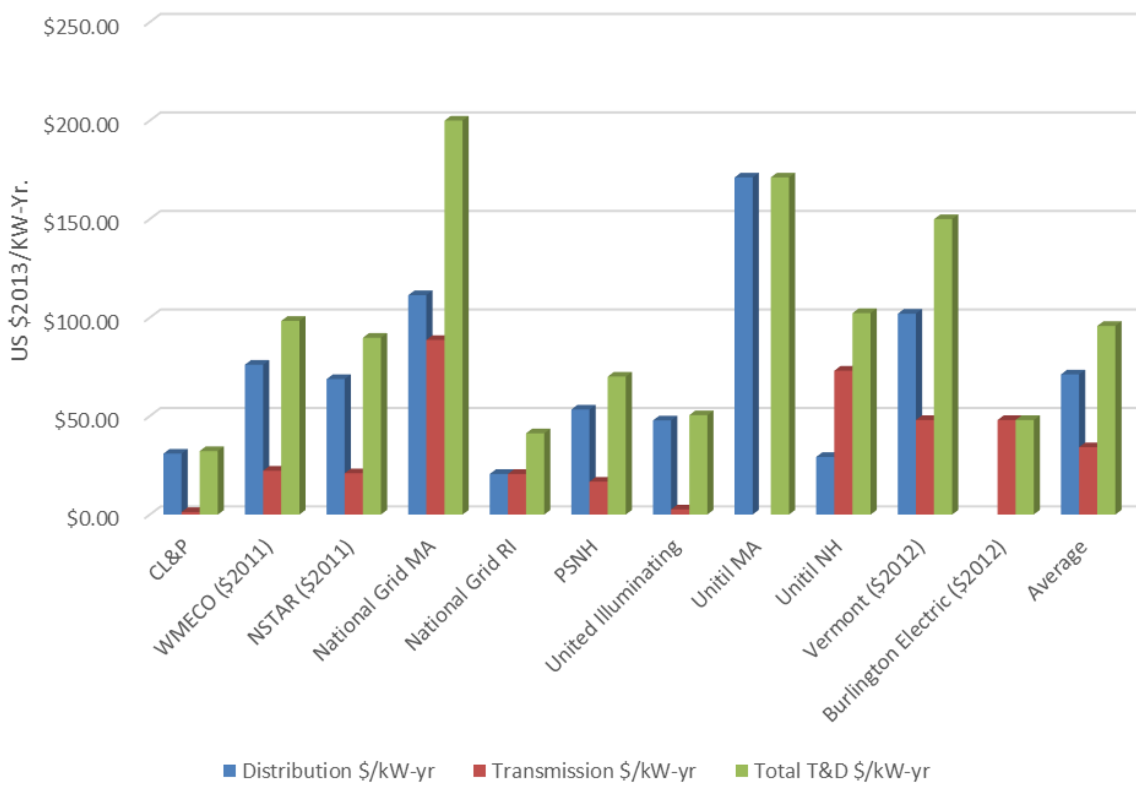
[14] http://ma-eeac.org/wordpress/wp-content/uploads/2015-Regional-Avoided-Cost-Study-Report1.pdf.

[15] Hornby, Rick et al. (Synapse Energy Economics), *Avoided Energy Supply Costs in New England: 2013 Report*, prepared for the Avoided Energy Supply Component (AESC) Study Group, July 12, 2013.

