Diane Roy
Vice President, Regulatory Affairs

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

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

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

March 16, 2018

BC Hydro
c/o Regulatory Group
16th Flr. 333 Dunsmuir Street
Vancouver, BC
V6B 5R3

Attention: Mr. Fred James, Chief Regulatory Officer

Dear Mr. James:

Re: FortisBC Inc. (FBC)

Project No. 3698820

Self- Generation Policy Stage II Application (the Application)

Response to the BC Hydro and Power Authority (BCH) Information Request (IR) No. 1

On November 10, 2016, FBC filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-51-18 setting out the amended Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCH IR No. 1.

If further information is required, please contact Corey Sinclair at 250-469-8038.

Sincerely,

FORTISBC INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

1.0 Reference: Exhibit B 2, FBC response to BCUC IR 1.1.2, 13 elements listed on pages 52 to 53 of the Commission's Order No. G 27 16 Decision

Element #3: "Establish policies that outline the circumstances under which FortisBC will do nothing, remove barriers or incent self generation"

Element #4: "Establish policies that assist in mitigating barriers to cost effective clean self generation"

1.1 Please confirm or explain otherwise that Exhibits B 1 and B 2 do not identify any barriers to new investment in cost effective clean self generation in the FBC service area.

Response:

Examples of barriers to cost effective clean self-generation were provided by the Commission in the Stage I Decision including:

- Interconnection issues and administrative complexity (page 7); and
- Difficulty accessing the market (page 14).

However, FBC does not believe that such barriers are significant and has not identified additions to those listed, and specifically does not believe that barriers exist specifically due to any FBC policies that place self-generation at a disadvantage as compared to other resources. To the extent that any such barriers may exist, the policies that FBC proposes that would provide mitigation are discussed in its response to BCUC IR 1.1.2.

1.2 Please confirm or explain otherwise that under existing approved FBC tariffs and/or service agreements, a FBC customer can currently install generation facilities on the customer's side of the point of interconnection with the FBC system and, subject to meeting FBC's technical connection requirements to ensure safe interconnected operation, such customer may operate such self generation to supply their plant and equipment and reduce their electricity purchases from FBC.

Response:

Confirmed.

1.3 Please confirm or explain otherwise that a generator meeting the requirements of FBC Tariff Supplement No. 7 Transmission Access Terms and Conditions can currently deliver energy and capacity to the FBC system and wheel such energy and capacity through the FBC system to a third party buyer in accordance with Tariff Supplement No. 7.

Response:

Confirmed.

1.4 Please confirm or explain otherwise that FBC can currently enter into an electricity purchase agreement with a generator to acquire energy and capacity, subject to the criteria set out in section 71 of the *Utilities Commission Act* (e.g., the contract is in the interests of current and future FBC ratepayers, and aligns to B.C.'s energy objectives).

Response:

Confirmed.

1.5 Please confirm that under the SSO Guidelines an Eligible Customer would have to actually construct self generation facilities and produce self generation output before it could have a SSO established and take service pursuant to the SSO.

Response:

Confirmed. There must be some basis, either through experience with the generation facilities or an engineering estimate upon which to set an SSO.

1.5.1 Please discuss how the SSO Guidelines can be viewed as removal of an economic barrier or as an incentive, as stated at Exhibit B 2, page 2, lines 32 to 33, if service pursuant to a SSO would provide a self generating customer with an enhanced opportunity to realize a greater return on its past investment rather than removing a barrier to or providing an incentive for new investment in additional clean self generation.

Response:

The referenced portion of Exhibit B-2 discusses the proposed sharing of the net-benefits of self-generation that is contained in both the setting of an SSO and the SBBD reduction. To the extent that either mechanism provides a financial benefit to the SG customer, this additional benefit would naturally constitute removal of some portion of a perceived barrier. FBC does not consider this to be an incentive.

1.6 Please provide the analysis FBC performed to reach the conclusion that service pursuant to a SSO provides a self generating customer with an enhanced opportunity to realize a greater return on its investment relative to the current situation without unreasonably impacting other customers, as stated on page 2, lines 31 to 32.

Response:

No detailed analysis is required to support this conclusion. It is the case that if FBC's largest eligible self-generating customer (currently served on a combination of RS31 and RS37 on a net-of-load basis) increased its RS31 load from the current 3 MW to roughly 20 MW in each hour, other customers would receive a rate mitigation benefit for the foreseeable future.

1.6.1 Does FBC's conclusion that a FBC customer taking service pursuant to a SSO will not unreasonably impact other customers also apply to BC Hydro's customers? Please explain.

Response:

FBC agrees with the determination made by the Commission that under the terms of the PPA there is no significant risk of harm to BC Hydro or its customers presented by the potential activities of FBC's SG customers.

1.6.2 Please provide copies of pages 44 and 45 of FBC's 2016 Long Term Electric Resource Plan (**2016 LTERP**) regarding electricity market price forecasts. Please also provide any more recent electricity market price forecasts that FBC has submitted to the Commission.

Response:

Please refer to Attachment 6.2 for copies of pages 44 and 45 of FBC's 2016 LTERP, as well as Appendix D: Price Forecast and Rate Scenarios Tables, pages 4 to 6.

1.6.3 Please provide a copy of Appendix K to FBC's 2016 LTERP regarding FBC's long run marginal cost (**LRMC**). Please also provide any subsequent updates to FBC's LRMC that FBC has submitted to the Commission.

