Diane Roy
Vice President, Regulatory Affairs

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

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

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

April 6, 2017

British Columbia Public Interest Advocacy Centre
Suite 208 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Tannis Braithwaite, Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Inc. (FBC)

Project No. 3698896

2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Together Against Poverty Society, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On November 30, 2016, FBC filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCOAPO IR No. 1.

If further information is required, please contact Joyce Martin at 250-368-0319.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B-1, Volume 1, page ES1 and page ES8

1.1 At page ES1 (lines 23 and 35) and page ES8 (line 21) FBC uses the term "cost-effective". Please indicate how cost-effectiveness is defined in this context and, in particular, what "costs" are included/excluded in this determination.

Response:

In this context, cost-effective is being used to describe the costs of FBC's DSM resource options relative to supply-side resource options. Here, cost-effective is defined as having a lower unit cost than other resource options from a total cost perspective – that is, including costs to FBC and to the customer, also known as the Total Resource Cost (TRC).

As discussed in Section 8.1.1 of the LTERP, the TRC test comprises of benefits (the present value of the DSM measures' energy savings, over their effective measure life, valued at the utility's avoided costs) divided by the costs (incremental cost of the measures plus program administration costs). For the supply-side resource options, the unit costs include costs that would be incurred by FBC including capital, generation, operating and interconnection costs to the FBC transmission system, divided by the energy or capacity produced.

Please refer to the response to BCUC IR 1.38.2 for a table showing the estimated TRC Benefit/Cost ratios and average utility cost ($ per MWh) for each DSM Scenario considered.

2.0 Reference: Exhibit B-1, Volume 1, page ES7 and page 53

2.1 Please clarify (line 10) what is meant by incremental demand-side resources.

Response:

The reference to "incremental" DSM resources refers to new DSM resources during the planning horizon, compared to the already-realized DSM savings which are embedded in the historical actual loads, up to and including 2015.

2.2 Please indicate what years' DSM program impacts (e.g., does the reference load forecast include the impacts of programs implemented in and before 2015 or 2016 or what year?).

Response:

Please refer to the response to BCOAPO IR 1.2.1.

2.3 Does the reference load forecast account for a loss in the persisting effects of these programs in future years?

Response:

The reference load forecast is an econometric projection built upon FBC's past normalized load that includes embedded DSM program savings from prior years, with no adjustment for loss in persistence.

FBC considers that DSM measure persistence is likely given that the majority of DSM measures are either hard-wired (for example insulation or commercial building lighting retrofits), or, if they are removable (such as LED screw-in lighting products), government regulation has eliminated less efficient alternatives (such as incandescent lamps).

3.0 Reference: Exhibit B-1, Volume 1, page ES9

3.1 There is no Section 9.4.1 in FBC's 2016 LTERP Application. Please clarify the reference provided at line 25.

Response:

The reference should have been to Section 9.3.1 of the LTERP.

4.0 Reference: Exhibit B-1, Volume 1, page ES9 and pages 97-100

Preamble: The Application states (page ES9) that the High DSM Scenario "includes the majority of cost effective DSM from an LRMC perspective". The Application also states that the incremental cost of the High Scenario is $104 / MWh (page 100).

4.1 With respect to Figure 8-2 in Volume 1 (and Figure 3-2 in Volume 2), for each of the DSM Scenarios please explain what each of the following represent: i) the grey shaded area and ii) each of the two horizontal bars. Also, why in some cases does the colored bar exceed the grey shaded area and in other cases it does not?

Response:

With respect to Figure 8-2 in the LTERP (and Figure 3-2 in the LT DSM Plan), the grey shaded area represents the incremental resource cost *range* of the measures included in each DSM scenario or tranche.

The horizontal dark grey bar represents the average incremental resource cost of the group of measures included in each DSM scenario. The upper, coloured horizontal bars represent the same average cost amounts, with a program administration cost adder also included.

For two of the DSM scenarios (Base, High) the total incremental cost of each (shown by the colored bar) landed above the highest cost measure in the range, and vice versa in the other two scenarios (Low, Max) where the coloured bar lands within the range of costs of the measures included in those two DSM scenarios.

4.2 Please clarify what is meant by the term "incremental cost" (page 100). Does the $104 represent: i) the average cost of the High Scenario portfolio of DSM programs; ii) the average cost of the additional DSM measures included in the High Scenario versus the Base Scenario; or iii) the "cost" of the higher cost DSM measure included in the High Scenario?

Response:

In the referenced context, the term "incremental cost" represents ii) the average cost of the additional DSM measures included in the High Scenario versus the Base Scenario.

4.3 Given that the $104 LRMC for High DSM scenario exceeds the LRMC used to evaluate potential DSM programs ($100 per Exhibit B-1, Volume 2, page 8) why doesn't the High DSM scenario include all cost effective DSM from an LRMC perspective?

Response:

FBC uses the LRMC and the DCE to calculate cost effectiveness as provided by the Demand-Side Measures Regulation. DSM programs can have a cost of energy above the LRMC of $100/MWh and still be considered cost effective on a TRC basis. For example, the High Scenario can have an LRMC of $104 and still not include all of the cost effective DSM measures – because the benefits of the DCE are also included. Note that the $104 figure also includes program administration costs.

4.4 Does the High DSM scenario include any DSM programs that are not cost-effective (i.e., Program LRMC exceeds $100).

Response:

No. The High DSM scenario includes only DSM measures that are cost-effective[1].

The 2016 LT DSM Plan is not an expenditure filing. Therefore, the specific program costs and savings have not yet been determined. The Company anticipates filing its next DSM Expenditure Schedule, for 2018 onwards, later this year.

4.4.1 If so, what are they and what percentage of the savings in 2023 and 2035 are associated with these programs?

[1] Note that the DSM Scenarios are comprised of groups of cost-effective DSM measures that have not yet been assigned to specific programs. Those assignments, and the program delivery method(s), will be determined in the next DSM Expenditure schedule filing.

Response:

Please refer to the response to BCOAPO IR 1.4.4.

5.0 Reference: Exhibit B-1, Volume 1, pages 23, 32-36 and 40-45

5.1 The Application states (page 23) that uncertainty existed at that time "over the future of climate change action including the CPP rule in the U.S. as a result of the upcoming change in administration". Given the new administration is now in place and has indicated some of its policy direction, what changes, if any, are required to the outlooks as described in Sections 2.2.4.2; 2.2.5; 2.4.1; 2.4.2; 2.5.1; and 2.5.2?

Response:

FBC does not believe that any changes are required to the outlooks discussed in these sections of the LTERP at this time. While the new federal administration in the United States is now in place, many of its proposed or suggested policies have not been enacted into law or enforced yet. For example, while the new administration has indicated its intent to roll back the existing Clean Power Plan (CPP), how this will be done and what changes to the CPP regulation might be pursued are still being reviewed. Furthermore, changes to regulations under the Environmental Protection Agency (EPA) are required to go through a formal rulemaking process, which can take years, involving legal and procedural hurdles[2].

Given that policy changes can take up to several years to impact energy markets, the appropriate time to update these aspects of the planning environment would be in FBC's next long term electric resource plan.

[2] http://www.vox.com/energy-and-environment/2017/2/23/14691438/trump-repeal-clean-power-plan.

6.0 Reference: Exhibit B-1, Volume 1, pages 25-26 (Section 2.3.2)

6.1 Was the spending on the EV-related initiatives undertaken to date part of FBC's DSM expenditures? If not, under what program/business area was it funded?

Response:

FBC's EV-related initiatives, which are described in the response to BCUC IR 1.8.1.1, are funded under its capital expenditures program (Distribution Unplanned Growth).

6.2 Are potential new initiatives discussed here to be funded as part of FBC's DSM expenditures?

Response:

The 2016 LTERP/LT DSM Plan is not an expenditure schedule, as such it does not include detailed program listings, including new initiatives, or the associated costing.

The Company anticipates filing its next DSM Expenditure schedule, for 2018 onwards, later this year. At this time, FBC has not determined whether EV initiatives will form part of that expenditure schedule.

7.0 Reference: Exhibit B-1, Volume 1, page 40

7.1 Does FBC currently have any long-term capacity reservations (i.e., purchases LT transmission capacity access) for transmission linking it to either the U.S. or Alberta?

Response:

FBC's transmission access to market is mainly through its transmission rights on Teck Metals Ltd.'s 71 Line, as discussed on page 79 of the LTERP. Teck's 71 Line provides transmission both across the B.C./U.S. border and to the FBC system. FBC does not have any other long-term transmission rights. 71 Line provides FBC with access to 370 MW of import rights, when not used by Teck. FBC expects its access on 71 Line will remain through the planning period. However additional U.S. transmission is required to deliver the energy to the B.C./U.S. border to the market in the U.S.

7.1.1 If so, how much capacity is reserved and when do the current reservations expire?

Response:

Please refer to the response to BCOAPO IR 1.7.1.

7.1.2 What consideration was given to making any such reservations as part of the current LTERP?

Response:

For long-term planning purposes, such as the 2016 LTERP, FBC's access to 71 Line is treated as firm, but it must be recognized that the Company does not own the line. FBC did not give any consideration to any additional long-term transmission reservations, as there are no long-term firm reservations currently available across either the B.C./U.S. or the Alberta border. FBC will consider any additional long-term transmission reservations if any become available in the future.

8.0 Reference: Exhibit B-1, Volume 1, page 47

8.1 FBC states (line 13-14) that it believes its assumptions regarding future Tranche 1 PPA prices are reasonable given the recent historic rate increases by BC Hydro and the target increases to F2024. Please explain further how these historical and target increases have informed the forecast of Tranche 1 prices.

Response:

Please refer to the responses to BCUC IRs 1.6.1 and 1.6.2.

9.0 Reference: Exhibit B-1, Volume 1, pages 48-50

BCUC Decision re: BCH 2015 RDA, pages 10-11

9.1 Why did FBC use $129.70 / MWh as the Base Case value for PPA Tranche 2 energy when BC Hydro had already shifted its LRMC value towards $85 per MWh?

Response:

At this time, the BC Hydro PPA Tranche 2 rate remains $129.70 per MWh, and was therefore used as the base case in the LTERP. Once a new BC Hydro LRMC is accepted by the BCUC for rate making purposes, the Tranche 2 rate will be updated in BC Hydro's rate schedule 3808. FBC will continue to work with BC Hydro to update rate schedule 3808 when it is appropriate to do so. However, as discussed in the response to BCUC IRs 1.24.1 and 1.24.2, adjusting the PPA Tranche 2 energy rate to $85 per MWh or $100 per MWh has little to no impact on FBC's LRMC or preferred portfolio.

9.2 Given that the BCUC has now determined that "for the purpose of providing a basis for the Step 2 rate for RIB and TSR, either a range ($85/MWh to $100/MWh) or a point (less than $85/MWh) can be used as a reference for both the TSR and the RIB rate" would it not be reasonable to use a value of no more than $100 as the appropriate cost of Tranche 2 energy? If not, why not?

Response:

Please refer to the response to BCOAPO IR 1.9.1.

9.3 Are the values in Figure 2-11 expressed in nominal $, real 2015 $ or in some other form?

Response:

The values in Figure 2-11 are in real 2015 dollars.

9.3.1 If necessary, please re-do Figure 2-11 such that the values are expressed in real 2015 $.

Response:

Please refer to the response to BCOAPO IR 1.9.3.

9.4 Are the values in Figure 2-13 expressed in nominal $, real 2015 $ or in some other form?

Response:

The values in Figure 2-13 are in real 2015 dollars.

9.4.1 If necessary, please re-do Figure 2-13 such that the values are expressed in real 2015 $.

Response:

Please refer to the response to BCOAPO IR 1.9.4.

10.0 Reference: Exhibit B-1, Volume 1, pages 53-55

10.1 Are the load and peak demand forecasts based on normal weather conditions? If so, what is the definition of weather normal and is the definition assumed to change over the 20 year period?

Response:

The load forecast assumes normal weather conditions which are calculated based on a seasonal ten year rolling average of Heating Degree Days (HDD) and Cooling Degree Days (CDD) for FBC's service area. The definition of normal weather is not assumed to change over the 20 year forecast period. The peak forecast is based on actual weather data since peak demand needs to be able to accommodate variations from normal weather.

10.2 Please provide a schedule that compares FBC's load and peak demand forecast (prior to DSM) as filed in the current Application with that filed for the 2012 LTRP, and comment on the reasons for any material (5%) variances as of 2035.

Response:

Table 1: Gross Load and Forecast Peaks before DSM and Savings

Year	2012 LTRP Gross Load Forecast (GWh)	Annual 2012 LTRP Peak Forecast (MW)	2016 LTERP Gross Load Forecast (GWh)	Annual 2016 LTERP Peak Forecast (MW)
2016	3,816	780	3,551	731
2017	3,863	789	3,605	741
2018	3,916	800	3,644	749
2019	3,967	810	3,685	757
2020	4,020	821	3,723	764
2021	4,075	832	3,758	771
2022	4,130	843	3,800	780
2023	4,184	854	3,845	789
2024	4,239	865	3,884	797
2025	4,295	877	3,925	805
2026	4,350	888	3,967	813
2027	4,406	899	4,006	821
2028	4,462	910	4,046	829
2029	4,519	922	4,087	837
2030	4,576	933	4,123	844
2031	4,628	944	4,162	852
2032	4,682	955	4,202	860
2033	4,737	965	4,243	869
2034	4,791	976	4,284	877
2035	4,845	987	4,325	885

The gross load forecast for 2035 in the LTERP is 11 percent lower than the forecast for the same year from the 2012 LTRP, and the 2016 LTERP forecast for the 2035 peak load is 10 percent lower than the 2012 LTRP forecast for that year.

Many of the inputs, such as the CBOC GDP forecast, BC Stats forecast, new customers and survey results have changed since the 2012 LTRP was prepared resulting in these variances for 2035 as compared to the 2012 LTRP forecast.

11.0 Reference: Exhibit B-1, Volume 1, page 55 and Appendix F, page 11

11.1 Please clarify what the winter peak forecast values in Figure 3-3 represent (i.e., are they the winter peak value for customer demand, are they the winter peak values for required generation to serve customer peak demand after allowance for losses, or are they some other value?).

Response:

The winter peak value in Figure 3-3 represents a forecast of the largest demand (not weather normalized), including losses, that may need to be supplied over a single hour during the period from November to February.

11.2 Similarly, what do the monthly "System Peak" values set out in Table 2.10 of Appendix F represent?

Response:

The monthly system peak values in Table 2.10 represent the largest weather normalized actual and forecast demand, including losses, that may need to be supplied over a single hour during each month.

11.3 With respect to Table 2.10 in Appendix F, please explain why the winter peak value is higher than the system peak reported for any of the winter months in the same year.

Response:

The winter peak is a seasonal forecast, which will always be higher than the forecast for any given month. This is because, in preparing the seasonal forecast, the highest peak demand of the November to February period (the seasonal load) is used rather than the load in any individual month. For an example, please refer to the response to BCOAPO IR 1.21.1.

12.0 Reference: Exhibit B-1, Volume 1, pages 56-58

12.1 Please provide a schedule setting out the annual growth rates in BC GDP forecast by the CBOC as used in the 2012 LTRP.

Response:

The requested growth rates are set out in Table 1 below, which also contains the response to BCOAPO IR 1.12.2.

Table 1: GDP Growth Rates, 2012 - 2035

Year	2012 LTRP CBOC GDP Growth (%)	Actual CBOC GDP Growth (%)	2016 LTERP CBOC GDP Growth (%)
2012	3.0%	2.5%	
2013	3.2%	2.1%	
2014	2.7%	2.5%	
2015	2.4%	2.3%	
2016	2.0%	3.2%	2.7%
2017	1.9%		3.4%
2018	2.0%		3.1%
2019	1.8%		2.8%
2020	1.6%		2.3%
2021	1.6%		1.5%
2022	1.6%		2.5%
2023	1.4%		2.7%
2024	1.6%		2.1%
2025	1.5%		2.2%
2026	1.5%		2.1%
2027	1.6%		1.9%
2028	1.5%		1.9%
2029	1.6%		2.0%
2030	1.5%		1.7%
2031	1.3%		1.8%
2032	1.4%		1.9%
2033	1.4%		1.9%
2034	1.4%		1.9%
2035	1.3%		1.9%

12.2 In the same schedule please include the actual BC GDP growth rates up to 2015 (2016 if available) and the forecast growth rates now projected by the CBOC and used in the 2016 LTERP.

Response:

Please refer to the response to BCOAPO IR 1.12.1.

12.3 Please provide a schedule setting out the annual growth rates in population forecast by the BCStats as used in the 2012 LTRP.

Response:

The requested growth rates are set out in Table 1 below, which also contains the response to BCOAPO IR 1.12.4.

The residential customer additions forecast in the 2016 LTERP was prepared based on a customized population forecast for the FBC service territory provided by BC Stats. The 2012 LTRP customer additions forecast was based on the CBOC provincial housing starts forecast, which at the time exhibited a stronger correlation to customer additions (the CBOC housing starts correlation (R^2) was 79 percent versus 52 percent for the BC Stats population data). In 2014, FBC returned to using the BC Stats population data to forecast customer additions because the provincial housing starts no longer showed the same strong statistical correlation. FBC now uses the BC Stats customized service territory population forecast exclusively for customer additions forecasting.

Table 1: 2012 LTRP BC Housing Starts Growth Projections from the CBOC[3]

Year	2012 LTRP BC Housing Starts Growth (%)	Actual BC Stats Population Growth (%)	2016 LTERP BC Stats Population Growth (%)
2011		0.5%	
2012	18.7%	0.1%	
2013	5.2%	0.6%	
2014	4.9%	1.1%	
2015	1.8%	1.1%	
2016	-2.6%		1.2%
2017	-0.8%		1.2%
2018	-0.5%		1.1%
2019	-0.8%		1.1%
2020	-0.1%		1.1%
2021	-0.2%		1.1%
2022	-0.3%		1.1%
2023	-0.5%		1.1%
2024	0.6%		1.1%
2025	-0.8%		1.0%
2026	-1.1%		1.0%
2027	-1.5%		1.0%
2028	-0.1%		0.9%
2029	-1.1%		0.9%
2030	-1.8%		0.9%
2031	0.3%		0.8%
2032	-0.7%		0.8%
2033	-0.8%		0.8%
2034	-0.8%		0.8%
2035	-0.8%		0.7%

12.4 In the same schedule please include the actual population growth rates up to 2015 (2016 if available) and the forecast growth rates now projected by the BCStats and used in the 2016 LTERP.

[3] 2016 population growth rate from BC Stats is not available at the time of response.

Response:

Please refer to the response to BCOAPO IR 1.12.3.

12.5 At the bottom of page 58 it states, "Customer usage is forecast by averaging the most recent three years' usage rates and then assuming the average rate remains constant over the planning horizon". What is the rationale for assuming residential customer usage will remain constant, rather than factoring in depressive effects from, for example, DSM efforts and increased Building Code energy efficiency requirements?

Response:

The quotation above is regarding the before-savings forecast. The reference case load forecast uses the after-savings forecast, which includes the effect of other savings efforts. DSM is considered a resource option and is discussed in Section 8 of the LTERP.

The residential UPC does not exhibit a trend; therefore a method such as a three year average has the desirable characteristics of smoothing recent fluctuations while also providing a forecast that is sensitive to recent changes in customer behavior.