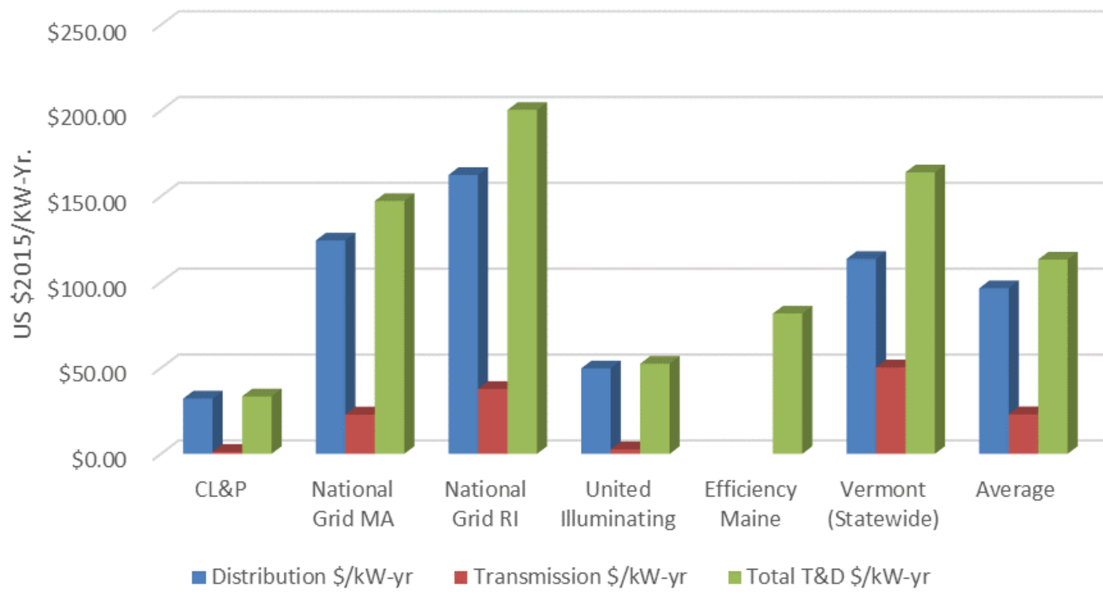
Figure 3
Value of Deferred Capital Expenditure – New England 2013*



*In $2013 unless noted.

For the 2015 study, the AESC 2015 project team issued a survey to the sponsoring electric utilities requesting the estimates of avoided Transmission and Distribution costs they use in their analysis of efficiency measure cost-effectiveness tests. The 2015 update resulted in a similar range of results as can be seen in Figure 4.

Figure 4
Value of Deferred Capital Expenditure – New England 2015



These estimates of avoided T&D costs were generally developed by dividing the portion of forecast T&D capital investments that are associated with load growth by the forecast growth in system load. These T&D investments exclude investments associated with replacement due to time-related deterioration or other factors that are independent of load. Such estimates vary considerably often as a function of the utilities' assumptions regarding how much investment is deferrable. More detail on the methodology used to develop the T&D estimates for some of the utilities is provided below.

Vermont

In 2012, the Vermont distribution utilities and Department of Public Service jointly reviewed and updated avoided T&D costs and filed those estimates with the Vermont Public Service Board. [16] The statewide estimates are based on load-related investments in the last decade ending in 1996 for which Vermont experienced significant load growth. The statewide avoided costs are reduced to reflect the reduction in line losses that would be associated with increasing T&D capacity. The annual avoided T&D costs start at $159/kW-year in 2013 and decline gradually resulting in a real-levelized value of $150/kW-year over a 29-year period

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[16] Docket EEU-2011-02 – EEU Avoided Costs – T&D Component Working Group Recommendation, August 31, 2012 http://psb.vermont.gov/docketsandprojects/eeu/avoidedcosts/2011, Order Re EEU Avoided Costs for Transmission and Distribution.

($2012 US). For 2015, the total avoided T&D cost was deemed at $150/kW-yr in $2012, which resulted in $164/KW-Yr in $2015 according to the updated AESC Study.

Burlington Electric

The Burlington Electric Department expects that no load-related distribution investments would be required over the next 20 years even without energy-efficiency programs, and, therefore, only uses the Vermont statewide avoided transmission cost.

ICF Tool

The ICF Tool is a workbook developed by ICF Consultants as part of the 2005 Avoided Energy Supply Component (AESC) Study and was most recently updated by ICF in 2009. The inputs for the workbook are:

- Historical and budgeted future capital costs,
- Historical and future load, and
- Various accounting parameters from FERC Form 1 data.

Analysis period cost data is divided by analysis period load data to derive an average capital cost per kW-yr. This average cost is multiplied by a factor representing the percentage of capital costs that are avoidable with DSM (another input variable). The model provides default avoidable percentages that are based on ICF's expert judgement and have been accepted by the AESC study group participants. The avoidable $/kW-yr is further modified by a carrying charge, determined from the accounting inputs, to develop an annualized avoided capacity value in $/kW-yr.

