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May 18, 2017

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

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 Utilities Commission (BCUC or the Commission) Information Request (IR) No. 2

On November 30, 2016, FBC filed the Application referenced above. In accordance with Commission Order G-197-16 setting out the Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 2.

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

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page No.**

A. CHAPTER 1 – INTRODUCTION

55.0 Reference: PURPOSE OF THE RESOURCE PLAN

Exhibit B-2, British Columbia Utilities Commission (BCUC) IR 1.1, 31.3

Guidance for future applications

In BCUC IR 1.1 Fortis BC Inc. (FBC) states that the Long Term Electricity Resource Plan (LTERP) will support future Applications. In BCUC IR 31.3, FBC states that it does not does not have any new resource requirements until after 2025.

55.1 Please expand on FBC's response to BCUC IR 1.1 by specifically describing the key guidance in this resource plan that FBC considers it may rely on in applications to the Commission over the next five years (2017 to 2021). For example, the actual dollar amount of Demand Side Management (DSM) funding per year, the long-run marginal cost (LRMC) value in ₵/kWh and $/MW-year, the percentage of the resource stack that is met with 'BC clean' resources etc. Please specifically address the following in your response:

a. <u>FBC Annual Electric Contracting Plans (AECP) and Energy Supply Contracts.</u> Please specifically include: resource planning objectives; long-run marginal cost (LRMC) of energy and capacity; planning reserve margin; load forecast; extent of reliance on non 'BC clean' (market) purchases to meet planned load; and an explanation as to why planned supply side energy purchases cannot be met through demand side resources (including DSM and distributed generation).

<u>Response:</u>

The LTERP planning objectives discussed in Section 1.3 of the LTERP are long term objectives applicable for the 20-year planning horizon. They are repeated here:

1. Ensure cost-effective, secure and reliable power for customers;
2. Provide cost-effective demand side management, and
3. Ensure consistency with provincial energy objectives.

FBC expects to refer to the LTERP throughout the next five years to support these planning objectives as it is required to do so.

FBC is not anticipating a requirement for additional resources for a considerable period of time and does not anticipate using the LRMC to justify obtaining new resources to meet either load or planning reserve margin requirements at this time. Given the inherent uncertainties regarding load, if events within the next five years were to result in FBC requiring additional resources on an accelerated time frame, then FBC expects that the LRMC and the preferred portfolio analysis would be used to generally support such an application for additional resources. It is important to note that any further application needs to stand on its own merits and must include updated information in regards to price and load forecast. System planning activities may require the impact on system losses to be evaluated. Using the LRMC may be appropriate for this type of analysis.

The objectives of the AECP are shorter term in nature and address the optimization of existing resources and short term resource gaps as opposed to acquiring new resources on a long term basis. Generally speaking, the objectives of the LTERP and AECP are consistent. The AECP's recommendations regarding the optimization of the PPA Tranche 1 energy and market purchases are aligned with the short-term recommendations of the LTERP provided in Table 9-3. Due to the short-term nature of the AECP, the LRMC is not applicable to the AECP.

The load forecast for the AECP will be the most recently approved load forecast used for revenue requirements applications (RRA) with additional years added as required. This will likely differ from the long-term load forecast used in the LTERP as the RRA forecast is updated annually based on more current information.

The extent to which supply side energy purchases cannot be met through demand-side resources is not as applicable for the AECP as it is for the LTERP because any incremental DSM would take time to implement and is therefore outside the scope of the AECP.

Other areas where FBC may rely on the LTERP for guidance include information about clean or green generation, the need for self-generation resources or any other issue that may arise where information in the LTERP is relevant.

b. <u>FBC Demand Side Management (DSM) s. 44.2 filings</u>. Please specifically include: the size of the annual funding envelope; whether DSM can include electrification initiatives; LRMC of energy and capacity for the total resource cost (TRC) test; FBC avoided cost of energy and capacity for the utility cost test (UCT).

Response:

The 2016 LT DSM Plan presents a pro-forma DSM Budget (Table 3-2 of the LT DSM Plan), which is a high-level estimate of the annual DSM budgets. The pro-forma budgets are based on general expectations as to the mix of measures to be included, the incentive levels and administrative and other costs, which will be refined in the expenditure schedules. FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

The LRMC value of $100.45 per MWh for DSM purposes is presented in the 2016 LTERP and is inclusive of capacity benefits (the DCE value for deferred infrastructure costs of $79.85 per kW-year was filed in the 2017 DSM expenditure schedule application); the LRMC and DCE will be reviewed at the time of the next LTERP.

As stated in the response to BCUC IR 2.83.1, FBC does not consider load-building activities such as fuel-switching programs to be DSM activities, but does intend to investigate opportunities for fuel-switching.

c. FBC Certificate of Public Convenience and Necessity (CPCN) filings. Please identify each expected CPCN filing and explain why the need could not be met through demand side resources (including customer preference for of a lower level of reliability at a reduced cost; DSM, and distributed generation).

Response:

The only upcoming planned CPCN filing that is driven by capacity requirements is the Kelowna Bulk Transformer Capacity Addition project (refer to the response to BCUC IR 1.22.3 and Table 6-3 of the LTERP). As described in the response to BCUC IR 1.23.2.1, DSM savings are considered to be a non-firm resource and therefore cannot be counted on to defer network system reinforcements that are predicated on peak load requirements. The response to BCUC IR 1.23.2 describes the potential for distributed generation to defer the requirement for system reinforcements. FBC does not presently have a rate schedule that offers customers a lower level of reliability at a reduced cost nor does FBC have a mechanism to exclude certain customers from calculations for reliability Service Quality Indicators at this time.

55.2 Please explain whether FBC expects the different portfolio options modeled for years 2022-2025 to have any significant effect on applications filed in the next 5 years (2017-2021), and if yes, please describe.

Response:

Most of the portfolios modelled will not have any significant effect on applications filed in the next 5 years. This is because most of the portfolios do not require any new resources until after 2025. However, Portfolio A3 includes self-sufficiency by 2020 and so requires a new resource, a CCGT plant, as early as 2021 (as discussed in Section 9.3.2 of the LTERP). Therefore, if FBC were to implement this portfolio, FBC would likely be required to file a CPCN application for the CCGT plant in 2017.

As market purchases continue to be a cost-effective and reliable source of power, FBC has assumed self-sufficiency by the end of 2025 with new resources not required until 2026 (per Portfolio A4 discussed in Section 9.3.6 of the LTERP).

B. CHAPTER 3 – LONG-TERM LOAD FORECAST

56.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, Appendix E, p. 1; Figure E-7, p. 8;

Exhibit B-2, BCUC IR 14.1, p. 46; BCUC IR 14.1.1, p. 47; BCUC IR 14.3, pp. 48-49; BCUC IR 14.3.1, p. 49

Residential UPC Historical data and load forecast methodology

On page 8 of Appendix E of the Application, FBC states:

> The graph below [Figure E-7: Residential UPC (MWh)] shows the UPC, which was calculated by taking the forecast residential loads and then dividing it by the average customer count. After adjusting for savings, UPC increases slightly over the planning horizon.
>
> The [residential] UPC is forecast by averaging the most recent three years' normalized historical UPCs (2013, 2014, 2015), and each year after this is assumed to remain constant at the 2016 level of 11.80 MWh. This value was assumed to remain constant since there is no significant long term trend in the UPC at this point in time.

In response to BCUC IRs 14.1 and 14.1.1, FBC presented the historical normalized residential UPC from 2006 through to 2015, along with the before-savings residential UPC forecast for 2016. The data shows that over the last 10 years normalized residential UPC had an overall decline of 5.6% from 12.09 MWh in 2006 to 11.41 MWh in 2015. The data also shows that from 2009 to 2015, normalized residential UPC declined each year except for 2013.

In response to BCUC IR 14.3, FBC states that: "[t]he residential after savings UPC in Figure E-7 is comprised of a normalized constant UPC of 11.80 MWh less an amount attributable to load savings" and in response to BCUC 14.3.1, FBC provides the residential UPC savings forecast in MWh from 2016 through to 2035.

On page 1 of Appendix E in the Application, FBC defines "savings" as "Load reductions due to FBC's Residential Conservation rate (RCR), Consumer Information Portal (CIP), Advanced Metering Infrastructure (AMI), and rate-driven impacts (price elasticity)."

56.1 Please complete the attached Excel spreadsheet titled "BCUC IR - Residential UPC," which was partially prepared using data from FBC's response to BCUC IRs 14.1, 14.3 and 14.3.1. Please make corrections to the spreadsheet if and where necessary.

Response:

The table requested is completed below. Note that the Before-Savings UPC values from the years 2006 through 2015 were moved to the Net Residential UPC column since they include historical Savings and DSM.

Year	Actual/Forecast	Normalized Residential UPC				
		Before-Savings (MWh)	Savings (MWh)	After-Savings (MWh)	DSM Impact (MWh)	Net Residential UPC (After-Savings and DSM Impact) (MWh)
2006	Actual	12.21	N/A	12.21	0.12	12.09
2007	Actual	12.90	N/A	12.90	0.16	12.74
2008	Actual	12.76	N/A	12.76	0.12	12.64
2009	Actual	12.99	N/A	12.99	0.09	12.90
2010	Actual	12.88	N/A	12.88	0.11	12.77
2011	Actual	12.80	N/A	12.80	0.10	12.70
2012	Actual	12.59	0.07	12.52	0.11	12.41
2013	Actual	12.73	0.10	12.62	0.14	12.48
2014	Actual	11.71	0.12	11.59	0.08	11.51
2015	Actual	11.48	0.02	11.46	0.05	11.41
2016	Forecast	11.80	0.01	11.79	0.03	11.76
2017	Forecast	11.80	0.00	11.80	0.08	11.72
2018	Forecast	11.80	-0.02	11.82	0.14	11.68
2019	Forecast	11.80	-0.04	11.84	0.20	11.64
2020	Forecast	11.80	-0.07	11.87	0.25	11.62
2021	Forecast	11.80	-0.08	11.88	0.31	11.57
2022	Forecast	11.80	-0.09	11.89	0.36	11.53
2023	Forecast	11.80	-0.10	11.90	0.41	11.49
2024	Forecast	11.80	-0.11	11.91	0.47	11.44
2025	Forecast	11.80	-0.11	11.91	0.52	11.39
2026	Forecast	11.80	-0.12	11.92	0.57	11.35
2027	Forecast	11.80	-0.13	11.93	0.62	11.31
2028	Forecast	11.80	-0.14	11.94	0.67	11.27
2029	Forecast	11.80	-0.15	11.95	0.72	11.23
2030	Forecast	11.80	-0.15	11.95	0.76	11.19
2031	Forecast	11.80	-0.16	11.96	0.81	11.15
2032	Forecast	11.80	-0.17	11.97	0.86	11.11
2033	Forecast	11.80	-0.18	11.98	0.91	11.07
2034	Forecast	11.80	-0.19	11.99	0.95	11.04
2035	Forecast	11.80	-0.19	11.99	1.00	10.99

56.1.1 Please confirm, or otherwise explain, that the negative savings forecast are a result of the residential AMI savings being greater in magnitude than the total savings attributable to the combination of the RCR, CIP and rate-driven savings.

Response:

Confirmed. AMI savings are forecast to become greater than the combined RCR, CIP and rate-driven savings starting in 2028 on a gross load basis, as shown in the line "Net Load Other Savings" in Table 1 of the response to BCOAPO IR 1.13.1.

56.2 Please explain if the historical normalized residential UPC provided in response to BCUC IR 14.1 includes the impact of DSM.

Response:

Confirmed. The historical normalized residential UPC values from 2006 to 2015 provided in response BCUC IR 1.14.1 do include DSM impacts.

56.3 Please confirm, or otherwise explain, that the residential UPC savings forecast does not include the impact of the DSM forecast.

Response:

Confirmed. DSM is not a component of Savings.

56.4 If the historical normalized residential UPC provided in response to BCUC IR 14.1 represents before-savings UPC and does not include the impact of DSM, please explain the use of a constant normalized before-savings residential UPC for each year of the 20-year planning period.

Response:

The historical normalized residential UPC values from 2006 to 2015 provided in response to BCUC IR 1.14.1 do include DSM impacts.

56.5 Please calculate the impact to the (i) residential forecast, (ii) total gross load forecast, and (iii) total net load forecast (presented in Appendix F of the Application) of using a forecast normalized before-savings pre-DSM residential UPC that declines at 0.5% per year for each year of the 20-year planning period. Please provide the necessary tables and charts with your response.

Response:

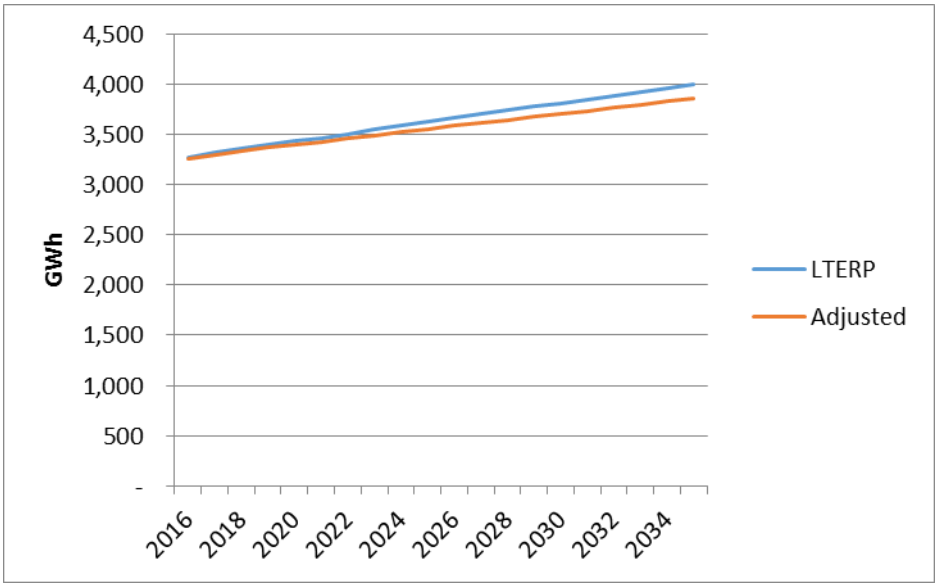
Table 1: Impact to UPC and Residential Load with Before-Savings Annual UPC Decreased by 0.5 Percent

Year	Before-Savings UPC (MWh)			Residential Load (MWh)		
	A	B = B - (B * 0.05)	C	D = B * C	E	F = D - E
	LTERP	0.5% Annual Decrease	Average Customer Count	Before-Savings	Savings	After-Savings
2016	11.80	11.74	114,623	1,345,787	1,464	1,344,324
2017	11.80	11.68	115,555	1,349,952	251	1,349,702
2018	11.80	11.62	116,503	1,354,220	-1,782	1,356,002
2019	11.80	11.57	117,449	1,358,383	-5,139	1,363,522
2020	11.80	11.51	118,399	1,362,530	-7,955	1,370,485
2021	11.80	11.45	119,356	1,366,670	-9,514	1,376,184
2022	11.80	11.39	120,317	1,370,787	-11,246	1,382,033
2023	11.80	11.34	121,272	1,374,760	-12,363	1,387,122
2024	11.80	11.28	122,207	1,378,435	-13,491	1,391,926
2025	11.80	11.22	123,129	1,381,893	-14,632	1,396,525
2026	11.80	11.17	124,041	1,385,166	-15,784	1,400,951
2027	11.80	11.11	124,935	1,388,167	-16,949	1,405,116
2028	11.80	11.06	125,808	1,390,883	-18,126	1,409,009
2029	11.80	11.00	126,660	1,393,305	-19,316	1,412,620
2030	11.80	10.95	127,488	1,395,393	-20,518	1,415,911
2031	11.80	10.89	128,292	1,397,174	-21,734	1,418,908
2032	11.80	10.84	129,077	1,398,690	-22,962	1,421,653
2033	11.80	10.78	129,839	1,399,921	-24,204	1,424,125
2034	11.80	10.73	130,579	1,400,860	-25,458	1,426,318
2035	11.80	10.67	131,293	1,401,477	-26,726	1,428,203

Table 2: Impact to Residential, Net and Gross Loads with Before-Savings Annual UPC Decreased by 0.5 Percent

YEAR	Residential Forecast (GWh)			Net Load (GWh)			Gross Load (GWh)		
	LTERP	Adjusted	Change	LTERP	Adjusted	Change	LTERP	Adjusted	Change
2016	1,351	1,344	-0.5%	3,264	3,257	-0.2%	3,544	3,537	-0.2%
2017	1,363	1,350	-1.0%	3,314	3,301	-0.4%	3,595	3,580	-0.4%
2018	1,377	1,356	-1.5%	3,353	3,332	-0.6%	3,633	3,611	-0.6%
2019	1,391	1,364	-2.0%	3,394	3,366	-0.8%	3,676	3,646	-0.8%
2020	1,405	1,370	-2.5%	3,432	3,397	-1.0%	3,715	3,677	-1.0%
2021	1,418	1,376	-3.0%	3,465	3,423	-1.2%	3,750	3,705	-1.2%
2022	1,431	1,382	-3.4%	3,505	3,456	-1.4%	3,794	3,741	-1.4%
2023	1,443	1,387	-3.9%	3,547	3,491	-1.6%	3,839	3,778	-1.6%
2024	1,455	1,392	-4.3%	3,585	3,522	-1.8%	3,880	3,811	-1.8%
2025	1,467	1,397	-4.8%	3,624	3,553	-1.9%	3,922	3,846	-2.0%
2026	1,479	1,401	-5.3%	3,663	3,585	-2.1%	3,965	3,880	-2.1%
2027	1,491	1,405	-5.7%	3,700	3,614	-2.3%	4,005	3,912	-2.3%
2028	1,502	1,409	-6.2%	3,738	3,645	-2.5%	4,046	3,945	-2.5%
2029	1,513	1,413	-6.6%	3,776	3,676	-2.7%	4,088	3,979	-2.7%
2030	1,524	1,416	-7.1%	3,811	3,703	-2.8%	4,126	4,008	-2.9%
2031	1,535	1,419	-7.6%	3,848	3,732	-3.0%	4,166	4,040	-3.0%
2032	1,545	1,422	-8.0%	3,886	3,762	-3.2%	4,207	4,073	-3.2%
2033	1,555	1,424	-8.4%	3,925	3,794	-3.3%	4,250	4,107	-3.4%
2034	1,565	1,426	-8.9%	3,964	3,825	-3.5%	4,292	4,140	-3.5%
2035	1,575	1,428	-9.3%	4,003	3,856	-3.7%	4,334	4,174	-3.7%

Figure 1: Net Load Forecast LTERP vs. Adjusted with Before-Savings Annual UPC Decreased by 0.5 Percent



As shown in the table and figure above, a compounding 0.5 percent decrease in the residential UPC results in a residential load estimate that is more than 9 percent lower by 2035 than the forecast as filed. In terms of overall net load, the impact is 3.7 percent.

56.6 Please calculate the impact to the (i) residential forecast, (ii) total gross load forecast, and (iii) total net load forecast (presented in Appendix F of the Application) of using a forecast normalized before-savings pre-DSM residential UPC that increases at 0.5% per year for each year of the 20-year planning period. Please provide the necessary tables and charts with your response.

Response:

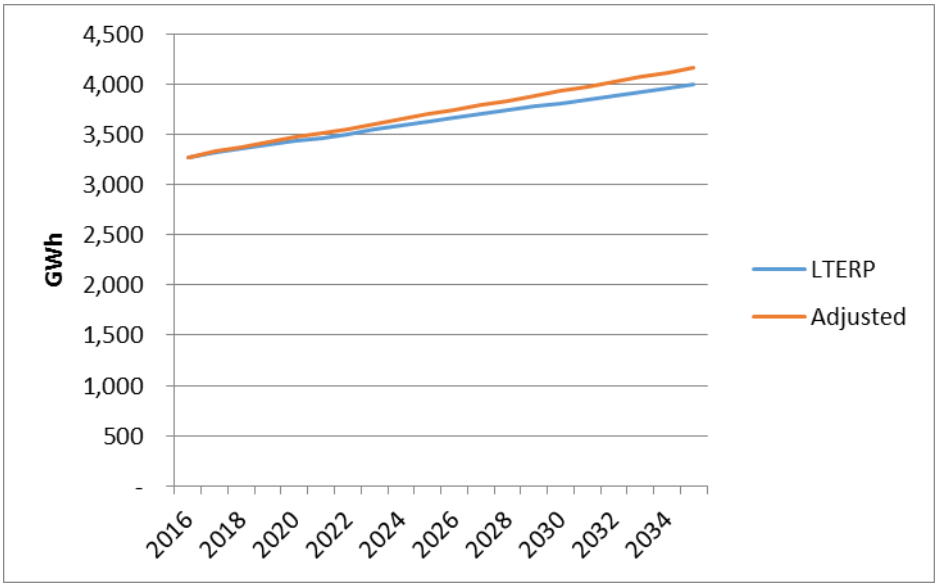
Table 1: Impact to UPC and Residential Load with Before-Savings Annual UPC Increased by 0.5 Percent

Year	Before-Savings UPC (MWh)			Residential Load (MWh)		
	A	B = B + (B * 0.05)	C	D = B * C	E	F = D - E
	LTERP	0.5% Annual Decrease	Average Customer Count	Before-Savings	Savings	After-Savings
2016	11.80	11.86	114,623	1,359,313	1,478	1,357,834
2017	11.80	11.92	115,555	1,377,223	256	1,376,968
2018	11.80	11.98	116,503	1,395,462	-1,837	1,397,299
2019	11.80	12.04	117,449	1,413,820	-5,349	1,419,169
2020	11.80	12.10	118,399	1,432,390	-8,363	1,440,752
2021	11.80	12.16	119,356	1,451,181	-10,102	1,461,283
2022	11.80	12.22	120,317	1,470,181	-10,451	1,480,633
2023	11.80	12.28	121,272	1,489,261	-11,451	1,500,711
2024	11.80	12.34	122,207	1,508,249	-12,462	1,520,711
2025	11.80	12.40	123,129	1,527,229	-13,484	1,540,713
2026	11.80	12.47	124,041	1,546,232	-14,516	1,560,749
2027	11.80	12.53	124,935	1,565,155	-15,561	1,580,716
2028	11.80	12.59	125,808	1,583,979	-16,617	1,600,596
2029	11.80	12.65	126,660	1,602,684	-17,685	1,620,369
2030	11.80	12.72	127,488	1,621,217	-18,765	1,639,982
2031	11.80	12.78	128,292	1,639,602	-19,858	1,659,460
2032	11.80	12.84	129,077	1,657,877	-20,963	1,678,840
2033	11.80	12.91	129,839	1,676,012	-22,080	1,698,092
2034	11.80	12.97	130,579	1,693,992	-23,210	1,717,201
2035	11.80	13.04	131,293	1,711,771	-24,352	1,736,123

Table 2: Impact to Residential, Net and Gross Loads with Before-Savings Annual UPC Increased by 0.5 Percent

YEAR	Residential Forecast (GWh)			Net Load (GWh)			Gross Load (GWh)		
	LTERP	Adjusted	Change	LTERP	Adjusted	Change	LTERP	Adjusted	Change
2016	1,351	1,358	0.5%	3,264	3,270	0.2%	3,544	3,552	0.2%
2017	1,363	1,377	1.0%	3,314	3,328	0.4%	3,595	3,610	0.4%
2018	1,377	1,397	1.5%	3,353	3,373	0.6%	3,633	3,656	0.6%
2019	1,391	1,419	2.0%	3,394	3,422	0.8%	3,676	3,706	0.8%
2020	1,405	1,441	2.5%	3,432	3,467	1.0%	3,715	3,753	1.0%
2021	1,418	1,461	3.0%	3,465	3,508	1.2%	3,750	3,797	1.2%
2022	1,431	1,481	3.5%	3,505	3,555	1.4%	3,794	3,848	1.4%
2023	1,443	1,501	4.0%	3,547	3,605	1.6%	3,839	3,902	1.6%
2024	1,455	1,521	4.5%	3,585	3,650	1.8%	3,880	3,951	1.8%
2025	1,467	1,541	5.0%	3,624	3,697	2.0%	3,922	4,002	2.0%
2026	1,479	1,561	5.5%	3,663	3,744	2.2%	3,965	4,054	2.2%
2027	1,491	1,581	6.0%	3,700	3,790	2.4%	4,005	4,103	2.4%
2028	1,502	1,601	6.6%	3,738	3,836	2.6%	4,046	4,154	2.6%
2029	1,513	1,620	7.1%	3,776	3,883	2.8%	4,088	4,204	2.8%
2030	1,524	1,640	7.6%	3,811	3,927	3.0%	4,126	4,252	3.1%
2031	1,535	1,659	8.1%	3,848	3,972	3.2%	4,166	4,301	3.3%
2032	1,545	1,679	8.6%	3,886	4,020	3.4%	4,207	4,353	3.5%
2033	1,555	1,698	9.2%	3,925	4,068	3.6%	4,250	4,405	3.6%
2034	1,565	1,717	9.7%	3,964	4,116	3.8%	4,292	4,457	3.8%
2035	1,575	1,736	10.2%	4,003	4,164	4.0%	4,334	4,509	4.0%

Figure 1: Net Load Forecast LTERP vs. Adjusted with Before-Savings Annual UPC Increased by 0.5 Percent



As shown in the table and figure above, a compounding 0.5 percent increase in the residential UPC results in a residential load estimate that is more than 10 percent higher by 2035 than the forecast as filed. In terms of overall net load, the impact is 4 percent.