Response:

Please refer to Attachment 6.3 for a copy of the requested document.

The most recent LRMC values can be found in FBC's 2016 LTERP Errata Update dated September 15, 2017 (Exhibit B-1-1) on page 4.

Portfolios Considered for Preferred Portfolio

Portfolio	Description	LRMC ($/MWh) - As filed	LRMC ($/MWh) - Correction
A1	No Self-Sufficiency	$76	$75
C1	93% Clean with CCGT	$91	$90
A4	93% Clean with SCGT	$96	$96
C4	100% Clean	$98	$97

Portfolios with Different DSM Levels

Portfolio	Description	LRMC ($/MWh) - As filed	LRMC ($/MWh) - Correction
B1	No DSM	$100	$100
B2	Base DSM	$92	$92
A4	High DSM	$96	$96
B4	Max DSM	$101	$99

1.6.4 Please provide FBC's total energy purchases from BC Hydro pursuant to the Rate Schedule (**RS**) 3808 Power Purchase Agreement for each contract year since the agreement came into effect in 2014.

Response:

The following table shows FBC's purchases of energy from BC Hydro under RS 3808 for each contract year since the agreement became effective on July 1, 2014.

Contract Year	GWh
July 1, 2014 to September 30, 2014	109.3
2015/2016	517.5
2016/2017	537.8

1.6.5 Making specific reference to FBC's electricity market price forecast and LRMC values as reported in the 2016 LTERP (or as subsequently updated in Commission filings), please further explain how service

pursuant to a SSO could provide a self generating customer with an enhanced opportunity to realize a greater return on its investment relative to the current situation without unreasonably impacting other customers, as stated on page 2, lines 31 to 32.

Response:

Service pursuant to a SSO is recognition that net benefits exist due to the SG customer generation. As such it provides an opportunity for a SG customer to potentially realize additional value for a portion of its generation. This is not a guarantee and FBC believes that under current market prices (and as forecast in the market price forecast) it is likely that a SG may find it difficult to find a buyer for its generation at a price that is higher than the utility rate. However, if this should occur, then the utility would be looking to replace the power. The LRMC is not an appropriate measure of this replacement cost as the utility obligation created under an SSO is relatively short term. Other customers may be either negatively or positively impacted depending on the price at which FBC is able to replace the power. However, any such impact is not an unreasonable impact as it directly flows from the recognition of a sharing of the overall net benefits provided by the SG.

1.6.6 Please confirm or explain otherwise that the loss calculated in the table below (based on Scenario 1, section 4.1.1 and sample data used in Table 4 1, page 36, of Exhibit B 1) is a possible outcome for FBC if a FBC self generating customer (i) has an SSO set at 50 per cent of the customer's normal historical self generation output, and (ii) exports out of B.C. the amount of energy between the 50 per cent SSO and the customer's normal self generation output.

	Scenario 1: FBC Self-generating customer exporting energy out of B.C. while generating not in excess of load	
A	Annual Plant Consumption	65,572,500 kWh
	(Reference Exhibit B-1, Table 4-1 row b, page 36)	
B	Previous Year Self-Generation Used to Serve Load	43,800,000 kWh
	(Reference Exhibit B-1, Table 4-1 row c, page 36)	
C	SSO (= 50% x B)	21,900,000 kWh
D	FBC blended rate for sales to customer	$0.078/kWh
	(Reference Exhibit B-1, Table 4-1 row l, page 36)	
E	LRMC for Avoided Purchases from LTERP	$0.085

	(Reference Exhibit B-1, Table 4-1 row g, page 36)	
	Customer exports the amount of energy between the 50% SSO and the customer's self-generation output	
F	FBC additional service to customer (= B - C)	21,900,000 kWh
G	FBC additional revenue (= F x D)	$1,708,200
H	FBC additional cost (= F x E)	$1,861,500
I	FBC Net Benefit / (Loss) per year (= G - H)	($153,300)

Response:

The information contained in Table 4-1 of the Application is specific to the calculation of an SBBD reduction for use in the Stand-by Rate over the long term. Regardless, the loss calculated per the included table above will only materialize utilizing the LRMC measure of cost effectiveness noted in line E. Using such a measure of cost effectiveness will result in an apparent loss under the status quo, which is not representative of the actual loss that would occur in the specific situation set out in the table. For the foreseeable future, the SSO provided in the table would provide a benefit for ratepayers. Please refer to the response to BCH IR 1.1.6.5.

1.6.7 Please confirm or explain otherwise that the loss calculated in the table below (based on Scenario 1, section 4.1.1 and sample data used in Table 4 1, page 36, of Exhibit B 1) is a possible outcome for FBC if a FBC self generating customer (i) has a SSO set at 100 per cent of the customer's normal historical self generation output, and (ii) exports out of B.C. the amount of energy the customer generates in excess of the 100 per cent SSO.