Based on review of some of the carrying charge calculations in the AESC 2009 study, National Grid updated this part of the workbook to create the updated ICF Tool. Other utilities have updated the workbook at other intervals. National Grid indicated that its practice is to use five years of historical and forecast data for both transmission and distribution data in developing the avoided transmission and distribution capacity values.

United Illuminating (B&V Report)

United Illuminating's methodology (B&V Report) is the following:

- Identification of historical and future T&D capacity additions which could have been fully or partially avoided with additional DSM programs.
- Collection of historical costs plus AFUDC associated with projects identified in the first step. Calculated project costs are then divided by each project's incremental MW load carrying capacity to derive a marginal capital cost for capacity per MW.

- Calculation of marginal O&M expenses.
- Converting marginal capital costs to annual costs adjusting for revenue requirements based on accounting inputs.
- Calculation of DSM savings based on historical and projected load growth.
- Calculations of annual avoided cost based on annual costs and identified DSM savings.

New England AESC Study Summary

Table 1 summarizes the methodology or tool used by the New England utilities using information from both the 2013 and 2015 AESC studies.

Table 1
Summary of New England Electric Utilities – Methodology

Company	Methodology
CL&P	ICF Tool
WMECO	ICF Tool
NSTAR	ICF Tool
National Grid MA	ICF Tool
National Grid RI	ICF Tool
PSNH	ICF Tool
United Illuminating	B&V Report
Efficiency Maine	Historical
Unitil MA	ICF Tool
Unitil NH	ICF Tool
Vermont (Statewide)	Historical
Burlington Electric Department	Historical

Notes

NA= Not applicable

ICF Tool = ICF workbook developed in 2009.

B&V Report = United Illuminating Avoided Transmission & Distribution Cost Study Report, Black & Veatch, September 2009.

When examining the results from the New England AESC study, it is important to recognize that the T&D DCE estimates are for utilities located outside WECC. Customer usage patterns, DSM programs and transmission and distribution systems constraints are different outside WECC than what is faced by FortisBC. While the general calculation methodology can be applied, it is unlikely that these estimates from the AESC study can be used by FortisBC to accurately reflect T&D DCE.

Michigan

In Michigan, the avoided transmission and distribution costs included in DSM cost-effectiveness analysis are specific to each utility and are generally relatively low. For example, Consumers Energy has noted that the current utility system structure would need to change substantially before the cost of building new transmission and distribution could be avoided. In its 2011 benefit cost analysis, the company used a $5/kW-yr figure for the T&D avoided cost value. This value essentially reflects reduced maintenance costs and does not represent changes in infrastructure costs.[17]

Illinois

The Ameren Illinois Company (AIC) separates the calculation of avoided transmission and distribution into two separate calculations.[18] The methodology used to estimate avoided distribution costs attributable to DSM programs involved estimating projected system load growth and estimate marginal cost of system capacity. Distribution engineering review a variety of bulk substation and distribution substation projects to determine an average marginal cost of capacity expansion. Typical costs for distribution circuit construction and line transformers were included. Next, the expenditures to serve load growth were estimated by evaluating budget information for an extended period. This evaluation is complicated by the fact that projects serve a variety of purposes: capacity upgrades to serve incremental system load, capacity upgrades to serve relocated system load, and refurbishment or replacement of equipment to avoid imminent failure.

The avoided electric transmission costs were estimated by using three factors:

- "Usage Growth-Related Factor." This factor is designed to capture the effect that some of the transmission projects may not be deferrable from DSM because it is not driven by growth in usage, but rather it is driven by customers moving to different areas. In this case, there is local growth but not system wide growth.

- "Location-Specific Factor/Deferrable Factor." This factor captures the effect that AIC is looking at the system as an aggregate and cannot tell whether load pockets will be deferred by DSM programs. Since DSM programs are not being designed to avoid or offset specific transmission projects, there is no certainty as to which projects will actually be deferred.

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[17] Consumers Energy 2012. Consumers Energy Company, "Consumers Energy 2011 Energy Optimization Annual Report," Case No. U-16736, May 31, 2012, available at: http://efile.mpsc.state.mi.us/efile/docs/16736/0001.pdf p.19.

