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March 7, 2017

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Laurel Ross, Acting Commission Secretary and Director

Dear Sirs/Mesdames:

Re: FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan) ~ Project No.3698896

We are counsel to the Commercial Energy Consumers Association of British Columbia (CEC). Attached please find the CEC's first set of Information Requests with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jlb
cc: CEC
cc: FortisBC
cc: Registered Interveners

CEC Information Request #1

FBC Long Term Electric Resource Plan

1. Reference: Exhibit B-1-1, page 8, Table 1-3

Table 1-3: Applicable *CEA* Objectives Relevant to the LTERP

Section of the CEA	CEA Objective	How LTERP Supports Objective
2(a)	To achieve electricity self-sufficiency.	FBC interprets this to mean using generation resources located within B.C. Self-sufficiency requirement by 2016 for BC Hydro; other utilities must consider this objective. FBC's supply is currently sourced mainly from within B.C. and market purchases are not recommended in the long term (see Section 9).
2(b)	To take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%	The 66 percent target applies to BC Hydro. FBC has assessed DSM scenarios and voluntarily adopted a target of 66 percent for 2018-2020 then ramping up to 80 percent by 2023 based on the LT DSM Plan.
2(c)	To generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity	Requirement to take actions to meet this target applies to BC Hydro or a prescribed utility. FBC-owned resources and long-term contracts are hydro-based. BC Hydro resources are currently 98 percent clean.[4] FBC alternative and preferred portfolios include clean or renewable resources.
2(d)	To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources	FBC's LT DSM Plan provides support for energy conservation and efficiency including the use and development of innovative technologies and the LTERP portfolio analysis includes clean or renewable resources.
2(e)	To ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers	Specific to BC Hydro. FBC ratepayers are indirect customers of BC Hydro and receive the benefits of BC Hydro heritage assets via the PPA (see Section 2.2.1.2).
2(f)	To ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America	Specific to BC Hydro. FBC strives to provide cost-effective, secure and reliable service for its customers while also meeting other LTERP objectives.

1.1. Please confirm that FBC has not been explicitly directed to achieve self-sufficiency.

1.1.1. If not confirmed, please provide the direction.

1.2. What were the driving factors that led FBC to voluntarily adopt a target of 66% to meet expected increases in the demand for electricity with DSM for the period 2018-2020?

1.3. What were FBC's key objectives in ramping up its DSM target to 80% by 2023?

1.4. If FBC could achieve cost effective DSM up to 100%, would FBC do so?

1.4.1. Please explain why or why not.

1.5. What proportion of FBC's energy is considered 'clean'?

1.6. Does the fact that FBC ratepayers are 'indirect' customers of the authority mean that there is no CEA objective for FBC ratepayers to receive the benefit of heritage assets? Please explain why or why not.

1.7. Please confirm that FBC rates are among the most competitive of rates charged by public utilities in North America. Please provide evidence to support the answer.

2. Reference: Exhibit B-1, pages 27 and 28

2.3.3.1 Community Solar

Solar costs fall as the size of an individual installation increases, all else equal. As a result, there is a growing interest in "community solar", in which the output of a larger solar array is divided between a number of customers.

For many FBC customers, the ownership, as well as placement and operation of solar PV system, are not desirable or feasible. Customer ownership and operation requires upfront capital costs, as well as ongoing expenses associated with system operation and maintenance. Beyond cost considerations, rooftop or ground-mounted solar installations are feasible only for certain property owners. Customers who live in rental properties, multi-unit residential buildings (MURBs), or townhomes are necessarily limited in their options. Other customers that have aging rooftops, or an unsuitable rooftop orientation may also be unable to install a PV system.

The Company is interested in helping customers interested in solar generation (and potentially other forms of distributed generation), but who have limited access to capital or who are not willing or able to install solar panels on their home. FBC is examining options that would allow participating customers to pay for the additional revenue requirement of community solar in exchange for a share of the solar output and is considering filing an application for a pilot program in late 2016 or early 2017.

2.1. What options are FBC examining that would allow participating customers to pay for the additional revenue requirement of community solar in exchange for a share of the solar output?

2.2. How will the costs of this program be recovered?

2.3. Will the fixed costs for this user group be recovered from the ratepayers as a whole? Please explain and provide quantification.

2.4. Is a pilot project underway as of yet?

2.4.1. If yes, please provide a brief overview of the project including its time frames, objectives and expected outcomes and costs.

3. Reference: Exhibit B-1, page 28

2.3.4 Rate Design Considerations

The emerging technologies described in the previous sections have the potential to change the manner in which the Company interacts with its customers. By extension, this may impact whether the rates FBC has in place are able to appropriately reflect changes in how customers use power.

FBC's practice is to allocate costs to customer rate classes on the basis of cost-causation and not simply with regard to the end use of the power. That is, rates are typically designed such that the revenues collected from a rate class will recover the costs that have been allocated to it, within a range of reasonableness. Should an emerging use, such as EVs for example, be shown to have a unique usage profile that impacts costs, the Company may need to consider rate options that reflect such new or changing electricity use by its customers. In this way, any benefits or incremental costs that result from the widespread adoption of new technologies will predominantly accrue to those customers that choose to participate without unduly impacting the rates of other customers. In the near term, FBC will monitor emerging market trends and consider new or amended rate structures as part of a future rate design process.

The Company does however have a small number of current or pending programs that may require new rates, or amendments to current rates within the next few years.

First, as discussed above, FBC is examining options for a solar pilot project in 2017 in response to customer interest in renewable generation and to gather information and insight into the location of such an installation in the service area.

Second, the growth in interest and participation in small scale customer-owned generation, such as the installations that qualify for the Company's Net Metering Program, may begin to pose rate stability challenges for all customers. While the current participation rates and installed capacity are not a cause for concern, FBC recognizes that a proliferation of grid-connected customers with greatly reduced, zero, or periodic load is problematic for the current regulatory model where the costs of providing all aspects of service are recovered primarily through volumetric rates. FBC, like many other utilities, is concerned that the result of the widespread installation of customer-owned generation will be the transfer of costs to customers who either cannot participate, or choose not to participate. These concerns have led utilities and regulatory bodies in other jurisdictions to explore solutions such as residential demand charges or higher fixed charges that better reflect the fixed costs of providing service. FBC intends to explore this potentiality in its next rate design process.