	Scenario 2: FBC Self-generating customer exporting energy out of B.C. while generating not in excess of load	
A	Annual Plant Consumption	65,572,500 kWh
	(Reference Exhibit B-1, Table 4-1 row b, page 36)	
B	Previous Year Self-Generation Used to Serve Load	43,800,000 kWh
	(Reference Exhibit B-1, Table 4-1 row c, page 36)	
C	SSO (= 100% x B)	43,800,000 kWh
D	FBC blended rate for sales to customer	$0.078/kWh
	(Reference Exhibit B-1, Table 4-1 row l, page 36)	
E	LRMC for Avoided Purchases from LTERP	$0.085
	(Reference Exhibit B-1, Table 4-1 row g, page 36)	
	Customer exports self-generation in excess of 100% SSO	
F	FBC additional service to customer (= B - C)	0
G	FBC additional revenue (= F x D)	$0
H	FBC additional cost (= F x E)	$0
I	FBC Net Benefit/(Loss) per year (= G - H)	($0)

Response:

Please refer to the response to BC Hydro IR 1.1.6 for a discussion of the impact of LRMC on the calculations, and its intended use, which remain valid here. FBC notes that the scenario in the table above provides no benefit for any customer in the near term. FBC would likely set an SSO in the manner suggested were it not for the requirement to recognize the benefits of self-generation in some manner as directed by the Commission in the Stage I Decision.

1.7 Has FBC considered who might be interested in paying a self generator in the FBC service area for self generation not in excess of load if the SSO Guidelines are implemented? If so, please discuss and provide a summary of FBC's consultation with such potential purchasers. If not, please explain why not.

Response:

The focus of FBC in this and related processes has been on meeting the requirements set out by the Commission and providing mechanisms that mitigate the potential for impacts on other customers. While the SGP may facilitate the sales to third parties by its SG customers, the

Company does not consider that the potential sales opportunities that may exist for a self-generation customer are properly a matter to which it should devote resources. SG customers are sophisticated entities that are responsible for assessing opportunities and making arrangements on their own behalf.

1.7.1 Under what conditions would FBC purchase a customer's self generation in excess of a 50 per cent SSO? Please provide the financial analysis supporting the answer.

Response:

Please refer to the response to CEC IR 1.16.5.

1.7.2 Under what conditions would FBC expect that BC Hydro would purchase a FBC customer's self generation in excess of a 50 per cent SSO? Please provide the financial analysis supporting the answer.

Response:

FBC cannot speak for BC Hydro and has no expectations in this matter. However, based on BC Hydro comments in this process, particularly Exhibit C2-2, the BC Hydro position seems clear. In Exhibit C2-2, BC Hydro stated,

> BC Hydro has been clear, and to avoid any misplaced expectations of FortisBC self-generating customers, BC Hydro reiterates that it will not be purchasing power based on any SSO that may exist between FortisBC and a FortisBC self-generating customer unless the SSO is comparable to the baseline BC Hydro would determine for the purpose of acquiring incremental/new clean energy. For greater certainty, the FortisBC SGP is not required for self-generators in the FortisBC service area to sell incremental clean energy to BC Hydro, and BC Hydro would not use the SSO, as proposed by FortisBC, for that purpose. The proposed SGP is not needed for such purpose and likely would only cause problems for BC Hydro's resource acquisition processes.

1.7.3 Under what conditions would FBC expect that a third-party other than FBC or BC Hydro would purchase a FBC customer's self generation in excess of a 50 per cent SSO? Please provide the financial analysis supporting the answer.

Response:

FBC considers this to be a straight-forward matter of comparative economics. Within the FBC service area, there are a number of customers with the right to purchase power from a party other than FBC.[1] However, these parties currently purchase power from FBC at a rate lower than or equal to the retail rate paid by a customer that could have an SSO. Given that BC Hydro has stated it will not be purchasing the power, it seems evident that a potential purchaser would be beyond the BC Hydro service area[2] and the SG customer would need to sell its power at a rate higher than its all-in retail rate plus the cost of any transmission service required.

[1] This ability is only available to Eligible Customers as defined by the Access Principles pursuant to Order G-27-99.

[2] Sales to an Eligible Customer within the FBC service area would result in the SG customer becoming a regulated utility. It seems unlikely that this would be a desired outcome.

2.0 Reference: Exhibit B 2, FBC responses to BCUC IRs 1.1.3 and 1.2.1

2.1 Please confirm that FBC remains of the view that the SSO Guidelines, if implemented, would introduce a risk of harm to other customers relative to the status quo.

Response:

In the view of FBC, the risk of harm to other customers due to the introduction of an SSO methodology, with or without a mechanism for net-benefits sharing, is very small for the foreseeable future.

In order for there to be an economic case for a SG customer to sell below-load power, the price at which it could do so must be in excess of its FBC retail rate. This is not the current situation.

Nevertheless, on the assumption that an SG customer has the right to make such sales and replace the power with an embedded cost supply, at some point in the future, there may be harm to other customers. The SSO Guidelines contain the sharing mechanism in an effort to mitigate this risk.

2.1.1 To the extent possible, please quantify the risk relative to the status quo to (i) other FBC customers, and (ii) BC Hydro customers. Please provide a financial analysis supporting the answer.

Response:

FBC does not believe there to be any risk of harm to the customers of either FBC or BC Hydro at this time, and that any potential future risk is too uncertain to quantify.

2.1.2 Under what circumstances could other FBC customers (i) be held harmless, and (ii) benefit, if a self generating customer in the FBC service area is taking service pursuant to a 50 per cent SSO? Please provide a financial analysis supporting the answer.

Response:

Please refer to the response to BCUC IR 2.4.1.1.