[18] Ameren 2013b. Ameren Illinois, "Electric and Gas Energy Efficiency and Demand-Response Plan, Program Years: June 1, 2014 – May 31, 2017 (Plan 3)," Case No. 13-0498, August 30, 2013, available at: http://www.icc.illinois.gov/docket/CaseDetails.aspx?no=13-0498. Pp 27-29.

- “Condition/Reliability Replacement Factor.” This factor approximates the effect that load growth projects cause transmission asset turnover, so if AIC does not upgrade or replace a substation because of DSM, then AIC will need to spend money on additional maintenance or reliability projects that would have been avoided had new equipment been installed to meet load growth.

This methodology resulted in avoided transmission costs of $6/kW-yr and avoided distribution costs of $17/kW-yr in $2014.

NV Energy

The methodology for quantifying T&D capital investment savings generated by DSM energy savings is based on the marginal cost study filed in Nevada Power’s last general rate case.[19] The adopted valuation process reduces potential difficulties regarding uncertainty in load forecasts and T&D construction budgets, and it takes into account the ripple effect or the effect of deferred construction investments during the useful life of DSM measures.

The annual revenue requirement for the marginal cost of transmission facilities and distribution substations is estimated at US $48.92 /kW-yr. NV Energy has utilized the conservative value of 25 percent of $48.92/kW or $12.23/kW-yr in the PortfolioPro cost/benefit model. The PortfolioPro model calculates peak demand savings for each year of the measure useful life and then multiplies annual revenue requirement per kW with the peak demand savings to come up with the annual avoided revenue requirement.

Public Service Company of Colorado 2010 DSM Case

In the 2010 DSM analysis, the Public Service Company of Colorado used a combined value of $30.00/kW-yr for 2007 avoided transmission and distribution escalating at 1.99 percent annually. This estimate was developed as part of a resource planning settlement in the Comanche 3 Settlement Agreement in Docket Nos. 04A-214E, 04A-215E and 04A-216E. No background on the calculation method was provided.

[19] Docket No. 11-06006.

Summary of Survey

Table 2 below summarizes the methodologies used by utilities or entities in the regions reviewed for literature research. The most common valuation approach is the marginal cost methodology.