13.0 Reference: Exhibit B-1, Volume 1, Appendix E, page 2

13.1 Please provide a schedule setting out the actual values underling Figure E-1.

Response:

Figure E-1 was incorrect and has been updated in the response to BCUC IR 1.15.1. Please see the actual values underlying the updated Figure E-1 below.

Note that the update affected Figure E-1 only. The correct values shown in the table below were used to prepare the forecast.

Load Savings (GWh)

GWh											
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CIP	0.0	2.0	4.1	4.2	4.2	4.2	4.3	4.3	4.3	4.4	4.4
RCR	4.1	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
AMI	-3.8	-8.8	-13.0	-16.5	-19.4	-21.1	-22.2	-23.3	-24.4	-25.5	-26.7
Rate Driven Savings	2.8	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1
AMI (Loss Decrease Partially Offsets Net Increase)	2.7	6.7	9.7	12.1	13.9	14.4	14.4	14.3	14.3	14.2	14.2
Loss Reduction due to Rate-driven Savings	0.6	0.9	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2
AMI	-1.1	-2.2	-3.3	-4.4	-5.5	-6.7	-7.8	-9.0	-10.2	-11.3	-12.5
Net Load Other Savings	3.1	1.9	-0.1	-3.5	-6.4	-8.0	-9.1	-10.1	-11.2	-12.2	-13.3
Loss Other Savings	3.3	7.6	10.8	13.2	15.0	15.6	15.5	15.5	15.4	15.4	15.3
Gross Other Savings	6.4	9.5	10.7	9.7	8.6	7.5	6.5	5.4	4.3	3.2	2.0

GWh									
	2027	2028	2029	2030	2031	2032	2033	2034	2035
CIP	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6
RCR	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
AMI	-27.8	-29.0	-30.2	-31.4	-32.5	-33.8	-35.0	-36.2	-37.4
Rate Driven Savings	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.4
AMI (Loss Decrease Partially Offsets Net Increase)	14.1	14.0	14.0	13.9	13.8	13.8	13.7	13.7	13.6
Loss Reduction due to Rate-driven Savings	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
AMI	-13.7	-15.0	-16.2	-17.4	-18.7	-20.0	-21.3	-22.6	-23.9
Net Load Other Savings	-14.4	-15.5	-16.6	-17.7	-18.8	-20.0	-21.1	-22.3	-23.5
Loss Other Savings	15.3	15.2	15.2	15.1	15.0	15.0	14.9	14.9	14.8
Gross Other Savings	0.9	-0.3	-1.4	-2.6	-3.8	-5.0	-6.2	-7.5	-8.7

13.2 It appears from a Figure E-1 that the only values which are growing over the 2016-2035 period are those for CIP and AMI. Please confirm whether or not this is correct.

Response:

Not confirmed. As shown in the Table 1 included in the response to BCOAPO IR 1.13.1, RCR savings are forecast to increase by approximately 2 GWh from 2016 to 2017 and then remain constant for the remainder of the forecast period. Additionally, rate driven savings are forecast to increase over the planning horizon.

13.2.1 If so, please explain why the Rate-Driven impacts are not increasing. Is FBC assuming that its rates will increase at the rate of inflation over the period to 2035?

Response:

Please refer to the response to BCOAPO IR 1.13.2.

13.3 Please indicate how the RCR values were determined and what underlying assumptions have been made about the future design of Residential rates.

Response:

As noted in the LTERP at the referenced location, GWh load savings attributable to the RCR were developed as follows:

> RCR savings reflect the conservation impact of changing FBC's residential rate structure in 2012 from a flat rate to an inclining block rate. The RCR forecast is a result of analysis performed for the Residential Conservation Rate Information Report submitted to the Commission in November 2014; RCR savings are expected to be fully realized by 2017.

The savings were assumed to materialize at the following percentages in each year, applied to the before-savings residential load, which sum to the total expected RCR savings through to 2017.

Table 1: RCR Savings

Year	Before Savings Load (GWh)	Cumulative RCR Savings (GWh)	Cumulative RCR Impacts (%)
2012	1,248	8	0.64%
2013	1,380	22	1.57%
2014	1,318	36	2.75%
2015	1,306	40	3.10%
2016	1,353	45	3.29%
2017	1,364	46	3.40%

The analysis assumed no changes in the current structure of residential rates.

13.4 Please indicate how the AMI values were determined.

Response:

The AMI values were determined based on the information provided as part of the AMI CPCN application, as modified by the Commission's determinations in Order C-7-13, which included a reduction in the assumed annual energy consumption for marijuana grow sites from 151.2 MWh to 113.4 MWh. The assumed annual consumption is then multiplied by the annual change in the number of forecast theft sites as well as the annual change in the number of forecast paying marijuana grow sites to determine the overall AMI savings.

Please also refer to the response to BCUC IR 1.15.1.

13.5 Please confirm that the AMI savings shown are just those related to increased sales.

Response:

Not confirmed. As explained in the response provided to BCUC IR 1.15.1, the AMI impact is fully accounted for by combining the AMI system losses savings forecast and the residential AMI savings forecast. .

13.6 Please indicate how the CIP values were derived.

Response:

The CIP values were derived using the assumptions in the BC Hydro Smart Metering and Infrastructure Program business case, which estimated that 15 percent of residential customers would use a CIP, and that those customers would use 2 percent less electricity.

14.0 Reference: Volume 1, Appendix E, pages 6-8

14.1 Please provide a Table similar to Table E-1 setting out the results of the Residential regression as used in the 2012 LTRP.

Response:

Table 1: Results of 2012 LTRP Residential Growth Regression

Regression	Residential Growth
Start Year	1990
End Year	2009
R^2	0.79
Adjusted R^2	0.78
df	18
Intercept (b0)	25.62
Slope Population (b1)	0.06

14.2 With respect to page 8 (lines 4-5), how has FBC determined that there is no long term trend in the "normalized" UPC value?

Response:

Please refer to the response to BCUC IR 1.14.1.1.

14.3 The text at lines 6-8 suggests that the UPC values were adjusted for "savings". However, the text at line 15 suggests that savings were also subtracted from the forecast derived using the UPC. Please clarify what, if any, specific adjustments for saving were made to the UPC values as opposed to what adjustments for savings were made to the forecast derived using the UPC values.

Response:

No adjustments are made to the UPC values directly.

Before-savings load is calculated by multiplying before-savings UPC with the average annual customer count. Savings are then subtracted from the before-savings load to calculate the after-savings load. The after-savings load is then divided by the average annual customer count to calculate the after-savings UPC. Please refer to the response to BCOAPO IR 1.14.4 for a detailed schedule of the calculations.

14.4 Please provide a schedule that sets out the annual residential load values (2016-2035) resulting from the calculation described at lines 13-14 and the subsequent adjustments for savings (itemized) that produces the values shown in Figure E-8.

Response:

Table 1: Residential Schedule

Loads (MWh)	A	B	C = A * B	D	E	F	G	F = C - D - E - F - G
Year	UPC Before-Savings	Average Customer Count	Before-savings Load	Residential Rate Driven Savings	RCR Savings	CIP Savings	AMI Savings	Residential After-savings Load
2016	11.80	114,623	1,352,649	1,163	4,118	-	(3,810)	1,351,178
2017	11.80	115,555	1,363,653	1,173	5,871	2,045	(8,836)	1,363,400
2018	11.80	116,503	1,374,838	1,182	5,871	4,125	(12,988)	1,376,648
2019	11.80	117,449	1,385,995	1,192	5,871	4,158	(16,465)	1,391,238
2020	11.80	118,399	1,397,213	1,202	5,872	4,192	(19,423)	1,405,370
2021	11.80	119,356	1,408,500	1,211	5,871	4,226	(21,113)	1,418,305
2022	11.80	120,317	1,419,842	1,221	5,871	4,260	(22,206)	1,430,696
2023	11.80	121,272	1,431,113	1,231	5,871	4,293	(23,309)	1,443,027
2024	11.80	122,207	1,442,149	1,240	5,871	4,326	(24,424)	1,455,135
2025	11.80	123,129	1,453,032	1,250	5,871	4,359	(25,550)	1,467,102
2026	11.80	124,041	1,463,793	1,259	5,871	4,391	(26,687)	1,478,959
2027	11.80	124,935	1,474,336	1,268	5,871	4,423	(27,835)	1,490,609
2028	11.80	125,808	1,484,644	1,277	5,871	4,454	(28,995)	1,502,037
2029	11.80	126,660	1,494,702	1,285	5,871	4,484	(30,167)	1,513,228
2030	11.80	127,488	1,504,464	1,294	5,871	4,513	(31,350)	1,524,136
2031	11.80	128,292	1,513,955	1,302	5,871	4,542	(32,545)	1,534,785
2032	11.80	129,077	1,523,214	1,310	5,871	4,570	(33,752)	1,545,216
2033	11.80	129,839	1,532,215	1,318	5,871	4,597	(34,972)	1,555,401
2034	11.80	130,579	1,540,947	1,325	5,871	4,623	(36,203)	1,565,331
2035	11.80	131,293	1,549,373	1,332	5,871	4,648	(37,447)	1,574,968

15.0 Reference: Volume 1, Appendix E, pages 9-10

15.1 Please provide a Table similar to Table E-2 setting out the results of the Commercial regression as used in the 2012 LTRP.

Response:

Table 1: 2012 LTRP Results of Commercial Regression

Regression	Commercial
Start Year	2000
End Year	2009
R^2	0.96
Adjusted R^2	0.95
df	7
Intercept (b0)	70,956
Slope GDP (b1)	0.06
Slope CoK Event (b2)	(48,603)

16.0 Reference: Volume 1, Appendix E, pages 11-12

16.1 Please provide a schedule that sets out the Wholesale Energy Forecast from the 2012 LTRP and that contrasts it with the actual values up to 2015 (or 2016 if available), plus the forecast values as used in the current 2016 LTERP.

Response:

Table 1: Wholesale Load (GWh)

	A	B	C = A - B	D	E
Year	2012 LTRP Wholesale Forecast Load	2012 LTRP CoK Forecast Load	2012 LTRP Wholesale Forecast Load w/o CoK	Actual Wholesale Load w/o CoK	2016 LTERP Wholesale Forecast Load w/o CoK
2012	925.8	332.6	593.1	565.8	
2013	935.4	333.5	601.9	578.1	
2014	942.7	334.3	608.4	571.9	
2015	948.0	334.9	613.1	561.7	
2016	950.6	335.4	615.2	547.6	588.1
2017	953.8	336.3	617.5		589.1
2018	959.0	337.6	621.4		592.4
2019	963.1	339.0	624.1		597.2
2020	966.2	340.4	625.8		602.3
2021	969.8	341.8	628.0		605.9
2022	973.3	343.3	630.1		609.5
2023	975.8	344.7	631.1		613.2
2024	979.3	346.2	633.1		616.8
2025	982.7	347.8	634.9		620.5
2026	986.1	349.4	636.7		624.3
2027	990.0	351.1	639.0		628.0
2028	993.8	352.7	641.1		631.8
2029	998.2	354.5	643.7		635.6
2030	1,002.5	356.3	646.3		639.4
2031	1,005.0	358.0	646.9		643.2
2032	1,008.6	359.8	648.7		647.0
2033	1,012.2	361.7	650.5		650.9
2034	1,015.7	363.6	652.2		654.8
2035	1,019.3	365.5	653.9		658.8

Note: FBC acquired the electric utility assets of the City of Kelowna (CoK) in 2013 and CoK therefore ceased to be a wholesale customer subsequent to the 2012 LTRP being filed and reviewed by the Commission. The table above shows the original 2012 LTRP forecast with CoK included as a wholesale customer in column "A". Column "B" shows the individual CoK customer forecast and column "C" shows the 2012 wholesale forecast without CoK. The columns "D" and "E" do not include the load from the CoK.

16.2 The Application states that after the first five years an average of each individual customer's forecasted growth rate is used to project the long term. Given that Penticton represents over ½ the total load, is a simple or weighted average used?

Response:

Each wholesale customer is forecast on an individual basis for before-savings load and then aggregated to calculate the total wholesale load for each year. This method ensures that the demand from each wholesale customer is properly weighted.

16.3 Has FBC assessed the reasonableness of using the 5-year growth rates provided by these customers to project their long term growth rates? If so, how and what were the results?

Response:

FBC believes that each wholesale customer is best qualified to forecast their usage and that using the average growth rate provided by each individual wholesale customer is the most reasonable approach for the long-term forecast. Each wholesale customer represents a unique mix of residential, commercial and industrial customers, rate classes and billing systems so FBC does not believe it would be practical to try to prepare the forecast at a more granular level.

17.0 Reference: Volume 1, page 57 and Appendix E, page 13

17.1 Please provide a schedule that sets out the Industrial Energy Forecast from the 2012 LTRP and that contrasts it with the actual values up to 2015 (or 2016 if available), plus the forecast values as used in the current 2016 LTERP.

Response:

FBC acquired the electric utility of the CoK in 2013 resulting in the increased industrial load seen in the table below. An additional 2 columns have been added to show estimated actual and forecast CoK load and to provide an estimate of the 2016 LTERP load forecast without CoK, which gives a better comparison between the two forecasts.

Note: 2012 and 2013 CoK loads are estimates (provided by Corix) and were calculated using allocation percentages.

Table 1: Industrial Load (GWh)

	A	B	C	D	E = B - D for actual E = C - D for forecast
Year	2012 LTRP Industrial Forecast Load w/o CoK	Actual Industrial Load with CoK	2016 LTERP Industrial Forecast Load with CoK	CoK Actual and Forecast	2016 LTERP Industrial Actual and Forecast Load w/o CoK
2012	253.4	364.2		72.9	291.3
2013	261.1	383.5		81.0	302.5
2014	266.5	380.9		59.4	321.5
2015	268.6	381.3		52.9	328.4
2016	258.8	382.9	394.4	55.5	338.9
2017	250.7		410.7	55.7	354.9
2018	246.3		412.2	55.7	356.5
2019	243.0		416.1	56.1	360.0
2020	242.5		419.2	56.4	362.8
2021	243.9		425.5	57.2	368.3
2022	245.7		431.6	58.1	373.5
2023	247.5		438.4	59.0	379.4
2024	249.7		445.0	59.9	385.1
2025	251.9		451.8	60.8	391.0
2026	254.1		459.2	61.8	397.4
2027	256.4		465.9	62.7	403.2
2028	258.7		473.0	63.6	409.4
2029	261.0		480.1	64.6	415.5
2030	263.4		486.0	65.4	420.6
2031	265.8		492.7	66.3	426.4
2032	268.2		500.4	67.3	433.1
2033	270.6		508.2	68.4	439.9
2034	273.1		516.0	69.4	446.6
2035	275.6		523.8	70.5	453.4

The increased industrial load in the 2016 LTERP forecast compared to the 2012 LTRP forecast is due to the addition of six new industrial customers combined with updated customer surveys and a higher CBOC GDP forecast. For example the average annual Industrial growth rate (developed by combining customer survey results and CBOC GDP forecasts) between 2015 and 2035 for the 2012 LTRP was 0.1 percent, compared to the 2016 LTERP annual average of 2 percent.

17.2 Please indicate the specific industrial sectors for which the CBOC provides GDP forecasts.

Response:

The CBOC provides GDP forecasts for the following industrial sectors. The 2015 sales are also shown in the table below.

Industry	2015 (GWh)
AGRICULTURE	19.9
COMMERCIAL SERVICES	20.3
CONSTRUCTION	2.9
EDUCATION SERVICES	35.9
FINANCE, INSURANCE AND REAL ESTATE	3.6
FORESTRY	128.4
GOODS PRODUCING INDUSTRIES	13.8
HEALTH CARE & SOCIAL SERVICES	27.2
MANUFACTURING	92.1
PUBLIC ADMINISTRATION AND DEFENCE	15.2
TRANSPORTATION & WAREHOUSING	6.4
UTILITIES	12.2

17.3 Please provide a breakdown of FBC's 2015 industrial sales by these industrial sectors.

Response:

Please refer to the response to BCOAPO IR 1.17.2.

17.4 For which industrial sectors is the growth rate for the first five years based predominantly on survey results, as opposed to the CBOC GDP forecast?

Response:

The following industrial sectors are predominantly based on survey results.

CBOC List of Industries
AGRICULTURE
FORESTRY
MANUFACTURING
CONSTRUCTION
UTILITIES
GOODS PRODUCING INDUSTRIES
TRANSPORTATION & WAREHOUSING
EDUCATION SERVICES
HEALTH CARE & SOCIAL SERVICES
PUBLIC ADMINISTRATION AND DEFENCE

17.5 The Application states on page 57 that the GDP composite rate is used to forecast industrial long term load. Does this rate differ from the overall GDP rate discussed on page 56?

Response:

Yes. The composite GDP rate discussed on page 57 is developed by multiplying the CBOC industry sector GDP growth rates by the proportion of demand from each sector. This industrial composite rate is then used specifically to forecast the industrial long term load.

The overall GDP rate discussed on page 56 is the CBOC Provincial GDP value and is used to forecast the commercial load.

17.5.1 If yes, how and what is the forecast for the first 5 years and over the full 20 years?

Response:

The first five years of the industrial forecast predominantly uses the results from the Industrial Customer Survey. FBC then prepares a weighted composite industrial GDP forecast based on the current FBC customer mix. The weighted GDP composite forecast is used to forecast demand for all industrial customers for the final 15 years of the forecast period. The full 20 year industrial demand forecast is presented in Appendix F, page 7, Table 2.6.

On page 57 of the LTERP, FBC stated that the individual sector GDP projections were available only for the first five years. This statement was in error as the individual sector GDP projections are available for the full 20 years. This correction does not in any way affect the industrial demand forecast.

18.0 Reference: Exhibit B-1, Volume 1, Appendix E, page 14

18.1 With respect to page 14 (line 5), how has FBC determined that there is no long term trend in the use by the Irrigation class?

Response:

FBC has tested the historical irrigation load class data and has determined that the current 10 year R^2 value is just 20 percent, indicating the absence of a statistically significant trend.

R^2 is a statistical measure of how well observed data can be used to predict future forecasts. R^2 results can range from 0 to 100 percent, where results closer to 100 percent indicate statistically significant trends that can be used to predict future outcomes.

19.0 Reference: Exhibit B-1, Volume 1, Appendix E, page 15

19.1 With respect to page 15 (lines 5-6), how has FBC determined that there is no long term trend in the use by the Lighting class?

Response:

The average absolute annual historical load fluctuations over the ten-year period from 2006 to 2015 were very low at approximately 0.66 GWh per year. Due to the relatively low energy demand (16 GWh per year), the minor historical fluctuations and in order to remain consistent with past practice, FBC forecast a constant demand of 16 GWh per year.

19.2 In many jurisdiction there have been conversion to more efficient street lighting, to date what activity has there been in this regard in the FBC service area?

Response:

On November 19, 2015, the Commission approved amendments to FBC's Rate Schedule 50 Lighting Tariff to include rates for Type I (Customer-owned and maintained) and Type II (Customer-owned and Company-maintained) LED lighting. Since then, 11 customers in FBC's service area have converted at least some of their existing lights to LED.

FBC is currently investigating the conversion of existing Company-owned lights to LED and any conversion would require an amendment to Rate Schedule 50 for Type III (Company-owned and maintained) LED rates. FBC expects to file an application with the Commission for a Company-owned LED street light rate in 2017.