57.0 Reference: LONG-TERM LOAD FORECAST

Exhibit B-1, Volume 1, Appendix E, p. 4 and p. 11;

Exhibit B-2, BCUC IR 16.1, pp. 58-60

Wholesale customer forecast accuracy and materiality

On page 4 of Appendix E of the Application, FBC presents a pie chart showing that wholesale customers accounted for 16.8 percent of 2015 gross load consumption. On page 11 of Appendix E in the Application, FBC explains that the wholesale class is forecast using survey information from each of the individual wholesale customers.

In response to BCUC IR 16.1, FBC presented a table which included the load variance for each wholesale customer from 2014 to 2016, which was calculated by comparing the after-DSM 2012 LTRP forecast load to the normalized actual load. This table showed that the average variance for Penticton normalized actual load for 2014, 2015 and 2016 was -6%.

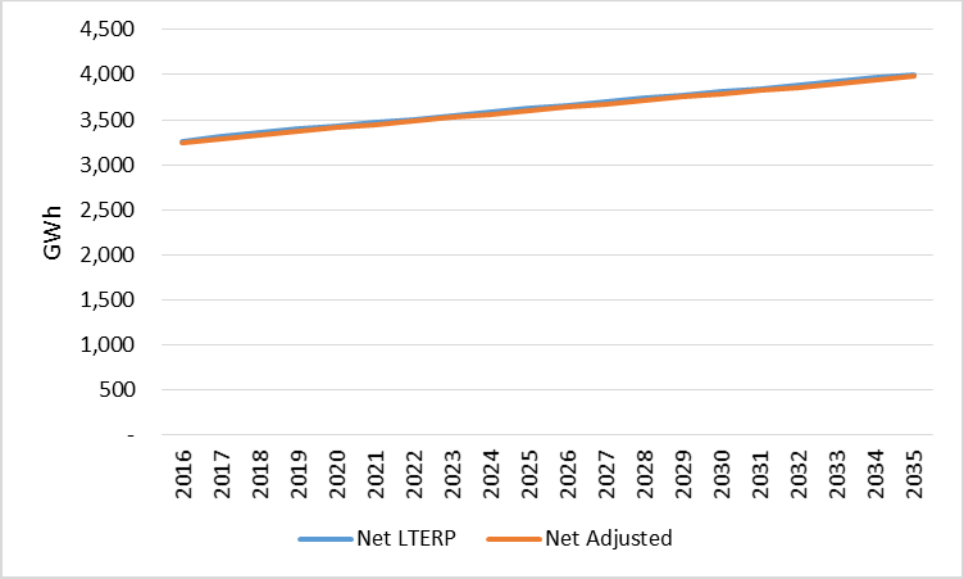
57.1 Please calculate the impact to the (i) wholesale load forecast, (ii) total gross load forecast, and (iii) total net load forecast (presented in Appendix F of the Application) if the Penticton load forecast for each year in the planning period was 6 percent less than forecast in the Application. Please provide the necessary tables and charts with your response.

Response:

Table 1: Impact to Wholesale, Net and Gross Loads with Before-Savings with City of Penticton Load Decreased by Six Percent

	Wholesale Forecast (GWh)			Net Load (GWh)			Gross Load (GWh)		
	LTERP	Adjusted	Change	LTERP	Adjusted	Change	LTERP	Adjusted	Change
2016	588	567	-3.6%	3,264	3,243	-0.6%	3,544	3,522	-0.6%
2017	589	568	-3.6%	3,314	3,293	-0.7%	3,595	3,571	-0.7%
2018	592	571	-3.6%	3,353	3,331	-0.7%	3,633	3,609	-0.7%
2019	597	576	-3.6%	3,394	3,372	-0.7%	3,676	3,651	-0.7%
2020	602	581	-3.6%	3,432	3,410	-0.7%	3,715	3,690	-0.7%
2021	606	584	-3.6%	3,465	3,443	-0.6%	3,750	3,726	-0.7%
2022	610	588	-3.6%	3,505	3,482	-0.6%	3,794	3,769	-0.7%
2023	613	591	-3.6%	3,547	3,524	-0.6%	3,839	3,814	-0.7%
2024	617	595	-3.6%	3,585	3,562	-0.6%	3,880	3,855	-0.7%
2025	621	598	-3.6%	3,624	3,601	-0.6%	3,922	3,897	-0.6%
2026	624	602	-3.6%	3,663	3,639	-0.6%	3,965	3,939	-0.6%
2027	628	605	-3.6%	3,700	3,677	-0.6%	4,005	3,979	-0.6%
2028	632	609	-3.6%	3,738	3,714	-0.6%	4,046	4,020	-0.6%
2029	636	613	-3.6%	3,776	3,752	-0.6%	4,088	4,062	-0.6%
2030	639	616	-3.6%	3,811	3,787	-0.6%	4,126	4,100	-0.6%
2031	643	620	-3.6%	3,848	3,824	-0.6%	4,166	4,139	-0.6%
2032	647	624	-3.6%	3,886	3,862	-0.6%	4,207	4,181	-0.6%
2033	651	627	-3.6%	3,925	3,901	-0.6%	4,250	4,223	-0.6%
2034	655	631	-3.6%	3,964	3,939	-0.6%	4,292	4,265	-0.6%
2035	659	635	-3.6%	4,003	3,978	-0.6%	4,334	4,307	-0.6%

Figure 1: Net LTERP Load Compared to Net Load with City of Penticton Load Decreased by Six Percent

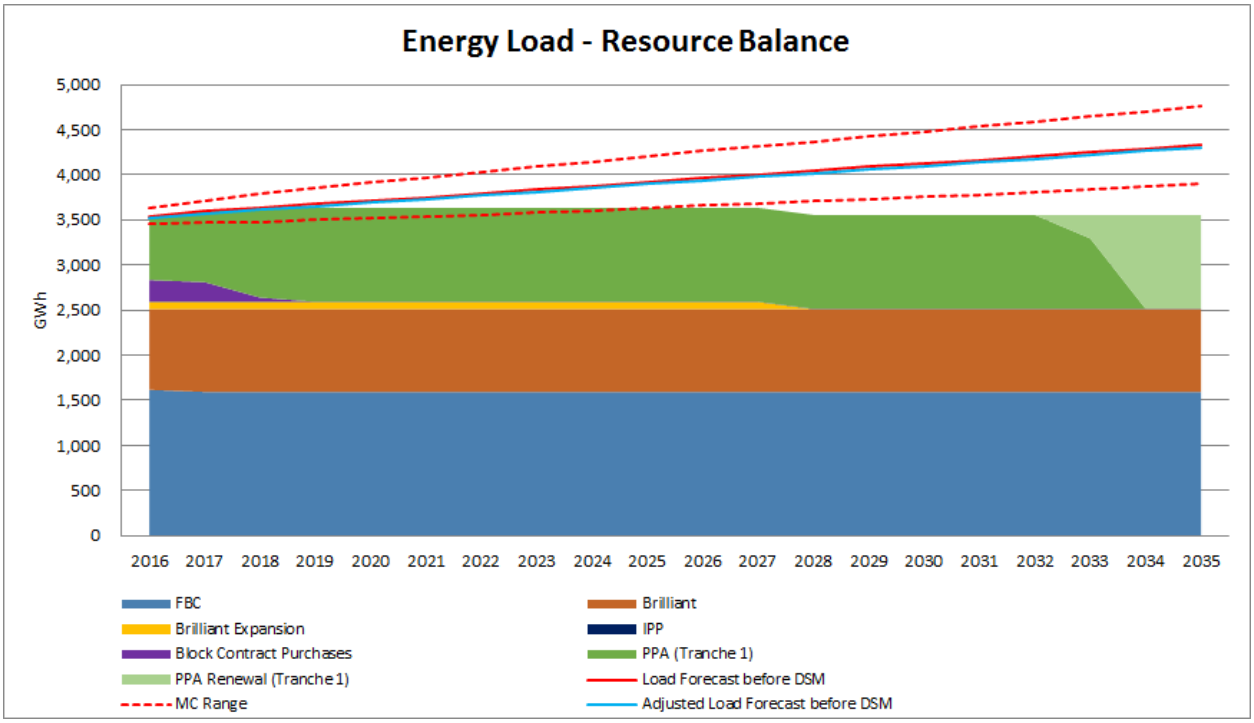


A decline of 6 percent in the Penticton load results in a 3.6 percent decline in the total wholesale load and a 0.6 percent decline in the net load in 2035.

57.1.1 Please discuss, and provide updates where necessary, whether this would impact the FBC's load-resource balance as seen in figure 7-1 in the Application.

Response:

The impacts discussed in the response to BCUC IR 2.57.1 would not have a material impact on FBC's LRB as seen in Figure 7-1 of the LTERP. An updated version of this figure is provided below showing the adjusted load forecast in light blue.



The impact is immaterial because the impact of the 6 percent lower load forecast for Penticton results in a less than 1 percent impact on the overall net load forecast.

C. CHAPTER 6 – TRANSMISSION AND DISTRIBUTION SYSTEM

58.0 Reference: RECENT SYSTEM UPGRADES AND EXPENDITURES

Exhibit B-2, BCUC IR 21.1, 21.1.1, 22.1

Capital Expenditures and Long Term Capital Plan

In response to BCUC IR 21.1, FBC provided a table containing the current plan for capital expenditures covering the next five years. For Commission IR 21.1.1, FBC's response listed three projects it intends to construct or extend in order to serve the estimated demand in the next four years: Sexsmith Second Distribution Transformer Addition, DG Bell Distribution Transformer Addition, and DG Bell Feeder 4 Addition.

Further, in response to BCUC IR 22.1, FBC states it "confirms that it is not filing a long term capital plan under this proceeding" and that it "is currently reviewing the timing for filing of future capital plans and does not have a specific filing date at this time."

58.1 Please confirm that for each of the three capital expenditure projects listed, FBC intends to file the projects under UCA section 44.2? If so, what would be the general filing timeframe?

Response:

The specific approvals required will be determined prior to undertaking the projects, but at this time the exact timing and scope of the projects has not been confirmed.

58.2 Please confirm that FBC is not requesting Commission acceptance of these projects in this proceeding. If not confirmed, please discuss.

Response:

Confirmed. FBC is not requesting Commission acceptance of the referenced projects from the response to BCUC IR 1.21.1.1 in this proceeding.

59.0 Reference: ANTICIPATED SYSTEM REINFORCEMENTS

Exhibit B-1, Section 3.2.1, p. 53; Exhibit B-2, BCUC IR 22.2; Resource Planning Guidelines [1]

Transmission Project CPCNs and the Action Plan

The Commission's Resource Planning Guidelines states the action plan "consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years to meet the most likely gross demand forecast." [emphasis added]

In response to Commission IR 22.2 explaining why Grand Forks Terminal Transformer Addition Certificate of Public Convenience and Necessity (CPCN) and Kelowna Bulk Transformer Capacity Addition CPCN are not on the Action Plan, FBC stated it "included in its Action Plan only activities and actions specific to the acquisition of new energy and capacity resources, which are reflected in the selected portfolio, to meet the requirements of its customers." [emphasis added]

FBC further described the Kelowna Bulk Transformer Capacity Addition CPCN in response to Commission IR 22.3 as a project "needed to adequately serve Kelowna area load in a single contingency" and that "without additional bulk transformation capacity, this may require load shedding as Kelowna load increases".

In its application on page 53, FBC states it's "reference case load forecast anticipates a modest rate of load growth over the twenty-year planning horizon of the LTERP. The Company is forecasting an increase in gross load from 3,544 GWh in 2016 to 4,334 GWh by 2035..." [emphasis added]

59.1 Please confirm the "most likely gross demand forecast" for FBC is the "reference case load forecast" which is an "increase in gross load from 3,544 GWh in 2016 to 4,334 GWh by 2035".

Response:

Confirmed.

[1] http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf

59.2 Is the Kelowna Bulk Transformer Capacity addition CPCN to replace an existing transformer with a higher capacity one or is it intended to add a new transformer? Please describe.

Response:

The Kelowna Bulk Transformer Capacity Addition project scope includes the addition of a new transformer to adequately serve Kelowna area load in a single contingency. Replacing a single transformer with a higher capacity one would not mitigate the issue described in the response to BCUC IR 1.22.3.

59.3 If the Kelowna Bulk Transformer Capacity is to add a new transformer and is included in the most likely gross demand forecast:

59.3.1 Please explain whether this project is related to load growth. If no, please discuss.

Response:

Yes, this project is related to load growth in the Kelowna area.

59.3.2 Please explain whether FBC consider adding a new transformer to increase Kelowna bulk transformer capacity in an existing station as a "new energy and capacity resource". If no, please discuss.

Response:

No, FBC does not consider adding a new transformer to be a new energy and capacity resource. While transformers and transmission infrastructure can help mitigate capacity issues in constrained areas of the FBC electric system, they do not provide additional electricity generation like supply-side energy or capacity resources.

59.3.3 If the project is related to load growth and is a new energy and capacity resource, does FBC consider Kelowna Bulk Transformer Capacity Addition CPCN should be added to the Action Plan?

Response:

FBC does not consider that the Action Plan should be revised to add the Kelowna Bulk Transformer Capacity Addition CPCN application. As noted in the response to BCUC IR 2.59.3.2, FBC does not consider adding a new transformer to be a "new energy and capacity resource". Furthermore, FBC explained in its response to BCUC IR 1.22.2:

> As described in the Resource Planning Guidelines, the action plan "consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years to meet the most likely gross demand forecast."
>
> FBC therefore included in its Action Plan only activities and actions specific to the acquisition of new energy and capacity resources, which are reflected in the selected portfolio, to meet the requirements of its customers. FBC will seek Commission approval of these projects prior to their commencement.

D. CHAPTER 8 – RESOURCE OPTIONS

60.0 Reference: RESOURCE OPTIONS

Exhibit B-1, Volume 1, Table 8-3, p. 108; Table 8-4, p. 109; p. 127

Wood-Based Biomass

The following information was extracted from Tables 8-3 and 8-4 in the Application.

Resource Option	Wood-Based Biomass	Biogas
Type	Baseload	Baseload
Dependable Capacity (MW)	12 - 63	1 - 2
Annual Energy (GWh)	98 - 503	7 - 18
Clean/Renewable	Yes	Yes
Socio-Economic Benefits	High	Medium
Unit Energy Cost ($/MWh)	$118 - $188	$77 - $101
Unit Capacity Cost ($kW-year)	$663 - $774	$621 - $838

On page 127 of the Application, FBC explained that portfolio A4 best meets the LTERP objectives and is FBC's preferred portfolio. The incremental resources in portfolio A4 comprise of market (31%), wind (65%), biogas (3%) and simple cycle gas turbine (SCGT) (1%). Portfolio A4 has a LRMC of $96 per MWh.

60.1 Please explain and quantify the impact to the LRMC for portfolio A4, of using wood-based biomass to replace biogas.

Response:

Replacing biogas with wood-based biomass increases the LRMC from $96 per MWh to $101 per MWh. To respond to this question, FBC included the wood-based biomass resource in the preferred resource portfolio in the year 2031. The particular wood-based biomass resource selected has a UEC of $118 per MWh (the lowest UEC among the wood-based biomass resource options evaluated by FBC in its Resource Options Report in Appendix J of the LTERP) and an installed capacity of 26 MW. The year 2031 was selected to introduce the resource into the portfolio as this is the same year the two biogas resources are optimally dispatched in portfolio A4. The UECs of the two biogas resources in portfolio A4 are $77 per MWh and $88 per MWh. The increase in both fixed capital costs and variable energy costs associated with the wood-based biomass resource leads to an increase in the LRMC of the portfolio. The incremental energy resources included in this portfolio are wood-based biomass (13 percent), wind (59 percent) and market (28 percent).

60.2 Please explain and quantify the impact to the LRMC for portfolio A4, of combining wood-based biomass and biogas equally to provide a total of 3% of incremental resources for portfolio A4.

Response:

The smallest wood-based biomass resource option evaluated by FBC in its Resource Options Report in Appendix J of the LTERP has an installed capacity of 12 MW and a UEC of $188 per MWh (as shown in Tables 8-3 and 8-4 of the LTERP). In contrast, the biogas resource options contained in the portfolio range in installed capacity between 1 MW and 2 MW. Consequently, it is unreasonable to combine the smallest wood-based biomass resource option and one or more biogas resource options equally to provide a total of 3 percent of incremental energy resources for portfolio A4. FBC does not have detailed cost information for a biomass resource option smaller than one with 12 MW of installed capacity.

60.3 Please discuss the considerations that were made to use biogas to supply 3% of the incremental resources in FBC's preferred portfolio, when compared to wood-based biomass. In your response please be sure to include a discussion of the environmental attributes, the socio-economic attributes and the availability of fuel.

Response:

As discussed in the response to CEC IR 1.23.2, FBC developed a resource portfolio model that incorporates an optimization routine to identify the lowest present value cost of combining resource options given a set of constraints. The wood-based biomass resource option is a significantly larger plant than the two biogas resource options included in portfolio A4, which leads to a greater capital cost in the portfolio. Additionally, the variable energy cost of biomass is greater than biogas. Biogas energy is generated from the decomposition of organic waste with the resulting methane gas captured and used as a fuel source. In contrast, wood-based biomass variable costs are higher, reflecting the transportation and storage of wood-based fuel products to the plant (as discussed in Section 3.1.1 of Appendix J of the LTERP). The output of the optimization routine resulted in a biogas dispatch equal to approximately 3 percent of the incremental energy resources in FBC's preferred portfolio. Please also refer to the responses to BCUC IRs 2.60.1 and 2.60.2.

As wood-based biomass and biogas are both considered to be clean or renewable under the *Clean Energy Act* (see Table 8-3 of the LTERP), these resource options were both available to

be selected in the FBC portfolio analysis in meeting the requirement for at least 93 percent clean and renewable energy.

The socio-economic attributes and the availability of the fuel source were not a consideration in the portfolio analysis in determining the mix of resources for the preferred portfolio. The socio-economic benefits factor, represented by Full-time equivalents (FTEs) per year, was a consideration in determining the preferred portfolio from several considered portfolios (as discussed in Section 9.3.6 of the LTERP). The biomass and biogas resource options FBC considered have FTEs that fall into the high to medium categories as shown in Table 8-3 of the LTERP.

The availability of biomass is generally forecast to decline in B.C. over time but availability in the Kootenay region is projected to remain constant through 2040 per Appendix J, Figures J3-3, J3-4 and J3-5 of the LTERP. Biogas potential depends on availability of landfill sites, sewage treatment plants and organic waste processing facilities (per Appendix J, Section 3.1.2) and the resource options collaboration with BC Hydro identified a dozen potential sites.

61.0 Reference: RESOURCE OPTIONS

Exhibit B-1, Volume 1, Table 9-2, p. 126; p. 127; Table 8-4, p. 109;

Exhibit B-2, BCUC IR 26.1, pp. 88-90; BCUC IR 26.3, pp. 91-92

Expiring Energy Purchase Agreements

In response to BCUC IR 26.3, FBC stated:

> BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. BC Hydro expects to negotiate a lower energy price than the initial EPAs … In its 2016 RDA, BC Hydro noted that the costs for service for IPPs can vary significantly and that it expects cost differences for biomass renewals and run-of-river renewals, with biomass having greater ongoing costs for operations. However, BC Hydro also estimated that the renewal volumes in the plan could be acquired at or below the LRMC of $85 per MWh. … The non-renewed EPAs will likely be higher cost resources.

Table 8-4 on page 109 of the Application shows the supply-side resource options unit cost summary, which includes the unit energy cost (UEC) and the unit capacity cost (UCC) for wind and biogas.

Table 9-2 on page 126 of the Application shows the attributes of portfolios that FBC considered for the preferred portfolio. On page 127 of the Application, FBC explained that portfolio A4 best meets the LTERP objectives and is FBC's preferred portfolio. Portfolio A4 has a LRMC of $96 per MWh and includes market, wind, biogas and SCGT.

In response to BCUC IR 26.1, FBC estimated that the amount of expiring EPA energy and capacity available to the market by the end of F2024 to be 450 GWh of energy and 147 MW of peak capacity.

61.1 Please explain the possibility that the non-renewed EPAs could be procured at or below BC Hydro's LRMC of $85 per MWh while still being a higher cost resource than BC Hydro's renewed EPA's. For example, is it possible that BC Hydro's renewed EPAs have a maximum energy cost of $70 per MWh and that the non-renewed EPAs could be obtained by FBC for a maximum energy cost of $80 per MWh?

Response:

According to BC Hydro's filings in its F2017 to F2019 RRA, fourteen of its existing EPAs with IPPs are expiring by the end of fiscal 2019.[2] BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 per cent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 2013 10 Year Rates Plan.[3]

As described in the question, BC Hydro is targeting renewal of contracts for those facilities that have the lowest cost, greatest certainty of continued operation and best system support characteristics. BC Hydro expects to negotiate a lower energy price than the initial EPA.[4] In its EPA renewal negotiations, BC Hydro will consider the IPPs' opportunity cost, the electricity spot market, the cost of service for the IPPs (including fibre supply costs for biomass facilities) and other factors such as the attributes of the energy produced and other non-energy benefits.[5]

BC Hydro defines its LRMC as the price for acquiring resources to meet incremental customer demand beyond existing and committed resources. A consideration in setting the LRMC is providing a steady and consistent price signal for determining/screening the cost-effectiveness of different resources. ***BC Hydro does not expect to acquire all available resources up to the LRMC, nor does it expect the LRMC to be the clearing price.***[6] Therefore it is possible that non-renewed EPAs could be procured at or below BC Hydro's LRMC of $85 per MWh while still being a higher cost resource than BC Hydro's renewed EPAs.

BC Hydro renewal contracts negotiations are confidential, and FBC does not know which EPAs will not be renewed. In addition, FBC would not know the operating and maintenance costs and undepreciated capital costs of those plants. Therefore, FBC does not have the information needed to calculate the feasibility of non-renewed BC Hydro EPAs having a cost lower than the UECs identified in Table 8-4 of the LTERP.

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[2] BC Hydro F2017 to F2019 Revenue Requirements Application, Exhibit B-1-1, Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 1-26, lines 21-22.

[3] BC Hydro F2017 to F2019 Revenue Requirements Application, Exhibit B-1-1, Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 1-29, lines 23-26.

[4] BC Hydro F2017 to F2019 Revenue Requirements Application, Exhibit B-1-1, Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 1-30, lines 1-7.

[5] BC Hydro F2017 to F2019 Revenue Requirements Application, Exhibit B-1-1, Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 1-27, lines 7-11.

[6] BC Hydro F2017 to F2019 Revenue Requirements Application, Exhibit B-1-1, Letter dated July 28, 2016 – BC Hydro Submitting Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, page 3-45, lines 20-16.

61.2 Please explain the feasibility of non-renewed BC Hydro EPAs having a cost lower than the UECs identified in Table 8-4 of the Application for (i) wind, and (ii) biogas. Please include calculations with your response.

Response:

Please refer to the response to BCUC IR 2.61.1.

61.2.1 Please explain the impact to FBC's preferred portfolio if FBC procured half of the energy available to the market from expiring non-renewed BC Hydro EPAs and did so at a cost lower than the UEC for both wind and biogas. Please include calculations with your response and an updated version of Table 9-2 on page 126 of the Application.

Response:

To estimate the impact to FBC's preferred portfolio additional details are required, specifically the anticipated performance profile of the particular resource being considered, information regarding the operational costs, and the terms of the agreement. The UEC is a high level metric that does not consider the timing of when the capacity and energy of the resource will be delivered, or the corresponding impact on other resources in the portfolio.