2.2 In its response to BCUC IR 1.2.1 (at page 8, lines 28 to 29), FBC states that it "has formulated the SSO Guidelines in order to mitigate the risk to other customers, (though… some level of risk remains)." Please explain and to the extent possible quantify the risk reduction provided by each mechanism in the Application that reduces the risk of harm to other customers associated with the SSO Guidelines. If there is a difference, please separately identify and explain how each such mechanism reduces the risk of harm to (i) FBC's other customers, and (ii) BC Hydro's customers.

Response:

FBC discusses the risk mitigation provided by the SGP, to both FBC customers and BC Hydro customers, in the response to BCUC IR 2.4.1.1.

2.3 Please discuss whether the risk to other customers would be further mitigated if the SSO was set at a higher percentage of historical self generation output, for example at 100 per cent of historical self generation output?

Response:

The risk of harm to other customers, where such risk is assumed to result from a difference between the revenue derived from an SG customer and the cost of providing additional service that increases rates, is increasingly mitigated the higher the SSO for the SG customer is set. However, the opposite is also true as setting the SSO at 100% of historical load for an existing customer, or setting the SSO at higher that 50% of new generation, would also limit potential benefits to be shared with all customers.[3] In addition, it would serve to discourage new generation such that any net benefits from new generation would never be realized. Both of these outcomes could also be considered risks to customers in general.

[3] These are complex issues and in addition to any positive revenue the utility may forego for the benefit of all customers, it cannot be assumed that a SG would continue to generate at 100% of load in all circumstances even if the SSO is set to 100%. It is entirely possible that the higher the SSO, the lower the self-generation may be if the economics are such that third party sales are required to offset the high cost of fuel to self-generate.

2.4 Please further explain the statement at Exhibit B 2, FBC response to BCUC IR 1.1.3, page 7, lines 4 to 5, indicating FBC assumes that "it will not be placed in the position where it must furnish electricity to support those exports while placing its own embedded cost supply at risk."

Response:

This statement reflects an expectation on the part of FBC that if its SGP, either as filed or with changes as directed by the Commission, is approved by the Commission, then any increase in FBC native load that results would be resourced in a manner determined by the Company.

In other words, a load increase due to SG third party sales should be treated no differently than a load increase for any other reason. FBC should not have any concerns related to Section 2.5 of the PPA and any actions by BC Hydro that would seek to limit supply to FBC that otherwise was taken in compliance with the PPA in general.

2.4.1 Please specifically explain what "placing its own embedded cost supply at risk" means.

Response:

"Placing its own embedded cost supply at risk" refers to any outcome that would result in FBC not having access to any portion of the power normally available pursuant to its PPA with BC Hydro. Please refer to the response to BC Hydro IR 1.2.4.

2.4.2 Please identify the terms, conditions or other mechanism(s) in the SSO Guidelines that are intended to prevent FBC's own embedded cost supply from being placed at risk.

Response:

Please refer to the response to BC Hydro IR 1.2.4.

2.4.3 Does FBC believe that BC Hydro's embedded cost supply also should not be placed at risk as a result of FBC's proposed SSO Guidelines? Please discuss.

Response:

FBC does not see any circumstance where the embedded cost supply of BC Hydro could be placed at risk as a result of the FBC SSO Guidelines.

2.4.4 Please discuss whether FBC means by its statements at Exhibit B 2, FBC response to BCUC IR 1.1.3, page 7, lines 4 to 9, that in FBC's view BC Hydro and its customers should bear the majority or all of the risks associated with a FBC self generating customer taking service pursuant to a SSO.

Response:

To the extent that there is any risk to the customers of BC Hydro as a result of a FBC self-generating customer taking service pursuant to a SSO, FBC relies on previous Commission determinations that such risk is immaterial and not significant, and that no contractual protection is required.

2.5 In Exhibit B 2, FBC response to BCUC IR 2.1 at page 8, line 32 to 35, FBC explains that it believes that certain limitations in section 2.5 of BC Hydro's RS 3808 Power Purchase Agreement with FBC should be removed or rendered inoperable if the Commission considers that the SSO Guidelines provide protection for both the customers of FBC and BC Hydro. Please explain where in the Application FBC has provided analysis and quantification of the risks to BC Hydro customers and the extent to which mechanisms in the SSO Guidelines mitigate those risks such that the Commission could make a determination on whether the SSO Guidelines provide adequate protection for BC Hydro customers.

Response:

It is apparent through previous filings in this process (and these IRs) that BC Hydro's main concern regarding the proposed FBC SGP pertains to the impact that below-load third-party sales by FBC's SG customers may have on the customers of BC Hydro.

The BC Hydro position ignores the Commission determinations made in the PPA Decision as repeated on page 7 of the SGP Stage II Application.

Either there is a material risk to the customers of BC Hydro or there is not. As the adjudicator of such matters in BC, the Commission has found, quite strongly in the view of FBC, that there is no longer the need to protect against any such risk since it is not considered material or significant.

To the extent that any risk to BC Hydro customers were to exist, the mitigation that the mechanisms included in the SGP provide to FBC customers also reduce the prospect of harm to BC Hydro customers no matter how remote.

2.6 What changes would FBC propose to make to its SSO Guidelines if FBC did not have access to any energy from BC Hydro at embedded cost rates pursuant to the RS 3808 Power Purchase Agreement or otherwise?

Response:

The SSO Guidelines were not designed and are not contingent on any assumption about the availability of existing embedded cost supply. Therefore, the SSO Guidelines would not change in the case where FBC did not purchase energy from BC Hydro.