19.3 Has FBC consulted with BC Hydro regarding any potential plans to move to more efficient street lighting that might impact the forecast of a constant load for the lighting class? If not, why not?

Response:

FBC has not consulted with BC Hydro regarding any potential plans to move to more efficient street lighting at this time. While FBC will pursue relevant information as needed, it has the

1 resources required to evaluate the potential system impact of emerging technologies such as
2 LED lighting.

3

20.0 Reference: Exhibit B-1, Volume 1, page 54; Appendix E, page 16 and Appendix F, page 10

20.1 The discussion on page 54 suggests that the loss values used to derive gross load (from net load) are assumed to be 8% for the period. However, the discussion in Appendix E suggests that the loss values have been adjusted for reductions in theft. Please clarify and indicate the assumptions used to determine the energy loss values set out Figure E-15 and Appendix F, Table 2.9.

Response:

The before-savings loss load is 8 percent. AMI loss reduction and other savings further reduce the before-savings loss load resulting in after-savings loss as shown in Figure E-15 and also in Appendix F, Table 2.9.

After-savings Gross load is calculated by adding after-savings net load with after-savings loss load as shown in Figure 3-1 on page 54.

21.0 Reference: Exhibit B-1, Volume 1, Appendix E, page 17

21.1 Please provide a schedule that clearly sets out the calculations described in lines 2-9.

Response:

The example below shows how the peak forecast was calculated on a monthly basis. The process is the same for the winter and summer peaks except instead of using the monthly peaks the winter peak is collected between the months of November to February and the summer peak is collected between the months of July and August for the ten year period.

To calculate January 2017 peak:

- Collect the January peaks, excluding the monthly coincidental peaks of self-generating customers, for each year from 2006 – 2015 (Columns B to K in red font in the table below).
- Calculate the gross load annual growth rates from 2006 – 2015 based on the demand forecast (Column A).
- Apply the growth rate (Column A) to the peak base year (Columns B in red font) and repeat the process for the remaining nine base years (Columns C to K).
    - For example, for 2008, 551 MW (in Column B) is increased by 2.3% resulting in 564 MW to get the load for 2009.
    - 564 = 551*(1 + 0.023)
    - This step is indicated by the downward arrows
- The resulting ten 2017 values (Line 12, Columns B to K) are then averaged to give the monthly peak (Line 12, Column L). This step is indicated by the horizontal arrow.

		A	B	C	D	E	F	G	H	I	J	K	L
Line	Year	Gross Load Growth	Jan	Jan	Jan	Jan	Jan	Jan	Jan	Jan	Jan	Jan	Average
1	2006		552										
2	2007	0.1%	553	673									
3	2008	-0.3%	551	671	669								
4	2009	2.3%	564	686	684	674							
5	2010	-4.4%	539	656	654	644	639						
6	2011	3.8%	560	681	679	669	664	652					
7	2012	-1.1%	553	674	672	662	656	645	737				
8	2013	2.2%	566	688	686	676	670	659	753	623			
9	2014	-1.1%	559	681	679	669	663	652	745	616	624		
10	2015	-1.9%	549	668	666	656	650	639	731	604	612	604	
11	2016F	3.0%	565	688	686	676	670	659	753	623	631	622	
12	2017F	1.5%	574	699	696	686	680	669	764	632	640	632	667

The final calculated value of 667 MW, plus 16 MW for self-generating customers, gives 683 MW, which is the forecast January 2017 system peak shown in Table 2-10, Appendix F of the LTERP.

21.2 How are the historic peak demand values (line 4) defined (e.g., is it the coincident peak demand delivered to customers, is it the coincident peak demand at point of generation, or some other value)?

Response:

The historic peak demand is defined as the coincident peak demand delivered to customers at a point in time within a specified period (e.g. one month).

21.3 What was the historic self-generating customer load that was removed and what is the basis for the 16 MW of load added for the self-generation customers?

Response:

The monthly historical self-generating customer coincident peak load was removed from the historical monthly peak load from 2006 to 2015. The 16 MW of load added for the self-generator customers was a reasonable estimate based on the historical load. Since that time FBC now expects that Schedule 37- Large Commercial Stand by Service will serve approximately 13 MW of the 16 MW, meaning that only 3 MW would be served under FBC's industrial rate. The result

is that the load forecast used in the LTERP is approximately 13 MW high. This is not expected to have a material impact on the portfolio analysis.

21.4 Does the use of the gross energy growth rate mean the FBC is assuming that there will be no change in overall system load factor over the planning period?

Response:

Not confirmed.

FBC is not assuming the overall system load factor will remain constant. The overall system load factor is defined as the average load divided by the peak load in a specified time period. Because the peak load is forecast to increase over the planning horizon at an average annual rate of 1 percent and the gross load is forecast to increase at an average annual rate of 1.1 percent, there will be a slight increase in the load factor over the planning horizon.

21.4.1 If yes, why is this assumption reasonable?

Response:

Please refer to the response to BCOAPO IR 1.21.4.

21.4.2 If no, what change is anticipated and how has it been factored into the forecast?

Response:

The overall system load factor is not a component of the forecast, and as such, has not been factored in to the forecast.

Please also refer to the response to BCOAPO IR 1.21.4.

22.0 Reference: Exhibit B-1, Volume 1, pages 68-70

22.1 Are the energy impacts set out in Figure 4-1 based on Net or Gross Load?

Response:

The energy impacts are based on net load (i.e. after losses).

22.2 Are the peak demand impacts set out in Figure 4-2 based on the Winter Peak forecast (per Figure 3-3) or some other reference forecast?

Response:

The peak demand impacts presented in Figure 4-2 are based on the potential incremental impacts to the FBC winter peak demand requirements. They are incremental to the Winter Peak Forecast presented in Figure 3-3.

23.0 Reference: Exhibit B-1, Volume 1, Appendix G, page 2

23.1 What other potential load drivers were in the "broader list" considered by Navigant and FBC staff?

Response:

Other potential load drivers that were originally considered in the "broader list" included the following:

- DC fast charging;
- Increases in LED installation and usage;
- Energy storage at the customer level;
- Sharing economy/teleworking; and
- 3D printing.

These other load drivers were either incorporated into the final eight load drivers or excluded from the load scenarios analysis as follows:

- Rather than treating DC fast charging for EVs as a separate driver, it was instead included in the EV load driver where different levels of charging were included;
- LED impacts were included in the CPR scope and so are included in the DSM programs rather than the load scenarios to avoid duplication;
- Energy storage at the customer level was included in the roof top solar with the storage load driver;
- Sharing economy/teleworking was seen as a load driver more applicable for larger cities, like Vancouver, rather than the cities and towns in FBC's service area; and
- 3D printing was determined to be a potential driver for increased industrial loads, already generally covered by the Large Load Sector Transformation load driver.

24.0 Reference: Exhibit B-1, Volume 1, page 78

24.1 Please demonstrate, with an example, the benefits of the EEA as described at lines 13-22.

Response:

The benefit of the EEA to FBC is that it provides FBC with the ability to export surplus generation in the same hour as it is taking supply under the PPA with BC Hydro. Having the ability to export surplus generation helps to offset the cost of building or acquiring new resources. For example, in preferred portfolio A4, the value of FBC's surplus sales are forecast to range from approximately $1 million per year in 2020, increasing to $7.4 million in 2035. FBC expects there will be additional benefits of the EEA operationally, as FBC optimizes its portfolio on an hourly basis. In the absence of the EEA or a similar agreement, FBC would not be able to complete these exports while taking supply under the PPA, which would result in a significant negative financial impact to FBC ratepayers under the current regulatory framework.

24.2 Has the EEA had any impact on FBC's 2016 LTERP?

Response:

No, not directly, although in all scenarios under the LTERP, FBC assumes it will have the ability to export surplus generation, if any, from new generation resources while taking supply under the PPA with BC Hydro, consistent with the principles of the EEA.

25.0 Reference: Exhibit B-1, Volume 1, page 79

25.1 Please provide more details regarding FBC's transmission rights on Teck's 71 Line in terms of the associated energy and capacity capability.

Response:

FBC currently has access to 370 MW of import rights on 71 Line when not being used by Teck. FBC considers that 150 MW is reliable in terms of meeting its capacity requirements. Over the course of a year, the maximum amount of imported energy on Teck's rights is 3,241,200 MWh[4]. Please refer to the LTERP, Appendix L, Section 2.1.3 for further information.

25.2 Please explain why "additional firm transmission cannot be reliably obtained on the U.S. side of the border".

Response:

Additional firm transmission cannot be reliably obtained on the U.S. side of the border because all of the long-term firm transmission rights have been acquired. However, U.S. transmission can generally be obtained through short-term non-firm reservations, when it is available, which can be used to deliver firm energy. For the most part, FBC has been able to secure non-firm transmission when required, although there have been times when no transmission was available. At this time, FBC has been able to mitigate this risk by entering into the Capacity and Energy Purchase and Sale Agreement with Powerex, as Powerex is a significant holder of firm transmission capacity from the U.S. to the B.C./U.S. border.

[4] Calculated as follows: 8,760 hours x 370 MW.

26.0 Reference: Exhibit B-1, Volume 1, page 84

26.1 Is there an FBC (or BCUC) policy statement that specifies that the resource planning requirement is to acquire energy resources to meet energy and peak demand requirements under "normal" or "expected" weather conditions? If so, please provide.

Response:

FBC is not aware of such a policy statement. However, FBC believes it is prudent and cost effective to plan for new resources over the long term based on energy and peak demand requirements under normal or expected weather conditions, as per its reference case load forecast, rather than extreme weather conditions. In its 2013 IRP, BC Hydro states on page 2-1 in Chapter 2: Load-Resource Balance:

> As required by the B.C. Electricity Self-Sufficiency Regulation, and consistent with 9 other utilities, BC Hydro bases the need for new resources on its mid load forecast; this methodology has been endorsed by the British Columbia Utilities Commission (BCUC) in proceedings including the 2008 Long Term Acquisition Plan (LTAP).

This mid load forecast is BC Hydro's equivalent of FBC's reference case (i.e. expected) load forecast.

27.0 Reference: Exhibit B-1, Volume 1, pages 92-93

Preamble: At page 49 the Application states that for the base case the BCH PPA Tranche 2 is $129.70 per MWh and that $85 is used as a rate scenario.

27.1 Where in the Application are the implications of a $85 Tranche 2 rate scenario examined?

Response:

All portfolios presented in Section 9 of the LTERP were evaluated using the Tranche 2 Energy Price in place at the time of filing[5]. FBC internally evaluated a small number of portfolios using a Tranche 2 energy price of $85 per MWh. There was minimal impact on the results therefore these scenarios were not presented. Please also refer to the responses to BCOAPO IRs 1.9.1, and 1.38.1 through 1.42.2.

27.2 How would the Energy Load Resource Balance (i.e. Figure 7-1) change if BC Hydro Tranche 2 PPA energy was available at $85/MWh?

Response:

The Load-Resource Balance in Figure 7-1 illustrates the contract year limit of Tranche 1 energy (1,041 GWh). A Load-Resource Balance including Tranche 2 energy has been provided in the response to BCUC IR 1.24.1 (the Load-Resource Balance illustrates the availability of resources, which are unaffected by the price). Discussion regarding monthly PPA energy available to FBC is provided in the response to BCUC IR 1.24.2.

27.3 How would the Energy Load Resource Balance (i.e. Figure 7-1) change if BC Hydro Tranche 2 PPA energy was available at $100/MWh?

[5] BC Hydro and Power Authority. Electric Tariff. March 3, 2016. Schedule 3808 – Transmission Service – FortisBC.

Response:

As explained in the response to BCOAPO IR 1.27.2, the Load Resource Balance illustrates the availability of resources, which are unaffected by price.

28.0 Reference: Exhibit B-1, Volume 1, pages 94, 102 & 103 and Appendix E, page 17

28.1 Appendix E indicates that the PRM is not included in the Load Forecast. Is any allowance for the PRM included in Figures 7-2, 8-4 and 8-5?

Response:

Figures 7-2, 8-4 and 8-5 show the forecast expected peak demand over the planning horizon and do not include any allowances for PRM.

28.1.1 If not, please re-do Figures 8-4 and 8-5 to include the PRM in the peak forecast.

Response:

As described in Appendix L, Section 3.2 of the LTERP, the required resources needed to meet Planning Reserve Margin is calculated in an iterative manner. Planning Reserve Margin, based on a probabilistic approach, cannot be shown as an additional requirement to the peak forecast. Planning Reserve Margin accounts for both the possibility of variances in forecast peak demand as well as the possibility of forced outages associated with all available[6] supply side resources.

[6] This includes the resource stack of the specific portfolio plus 150 MW (225 MW June) of market access.

29.0 Reference: Exhibit B-1, Volume 1, pages 97-100

Exhibit B-1, Volume 2, pages 12-14

29.1 Please outline the principles/basis for the Low DSM Scenario.

Response:

The Low DSM Scenario is based on the 2007 BC Energy Plan, which referenced a DSM offset target of 50 percent of load growth. Although this target was only stated to apply to BC Hydro, FBC voluntarily adopted the 50 percent target in its previous (2012) LTRP. The Low DSM Scenario is included in the LTERP/LT DSM Plan simply as a reference case.

29.2 For Resource Cost attributed to each of the scenarios set out in Volume 1, Table 8-2, does the value represent the average (or overall) cost of the DSM Scenario or the cost of the most expensive DSM measure in the portfolio?

Response:

The Resource Cost attributed to each of the scenarios set out in LTERP, Table 8-2, represents the incremental cost of the additional DSM measures included in each scenario: incremental to the next lowest DSM scenario (Low < Base < High < Max).

The following table provides the information requested in BCOAPO IRs 1.29.2.1 to 1.29.2.3 where: the marginal cost is the cost of the highest cost measure included in the scenario; the average cost including program costs is the average resource cost of each scenario; and the incremental cost including program costs represents the incremental cost of the additional DSM measures included in each scenario.

Table 1: DSM Scenario Costs

Category	DSM Scenario			
	Low	Base	High	Max
Resource Cost, 2016 $/MWh				
Marginal cost	$61	$83	$92	$116
Average cost incl. program costs	$45	$54	$61	$67
Incremental cost incl. program costs	$45	$88	$104	$114

29.2.1 If the value represents the average cost of the portfolio of measures, what is the highest cost measure included in each DSM scenario and what is the associated cost?

Response:

Please refer to the response to BCOAPO IR 1.29.2.

29.2.2 If the values represent the cost of the most expensive measure, what is the average overall cost of each DSM Scenario?

Response:

Please refer to the response to BCOAPO IR 1.29.2.

29.2.3 For each of the Base, High and Max DSM Scenarios, what is the average cost of the additional DSM measures added (relative to the next lowest DSM Scenario)?

Response:

Please refer to the response to BCOAPO IR 1.29.2. The average cost of the additional DSM measures added (relative to the next lowest DSM Scenario) is represented by the category in the table described as "Incremental cost incl. program costs".

29.3 With respect to page 100, please explain more fully "the opportunity cost of offsetting the relatively inexpensive PPA in the near term" and how it is offset by the High DSM Scenario.

Response:

The resource cost of the PPA is lower than the resource cost of DSM in the High Scenario. FBC will reduce the overall portfolio resource cost (mitigate opportunity cost), by utilizing the PPA resource over DSM, before the ramp-up in the High Scenario.

30.0 Reference: Exhibit B-1, Volume 1, pages 107 & 109 and

Appendix J, page 6

30.1 Please confirm that the UEC and UCC values are each based on the total cost of the resource?

Response:

Confirmed.

UEC, or Unit Energy Cost, is defined as the annualized cost of generating a unit of electrical energy for a specific resource option, expressed in $ per MWh.

UCC, Or Unit Capacity Cost, is defined as the annualized cost of providing dependable capacity for a specific resource option, expressed in $/kW-year.

UECs consider all direct capital and operating costs. They do not consider socioeconomic values.

UCCs only consider fixed costs (capital recovery plus fixed operations, maintenance and administration (OMA)), and do not include fuel costs and variable OMA.

31.0 Reference: Exhibit B-1, Volume 1, page 111

31.1 Does the levelized cost of market purchases vary depending upon whether one is looking at purchases to be made in the short (next five years), medium (5-10 years out) or long (more than 10 years out) term? If so, what are the relative values?

Response:

Yes. On a levelized basis over the twenty-year planning horizon (using a 6 percent discount rate), the unit cost of market energy is about $51 per MWh, including transmission costs and losses from Mid-C to the FBC system (page 111, line 18 of the LTERP). The levelized cost of market purchases for the next five years only (i.e. 2017 to 2021) would be about $46 per MWh and for the following five years only (i.e. 2022 to 2026) it would be about $51 per MWh, including transmission costs and losses from Mid-C to the FBC system.

32.0 Reference: Exhibit B-1, Volume 1, Appendix J, pages 15 and 22

32.1 Please explain more fully why biomass is considered as producing "carbon neutral air emissions from combustion" and therefore "clean".

Response:

As discussed in Section 8.2.2.3 of the LTERP, FBC has assessed whether resource options are "clean" or not based on whether the resources are included in the CEA's definition of "clean or renewable resource", which includes biomass.

32.2 Does the assessment of biomass as "clean" include the transportation impacts required to deliver the fuel to the generation plant?

Response:

No. As discussed in Section 8.2.2.3 of the LTERP, the assessment of biomass as "clean" is based upon what the CEA defines as clean or renewable resources, which includes biomass.

32.3 Please also explain why, in contrast, the combustion of municipal solid waste is viewed as producing air contaminants and not 100% clean.

Response:

FBC has not assessed municipal solid waste as "clean" because it is not included in the CEA's defined clean or renewable resources, as discussed in Section 8.2.2.3 of the LTERP.

33.0 Reference: Exhibit B-1, Volume 1, Appendix J, pages 26-27

33.1 Figure J3-14 suggests that there are diseconomies of scale associated with CCGTs (i.e., large unit sizes have a higher cost per MWh). Please confirm that this is the case and, if so, explain why.

Response:

Not confirmed. The graph demonstrates that economies of scale are associated with larger CCGTs. The FBC portfolio modeling looked at specific possible resource additions. In the case of CCGT, it looked at 3 possible plant sizes: a 67 MW plant, a 119 MW plant, and a 279 MW plant.

Figure J3-14 in Appendix J of the LTERP is an indicative Energy Supply Cost Curve. It assumes that as energy demand increases, the lower UEC CCGT resource in the list of 3 options (279 MW) is built first and the most costly UEC CCGT resource (67 MW) is built last. It plots the specific UEC cost of each CCGT resource against cumulative energy demand, generating an energy supply cost curve showing the rising UEC cost of CCGT energy supply as more energy is required. The UECs for the individual CCGT plant sizes are as follows: $100 per MWh for the 67 MW plant, $94 per MWh for the 119 MW plant and $82 per MWh for the 279 MW plant.

34.0 Reference: Exhibit B-1, Volume 1, Appendix J, pages 28-29

34.1 Figure J3-15 suggests that there are also diseconomies of scale associated with SCGTs (i.e., large unit sizes have a higher cost per MWh). Please confirm that this is the case and, if so, explain why.

Response:

Not confirmed. The FBC portfolio modeling looked at specific possible resource additions. In the case of SCGT, it looked at 4 possible plant sizes: two 48 MW plants, a 100 MW plant, and a 192 MW plant.