It is possible that an expiring BC Hydro EPA could replace a portion the energy generated by the wind or biogas resources in portfolio A4 (for example, half of the energy available to the market from the given BC Hydro expiring EPA resource), but the impact on the composition and corresponding costs of FBC's preferred portfolio as a whole depends on the monthly capacity and energy profiles of the particular resource, most notably the quantity of winter energy delivered. Furthermore, once a particular resource is acquired, the extent the resource is utilized within the portfolio is not only dependent on the time of need, but also the variable energy cost and/or terms of the agreement. As the performance profiles and variable energy costs of the resource types can vary (e.g. the performance profile of run-of-river versus biomass), it is not possible to assess the change in the preferred portfolio by simply including energy that has a lower UEC than wind or biogas.

E. CHAPTER 9 – PORTFOLIO ANALYSIS AND LONG RUN MARGINAL COST

62.0 Reference: PORTFOLIO ANALYSIS

Exhibit B-1, Volume 1, p. 47; Table 9-2, p. 126;

Exhibit B-2, BCUC IR 6.1, pp. 15-16

Tranche 1 Power Purchase Agreement (PPA) high rate scenario

On page 47 of the Application, FBC states:

> In order to estimate the potential costs for the BC Hydro PPA in the future, FBC has developed some PPA scenarios based on annual percentage increases in residential rates and BC Hydro's LRMC. … In the low case, rate increases keep up with inflation of about 2 percent per year and so rates do not increase in real terms … In the base case, rate increases are 1 percent per year in real terms. In the high case, rate increases are 3 percent in real terms.

Table 9-2 on page 126 of the Application shows the attributes of portfolios that FBC considered for the preferred portfolio.

62.1 Please state whether the LRMC figures in Table 9-2 was calculated using the base case PPA rate scenario.

Response:

Confirmed.

62.1.1 If the LRMC figures in Table 9-2 are based on the base case PPA rate scenario, please present an updated version of Table 9-2 based on the high PPA rate scenario.

Response:

The following figure includes the portfolios listed in Table 9-2 of the LTERP, updated to include the high PPA rate scenario instead of the base case rate scenario.

Portfolio		Incremental Resources	LRMC ($/MWh)	Max % Non-Clean BC Resources (based on energy)	GHG emissions produced in BC (tonnes CO2e)	Full-Time Equivalents per year	Geographic Resource Diversity	Comments
A1	No Self-Sufficiency	Market (98%) Biogas (2%)	$84	0.0%	0	7	Low	LT market supply access and price risks
C1	93% Clean with CCGT	Market (44%) CCGT (53%) Biogas (3%)	$96	7.0%	339k	164	Medium	Gas and carbon price risks
A4	93% Clean with SCGT	Market (39%) Wind (57%) Biogas (3%) SCGT (1%)	$100	0.2%	3k	145	High	Minimal gas and carbon price risks
C4	100% Clean BC Resources	Market (35%) Wind (53%) Biomass (12%)	$103	0.0%	0	249	High	Higher cost, lower reliability than with CCGT or SCGT

62.1.1.1 If the high PPA rate scenario occurred, please discuss which portfolio would best meet the LTERP objectives and would be FBC's preferred portfolio.

Response:

Based on the results provided in the response to BCUC IR 2.62.1.1, Portfolio A4 is still the preferred portfolio as it best meets the LTERP objectives in terms of balancing cost, reliability and geographic diversity with B.C.'s energy objectives.

63.0 Reference: INFORMING Annual Electric Contracting Plan (AECP)/ENERGY SUPPLY CONTRACTS

Exhibit B-2, BCUC IR 5.2, 30.1, 30.1.1, 30.2, 30.3, 51.2.1; Exhibit B-3, BCOAPO IR 38.0-41.0

Reliance on the market

FBC states in BCUC IR 30.3 that relying on the market is no longer a low cost/low risk strategy in the long term.

FBC states in BCUC IR 5.2: "The main metrics FBC uses to establish achievement of its strategy of making market purchases to close the gap between supply and demand are reliability, cost effectiveness and consistency with provincial energy objectives."

FBC provides schedules of annual costs for portfolios modelled in BCOAPO IR 38.0-41.0 series. FBC calculates the percentage of total energy after planned DSM served by the market in Table 1 of BCUC IR 30.1, and the percentage if BC were to make no further market purchases in BCUC IR 30.1.1.

FBC provides a comparison of the energy rates of FBC's main rate schedules to the long-run marginal cost (LRMC) of Portfolio A4 in BCUC IR 51.2.1.

FBC states in BCUC IR 30.2: "FBC could also expand the net metering program, but does not expect that such a supply would significantly change LTERP requirements … The company believes that DSM resources are reliable but non-firm and thus does not believe it is prudent to expand DSM beyond that."

63.1 Please provide in table form a comparison of annual expenditures for market energy for each year from 2017 to 2021 (including a portfolio total for), for each of FBC's portfolio modelled. Please provide additional rows showing (i) the average market price assumed over those years for each portfolio, and (ii) the average BC Hydro PPA Tranche 1 price. Please identify the portfolio(s) that use the same market price assumptions as portfolio A4 but show significant variation in reliance on the market to meet energy needs for the period 2017-2021.

Response:

The following tables show the annual expenditures for market energy by year as well as the weighted average market prices and blended PPA rates. The tables are organized according to how the portfolios are categorized in Section 9.3 of the LTERP. Table 1 includes portfolios based on different levels of DSM (per Section 9.3.1 of the LTERP) and different levels of market reliance (per Section 9.3.2 of the LTERP). Table 2 includes portfolios with different levels of clean or renewable resources (per Section 9.3.3 of the LTERP), varying load requirements (per

Section 9.3.4 of the LTERP) and with and without PPA renewal (per Section 9.3.5 of the LTERP).

Table 1: 2017-2021 Annual Expenditures[7] for Market Energy: Portfolios A4, B1, B2, B4, A1, A2, and A3.

	A4 (in '000s)	B1 (in '000s)	B2 (in '000s)	B4 (in '000s)	A1 (in '000s)	A2 (in '000s)	A3 (in '000s)
2017	$ 5,607	$ 5,952	$ 5,607	$ 5,607	$ 5,607	$ 3,525	$ 5,607
2018	$ 13,136	$ 13,776	$ 13,136	$ 13,136	$ 13,136	$ 5,055	$ 13,136
2019	$ 13,475	$ 14,000	$ 13,475	$ 13,475	$ 13,475	$ 4,493	$ 13,475
2020	$ 12,646	$ 13,063	$ 12,646	$ 12,646	$ 12,646	$ 2,038	$ 13,165
2021	$ 10,565	$ 13,309	$ 10,593	$ 10,565	$ 10,565	$ 1,038	$ -
Weighted Average Market Price (per MWh)	$ 53.72	$ 54.88	$ 53.72	$ 53.72	$ 53.72	$ 62.27	$ 52.91
PPA Blended Rate (per MWh)	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58

Table 2: 2017-2021 Annual Expenditures[1] for Market Energy: Portfolios C1, C3, C4, D2, D4, E1, E2, E3, and E4.

	C1 (in '000s)	C3 (in '000s)	C4 (in '000s)	D2 (in '000s)	D4 (in '000s)	E1 (in '000s)	E2 (in '000s)	E3 (in '000s)	E4 (in '000s)
2017	$ 5,607	$ 3,525	$ 5,607	$ 5,624	$ 5,624	$ 5,607	$ 5,607	$ 5,607	$ 5,607
2018	$ 13,136	$ 5,055	$ 13,136	$ 13,155	$ 13,155	$ 13,136	$ 13,136	$ 13,136	$ 13,136
2019	$ 13,475	$ 4,493	$ 13,475	$ 13,355	$ 13,355	$ 13,475	$ 13,475	$ 15,612	$ 13,475
2020	$ 12,646	$ 2,038	$ 12,646	$ 12,366	$ 12,366	$ 12,646	$ 12,646	$ 15,871	$ 12,646
2021	$ 10,565	$ 1,038	$ 10,565	$ 11,859	$ 11,859	$ 10,565	$ 10,565	$ 12,914	$ 10,565
Weighted Average Market Price (per MWh)	$ 53.72	$ 62.27	$ 53.72	$ 54.76	$ 54.76	$ 53.72	$ 53.72	$ 53.10	$ 53.72
PPA Blended Rate (per MWh)	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 58.58	$ 59.80	$ 58.58

The weighted average market price[8] and blended PPA rate for the years 2017-2021 are more appropriate comparative values[9]. The blended PPA rate reflects the bundled nature of the PPA product and market activity is able to provide both PPA energy and PPA capacity savings. Portfolios A2 and C3 assume the high Mid-C pricing scenario; all other portfolios assume the base Mid-C pricing scenario. Portfolio D2 and D4 share the same market price assumptions as portfolio A4, but investigate high load scenarios, therefore load requirements to be served by supply-side resources, including market purchases, are increased. Portfolio B1 shares the same market price assumptions as portfolio A4, but includes no DSM, therefore load requirements to be served by supply side resources, including market purchases, are increased. Portfolio E3 shares the same market price assumptions as portfolio A4, but assumes the high PPA cost scenario and so more market purchases are selected. Portfolio A3 includes a self-sufficiency target of 2020, therefore no market access is permitted in 2021.

[7] Values in 2015$

[8] Total portfolio model determined market costs in the years 2017-2021 divided by the market energy (excluding existing and committed blocks) in the years 2017-2021

[9] For completeness, the average market price for the base Mid-C scenario for the period 2017-2021 is $46.33 per MWh (2015$) and the average PPA Tranche 1 price for the period 2017-2021 is $47.47 per MWh based on values tabled in Appendix D of the LTERP.

63.1.1 In table and graphical form, please show FBC market purchases for the previous five years (2012-2016), those proposed for 2017-2021 in portfolio A4, and those proposed for any significantly different alternative portfolio(s) identified above (i.e., same market price assumption but significantly different market energy purchase volumes). Please explain any change in historical/forecast market purchases over time.

Response:

Please refer to Figure 1 below as well as Table 1.

Figure 1

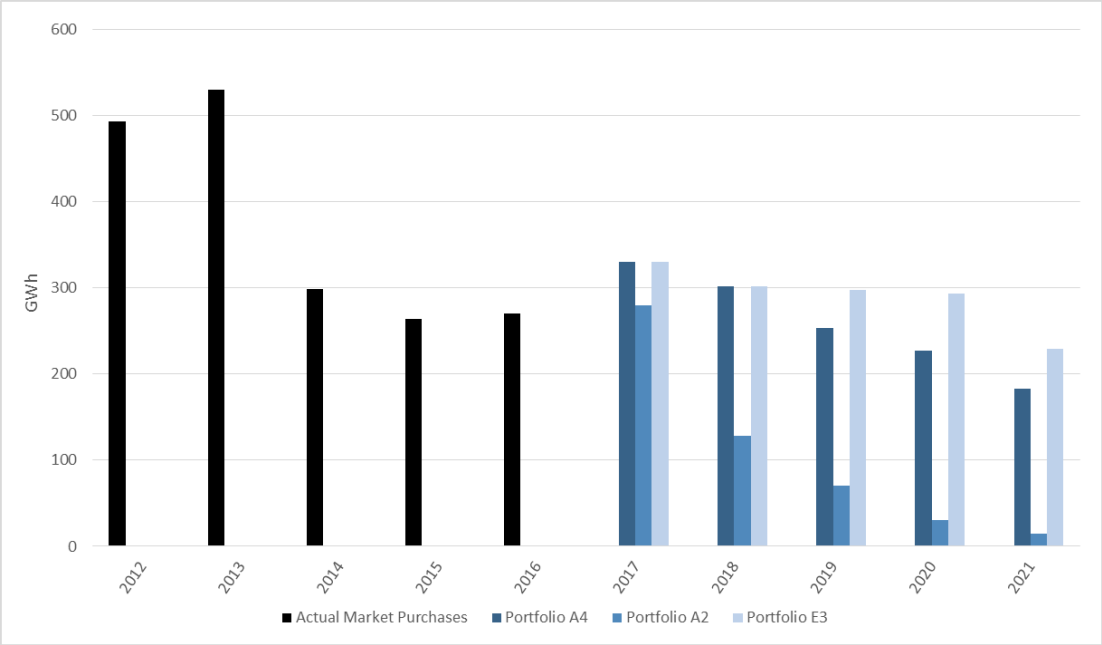


Table 1

	Actual Market Purchases (GWh)	Portfolio A4 (GWh)	Portfolio A2 (GWh)	Portfolio E3 (GWh)
2012	493			
2013	530			
2014	299			
2015	264			
2016	270			
2017		330	280	330
2018		301	128	301
2019		253	70	298
2020		227	30	294
2021		183	15	229

FBC's actual annual market purchase volumes have decreased since 2013. This is partially due to the new PPA with BC Hydro becoming effective July 1, 2014. Under the new PPA, FBC must nominate in advance its annual energy take prior to the contract year, and then take or pay for at least 75 percent of that annual volume. This has reduced the amount of flexibility available to FBC when purchasing from the market.

Also included in Figure 1 and Table 1 are the forecast market purchase volumes[10] under FBC's preferred Portfolio A4 as well as market purchases within Portfolio A2 and Portfolio E3. Portfolio A2 has lower market purchase volumes relative to other portfolios, whereas portfolio E3 has higher market purchase volumes relative to other portfolios. Portfolio A2 assumes a high Mid-C pricing scenario, which accounts for the lower volume of forecast market purchases. Portfolio E3 assumes a high PPA purchase price scenario with the base Mid-C pricing scenario, which accounts for the higher forecast volume of market purchases as market purchases become more economical relative to PPA. Portfolio A4 assumes the reference case load forecast, base case Mid-C prices, and base case PPA prices.

Although the forecast market purchases shown in the Figure 1 and Table 1 are for the next five years, the market purchase volumes from the LTERP are not intended to be prescriptive. FBC's short term market purchase strategy is outlined in the AECP and varies with real-time conditions. Please refer to the response to BCUC IRs 2.63.2 and 2.64.2 for further discussion.

[10] Market volumes reflect both existing market blocks, which are considered existing committed resources as well as the optimal market dispatch as determined by the optimization routine for the particular portfolio scenario.

63.1.2 Please explain whether (and if so how) FBC modelled in its LTERP greater/lesser reliance on the market (compared to BC clean energy) to meet energy needs over the next five years (2017-2021) in order to provide guidance for the Annual Electric Contracting Plan.

Response:

FBC did not model a greater or lesser reliance on the market to meet energy needs over the first five years of 2017-2021. The volume of market purchases in the LTERP is not intended to set the market volumes for FBC's future Annual Electric Contracting Plans (AECP).

Market use within the portfolios is determined by the optimization routine, which takes into account the high-level constraints of a particular portfolio scenario. These constraints include PPA pricing and the market energy pricing assumed over the planning horizon, as shown in Appendix D of the LTERP. By allowing the model the option to displace PPA, the various portfolio scenarios support the conclusion that optimizing the PPA and market purchases in the short term is cost effective in principle, thus providing high level guidance for the AECP.

63.2 Please estimate the annual and cumulative total over 2017-2021 (i) revenue requirement impact and (ii) rate impact if FBC purchases from the market aligned with those presented in the first column on Table 1 of BCUC IR 30.1.1, and the energy shortfall was made up BC Hydro PPA Tranche I purchases.

Response:

As discussed in the response to BCUC IR 2.63.1.2, the LTERP supports the conclusion that optimizing the PPA and market purchases in the short term is a cost-effective strategy, thus providing high level guidance for the Company's AECP.

The LTERP does not incorporate all the short-term flexibility that FBC has available to optimize its portfolio in the market. Furthermore, the market price forecast used in the LTERP is a flat monthly term forecast, and does not take into account fluctuations around the average monthly price, nor short term market conditions. For example, the current market prices in 2017 are lower than the forecast included in the LTERP due to the current high water year in 2017. Therefore, potential short-term rate impacts with respect to FBC's market activity should be illustrated with actual savings achieved, as opposed to market volumes identified on a planning basis within the LTERP portfolios.

FBC's access to market purchases provides significant value to its rate payers. For example, in 2016 FBC purchased 270 GWh of market energy and reduced power purchase expense by approximately $5.3 million. If the $5.3 million in savings due to FBC market access in 2016 had not been achieved, the incremental rate impact would be approximately 1.5 percent. Furthermore, actual savings can increase in years where FBC has comparatively more flexibility. For example, the winter of 2015/16 was very mild, resulting in FBC load being below forecast, and FBC using its 25 percent flexibility under the BC Hydro PPA to offset reduced load rather than to achieve market based savings. On the other hand, the winter of 2016/17 was colder than forecast and load was above forecast. This resulted in FBC being able to use its 25 percent flexibility under the BC Hydro PPA to take advantage of lower cost market purchases, further reducing power purchase expense.

The following table calculates the expected revenue requirement increase and associated rate impact for FBC's customers if market purchases were limited to the first column of Table 1 in BCUC IR 1.30.1.1 (6.08 percent in 2017 and 2.06 percent in 2018, which is based on the fixed price market blocks that FBC has already executed) and the remaining requirements were met with BC Hydro PPA tranche 1 energy purchases, rather than potentially lower cost market purchases. The total increased Power Purchase Expense over the 2017 to 2021 period is about $38.5 million and the total cumulative rate increase would be approximately 2.5 percent.

Table 1: Estimated revenue requirement and rate impact

Year	Forecast Increase to Power Purchase Expense ($ millions)	Forecast Annual Increase in Power Purchase Expense ($ millions)	Approximate Incremental Rate Increase
2017	5.296	5.296	1.46%
2018	6.806	1.510	0.42%
2019	8.497	1.691	0.47%
2020	8.857	0.360	0.10%
2021	9.043	0.187	0.05%

63.2.1 Please estimate how this response would change if market purchases were instead replaced with: (i) additional DSM (at FBC's utility cost of acquiring DSM), or (ii) additional distributed generation (DG) from a large commercial customer (not in excess of the customers annual consumption).

Response:

Portfolio A4 includes market purchases ranging in volume from 330 GWh to 183 GWh over the period 2017-2021. Incremental DSM activities cannot meet this level of load over the period as it is approximately 10 times the level of incremental annual DSM savings[11].

If it were possible to achieve this level of DSM savings, it could only be done by employing high cost DSM measures that when combined with the reduction in electricity sales to customers are anticipated to lead to rate impacts higher than those calculated in the response to BCUC IR 2.63.2.

FBC cannot calculate an expense or rate impact differential for the replacement of market purchases with DG from a large commercial customer because neither the price nor the attributes of the DG have been specified; however, the market is currently the least-cost option, therefore the scenario would result in an increase to customer rates.

63.3 Please explain the extent to which FBC, over the next 5 years, plans to rely on the market to meet above plan load, for example as a result of a colder than average weather.

Response:

If FBC's actual load for the next five years is greater than forecast, FBC will be required to meet the increased load with either incremental market purchases at the prevailing market rate or purchases under its PPA with BC Hydro. The amount that FBC will rely on market purchases will depend on whether the increases in load are related to peak capacity requirement or annual energy requirements. FBC expects that it will have sufficient peak capacity resources available to address any reasonable increases to peak demand compared to forecast over the next five years. For any increase to FBC's annual energy requirement above forecast, FBC will address the increase with either purchases under the PPA with BC Hydro that are above its annual energy nomination, or market purchases, whichever has the lowest total cost. However, FBC does have some flexibility in the timing of the purchases, and could use PPA energy to meet increased energy requirements in the winter, and then meet the shortage in annual energy requirement with potentially lower cost market purchases later in the contract year, which could help to lower total costs.

[11] Exhibit B-2, Response to BCUC IR 1.45.1.

64.0 Reference: INFORMING AECP/ENERGY SUPPLY CONTRACTS

Clean Energy Act section 6; Exhibit B-2, BCUC IR 4.1, 28.1, 30.1

BC self-sufficiency objective

The Clean Energy Act (CEA) in section 6 (4) states: "A public utility, in planning in accordance with section 44.1 of the *Utilities Commission Act* (UCA) for (a) the construction or extension of generation facilities, and (b) energy purchases, must consider British Columbia's energy objective to achieve electricity self-sufficiency."

The CEA also includes as a BC energy objective: "(c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources ..." FBC states in response to BCUC IR 4.1 that items in the Climate Leadership Plan (CLP) FBC considers relevant include: Requirement for 100 percent of BC Hydro electricity supply acquired in B.C. to be from clean or renewable sources.

In BCUC IR 30.1, FBC states in Table 1 that its energy purchases from sources that meet the CEA definition of self-sufficiency are 90.8% in 2017 and 91.6% in 2018 (based on the portfolio scenario A4 as opposed to the actual planned 2017/2018 market purchases as discussed in the AECP).

FBC's 2016/2017 AECP objectives are described in the preamble to BCUC IR 28.1.

64.1 Provide update 2017 and 2018 rows of BCUC IR 30.1 Table 1 to reflect the actual planned 2017/2018 market purchases as discussed in the AECP.

Response:

The following table provides an updated 2017 and 2018 table BCUC IR 1.30.1 with forecast market purchases as contemplated in the confidential 2017/18 AECP, including forward market purchases as discussed in Section 5.1 of the 2017/18 AECP and real-time portfolio optimization as discussed in Section 5.2 of the 2017/18 AECP.

Table 1: Percentage of Total Energy after Planned DSM Served by Self-Sufficient Resources

Year	(i) the market	ii) Canadian Entitlement energy generated from generators not located in BC	(iii) energy that FBC considers meets the CEA definition of electricity self-sufficiency
2007	1.0%	0.0%	99.0%
2008	1.3%	0.0%	98.7%
2009	3.4%	0.0%	96.6%

Year	(i) the market	ii) Canadian Entitlement energy generated from generators not located in BC	(iii) energy that FBC considers meets the CEA definition of electricity self-sufficiency
2010	8.4%	0.0%	91.6%
2011	14.1%	0.0%	85.9%
2012	14.4%	0.0%	85.6%
2013	15.1%	0.0%	84.9%
2014	8.6%	0.0%	91.4%
2015	7.8%	0.0%	92.2%
2016	7.9%	0.0%	92.0%
2017	**10.1%**	**0.0%**	**89.9%**
2018	**8.0%**	**0.0%**	**92.0%**
2019	7.0%	0.0%	93.0%
2020	6.3%	0.0%	93.7%
2021	5.1%	0.0%	94.9%
2022	1.6%	0.0%	98.4%
2023	1.6%	0.0%	98.4%
2024	1.7%	0.0%	98.3%
2025	3.2%	0.0%	96.8%
2026	Self-Sufficiency	0.0%	100.0%

64.2 Please explain whether, and if so why, FBC is planning to purchase less than 93% of its energy from resources meeting the CEA definition of electrical self-sufficiency in the next five years. Please estimate the incremental cost and rate impact if FBC's AECP objectives were to include a requirement that in any year at least 93% of its energy from resources must meet the CEA definition of electrical self-sufficiency.

Response:

As discussed in the response to BCUC IR 2.64.1, FBC expects that it will purchase 10.1 percent and 8.0 percent of its forecast annual energy requirements from the market in 2017 and 2018 respectively. Furthermore, based on the forecast used in the response to BCUC IR 2.63.2, FBC expects that it will purchase approximately 8 percent of its forecast annual energy requirements from the market for the years 2018 to 2021. Please note that this is different than the

percentages shown in BCUC IR 2.64.1 for 2019 to 2021 as the percentages in the response to BCUC IR 2.64.1 are based on the LTERP portfolio model results which, as discussed in the response to BCUC IR 2.63.2, does not take into account all the short-term flexibility that FBC has available to optimize its portfolio in the market.

The following table calculates the expected revenue requirement impact and associated rate impact for FBC's customers if market purchases were limited to 7 percent of forecast annual energy requirements in 2017 to 2021 and the remaining requirements were met with BC Hydro PPA Tranche 1 energy purchases, rather than potentially lower-cost market purchases. The cumulative rate impact is estimated to be an increase of about 0.2 percent.

Table 1: Estimated revenue requirement and rate impact

Year	Forecast Increase to Power Purchase Expense ($ millions)	Forecast Annual Increase in Power Purchase Expense ($ millions)	Approximate Incremental Rate Increase
2017	1.550	1.550	0.43%
2018	0.538	-1.012	-0.28%
2019	0.631	0.093	0.03%
2020	0.623	-0.008	0.00%
2021	0.616	-0.007	0.00%

65.0 Reference: INFORMING AECP/ENERGY SUPPLY CONTRACTS

Exhibit B-2, BCUC IR 17.1, 17.1.1, 31.1

Environmental attributes of market purchases

FBC states in response to BCUC IR 31.1: "Market purchases are considered 50 percent clean." FBC states in response to BCUC IR 17.1: "FBC has assumed market energy purchases contain 0.19 CO2e ton/MWh. This assumption is based on historical FBC GHG emission data and is independent from the market price forecast."

FBC states in response to BCUC IR 17.1.1: "… a wind generator may sell the environmental attributes of its generation to California, and the physical generation to the regional market, which could then be purchased by FBC. At this time, FBC cannot estimate the cost that it would take to ensure all market purchases come from green resources."