Table 2
Summary of T&D Avoided Cost Methodologies in Practice

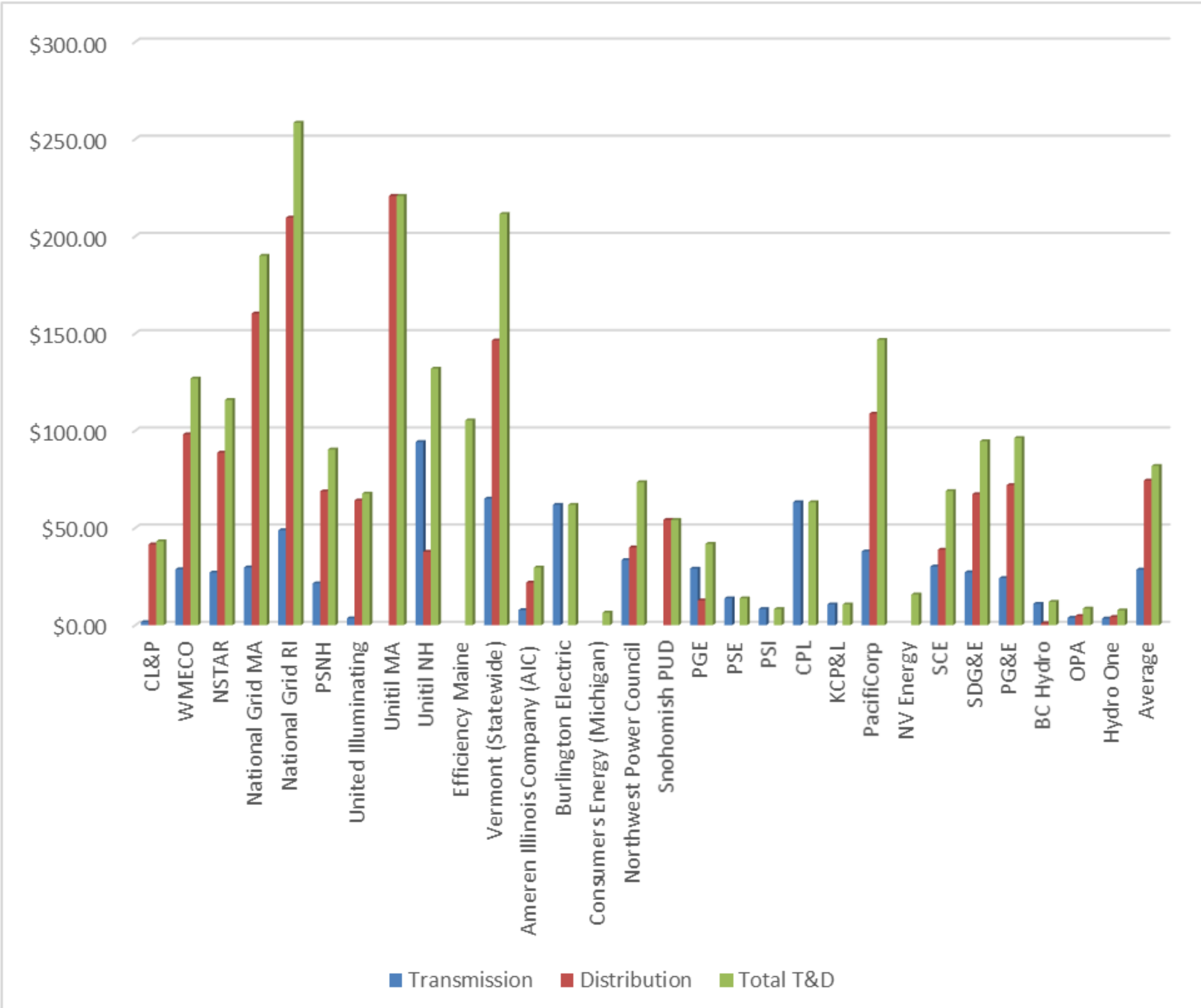
Entity/Region	Marginal Cost	Average Cost	Market Value	Scenario	Bench-marking
BC Hydro					
Ontario Power Authority					
Hydro One					
Northwest Power Council					
Snohomish PUD					
CPUC					
New England AESC Study					
Vermont					
ICF Tool					
United Illuminating					
Michigan					
Illinois					
NV Energy					
Public Service Company Colorado					

Figure 5 summarizes the estimated deferred T&D costs from the studies cited in this section in 2015 Canadian dollars. Appendix A containing a summary table of all the estimated DCE. The average, high and low DCE by function are provided in Table 3 below for the full survey and for utilities in WECC.

Table 3
Survey Results (CA$)

	Transmission	Distribution	Total T&D
Average			
All Utilities	$28.60	$74.39	$81.93
WECC	$20.23	$40.39	$52.20
High			
All Utilities	$94.21	$220.78	$258.43
WECC	$37.95	$108.81	$146.76
Low			
All Utilities	$1.61	$1.00	$7.60
WECC	$5.13	$1.00	$6.45

Figure 5
Value of Deferred Capital Expenditure – 2015 CA$



Based on the survey of methodology and DCE results, the following best practices can be concluded:

- Calculate separate estimates for Transmission and Distribution.
- Results differs by region and utility. Therefore, the best option for FortisBC is to estimate T&D DCE based on FortisBC data.
- While benchmarking may be indicative, benchmarking DCE results for FortisBC outside WECC does not appear to be appropriate.
- Using a marginal costing approach appears to be the most common calculation methodology.

Updated DCE Calculation

Introduction

As a fundamental principle, the avoided T&D costs included in a utility's DSM screening test should fairly represent the potential reduction or deferral in capital investments in the transmission and distribution system due to the addition of DSM programs. It is important to consider if the specific DSM programs are likely to reduce peak demand and, therefore, capital investments. While the averages of other utilities are useful for comparison purposes, FortisBC can develop more utility-specific numbers using data already published and available.

A sound avoided cost calculation practice should:

- Be based on forward looking avoided costs
- Be separated into two calculations: one for distribution and one for transmission
- Be annualized based on the cost of capital of FortisBC
- Reflect avoided O&M expenses, if any
- Consider the likelihood that reduction in capacity from DSM programs would occur during constrained periods and in locations that are constrained

Based on the survey of other utilities, a proposed methodology for FortisBC is provided below.