3.1. When does FBC expect to file its next Rate Design Application?

3.2. At what levels of participation in small scale generation does FBC believe that rate stability or other challenges will arise? Please quantify.

3.2.1. When would FBC expect to reach this level of participation?

3.3. To the extent that net metering or future programs (such as the solar program) are already in existence or planned, are customers contributing or expected to contribute their full cost of service? Please explain and provide quantification of costs not covered and a cost of service ratio if available.

4. Reference: Exhibit B-1, page 40 and page 79

A further key consideration for FBC is the transmission transfer limit at the three interconnections on the B.C./United States border[57] and at the two interconnections on the B.C./Alberta border. These transmission interconnections often operate at their maximum available transfer limits; therefore wheeling additional power between utilities in the region is frequently impossible. It should be noted that FBC has no transmission facilities that connect directly with markets outside of B.C. Accordingly, FBC is dependent on the availability of adequate third-party transmission capacity to serve its customers' needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand. However, market energy and capacity is expected to remain adequate through the short to medium term. This is particularly true if the CEPSA agreement with Powerex is assumed to continue. On a longer term basis, market capacity and transmission availability are expected to continue to tighten and therefore FBC may not be able to rely upon them, but sufficient supply of market energy will likely be available.

FBC access to the market is mainly through its transmission rights on Teck's 71 Line, which provides transmission both across the B.C./U.S. border and to the FBC system. For long-term planning purposes such as the 2016 LTERP, this access is treated as firm but it must be recognized that the Company does not own the line. Also, additional U.S. transmission is required to access the Mid-C trading hub, which is located along the Columbia River on the border between Washington and Oregon. Additional firm transmission cannot be reliably obtained on the U.S. side of the border and as such, while the market remains an excellent source of energy to meet FBC customer requirements and could meet the relatively small energy gaps that the Company expects through 2035, it cannot be considered a long-term resource to meet capacity requirements (as described in more detail in Section 8.2.4). The Company intends to continue to explore what B.C.-based market options may be available to meet future needs.

4.1. What are the interconnection limits at the five connection points to BC Hydro's system?

4.2. Please provide accessibility data for each interconnection point for the past 5 years, including frequency and duration of the times in which wheeling becomes impossible.

Please ensure that time of day, weekly, monthly and seasonal variations can be determined from the data provided.

4.3. How much power has FBC imported through each interconnection point – by month, for the last 5 years?

4.4. What, if any, has been the economic impact to FBC ratepayers of being unable to wheel power through these interconnection points? Please provide quantification where possible.

4.5. Please provide FBC's future projections of access to the wholesale electricity market over the period covered by the LTERP (until 2035).

4.6. What, if any, is the economic impact on ratepayers of future limitations on the purchase of market electricity? Please quantify and provide the calculations.

4.7. What steps, if any, is FBC taking to assure access to the wholesale electricity market?

4.8. What is preventing FBC from purchasing additional transmission capacity to assure access to the wholesale market? Please explain.

4.9. What ability does FBC have to secure priority access to Canadian Entitlement electricity, currently marketed by Powerex? Please explain.

5. Reference: Exhibit B-1, page 53

> **3.2.1 Gross Load Forecast**
>
> FBC'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, a compound annual growth rate of 1.1 percent.

5.1. Please provide FBC's Actual gross load, and the Actual growth rates for the last 30 years by customer class. Please break out data from the City of Kelowna to the extent that FBC has the data since purchase and as wholesale customer before purchase. Please provide the information both Before and After DSM.

5.2. Please provide FBC's forecasts of load and growth rates for the last 30 years by customer class, by vintage year. Please break out data from the City of Kelowna, and provide the information both Before and After DSM.

5.3. Please provide FBC's revenue by customer class over the last 30 years.

6. Reference: Exhibit B-1, page 55 and page 55

> The peak demand forecast is the largest amount of capacity expected at one point in time on the FBC system due to high customer demand, which is affected by weather and system growth. FBC's system is dual peaking, with annual winter and summer peaks. Winter peaks have historically been larger than the summer peak and are forecast to continue to be larger in the future.
>
> The winter peak is when the most capacity is needed at a single point in time during the months of November to February and is usually on one of the coldest days of the year. The reference case winter peak demand forecast increases from 731 MW in 2016 to 885 MW in 2035, growing at a compound annual growth rate of 1.0 percent.
>
> The reference case summer peak demand forecast increases from 590 MW in 2016 to 716 MW in 2035, growing at a compound annual growth rate of 1.0 percent.

6.1. On what basis did FBC select an annual compound growth rate of 1.0% for the peak demand forecast?

6.2. Please provide actual summer and winter peak demand, including growth rates for the last 30 years. Please break out data from Kelowna if available and qualify the data as either Before or After DSM.

6.3. Please break out data from Kelowna.

6.4. Please provide FBC's capacity forecasts by vintage year, breaking out City of Kelowna since purchase, and as wholesale prior to purchase to the extent available.

7. Reference: Exhibit B-1, page 57

> ***3.3.1.1 Commercial Load***
>
> There is a high statistical correlation between the provincial GDP and FBC's commercial load, which is explained in further detail in Appendix E. The commercial class is a mix of different types of businesses, from small store-front operations and restaurants to larger operations such as hotels and ski resorts. In 2015, there were 14,976 customers in the commercial class, representing 25 percent of the gross load.
>
> Commercial load growth is expected to increase at a compound annual growth rate of 1.6 percent over the planning horizon. The commercial load is forecast to increase significantly during the near to medium term and then slow somewhat due to reduced economic growth.

7.1. Please provide a comparison of provincial GDP forecasts and the actual GDP growth rates over the last 30 years.

8. Reference: Exhibit B-1, page 57

3.3.1.2 Industrial Load

In 2015, there were 50 customers in the industrial class, representing 11 percent of FBC's gross load.

Industrial load growth is expected to increase at a compound annual growth rate of 1.5 percent over the planning horizon. The industrial load is forecast to have consistent strong growth during the planning horizon except for during the short term which is partly due to the forecast decline of the forestry sector from the mountain pine beetle epidemic.