Figure J3-15 in Appendix J of the LTERP is an indicative Supply Cost Curve. It assumes that as capacity demand increases, the least cost SCGT resource in the list of 4 options (192 MW) is built first and the most costly SCGT resources (the 48 MW plants) are built last. The figure plots the specific UCC of each SCGT resource against cumulative capacity demand, generating a capacity supply cost curve showing the rising UCC cost of SCGT supply as more capacity is required. The individual UCCs of the SCGT plant sizes are as follows: $143 per kW-year for the 48 MW plants, $135 per kW-year for the 100 MW plant and $80 per kW-year for the 192 MW plant.

35.0 Reference: Exhibit B-1, Volume 1, Appendix J, pages 43-44

35.1 Given that the generation of electricity is not the primary business of industrial customers that would provide self-generation, are there not also risks related to the primary business of the self-generator that could impact the reliability of supply over the long-term?

Response:

Yes, purchases from self-generators are potentially vulnerable to a situation of economic distress, whether it be the cost or availability of the generation fuel supply (e.g. biomass) or from a temporary or long-term shutdown of the base industrial activity. The specific impact to the FBC resource stack in that situation would depend on the terms negotiated in the Electricity Purchase Agreement with the supplier.

36.0 Reference: Exhibit B-1, Volume 1, pages 98 and 116

36.1 What is the difference, if any, between the Low DSM Scenario (page 98) and the No DSM case (page 116)?

Response:

The No DSM sensitivity case is an energy supply scenario used in the portfolio analysis for the purpose of determining the LRMC of BC clean and renewable resources. The No DSM sensitivity case was not a DSM scenario that FBC considered and evaluated. The Low DSM Scenario has the lowest energy savings targets of the four DSM scenarios considered.

37.0 Reference: Exhibit B-1, Volume 1, Appendix K

37.1 With respect to page 2, please clarify what year's real dollars FBC's previous LRMC of $112 was expressed in.

Response:

FBC's previous LRMC of $112 per MWh was expressed in nominal dollars rather than in real dollars. The $112 per MWh value is a levelized number that was developed from the BC Hydro Standing Offer Program (SOP) as described in FBC's 2012 LTRP (Appendix B)[7] and a previous BCUC IR response[8].

37.2 With respect to page 3 (lines 26-28), would it be reasonable to conclude that BCH's LRMC (including both capacity and energy) is in the order of $100/MWh when expressed in 2015 real $ (the basis on which FBC has expressed its LRMCs – per Figure 9-1)?

Response:

With respect to the stated reference in Appendix K of the LTERP, if the LRMC of $106 per MWh was discounted to 2015$ using an assumed 2 percent inflation rate, the LRMC for BC Hydro (including both capacity and energy) would be approximately $102 per MWh (2015$)[9,10]

37.3 How are losses treated in the determination of the LRMCs for FBC and BCH?

Response:

BC Hydro has identified specific resources, both demand-side and supply-side, that will be used to meet forecast load requirements. BC Hydro states the Unit Energy Cost (UEC), at Point of

[7] FBC. 2012 Integrated System Plan (Vol. 2) & 2012 Long Term Resource Plan. June 30, 2011. Appendix B: 2011 FortisBC Energy & Capacity Market Assessment. Midgard Consulting Inc. May 26, 2011. Pages 26-28 of 54.

[8] FBC. Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Response to BCUC Information Request (IR) No. 1.3.1. September 18, 2014. Page 12-13.

[9] $106 / (1.02)^2 = $101.88.

[10] This statement solely represents FBC's understanding of BC Hydro's LRMC and should not be attributed to BC Hydro.

Interconnection, then makes adjustments to account for losses and other items, for delivery to the Lower Mainland[11].

In contrast, FBC has developed a collection of resource options and performed portfolio analysis to determine the lowest cost of meeting forecast gross load requirements, including losses, with consideration for PRM, which is a different approach from BC Hydro. Therefore, FBC does not make a separate adjustment to the LRMC to account for losses. Please also see the response to BCUC IR 1.34.1.2.

37.3.1 If not treated the same, please express FBC's LRMC in real 2015$ using the same treatment of losses as BCH.

Response:

Please refer to the response to BCOAPO IR 1.37.2 for the requested calculation that, to the best of FBC's knowledge, calculates BC Hydro's LRMC expressed in 2015$ with similar assumptions regarding losses.

[11] BC Hydro. F2017-2019 Revenue Requirements Application. Responses to BCUC IR 1. November 21, 2016. IRs 1.171.1.1, 1.171.1.2, and 1.171.2.1. Please also refer to: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-total-adjusted-firm-energy-price.pdf.

38.0 Reference: Exhibit B-1, Volume 1, page 119

38.1 For each of the four Portfolios (B1, B2, A4 and B4), to what extent is BCH PPA Tranche 2 energy relied upon?

Response:

Portfolios B1, B2, A4, and B4 do not use any BCH PPA Tranche 2 energy.

38.2 For each of the four Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each increment resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio B1 ('000s 2015$)

B1 Schedule														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Biomass1	Biogas1	Wind4	Wind6	RoR2	RoR4	Biomass3	Biogas4	Biogas3	Market
2016	$0	$10,707	$29,167	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,174
2017	$0	$11,274	$31,963	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,952
2018	$0	$12,048	$35,096	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,776
2019	$0	$12,781	$39,767	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,000
2020	$0	$13,497	$43,312	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,063
2021	$0	$14,920	$46,247	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,309
2022	$0	$16,205	$51,392	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,318
2023	$0	$16,304	$51,823	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,894
2024	$0	$16,591	$52,163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,624
2025	$0	$16,682	$51,908	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,151
2026	$0	$16,272	$48,044	$0	$0	$0	$47,190	$0	$0	$0	$0	$0	$0	$0
2027	$0	$16,696	$50,594	$0	$0	$0	$47,190	$0	$0	$0	$0	$0	$0	$0
2028	$0	$17,498	$50,730	$0	$22,703	$0	$47,015	$0	$0	$0	$0	$0	$0	$0
2029	$0	$17,776	$51,471	$0	$22,637	$1,408	$47,024	$0	$0	$0	$0	$684	$1,436	$0
2030	$0	$17,679	$49,701	$0	$22,499	$1,408	$47,060	$14,043	$0	$0	$0	$684	$1,436	$0
2031	$0	$17,670	$50,799	$0	$22,420	$1,408	$47,100	$13,876	$0	$5,919	$0	$684	$1,436	$0
2032	$0	$18,144	$52,789	$0	$22,571	$1,408	$47,128	$13,977	$0	$5,939	$0	$685	$1,455	$0
2033	$0	$18,513	$54,424	$0	$22,582	$1,408	$47,151	$13,948	$3,602	$5,965	$0	$693	$1,455	$0
2034	$0	$18,754	$56,279	$0	$22,582	$1,408	$47,174	$14,071	$3,609	$6,001	$9,734	$693	$1,455	$0
2035	$0	$19,015	$58,312	$0	$22,667	$1,408	$47,190	$14,136	$3,609	$6,038	$10,323	$693	$1,466	$0

Table 2: Schedule of Costs for Portfolio B2 ('000s 2015$)

B2 Schedule												
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	Biogas1	Wind3	RoR2	Biogas2	Biogas4	Biogas3	Market
2016	$10,609	$10,502	$28,379	$0	$0	$0	$0	$0	$0	$0	$0	$5,020
2017	$11,806	$10,834	$30,183	$0	$0	$0	$0	$0	$0	$0	$0	$5,607
2018	$12,257	$11,306	$32,295	$0	$0	$0	$0	$0	$0	$0	$0	$13,136
2019	$12,257	$11,730	$35,548	$0	$0	$0	$0	$0	$0	$0	$0	$13,475
2020	$12,257	$12,130	$37,669	$0	$0	$0	$0	$0	$0	$0	$0	$12,646
2021	$12,257	$13,791	$39,730	$0	$0	$0	$0	$0	$0	$0	$0	$10,593
2022	$12,257	$16,035	$47,090	$0	$0	$0	$0	$0	$0	$0	$0	$3,457
2023	$12,257	$16,391	$48,377	$0	$0	$0	$0	$0	$0	$0	$0	$3,644
2024	$12,257	$16,687	$49,449	$0	$0	$0	$0	$0	$0	$0	$0	$3,971
2025	$12,257	$16,507	$48,702	$0	$0	$0	$0	$0	$0	$0	$0	$6,883
2026	$12,257	$14,616	$38,464	$0	$0	$0	$38,202	$0	$0	$0	$0	$0
2027	$12,257	$14,557	$39,498	$0	$0	$0	$38,215	$0	$0	$0	$0	$0
2028	$12,257	$16,337	$46,944	$0	$0	$0	$37,785	$0	$0	$0	$0	$0
2029	$12,257	$17,327	$47,773	$0	$0	$0	$37,819	$0	$0	$668	$0	$0
2030	$12,257	$17,559	$48,060	$0	$0	$1,408	$37,785	$0	$0	$668	$0	$0
2031	$12,257	$17,701	$48,228	$0	$0	$1,408	$37,792	$0	$728	$668	$1,398	$0
2032	$12,257	$17,510	$48,988	$0	$7,422	$1,408	$37,827	$0	$728	$668	$1,398	$0
2033	$12,257	$17,438	$50,137	$0	$7,433	$1,408	$37,864	$0	$728	$668	$1,398	$0
2034	$12,257	$17,847	$51,281	$0	$7,445	$1,408	$37,900	$0	$728	$668	$1,398	$0
2035	$12,257	$18,182	$51,840	$0	$7,389	$1,408	$37,937	$3,497	$728	$668	$1,398	$0

1 **Table 3: Schedule of Costs for Portfolio A4 ('000s 2015$)**

A4 Schedule									
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Wind3	Biogas1	Biogas3	SCGT1	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$0	$0	$13,475
2020	$12,251	$12,130	$37,669	$0	$0	$0	$0	$0	$12,646
2021	$14,122	$13,775	$39,658	$0	$0	$0	$0	$0	$10,565
2022	$15,992	$15,985	$46,831	$0	$0	$0	$0	$0	$3,416
2023	$17,507	$16,283	$47,852	$0	$0	$0	$0	$0	$3,585
2024	$17,507	$16,555	$48,703	$0	$0	$0	$0	$0	$3,718
2025	$17,507	$16,206	$46,900	$0	$0	$0	$0	$0	$7,377
2026	$17,507	$14,401	$37,132	$0	$38,180	$0	$0	$0	$0
2027	$17,507	$14,218	$37,870	$0	$38,192	$0	$0	$0	$0
2028	$17,507	$15,873	$45,190	$0	$37,727	$0	$0	$0	$0
2029	$17,507	$16,877	$45,999	$0	$37,752	$0	$0	$0	$0
2030	$17,507	$17,184	$46,662	$0	$37,770	$0	$0	$0	$0
2031	$17,507	$17,316	$46,172	$0	$37,730	$1,408	$1,398	$0	$0
2032	$17,507	$17,274	$46,662	$0	$37,756	$1,408	$1,398	$7,422	$0
2033	$17,507	$16,879	$47,535	$0	$37,783	$1,408	$1,398	$7,433	$0
2034	$17,507	$17,220	$48,401	$0	$37,809	$1,408	$1,398	$7,445	$0
2035	$17,507	$17,623	$49,554	$0	$37,836	$1,408	$1,398	$7,003	$0

2

Table 4: Schedule of Costs for Portfolio B4 ('000s 2015$)

B4 Schedule								
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Wind2	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$0	$13,475
2020	$12,251	$12,130	$37,669	$0	$0	$0	$0	$12,646
2021	$14,122	$13,775	$39,658	$0	$0	$0	$0	$10,565
2022	$15,992	$15,985	$46,831	$0	$0	$0	$0	$3,416
2023	$17,892	$16,280	$47,836	$0	$0	$0	$0	$3,581
2024	$19,918	$16,534	$48,586	$0	$0	$0	$0	$3,693
2025	$21,944	$16,443	$47,893	$0	$0	$0	$0	$5,647
2026	$23,971	$14,773	$39,169	$0	$0	$0	$33,221	$0
2027	$25,516	$14,775	$39,564	$0	$0	$0	$33,224	$0
2028	$25,516	$16,253	$46,057	$0	$0	$0	$32,843	$0
2029	$25,516	$17,202	$46,520	$0	$0	$0	$32,856	$0
2030	$25,516	$17,321	$46,187	$0	$0	$1,408	$32,814	$0
2031	$25,516	$17,438	$46,572	$0	$0	$1,408	$32,819	$0
2032	$25,516	$17,410	$46,702	$0	$7,422	$1,408	$32,830	$0
2033	$25,516	$17,188	$47,209	$0	$7,433	$1,408	$32,842	$0
2034	$25,516	$17,445	$47,702	$0	$7,445	$1,408	$32,856	$0
2035	$25,516	$17,749	$48,424	$0	$7,096	$1,408	$32,871	$0

38.3 For each of the four Portfolios, please provide an Energy Load Resource Balance (similar to Figure 7-1) that includes the additional resources identified (including DSM) and that breaks out the contributions from Tranches 1 and 2 of BCH's PPA.

Response:

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio B1

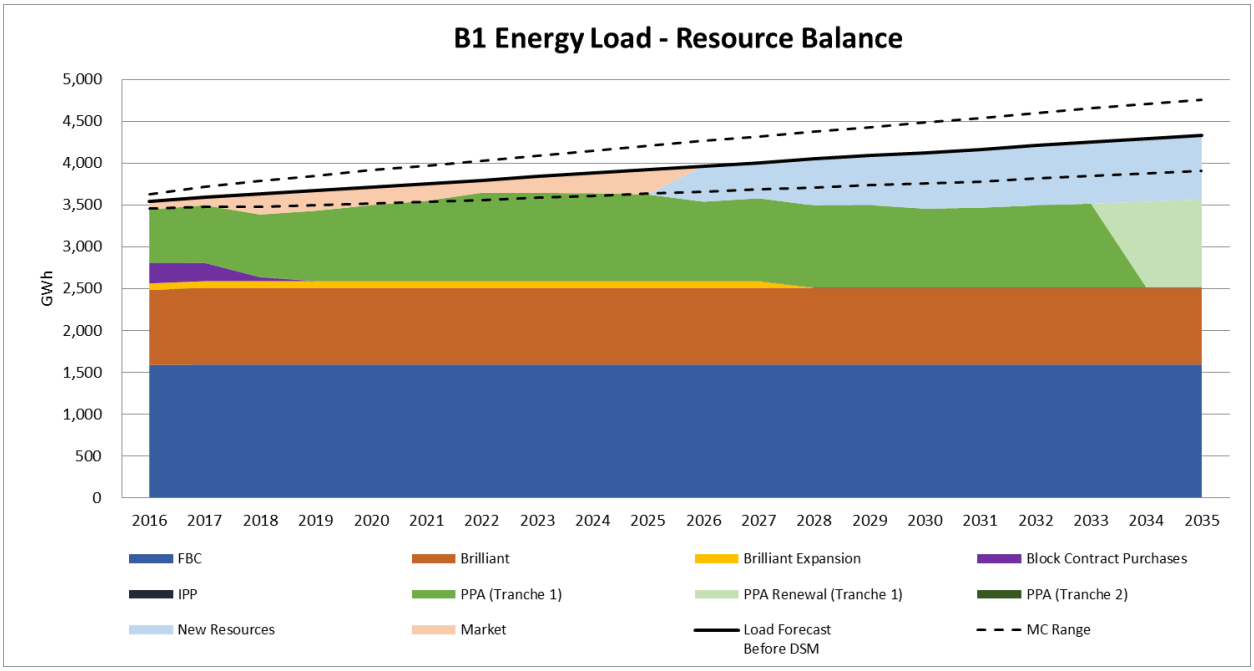


Figure 2: Energy Load-Resource Balance (LRB) for Portfolio B2

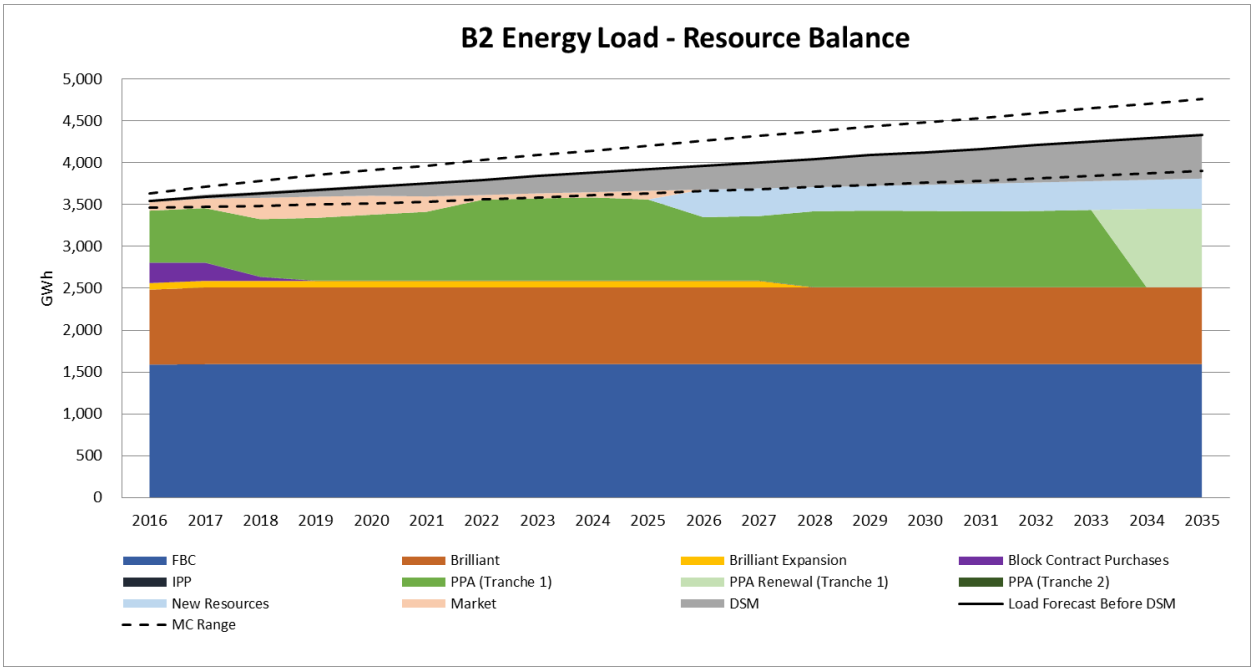


Figure 3: Energy Load-Resource Balance (LRB) for Portfolio A4

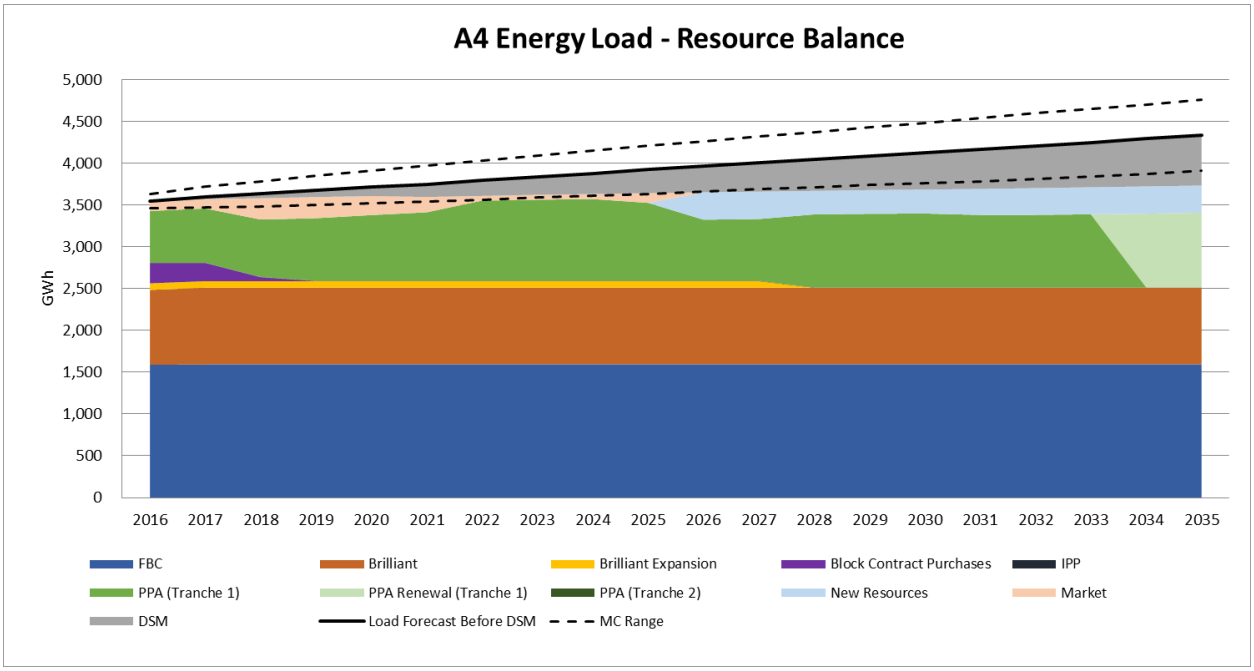
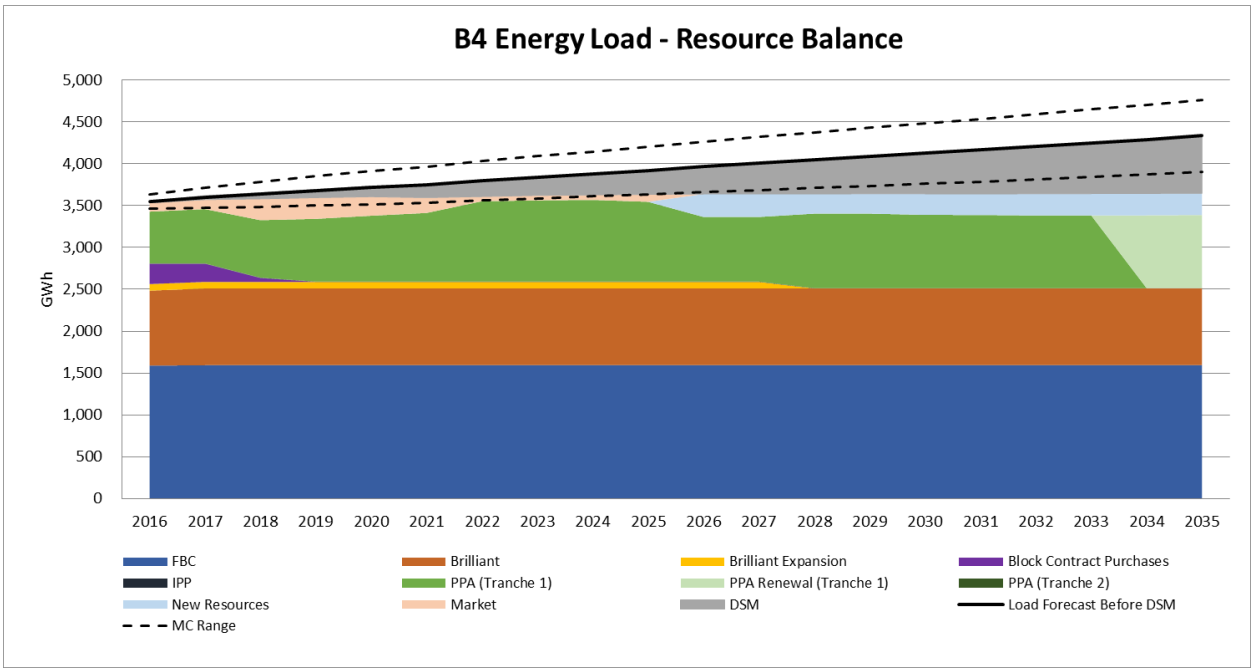


Figure 4: Energy Load-Resource Balance (LRB) for Portfolio B4



38.4 What was the cost of BCH PPA Tranche 2 used in determining the LRMC for the various Portfolios?

Response:

All portfolios presented were evaluated using a PPA Tranche 2 energy price of $129.70 per MWh.

38.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

Response:

Please refer to the response to BCOAPO IR 1.38.4.2.

38.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

Response:

FBC re-ran portfolios B1, B2, A4, and B4 using a Tranche 2 PPA Energy price of $85 per MWh and there was no resulting change in the optimal selected resources or LRMC. Therefore, if PPA Trance 2 energy was $100 per MWh it can also be concluded there would be no impact on these portfolios.

39.0 Reference: Exhibit B-1, Volume 1, page 120

39.1 For each of the three Portfolios (A1, A2, A3), to what extent is BCH PPA Tranche 2 energy relied upon?

Response:

Portfolios A1, A2, and A3 do not use any BCH PPA Tranche 2 energy.

39.2 For each of these three Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each increment resource. Costs include levelized fixed and variable energy costs.

1 **Table 1: Schedule of Costs for Portfolio A1 ('000s 2015$)**

A1 Schedule								
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas3	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$0	$13,475
2020	$12,251	$12,130	$37,669	$0	$0	$0	$0	$12,646
2021	$14,122	$13,775	$39,658	$0	$0	$0	$0	$10,565
2022	$15,992	$15,985	$46,831	$0	$0	$0	$0	$3,416
2023	$17,507	$16,283	$47,852	$0	$0	$0	$0	$3,585
2024	$17,507	$16,555	$48,703	$0	$0	$0	$0	$3,718
2025	$17,507	$16,464	$48,034	$0	$0	$0	$0	$5,928
2026	$17,507	$14,916	$47,920	$0	$0	$0	$0	$7,494
2027	$17,507	$14,311	$47,595	$0	$0	$0	$0	$9,154
2028	$17,507	$16,506	$52,320	$0	$0	$0	$0	$9,773
2029	$17,507	$17,392	$54,247	$0	$0	$0	$0	$8,738
2030	$17,507	$17,541	$54,600	$0	$0	$0	$0	$9,593
2031	$17,507	$16,715	$54,808	$0	$6,822	$0	$0	$10,858
2032	$17,507	$17,874	$57,706	$0	$6,822	$0	$0	$8,594
2033	$17,507	$17,510	$55,091	$0	$6,822	$1,408	$0	$12,627
2034	$17,507	$18,090	$57,197	$0	$6,822	$1,408	$0	$12,144
2035	$17,507	$18,780	$59,636	$0	$6,822	$1,408	$1,474	$9,575

2

Table 2: Schedule of Costs for Portfolio A2 ('000s 2015$)

A2 Schedule										
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas2	Biogas4	Biogas3	Market
2016	$10,714	$10,620	$30,246	$0	$0	$0	$0	$0	$0	$3,396
2017	$11,924	$11,113	$32,348	$0	$0	$0	$0	$0	$0	$3,525
2018	$12,251	$12,647	$40,295	$0	$0	$0	$0	$0	$0	$5,055
2019	$12,251	$14,124	$43,727	$0	$0	$0	$0	$0	$0	$4,493
2020	$12,251	$15,478	$46,247	$0	$0	$0	$0	$0	$0	$2,038
2021	$14,122	$16,160	$47,781	$0	$0	$0	$0	$0	$0	$1,038
2022	$15,992	$16,482	$48,755	$0	$0	$0	$0	$0	$0	$1,294
2023	$17,507	$16,791	$49,812	$0	$0	$0	$0	$0	$0	$1,520
2024	$17,507	$17,056	$50,681	$0	$0	$0	$0	$0	$0	$1,707
2025	$17,507	$17,329	$51,578	$0	$0	$0	$0	$0	$0	$1,975
2026	$17,507	$17,027	$52,459	$0	$0	$0	$0	$0	$0	$2,355
2027	$17,507	$17,154	$52,931	$0	$0	$0	$0	$0	$0	$3,297
2028	$17,507	$17,484	$53,976	$0	$0	$1,408	$0	$0	$0	$9,297
2029	$17,507	$17,516	$54,587	$0	$0	$1,408	$0	$0	$0	$10,453
2030	$17,507	$17,759	$54,823	$0	$0	$1,408	$0	$0	$1,460	$10,472
2031	$17,507	$17,906	$55,374	$0	$0	$1,408	$0	$0	$1,466	$11,669
2032	$17,507	$17,358	$56,007	$0	$6,822	$1,408	$0	$0	$1,474	$13,097
2033	$17,507	$17,527	$56,658	$0	$6,822	$1,408	$0	$701	$1,474	$13,760
2034	$17,507	$17,827	$57,343	$0	$6,822	$1,408	$728	$700	$1,474	$14,251
2035	$17,507	$18,381	$58,505	$0	$6,822	$1,408	$728	$701	$1,474	$14,384

Table 3: Schedule of Costs for Portfolio A3 ('000s 2015$)

A3 Schedule							
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	CCGT1	Biogas1	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$13,475
2020	$12,251	$11,956	$37,450	$0	$0	$0	$13,165
2021	$14,122	$11,817	$39,000	$0	$30,194	$0	$0
2022	$15,992	$13,086	$44,212	$0	$25,639	$0	$0
2023	$17,507	$13,449	$45,409	$0	$25,632	$0	$0
2024	$17,507	$13,772	$46,400	$0	$25,615	$0	$0
2025	$17,507	$14,072	$47,418	$0	$25,662	$0	$0
2026	$17,507	$14,230	$48,467	$0	$25,697	$0	$0
2027	$17,507	$14,620	$49,771	$0	$25,287	$0	$0
2028	$17,507	$15,584	$53,063	$0	$27,698	$0	$0
2029	$17,507	$16,758	$54,588	$0	$27,158	$0	$0
2030	$17,507	$16,974	$55,074	$0	$27,768	$0	$0
2031	$17,507	$17,124	$55,389	$0	$28,800	$0	$0
2032	$17,507	$17,248	$55,614	$0	$30,133	$0	$0
2033	$17,507	$17,454	$56,165	$0	$31,118	$0	$0
2034	$17,507	$17,802	$57,283	$0	$31,314	$0	$0
2035	$17,507	$18,491	$59,277	$0	$28,915	$1,408	$0

39.3 For each of these three Portfolios, please provide an Energy Load Resource Balance (similar to Figure 7-1) that includes the additional resources (including DSM) identified and that breaks out the contributions from Tranches 1 and 2 of BCH's PPA.

Response:

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A1

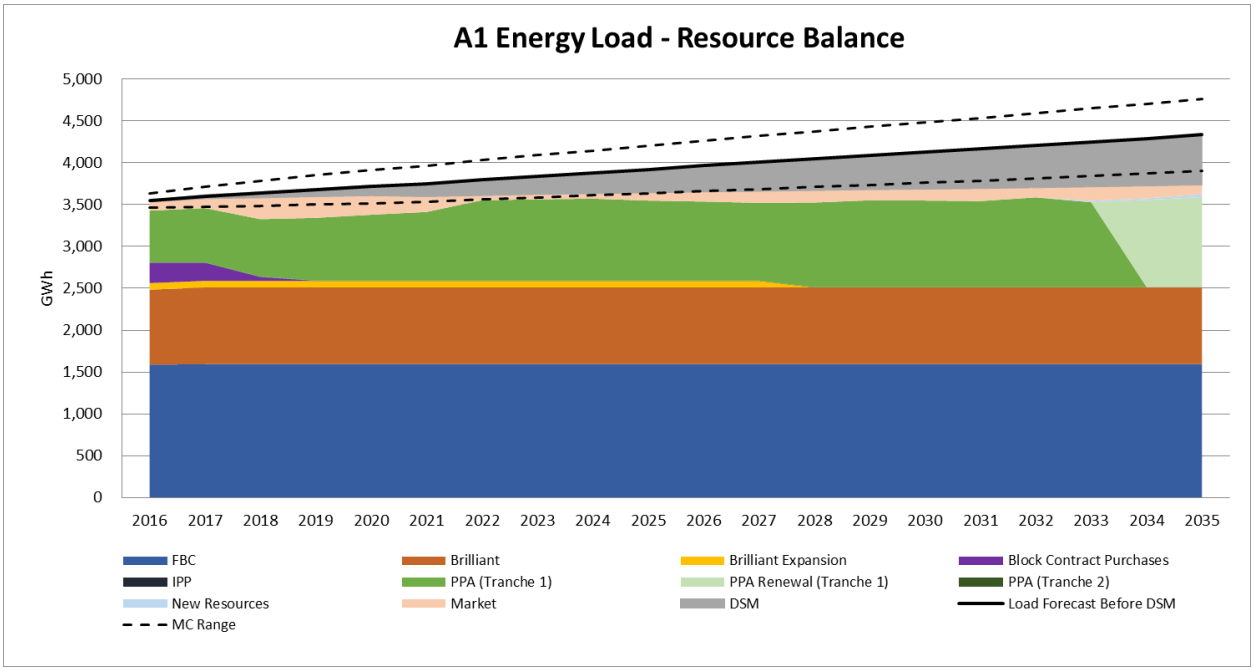


Figure 2: Energy Load-Resource Balance (LRB) for Portfolio A2

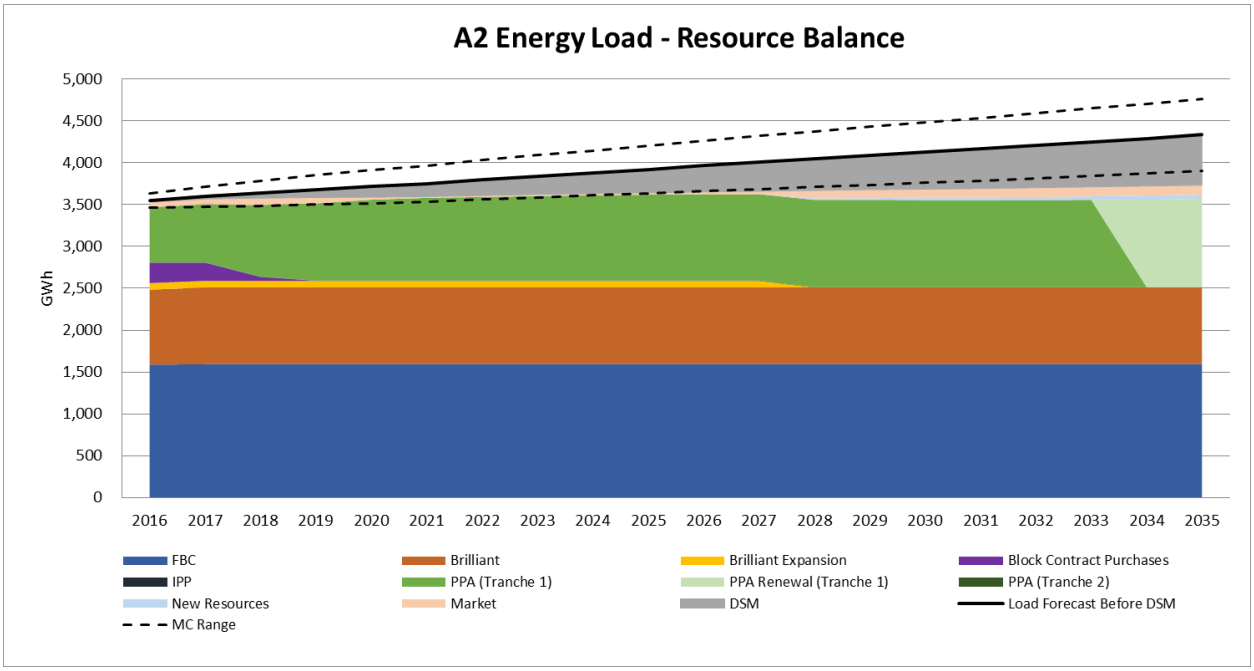
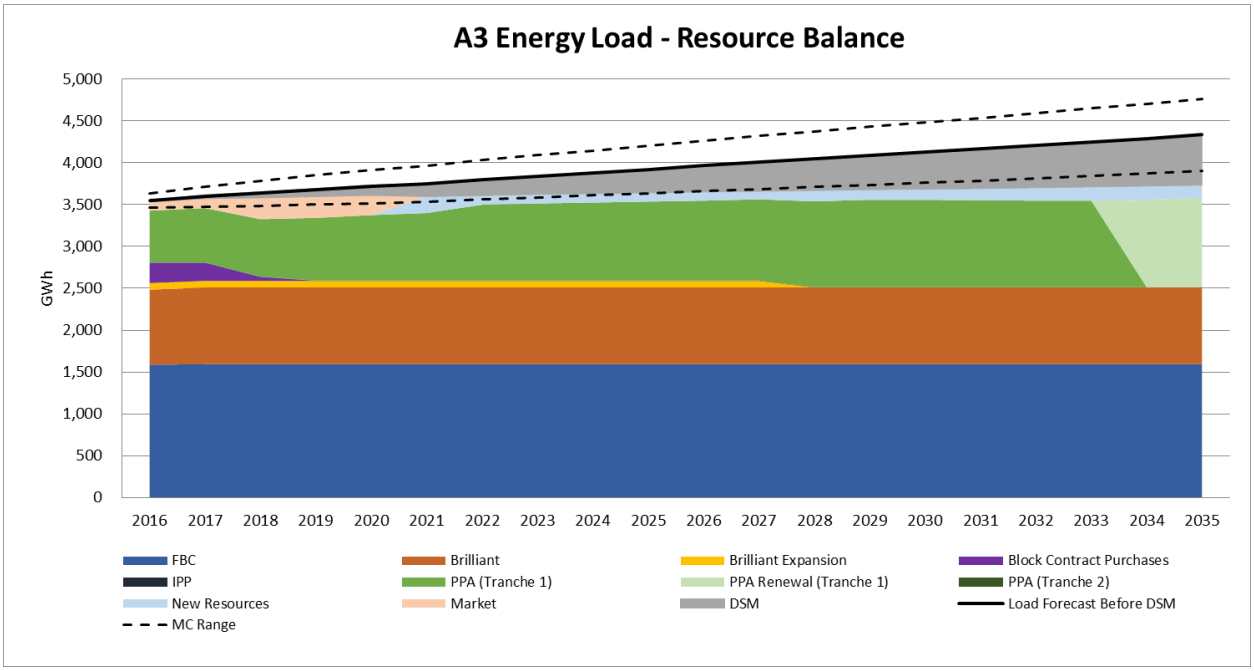


Figure 3: Energy Load-Resource Balance (LRB) for Portfolio A3



39.4 What was the cost of BCH PPA Tranche 2 used in determining the LRMC for the various Portfolios?

Response:

Please refer to the response to BCOAPO IR 1.38.4.