65.1 Please explain the basis for the assumption that market purchases are 50 percent clean, and whether (and if not why) it is consistent with (i) FBC's assumption as to the source of market generation used for the market price forecast; and (ii) FBC's statement that the market energy purchased by FBC may have sold the environmental attributes of its generation to California.

Response:

FBC's assumption that market purchases are 50 percent clean is a high level estimate. The generation mix in the Pacific Northwest in 2016 was 58 percent hydro[12], and hydro generation is not considered green in the U.S., but is clean in B.C. Of the generation in the Pacific Northwest region, 11 percent is from other renewables including wind and solar, while coal, nuclear and natural gas account for a total of 31 percent. Even if the environmental attributes from all renewable energy sources were sold to California, 58 percent of the energy in the region would still be from a clean hydro source. Therefore FBC's estimate of 50 percent clean could be conservative, as it is unlikely that the environmental attributes of all renewable energy has been sold to California.

FBC believes this assumption is consistent with both the market price forecast used, based on the generation mix, and with the potential that some renewable generators could sell their environmental attributes to California.

[12] Energy Information Administration (EIA). Electricity Data Browser URL:http://www.eia.gov/electricity/.

65.1.1 If FBC were to purchase the environmental attributes of market priced energy, and the annual cost per year based on forecast market purchases over the next 5 years.

Response:

FBC does not have definitive information available on the cost of environmental attributes of market energy. The following table illustrates the potential cost of environmental attributes based on informal discussions with market participants, recognizing actual costs could be higher or lower. Using the volume of market purchases identified in Portfolio A4, the following are the estimated increases in market cost.

Table 1: Potential costs of environmental attributes of Market Energy

	Portfolio A4 Energy (GWh)	Incremental Costs (in millions)		
		+$5 per MWh	+$10 per MWh	+$15 per MWh
2017	330	$1.7	$3.3	$5.0
2018	301	$1.5	$3.0	$4.5
2019	253	$1.3	$2.5	$3.8
2020	227	$1.1	$2.3	$3.4
2021	183	$0.9	$1.8	$2.7

65.1.2 Please explain whether FBC has consulted with ratepayers to determine if they are prepared to pay more for electricity that is '100% clean'? If yes, please describe the result. If no, please explain why not.

Response:

As discussed in Section 10.2 of the LTERP and the responses to BCUC IRs 1.37.1 and 1.37.2, FBC hosted community workshops within its service area to provide information and gain feedback from stakeholders and rate payers on various resource planning items. In the 2016 community workshops, FBC discussed the preliminary portfolio analysis results and, in particular, the portfolio trade-offs between cost and carbon emissions and cost and reliability, such as for a portfolio with gas-fired generation versus one without. FBC did not provide rate forecasts or potential bill impacts in the workshops, instead focusing on the high-level portfolio costs relative to one another and potential trade-offs between portfolios with different attributes (for example, 100 percent clean and renewable versus least cost) to gather feedback on the portfolios considered for the preferred portfolio.

Stakeholders who participated in the community workshop discussions indicated that their primary concerns relating to resource planning included cost, reliability, reducing energy usage and reducing carbon emissions. One stakeholder stated that they did not think FBC should be considering a portfolio with gas-fired generation as their preference was for electricity from 100 percent clean and renewable sources only, even if this came at a higher cost, given government policies and their own community carbon emission targets. Other stakeholders, however, preferred gas-fired generation due to the current low cost of natural gas relative to other resource options and reliability of gas-fired plants to meet peak customer demand. One stakeholder indicated that cost and reliability of electricity supply should be the first priority, with 100 percent clean and renewable sources as a secondary priority.

As described in Section 10.1 of the LTETP, FBC also hosted RPAG workshops to discuss various resource planning topics with stakeholders representing rate payers. In the last workshop in October 2016, FBC discussed the preliminary portfolio analysis results, comparing the portfolios with different attributes and their costs. In this workshop, one stakeholder commented that they do not support new gas-fired generation being included in the future FBC resource portfolio as it is not consistent with preventing future GHG emissions.

As discussed in Section 10.3 of the LTERP, FBC also conducted online discussion boards to survey customers about their views regarding the ranking of FBC's resource planning objectives. The results are presented in Appendix B of the LT DSM Plan. When presented with choosing between the resource planning objectives, customers surveyed ranked cost effectiveness, security and reliability first before other objectives relating to provincial energy policies. The results were consistent for both residential and commercial customers, presented on page 14 and 24 of Appendix B, respectively.

Based on these results gathered through the consultation process, FBC believes that, while there are differences in opinion amongst various rate payers and there is no consensus, in general, many rate payers are not prepared to pay more for electricity that is 100 percent clean.

66.0 Reference: INFORMING AECP/ENERGY SUPPLY CONTRACTS

Exhibit B-2, BCUC IR 18.2, 19.1.2; Exhibit B-9, Shadrack IR 10

Market purchases – availability, price volatility

FBC states in BCUC IR 19.1.2: "FBC's market purchases are all designated firm energy using industry standard scheduling practices. At this time, FBC does not purchase non-firm market energy. However, this should not be confused with an assurance that market energy is available to be purchased on any given hour, only that if it is purchased, it is firm."

FBC states in BCUC IR 18.2 "The market price forecast presented in Figure 2-9 of the LTERP does not include the risk of market price spikes since it presents average prices on an annual basis." FBC provides the average unit cost for FBC's market energy purchases from 2012 to 2016 in Shadrack 10 (ii):

Year	Market ($/MWh)
2012	$21.10
2013	$29.44
2014	$31.43
2015	$38.65
2016	$38.46

66.1 Please provide a table and line graph showing FBC market volumes by month delivered during each year from 2012 to 2016, including a five year monthly average.

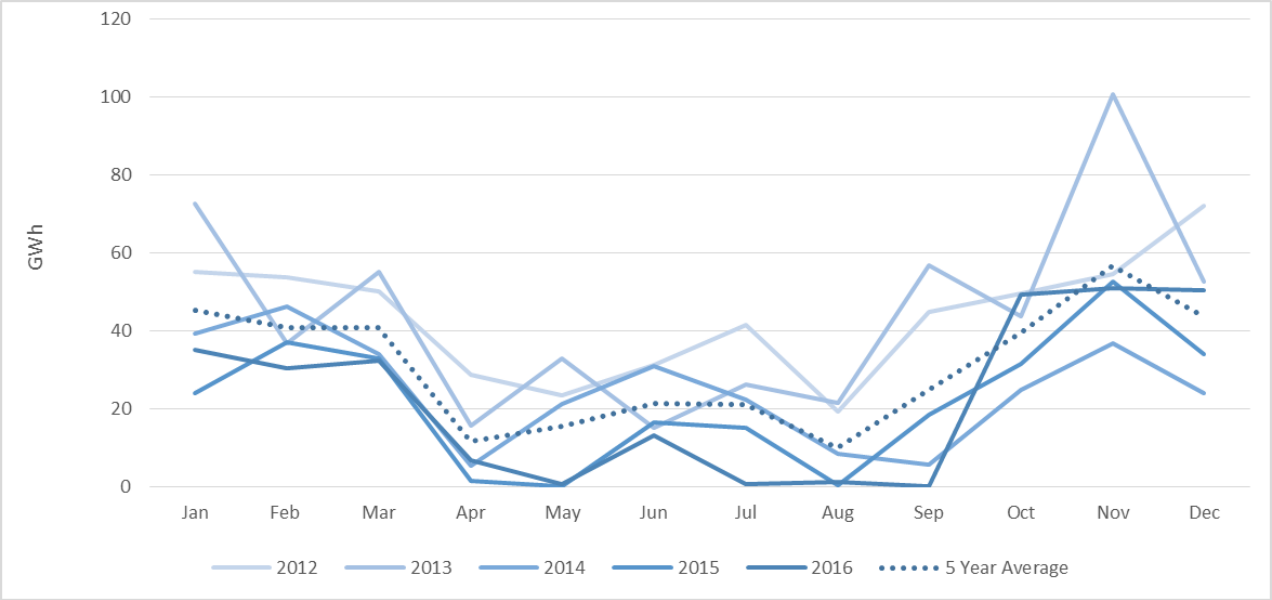
Response:

Please refer to Table 1 and Figure 1 below, which show FBC's market purchase volumes by month delivered during each year from 2012 to 2016 as well as a five year monthly average.

Table 1

(GWh)	2012	2013	2014	2015	2016	5 Year Average
Jan	55	73	39	24	35	45
Feb	54	37	46	37	30	41
Mar	50	55	34	33	32	41
Apr	29	16	5	1	7	12
May	23	33	21	0	1	16
Jun	31	15	31	16	13	21
Jul	41	26	22	15	1	21
Aug	19	21	9	0	1	10
Sep	45	57	6	18	0	25
Oct	50	44	25	31	49	39
Nov	54	101	37	53	51	57
Dec	72	53	24	34	51	44
Total	**524**	**530**	**299**	**264**	**270**	**371**

Figure 1



66.2 Please describe the extent to which FBC relies on market purchases to meet (i) generation energy needs (i.e. purchasing market priced energy during periods of low market price and storing that energy until needed) compared to (ii) meeting generation capacity needs (i.e. purchasing market priced energy during time when FBC has insufficient energy from other sources to meet its needs).

Response:

FBC currently has sufficient resources to meet its requirements. Even when its market purchases are made during peak hours, this is usually not because FBC does not have sufficient resources, it is because the market purchases can be completed at a lower cost than FBC's existing resources, specifically the PPA with BC Hydro. However, there have been some occasions in the past few years when FBC's market purchases were required that could not have been met with PPA resources. Most recently this occurred in June of 2015, when temperatures were very hot, and FBC's peak demand was 64 MW (14 percent) above forecast. This resulted in 2.842 GWh of market purchases that were required to meet peak demand that could not have been supplied under the PPA due to the maximum contract demand of 200 MW in any hour. In 2015, this represented approximately 1 percent of total market purchases. Since June 2015, FBC has not made any market purchases that could not have been supplied under existing resources, and FBC does not plan on requiring market purchases for peak demand requirements in the preferred portfolio.

66.2.1 Please explain whether the level of reliance on the market to meet generation energy vs. generation capacity needs has changed over the last 5 years, and whether it is expected to change over the next 5 years.

Response:

As discussed in the response to BCUC IR 2.66.2, FBC believes its reliance on market to meet energy requirements versus market to meet capacity requirements has been relatively consistent over the past five years, and will remain consistent over the next five years. FBC does not plan on requiring market purchases for peak demand requirements over the next five years.

Furthermore, FBC previously purchased capacity-only blocks during the winter from Powerex from 2010 through February 2015, and before that, similar products from Teck Metals Ltd. With the addition of the WAX CAPA to FBC's portfolio, FBC no longer purchases any capacity-only blocks from a third party.

66.3 Please calculate the percentage increase in the $/MWh cost of market purchases from 2012 to 2016. Please explain the reason for this increase, including the

extent that it relates to overall increased in market prices (and if so, whether it is correlated to an increase in gas prices) compared to a change in the timing of when market purchases are made (peak vs. off-peak).

Response:

Please refer to Table 1 below to see the percentage change in the cost of market purchases from 2012 to 2016.

Table 1

Year	Market ($/MWh)	Year over Year Percent Change
2012	$21.10	
2013	$29.44	39.5%
2014	$31.43	6.8%
2015	$38.65	23.0%
2016	$38.46	-0.5%

The main reason for the change in costs is due to the significant change to the Canadian/U.S. exchange rate. The Canadian dollar has depreciated by nearly 25 percent over that time period, from $0.99 CAD/USD down to $0.74 CAD/USD at the end of 2016. Mid-C based contracts are typically entered into in U.S. dollars and, as such, the changes in exchange rates have increased FBC's market purchase costs.

There have also been some timing differences of market purchases, as noted in the response to BCUC IR 2.66.2, and there have been times when FBC has required more market purchases in peak hours than others, such as those in June of 2015, but overall the timing and purpose of FBC's market purchases has not changed materially.

67.0 Reference: INFORMING AECP/ENERGY SUPPLY CONTRACTS

Exhibit B-5, CEC IR 19.3; Exhibit B-9, Shadrack IR 4; BC Hydro, Standard Form Electricity - Purchase Agreement Standing Offer Program (SOP), March 2016, Appendix 3; BC Hydro, SOP – Program Rules (April 2016), p.10; Exhibit B-1 (the Application), Volume 1 (2016 LTERP Application), p.77

Valuing seasonal energy supply

FBC provides historical average Mid-C prices by month in CEC IR 19.3.

FBC states in Shadrack IR 4 (i): "…FBC is severely limited in its ability to store energy for use in a later season as compared to the BC Hydro system."

Appendix 3 of BC Hydro's March 2016 SOP standard form electricity purchase agreement includes a table showing time of delivery factor adjustments (monthly and within day).[13] Page 10 of BC Hydro's April 2016 SOP rules includes locational adjustments.[14]

FBC states on page 77 of the Application: "The amount of Residual Capacity provided under the WAX CAPA is greater than FBC's current capacity requirements in most months and, as a result, FBC sells the surplus capacity to mitigate power purchase expense. FBC has contracted to sell a 50 MW block of WAX CAPA Residual Capacity to BC Hydro under the Residual Capacity Agreement (RCA), entered into as of July 15, 2013."

67.1 Please explain whether generation capacity ($/kW-year) could be used to store energy purchased/delivered during periods when it is not needed so that it can be used at times when it is needed.

Response:

Storage can be accomplished by reducing generation and relying on purchased power from either the market or the PPA with BC Hydro to meet load in that hour. This increases the amount of generation that can be produced at a later time. The more generation capacity available, the more effectively this can be accomplished, all other things being equal. With the WAX CAPA in place, FBC has sufficient generation capacity to effectively make use of stored energy on a daily basis but is still severely limited by the actual amount of storage available under the CPA to shift usage across seasons.

[13] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/standing-offer/sop-standard-form-epa.pdf

[14] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/standing-offer/standing-offer-program-rules.pdf

The capacity purchased under the WAX CAPA does not allow FBC to store additional energy. However, FBC has the ability to store energy through its storage accounts under the CPA. FBC currently uses its CPA storage accounts to purchase energy when it is not needed so that it can be paired with capacity purchased under the WAX CAPA to be used at a time when it is needed. Please refer to the response to BCUC IR 2.67.2 for further information on FBC's storage ability.

67.1.1 Please explain whether the cost of generation capacity could reflect the difference in value between energy delivered to FBC's network at a time that it is needed by FBC, compared to energy delivered to FBC at a time that is not.

Response:

FBC agrees that this approach reflects one measure of the market value of generation capacity. The value created by doing this is generally not sufficient to justify the construction of new capacity resources and as such is mainly useful to determine the market value of surplus generation capacity in the short-term.

For example, if 1 MW was purchased at a price of $10 during April and stored for later use in December when the price was $50, then the value of the generation capacity that allows the stored energy to be used is $40 for that transaction. The annual value of the generation capacity will depend on how many similar transactions can be accomplished over the year.

67.1.2 Please provide an estimate of the long term market value of generation capacity. Please provide supporting assumptions.

Response:

FBC expects that the long-term value of generation capacity would be consistent with the UCCs of new resources, and could range from $80-$143 per kW-year, based on a single cycle gas turbine, which has the lowest UCC for new resources, as shown in Table 8-1 of the LTERP.

67.2 Please explain why FBC is severely limited in its ability to store energy for use in a later season as compared to the BC Hydro system. Specifically, is FBC in a generation capacity shortage or surplus situation following WAX CAPA (and if so, for which months)?

Response:

FBC's ability to store energy is based on the storage accounts provided under the CPA, which are in turn based – for the most part – on the ability to store water in Kootenay Lake. The ability to store energy as stored water is related to the actual hydrology of the system and can only be increased by building additional reservoirs or adjusting constraints such as the maximum storage elevation on existing reservoirs. Adding generation does not directly increase the amount of stored energy, but just increases the flexibility with which that stored energy can be used by shifting generation to higher value time periods or by reducing the amount of stored water that must be spilled at certain times of the year due to a lack of generation. The WAX plant did not change the physical storage constraints of the system and therefore the CPA storage accounts did not increase and FBC's ability to store energy did not change with the addition of the WAX CAPA.

The CPA has two separate storage mechanisms. One allows FBC to shift its Entitlement Energy from month to month by up to 7 percent, however energy cannot be shifted out of the May to July period, the November to February period, or the August to April period. The second account is an operational account that allows for storage of up to a maximum of 49 GWh. For this account, again, energy cannot be shifted out of the May to July period. FBC uses both of these accounts with its current portfolio to shift energy from low cost to high cost times, and to manage fluctuations in load requirements through the year. Due to BC Hydro's numerous reservoirs, its storage flexibility is significantly greater.

As discussed in the response to BCUC IR 2.67.1, the addition of WAX CAPA to FBC's portfolio did not increase FBC's ability to store energy. Following WAX CAPA, FBC is currently forecasting to be in a generation capacity surplus for all months through 2026.

67.3 Please shows the results to CEC IR 19.3 graphically, showing the results for each year from 2012-2016 with a five year average. In a separate graph, please compare the five year average (2012-2016) with a ten year average (2007-2016).

Response:

Figure 1 below shows the historical Mid-C day ahead prices on a monthly basis for each year from 2012-2016 along with a five year average.

Figure 1

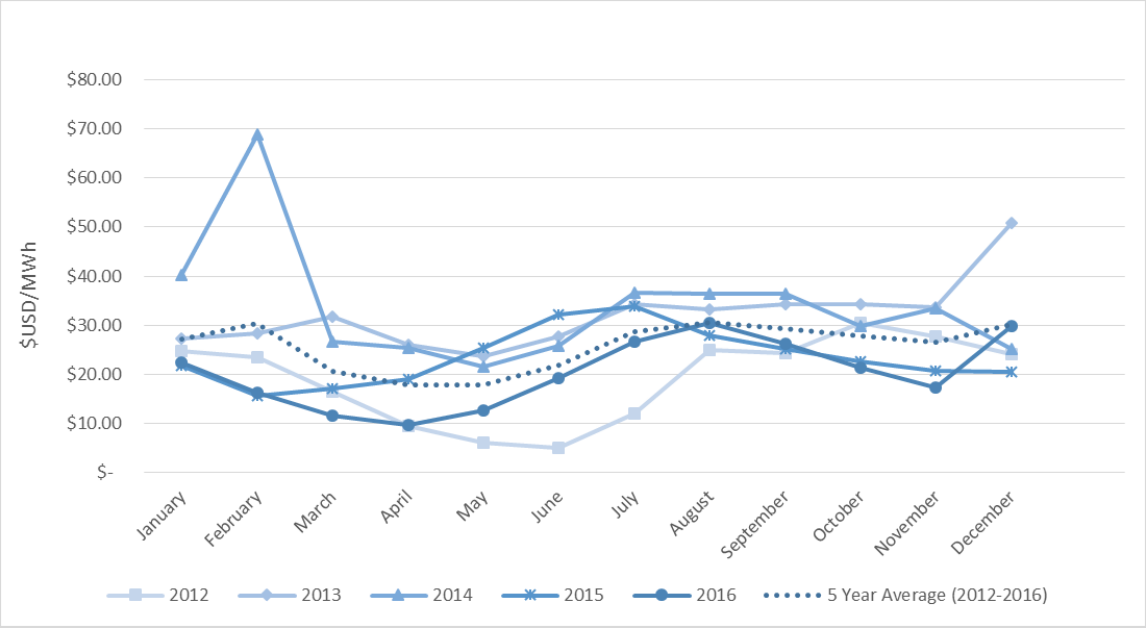
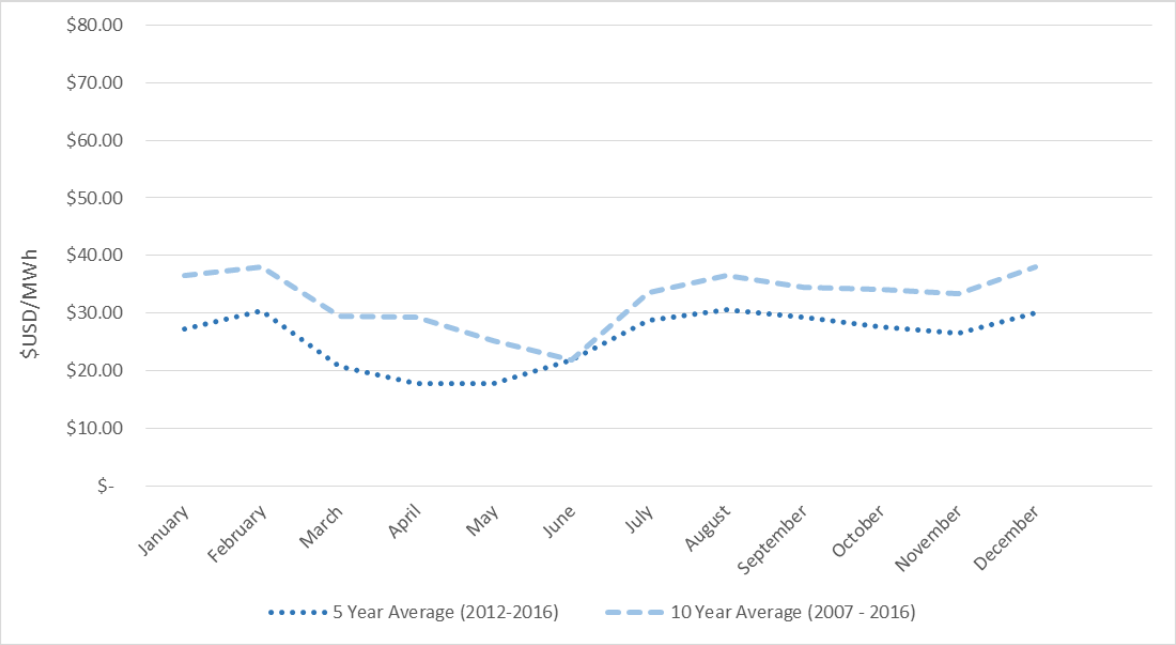


Figure 2 below shows the 2012-2016 five year average historical Mid-C day ahead prices on a monthly basis as well as the 2007-2016 ten year average.

Figure 2



67.4 Please provide an estimate of FBC's (i) locational generation adjustments and (ii) time of delivery factor adjustments (if any) in a manner similar to those provided by BC Hydro for its SOP program. If FBC's adjustments are significantly different, please explain why.

Response:

FBC has not developed locational and time of delivery factor adjustments. Rather, FBC included each proposed resource, with its associated energy and capacity profiles, in the LTERP portfolio model. The results from the modeling process presented in the response to BCUC IR 1.24.2 show that FBC's energy requirements are primarily in the winter months. Resources that do not provide winter energy generally speaking only displace existing resources such as the PPA or low cost market energy. FBC has only a very limited ability to store energy to move it between seasons as described in the response to BCUC IR 2.67.2. This is unlike BC Hydro, which has much greater flexibility to store energy for winter use. For this reason alone, FBC believes that the BC Hydro table cannot apply to FBC.

Please refer to the response to BCUC IR 1.36.3 for a discussion of time of delivery factor adjustments. On a practical basis, unless the project provides winter energy, it adds no value to

FBC at all, just displacing the PPA. Depending on the project's characteristics, if it is located in the Okanagan region there may be a small locational line losses benefit compared to projects located in the Kootenay region.

68.0 Reference: INFORMING CPCN/REVENUE REQUIREMENT FILINGS

Exhibit B-2, BCUC IR 2.2, 29.1

Reliability

FBC states in response to BCUC IR 2.2: "Loss of load expectation (LOLE) (related to network/generator capacity) is another appropriate metric for evaluating portfolios. FBC has ensured that the portfolios considered for the preferred portfolio have met the Planning Reserve Margin requirements in terms of LOLE resource adequacy."

FBC states in BCUC IR 29.1: "There were no occasions in the last 10 years when FBC had to shed load due to resource insufficiency."

68.1 Please provide in table and graphical form, for each year over the past 10 years, FBC metrics used to measure network reliability (for example, the System Average Interruption Duration Index, System Average Interruption Frequency Index, Customer Average Interruption Duration Index). Please comment on any trend over time.

Response:

FBC measures network reliability using the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) metrics. FBC's normalized SAIDI and SAIFI performance over the past 10 years are shown in the below tables. It is difficult to determine any trend in the SAIDI and SAIFI metrics over time since yearly results are very weather dependent and influenced by other factors outside of FBC's control (such as motor vehicle incidents, off right-of-way trees and access to the location of trouble).