3.0 Reference: Exhibit B 2, Attachment 1.1, Policies Regarding Self Generating Customers

3.1 Sections 4 (Supporting Documentation) and 5 (Uses of FBC Transmission Infrastructure) of the Policies Regarding Self Generating Customers provide that a self generating customer that intends to sell any portion of its self generation output to a third-party other than FBC must also apply for transmission service and comply with Tariff Supplement No. 7.

3.1.1 Please confirm or explain otherwise that FBC Tariff Supplement No. 7 is up to date with U.S. Federal Energy Regulatory Commission (**FERC**) reforms to the open access transmission tariff including FERC Order 890 issued in 2007.

Response:

Tariff Supplement No. 7 has not been updated since originally approved by the Commission. FERC Order 890 was issued subsequent to the approval of Tariff Supplement No. 7 and FBC has not since undertaken a full review. The current version of Tariff Supplement No. 7 is the version approved for use by the Commission.

3.1.2 The Preamble to Point to Point Transmission Service on page 21 of FBC's Tariff Supplement No. 7 states that "Point to Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery". Please discuss how a self generating customer with a plant load of 100 MW, self generation output of 20 MW and a SSO of 10 MW could deliver capacity and energy to the FBC's transmission system and use Point to Point (**PTP**) transmission service in compliance with Tariff Supplement No. 7 to deliver 10 MW of self generation to a third-party other than FBC.

Response:

FBC considers that the arrangements in the scenario that BC Hydro has put forward would be arrived at through the discussions described by BC Hydro in its *Application for Approval of the Section 2.5 Guidelines for the New Power Purchase Agreement with FortisBC - Rate Schedule 3808, Tariff Supplement No. 3 Regarding Commission Order No. G-60-14*, Attachment 2, Section 2.3, which contemplated exactly these types of transactions. This submission is repeated below.

Accounting and scheduling methodologies will need to be agreed to as between FortisBC, BC Hydro and the FortisBC customer to determine electricity the customer uses for self-supply, electricity available for sale to a third party, electricity deemed to be provided by FortisBC to its customer, ancillary services provided by FortisBC to its customer under FortisBC's open access transmission tariff, and electricity deliveries accounted for as exports under the Master Accounting Agreement.

3.1.3 What changes does FBC expect would need to be made to Tariff Supplement No. 7 to enable self generating customers to use PTP transmission service to sell self generation output below the self generator's load to third parties other than FBC?

Response:

FBC does not expect that any changes to Tariff Supplement No. 7 will be required in order to accommodate the transactions described in BC Hydro IR 1.3.1.2.

3.1.4 Please further explain the following conditions in section 6.1 (Purchases by a Third Party other than FBC) of the Policies Regarding Self Generating Customers: "Arrangements for the sale of self generation output to a third-party other than FBC are the sole responsibility of the self generator. FBC will work with the self generator to facilitate the transmission of power in accordance with the discussion in section 5 of this document." (underling added)

Response:

FBC believes the quoted section in the question, including the underlined portion, is straightforward. Section 5 of the referenced document discusses the requirements that must be satisfied in order to arrange for use of the FBC transmission system. FBC indicates that it will work with the SG customer to see that these requirements are met in the same manner it would work with any customer making such a request.

4.0 Reference: BC Hydro Application to the Commission dated December 17, 2014 for Approval of Section 2.5 Guidelines for the RS 3808 Power Purchase Agreement (the "Section 2.5 Guidelines Application")

4.1 The Section 2.5 Guidelines Application puts forward an approach employing Customer specific Baselines (**CSBs**) and options for determining a CSB. Please explain FBC's concerns, if any, with the approach and options presented in BC Hydro's Section 2.5 Guidelines Application.

Response:

In the view of FBC, the updated Section 2.5 guidelines are cumbersome as compared to the SSO Guidelines proposed by FBC, and continue to involve BC Hydro in the FBC-customer relationship.

BC Hydro noted on page 8 of the referenced Application,

> As noted in the Section 2.5 Guidelines, it remains the case that if FortisBC offers a service to its self-generating customers that enables them to simultaneously buy electricity from FortisBC and sell electricity and the service includes conditions that provide reasonable protection to BC Hydro and its ratepayers, and so long as such service is filed and approved by the Commission, a CSB will not be required.

Even taking BC Hydro's standard for not requiring a CSB as a guidepost, there is no material risk from which BC Hydro and its customers need to be protected. If there is, the SSO Guidelines have the effect of mitigating against any such risk.

4.2 Please confirm or explain otherwise that the approaches presented in the Section 2.5 Guidelines Application would place less risk on other customers relative to the approach in FBC's SSO Guidelines application.