39.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

Response:

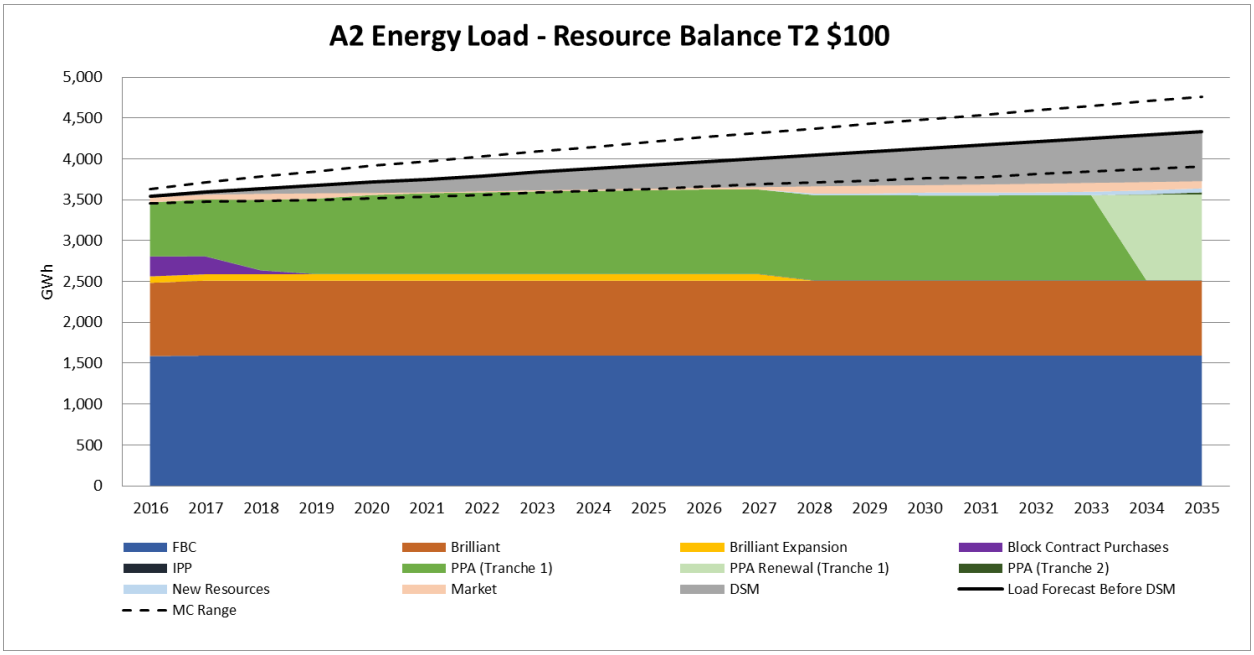
FBC re-ran portfolios A1, A2, and A3 using a Tranche 2 PPA Energy price of $100 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio A1 and A3.

In regards to portfolio A2, PPA Tranche 2 energy at $100 per MWh is used minimally in the last two years of the planning horizon. The LRMC of portfolio A2 decreased by $0.03 per MWh

Table 1: Schedule of Costs for Portfolio A2 ('000s 2015$) with PPA Tranche 2 Energy at $100 per MWh

A2 Schedule T2 $100										
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas2	Biogas4	Biogas3	Market
2016	$10,714	$10,620	$30,246	$0	$0	$0	$0	$0	$0	$3,396
2017	$11,924	$11,113	$32,348	$0	$0	$0	$0	$0	$0	$3,525
2018	$12,251	$12,647	$40,295	$0	$0	$0	$0	$0	$0	$5,055
2019	$12,251	$14,124	$43,727	$0	$0	$0	$0	$0	$0	$4,493
2020	$12,251	$15,478	$46,247	$0	$0	$0	$0	$0	$0	$2,038
2021	$14,122	$16,160	$47,781	$0	$0	$0	$0	$0	$0	$1,038
2022	$15,992	$16,482	$48,755	$0	$0	$0	$0	$0	$0	$1,294
2023	$17,507	$16,791	$49,812	$0	$0	$0	$0	$0	$0	$1,520
2024	$17,507	$17,056	$50,681	$0	$0	$0	$0	$0	$0	$1,707
2025	$17,507	$17,329	$51,578	$0	$0	$0	$0	$0	$0	$1,975
2026	$17,507	$17,027	$52,459	$0	$0	$0	$0	$0	$0	$2,355
2027	$17,507	$17,154	$52,931	$0	$0	$0	$0	$0	$0	$3,297
2028	$17,507	$17,484	$53,976	$0	$0	$1,408	$0	$0	$0	$9,297
2029	$17,507	$17,516	$54,587	$0	$0	$1,408	$0	$0	$0	$10,453
2030	$17,507	$17,759	$54,823	$0	$0	$1,408	$0	$0	$1,460	$10,472
2031	$17,507	$17,906	$55,374	$0	$0	$1,408	$0	$0	$1,466	$11,669
2032	$17,507	$17,358	$56,007	$0	$6,822	$1,408	$0	$0	$1,474	$13,097
2033	$17,507	$17,527	$56,658	$0	$6,822	$1,408	$0	$701	$1,474	$13,760
2034	$17,507	$17,881	$57,575	$384	$6,822	$1,408	$728	$700	$1,474	$13,332
2035	$17,507	$18,557	$58,269	$2,511	$6,822	$1,408	$728	$701	$1,474	$12,097

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2 with PPA Tranche 2 Energy at $100 per MWh



39.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

Response:

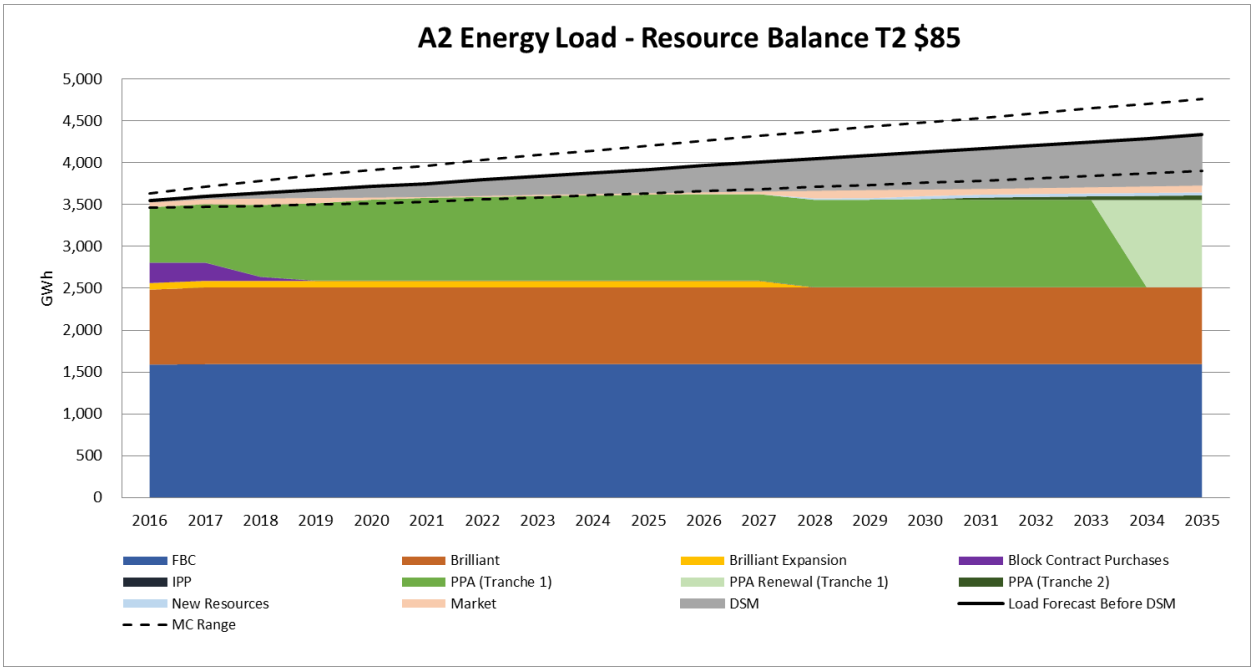
FBC re-ran portfolios A1, A2, and A3 using a Tranche 2 PPA Energy price of $85 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio A1 and A3.

In regards to portfolio A2, PPA Tranche 2 energy at $85 per MWh is used starting in the year 2031 of the planning horizon. Portfolio A2 does not include a self-sufficiency target and investigates the impact of high commodity prices, including market prices. As shown in the tables in Appendix D of the LTERP, the Market prices associated with the high price scenario are greater than $85 per MWh in later years of the planning horizon. Correspondingly, the portfolio uses additional PPA energy, including PPA Tranche 2 energy, rather than the comparatively more expensive Market energy. The LRMC of portfolio A2 decreased by $0.57 per MWh.

Table 1: Schedule of Costs for Portfolio A2 ('000s 2015$) with PPA Tranche 2 Energy at $85 per MWh

A2 Schedule T2 $85								
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Biogas1	Biogas3	Market
2016	$10,714	$10,620	$30,246	$0	$0	$0	$0	$3,396
2017	$11,924	$11,113	$32,348	$0	$0	$0	$0	$3,525
2018	$12,251	$12,647	$40,295	$0	$0	$0	$0	$5,055
2019	$12,251	$14,124	$43,727	$0	$0	$0	$0	$4,493
2020	$12,251	$15,478	$46,247	$0	$0	$0	$0	$2,038
2021	$14,122	$16,160	$47,781	$0	$0	$0	$0	$1,038
2022	$15,992	$16,482	$48,755	$0	$0	$0	$0	$1,294
2023	$17,507	$16,791	$49,812	$0	$0	$0	$0	$1,520
2024	$17,507	$17,056	$50,681	$0	$0	$0	$0	$1,707
2025	$17,507	$17,329	$51,578	$0	$0	$0	$0	$1,975
2026	$17,507	$17,027	$52,459	$0	$0	$0	$0	$2,355
2027	$17,507	$17,154	$52,931	$0	$0	$0	$0	$3,297
2028	$17,507	$17,484	$53,976	$0	$0	$1,408	$0	$9,297
2029	$17,507	$17,516	$54,587	$0	$0	$1,408	$0	$10,453
2030	$17,507	$17,930	$55,557	$0	$0	$1,408	$1,460	$8,983
2031	$17,507	$18,617	$55,554	$2,317	$0	$1,408	$1,466	$8,262
2032	$17,507	$18,372	$56,135	$2,904	$6,822	$1,408	$1,474	$8,836
2033	$17,507	$18,658	$56,599	$3,691	$6,822	$1,408	$1,474	$9,485
2034	$17,507	$18,851	$57,140	$4,159	$6,822	$1,408	$1,474	$10,441
2035	$17,507	$19,046	$57,702	$4,633	$6,822	$1,408	$1,474	$11,450

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2 with PPA Tranche 2 Energy at $85 per MWh



40.0 Reference: Exhibit B-1, Volume 1, page 121

40.1 For each of the three Portfolios (C1, C3, C4), to what extent is BCH PPA Tranche 2 energy relied upon?

Response:

Portfolios C1, C3, and C4 do not use any BCH PPA Tranche 2 energy.

40.2 For each of these three Portfolios, please provide a schedule setting out the cost for each incremental resource (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each incremental resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio C1 ('000s 2015$)

C1 Schedule							
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	CCGT1	Biogas1	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$13,475
2020	$12,251	$12,130	$37,669	$0	$0	$0	$12,646
2021	$14,122	$13,775	$39,658	$0	$0	$0	$10,565
2022	$15,992	$15,985	$46,831	$0	$0	$0	$3,416
2023	$17,507	$16,283	$47,852	$0	$0	$0	$3,585
2024	$17,507	$16,555	$48,703	$0	$0	$0	$3,718
2025	$17,507	$16,391	$47,712	$0	$0	$0	$6,344
2026	$17,507	$14,305	$47,664	$0	$26,753	$0	$0
2027	$17,507	$14,620	$49,771	$0	$25,287	$0	$0
2028	$17,507	$15,584	$53,063	$0	$27,698	$0	$0
2029	$17,507	$16,758	$54,588	$0	$27,158	$0	$0
2030	$17,507	$16,974	$55,074	$0	$27,768	$0	$0
2031	$17,507	$17,124	$55,389	$0	$28,800	$0	$0
2032	$17,507	$17,248	$55,614	$0	$30,133	$0	$0
2033	$17,507	$17,454	$56,165	$0	$31,118	$0	$0
2034	$17,507	$17,802	$57,283	$0	$31,314	$0	$0
2035	$17,507	$18,491	$59,277	$0	$28,915	$1,408	$0

Table 2: Schedule of Costs for Portfolio C3 ('000s 2015$)

C3 Schedule							
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	Wind3	Market
2018	$12,251	$12,647	$40,295	$0	$0	$0	$5,055
2019	$12,251	$14,124	$43,727	$0	$0	$0	$4,493
2020	$12,251	$15,478	$46,247	$0	$0	$0	$2,038
2021	$14,122	$16,160	$47,781	$0	$0	$0	$1,038
2022	$15,992	$16,482	$48,755	$0	$0	$0	$1,294
2023	$17,507	$16,791	$49,812	$0	$0	$0	$1,520
2024	$17,507	$17,047	$50,639	$0	$0	$0	$1,778
2025	$17,507	$17,278	$51,449	$0	$0	$0	$2,198
2026	$17,507	$15,703	$37,132	$0	$0	$38,180	$0
2027	$17,507	$14,218	$37,870	$0	$0	$38,192	$0
2028	$17,507	$15,873	$45,190	$0	$0	$37,727	$0
2029	$17,507	$16,877	$45,999	$0	$0	$37,752	$0
2030	$17,507	$17,184	$46,662	$0	$0	$37,770	$0
2031	$17,507	$17,490	$47,413	$0	$0	$37,792	$0
2032	$17,507	$17,460	$48,245	$0	$6,861	$37,817	$0
2033	$17,507	$17,766	$49,051	$0	$7,113	$37,844	$0
2034	$17,507	$17,981	$49,849	$0	$7,374	$37,870	$0
2035	$17,507	$18,200	$50,679	$0	$7,661	$37,897	$0

Table 3: Schedule of Costs for Portfolio C4 ('000s 2015$)

C4 Schedule														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Solar1	Solar2	Solar3	Biogas1	Biogas2	Biogas3	Biogas4	Wind3	Biomass3	Market
2016	$10,714	$10,502	$28,379	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,020
2017	$11,924	$10,834	$30,183	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,607
2018	$12,251	$11,306	$32,295	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,136
2019	$12,251	$11,730	$35,548	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,475
2020	$12,251	$12,130	$37,669	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,646
2021	$14,122	$13,775	$39,658	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,565
2022	$15,992	$15,985	$46,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,416
2023	$17,507	$16,283	$47,852	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,585
2024	$17,507	$16,555	$48,703	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,718
2025	$17,507	$16,206	$46,900	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,377
2026	$17,507	$14,401	$37,132	$0	$0	$0	$0	$0	$0	$0	$0	$38,180	$0	$0
2027	$17,507	$14,218	$37,870	$0	$0	$0	$0	$0	$0	$0	$0	$38,192	$0	$0
2028	$17,507	$15,873	$45,190	$0	$0	$0	$0	$0	$0	$0	$0	$37,727	$0	$0
2029	$17,507	$16,877	$45,999	$0	$0	$0	$0	$0	$0	$0	$0	$37,752	$0	$0
2030	$17,507	$17,184	$46,662	$0	$0	$0	$0	$0	$0	$0	$0	$37,770	$0	$0
2031	$17,507	$17,316	$46,172	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,730	$0	$0
2032	$17,507	$17,429	$46,811	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,756	$9,276	$0
2033	$17,507	$17,346	$47,750	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,783	$9,163	$0
2034	$17,507	$17,775	$48,684	$0	$0	$0	$0	$1,408	$0	$1,398	$0	$37,809	$9,046	$0
2035	$17,507	$18,032	$48,457	$0	$1,277	$1,265	$1,259	$1,408	$728	$1,398	$668	$37,719	$8,926	$0

40.3 For each of these three Portfolios, please provide an Energy Load Resource Balance (similar to Figure 7-1) that includes the additional resources identified (including DSM) and that breaks out the contributions from Tranches 1 and 2 of BCH's PPA.

Response:

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio C1

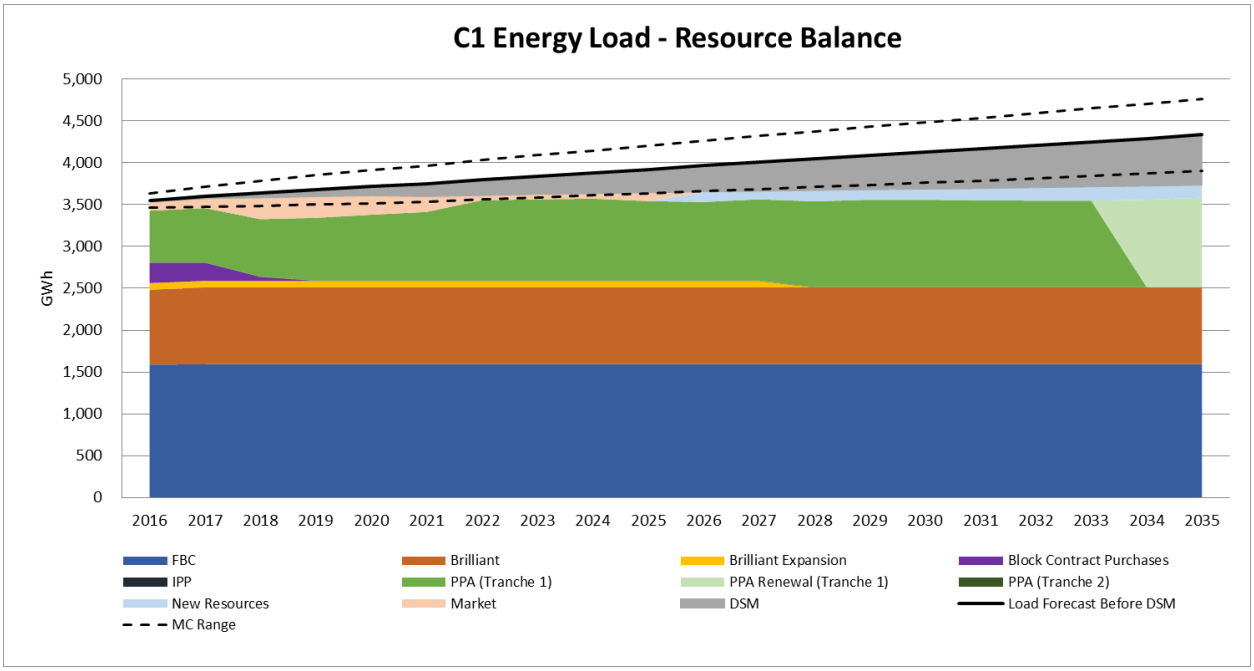


Figure 2: Energy Load-Resource Balance (LRB) for Portfolio C3

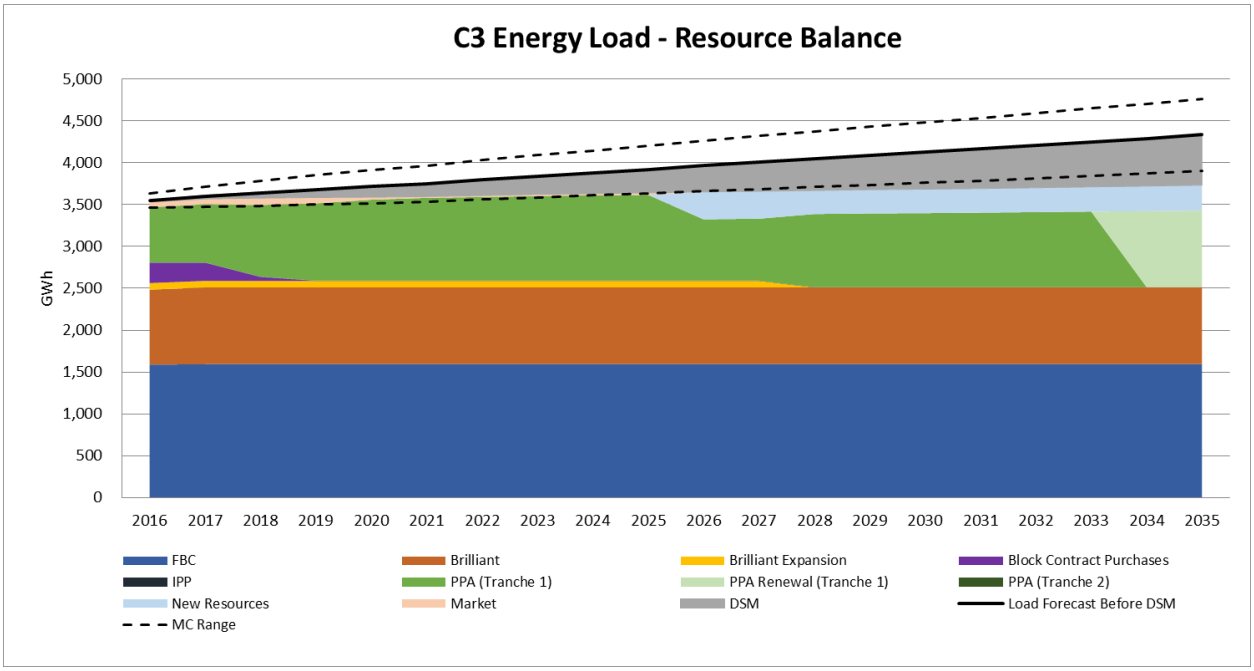
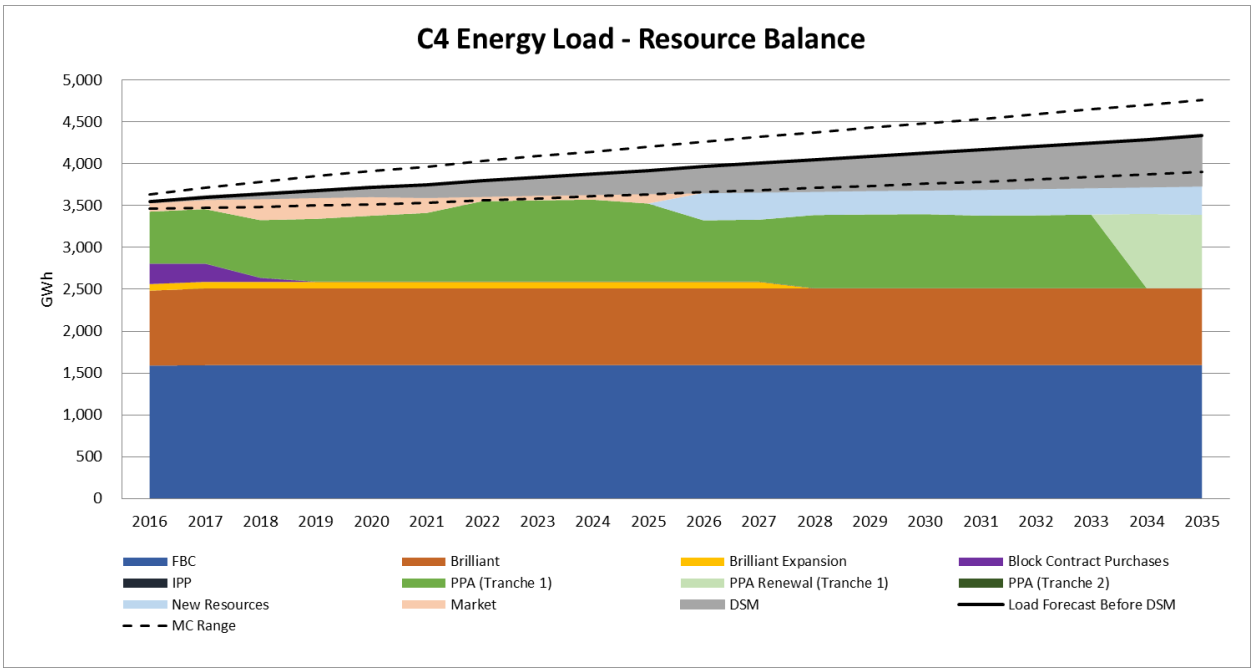


Figure 3: Energy Load-Resource Balance (LRB) for Portfolio C4



40.4 What was the cost of BCH PPA Tranche 2 used in determining the LRMC for the various Portfolios?

Response:

Please refer to the response to BCOAPO IR 1.38.4.

40.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

Response:

Please refer to the response to BCOAPO IR 1.40.4.2.

40.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

Response:

FBC re-ran portfolios C1, C3, and C4 using a Tranche 2 PPA Energy price of $85 per MWh and there was no resulting change in the optimal selected resources or LRMC. Therefore, if PPA Tranche 2 energy was $100 per MWh it can also be concluded there would be no impact on these portfolios.

41.0 Reference: Exhibit B-1, Volume 1, page 122

41.1 For each of the two Portfolios (D2 and D4), to what extent is BCH PPA Tranche 2 energy relied upon?

Response:

Portfolios D2 and D4 do not use any BCH PPA Tranche 2 energy.

41.2 For each of these two Portfolios, please provide a schedule setting out the cost for each incremental resources (including BCH PPA Tranche 2 energy) included.

Response:

The following tables show the schedule of total annual costs for each incremental resource. Costs include levelized fixed and variable energy costs.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$)

D2 Schedule													
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	CCGT2	Biomass1	Biogas1	Biogas2	Biogas3	Biogas4	RoR10	Market
2016	$10,714	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,924	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$12,251	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$12,251	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$12,251	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$14,122	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,992	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$17,892	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$19,918	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$21,944	$17,129	$46,484	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$34,143
2026	$23,971	$15,604	$54,649	$0	$0	$46,297	$0	$1,408	$0	$0	$0	$0	$0
2027	$25,516	$14,022	$57,607	$0	$0	$47,183	$0	$1,408	$0	$0	$0	$0	$0
2028	$25,516	$14,863	$52,368	$0	$0	$45,585	$0	$1,408	$0	$0	$0	$24,222	$0
2029	$25,516	$15,288	$53,439	$0	$0	$48,789	$0	$1,408	$0	$0	$0	$24,330	$0
2030	$25,516	$15,969	$56,543	$0	$0	$49,766	$0	$1,408	$0	$1,455	$0	$24,417	$0
2031	$25,516	$17,081	$58,702	$0	$0	$50,482	$0	$1,408	$728	$1,474	$698	$24,434	$0
2032	$25,516	$17,110	$53,479	$0	$0	$49,355	$23,945	$1,408	$728	$1,474	$701	$24,434	$0
2033	$25,516	$16,854	$56,092	$0	$7,433	$49,548	$24,261	$1,408	$728	$1,474	$701	$24,434	$0
2034	$25,516	$16,156	$56,564	$0	$7,459	$53,074	$24,493	$1,408	$728	$1,474	$701	$24,434	$0
2035	$25,516	$17,481	$61,252	$0	$6,822	$50,524	$24,663	$1,408	$728	$1,474	$701	$24,434	$0

Table 2: Schedule of Costs for Portfolio D4 ('000s 2015$)

D4 Schedule																	
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	Biomass1	Biomass2	Biogas1	Biogas2	Biogas3	Biogas4	Wind1	Wind3	Wind4	RoR7	Biomass3	Biomass4	Market
2016	$10,714	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,924	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$12,251	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$12,251	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$12,251	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$14,122	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,992	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$17,892	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$19,918	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$21,944	$17,106	$51,939	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,147	$0	$0	$14,478
2026	$23,971	$16,136	$45,602	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,190	$12,457	$0	$0	$0
2027	$25,516	$16,669	$48,202	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47,190	$12,621	$0	$0	$0
2028	$25,516	$17,401	$48,105	$0	$22,138	$0	$1,408	$728	$1,455	$693	$0	$0	$47,117	$12,185	$0	$0	$0
2029	$25,516	$17,615	$50,124	$0	$22,363	$0	$1,408	$728	$1,455	$693	$0	$0	$47,157	$12,359	$0	$15,564	$0
2030	$25,516	$16,728	$43,168	$0	$21,043	$0	$1,408	$728	$1,398	$668	$0	$38,161	$46,847	$12,071	$0	$14,950	$0
2031	$25,516	$17,015	$45,147	$0	$21,358	$0	$1,408	$728	$1,414	$668	$0	$38,219	$46,917	$12,071	$0	$14,950	$0
2032	$25,516	$17,678	$47,149	$0	$21,675	$0	$1,408	$728	$1,417	$676	$0	$38,050	$47,190	$12,113	$8,926	$14,950	$0
2033	$25,516	$17,903	$45,735	$0	$21,279	$0	$1,408	$728	$1,417	$676	$15,720	$38,163	$47,092	$12,075	$8,926	$14,950	$0
2034	$25,516	$17,693	$46,920	$0	$21,552	$16,667	$1,408	$728	$1,417	$676	$15,666	$38,208	$47,190	$12,122	$8,926	$14,950	$0
2035	$25,516	$17,540	$47,590	$0	$21,784	$17,565	$1,408	$728	$1,417	$676	$15,776	$38,216	$47,147	$12,164	$8,926	$14,950	$0

41.3 For each of these two Portfolios, please provide an Energy Load Resource Balance (similar to Figure 7-1) that includes the additional resources identified (including DSM) and that breaks out the contributions from Tranches 1 and 2 of BCH's PPA.

Response:

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio D2

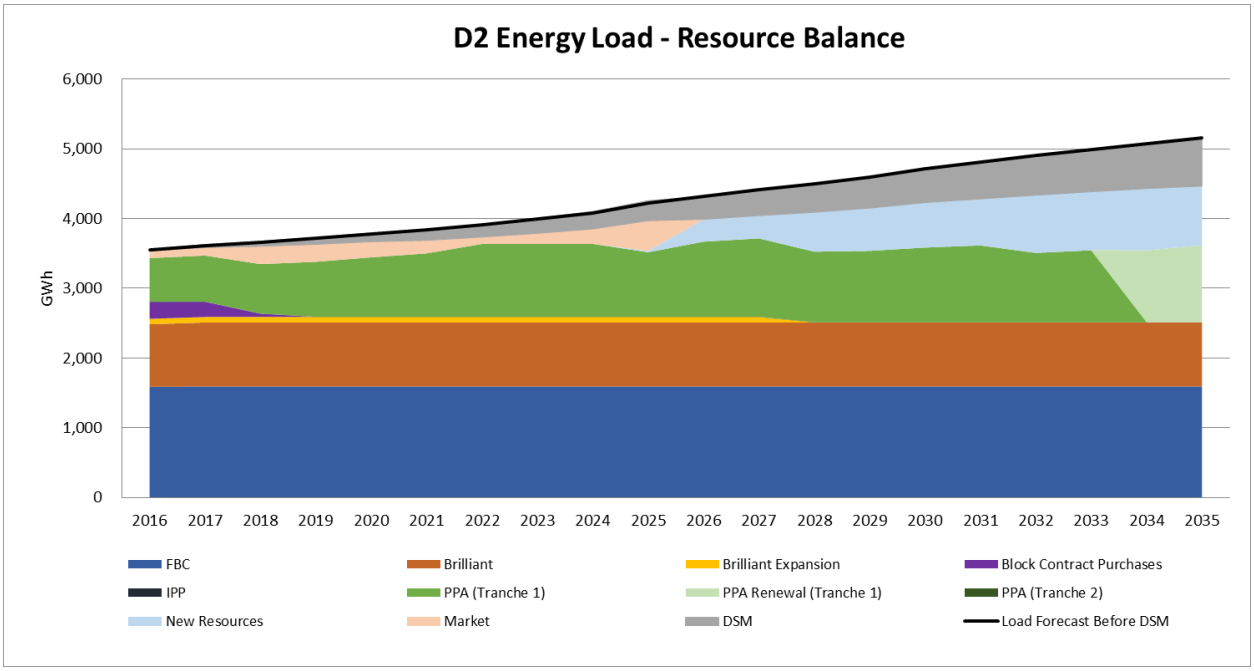
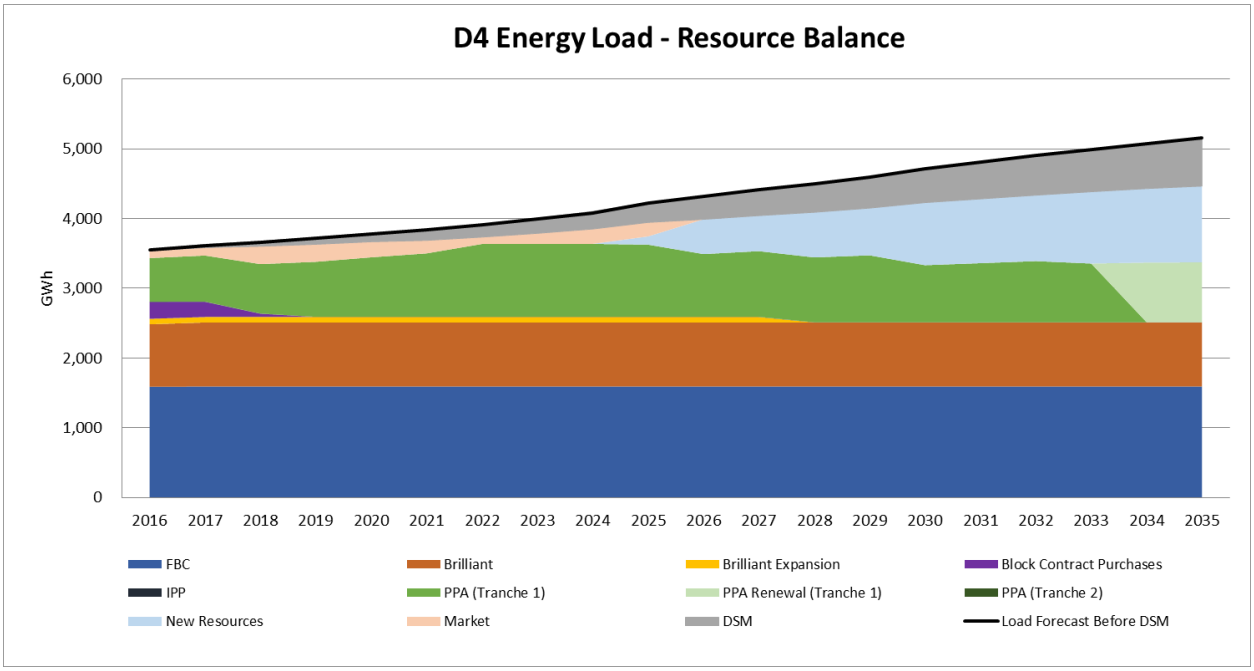


Figure 2: Energy Load-Resource Balance (LRB) for Portfolio D4



41.4 What was the cost of BCH PPA Tranche 2 used in determining the LRMC for the various Portfolios?

Response:

Please refer to the response to BCOAPO IR 1.38.4.

41.4.1 How would the response to parts 1-3 of this question change if the cost of PPA Tranche 2 energy was $100 / MWh (real 2015 $)?

Response:

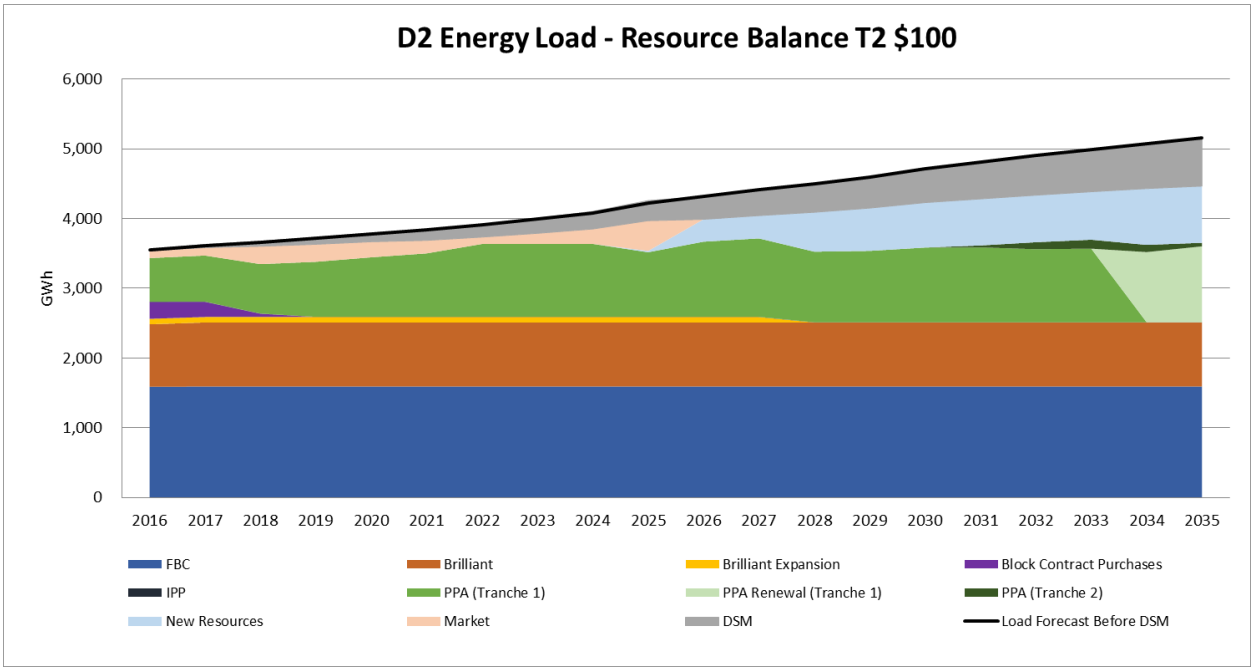
FBC re-ran portfolios D2 and D4 using a Tranche 2 PPA Energy price of $100 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio D4.