Table 1: FBC SAIDI and SAIFI Indices

Year	SAIDI	SAIFI
2016	2.10	1.34
2015	2.13	1.56
2014	2.32	1.64
2013	2.01	1.27
2012	1.95	1.27
2011	1.86	1.38
2010	2.84	2.27
2009	2.28	1.48
2008	2.42	2.13
2007	2.49	1.99

68.1.1 Please compare the results above to utilities in other jurisdictions (for example BC Hydro and Canadian Electricity Association averages) and comment on any significant differences in network reliability.

Response:

The same information is provided in the table below for a composite of Canadian utilities obtained from the Canadian Electricity Association's report on Service Continuity Data on Distribution System Performance in Electrical Utilities. The Canadian Electricity Association data excludes Significant Events (Significant Events are those major events that the Canadian Electrical Association committee has deemed completely outside the control of the utility, and that significantly impact the Canadian Index.) Data of individual participants in the survey is confidential.

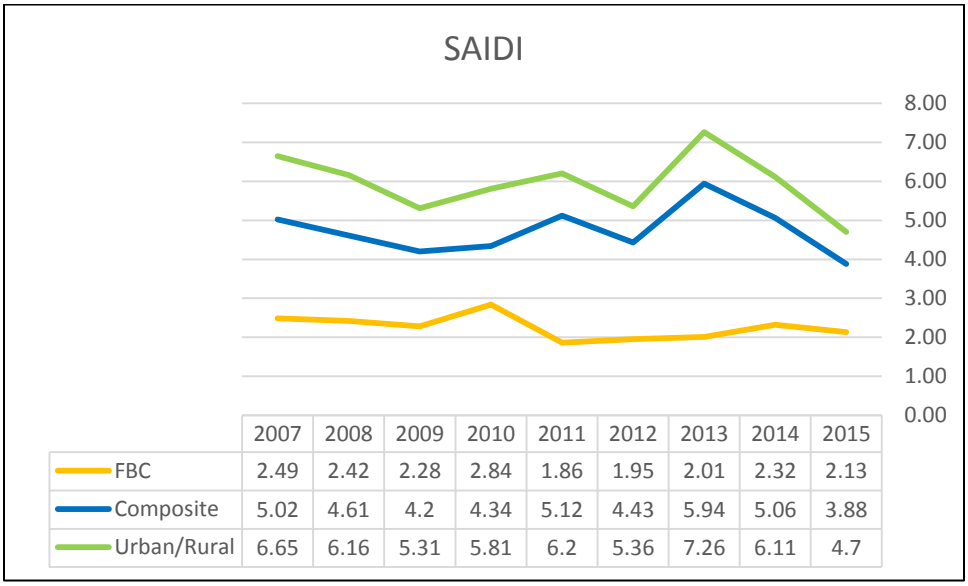
Table 1 SAIDI and SAIFI Composite Utility Indices

	SAIDI			SAIFI	
	Composite	Urban/Rural		Composite	Urban/Rural
2015	3.88	4.70		2.21	2.48
2014	5.06	6.11		2.33	2.59
2013	5.94	7.26		2.45	2.77
2012	4.43	5.36		2.48	2.79
2011	5.12	6.20		2.53	2.85
2010	4.34	5.81		2.06	2.34
2009	4.20	5.31		2.01	2.31
2008	4.61	6.16		2.18	2.53
2007	5.02	6.65		2.27	2.61

FBC is unable to directly comment on the differences between FBC's reliability performance and those of other utilities, including composite indices. Direct comparisons between the SAIDI and SAIFI performance of FBC and other utilities may be misleading since system reliability is influenced both by factors within the utility control and others which are not controllable such as the specific geography, weather, and levels of third-party interference, which are unique to each utility's service territory.

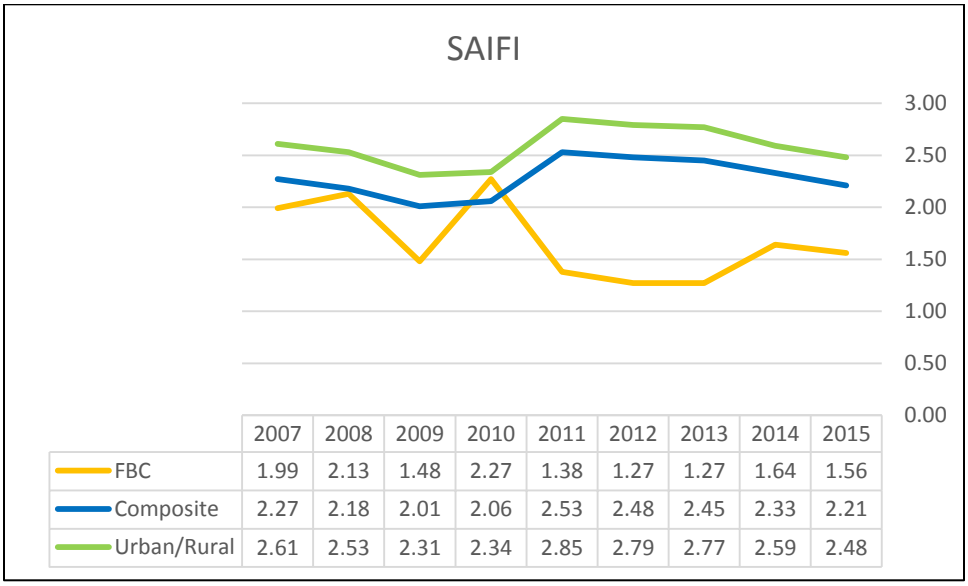
FBC's annual SAIDI is significantly lower than the Canadian composite data, while the SAIFI values are somewhat lower.

Figure 1: Comparison of FBC and Utility Composite SAIDI



	2007	2008	2009	2010	2011	2012	2013	2014	2015
FBC	2.49	2.42	2.28	2.84	1.86	1.95	2.01	2.32	2.13
Composite	5.02	4.61	4.2	4.34	5.12	4.43	5.94	5.06	3.88
Urban/Rural	6.65	6.16	5.31	5.81	6.2	5.36	7.26	6.11	4.7

Figure 2: Comparison of FBC and Utility Composite SAIFI



	2007	2008	2009	2010	2011	2012	2013	2014	2015
FBC	1.99	2.13	1.48	2.27	1.38	1.27	1.27	1.64	1.56
Composite	2.27	2.18	2.01	2.06	2.53	2.48	2.45	2.33	2.21
Urban/Rural	2.61	2.53	2.31	2.34	2.85	2.79	2.77	2.59	2.48

FBC is unable to locate any publicly available source of recent BC Hydro reliability statistics on a comparable basis. BC Hydro reported its SAIDI and SAIFI performance in its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (Exhibit B-1-1, Appendix U) on a non-normalized basis. In addition to the impact of the factors identified above, the difference in BC Hydro's fiscal year compared to FBC's calendar year and the lack of weather normalization, the BC Hydro metrics are not directly comparable to FBC's.

68.2 In the course of preparing this LTERP, did FBC consult with customers to determine if its price/network reliability trade-offs reflect customer preferences (for example, whether customers would pay more for higher levels of network reliability). If yes, please provide the results. If no, please explain why not.

Response:

As discussed in the response to BCUC IR 2.65.1.2, while FBC did consult with customers on the potential portfolio trade-offs between cost-effectiveness and reliability versus 100 percent clean resources, it did not directly determine their views regarding trade-offs between cost and reliability. This is because, although FBC strives to ensure reliable electricity to customers as cost effectively as possible, FBC is not required to have a 100 percent clean power supply portfolio. Through the consultation process, in general, customers indicated that both cost-effectiveness and reliability were among their top priorities.

69.0 Reference: INFORMING RATE DESIGN FILINGS

Exhibit B-9, Shadrack IR 3; Bonbright, J., et al, Principles of Public Utility Rates (1988), p. 511

Rate design principles

FBC states in Shadrack IR 3 (i): "A tenet of rate design is that to the extent possible, the fixed costs of the utility, those that do not vary with the level of customer consumption, should be collected through a fixed charge, and similarly that variable costs are collected through a variable charge."

Bonbright (1988) states on page 511: "Embedded costs are used in the determination of customer class revenue allocations, whereas marginal costs are used to design specific rates and to determine rate relationships (e.g., peak and off-peak rates)."

69.1 Please explain whether, in response to Shadrack IR 3 (i), FBC is referring to using embedded costs (as opposed to marginal costs) as a point of departure for ratemaking. If yes, please explain (i) if that is consistent with Bonbright rate design principles, and (ii) if that could affect the ability of FBC to design rates that encourage efficient customer consumption and investment decisions.

Response:

In allocating costs to customer classes, the Company adheres to the methodology used in its most recent COSA and that resulted in Order G-156-10, utilizing embedded costs. The results of this process form the foundation for the setting of rates and the Company's response to the referenced IR reflects the allocation of costs known to be fixed and appropriately recovered through fixed charges. This is consistent with Bonbright rate design principles, particularly those which are summarized as *Fair apportionment of costs among customers (appropriate cost recovery should be reflected in rates)* and *Revenue Stability*.

Were FBC to design a specific rate meant to reflect variable current or future costs (such as a time varying rate) it may do so on a marginal cost basis. However, within the context of the IR in question, which was the relevance of the current residential rate to net-metering, no such rationale exists for varying the fixed portion of the charges. FBC recognizes that the Bonbright principle, *Price signals that encourage efficient use and discourage inefficient use*, is also a consideration. However, FBC's starting point for its rate design is that efficient customer consumption and investment decisions are made in response to rates that best reflect their cost basis, and not where one or more elements of the rate may be engineered to elicit a response that does not provide a benefit to customers in general.

70.0 Reference: INFORMING RATE DESIGN FILINGS

Exhibit B-8, Scarlett IR 1; British Columbia Utilities Commission, Report to The Government of British Columbia on the Impact of BC Hydro and FortisBC's Residential Inclining Block Rates (2017) (RIB Rate Report), p. 6; FBC 2014 Stepped and Standby Rates for Transmission Voltage Customers Decision dated May 26, 2014 and Order G-67-14 (FBC 2014 Stepped and Standby Decision), p. 54

DG subsidy

FBC states in Scarlett IR 1 (d): "… customers with low consumption, whether as a result of consumption habits or participation in DSM, still make a standard contribution towards the fixed costs of the system through the Customer Charge. Only customers with DG that have the ability to reduce bills to zero (or negative) can avoid this contribution completely. This means that DG customers, who still rely on and benefit from connection to the electric grid, are being subsidized by other non-DG customers."

The Commission's 2017 RIB Rate Report states on page 6:

> The Commission also notes that it is important to consider the reasons for differences in R/C ratios before determining whether or not a subsidy exists. In Prince George Gas Co. v Inland Natural Gas Co.13 (Prince George decision), a decision of the BC Court of Appeal cited by BC Hydro in its 2015 Rate Design Application, the court observed that payments from one group of consumers that reduce the rates of other consumers do not constitute a subsidy, as long as the reduction in rates is an "incidental result flowing from a proper rate based upon the cost of service." … Since it is not the purpose of the RIB rates to benefit any customers at the expense of other customers, this supports the Commission's view based on the R/C ratios that there is no undue discrimination in the RIB rate.

The FBC 2014 Stepped and Standby Decision states on page 54:

> The Panel considers that stand-by wires charges should be set such that they do not inadvertently either restrict the growth of cost-effective distributed generation, or promote uneconomic bypass. Wires charges should also result in a fair contribution to the sunk costs of the utility's network, although the Panel notes the difficulty in determining the fairness of a Wires Demand Charge from a cost causation perspective.

70.1 Please explain FBC's statement that DG customers are being subsidized by other non-DG customers. In your response, please specifically address whether FBC's response is consistent with the extracts from (i) the 2017 RIB Rate Report

above on what constitutes a subsidy and (ii) the FBC 2014 Stepped and Standby Decision on the difficulty of determining what is a fair contribution to sunk network costs from a cost causation perspective.

Response:

The situation described in the referenced IR response is not analogous with that examined during the Commission's RIB Report process. Rates are designed such that all customers within a given rate class make a similar contribution to the fixed costs of the utility. For residential customers, this contribution is collected through the Customer Charge and is the same for all customers charged under a given rate. Although the Customer Charge does not collect 100 percent of the costs as determined during the Cost of Service Analysis (COSA), it is set at the same level for all customers.

Regardless of the relative impact of the RIB rate on individual customers, which is driven by the consumption habits of the customer and the variable portions of the rate, all customers make, at a minimum, the standard contribution to the fixed charges.

The situation with DG customers is different. While the RIB rate is, as described in the reference, capable of producing an, "…incidental result flowing from a proper rate based upon the cost of service", the current application of the NEG provisions in the NM tariff has no relationship to a cost-based rate designed for that purpose. Rather, the compensation for NEG each billing period at the retail rate instead of the use of a kWh Bank enables customers with small-scale generation, such as those in the NM Program, to avoid even the minimum contribution to fixed charges if their bill is less than the Customer Charge. A customer that reduces their bill to zero, or less, is still using the FBC system, and still driving a system cost, which in the absence of a sufficient bill amount will fall to the account of the remaining customers. FBC is seeking the use of a kWh Bank and an appropriate compensation rate through its Application for Reconsideration of Order G-199-16, in part, to mitigate this situation.

With respect to part (ii) of the question, FBC is of the opinion that the contribution to the sunk costs of the network has been established during the COSA and rate design process, and although it is insufficient to collect all of the associated costs, is represented by the Customer Charge and Demand Charges (where appropriate) as previously approved by the Commission.

71.0 Reference: INFORMING ELECTRIFICATION RELATED FILINGS

Exhibit B-2, BCUC IR 4.1, 8.1.1; Exhibit B-6, Gabana IR 3-4

Electric vehicles

FBC states in response to BCUC IR 4.1 that items in the Climate Leadership Plan (CLP) FBC considers relevant are include: Support for expansion of zero-emission vehicle charging infrastructure and Clean Energy Vehicle Program incentives.

FBC states in response to BCUC IR 8.1.1: "FBC established an annual budget of $50 thousand in 2015 to help support the installation of public EV charging stations in its service territory. … FBC notes that it is currently evaluating recent amendments to the *Greenhouse Gas Reduction (Clean Energy) Regulation* to determine if additional investment in EV infrastructure is warranted."

Gabana asks in IR 3: "Why should Fortis customers expend capital to subsidize the operations of vehicles that a large percentage of customers will not ever be able to afford?" FBC response includes: "Although the initial cost of an EV is often more expensive than a gasoline powered equivalent, the costs to operate EVs on a per-kilometer basis are generally far less."

FBC states in response to Gabana IR 4 that it has spent approximately $15 thousand on the three Level 3 DC fast-charging stations, and has collected revenue of approximately $3.5 thousand from the Keremeos and Princeton charging stations to date."

71.1 Please explain the recent amendments to the Greenhouse Gas Reduction (Clean Energy) Regulation and describe how they could affect FBC filings over the next 5 years.

Response:

On March 1, 2017, the B.C. government amended the *Greenhouse Gas Reduction (Clean Energy) Regulation* (*GGRR*) by adding prescribed undertakings pertaining to electrification.[15] Prescribed undertakings under section 18 of the Clean Energy Act (*CEA*) refer to projects, programs, contracts or expenditures for the purpose of reducing greenhouse gas (GHG) emissions in B.C. The BCUC must set rates that allow public utilities to recover costs incurred with respect to the prescribed undertakings in each fiscal year.

The electrification prescribed undertakings issued on March 1, 2017 include:

[15] Via Order in Council No. 101/2017, deposited Mar. 2, 2017

1. The development of additional electrical transmission and distribution infrastructure in northeast B.C. to serve increasing electric demand from the upstream natural gas sector (to support BC Hydro's Peace River Electrification Strategy); and

2. The following items:

   - Programs to encourage customers or potential customers to use electricity, rather than higher GHG-emitting energy sources, by way of education, training, public awareness campaigns, energy management and auditing; or to provide funding for buying, installing or using electric equipment or equipment that affects the use of electricity;

   - Providing funds to those who design, manufacture, sell, install or provide advice respecting equipment that uses or affects the use of electricity (e.g. equipment manufacturers, retailers, installers, contractors); to those who design, build, manage or advise on energy systems in buildings or facilities (e.g. consultants, engineers and building operators); and to those who design, build or manage district energy systems;

   - Projects, programs, contracts or expenditures for technology pilot projects or research and development that may encourage the use of electricity instead of other energy sources that produce more GHG emissions;

   - Projects, programs, contracts or expenditures to support standards-making bodies in developing standards that respect technologies that use electricity or affect the use of electricity instead of other sources of more GHG-intensive energy; and

   - Infrastructure projects to build, acquire or extend a plant or system that may be necessary to meet the incremental load arising from the above undertakings, up to $20 million per project.

The electrification amendments to the *GGRR* also set out cost effectiveness requirements that undertakings in certain categories must meet in order to qualify as "prescribed undertakings". At this point FBC has not developed a cost effectiveness model for electrification undertakings but the cost effectiveness requirements in the *GGRR* amendments appear to be similar to the Ratepayer Impact Measure (RIM) test used in assessing DSM projects or programs.

FBC became aware of the content of OIC 101/2017 on March 2, 2017, and has had limited opportunity to evaluate the potential for electrification that may now be encompassed by the GGRR.

When undertaking prescribed activities as defined in the GGRR, FBC will file applications for recovery of the costs associated with the undertakings in customer rates. The nature of these applications has not been developed in detail, but it would likely make sense to develop rate recovery approaches that are applicable to a range of possible electrification undertakings. FBC

notes that another Order in Council – OIC 100/2017 - was issued specifically for BC Hydro at the same time as OIC 101/2017 and requires certain categories of BC Hydro's electrification undertakings to be treated in the same manner as its DSM expenditures. This approach may be suitable for FBC as well, but further consideration of rate recovery approaches for electrification initiatives is needed before settling on the proposed treatment.

71.2 Please expand on FBC's response to Gabana's concern regarding the affordability of EV's. In your response, please compare the difference in initial purchase cost and annual running costs of (i) a used 2013 Nissan Leaf with (ii) a similar gasoline fueled vehicle (such as a Toyota Camry).

Response:

Although the affordability of EVs has typically been identified as a barrier for prospective buyers, the declining costs of lithium-ion EV batteries as discussed in response to Gabana IR 1.3 are enabling vehicle manufacturers to begin introducing battery-only EVs (BEVs) with significantly more highway range at lower prices as compared to earlier BEV models.

With respect to the requested comparison, FBC notes that a Toyota Corolla may be considered a more appropriate class of vehicle for comparison with the Nissan Leaf, and as such has also been included in the following table. Please note, for the purposes of the comparison, annual operating costs have been limited to fuel costs only.

Table 1

Vehicle	Purchase Price[1]	Annual Operating Costs[2]	Fuel Economy (city/highway)[3]
2013 Toyota Camry	$16,630	$2,092.64	8.8 liters / 100 km
2013 Toyota Corolla	$11,767	$1,902.40	8.0 liters / 100 km
2013 Nissan Leaf	$15,438	$659.04	18.7 kWh / 100 km 2.4 liters equivalent / 100 km

[1] Based on a provincial search of used BC vehicles at autotrader.com, accessed May 3, 2017.

[2] Based on 20,000 kilometers per year, $1.189 per liter of gasoline, $0.15617 per kwh (FortisBC Residential Tier 2 Rate).

[3] http://www.nrcan.gc.ca/energy/efficiency/11938

71.2.1 Please expand on FBC's response to Gabana's concern regarding EV subsidies. Specifically, does FBC consider that a strategy to encourage the adoption of EV could over the long-term benefit FBC's customers who do not have EVs?

Response:

As discussed in response to Gabana IR 1.3, FBC believes the moderate investment it has made in EV charging stations is warranted given the additional insight provided for both the infrastructure requirements for supporting public EV charging stations as well as customer uptake of public charging resources. In the long term, FBC believes this insight will benefit all customers by minimizing the costs associated with the incremental load growth related to EVs.

72.0 Reference: INFORMING DG/Self Generation (SG) RELATED FILINGS

Exhibit B-2, BCUC IR 10.2; BC Hydro, Comparison of BC Hydro's Distributed Generation Offers Draft, (2014)[16]; BC Hydro, Distributed Generation Interconnection Practices (distribution-connected projects only)[17]; BC Hydro 2013 Integrated Resource Plan, pp.8-6 to 8-9

DG Strategy Issues

FBC summarizes its distributed generation strategy in BCUC IR 10.2 as: "FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. However, if a self-generator could provide power at a cost lower than FBC's alternatives there may be an opportunity for FBC to purchase the output of the self-generation." FBC further states: "The Company seeks to neither advantage nor disadvantage DG regardless of size, type, or ownership."

FBC's response to BCUC IR 10.2 includes the following:

DG Policy Issue	FBC Comments
Should grid-side benefits of customer DG be monetized and allocated among stakeholders?	FBC has a Self-Generation Policy Stage II Application before the Commission in which it proposes to share any net benefits of self-generation on a 50-50 basis between the DG customer and other customers.
Should DG interface with grid operations and markets?	Self-Generating customers in the FBC service area have access to markets utilizing the Company's Open Access Tariff and wheeling related rate schedules.
Should the interconnection technical requirements, processes, and contracts be modified for DG?	FBC has established interconnection guidelines that are applicable to DG customers.
Should utilities be compensated for providing standby services?	FBC has an approved standby rate.

BC Hydro 2014 draft comparison of DG offers describes the key attributes of the net metering program, standing offer program (SOP) and micro-SOP. BC Hydro also provides a summary of its DG interconnection practices by program type. BC Hydro describes on page 8-6 to 8-9 its 2013 Integrated Resource Plan (IRP) its approach to broaden opportunities for distributed generation through standing offers for clean energy (net metering, micro-standing offer program (SOP), and SOP) and its approach to promote First Nations participation in clean energy projects.

[16] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/initiatives-in-development/cheat-sheet-hand-out-comparison-of-DG-offers-final.pdf

[17] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/independent-power-producers-calls-for-power/distribution-generator-interconnections/bc-hydro-distributed-generation-interconnection-practices.pdf

72.1 For grid-side benefits, please provide an overview of how FBC proposes to (i) monetize grid benefits from customer investment in SG/DG (for example, avoided network infrastructure costs, reduced line losses etc.), and (ii) allocate 50% of these benefits to SG/DG customers.

Response:

The topic area now broadly referred to as the "potential net-benefits of self-generation" (net benefits) entered the discussion surrounding FBC self-generation policy primarily during the regulatory processes associated with BC Hydro's 2014 application for approval of a new Power Purchase Agreement between BC Hydro and FBC, and FBC's Stepped and Stand-By Rates for Transmission Voltage Customers Application. In the decision accompanying Order G-60-14 regarding the BC Hydro application, the Commission determined that FBC must establish Self-Generating customer polices that, among other items, addressed the following, "… the potential benefits of self-generation …". The Company has acknowledged that such theoretical net benefits may exist, and that they would vary depending on the particular customer characteristics, location, and timing.

In order to comply with BCUC direction to recognize the net-benefits, FBC has provided two mechanisms within its proposed Self-Generation Policy (SGP) that is currently before the Commission. Customers taking service utilizing the Company's Stand-by Rate (RS 37) do so at a reduced cost from the otherwise applicable standard tariff rate. As part of the determination of billing determinants under RS 37, FBC has proposed that the power-supply benefit of the self-generation be recognized through a reduction in the Stand-by Billing Demand (SBBD). The periodic reliance on the FBC infrastructure is already a feature in the RS 37 SBBD determination. In the scenario where a customer intends to sell power that would otherwise be used to serve its load, the Company's proposed Self-Supply Obligation (SSO) Guidelines include a 50 percent net benefit sharing factor that notionally places a value on the net-benefits by setting the SSO at 50 percent of the load historically served by the customer's own resources.

72.2 For the ability of DG to access markets, please explain whether (and if so how) FBC customers with SG/DG opportunities have the same opportunities to access markets as IPPs.

Response:

FBC has a standard set of guidelines for the interconnection of generation facilities, and a standard Open Access Transmission Tariff (OATT) and set of transmission rates and ancillary

services charges that apply to all interconnected generation regardless of whether it is a load customer with SG/DG or an IPP. None of these standards and tariffs make a distinction between the types of facilities identified in this question and therefore market access opportunities are the same.

72.2.1 Please reproduce BC Hydro's draft 2014 comparison of distributed generation offers, and prepare a similar table showing FBC's distributed generation offers. Please identify any gaps in FBC's offerings compared to BC Hydro's.

Response:

BC Hydro's 2014 summary of DG offers is reproduced below, followed by a summary of FBC's offers.