Response:

FBC assumes BC Hydro is referring to the December 15, 2014 letter for Application for Approval of the Section 2.5 Guidelines for the New Power Purchase Agreement[4]. It is important to note the basis for the proposed guidelines contained therein as stated by BC Hydro, "*The CSB approach provides FortisBC access to the New PPA comparable to the access it would have if FortisBC used principles similar to those underlying BC Hydro's Contracted GBL Guidelines in*

[4] http://www.bcuc.com/Documents/Proceedings/2014/DOC_42804_B-1_BCH_New-PPA_RS3808-Application.pdf.

connection with FortisBC's services, if any, that would enable its self-generating customers to simultaneously buy and sell electricity."[5] Again, on the next page, "*The principles and methodology reflected in the Section 2.5 Guidelines are consistent with the principles BC Hydro uses to determine Contracted GBLs for EPAs and LDAs with its customers…*"[6]

On December 12, 2014 BC Hydro also filed the Reconsideration and Variance of Commission Order No. G-19-14 Directive 2 Contracted Generator Baseline (GBL) Guidelines Application[7]. Given this document was filed shortly before the document referenced in the IR, it provides useful insight into the BC Hydro approach. Most notably, BC Hydro acknowledges that the BC Hydro approach does not address all aspects of the SG issue. Indeed, BC Hydro acknowledges that the BC Hydro approach does not apply to what is a central facet of FBC's present Application, noting, "*The Contracted GBL Guidelines do not enable or apply to the case where a self-generating customer might wish to simultaneously purchase electricity from BC Hydro and sell electricity into the market*".[8] BC Hydro correctly identifies why this must be the case further on. "*The Contracted GBL Guidelines in Attachment 2 begin by explaining the purpose and principles of Contracted GBLs, as used by BC Hydro. The Contracted GBL Guidelines are not a 'self-generation policy' for BC Hydro's service area. They do not purport to deal with all issues associated with serving customers with self-generation*."[9]

It appears that in its information request, BC Hydro is suggesting that the Contracted GBL Guidelines (which, again, it described as consistent with BC Hydro's Section 2.5 Guidelines approach) do or could form the correct basis for a "self-generation policy" in the FBC service area. This is despite the fact that, as explained above, BC Hydro expressly states that they do not do so in the BC Hydro service area. Furthermore, BC Hydro implies that if FBC does not adapt that which BC Hydro states is not applicable within the BC Hydro service area, then BC Hydro will attempt to limit FBC access to PPA power.

Despite the caution with which BC Hydro's apparent premise in its information request must be approached, certainly there are elements of commonality between the BCH CSB approach and the suggested FBC approach as described in the Application. Most obviously, both seek to establish a typical generation number for an SG customer. However, while this is substantially all that BC Hydro looks at, FBC must consider all the issues surrounding self-generation and therefore consideration must be given to net-benefits as per the Commission's decisions with regard to FBC. As such the SSO methodology as described in the Application is necessarily different than if it were solely based on the principles of BC Hydro Contracted GBL's or, by extension, BC Hydro's Section 2.5 Guidelines application.

---

[5] Ibid, page 7 of 10 of the BC Hydro letter.
[6] Ibid, page 8 of 10.
[7] http://www.bcuc.com/Documents/Proceedings/2015/DOC_42886_B-1_BCH-GBL-GuidelinesApplication.pdf.
[8] Contracted Generator Baseline (GBL) Guidelines Application, page 3, row 1.
[9] Ibid, page 36, row 2.

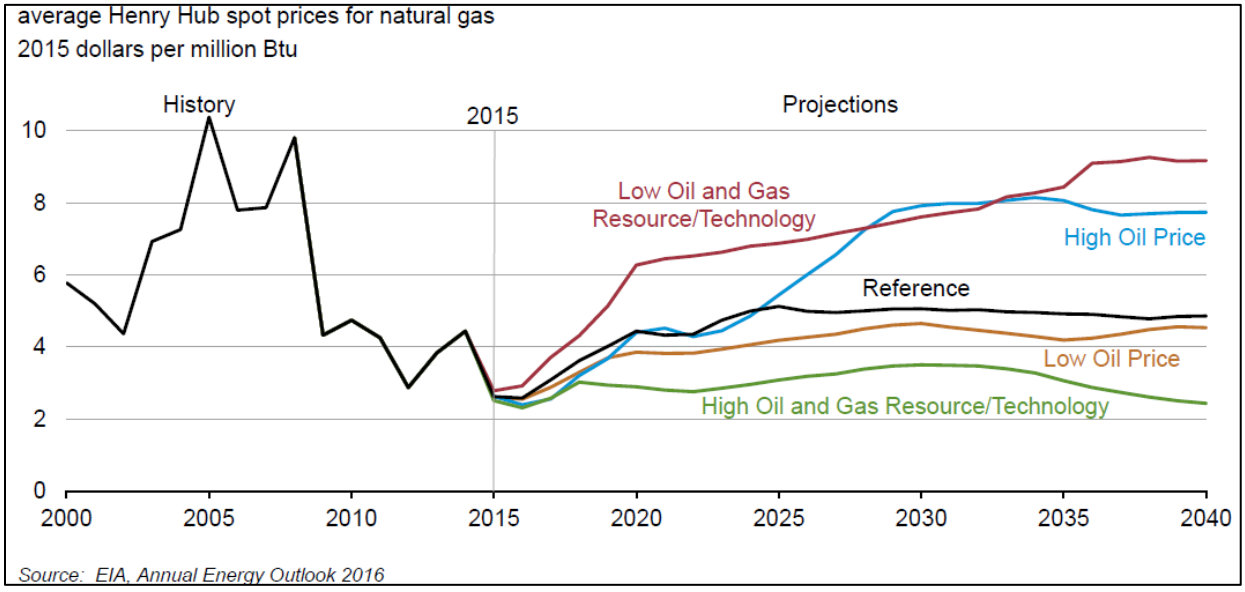
Applying principles based on the BC Hydro Contracted GBL Guidelines to establish an SSO under this Application may reduce the risk to other customers under some circumstances, though may not do so in others; as noted above, the BC Hydro approach was not tailored for the range of circumstances that the FBC SGP is to address.

