British Columbia Utilities Commission

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April 27, 2017

FORTISBC INC. LONG TERM ELECTRIC RESOURCE PLAN & LONG TERM DEMAND SIDE MANAGEMENT PLAN EXHIBIT A-6

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Roy:

Re: FortisBC Inc.
2016 Long Term Electric Resource Plan & Long Term Demand Side Management Plan

Further to FortisBC Inc.'s November 30, 2016 filing of the above-noted application, enclosed please find British Columbia Utilities Commission Information Request No.2. In accordance with the Regulatory Timetable, please file your responses no later than Thursday, May 18, 2017.

Yours truly,

Original signed by:

Patrick Wruck

/kn
Enclosure

cc: Registered Interveners

FortisBC Inc.
2016 Long Term Electric Resource Plan & Long Term Demand Side Management Plan

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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. FBC Annual Electric Contracting Plans (AECP) and Energy Supply Contracts. 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).

b. FBC Demand Side Management (DSM) s. 44.2 filings. 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).

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).

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.

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.

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.

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

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

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.

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.

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.

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.

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.

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?

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

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".

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.

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.

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.

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?

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.

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

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.

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.

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.

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?

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.

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.

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.

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.

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.

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.

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.

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.

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.

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).

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.

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.

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.

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 CO_2e 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.

65.1.1 If FBC were to purchase the environmental attributes of market priced energy, please estimate the additional cost to FBC ratepayers, both in terms of $/MWh and the annual cost per year based on forecast market purchases over the next 5 years.

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.

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.

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).

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.

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).

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).[2] Page 10 of BC Hydro's April 2016 SOP rules includes locational adjustments.[3]

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.

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.

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

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)?

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).

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.

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

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

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

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.

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.

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.

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.

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.

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.

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).

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?

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) [4]; BC Hydro, Distributed Generation Interconnection Practices (distribution-connected projects only) [5]; 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.

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.

72.2 For the ability of DG to access markets, please explain whether (and if so how) FBC customers

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[4] 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

[5] 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

with SG/DG opportunities have the same opportunities to access markets as IPPs.

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.

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.

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?

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.

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?

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.

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.

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.

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

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.

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.

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).

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.

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.

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.

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.

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.

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

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.

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.

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.

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

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.

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.

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.

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

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).

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.

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.

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.

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).

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

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?

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.

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.

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.

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.

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.

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.

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.

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.

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.

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.

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

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.

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:

Category	DSM Scenario 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.

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?

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.

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.

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?

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.

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.

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.

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.

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.

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.

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?

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

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?

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.

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.

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.