Table 1: BC Hydro Distributed Generation Offers, June 2014

ISSUE	Net Metering – RS 1289 (proposed up to 100 kW)	Existing SOP (50 kW to 15 MW)	Proposed Micro-SOP (100 kW to 1 MW)
Application Process	2-page application form	27 pages of rules 23-page application	Simplify SOP application process; reduce amount of information required
Electricity Purchase Agreement (EPA)	None	68-page EPA (including appendices)	Simplified EPA of about 20 pages (with few appendices)
Contract Term	NA – customer can discontinue participation at any time	20 to 40 years	Consider a more flexible term of 5 to 20 years
Base Price	Price is periodically set at a fixed level based on the SOP price	Regional pricing, however BC Hydro is engaging on and evaluating the potential for a single price	Proposing a single price
Price Escalation	No escalation	50% of base price is escalated at CPI after signing of EPA	Same as SOP, but may allow developer a 100% escalation option (with lower price)
Delivery Requirements	Non-firm with no delivery requirements	Non-firm with no delivery requirements. COD must be within 3 years of EPA signing. If proponent doesn't deliver for 2 consecutive years, can terminate EPA.	Same as SOP
Technical Interconnection Requirements	Simplified - prescribed in Net Metering Interconnection Requirements (NMIR)	Use Distribution Interconnection Requirements for Power Generators 35 kV and Below	Will follow Distribution Interconnection Requirements, with some modifications for projects under 1 MW
Interconnection Studies	Engineering review and multiple screening tests may be required for more complex projects	Optional $5,000 Screening Study followed by required interconnections study	Mandatory Screening Study. Where further studies are required (10% of offers), a reduced-scope interconnection study will be used
Network Upgrades	NU costs are typically minimal; for projects > 50 kW, system upgrade costs will be recovered from customer	BC Hydro is responsible for all upgrade costs up to a cap of $150/kW installed capacity; developer provides security for NU costs	Similar to SOP, with BC Hydro paying for all upgrade costs up to a cap of $150/kW and developer providing security for such costs

ISSUE	Net Metering – RS 1289 (proposed up to 100 kW)	Existing SOP (50 kW to 15 MW)	Proposed Micro-SOP (100 kW to 1 MW)
Metering	Most customers now have Smart Meters	IPP pays for installation of meter ($25,000) and transformers plus monthly fee ($250) for meter lease, telecom and e-metering	Use Smart Meters as revenue meters; developer pays one-time installation fee of $3,000 with no monthly fees
Load vs. Generation	Customers must offset their load. Customer receives payment for generation in excess of load	Customer-owned generation that receives load displacement or DSM funding is not eligible for SOP.	Require customers to offset their load prior to selling any excess electricity to BC Hydro.
Regulatory	RS 1289 is subject to BCUC approval	Exempt per *Clean Energy Act*	Exempt per *Clean Energy Act*

Table 2: FBC's Distributed Generation Offers

ISSUE	Net Metering – RS 95 (up to 50 kW)	All other Distributed Generation (50 kW and above)
Application Process	3-page application form	28 Facility Interconnection Requirements 2 page application
Electricity Purchase Agreement (EPA)	None	Required
Contract Term	1 year after which there is a 60 day cancellation notice period	Subject to Negotiation
Base Price	Retail	In most cases, notionally avoided cost in consideration of BC Hydro PPA rate and market. Will be considered in light of LTERP alternatives.
Price Escalation	Price subject to annual revenue requirement adjustments	No standard terms.
Delivery Requirements	Non-firm with no delivery requirements	Subject to Negotiation
Technical Interconnection Requirements	Simplified - prescribed in Net Metering Interconnection Requirements	Facility Interconnection Requirements Document
Interconnection Studies	Engineering review	Required.
Network Upgrades	Interconnection costs are the responsibility of the customer.	Interconnection costs are the responsibility of the customer.
Metering	Typically a single, bi-directional meter with other arrangements possible with approval of FBC	IPP pays actual cost for installation of meter and transformers
Load vs. Generation	Program intended for Customers to offset load. Incidental excess generation compensated at retail rate	Load customer must offset load prior to delivering power to any third party.
Regulatory	RS 95 is subject to BCUC approval	EPA subject to BCUC Approval

The BC Hydro chart shows three defined programs with applicability based on generation capacity. The programs cover a range of generation size from zero kW to 15 MW. FBC

understands that currently, BC Hydro offers a Net Metering Program for DG up to 100 kW, a Standing Offer Program (SOP) for DG 100 kW to 15 MW, and a Micro SOP for DG 100 kW to 15 MW that is limited to First Nations and Communities participation.

While FBC does not have a standard offer to purchase the output for interconnected DG above 50 kW, there is no "gap" in the generation capacity that can be interconnected as the Company has interconnection guidelines and transmission services available for generation of any size. The Company will also entertain the purchase of SG/DG output as a supply-side resource using the evaluation criteria discussed in Section 8.2 of the LTERP.

As explained in the reference to this IR, FBC is not seeking additional sources of supply at this time and is therefore not actively looking to purchase power from self-generator customers. It would not therefore be prudent to set a standard offer for resources at a cost to customers above what is otherwise available.

This situation is different than that described by BC Hydro which notes that,

> BC Hydro faces a gap when the amount of electricity that (it) can supply from existing resources is outstripped by the amount (it will) need to meet future demands from our growing population and economy. A variety of measures are required to ensure (it) has sufficient, reliable power for generations. These include implementing conservation and efficiency initiatives, maintaining and expanding (its) existing generation and transmission system assets, and adding more supply to (its) system through long-term electricity purchase agreements with IPPs.[18]

72.2.2 Please explain how much of a bill credit (in ₵/kWh) a medium or large commercial customer with DG will receive for electricity generated if they offset the electricity generated against their own supply.

Response:

FBC assumes that what is meant by, "…offset the electricity generated against their own supply" means that the customer uses its self-generation output to serve its own load. A Large

[18] https://www.bchydro.com/energy-in-bc/acquiring_power/meeting_energy_needs/how_power_is_acquired.html

Commercial customer that uses generation in this manner will not see a credit on its bill, but the energy will inherently have a value to the customer equal to the retail rate at which the customer would otherwise have purchased the power. For a customer on RS 30, that would be 5.571 ₵/kWh and for a customer on RS 31, that would be 5.516 ₵/kWh. Depending on whether or not the self-generation also results in a reduction of the peak demand recorded for the customer there may also be a benefit in reduced demand related charges.

72.2.2.1 Please explain whether the 50kW net metering capacity cap could prevent commercial customers from making DG investments that reduce (but do not exceed) their annual energy consumption?

Response:

FBC has four classes of Commercial customers: Rate Schedule 20 – Small Commercial, which is limited to customers with a demand not in excess of 40 kW; Rate Schedule 21 – Commercial, which is limited to customers with a demand not in excess of 500 kW; and Rate Schedules 30 and 31 – Large Commercial, limited to customers with a demand in excess of 500 kVA and 5,000 kVA respectively. Customers on Rate Schedules 30 and 31 are not eligible for the Net Metering Program.

The 50 kW cap on net metering installations does not prevent customers from making DG investments greater than 50 kW. The cap only prevents such a customer from installing a system with a capacity greater than 50 kW *and* enrolling in the Net Metering Program.

72.2.3 Please explain how much a residential/commercial customer with DG will receive for electricity fed into the grid if they are not eligible for FBC's net metering program.

Response:

FBC does not have any program that is designed for customers with self-generation to deliver power into its system on a routine basis as a power-supply option for the Company. At the present time, Net-Metering Program participants who have periodic excess generation are compensated at the prevailing retail rate. While the Company is not aware of any residential or

smaller commercial customers that are either ineligible for or choose not to take part in the Net-Metering Program, they would not be compensated unless a separate agreement was reached with FBC. FBC has in the past entered into separate agreements with customers to receive compensation at an avoided cost rate and has a small number of agreements with larger customers that reflect these terms.

72.3 For modified interconnection requirements, please reproduce BC Hydro's DG interconnection practices table, and describe any key differences in FBC's interconnection practices. Does FBC consider that its interconnection policies could be safely simplified for small-scale DG?

Response:

The tables provided in the response to BCUC IR 2.72.2.1, contain FBC and BC Hydro interconnection practice information. FBC requires a signed Interconnection Agreement from NM customers, while BC Hydro does not. In terms of other DG, the interconnection policies appear to be functionally similar. FBC considers that its interconnection policies for both NM and other DG are efficient and should not result in undue cost or delay.

72.4 Please provide an estimate of the percentage of generation supplied from customer owned DG on FBC's network, compared to the percentage of generation supplied from transmission connected generation.

Response:

FBC notes that customer-owned DG generation and transmission connected generation are not mutually exclusive categories. However, in 2016, the unplanned deliveries purchased by FBC from larger DG customers (Tolko, Celgar and Nelson Hydro) was 3,296 MWh[19]. In comparison, net metering customers delivered approximately 310 MWh during the same period.

[19] Refer to the response to ICG IR 2.5.2.

72.4.1 Does FBC consider that distribution connected generation is an immature industry compared to transmission connected generation? If yes, does FBC consider this to be a market barrier that it should attempt to mitigate? Please explain.

Response:

FBC has had distributed generation connected at both distribution and transmission voltages for decades and therefore does not consider one to be less mature than the other.

73.0 Reference: INFORMING DG/SG RELATED FILINGS

Exhibit B-1, Volume 1, p.21; Exhibit B-2, BCUC IR 11.6

Community solar

On page 21 of the FBC 2016 LTERP Application, FBC states that the City of Nelson is proposing to build a small solar photovoltaic (PV) array.

FBC states in response to BCUC IR 11.6 that the community solar PV pilot being considered by FBC would be included in rate base and that self-generators are not in a position to make an investment that is analogous to the community solar PV project.

73.1 Does FBC ensure customer investments in PV are on a level playing field with its own PV investments, such that the most cost-effective PV opportunity (from a BC perspective) is more likely to be built first? Please explain.

Response:

FBC does not consider PV to be a cost-effective energy supply option at this time, regardless of ownership. The proposed community solar pilot aims to provide a solar option for customers that cannot easily install a PV system, or cannot afford the up-front costs, but still desire to source some of their power in this manner. The pilot is designed such that the customers in general are insulated from the incremental revenue requirement of the project. Customers have full visibility of the costs involved in participation and can make an informed choice about the solar options that are available.

73.2 Does FBC ensure that distribution connected customer DG investments are on a level playing field with larger transmission connected customer SG investments, such that the most cost-effective opportunity (from a BC perspective) is more likely to be built first? Please explain

Response:

With the exception of DG connected as part of the net metering program (which is compensated at higher-than-market rates), FBC considers DG and SG to be on “a level playing field”.

Within the context of the LTERP and LT DSM plan, FBC is primarily concerned with making an accurate assessment of the aggregate customer load requirements over the planning horizon and developing the most appropriate and cost-effective resourcing strategy to ensure that the load is met. The referenced Community Solar project is not expected to serve non-participants

in the project, and the Company is not aware of any other solar installations planning to attach to the FBC system.

Generally, customer-owned SG projects are responsible for their own project costs including the cost of interconnection. FBC does not create additional costs for project proponents depending on voltage, however transmission connections are typically more expensive. All costs for services related to the interconnection and transmission are approved within the existing tariffed rates.

Beyond the provision of regulated services provided to SG customers at approved rates, FBC is not involved in the investment decisions of third parties.

73.3 Does FBC consider that it is appropriately incentivized to mitigate market barriers to DG/SG? If no, please comment on alternative methods that could be better align utility incentives and whether these alternative methods have been used in other jurisdictions.

Response:

The Company does not consider that it is currently incented to mitigate (or exacerbate) market barriers to DG/SG. FBC correctly treats all potential generation sources (with the exception of net metering) on an equal basis according to their supply characteristics. FBC does not perceive that it presents any significant market barriers either in the administrative or technical requirements that are in place and must be met prior to DG/SG interconnection. With respect to the alignment of utility incentives, it is unclear with what the incentives are to be aligned.

In FBC's view, an increase in the number of DG/SG installations would be driven primarily by economic considerations, a decrease in cost or through an increase in revenue that would result from higher prices in the available markets. As stated, the Company does not believe that its contribution to the costs of interconnection are a significant barrier, or that they are unfair in their treatment of customers depending on connection voltage. The price of power in available markets is not within the control of the Company and for its own power purchases FBC is guided by considerations as outlined in the LTERP.

74.0 Reference: INFORMING DG/SG RELATED FILINGS

Exhibit B-2, BCUC IR 11.2, 11.3, 23.2

Technical considerations, connection

FBC states in response to BCUC IR 11.2: "The primary safety concern with respect to grid-connected DG is the potential risk to customers, the public, and FBC employees presented by the back-feed of electricity from customer-owned generation into the FBC system. This risk is mitigated by the FBC interconnection requirements, however, that is only the case where a customer advises FBC of the interconnection."

FBC states in response to BCUC IR 11.3: "The connection policy, in its current form, is intended for the current low uptake levels of DG and so does not address distribution stability concerns. It would have to be modified to address the highly variable nature of DG; one example of how this could be done would be to require battery back-up to smooth out generation swings."

FBC states in BCUC IR 23.2: "It is possible that small-scale or larger clean DG resources could (i) defer the requirement for the anticipated network system reinforcements …"

74.1 Please explain whether FBC currently has distribution stability and/or or safety issues as a result of customer investment in DG, and how this has generally been addressed in other jurisdictions with (i) similar and (ii) higher levels of DG penetration.

Response:

FBC has not experienced distribution stability or safety issues as a result of existing customer investment in DG. It is expected that other utilities with similarly low levels of DG penetration have likewise experienced limited issues. In areas with higher DG penetration, utilities have indicated that these systems can lead to voltage stability issues. This is currently an area of considerable study by the industry.

74.1.1 Does FBC require/encourage the installation of advanced inverters in the design of solar PV systems that provides the ability to improve grid stability, support power quality, and provide ancillary services? If yes, please explain who pays for the cost of the additional functionality and who benefits (utility vs. customer).

Response:

In the case that an engineering assessment of a proposed PV installation indicated a requirement for additional or upgraded equipment in order to maintain the integrity of the FBC system, any associated costs would be the responsibility of the project proponent.

74.2 Please explain whether DG 'generation swings' are considered a significant issue in other jurisdictions with (i) similar and (ii) higher levels of DG penetration. Please explain how these concerns are generally addressed, and whether requiring customer purchase of battery back-up is generally considered a cost-effective solution.

Response:

As variability of DG power output is not presently a significant issue for FBC, it is unlikely that it is considered a significant issue in jurisdictions with similar levels of DG penetration. Some utilities experiencing higher levels of DG penetration have indicated that these systems can present significant issues. Examples of mitigation measures to address stability concerns include capacitor switching, installation of voltage regulators, installation of VAR Compensators, and installation of battery storage. The cost-effectiveness of battery storage rather than another mitigation measure would need to be determined based on the specifics of a proposed DG project.

74.3 Please describe (in general terms) the type and location of DG resources that, in aggregate, could defer the requirement for the anticipated network system reinforcements.

Response:

As described on page 89 of the LTERP, a large-scale generation resource, such as a gas-fired generation plant in the Kelowna area, is an example of a generation resource that could defer an anticipated system reinforcement. For an aggregation of clean DG resources, only those that are not intermittent in nature could have an impact on the required in-service date of system reinforcements. In general, DG resources would need to be locally interconnected in the area of the system requiring reinforcement in order to have this impact.

74.4 Please explain whether FBC requires that a customer notifies the utility before connecting DG. If no, please explain why it is not required. If yes, please explain how FBC ensures that the policy is followed.

Response:

The interconnection of customer-owned generation is permitted by Section 10 of FBC's Electric Tariff which states in part:

> Prior to the commencement of installation of any generating facilities, the Customer shall provide to the Company full particulars of the facilities, and the proposed installation, and shall permit the Company to inspect the installation. The Customer at its own expense shall provide approved synchronizing equipment before connecting parallel generating facilities to the Company electrical system.

It is not possible for the Company to monitor all activities on the customer side of the point of interconnection with FBC. However, while unauthorized connections would present a safety concern, the Company has no reason to believe that such connections persist in its service area. Installations of this type typically involve a utility reconnection and provincial permitting. In addition, were such an installation discovered, it would be subject to immediate disconnection. With the introduction of AMI, an unauthorized disconnection/reconnection will be detected and investigated.

75.0 Reference: INFORMING DG/SG RELATED FILINGS

2007 BC Energy Plan: A Vision for Clean Energy Leadership (2007 BC Energy Plan), Policy Action # 25; Exhibit B-2, BCUC IR 36.1, 36.3; BC Hydro, SOP Standard Form Electricity - Purchase Agreement, March 2016, Appendix 3

Avoided cost

The 2007 BC Energy Plan includes as Policy Action #25: "Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources."

FBC states in BCUC IR 36.1: "… the primarily residential nature of the premises on which the [small-scale customer-owned generation] facilities are installed are subject to the ability of the original project owner to relocate. Small-scale customer-owned generation of the size typified by net metering installations is highly variable both in terms of generation and the associated load. For these reasons, as well as the timing of the generation, the Company cannot consider it to be long term in nature."

FBC states in BCUC IR 36.3: "If the resource provides little to no winter energy, such as solar PV, then it will have little to no impact on the LTERP required resources in the preferred portfolio A4, meaning that any energy produced at best only displaces BC Hydro PPA energy costs. A LRMC based on the PPA Tranche 1 energy rate is in the range of $47 - $56 per MWh (per Table 8-4 of the LTERP)."

Appendix 3 of BC Hydro's March 2016 standard form electricity purchase agreement for its SOP program includes a table showing time of delivery factor adjustments (monthly and within day).

75.1 Please provide evidence to support FBC's concern that energy from small-scale DG is not long term in nature as facilities can be relocated once they are installed. Please include in your response whether this has been a significant issue faced by other jurisdictions with a higher level of DG penetration.

Response:

In its response to the referenced IR, FBC did not indicate that it had a concern stemming from the fact that the "...facilities can be relocated…" Rather, the response says that, "…the installation itself may be difficult to dismantle and move, the primarily residential nature of the premises on which the facilities are installed are subject to the ability of the original project owner to relocate." (Underline added).

While this is true, it is not the most important consideration when evaluating net metering installations as an economic supply resource.

The intent of the Net Metering Program was recently confirmed by the Commission, which clarified that new customers will not be accepted into the NM Program if their proposed generating capacity exceeds their anticipated annual consumption.[20]

As such, Net Metering is, by definition, precluded from consideration as it should not account for an appreciable amount of deliveries to FBC greater than the sum of incidental net excess generation which, due to the expected timing, is generally of little value.

The impact of Net Metering materializes as a reduction in load as was considered in the load scenarios incorporated into the LTERP and FBC plans to continue to monitor its expected impact on load to ensure that it is appropriately taken into account.

75.2 Please provide evidence to support FBC's concern that energy from small-scale DG is not long term in nature as installations are highly variable both in terms of generation and the associated load. Please include in your response (i) an estimate of the level of annual variability (in terms of total kWh produced) on an aggregated annual basis of DG on FBC's network compared to the annual variability generally seen in FBC's load, and (ii) to what extent this is a significant issue faced by other jurisdictions, and if so how it is generally addressed.

Response:

This question links the lack of a long-term nature and the variability of load and generation in a manner that was not intended in the original response. The Company has explained why it cannot at this time consider small-scale DG, and in particular net-metering, a long-term resource in its response to BCUC IR 2.75.1.

The Company has insufficient experience and data regarding this type of resource to provide meaningful information of the type requested.

With respect to other jurisdictions, while there are many examples of revisions being made to net metering rates, programs, regulations and the treatment of excess generation to mitigate issues related to the transfer of costs to non-participants, the Company has been unable to locate any discussion of net metering as a long-term resource and therefore no discussion of related issues or solutions.

[20] Appendix A to Order G-199-16 Page 11

75.3 Please provide FBC's LRMC of energy, and explain the seasonal energy shape assumed.

Response:

FBC's LRMC of energy can be found in the response to BCUC IR 1.34.2.

75.3.1 Using the monthly delivery factor adjustments included in BC Hydro's SOP program, please provide an estimate of the seasonal adjusted LRMC for energy with a shape similar to that produced by (i) solar PV installation, and (ii) micro-hydro generation.

Response:

FBC does not believe it is correct to apply the BC Hydro SOP adjustments to FBC, as explained in the response to BCUC IR 2.67.4. As shown in Table 1 and Table 2, the portion of the annual energy generated by these resource types in the winter season is comparatively low and therefore their value is quite low as they will not displace required new resources to provide the winter energy needed. However, for purposes of this question, FBC has applied BC Hydro's SOP delivery factor adjustments[21] to FBC's $84 per MWh LRMC of acquiring energy[22]. The annual energy shape of a solar PV installation is estimated as the average of the solar resource options included in the FBC resource portfolio. The annual energy shape of a micro-hydro generator is estimated as the average of the three smallest run-of-river hydro resource options included in the FBC resource portfolio.

[21] As FBC does not have hourly delivery shapes for the resource options included in the LTERP, FBC weighted the time of delivery factors.
[22] Please refer to the response to BCUC IR 1.34.2.

Table 1: Solar PV seasonal adjusted LRMC for energy using BC Hydro SOP monthly delivery factor adjustments

	Weighted BC Hydro SOP	FBC Adjusted LRMC	Assumed Delivery Profile - Solar PV	Monthly LRMC Weight
Jan	117%	$ 98	**4%**	$ 4
Feb	110%	$ 92	**6%**	$ 5
Mar	108%	$ 91	9%	$ 8
Apr	92%	$ 77	10%	$ 8
May	78%	$ 65	11%	$ 7
Jun	77%	$ 65	11%	$ 7
Jul	89%	$ 75	12%	$ 9
Aug	96%	$ 80	11%	$ 9
Sep	101%	$ 84	10%	$ 9
Oct	106%	$ 89	8%	$ 7
Nov	108%	$ 91	**5%**	$ 4
Dec	116%	$ 97	**3%**	$ 3
			100%	**$ 81**

Table 2: Micro-Hydro seasonal adjusted LRMC for energy using BC Hydro SOP monthly delivery factor adjustments

	Weighted BC Hydro SOP	FBC Adjusted LRMC	Assumed Delivery Profile - Micro Hydro	Monthly LRMC Weight
Jan	117%	$ 98	**5%**	$ 4
Feb	110%	$ 92	**4%**	$ 4
Mar	108%	$ 91	5%	$ 5
Apr	92%	$ 77	10%	$ 8
May	78%	$ 65	17%	$ 11
Jun	77%	$ 65	17%	$ 11
Jul	89%	$ 75	13%	$ 10
Aug	96%	$ 80	7%	$ 6
Sep	101%	$ 84	5%	$ 4
Oct	106%	$ 89	6%	$ 5
Nov	108%	$ 91	**6%**	$ 6
Dec	116%	$ 97	**6%**	$ 5
			100%	**$ 78**

76.0 Reference: LONG RUN MARGINAL COST

Exhibit B-1, Volume 2, 2016 Long-term (LT) DSM Plan, p. 3; Exhibit B-2, BCUC IR 35.1

Guidance for future applications

FBC states on page 3 of the 2016 LT DSM Plan Application that its LRMC of firm energy (inclusive of generation capacity) is $100.45/MWh (abbreviated as $100/MWh) and the avoided capacity cost of deferred infrastructure is $79.85/kW-year.

FBC states in BCUC IR 35.1: "The LRMC includes line losses, therefore includes delivery to the customer. If a generation resource were to be located in the FBC system at the distribution level, it can be expected that transmission losses would be reduced by 2 to 3 percent."

76.1 Please break down FBC's LRMC of firm energy into its 'generation-energy' and 'generation-capacity' components. If FBC is not able to unbundle its generation LRMC between energy and capacity, please approximate this by estimating the long-run market value of generation-capacity (in $-kW-year) and, using an appropriate load factor assumption, translate this into a $/MWh generation capacity estimate. Deduct this value from the $100/MWh firm generation estimate to approximate a non-firm generation estimate. Please provide supporting calculations and assumptions.

Response:

Please refer to the responses to BCUC IRs 1.34.1 and 1.34.2.

76.1.1 Please provide a side by side comparison of the following components FBC's LRMC estimate with that of BC Hydro: generation (energy), generation (capacity), network (capacity), and explain any significant differences.

Response:

	BC Hydro[23] Avoided Costs	FBC Avoided Costs Portfolio B1 (2015$)	FBC Preferred Portfolio Portfolio A4 (2015$)
Energy	$87 per MWh (2016$) – 2022-2033 $102 per MWh (2016$) - 2034 onward	$86 per MWh	$84 per MWh
Capacity	$37 per kW-year (2016$) - 2016-2019 $58 per kW-year (2016$) - 2020-2028 $118 per kW-year (2016$) -2029 onward	$115 per kW-Year	$98 per kW-Year
Network Capacity	Bulk transmission capacity: $0 per kW-year (2011$) Regional transmission and substation capacity: $11 per kW-year (2011$) Distribution capacity $1 per kW-year (2011$)	$80 per kW-Year[24]	$80 per kW-Year

As stated in Appendix K of the LTERP, FBC and BC Hydro have taken different approaches to calculating the LRMC. Despite the different methodologies, overall the FBC energy LRMC numbers are similar to those used by BC Hydro. BC Hydro has identified specific resources to address forecast load requirements, such as Revelstoke Unit 6[25] for capacity, which is exclusively available to BC Hydro.