However, beyond this, FBC believes that any absolute level of risk (the existence of which seems to be among the premises for BC Hydro's question) is very small in the present circumstances, if it exists at all.

In addition, BC Hydro's approach would provide little or no opportunity for benefit to other customers, little or no opportunity for benefit to FBC's existing SG customers, and no provision for the sharing of any net-benefits of self-generation. That in itself, within the principles and regulatory framework that the Commission has set out, would seem to be a form of risk to be considered and is one that FBC's SSO Guidelines approach addresses.

Attachment 6.2

Figure 2-8: EIA Henry Hub Price Forecasts[62]



The NPCC gas price forecasts are slightly higher than the EIA's price forecast cases, on an equivalent Canadian dollar per GJ basis.

2.5.2 Electricity Market Price Forecasts

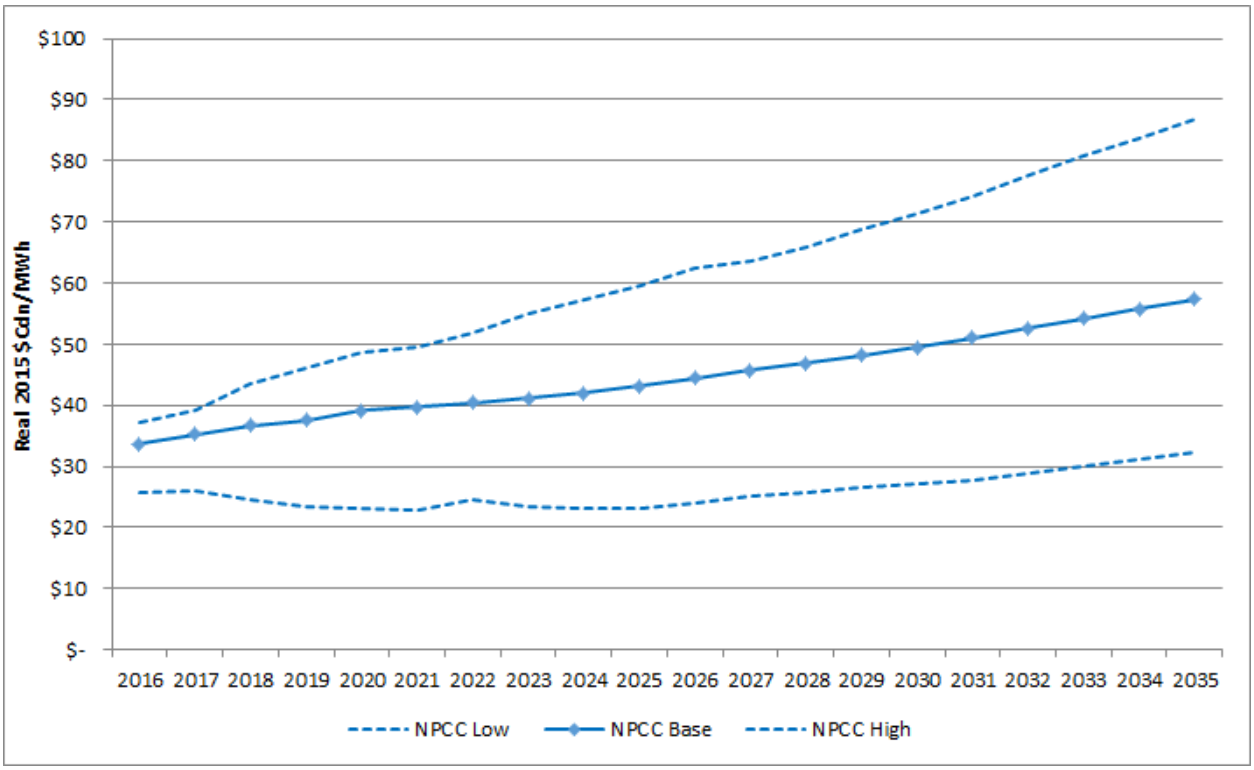
The NPCC Seventh Power Plan Mid-C electricity market price forecast is largely based on the Sumas natural gas price forecast. This is because natural gas-fired plants are often the marginal generating resource in the region to meet load requirements. As such, natural gas prices exert a strong influence on electricity prices. The high and low cases for the forecast electricity prices were set by the associated high and low natural gas price forecasts.

The Seventh Power Plan provides market electricity price forecasts, with high and low cases, based on the Mid-C market trading hub. Mid-C is the primary market electricity trading hub for the Pacific Northwest.

The Mid-C market annual price forecasts in real Canadian dollars per megawatt-hour (MWh) are presented in the following figure.

[62] EIA Annual Energy Outlook 2016 Rollout Presentation, June 28, 2016, slide 33, http://www.eia.gov/pressroom/presentations/sieminski_06282016.pdf.