8.1. Please provide FBC's basis for selecting 1.5% as a compound annual growth rate.

8.2. Please provide evidence that BC Hydro is experiencing similar load growth rates for industrial accounts.

9. Reference: Exhibit B-1, page 58

3.3.2 Population Growth

BC Stats forecasts annual population growth of 1.0 percent on average over the planning horizon for FBC's service territory. This is consistent with the 1.0 percent annual average growth rate experienced in the last 10 years. Population growth is forecast to be strongest at the start of the planning horizon at 1.2 percent and then is predicted to fall gradually to 0.7 percent by 2035.

9.1. Please provide the population growth forecast by year, breaking out the City of Kelowna.

9.2. Please provide the population growth over the last 30 years, and break out the City of Kelowna.

9.3. Please provide BC Stats forecasts for population growth and compare to actual population growth for the last 30 year period.

9.4. Please explain why FBC is using consistent, average population growth over the planning period when the trend is not consistent and declining.

9.5. Please provide the forecast load using current BC Stats forecasts for population growth of the average.

10. Reference: Exhibit B-1, page 70

4.3 *RPAG FEEDBACK*

The load scenarios described above were discussed with the RPAG stakeholders in the April 27, 2016 workshop. At that session, FBC received feedback regarding the load drivers and scenarios. For example, one stakeholder commented that the electric vehicle penetration included in the high consumption boundary scenario (Scenario 1) might be overstated if electric vehicle manufacturers are not able to keep up with the demand from customers. Another stakeholder commented that the generally older population in the FBC service area relative to other cities, such as Vancouver, might lead to lower adoption of EVs in the FBC territory. Another stakeholder commented that the level of solar PV with storage seemed high without time-of-use rates providing an incentive for the use of energy storage. FBC notes that while the high and low boundary scenarios represent plausible extremes, the three intermediate scenarios cover less-extreme scenarios and may be more aligned with those situations described by stakeholders in the workshop.

10.1. Please provide any evidence FBC may have on the automobile industry's capacity to produce EVs, with quantification, and explain how that may affect the timing of system planning and infrastructure.

10.2. Please provide a comparison of FBC's expected EV adoption rates to that anticipated in larger urban environments elsewhere in Canada and the US.

10.3. Does FBC expect to introduce Time of Use rates at any time in the future? Please explain why or why not.

10.3.1. If yes, please provide an estimate of when FBC might introduce TOU rates in the future.

10.3.2. If yes, please provide an overview of any work FBC has done on TOU rates.

10.3.3. If yes, please provide FBC's expectations as to how TOU rates would affect peak load. Please provide quantification.

10.4. Does FBC expect that TOU rates will result in additional conservation and efficiency savings? Please explain why or why not.

10.4.1. If yes, please provide quantification of any savings FBC believes may be possible if available.

10.5. Please provide BC Hydro's TOU pilot rate experience data showing conservation and efficiency savings.

11. Reference: Exhibit B-1, page 87

An assessment of reactive power[90] capabilities is also necessary. As previously noted, the FBC system consists of two areas, the Kootenay region, with surplus generation, and the Okanagan, with a total absence of generation. The lack of dynamic reactive support in the Okanagan (due to absence of generation resources which can respond to load changes in real-time) can lead to low voltages or voltage collapse during contingency conditions.

Each thermal or voltage violation found in the studies is then analyzed in order to define the most cost-effective mitigation plan. These studies identify a collection of transmission reinforcement projects that are required within the 20 year planning horizon.

11.1. Please provide data from the last 10 years to illustrate how the lack of dynamic reactive support in the Okanagan has led to low voltages or voltage collapse.

11.2. Please provide a brief overview of the cost-effective mitigation plans that have been defined to address the lack of dynamic reactive support in the Okanagan including any known costs.

11.3. Please advise whether upgrades to the connections to BC Hydro's system at Vernon Terminal Station and / or Vaseau Lake Terminal Station (reference section 6.1.2) would address this problem, and what those upgrades would entail.

11.4. Would such upgrades be cost effective mitigation to the lack of dynamic support in the Okanagan? Please explain why or why not and provide quantification of any known costs.

11.5. Are there interconnection guarantees or limitations under the PPA 3808 agreement?

12. Reference: Exhibit B-1, page 89

6.3.1 Impacts of Supply-Side Resource Options

FBC considers supply-side resource option location assumptions to determine transmission and distribution requirements as part of the LTERP development process. Regardless of the location, supply-side resources included in the LTERP typically require some amount of local transmission and distribution improvements to allow them to interconnect with FBC's electrical system.

The most impactful resource addition currently identified would be the integration of a new large-scale generation resource, such as a gas-fired generation plant, within the Kelowna 138-kV sub-transmission network. This is because this resource could defer the requirement for the proposed third 230/138-kV bulk transformer at the Lee Terminal in Kelowna (as discussed in section 6.3).

12.1. Please provide quantification of the costs associated with the new gas fired generation plant.

12.2. Please provide details of any planning or feasibility studies FBC has done for the gas fired generation plant identified, and provide the NPV analysis if one has been completed.

12.3. What financial effect would the deferral of the proposed third transformer at the Lee Terminal have? Please discuss and provide quantification.

12.4. How would the gas-fired generation plant affect FBC's proportion of clean energy? Please discuss and provide quantification.

13. Reference: Exhibit B-1, page 89

6.4.1 Distributed Generation

Currently, FBC has approximately 110 Net Metering Program customers with Distributed Generation (DG) facilities (mostly rooftop solar PV installations) interconnected on the distribution system.[93] Combined, these facilities represent less than 1 MW of non-firm generating capacity, which is less than 0.5 percent of the approximate 225 MW firm generating capacity of FBC's four hydroelectric generating plants. As a result, the near-term impacts of existing DG facilities on transmission and distribution grid operations and reliability are currently relatively low.

However, the pace of FBC DG interconnections has increased over the past few years. Recent studies predict further cost declines in solar PV and associated increases in solar PV penetration rates. Additionally, provincial or federal incentives and/or federal tax credits, *CEA* or RPS legislation or feed-in tariffs for the purchase of renewable generating capacity from small facilities could make solar PV more cost-effective for customers. Further study will be required to ensure that potential system impacts and necessary mitigation are understood and addressed in the FBC system.

13.1. When does FBC intend to undertake the studies necessary to understanding system impacts and identifying mitigation options?

13.2. Please provide data on the increase in DG interconnections over the past five years.

13.3. Please provide FBC's projections on the number of DG connections over the next five years.

13.4. At what threshold level of generation would FBC expect DG to have a meaningful impact on transmission and grid operations and reliability? Please discuss and provide quantification.