FBC has developed a portfolio of resources and presented a LRMC that reflects the incremental costs of serving incremental load requirements over the planning horizon. Other factors that result in differences include the size and scale of resource options, the timing of resource requirements and locational attributes. For further discussion regarding FBC's Deferred Capital Expenditure (DCE) value compared to other utilities including BC Hydro, please refer to the response to BCUC IR 1.34.3.

[23] BC Hydro. F2017-F2019 Revenue Requirements Application. Revision 1 – August 17, 2016. Appendix X: Demand-Side Management Assumptions. Table X-1: Portfolio Wide Assumptions.

[24] Represented by FBC's Deferred Capital Expenditure (DCE) value of $79.85 per kW-Year rounded to the nearest dollar

[25] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28th, 2016. Section 3.4.4.3.

76.2 Please provide a description of the key portfolio components making up FBC's portfolio LRMC estimate (including cost and weighting).

Response:

The key components that make up FBC's LRMC estimate include incremental DSM[26], PPA, new resources, market purchases, and surplus sales[27]. Only incremental costs and incremental energy within the planning horizon is considered within the LRMC calculation (please refer to the response to BCOAPO 2.61.1 for a simplified numerical example). The portfolio composition, and therefore the cost and weighting of each component, change depending on the portfolio characteristics such as the level of DSM activity, the restriction to include only clean resources, the load scenario, the assumed cost of market energy, the assumed cost of PPA, or inclusion of a self-sufficiency target. Correspondingly, the LRMC for each portfolio scenario changes as the weighting and costs of the key components contained in the portfolio change.

This variability between the various portfolios leads to non-intuitive results such as the cost of new resources on a per MWh basis being lower if DSM is not undertaken as compared to where a high level of DSM is achieved. This is due to the economies of scale wherein a much larger generation plant achieves a lower unit cost compared to the relatively small plants required under the high DSM A4 portfolio. For portfolio B1, the LRMC is $100 per MWh. Table 1 provides a breakdown of the key components of portfolio B1, including the weights and costs

Table 1: Portfolio B1 Components

	Weighting	$ per MWh	Weighted Average Cost ($ per MWh)
DSM	0.00%	$0.00	$0.00
PPA	29.98%	$58.72	$17.60
New Resources	57.51%	$126.17[28]	$72.56
Market	12.63%	$60.13	$7.59

[26] FBC assumes the "Low DSM" scenario against which the incremental costs associated with higher levels of load growth offset due to DSM are compared in the various portfolios.

[27] Incremental surplus sales by FBC vary from portfolio to portfolio as the portfolio model optimizes the use of resources. Since surplus sales impact the total portfolio cost, they also impact the LRMC.

[28] The values for New Resources in both Tables 1 and 2 tend to be higher than would be expected from the Unit Energy Costs (UECs) of the available New Resources. The model is just an approximation of actual operations that does not dispatch a resource in cases where the power is not needed to meet load and this can lead to higher than expected costs on a $ per MWh basis. In addition, if capacity-only resources are included in the total (as in Table 2 for the A4 portfolio), this will also increase the cost on a $ per MWh basis. The appropriate method to evaluate a new resource alternative is to include it in the portfolio model to see if it is selected for dispatch to meet load requirements. UECs are based on total resource costs divided by total available energy and do not account for the timing of energy requirements in the planning horizon or energy requirements less than total available from the resource.

	Weighting	$ per MWh	Weighted Average Cost ($ per MWh)
Surplus Sales	0.44%	N/A[29]	$2.69
		LRMC	**$100.45**

For FBC's preferred portfolio A4, the LRMC is $96 per MWh. Table 2 provides a breakdown of the key components of portfolio A4, including the weights and costs.

Table 2: Portfolio A4 Components

	Weighting	$ per MWh	Weighted Average Cost ($ per MWh)
DSM	20.16%[30]	$107.00	$21.57
PPA	38.09%	$61.08	$23.26
New Resources	34.93%	$133.57	$46.65
Market	3.38%	$57.70	$1.95
Surplus Sales	3.40%	N/A	$2.88
		LRMC	**$96.32**

76.2.1 If FBC's portfolio LRMC estimate includes (i) DSM or (ii) short-term market purchases, please explain if this is consistent with general industry practice. If yes, please provide specific examples.

Response:

In Section 4 of Appendix K of the LTERP, FBC considers three different approaches to calculating the LRMC based on FBC's understanding of the approaches used by other utilities, including BC Hydro. FBC has used the Average Incremental Cost (AIC) method and included all incremental resources required by FBC, including DSM and market purchases, to meet customer load requirements. FBC cannot state how utilities other than BC Hydro developed their LRMC numbers within the broad guidelines of these approaches. A discussion of these three methods follows.

[29] Surplus sales are a combination of energy and capacity sales which makes representation on a $ per MWh basis inappropriate.

[30] Under portfolio A4, low DSM of about 55 percent is assumed to occur and not considered incremental and therefore it is not part of the weighting. In addition, since all cost values are net present value (NPV), load values must also have NPV applied to them to calculate the appropriate weightings. Since the DSM performance is greater in the later part of the planning horizon, the overall weighting on a NPV basis is much lower than on an actual basis. On an actual basis, all DSM is meeting about 77 percent of total load growth throughout the planning horizon as per Section 8.1.1 of the LTERP.

The first of the options was the Levelized Unit Energy Cost (LUEC) method, which is a resource-specific calculation. Since FBC has more than a single specific resource option to consider, any selected resource would be somewhat arbitrary. BC Hydro currently has an avoided energy cost value of $87 per MWh[31] (for 2022-2033) and an avoided cost of capacity of $118 per KW-year (for 2029 onwards, which FBC assumes is applicable post Revelstoke Unit 6). FBC's understanding is that, since BC Hydro is required to be electricity self-sufficient by 2016, its avoided costs do not include market purchases[32]. BC Hydro does consider DSM a marginal energy resource[33]. If FBC were to use the LUEC method, then adopting the BC Hydro avoided cost values would provide the benefit of consistency of LRMC values within B.C. However, this would not take into account FBC's unique circumstances and therefore FBC has determined that the LUEC method is not the preferred method to determine the FBC LRMC.

The second option FBC considered was the Perturbation approach, which, while a portfolio-based approach, is only concerned with the costs associated with a small change in demand. This method could include DSM and market purchases. Given that FBC new resource options tend to be smaller in size, this approach becomes extremely sensitive to the exact size and shape of the demand increment. In addition, results from one long term electric resource plan to the next could vary significantly simply due to timing issues. FBC believes that it is more realistic and appropriate for LRMC numbers to remain relatively stable from one long term electric resource plan to the next. For these reasons FBC determined that the Perturbation approach was not appropriate for FBC.

The final approach FBC considered was the portfolio based AIC method. FBC believes this method provides a reasonable approximation of FBC's LRMC as it considers the entire planning horizon, takes into account all the resource options available to FBC, including DSM and market purchases, and is consistent with a portfolio analysis approach as described in the Commission's Resource Planning Guidelines. Furthermore, while FBC and BC Hydro employed different methodologies to arrive at LRMC values, the AIC methodology used by FBC provides results that are not significantly different than the BC Hydro values.

Any individual project must be evaluated on its own merits, considering the timing and shape of FBC loads and other resources. FBC performed portfolio analysis to evaluate the suitability of the available resources, including the availability of DSM and market opportunities. As DSM and market are part of the portfolio analysis, it is consistent that all aspects of the portfolio should be used to determine the LRMC. Changing one or more aspects of the portfolio such as increasing the level of planned DSM activity or varying the market pricing has an impact on the other components within the portfolio. As a result, FBC believes the entire portfolio must be

[31] Please refer to the response to BCUC IR 2.76.1.1 for references to the BC Hydro LRMC values.

[32] BC Hydro does include Market Price as a "reference price" in the fiscal years 2016-2021.
Source: BC Hydro. F2017-2019 Revenue Requirements Application. Appendix X: Table X-1, Avoided Costs.

[33] BC Hydro F2017-2019 Revenue Requirements Application, Chapter 3.4.4.2 Table 3-10: Marginal Energy Resources and Related Costs.

considered to ensure the LRMC best reflects the marginal decisions or corresponding incremental costs to the rate payer over the long term.

76.2.2 Please show the effect on the LRMC portfolio under the following scenarios: (i) DSM is excluded; (ii) market purchases are excluded; (iii) non-BC clean energy is excluded; (iv) DSM and market purchases are excluded; and (ii) DSM and non-BC clean energy is excluded.

Response:

Table 1 shows the impact on the LRMC of Portfolio B1 and Portfolio A4 with various portfolio components removed from the LRMC calculation. To derive the adjusted LRMC both the incremental costs and incremental energy of the components being removed from the portfolio were excluded from the portfolio LRMC calculation.

Table 1: Effect on the LRMC portfolio with components excluded

	Portfolio B1 (2015$)	Portfolio A4 (2015$)
Portfolio LRMC per LTERP	**$100**	**$96**
(i) DSM is excluded	N/A	$94
(ii.a) Market Purchases are Excluded	$106	$98
(ii.b) Market Purchases and Surplus Sales are excluded	$104	$98
(iv.a) DSM and Market Purchases are Excluded	N/A	$95
(iv.b) DSM, Market Purchases and Surplus Sales are excluded	N/A	$96

Note that for question item (iii) FBC does not have any non-BC clean energy other than potential market sources and therefore the response is the same as for question (ii).

76.3 Please explain whether, in arriving at the portfolio cost, delivery was assumed to be at the transmission voltage level, primary distribution or secondary distribution voltage level.

Response:

Delivery was assumed to be at the transmission voltage level.

76.3.1 Please provide the average percentage losses on the (i) primary and (ii) secondary distribution voltage networks.

Response:

FBC does not currently have an accurate breakdown of losses between the primary and secondary distribution networks. For an estimate of the breakdown between transmission and distribution losses please see the response to ICG IR 2.1.2.

F. VOLUME 2 – LONG-TERM DEMAND-SIDE MANAGEMENT PLAN

77.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 33.1; FBC Long Term DSM Plan (2012), p.11; FBC Application for Acceptance of DSM expenditures for 2017 Reasons for Decision to Order G-9-17 dated January 25, 2017, pp. 4, 10; 2017 RIB Rate Report, p. 27

DSM portfolio options

FBC provides the 2017-2021 DSM budget for the four DSM portfolio options modelled in the FBC LTERP in BCUC IR 33.1:

Table 1: Estimated Annual Cost (DSM Budget) i

Year	Low	Base	High	Max
2017	$7,610	$7,610	$7,610	$7,610
2018	$5,200	$7,900	$7,900	$7,900
2019	$5,200	$7,900	$7,900	$7,900
2020	$5,200	$7,900	$7,900	$7,900
2021	$5,200	$7,900	$9,000	$9,000
Total	**$28,410**	**$39,210**	**$40,310**	**$40,310**

On page 11 of the FBC 2012 long-term DSM Plan, FBC provided an overview of its three DSM options (Low: $5 million/year; Medium: $9 million/year and High: $20 million/year).

The Commission stated in its January 25, 2017 Reasons for Decision to Order G-9-17 on an FBC Application for Acceptance of DSM expenditures for 2017 (pp. 4, 10):

> The Panel accepts FBC's DSM requested expenditure schedule of $7.6 million for 2017, and considers that making the expenditures referred to in the schedule is in the public interest. Despite the acceptance of the proposed expenditure schedule, the Panel is concerned that it falls short of addressing a range of DSM possibilities that could be pursued in the coming year. ...
>
> The Panel is further concerned that the extension of existing programming sits on a foundation of recent activity which in itself can be characterized as having fallen short. In other words, "more of the same" is inherently plagued by underperformance. FBC has provided responses/justifications for many of the challenges laid down by the interveners in terms of past performance shortfalls, but the Panel finds some of these explanations unpersuasive.

The 2017 RIB Rate Report states on page 27: "For FortisBC, the current environment would support an expansion of DSM funding to accommodate new programs."

77.1 Please explain why (i) FBC's DSM portfolio options do not show significant variations in spending levels for 2017-2021between the base, high and max DSM portfolio options, and (ii) the DSM options modelled are lower in annual average DSM spending over this period than the medium option modelled in the 2012 long-term DSM Plan ($9million/year).

Response:

The period 2017-2021 does not show significant variation in estimated DSM portfolio budgets to allow FBC to make better use of more cost-effective resources, namely PPA tranche 1 energy, before DSM begins to escalate.

FBC considers that the $9 million figure from the 2012 LT DSM Plan was a high level estimate. It included two expenditure components ($300 and $750 thousand) for Codes & Standards and Compliance respectively that were not undertaken. The resulting adjusted 2012 medium option figure of $7.95 million, for DSM programs and supporting initiatives is similar to the proposed High DSM Scenario pro-forma budget estimates of $7.90 million for the 2018 to 2020 period (Table 3-2 of the LT DSM Plan).

77.1.1 Please explain what actions FBC has taken in this Application to address the concerns raised by the Commission in its Decision on FBC's 2017 DSM expenditure schedule that it falls short of addressing a range of DSM possibilities that could be pursued by FBC.

Response:

FBC considers that a long-term resource plan is developed to optimize the selection and quantity of supply-side and demand-side resources required to meet the Company's forecast load, while managing risk.

The 2016 LT DSM Plan developed and considered four levels of DSM resource acquisition, based on load growth offsets as per provincial policy (BC Energy Plan, *CEA*). The four DSM options were informed by the 2016 FBC CPR economic potential results. The CPR included an extensive review of measures, including updating the measure costs and TRC. The FBC CPR results show ample, cost effective DSM is available.

FBC selected the high DSM Scenario as the preferred option for the 2016 LTERP based on the portfolio analyses undertaken as described in Section 9.3.1 of the LTERP. The high DSM scenario ramp-up to 80 percent load growth offset, was tempered in the near term to better utilize the more cost-effective PPA tranche 1 resource.

The High DSM Scenario, that was independently determined through the LTERP process, provided a near term target of 26.4 GWh/yr for 2018-2020. The High DSM Scenario target is co-incidentally similar in magnitude to the approved 2017 DSM Plan target of 25.7 GWh. Furthermore, the High DSM Scenario is proposed to escalate to target 32 GWh/yr in 2023 and for the remainder of the planning horizon.

The High DSM Scenario pro-forma DSM budget was costed based primarily on the 2016 FBC CPR economic potential results. FBC used 50 percent of measure cost as the estimated incentive level, a commonly used assumption for DSM budgeting purposes, for an estimated incentive budget of $4.5 million in 2018. A program administration cost of $3.4 million was added, based on the approved 2017 DSM Plan administration costs, thereby totaling the $7.9 million 2018 budget presented in Table 3-2. The 2018 estimated DSM budget is co-incidentally similar in magnitude to the 2017 approved DSM expenditure of $7.6 million. The pro-forma High DSM Scenario budget subsequently escalates to $10.9 million in 2023 (in constant dollars) and for the remainder of the planning horizon.

The BC CPR additional scope services work now underway, though not incorporated into the LTERP and LT DSM Plan, will include a number of components that are anticipated to address the range of DSM possibilities for consideration in FBC's future filings including the next DSM expenditure schedule. The CPR additional components include: market potential, demand response (DR) potential, electrification (fuel switching) potential.

The CPR market potential will inform FBC's next DSM expenditure schedule, for 2018 onwards, that is anticipated to be filed later this year. FBC considers the CPR market potential is not needed to inform the LTERP/LT DSM Plan, as the FBC CPR economic potential results were sufficient for those purposes.

Subject to the results of the DR potential, FBC may propose DR pilot projects in the Innovative Technology section in its next DSM expenditure schedule filing, in order to gain experience in this mode of DSM. FBC forecasts there is considerable time before DR DSM resources may be needed as the LTERP shows the Company is long on capacity for approximately the next decade.

Electrification (fuel switching) has been discussed at some length elsewhere in these proceedings. FBC reiterates its belief that such an undertaking is not a DSM program per se, and awaits the results of the updated fuel switching potential – using the newly prescribed benefit/cost test for Electrification undertakings pursuant to section 4.1 of the *GGRR* - to inform its actions going forward.

77.2 Please provide in table form: the annual DSM funding assumed for the low, base, high and max DSM options for each year from 2018 to 2022 (with a total row); additional rows showing average annual DSM funding (2018-2022); accepted 2017 DSM funding; average annual DSM funding (2018-2022) as a percentage of the accepted 2017 DSM funding.

Response:

Please refer to the table which provides high-level estimates of annual DSM expenditures for the four DSM scenarios presented in the LT DSM Plan filing. The figures, including the DSM savings targets and notably the pro-forma DSM budget cost estimates, are intended to be illustrative and FBC is not seeking approval as part of the LT DSM Plan. 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.

Annual DSM funding, accepted 2017 and LTERP forecast 2018 to 2022

Year	Annual DSM Funding (2016 $000s)			
	Low	Base	High	Max
2018	$5,200	$7,900	$7,900	$7,900
2019	$5,200	$7,900	$7,900	$7,900
2020	$5,200	$7,900	$7,900	$7,900
2021	$5,200	$7,900	$9,000	$9,000
2022	$5,200	$7,900	$10,000	$10,000
Total	$26,000	$39,500	$42,700	$42,700
Average	$5,200	$7,900	$8,540	$8,540
2017 Accepted	$7,610	$7,610	$7,610	$7,610
2018-2022 avg as % of 2017	68%	104%	112%	112%

77.3 Does FBC consider that the size of the DSM funding envelope for 2018-2021 could reasonably be increased by 50% compared to that proposed by FBC, while ensuring that the DSM portfolio (on a total basis) passes the TRC and UCT? If no, please explain why not.

Response:

FBC's preferred DSM scenario (detailed in Table 3.2 of the LT DSM Plan) escalates the DSM funding envelope to $10.5 million in 2025, which is timed to make full use of the BC Hydro PPA Tier 1. FBC does not believe it is reasonable to escalate the DSM funding envelope before maximizing use of cost-effective PPA Tier 1.

78.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 45.3.1, 48.1; Exhibit B-1, Volume 1, p. 95

Bottom up vs. top down portfolio planning

FBC states in BCUC IR 45.3.1 that it is unable to estimate DSM savings from a DSM portfolio option that is 50% higher than the annual 'High DSM' scenario as the starting point is energy savings targets rather than alternative DSM budgets. FBC states in BCUC IR 48.1: "FBC primarily considered the LRMC, rather than specific rate or bill impacts, to assess the cost effectiveness of the various portfolios."

FBC states on page 95 of the 2016 LTERP Application: "… FBC looks to demand-side resources first to meet any future [load resource balance] gaps."

78.1 Please explain whether FBC would describe its DSM portfolio planning as 'top down' (for example, using a target percentage of energy savings to set the DSM funding envelope) as opposed to 'bottom up' (for example, using the Conservation Potential Review (CPR) as the starting point to develop alternative DSM portfolios for evaluation against supply side options).

Response:

No, FBC would not use such terminology for its DSM portfolio planning approach.

Section 3 of the LT DSM Plan describes FBC's DSM portfolio planning methodology. FBC used load growth offset, based on provincial policy, to establish four DSM "energy savings" scenarios. The cost of each DSM scenario was informed by the CPR economic potential results plus an assumed addition for program administration. The DSM scenarios were then incorporated into the LTERP portfolio model as discussed in section 9 of the LTERP.

78.1.1 Please also describe the approach used in FBC's last LTERP in similar terms, and comment on any differences.

Response:

In the 2012 LTRP, FBC took a similar approach to the 2016 LTERP in terms of first determining the amount of DSM load growth offset before determining required supply-side resources to fill remaining forecast load-resource gaps. For the 2012 LTRP, FBC targeted 50 percent load growth offset from DSM, consistent with the 2007 B.C. Energy Plan target for BC Hydro. Then FBC evaluated several different supply-side resource options to meet any remaining LRB

gaps. FBC did not consider different DSM scenarios or conduct portfolio analysis in the 2012 LTRP.

78.2 Please explain why FBC used LRMC in assessing the cost effectiveness of the various portfolios. Specifically, how did this approach inform FBC as to the appropriate level of DSM incentives to offer, whether funding levels for existing programs should be increased and/or whether new programs should be offered?

Response:

FBC's LRMC of acquiring electricity generated from clean or renewable resources, for purposes of evaluating DSM programs, is represented by Portfolio B1 in Section 9.3.1 of the LTERP: FBC valued the measures' energy savings at the LRMC of $100.45 per MWh.

Section 3.2 of the LT DSM Plan explains how FBC chose its preferred High DSM scenario. The LRMC was used to calculate a TRC benefit cost ratio (1.9) to inform the selection of this scenario. This TRC indicates that the LRMC was not a limiting factor on selecting the preferred scenario.

In terms of funding levels, the 2016 LT DSM Plan is not an expenditure schedule, so funding levels by sector or by program were not estimated. FBC anticipates filing its next DSM expenditure schedule, for 2018 onwards, later this year.

78.3 Please explain whether (and if so, how) FBC's approach to setting the DSM portfolios is consistent with FBC's statement that it looks to demand-side resources first to meet any future gaps.

Response:

Yes, FBC's approach to setting the DSM scenarios is consistent with looking to demand-side resources first to meet any future gaps. As discussed in Section 8.1.1 of the LTERP, FBC assessed several different levels of DSM load growth offset to help meet future LRB gaps before determining the supply-side resource options to meet any remaining gaps after DSM. Once the preferred level of DSM was determined, FBC's portfolio analysis then incorporated this preferred level of DSM in determining the optimal mix of supply-side resources to meet LRB gaps.

79.0 Reference: LT DSM PLAN

FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) Decision dated December 3, 2014, p. 25; Exhibit B-2, BCUC IR 33.1, 41.2.1, 44.1, 44.2.1, 45.6

Linkage to the CPR

The Commission stated in its December 3, 2014 Decision on FEU 2014 Long Term Resource Plan (LTRP), page 25:

> Ideally, the utility should first file an LTRP and then file a DSM expenditure schedule under section 44.2 of the UCA. This allows the utility to receive guidance regarding the overall size and approach of the DSM funding proposal prior to filing the detailed DSM expenditure schedule. This preferred order of filing is reflected in the UCA – the Commission is required for DSM expenditure filings to consider the most recent long-term resource plan filed by the utility in determining whether to accept the DSM expenditure schedule, and not vice versa.

FBC states in BCUC IR 41.2.1: "FBC has not (yet) estimated the achievable potential for each measure in the 2016 LT DSM Plan, which is an anticipated result of the market potential in the next phase of the BC CPR." FBC states in BCUC IR 33.1: "The Company intends to develop, and file later in 2017, a detailed DSM expenditure schedule allocating savings targets to programs and sectors, and thus has not estimated the energy cost, TRC, and [rate impact measure (RIM)] on an annual basis, however pro-forma values are presented at the portfolio level for each scenario."

FBC states in BCUC IR 44.2.1 that TRC and utility costs for measures FBC no longer offers are not available as they were not included in the BC CPR study. In BCUC IR 44.1, FBC identifies the measures included in the Seventh 2016 Northwest Conservation and Electric Power Plan (2016 NW PP) that are not included in the 2016 FBC CPR. FBC further states: "For the purpose of the BC CPR, Navigant prioritized measures with high impact, data availability, and most likely to be cost-effective as a criteria for inclusion in the study."

FBC states in BCUC IR 45.6 that key assumptions used to determine the utility cost of alternative DSM portfolios included: utility incentive rate of half the measure cost and free-rider/spillover rates of zero percent.

79.1 Please explain the purpose of the CPR. Please include in your response whether, in general terms, the purpose of a CPR is to: (i) identify where customers are (from a BC perspective) not efficiently using electricity (for example, inefficient lighting, under-heating homes), and (ii) estimate the energy

savings that the utility could reasonably achieve through DSM programs that encourage customers to improve the efficiency of their electricity use.

Response:

In general, the CPR characterizes opportunities to achieve energy savings but does not suggest areas where "customers are not efficiently using electricity". FBC's DSM programs promote more efficient ways to use electricity for the desired end-uses. Further, the market potential component of the BC CPR study will identify energy savings that the utility could reasonably achieve through DSM programs over the planning horizon.

A CPR examines the conservation potential (energy and capacity savings potential) of DSM measures (technologies and activities) in a defined study area relative to a reference case. A CPR defines where, how and at what cost energy and demand can be reduced.