In regards to portfolio D2, PPA Tranche 2 energy at $100 per MWh is used in the later years of the planning horizon. The LRMC of portfolio D2 decreased by $0.08 per MWh.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$) with PPA Tranche 2 Energy at $100 per MWh

D2 Schedule T2 $100														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT2	CCGT2	Solar1	Biogas1	Wind1	Biogas2	RoR10	Biogas4	Biogas3	Market
2016	$10,714	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,924	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$12,251	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$12,251	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$12,251	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$14,122	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,992	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$17,892	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$19,918	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$21,944	$17,129	$46,484	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$0	$34,143
2026	$23,971	$15,604	$54,649	$0	$0	$46,297	$0	$1,408	$0	$0	$0	$0	$0	$0
2027	$25,516	$14,022	$57,607	$0	$0	$47,183	$0	$1,408	$0	$0	$0	$0	$0	$0
2028	$25,516	$14,857	$52,342	$0	$0	$45,618	$0	$1,408	$0	$0	$24,222	$0	$0	$0
2029	$25,516	$15,304	$53,439	$0	$0	$48,788	$0	$1,408	$0	$0	$24,330	$0	$0	$0
2030	$25,516	$15,969	$56,543	$0	$0	$49,767	$0	$1,408	$0	$0	$24,417	$0	$1,455	$0
2031	$25,516	$16,720	$57,206	$2,798	$0	$50,667	$0	$1,408	$0	$728	$24,434	$698	$1,474	$0
2032	$25,516	$17,630	$56,358	$10,005	$7,422	$51,165	$0	$1,408	$0	$728	$24,434	$701	$1,474	$0
2033	$25,516	$17,733	$57,340	$12,813	$7,451	$52,079	$1,277	$1,408	$0	$728	$24,434	$701	$1,474	$0
2034	$25,516	$17,705	$55,206	$10,321	$7,445	$53,037	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0
2035	$25,516	$17,925	$60,316	$5,082	$6,985	$54,059	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio D2 with PPA Tranche 2 Energy at $100 per MWh



41.4.2 How would the LRMC for each Portfolio change if the cost of PPA Tranche 2 energy was $85 / MWh (real 2015 $)?

Response:

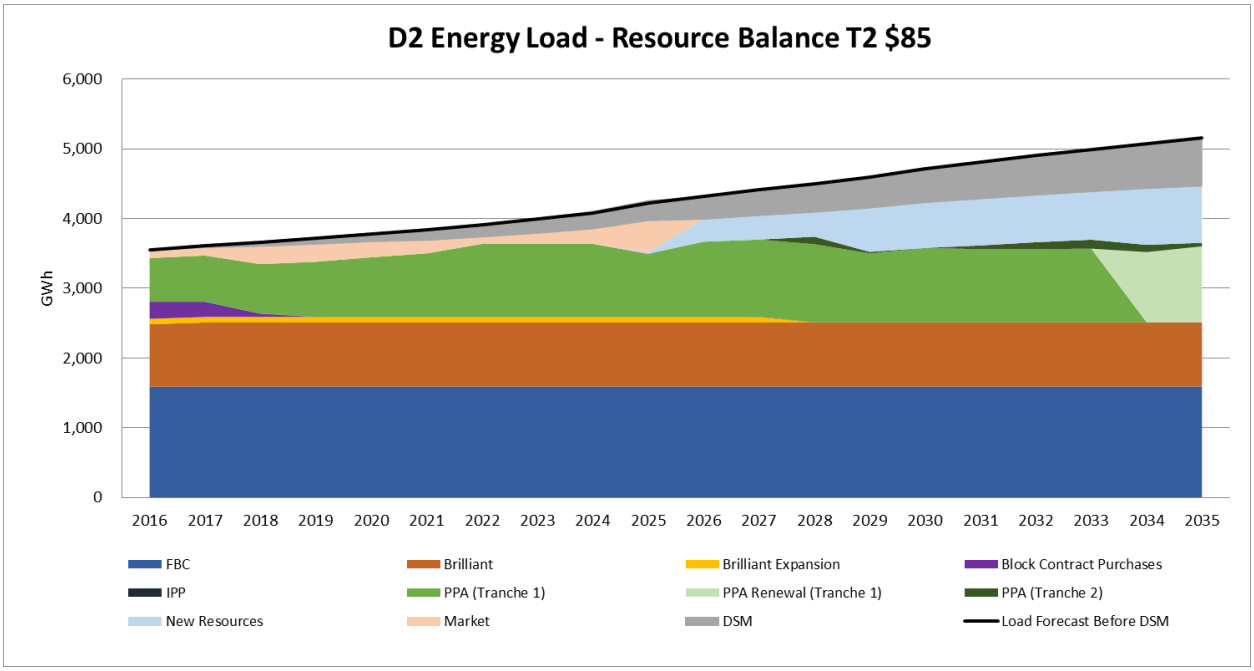
FBC re-ran portfolios D2 and D4 using a Tranche 2 PPA Energy price of $85 per MWh. There was no resulting change in the optimal selected resources or LRMC for portfolio D4.

In regards to portfolio D2, PPA Tranche 2 energy at $85 per MWh is used in the portfolio. Portfolio D2 investigates the High Load scenario. The LRMC of portfolio D2 decrease by $0.44 per MWh.

Table 1: Schedule of Costs for Portfolio D2 ('000s 2015$) with PPA Tranche 2 Energy at $85 per MWh

D2 Schedule T2 $85														
Year	DSM (TRC)	PPA Capacity	PPA T1 Energy	PPA T2 Energy	SCGT1	CCGT2	Solar1	Biogas1	Wind1	Biogas2	RoR10	Biogas4	Biogas3	Market
2016	$10,714	$10,589	$28,629	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,035
2017	$11,924	$11,006	$30,720	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,624
2018	$12,251	$11,642	$33,289	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,155
2019	$12,251	$12,318	$37,371	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,355
2020	$12,251	$13,114	$40,831	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,366
2021	$14,122	$14,766	$43,937	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,859
2022	$15,992	$16,545	$50,930	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,831
2023	$17,892	$16,566	$51,520	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,074
2024	$19,918	$16,722	$52,029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,850
2025	$21,944	$17,129	$45,379	$0	$0	$0	$0	$1,408	$0	$0	$0	$0	$0	$35,565
2026	$23,971	$15,858	$54,638	$0	$0	$46,298	$0	$1,408	$0	$0	$0	$0	$0	$0
2027	$25,516	$13,917	$56,734	$0	$0	$47,139	$0	$1,408	$0	$0	$0	$0	$1,474	$0
2028	$25,516	$16,165	$57,949	$9,120	$0	$47,950	$0	$1,408	$0	$0	$0	$0	$1,474	$0
2029	$25,516	$15,891	$51,577	$1,872	$0	$48,795	$0	$1,408	$0	$0	$24,330	$0	$1,436	$0
2030	$25,516	$15,869	$56,220	$0	$0	$49,720	$0	$1,408	$0	$0	$24,417	$693	$1,455	$0
2031	$25,516	$16,688	$55,790	$4,629	$0	$50,667	$0	$1,408	$0	$728	$24,434	$698	$1,474	$0
2032	$25,516	$17,630	$56,334	$8,542	$7,422	$51,165	$0	$1,408	$0	$728	$24,434	$701	$1,474	$0
2033	$25,516	$17,733	$57,340	$10,891	$7,451	$52,079	$1,277	$1,408	$0	$728	$24,434	$701	$1,474	$0
2034	$25,516	$17,705	$55,206	$8,772	$7,445	$53,037	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0
2035	$25,516	$17,925	$60,316	$4,320	$6,985	$54,059	$1,277	$1,408	$15,880	$728	$24,434	$701	$1,474	$0

Figure 1: Energy Load-Resource Balance (LRB) for Portfolio A2 with PPA Tranche 2 Energy at $85 per MWh



42.0 Reference: Exhibit B-1, Volume 1, pages 125-127

42.1 How would the four portfolios and their subsequent evaluation change if the cost of BCH PPA Trance 2 energy was $100/MWh (real 2015$)?

Response:

There would be no change in the evaluation of portfolios A1, C1, A4, or C4 if the cost of BCH PPA Tranche 2 energy was $100 per MWh. For further discussion, please refer to the response to BCUC IR 1.24.2.

42.2 How would the four portfolios and their subsequent evaluation change if the cost of BCH PPA Trance 2 energy was $85/MWh (real 2015$)?

Response:

There would be no change in evaluation of portfolios A1, C1, A4, or C4 if the cost of BCH PPA Tranche 2 energy was $85 per MWh. For further discussion, please refer to the response to BCUC IR 1.24.2.

43.0 Reference: Exhibit B-1, Volume 1, pages 126-127

43.1 Please explain why none of the preferred portfolios include run-of-the-river resources, as this resource has similar characteristics to onshore wind (per Table 8-3) and has opportunities with lower cost (per Table 8-4).

Response:

The Run-of-River resource options considered have a presumed performance shape that reflects energy production in the spring (freshet) and summer months (i.e. May, June, July, August). In contrast, Wind resources have a presumed performance shape that reflects more favorable energy production in the winter months, which better aligns with FBC's forecast future energy needs.

43.2 Please explain why Portfolios A4 and C4 both have a greater reliance on wind than biogas when the later has a lower cost (per Table 8-4).

Response:

The Biogas resource options considered are smaller in size and do not have the physical capability to meet a larger portion of the forecast incremental energy requirements.

43.3 For each of Portfolios C1 and A4 please explain how the balance between the various incremental resources was determined.

Response:

Resource allocation was determined using an optimization routine with considerations for PRM requirements. For further details please refer to the response to CEC IR 1.23.2.

Depending on the characteristics of the portfolio scenario, some resource options were excluded from selection. In portfolio A4, Combined Cycle Gas Turbine (CCGT) resource options were excluded from the set of available resource options. In portfolio C1, CCGT resource options were included in the set of available resource options.

44.0 Reference: Exhibit B-1, Volume 1, pages 127-128

44.1 For Portfolio C4 was any additional capacity added to meet the PRM requirements or was the resource mix simply changed? If the former, how much additional capacity was added and when?

Response:

For the optimization routine to select a different set of optimal resources that met the LOLE target in all years of the planning horizon, additional Planning Reserve Margin requirements were added to portfolio C4 starting in the year 2031, per the process described in Section 3.2, Appendix L of the LTERP. In this case, optimal portfolio C4 that met PRM requirements contains 13 MW of additional capacity by the year 2035 compared to a portfolio that has the same attributes as portfolio C4, but did not meet PRM requirements.

44.2 For Portfolios C1 and A4 please provide a Capacity Load Balance Graph similar to Figure 7-2 but:

- Include the incremental resources of each of the preferred portfolio (including DSM), and
- Revise the Peak Forecast to include the PRM.

Response:

The updated figures below are based on FBC's peak demand requirements during each year's winter period.

Figure 1: Capacity Load-Resource Balance for Portfolio A4

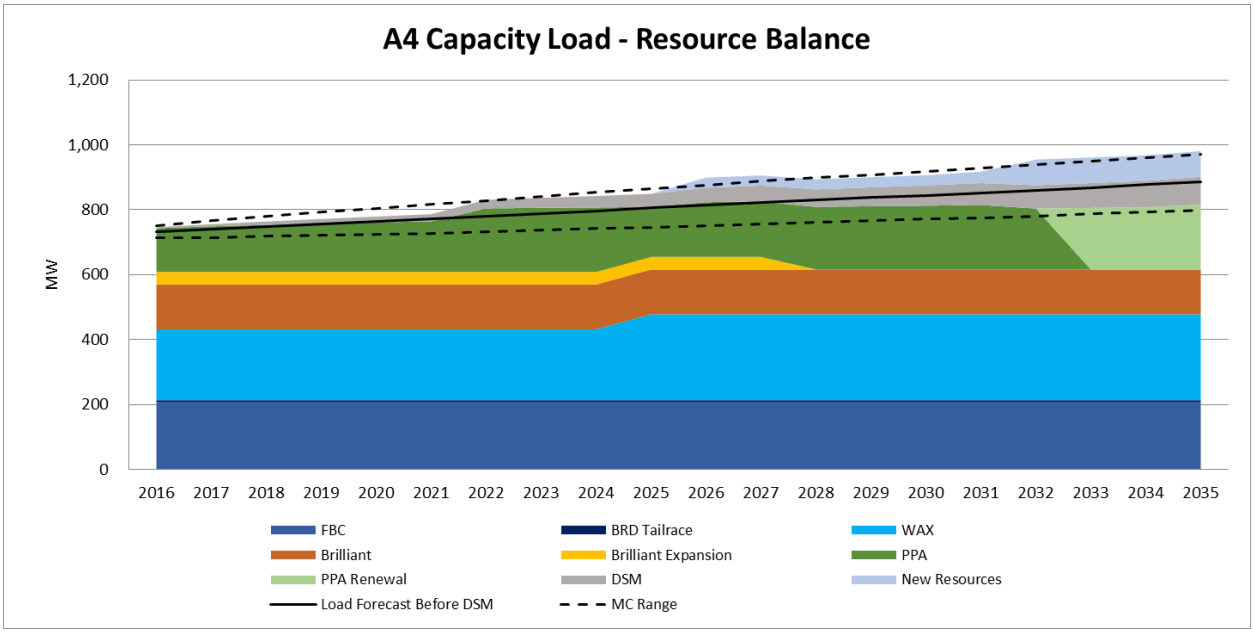
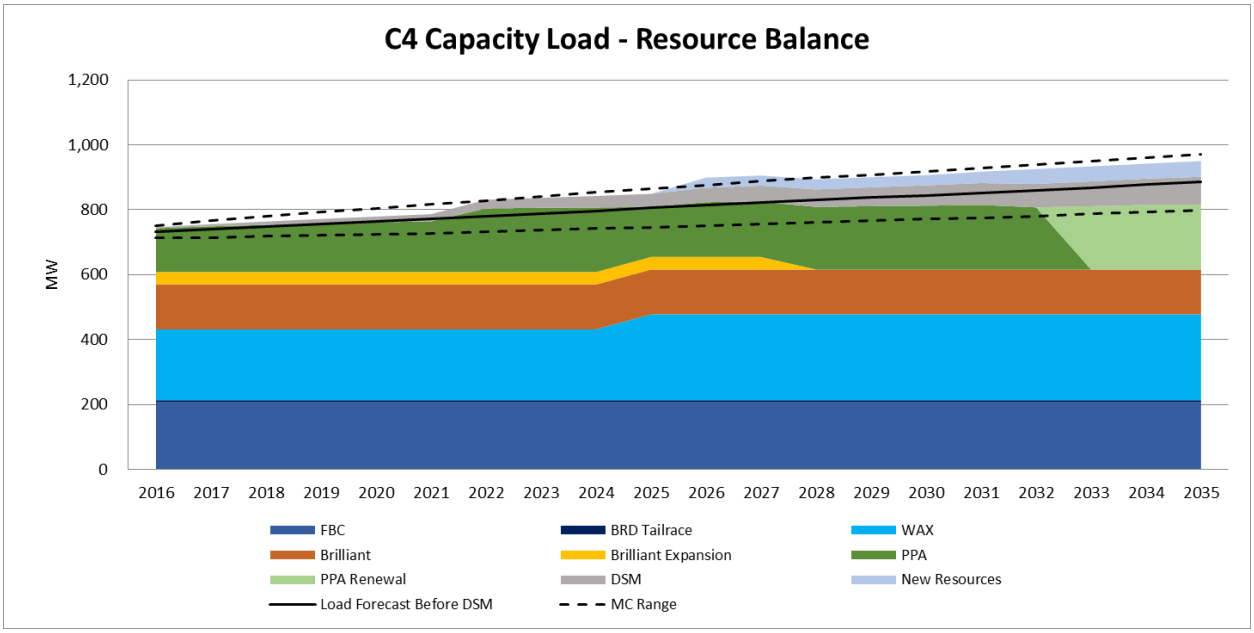


Figure 2: Capacity Load-Resource Balance for Portfolio C4



As discussed in the response to BCOAPO IR 1.28.1.1, it is not possible to simply show PRM as an additional requirement to the peak forecast.

45.0 Reference: Exhibit B-1, Volume 1, page 128

45.1 At lines 26 and 34 references are made to sections 9.4.3 and 9.4.4 respectively. However, the Application does not contain these sections. Please indicate where the referenced issues are discussed in the Application.

Response:

The reference to Section 9.4.3 should have been to Section 9.3.3 and the reference to Section 9.4.4 should have been to Section 9.3.4.

46.0 Reference: Exhibit B-1, Volume 1, pages 140-141

46.1 Assuming new supply-side resources are not required until 2026, when would activities for supply procurement have to start in order to meet this requirement?

Response:

Please refer to the responses to CEC IRs 1.26.2 and 1.26.2.1.

46.2 Would any material action, commitments or expenditures be required prior to the filing of FBC's next LTERP in approximately 5 years?

Response:

No. Please refer to the responses to CEC IRs 1.26.2 and 1.26.2.1.

46.2.1 If yes, what are they?

Response:

Please refer to the responses to CEC IRs 1.26.2 and 1.26.2.1.

47.0 Reference: Exhibit B-1, Volume 2, pages 11-15

47.1 What would be the effect (per Figure 3-1 and Table 3-1) of a DSM scenario that only included DSM measures with an LRMC of $100/MWh or less? As with the High and Max scenarios please assume any required ramp up starts in 2021.

Response:

Please refer to the response to BCOAPO IR 1.4.3.

If applied to the marginal measure cost (please refer to the response to BCOAPO IR 1.29.2 for definitions), the requested $100/MWh scenario would land between the High and Max case, achieving 96 percent of the savings potential of the Max scenario.

FBC prepared the DSM scenarios based on load growth offset targets, not on an LRMC basis. This additional scenario would thus be inconsistent with the methodology used in the LTERP and is not recommended. The results are close enough to use the Max scenario as a proxy for the requested $100 per MWh scenario.

47.2 Please revise Figure 3-2 to include the results of the DSM scenario described in part 1.

Response:

Please refer to the response to BCOAPO IR 1.47.1.

47.3 Please provide revised versions of Figure 8-3, Figure 8-4 and Table 9-2 assuming DSM consistent with that in part 1.

Response:

Please refer to the response to BCOAPO IR 1.47.1.

47.4 What specific DSM measures would be included in the High scenario proposed by FBC and the scenario as specified in part 1?

Response:

Please refer to the response to BCOAPO IR 1.47.1. All measures from the High scenario would be included in the requested $100 per MWh scenario.

47.5 Does the High Scenario include all DSM measures identified by the CPR with a cost of $100/MWh or less? If not, which ones are excluded and why?

Response:

No, the High scenario included only measures with a marginal cost of up to $92/MWh. The $104/MWh incremental cost shown for the High DSM scenario in Figure 3-2 and Table 3-1 at pages 13-14 of the LT DSM Plan includes an adder for program administration costs.

The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. Similarly, FBC did not include an analysis of the individual measures included within each scenario.

48.0 Reference: Exhibit B-1, Volume 2, page 16

48.1 Please provide a revised version of Table 3-2 that includes:

- The TRC value for each year.
- The year by year cumulative DSM savings, accounting for loss of persistence.

Response:

Please refer to the response to BCUC IR 1.38.2 for the TRC (Benefit/Cost) value for each DSM scenario as a whole.

The 2016 LT DSM Plan is not an expenditure filing, thus FBC has not developed details of program and sector costs or savings, including adjustments (if any) for loss of persistence. The Company anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

49.0 Reference: Exhibit B-1, Volume 2, pages 17-23

49.1 What specific DSM measures (programs) are included in the High scenario that were not included in the 2017 DSM Plan?

Response:

Specific DSM measures (programs) were not defined in the DSM scenarios. The 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not determined.

FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

49.2 Are there any DSM measures that were included in the 2017 DSM Plan but are not in the High scenario?

Response:

Please refer to the response to BCOAPO IR 1.49.1.

49.2.1 If yes, what are they and why were they excluded?

Response:

Please refer to the response to BCOAPO IR 1.49.1.

50.0 Reference: Exhibit B-1, Volume 2, page 22

50.1 Does FBC intend to employ specific measures aimed at increasing public awareness of DSM programs for low-income customers?

Response:

Please refer to the response to BCUC IR 1.50.4 for a discussion on FBC's hard to reach customer segments, including efforts to raise awareness of DSM programs for low-income customers.

50.1.1 If yes, what are these measures?

Response:

Please refer to the response to BCUC IR 1.50.4.