13.5. Could small scale wind power also be integrated into the FBC systems in DG?

13.5.1. If yes, please explain whether or not this is likely to become another DG option for customers and why.

13.5.1.1. If it is likely to become another DG option, please advise what steps must be taken by FBC to integrate small scale wind power into the FBC electricity system and quantify any known costs.

14. Reference: Exhibit B-1, page 90

> Notwithstanding the limited impacts given current adoption rates, the potential future impacts on transmission and distribution system planning and operations are more complex. Intermittent renewable generation creates many new challenges not experienced with conventional distributed generation. Distributed solar PV increases the complexity of managing voltage regulation on circuit feeders due to its intermittent nature. These facilities will have increasing impacts on the distribution system first and then the transmission system later as DG growth continues.
>
> The extent to which DG affects power losses and voltage profiles depends on the type of DG technology, penetration levels, and the location of its connection to the grid. Depending on its location, the integration of DG can reduce power losses on the transmission and distribution network, but as the penetration level increases, the power losses may begin to increase.
>
> If DG uptake increases significantly in the near future, FBC transmission and distribution planners will need to have the tools and knowledge for planning and modeling a high-penetration of solar PV or other DG technology into the system. Alternative engineering designs, technology solutions, and new and updated planning and operations practices may be needed for the FBC transmission and distribution system of the future.

14.1. Does FBC currently have the tools and knowledge for planning and modelling a high penetration of DG technology into the system at present?

14.1.1. If no, please provide a brief overview of the costs and timing of when these requirements will be acquired.

14.1.1.1. If FBC does not have plans to acquire the tools and knowledge, please identify the criteria FBC will use to determine when alternative engineering designs, technology solutions and new and updated planning and operations practices will be required.

15. Reference: Exhibit B-1, page 91

The Electric Power Research Institute (EPRI) has analyzed distribution system impacts of Plug-in Electric Vehicle (PEV) charging and, in its report[94], concluded that:

- Diversity of vehicle location, charging time, and energy demand will minimize the impact on utility distribution systems;
- Level 1 (standard residential voltage; no extra cost) charging generates the fewest distribution system impacts;
- Higher power (Level 2) charging generates stronger system impacts and is typically not required for most customer charging scenarios with light duty vehicles;
- Short-term PEV impacts for most utility distribution systems are likely minimal and localized to areas where the available capacity per customer is already low; and
- Controlled or managed charging could defer system impacts for a significant period of time.

FBC intends to use the recommendations from the EPRI study as a guide. The potential stresses on the electric grid can be mitigated through asset management, system design practices, and, to some degree, managing the timing of charging PEVs to shift the load away from system peak. A proactive FBC approach that includes understanding where PEVs are appearing in the system, addressing near-term localized impacts, and developing both customer programs and technologies for managing long-term charging loads will effectively and efficiently support PEV adoption.

15.1. In what ways can FBC use 'asset management' to mitigate potential stresses on the electrical grid? Please explain.

15.2. What types of 'systems design practices' can FBC use to mitigate potential stresses on the electrical grid? Please explain.

15.3. What are the expected costs of any system design and upgrades that may be needed to accommodate the adoption of EVs?

15.4. How much lead time is required for FBC to do any required system design and upgrades to accommodate the adoption of EVs? Please explain.

15.5. Is FBC aware of the work BC Hydro has done to plan for load growth from EVs?

15.5.1. If yes, please explain how this work has informed the FBC LTERP submission.

15.5.2. Would FBC consider mandatory TOU for EV charging? Please explain why or why not.

16. Reference: Exhibit B-1, page 93 and page 49

> With regard to the BC Hydro PPA, it is also important to note that the figure reflects PPA Tranche 1 Energy available to FBC up to the maximum of 1,041 GWh. In the portfolio analysis, discussed in Section 9, the portfolio model will optimize the amount of PPA Tranche 1 Energy with the other resource options available to FBC and, as a result, the maximum Tranche 1 Energy available may not always be selected within the various alternative portfolios. PPA Tranche 2 Energy is also available to FBC but at a much higher cost, as discussed in Section 5. Based on the supply-side resource options presented in Section 8.2, FBC expects that it would be able to build or contract for new energy resources at a lower cost than the PPA Tranche 2 Energy cost. For this reason, the energy LRB is presented here with only the PPA Tranche 1 Energy amount.

> The PPA tranche 2 energy rate is set based on a proxy for BC Hydro's LRMC of new supply. Currently, the PPA Tranche 2 energy rate is $129.70 per MWh[68], which is tied to BC Hydro's proxy for long run marginal cost based on the BC Hydro 2008 Clean Power Call. However, BC Hydro's LRMC for energy has since been updated and is significantly lower than this as stated in BC Hydro's recent 2015 Rate Design Application Evidentiary Update on Load Resource Balance and Long Run Marginal Cost dated February 18, 2016. In this update BC Hydro states that the LRMC has shifted towards $85 per MWh from a range of $85 per MWh to $100 per MWh[69]. Therefore, FBC has assumed that the PPA Tranche 2 energy rate could be lowered to the BC Hydro LRMC value of $85 per MWh in the future and has treated this as a PPA Tranche 2 rate scenario. FBC has assumed this $85 per MWh value is adjusted for inflation and so does not increase in real terms. The following figure shows the base case $129.70 per MWh PPA Tranche 2 rate and the $85 per MWh rate scenario.

Table 8-4: Supply-Side Resource Options Unit Cost Summary

Resource Option	UEC ($/MWh)	UCC ($kW-year)
PPA Tranche 1 Energy	$47 - $56	N/A
PPA Tranche 2 Energy	$85 - $130	N/A
PPA Capacity	N/A	$96 - $115
Market Purchases	$34 - $64	$169 - $355
Wood-Based Biomass	$118 - $188	$663 - $774
Biogas	$77 - $101	$621 - $838
Municipal Solid Waste	$134	$1,031
Geothermal	$132 - $217	$857 - $1,506
Gas-Fired Generation (CCGT)	$82 - $100	$147 - $279
Similkameen Hydro Project	$202	$1,298
Gas-Fired Generation (SCGT)	N/A	$80 - $143
Pumped Hydro Storage	N/A	$217
Onshore Wind	$111 - $145	$1,219 - $1,618
Run-of-River Hydro	$87 - $150	$1,230 - $1,924
Solar	$169 - $184	$1,399 - $1,413

16.1. When would FBC expect the price of Tranche 2 energy to be lowered?

16.2. When will FBC be able to confirm the price of Tranche 2 energy?

17. Reference: Exhibit B-1, page 104

> Furthermore, DSM levels higher than the High scenario create risks in terms of managing the LRB. DSM is neither available on demand nor as reliable as a supply-side resource option because DSM programs require voluntary participation by customers. Therefore, there is no guarantee that actual DSM program uptake will materialize as planned and an over-reliance on DSM could leave unexpected gaps in the LRB that still need to be filled to meet customer load requirements.