Proposed Calculation Methodology

The following methodology is proposed for FortisBC based on the review of methodologies used by other utilities. The proposed methodology is a marginal costing approach incorporating the forecast capital investments for FortisBC. In addition, it is based on forecasted data, rather than historical, to ensure the calculation captures capital expenditures that could be deferred, not investments already made. This methodology also allows FortisBC to use load forecasts and system investments that have already been published to the extent possible. In addition, the carrying costs calculations should be calculated from the most recent revenue requirements.

Distribution Avoided Costs

- Determine analysis period
- Determine expected peak growth over the analysis period
- Determine the forecasted distribution system investments due to growth over the analysis period
    - Exclude capital investments needed to support current load
    - Exclude capital investments needed to repair or replace current equipment
    - Exclude new connection capital costs
- Calculate the annualized $/kW-yr avoided distribution cost as the avoided investment divided by load growth times a real carrying charge
- If applicable add avoidable general plant and O&M adders

Transmission Avoided Costs

- Determine analysis period
- Determine expected peak growth over the analysis period
- Determine the forecasted transmission system investments due to growth over the analysis period
    - Exclude capital investments needed to support current load
    - Exclude capital investments needed to repair or replace current equipment
    - Exclude new connection capital costs
- Calculate the annualized $/kW-yr avoided transmission cost as the avoided investment divided by load growth times a real carrying charge
- Review the proposed programs and determine if a de-ration factor needs to be applied

Resulting DCE values

Based on the methodology described above, the following levelized transmission and distribution deferred capital expenses were determined, as shown in Table 4.

Table 4 Estimated Capital Deferred Value			
	Transmission	**Distribution**	**T&D**
Avoided Investment ($/kW-Yr)	$686.08	$131.30	$817.38
Annualized DCE			
Avoided Annual Return (6.00%)[20]	$41.16 per kW	$7.88 per kW	$49.04 per kW
Avoided Depreciation (2.54%)[21]	$17.44 per kW	$3.34 per kW	$20.78 per kW
Avoided Taxes (1.23%)[22]	$8.42 per kW	$1.61 per kW	$10.03 per kW
Avoided O&M (0.00%)[23]	$0.00 per kW	$0.00 per kW	$0.00 per kW
Total DCE	$67.03 per kW	$12.83 per kW	$79.85 per kW

FortisBC needs to consider if the avoided T&D costs need to be de-rated. Specifically, T&D costs will only be reduced if a significant amount of load reduction is attained in an area where the utility expansion plans can be altered. Using a deration approach helps mitigate the risk of overvaluing DSM program peak reduction potential.

Summary

The recommended Marginal Cost methodology was selected based on the literature review of the common methodologies used to determine avoidable T&D expenditures due to DSM program implementation. The methodology requires a utility-specific analysis of the growth on both the distribution and transmission system, an analysis of the investments needed to meet growth and a consideration of how potential DSM measures can impact the growth in the distribution and the transmission systems. Based on FortisBC's forecast growth-related capital T&D expenditure schedules and annualizing factors obtained from FortisBC, this study found the levelized T&D DCE values to be $67.03 and $12.83 respectively in 2015 dollars. Annual values for use in the DSM evaluation studies can be calculated by increasing these values by inflation on an annual basis.

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[20] Annual Return Factor is provided by FortisBC staff.

[21] The depreciation expense factor is based on the estimate life by cost category for transmission and distribution facilities.

[22] The taxes factor is based on the 2015 Approved property taxes as percent of total utility rate base

[23] The O&M factor is set to zero, since the O&M budget does not change under PBR, except for inflationary/productivity adjustments that are not related to capital expenditures.

Appendix A

Summary table of the estimated DCE values from review of other utilities.