A CPR is an important planning tool that is used to:

- provide input into DSM Planning and long term energy conservation goals;
- develop new energy efficiency and conservation programs or initiatives, including behavior programs, and modify existing ones;
- provide input into integrated resource planning; and
- provide input into load forecasts.

79.1.1 Please explain which steps of the CPR were used to inform the FBC 2016 LTERP, and which steps have yet to be completed. For the steps to be completed, please also provide the anticipated completion date.

Response:

The initial phase of the BC CPR and FBC's results and report regarding technical and economic potential results for its service area was completed and filed as Appendix A of the LT DSM Plan. The work contained in the initial phase of the BC CPR is sufficient to inform the 2016 LTERP as to the magnitude of DSM resource potential available and for the costing of the DSM Scenarios considered.

The next step was to estimate FBC's CPR market potential, which is now underway and expected to be complete mid-year. The market potential results will inform FBC's next DSM expenditure schedule, for 2018 onwards, which is anticipated to be filed later this year.

79.2 In this LTERP, please explain whether FBC performed each of the following steps (and if not performed, why not):

- for each area identified in the CPR as being an example of a customer not efficiently using electricity, identification of the potential reason for that behaviour (for example, high upfront cost, lack of information, hassle factor);
- development of potential DSM programs to 'nudge' the customer to be more efficient in electricity use, with sub-options such as varying levels of incentives provided to customers
- estimation of the utility cost of these programs (¢/kWh of energy saved), taking into account free-riders and spillover effects;
- development of alternative portfolios DSM programs, taking into account effectiveness (e.g. utility cost of the DSM program, missed opportunities) and balance (e.g., targeting 'hard to reach' customers and ensuring a reasonable level of DSM offered to each customer class); and
- evaluation of alternative DSM portfolios against supply side options (for example, reviewing the effect on average customer bills resulting from being more efficient in their electricity use, rate impact, environmental/social considerations etc.) to arrive at a preferred DSM portfolio.

Response:

Only the final bullet "evaluation of alternative DSM portfolios against supply side options" are appropriate to and undertaken in this LTERP. The other bullets (steps) will be considered in the development of the 2018 DSM Expenditure Schedule filing.

79.3 Please explain to what extent the evaluation of the proposed DSM funding envelope for the next five years in the FBC 2016 LTERP is limited by: (i) no updated information on energy cost, TRC, and RIM on an annual basis; (ii) no variation in the utility incentive provided between DSM portfolios; and (iii) a free-rider/spillover rate assumption of zero percent.

Response:

FBC does not consider the proposed funding envelope to be limited by the cited items.

(i) The BC CPR included an extensive review of measures, including updating the measure costs and TRC. The FBC CPR results show ample, cost effective DSM is available to achieve the funding envelopes proposed in the 2016 LT DSM Plan;

(ii) The estimated incentive spend, calibrated to historical results, is achievable, in aggregate, across DSM programs and measures that will be determined in the subsequent expenditure filing;

(iii) The free rider/spillover rate of zero percent is consistent with FBC's 2012 LT DSM Plan. FBC will include free rider/spillover rates in the 2018 expenditure filing.

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. As stated in the response to BCUC IR 2.55.b, the pro-forma budgets presented in the LT DSM Plan are based on general expectations as to the mix of measures to be included, the incentive levels and administrative and other costs, which will be refined in the expenditure schedules. The expenditure schedule filing is also anticipated to incorporate: (i) updated information including Benefit/Cost tests; (ii) variations in utility incentives across measures and programs; and (iii) free-rider/spillover assumptions, in addition to the results of the BC CPR additional scope services.

79.4 Please explain whether (and if so why) FBC considers that (i) measures FBC no longer offers , and (ii) measures identified in BCUC IR 44.1 as included in the 2016 NW PP but not in the 2014 BC CPR, would not pass the total resource cost test and/or would not pass the utility cost test.

Response:

FBC has not considered whether (i) measures FBC no longer offers, and (ii) measures identified in the response to BCUC IR 1.44.1 as included in the 2016 NW PP but not in the 2016 BC CPR, would not pass the total resource cost test and/or would not pass the utility cost test.

For the purposes of the BC CPR, Navigant prioritized measures with high impact, data availability, and most likely to be cost-effective as criteria for inclusion in the study. The other measures identified in this IR were not included and thus FBC has not estimated the total resource cost test nor the utility cost test.

79.4.1 Were non-energy benefits (such as noise reduction) were taken into consideration in determining if any of the measures identified would pass the total resource cost test? If yes, please explain how. If no, please explain why not.

Response:

FBC stated the following in its response to BCUC IR 1.40.2.1 regarding non-energy benefits:

Environmental and non-energy benefits are not incorporated into the 'cost effective' DSM definition in the 2016 LT DSM Plan. The avoided costs (LRMC, DCE) that are currently being used by FBC result in most DSM measures being cost effective without incorporating environmental and non-energy benefits. For example, 95 percent of the technical potential identified by 2035 in the 2016 CPR is considered economic, or 'cost effective'.

79.4.2 Please explain whether Navigant was directed by the utilities as to which measures should/should not be prioritized in the 2016 BC CPR. If yes, please describe.

Response:

No. For the purposes of the BC CPR, the BC Utilities worked with Navigant to prioritize measures with high impact, data availability, and most likely to be cost-effective as criteria for inclusion in the study.

80.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 41.2.1; Utilities Commission Act (UCA), section 44.1

Timing of the next LTERP and DSM Plan filing

FBC states in BCUC IR 41.2.1: "FBC has not (yet) estimated the achievable potential for each measure in the 2016 LT DSM Plan, which is an anticipated result of the market potential in the next phase of the BC CPR."

The UCA section 44.1 states:

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

(a) the public utility may resubmit the part within a time specified by the commission, and

(b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

80.1 Hypothetically, if the Long Term DSM plan portion of the application were rejected, please comment on how it would impact any future DSM expenditure schedule applications filed before the next LTERP and DSM Plan.

Response:

Under Section 44.1(7), if the Commission does reject the plan (or part of the plan) then FBC may resubmit that part of the plan. However, FBC assumes the hypothetical presented in this IR contemplates that the LT DSM Plan portion of the LTERP is rejected, but the balance of the LTERP is accepted. If that is the correct interpretation, then FBC disputes that the hypothetical is a plausible outcome. The portfolio analysis in Section 9 of the LTERP that is the basis for FBC's overall resource acquisition strategy is predicated on the High level of DSM selected pursuant to the LT DSM Plan. If the LT DSM Plan and its associated DSM level is rejected, then it would necessarily entail a revised portfolio analysis, and potentially changes to FBC's long term resource acquisition plan and strategy based on a resubmitted LT DSM Plan.

In any event, if the LT DSM Plan portion of the LTERP was rejected, there would be an impact on what the Commission is required to consider in future DSM expenditure schedule applications. Under section 44.2(5) of the UCA, in deciding whether to accept an expenditure schedule, the Commission is required to consider "(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any". The 2012 LTRP is the most recently filed FBC long term resource plan that includes an accepted long term DSM plan in this hypothetical. Accordingly, if the 2016 LT DSM Plan is rejected, then the Commission would be required to

address future FBC expenditure schedules using the 2012 LTRP and its associated long term DSM plan as the basis for FBC's overall DSM approach and funding level.

FBC considers that such an approach would unduly complicate the Commission's consideration of FBC's future DSM expenditure filings as the circumstances of FBC's DSM programs, funding levels and savings targets have changed since the 2012 LTRP was filed. The approach that would result from rejecting the 2016 LT DSM Plan would also be contrary to the Commission's comments on the preferred order of processes for developing DSM expenditure requests in its Decision and Order G-186-14 regarding FBC's 2015-2016 DSM Plan, where the Panel stated, at p. 33:

> The Commission Panel considers that, ideally, a utility should first file a LTRP with a DSM Plan under section 44.1(8)(c) and then file a DSM expenditure schedule. This will allow the utility to receive guidance regarding the overall size and approach of the DSM funding proposal prior to filing the detailed DSM expenditure schedule. The preferred order of filing is reflected in the UCA – the Commission is required for DSM expenditure filings to consider the most recent LTRP filed by the utility in determining whether to accept the DSM expenditure schedule, and not vice versa.

80.1.1 Please explain the timing of when FBC can complete an updated i) DSM plan, ii) LTERP, and iii) LTERP and DSM plan following the completion of the items mentioned in response to IR 79.1.1 above.

Response:

The FBC CPR Economic results that were filed as Appendix A of the 2016 LT DSM Plan provide the foundation for the LT DSM Plan without any further input.

The BC CPR additional scope services, namely the FBC market potential, is anticipated to inform the DSM expenditure schedule for 2018 onwards that FBC expects to file later this year. This will not provide any additional information that would change the preferred DSM Scenario proposed in the LTERP or LT DSM Plan and so no updates, as suggested in the question, will be required.

80.2 Please comment on when, in FBC's view, would be the appropriate filing date of the next LTERP and DSM plan application.

Response:

As discussed in the response to BCUC IR 1.41.5, FBC expects that it would submit its next long term electric resource plan and long term DSM plan in approximately five years from the submission date of this LTERP (November 30, 2016). Please also refer to the response to BCUC IR 2.80.1.1.

80.2.1 Please discuss FBC's view on a sooner filing date of FBC's next LTERP and LT DSM plan than proposed above that includes all components of the application, including a completed CPR.

Response:

Please refer to the response to BCUC IR 2.80.1.1.

81.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 35.2

DSM Portfolio analysis - approach

FBC compares average and incremental TRC costs in BCUC IR 35.2:

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

81.1 In evaluating the DSM portfolio against supply side options, please explain whether FBC primarily relies on the total resource cost (which excludes incentives provided to the customer) compared to the utility cost (which includes incentives), and provide the reason why.

The assumption in the question is incorrect: the total resource cost **includes** incentives paid to the participating customer.

FBC relies on the TRC in comparing DSM to supply side options. The TRC is comprised of the measure costs, which are divided between the utility incentive and the customer's portion of the cost (CPC), as well as program administration costs. All of these costs are borne by FBC ratepayers, whether through rates or as participant costs.

As discussed in the response to BCOAPO IR 1.1.1, and in line with BC Hydro's approach[34], cost effective refers to having a lower unit cost than other resource options from a total cost perspective – that is including costs to FBC and to FBC customers. In contrast, FBC customers will not incur the full cost of the generator that produced electricity procured from the wholesale market, rather, FBC customers will only incur the utility cost of the electricity.

81.1.1 Please explain whether FBC's approach is consistent with the evaluation of supply side market purchases. Specifically, does FBC only include the cost to the utility of the energy purchased, and not the cost to the generator of producing it?

[34] BC Hydro 2013 Integrated Resource Plan, Section 6.3.3 Financial Factors: Cost of DSM Options. Page 6-27. November 2013.

Response:

Please refer to the response to BCUC IR 2.81.1.

81.1.2 Please comment on whether the following approaches would treat DSM on a level playing field with supply side resources: (i) use the TRC as a tool to identify cost effective measures, and then (ii) evaluate the utility cost of alternative DSM portfolio's targeting those measures against the utility cost of supply side alternatives.

Response:

(i) The TRC is the governing test, under the DSM Regulation, used to identify cost effective measures.

(ii) Evaluating the utility cost (only) of alternative DSM portfolios, targeting those measures against the utility cost of supply side alternatives, would inherently place DSM at an advantage since that approach would ignore the customers' portion of costs that are also borne by DSM participants.

The opportunity cost for an FBC customer to replace energy generated from a supply side resource through a DSM measure is the TRC, not the utility cost.

81.2 In evaluating the DSM portfolio against supply side options, please explain if FBC uses incremental or average DSM portfolio costs, and provide the reason why.

Response:

Within the resource portfolio, the overall annual Total Resource Costs of the DSM scenario are included along with the annual cumulative DSM Savings, which together were optimized with the total cost of supply side resource options.

For the purposes of calculating the LRMC, as discussed in Section 4.3 of Appendix K (Step 3) of the LTERP, FBC assumes the Low DSM scenario (as described in Section 8.1.1 of the LTERP) against which the incremental costs associated with higher levels of load growth offset are compared in the various portfolio scenarios. This approach was taken to represent the

marginal decision and costs of including incrementally higher levels of DSM. "Low DSM" is the minimum level of DSM considered in the 2016 LTERP, therefore, the marginal decision is whether to undertake DSM levels greater than the minimum.

81.2.1 Please explain whether FBC's approach is consistent with the evaluation of supply side market purchases. Specifically, does FBC include in its portfolio the average or incremental cost of market purchases?

Response:

Within the resource portfolios, the total annual costs of market purchases are included along with the annual quantity of market energy.

For purposes of calculating the LRMC, as described in Section 4.3 of Appendix K of the LTERP, only the incremental market purchases above and beyond the market purchases used to meet the 2016 forecast load requirements of the particular portfolio scenario were included in the LRMC calculation. From this perspective, incremental levels of DSM were compared to incremental market purchases.

82.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 23.2.1

Deferment of network expenditures

FBC states in BCUC IR 23.2.1: "Targeted regional offers introduce disparate incentive offers, which are inequitable to customers outside of the target region."

82.1 Please explain why FBC considers targeted regional DSM offers to be inequitable. Please specifically comment on whether FBC's considers it would be inequitable if the DSM program has a lower cost than the supply side investment.

Response:

The Company believes that it is important to maintain equity in its DSM programs for qualifying customers to encourage widespread participation regardless of a customer's location in the FBC service area. FBC believes that offering different incentives to customers in the same rate class, based on their location in the service area is inequitable.

Regardless of whether targeted regional DSM is inequitable or not, DSM is not a reliable resource for the purposes of offsetting supply side investment as discussed in the responses to BCOAPO IR 2.58.2.1 and BCSEA IR 2.25.2.

82.2 Please explain whether FBC has evaluated the potential for targeted DSM programs to defer anticipated network system reinforcements. If yes, please describe the results. If no, please explain why not.

Response:

FBC has not evaluated this potential and considers DSM savings to be a reliable but non-firm resource. Thus, DSM savings cannot be counted on to defer network system reinforcements that are predicated on peak load requirements.

83.0 Reference: LT DSM PLAN

Greenhouse Gas Reduction (Clean Energy) Regulation, Order in Council Nos. 100, 101; Exhibit B-4, BCSEA IR 20.10; Exhibit B-2, BCUC IR 9.1, 9.4

Electrification

The Greenhouse Gas Reduction (Clean Energy) Regulation, Order in Council No. 101 includes as a prescribed undertaking for the purpose of section 18 of the CEA a program to encourage the public utility's customers, or persons who may become customers of the public utility, to use electricity instead of other sources of energy that produce more greenhouse emissions (subject to certain conditions). *Greenhouse Gas Reduction (Clean Energy) Regulation*, Order in Council No. 100 states: "The Commission must allow the authority to defer to the DSM regulatory account amounts equal to the undertaking cost."

FBC states in BCSEA IR 20.90: "FBC considers fuel switching to be load building, and as such is not within the scope of the LT DSM Plan." FBC states in BCUC IR 9.1: "FBC's strategy has been neutral to customer fuel switching from natural gas to electricity,"

FBC states in BCUC IR 9.4 that customers who fuel switch from natural gas to an efficient electric appliance are not eligible for FBC DSM incentives.

83.1 Does FBC consider that the regulatory environment supports expanding DSM to include low-carbon electrification programs? Please explain.

Response:

FBC agrees that the regulatory environment supports low-carbon electrification as a prescribed undertaking, not necessarily as a DSM program. One of the objectives of BC's *CEA* is to "*(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia*". The amendment of the *GGRR* on March 1, 2017 by way of OIC. 101/2017, gives support to this objective by defining fuel switching programs and activities as prescribed undertakings for the purposes of section 18 of the CEA.

FBC intends to investigate opportunities for fuel-switching, however FBC does not consider fuel-switching programs to be DSM activities (for example, please refer to the response to BCUC IR 1.9.4). Furthermore the *CEA* definition of "demand-side measure" expressly:

"does <u>not</u> include… (e) any rate, measure, action or program prescribed".

However, the Commission's DSM Accounting Policy (Appendix A to Order G-55-95) states that *"(u)tilities engaged in strategic load building by fuel substitution may account for this in the same manner as other DSM strategies subject to Commission directions specific to that utility*". FBC

notes that OIC 100, also approved on March 1, 2017, requires that the Commission "*must allow the authority to defer to the DSM regulatory account amounts equal to the undertaking costs*", which is consistent with the DSM Accounting Policy.

83.1.1 Please explain whether a DSM program offered to customers switching from natural gas to electricity could pass the mTRC, when the DSM Regulations zero-emission energy alternative (ZEEA) value is used to value the gas savings.

Response:

FBC provided a fuel switching analysis in Appendix C of the LT DSM Plan. The analysis found the TRC cost test yielded zero, based on the respective avoided costs of natural gas and electricity.

FBC considers that calculating the mTRC using ZEEA is moot, since the GGRR has prescribed a new benefit/cost calculation for Electrification (fuel-switching) purposes. Section 4(1) of OIC 101/2017 (now s. 4(1) of the GGRR) provided as follows:

Prescribed undertaking - electrification

4 (1) In this section:

"benefit", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means all revenues the public utility reasonably expects to earn as a result of implementing the undertaking, less revenues that would have been earned from the supply of undertaking electricity to export markets;

"cost", in relation to an undertaking in a class defined in subsection (3) (a) or (b), means costs the public utility reasonably expects to incur to implement the undertaking, including, without limitation, development and administration costs;

"cost-effective" means that the present value of the benefits of all of the public utility's undertakings within the classes defined in subsection 3 (a) or (b) exceeds the present value of the costs of all of those undertakings when both are calculated using a discount rate equal to the public utility's weighted average cost of capital over a period that ends no later than a specified year;

83.2 Please explain how FBC's policy to deny DSM incentives to customers switching from natural gas to electricity is consistent with a policy to be neutral regarding a customer's fuel choice.

Response:

FBC considers its position neutral in that it does not support, i.e. incentivize, the use of one fuel over the other. DSM incentives are offered to customers to improve the efficiency of their appliances, building envelope and systems, commensurate with the fuel that they currently use.

FBC became aware of the content of OIC 101 on March 2, 2017, and has had limited opportunity to evaluate the potential for electrification (fuel switching) that may now be encompassed by the GGRR, but intends to do so.

83.2.1 Are customers who partly heat their home with electricity (for example, plug in electric heaters or baseboard heaters), but who have gas as their primary source of heating, eligible for DSM incentives (such as for heat pumps)? If no, please explain whether this could encourage customers to fuel switch to natural gas.

Response:

A customer with natural gas as their primary heat source would not be eligible for a heat pump incentive as this customer's primary fuel source is natural gas. Since the primary heat source is already natural gas, FBC does not believe that this lack of incentive would promote further fuel switching to natural gas.

84.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 52.2.1, 52.2, 52.3

Self-generator eligibility

FBC states in BCUC IR 52.2: "From the utility perspective, the less energy that the customer purchases from the utility the less of the energy savings from the measure the utility realizes, which lowers the benefits of the TRC and UCT."

FBC states in BCUC IR 52.2.1: "[FortisBC Energy Inc. (FEI)] provides incentives to customers who take natural gas delivered by FEI regardless of who they have contracted with for the commodity. … BC Hydro does not provide DSM incentives to customers who self-generate the entirety of their load or where a DSM project would result in the customer self-generating the entirety of their load."

FBC states in BCUC IR 52.3: "The Company considers linking the demand charge/fixed cost recovery to DSM is not appropriate since DSM activities are primarily related to the reduction in energy usage by the customer, and by extension, a reduction in the energy requirement of FBC."

84.1 Please explain how a customer being a full or partial service customer of FBC can affect the TRC of a DSM program. Specifically, does the TRC measure the cost/benefit to BC, and not the cost/benefit to the utility?

Response:

FBC has approached the benefit side of TRC calculations from the utility's perspective: the savings of the measure that accrue to FBC are used to calculate the benefits of the TRC. If a customer receives only a portion of the load from FBC then only that portion of the load that could be reduced with DSM would be included in the TRC calculation.

84.1.1 Please explain the difference between FBC and BCH regarding their network related standby charge self-generators.

Response:

FBC assumes this question is meant to read, "Please explain the difference between FBC and BCH regarding their network related standby charge *for* self-generators."

In the case of FBC's Stand-By Rate (RS 37) and BC Hydro's Stand-By Rate (RS 1880), the stand-by rate is part of a package of rates under which the customer is served. The other main part of the package is the underlying transmission rate.

In this regard, there is language in each of the FBC and BC Hydro Stand-By Rate schedules that provides for peak demands recorded during billing periods to be reflected in the billing of the underlying transmission service rate. Neither utility's stand-by rate schedule contains Demand Charges itself.

In BC Hydro's RS 1823 (the underlying transmission rate schedule for that utility), Billing Demand may be determined as:

1. the highest kV.A Demand during the High Load Hours (HLH) in the Billing Period; or
2. 75% of the highest Billing Demand for the Customer's Plant in the immediately preceding period of November to February, both months included; or
3. 50% of the Contract Demand stated in the Electricity Supply Agreement for the Customer's Plant,

In the case of FBC, under RS 31, wires charges are assessed per kVA of Billing Demand where Billing Demand is:

The greatest of:

i. eighty percent (80%) of the Contract Demand, or

ii. The maximum Demand in kVA for the current billing month; or

iii. eighty percent (80%) of the maximum Demand in kVA recorded during the previous eleven month period.

Plus, for Customers with a Stand-by Billing Demand under RS 37 (except when RS 37, Special Provision 7 applies);

Stand-by Billing Demand.

Stand-by Billing Demand is set for each customer on an individual basis and is meant to recover network charges in relation to the amount of Stand-by service available to the customer.

For both utilities, under normal circumstances, a peak demand that is recorded during a period of stand-by service does not factor into the billing under the transmission rate schedule.

84.1.2 Please explain whether BC Hydro's approach described in BCUC IR 52.2.1 is consistent with an approach that prorates DSM funding for self-generators to reflect their contribution to the sunk cost of the wires customers. Specifically, if BC Hydro self-generators do not pay a network charge for standby service, would it then be appropriate that they are not eligible for DSM incentives?

Response:

Both the response to BCUC IR 1.52.2.1 (describing the BC Hydro approach) and BCUC IR 1.52.3 (describing FBC's position on linking DSM to demand charges) indicate a linkage between DSM and energy consumption, and are therefore not consistent with using DSM to reflect a contribution to demand charges or recovery of sunk wires costs. FBC does not have an opinion on what is appropriate for BC Hydro which is a matter for BC Hydro given its particular circumstances, but notes that a BC Hydro customer taking stand-by service will pay, at a minimum, a contribution to fixed costs based on 50 percent of its Contract Demand pursuant to the non-stand-by rate under which it must also take service.

84.2 Please explain whether FBC's response to BCUC IR 52.3 above for self-generators is consistent with FEI's policy to provide DSM incentives to customers who purchase gas from a third party, and if not, why.

Response:

Consistency should not be expected in this case because there are fundamental differences in the DSM models of the two companies. FEI recovers its DSM costs through its unbundled delivery charges, which are paid by all gas customers regardless of the commodity supplier, whereas FBC has a bundled rate tariff and thus relies on a reduction in energy sales to realize its DSM benefits.

85.0 Reference: LT DSM PLAN

Exhibit B-2, BCUC IR 54.4; Exhibit B-7, ICG IR 4.5

Rate Schedule 90

FBC states in BCUC IR 54.4: "While there has been a dispute related to the application of RS 90 to an individual customer with respect to a single potential project, to FBC's knowledge RS 90 has not been used as part of a dispute resolution."

FBC states in ICG IR 4.5: "Commission Order G-16-15 denied the retroactive payment of a DSM project at the Celgar plant that was the subject of the related complaint. … Order G-16-15, and the letter dated March 25, 2015 contained confirmation by the Commission that, "…Celgar is an eligible customer for demand side management (DSM) financial incentives pursuant to Rate Schedule 90.""

85.1 Please identify the specific parts of RS 90 that were referenced in the reasons supporting Commission Order G-16-15.

Response:

Commission Order G-16-15 referenced the following specific portions of RS 90:

APPLICABLE: To all Customers in all areas served by the Company and its municipal wholesale Customers.

FINANCIAL INCENTIVES:

1. In order to be eligible for financial incentives, a Customer must receive the Company's approval prior to initiation of work on the approved Measure.

85.1.1 For each specific part of RS 90 referenced, please explain if that requirement/policy is already included in FBC's DSM programs.

Response:

The policies referenced, namely to be eligible (i) Customers must be located in the FBC service area and (ii) the Company's approval [is received] prior to initiation of work on the approved Measure (where applicable, i.e. for large, custom projects), are already included in FBC DSM program terms and conditions.