17.1. Please confirm that conservation and efficiency options, and DSM programs are continuously changing and improving.

17.1.1. If not confirmed, please explain why not.

17.2. Please provide a discussion of the types of programs, rate design or other options that are available to utilities to create DSM that is reliable and available on demand?

17.2.1. Please discuss FBC's use, and planned use of any such options.

18. Reference: Exhibit B-1, page 105

> FBC has taken into account a number of attributes when evaluating the various resource options. In addition to financial attributes (i.e. costs), these include operational/technical characteristics and environmental and socio-economic impacts, which are discussed in the following sections. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and expected load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future.

18.1. What steps, short of new generating resources, is FBC taking to mitigate risks relating to transmission disruptions and reliability in the future? Please discuss.

19. Reference: Exhibit B-1, page 111 and page 112

> Relying on market purchases over the long term, however, can be risky in terms of price and supply availability. While there are market price forecasts for future electricity prices, there is no guarantee that market prices will remain at these levels given the degree of price volatility and uncertainty in the marketplace. This is why FBC has presented varying market price forecast scenarios in Section 2.5. There is also no guarantee that FBC will be able to access market
>
> supply reliably, especially if there is no access to long term firm transmission (as discussed in Section 5.5). Therefore, FBC does not believe that market supply can be relied on as a long-term resource option.

19.1. Please provide any risk analysis has FBC has done with regard to reliance on market purchases.

19.2. Please provide market price forecasts for future electricity prices with the source and compare these to BC Hydro's forecast for High Load hours and Low Load hours..

19.3. Please provide historical prices for the market prices on a monthly basis over the last 10 years.

19.4. Please discuss the causes of uncertainty in the marketplace.

20. Reference: Exhibit B-1, pages 32, 35,36, and 112

2.4.1 Market Price Environment

> Regional market electricity prices continue to be highly correlated with regional natural gas prices. This is largely because natural-gas fired power plants are often the marginal generating unit for generating electricity. Natural gas prices continue to remain low relative to historical values prior to the shale gas surge after 2008. Advances in drilling technology and cost reductions for producers have led to an abundance of low-cost shale gas in North America and increases in shale gas production are only expected to continue. Low gas prices are providing opportunities for increased natural gas use, particularly in power generation, LNG exports, and the transportation sector. Natural gas supply has kept up with this increased demand, keeping prices at low levels.

> As shale gas production in the northeastern portion of the U.S. expands, there will be less of a need to export western produced gas to the eastern consuming regions. This fundamental change will create a surplus of available natural gas in the western portion of the continent and help sustain the regional price advantage for consumers in the Pacific Northwest.

The West Coast energy crisis of the early 2000s resulted in an expansion of new gas-fired combined-cycle power plants in order to meet the market's capacity deficit. As a result, the Mid-Columbia (Mid-C) power market[35] has generally been in an energy and capacity surplus since the mid-2000s. This provides a cost effective way for utilities in the region to meet their load as it has generally been cheaper to buy energy and capacity in the wholesale market rather than building new generation plants[36]. The majority of the electric utilities in the Pacific Northwest region rely on wholesale market purchases to some extent (see Comparison Table in Appendix C).

Due to the Pacific Northwest's proximity to natural gas producing regions in the WCSB and the U.S. Rocky Mountain region along with low natural gas prices, gas-fired power plants have become a low-cost alternative for power generation. Gas-fired generation is expected to make up the capacity shortfall caused by coal retirements, intermittent resources, and load growth. This will further strengthen the interdependency between natural gas and electricity prices in the Pacific Northwest region.

8.2.6 Expiring Energy Purchase Agreements

Energy currently provided to BC Hydro from IPPs under Electricity Purchase Agreements (EPAs) may become available to the market when these EPAs expire. In its 2013 IRP, BC Hydro has assumed, for planning purposes, that about 50 percent of its bioenergy EPAs will be renewed, about 75 percent of its run-of-river EPAs that are up for renewal in the next five years will be renewed, and that all of its other EPAs will be renewed. BC Hydro also amended its Standing Offer Program rules to specifically exclude generators with expiring EPAs. BC Hydro's F2017-F2019 Revenue Requirements Application also addresses expiring EPAs. Fourteen of BC Hydro's existing EPAs with IPPs are expiring by the end of fiscal 2019. Consistent with the approved 2013 Integrated Resource Plan (IRP), BC Hydro continues to assume renewal of 50 percent of the energy and capacity contributions from biomass EPAs and 75 percent from the run-of-river hydroelectric EPAs that are due to expire within the remaining years of the 10 Year Rates Plan the BC government announced in 2013.

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. However, there may be opportunities for FBC to acquire power from the other facilities on a cost-effective basis. In addition, BC Hydro will need to address expiring EPAs after 2019. FBC will continue to monitor the BC Hydro contract renewals for any resource option opportunities.

20.1. Please provide the forward price curve for natural gas.

21. Reference: Exhibit B-1, page 117

> FBC currently accesses market supply to complement its existing resources with reliable and low-cost power. There is no indication at this time that market supply will increase significantly in price or that FBC will not be able to access it reliably over the next ten years. However, market conditions can change over time and market prices and access could change in the future. FBC's base case assumption is that it will be able to access low-cost and reliable market supply for the next ten years, out to 2025. After this time, FBC has assumed that it will become self-sufficient, with incremental supply coming from its own generation and/or long-term contracts from B.C. suppliers. This also provides consistency with the *CEA* objective of achieving electricity self-sufficiency. As sensitivity cases, FBC has developed portfolios that do not include self-sufficiency within the planning horizon (i.e. long term market reliance) and self-sufficiency by an earlier date of 2020. FBC has also modelled the impacts of higher market power and carbon prices based on the price forecasts and scenarios provided in Section 2.5.