		U.S. $			Canadian $[24]			
Company	**Year $**	**Trans. $/kW-yr.**	**Dist. $/kW-yr.**	**Total T&D $/kW-yr.**	**Trans. $/kW-yr**	**Dist. $/kW-yr**	**Total T&D $/kW-yr.**	**Methodology**
BC Hydro	2011				$11.00	$1.00	$12.00	
OPA	2014				$3.83	$4.73	$8.56	Marginal Cost
Hydro One	2007				$3.40	$4.20	$7.60	Marginal Cost
Northwest Power Council	2012	$26.00	$31.00	$57.00	$33.54	$39.99	$73.53	Benchmarking
Snohomish PUD	2013	N/A	$42.00	$42.00	N/A	$54.18	$54.18	Marginal Cost
PGE	2012	$22.56	$9.87	$32.43	$29.10	$12.73	$41.83	Unknown
PSE	2012	$10.71	N/A	$10.71	$13.82	N/A	$13.82	Unknown
PSI	2012	$6.43	N/A	$6.43	$8.29	N/A	$8.29	Unknown
PacifiCorp	2012	$29.42	$84.35	$113.77	$37.95	$108.81	$146.76	Unknown
Pacific Northwest Average		**$19.02**	**$41.81**	**$43.72**	**$17.62**	**$53.93**	**$40.73**	
Standard Deviation		**$8.91**	**$27.14**	**$35.81**	**$11.49**	**$35.01**	**$46.19**	
Standard Deviation (%)		**47%**	**65%**	**82%**	**65%**	**65%**	**113%**	
CL&P	2015	$1.25	$32.19	$33.44	$1.61	$41.53	$43.14	ICF Tool
WMECO	2011	$22.27	$76.08	$98.35	$28.73	$98.14	$126.87	ICF Tool
NSTAR	2011	$21.00	$68.79	$89.79	$27.09	$88.74	$115.83	ICF Tool
National Grid MA	2015	$23.01	$124.28	$147.29	$29.68	$160.32	$190.00	ICF Tool
National Grid RI	2015	$37.86	$162.47	$200.33	$48.84	$209.59	$258.43	ICF Tool
PSNH	2013	$16.70	$53.35	$70.05	$21.54	$68.82	$90.36	ICF Tool
United Illuminating	2015	$2.74	$49.75	$52.49	$3.53	$64.18	$67.71	B&V Report
Unitil MA	2013	N/A	$171.15	$171.15	N/A	$220.78	$220.78	ICF Tool
Unitil NH	2013	$73.03	$29.26	$102.29	$94.21	$37.75	$131.95	ICF Tool
Efficiency Maine	2015	N/A	N/A	$81.67	N/A	N/A	$105.35	Unknown
Vermont (Statewide)	2012	$50.45	$113.51	$163.96	$65.08	$146.43	$211.51	Historical
Ameren Illinois Company (AIC)	2014	$6.00	$17.00	$23.00	$7.74	$21.93	$29.67	Marginal Cost
Burlington Electric Dept.	2012	$48.00	N/A	$48.00	$61.92	N/A	$61.92	Historical
Consumers Energy (MI)	2011	N/A	N/A	$5.00	N/A	N/A	$6.45	Proxy
CPL	2012	$49.02	N/A	$49.02	$63.24	N/A	$63.24	Unknown
KCP&L	2012	$8.28	N/A	$8.28	$10.68	N/A	$10.68	Unknown
NV Energy	2011	N/A	N/A	$12.23	N/A	N/A	$15.78	Marginal Cost
SCE	2011	$23.39	$30.10	$53.49	$30.17	$38.83	$69.00	Marginal Cost

[24] Exchange rate used:1 US Dollar equal 1.29 Canadian Dollar (07/05/2016)

		U.S. $			Canadian $[24]			
Company	**Year $**	**Trans. $/kW-yr.**	**Dist. $/kW-yr.**	**Total T&D $/kW-yr.**	**Trans. $/kW-yr**	**Dist. $/kW-yr**	**Total T&D $/kW-yr.**	**Methodology**
SDG&E	2011	$21.08	$52.24	$73.32	$27.19	$67.39	$94.58	Marginal Cost
PG&E	2011	$18.77	$55.85	$74.62	$24.21	$72.05	$96.26	Marginal Cost
Average		**$24.67**	**$66.85**	**$70.00**	**$28.60**	**$74.39**	**$81.93**	
Standard Deviation		**$17.60**	**$45.81**	**$52.11**	**$22.71**	**$60.58**	**$67.85**	
Standard Deviation (%)		**71%**	**69%**	**74%**	**79%**	**81%**	**83%**	