21.1. Under what circumstances would FBC consider not achieving moving toward self-sufficiency by 2025? Please explain.

21.2. Please describe the types of energy market conditions that would support the assumption that FBC will become self-sufficient after 2025.

21.3. Please describe the types of energy market conditions that would support the continued reliance on market supply for some portion of FBC's energy beyond 2025.

21.4. Please provide an overview of FBC's plan to develop incremental supply with time frames and high level expected costs, given that many years are required to put this in place.

22. Reference: Exhibit B-1, page 117 and page 100

> and help reduce their electricity bills. The maximum DSM level is based on meeting 89 percent of annual average forecast load growth for customers' energy requirements with DSM. The High DSM level is FBC's proposed DSM offset level while the Base DSM level is close to FBC's current level of DSM.

Table 8-2: Key DSM Scenario data

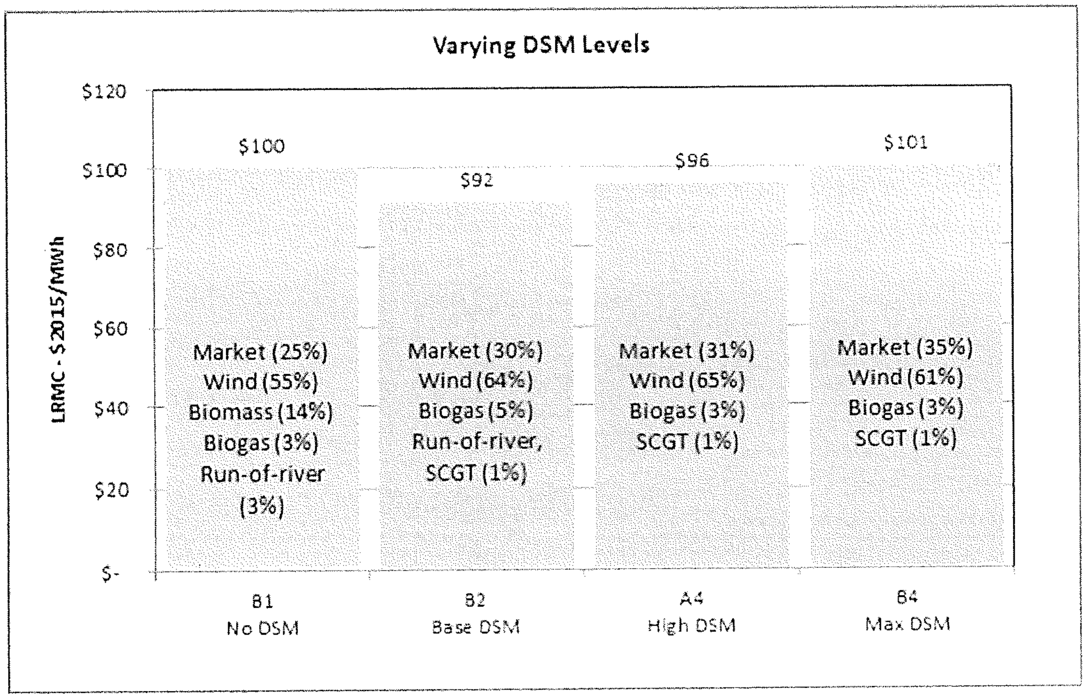
Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

22.1. Please describe the types of programs and activities FBC will likely undertake to raise the DSM program's current level close to Base DSM to High DSM level.

22.2. Does FBC have savings from Rate Designs, and if so, please identify them and their incremental costs.

23. Reference: Exhibit B-1, page 119

Figure 9-1: Portfolios with Different DSM Levels



The first column (B1) represents the portfolio of clean or renewable resources without any DSM, which, as described above, is used to determine the LRMC for the purposes of evaluating cost effective DSM (per the DSM Regulation). The LRMC for this portfolio is $100 per MWh and it includes wind, biomass, biogas, and run-of-river resource options as well as some market purchases out to 2025.

The other columns (B2 to B4) show three portfolios with different levels of DSM and which include the requirement that the total portfolio mix meet the *CEA* objective of at least 93 percent clean or renewable resources. These portfolios have LRMC values that range from $92 per MWh to $101 per MWh and all include market access to 2025, wind, biogas and minor contributions from SCGT. The least-cost portfolio (B2) includes the base amount of DSM while the highest cost portfolio (B4) includes the maximum level of DSM. This is because the cost of the higher DSM offset levels is greater than alternative supply-side resource options, including lower-cost market supply and PPA Tranche 1 Energy.

23.1. Please provide the expected costs of each of the energy resources included in this analysis on a $/MWh basis.

23.2. Please briefly describe the criteria under which the component resources were selected and how the portfolios were developed.

23.3. Please identify which energy resources included in the portfolios are not yet developed or available to FBC.

23.4. Are the renewable energy sources located and/or expected to be located within FBC service territory and offer direct access to FBC? Please explain.

23.4.1. If the renewable resources are not in FBC's service territory and would have to be accessed through the BC Hydro transmission system – for example, energy from wind projects in northwest BC, what additional costs would be incurred, and how would the final costs compare to electricity purchased from BC Hydro under the PPA?

23.5. Please provide an estimate of the total costs and benefits for each of the Base DSM, High DSM and Max DSM maximizing the use of market purchases.

23.6. In the case of the SCGT plant described, please provide details on the size and cost of the plant and time required to design, permit and construct.

24. Reference: Exhibit B-1, page 120

The results show that continued access to the market throughout the planning horizon, without any self-sufficiency requirement, provides a lower LRMC than portfolios where self-sufficiency is required by 2020 or 2025. This is because of the low cost of market supply relative to the cost of other resource options. The LRMC for this portfolio (A1) is $76 per MWh and increases to $81 per MWh in the scenario where higher market and carbon prices are assumed (A2). In the portfolio where there is no market access after 2020 (A3), the LRMC is the highest at $104 per MWh. In this case, the portfolio analysis indicates that FBC would require a new resource, a CCGT plant, as early as 2021. The LRMC of the portfolio where there is no market access after 2025 (A4) falls in between at $96 per MWh. This portfolio includes incremental wind and biogas resources after 2025. It also includes a SCGT plant, which is not required until 2032, and is needed only for low amounts of energy and capacity.

Due to the risks of relying on market access indefinitely into the future (as discussed in Section 5.5 and 8.2.4), FBC believes that self-sufficiency at some point in the planning horizon is a more prudent approach to resource planning. Self-sufficiency by 2020 results in a significantly higher LRMC and would mean that FBC would need to secure incremental resources within the next few years to meet the 2020 target. Self-sufficiency by 2025 allows more time to plan for new resources and to assess the LRB, as well as market conditions, at the time FBC prepares its next long term resource plan. This is a more balanced approach to market access. Self-sufficiency is also a B.C. energy objective in the *CEA*.

24.1. When does FBC expect to prepare its next Long Term Resource Plan? Please provide approximate time frames for the commencement, preparation and delivery.

24.2. Please confirm the CEC's understanding that the plan to allow for self-sufficiency by 2025 facilitates greater flexibility for FBC, in that it could choose to alter its course of action and make the determination to rely longer on market supply if market conditions appear favourable during the preparation for the next Long Term Resource plan.

24.2.1. If yes, does planning for self-sufficiency at 2025 result in any extra costs if, during the next LTERP, FBC were to decide to rely on market supply, or is there effectively no additional costs for this flexibility? Please discuss and provide quantification of any costs that are incurred.

24.3. Would planning for self-sufficiency at 2030 provide any greater flexibility to FBC, or does the 2025 self-sufficiency planning horizon provide full flexibility? Please explain why or why not.

24.3.1. If FBC were to decide to rely on market supply beyond 2025, what would be the latest time at which it could cost-effectively make that determination?

25. Reference: Exhibit B-1, page 125 and 126

> Note that for portfolios C1, A4 and C4, market purchases are selected until 2025 and incremental supply-side resources are not required until at least 2026. Market purchases are selected because they are lower cost than the PPA Tranche 1 Energy, at least for the first few years of the planning horizon. For portfolio A1 with no self-sufficiency, market purchases are selected throughout the 20 years because market power is lower cost than the other resource options.

Table 9-2: Attributes of Portfolios Considered for Preferred Portfolio

	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
A1	No Self-Sufficiency	Market (97%) Biogas (3%)	$76	0.0%	0	14	Low
C1	93% Clean with CCGT	Market (51%) CCGT (48%) Biogas (1%)	$91	3.9%	189k	164	Medium
A4	93% Clean with SCGT	Market (31%) Wind (65%) Biogas (3%) SCGT (1%)	$96	0.2%	3k	145	High
C4	100% Clean BC Resources	Market (31%) Wind (65%) Biogas (3% Biomass, Solar (1%)	$98	0.0%	0	216	Medium

25.1. Portfolio A1 includes 0.0% Non-Clean BC resources. Please confirm that A1 represents the lowest possible LRMC that FBC could create.

25.1.1. If not confirmed, please provide details of the lowest LRMC portfolio that FBC can create.

26. Reference: Exhibit B-1, page 128

The preferred portfolio includes several types of resources such as market purchases, SCGT, wind and biogas. Increases in market gas prices would not have a material effect on the costs of the SCGT given that it is used for limited amounts of energy and capacity for peaking and reliability purposes. Increases in market power prices, however, could have a more significant impact on the portfolio costs. This was discussed in Section 9.4.3, above, where the impacts of higher market prices increased the LRMC value from $96 per MWh (A4) to $98 per MWh (C3). With higher market prices, FBC selected more energy from wind generation and less from the market for the portfolio.

Section 4 discusses load scenarios and the potential for increased load due to fuel switching, EVs and the addition of new large loads to the FBC system. While the load increases from fuel switching from gas to electricity and EVs would likely occur gradually over time, a new large load addition, from a datacentre or hospital for example, could occur much more quickly. In this scenario, discussed in Section 9.4.4, FBC could rely on more market purchases but may also be required to add new resources such as wind, solar and gas-fired generation. Depending on the timing of the additional load requirements, FBC would have to accelerate the acquisition or building of new generation before 2026, when new resources are otherwise required based on the reference case load forecast. The inclusion of SCGT in the preferred portfolio does provide

26.1. What criteria will FBC use to determine whether to build or acquire new generation?

26.2. How much lead time is required to initiate a project to build new generation, including siting, design, permitting and construction?

26.2.1. When will FBC make the decision to build or acquire new generation?

27. Reference: Exhibit B-1, page 137

10.4 *DIALOGUE AND ENGAGEMENT WITH FIRST NATIONS*

FBC strives to develop and build mutually beneficial working relationships with First Nations communities. Understanding, respect, open communication and trust continue to be FBC's aim when working with First Nations groups throughout the province.

FBC works to ensure that First Nations' interests are represented in the Company's various stakeholder engagement initiatives. The RPAG includes a member that represents B.C. First Nations, which ensures that First Nations play an active role in the ongoing resource planning process. In addition, First Nations representatives from within the electric service area, including the Okanagan Nation Alliance, the Ktunaxa Nation, and the Secwepemc Nation, were invited to attend the Community Consultation workshops throughout the preparation of this LTERP.

FBC also met with representatives of the Ktunaxa Nation in Cranbrook on October 31, 2016. In this meeting, FBC provided an overview of its long term gas and electric resource planning. During the discussions, the Ktunaxa Nation expressed its concerns about not having access to lower-cost energy given the current unavailability of natural gas for space and water heating and a primary reliance on more expensive electricity for space and water heating. FBC will continue to engage with the Ktunaxa Nation to explore options to help meet its energy needs.

27.1. What, if any, are the major concerns that First Nations have identified with respect to the ongoing resource planning process?

27.1.1. What activities will FBC undertake to ensure that these concerns are addressed?

28. Reference: Exhibit B-1, Appendix J, pages 2 and 3

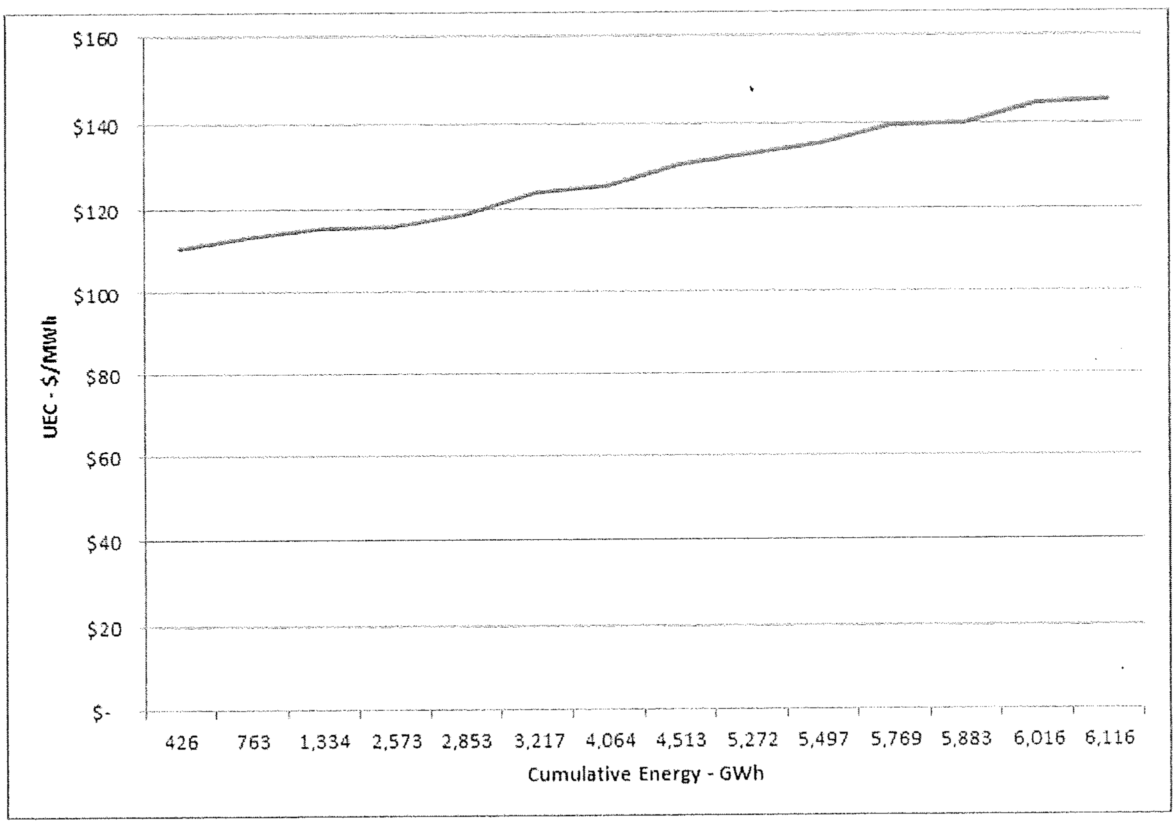
FBC has also given consideration to the geographical diversity of its resource base, given that the generation resources owned by FBC are all located in the Kootenay region while most of its load requirements are in the Okanagan region.

In addition to financial attributes, FBC considers a number of factors when evaluating its resource options. These include consistency with B.C. energy policy and resource attributes, such as operational characteristics and environmental impacts. Geographic diversity of resources is also a consideration given that all of the generation plants FBC owns are located in the Kootenay region whereas most of the load and recent load growth is in the Okanagan region. Locating new generation resources closer to the primary load centres would help mitigate risks relating to transmission disruptions and reliability in the future, and could reduce or delay the need for transmission upgrades in the future. Furthermore, a number of financial assumptions must be made in order to cost the resource options, such as gas and electricity market prices, BC Hydro electricity rates and the cost for carbon emissions. These are discussed in the following sections.

28.1. Are there benefits in terms of risk reduction from catastrophic events from have greater geographic diversity in its resources? Please explain why or why not.

29. Reference: Exhibit B-1, Appendix J, page 32

Figure J3-19: Onshore Wind Supply Curve



FBC's collaboration with BC Hydro identified over one hundred potential wind projects throughout B.C., with many of them in northern B.C. FBC has evaluated a smaller subset of lower cost sites outside and within its service area for the purposes of this ROR. The supply curve for these lower cost projects is provided in the following figure.

29.1. Please identify the smaller subset/shortlist of the potential wind projects and their expected in-service date.

29.2. Please provide their locations of the on a map of BC.

29.3. Please provide the expected size and costs for each project.

30. Reference: Exhibit B-1, Appendix J, page 33

> There is significant potential for run-of-river generation in B.C. and FBC's collaboration with BC Hydro identified over seven thousand possible sites. Most of the possible sites would not be considered economic at this time, however. For this ROR, FBC developed a smaller subset of the identified sites by selecting a sampling of cost-effective different-sized sites. The cost curves for these are provided in the following figure.

30.1. Please provide the smaller subset/shortlist of the potential run of river projects without specific identities and their expected in-service date.

30.2. Please provide their locations on a map of BC.

30.3. Please provide the expected size and costs for each project.

31. Reference: Exhibit B-1, Appendix J, page 39

> As part of the resource options collaboration with BC Hydro, five potential utility-scale solar PV sites with 5 MW of installed capacity were identified in southern B.C. FBC narrowed this group down to the three lowest cost projects. The supply curve for these options is provided in the following figure.

31.1. Please provide the names of the three lower cost options without their specific identities and their expected in-service dates.

31.2. Please provide locations on a map of BC.

31.3. Please provide the expected size and costs for each project.

32. Reference: Exhibit B-1, Volume 2 Long Term DSM Plan page 14

The following Table 3-1 shows key DSM scenario data, including the percentage of forecast load growth to be offset by DSM and the sum total of DSM savings to be targeted over the planning horizon. For context, of the total (2016 to 2035) annual savings, FBC has booked 511 GWh of DSM program savings from program inception in 1989 to 2015 inclusive.

Table 3-1: Key DSM Scenario Data

Category	DSM Scenario			
	Low	Base	High	Max
Annual Savings, GWh				
Average per annum ('18-'35)	20	26	31	36
% of load growth ('18-'35)	50%	66%	77%	89%
Total (2016 to 2035)	407	523	602	686
Resource Cost, 2016 $/MWh				
Incremental cost incl. program costs	$45	$88	$104	$114

32.1. Please provide total DSM program historical performance for each of the last ten years by rate class:

- Annual savings, GWh planned and actual
- Resource costs $/MWh planned and actual
- Customer participation planned and actual
- Please break out data from Kelowna