Figure 2-9: Mid-C Electricity Annual Price Forecasts[63]



2.5.3 B.C. Carbon Price Scenarios

There is uncertainty regarding the level of the B.C. carbon tax beyond 2018. As discussed in Section 2.2, the carbon tax in B.C. was introduced in 2008 at a level of $10 per tonne and increased to $30 per tonne by 2012. In April 2015, the B.C. government announced the formation of a CLT to provide recommendations to build upon B.C.'s existing Climate Action Plan. The CLT released its report in late November 2015. The report provides recommendations, including the development of several new strategies, and increasing B.C.'s existing $30 per tonne carbon tax by $10 per tonne per year starting in 2018. The CLT further recommended that the annual increases in the carbon tax are reviewed in five years; however, the CLT indicates that increases in the range of $10 per tonne per year will be required through to 2050 in order to achieve B.C.'s 2050 emissions targets. However, the CLP, released in August 2016, noted that the B.C. government would not be increasing the carbon tax until other jurisdictions caught up.

In September 2016, the Canadian federal government announced that it is planning to require the provinces to have a price of at least $10 per tonne of carbon dioxide equivalent emissions

[63] Based on Northwest Power and Conservation Council Seventh Power Plan, Chapter 8 and Appendix B Mid-C prices in 2012 $US/MWh converted to 2015 $Cdn/MWh using exchange and inflation rates per Section 2.5.5 and transmission costs per Section 2.5.6.

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - Low

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$35.80	$34.58	$33.76	$31.90	$31.31	$31.35	$32.88	$35.06	$34.66	$35.66	$35.93	$36.46
2017	$36.37	$34.96	$33.96	$31.97	$32.44	$31.43	$32.82	$35.27	$34.77	$35.76	$36.22	$36.94
2018	$35.12	$33.98	$32.85	$30.52	$29.86	$29.17	$31.45	$33.89	$33.75	$34.42	$34.35	$35.80
2019	$33.61	$32.46	$31.20	$29.28	$29.55	$28.44	$30.02	$32.10	$32.26	$32.88	$32.87	$34.27
2020	$33.51	$32.29	$31.15	$29.19	$28.43	$28.33	$30.04	$31.90	$32.14	$32.76	$32.93	$34.32
2021	$32.76	$31.81	$30.78	$28.70	$28.63	$28.84	$29.97	$31.67	$31.41	$32.34	$32.59	$33.64
2022	$34.69	$33.53	$32.50	$30.21	$29.60	$30.28	$31.57	$33.48	$33.03	$34.23	$34.47	$35.48
2023	$33.66	$32.39	$31.34	$29.01	$29.58	$29.80	$30.56	$32.43	$31.81	$33.15	$33.43	$34.35
2024	$33.22	$32.12	$30.94	$28.79	$28.31	$28.56	$30.17	$31.93	$31.79	$32.70	$32.56	$34.03
2025	$33.21	$32.07	$30.97	$28.81	$29.07	$29.21	$30.24	$31.90	$31.94	$32.75	$32.63	$34.37
2026	$34.04	$32.89	$31.82	$29.62	$28.81	$30.01	$31.31	$32.79	$32.69	$33.67	$33.63	$35.19
2027	$35.18	$34.08	$33.05	$30.58	$30.60	$31.49	$32.33	$34.03	$33.60	$34.68	$34.93	$36.50
2028	$36.28	$34.84	$33.77	$30.96	$30.70	$31.85	$33.13	$35.08	$34.19	$35.82	$36.01	$37.26
2029	$37.07	$35.78	$34.59	$31.47	$31.95	$32.25	$33.48	$35.87	$35.31	$36.41	$36.16	$38.09
2030	$37.93	$36.68	$35.20	$32.18	$31.65	$32.50	$34.48	$36.52	$36.26	$37.25	$37.01	$38.99
2031	$38.62	$37.23	$35.46	$32.59	$33.06	$33.52	$34.72	$36.82	$36.96	$37.97	$37.71	$39.92
2032	$40.03	$38.63	$36.98	$33.93	$32.80	$34.27	$35.81	$38.24	$38.08	$39.08	$39.37	$41.31
2033	$41.11	$39.62	$37.91	$34.58	$35.20	$35.61	$36.61	$39.44	$39.09	$40.42	$40.59	$42.29
2034	$42.65	$41.11	$39.08	$35.48	$35.10	$36.27	$37.88	$40.64	$40.37	$41.89	$42.14	$43.79
2035	$43.76	$42.32	$40.40	$36.60	$36.83	$37.04	$38.48	$41.87	$41.92	$43.24	$42.91	$45.01

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - Base

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$44.43	$42.77	$41.78	$39.24	$38.67	$38.80	$40.71	$43.38	$42.62	$44.12	$44.37	$45.29
2017	$46.43	$44.48	$43.19	$40.39	$41.28	$40.17	$41.87	$44.94	$43.95	$45.59	$45.96	$47.28
2018	$48.55	$46.91	$45.15	$41.63	$41.03	$40.56	$43.20	$46.83	$46.05	$47.41	$47.16	$49.56
2019	$49.48	$47.66	$45.66	$42.52	$42.75	$41.66	$43.92	$47.05	$46.94	$48.27	$48.04	$50.53
2020	$51.39	$49.39	$47.35	$44.29	$42.96	$43.42	$45.72	$48.66	$48.75	$50.19	$50.06	$52.80
2021	$51.40	$49.73	$47.89	$44.11	$44.07	$44.87	$46.34	$49.10	$48.73	$50.56	$50.91	$52.89
2022	$52.37	$50.65	$48.78	$44.93	$44.08	$45.58	$47.03	$50.25	$49.44	$51.56	$51.75	$53.70
2023	$53.32	$51.16	$49.41	$45.33	$46.08	$46.50	$47.85	$51.00	$49.82	$52.28	$52.40	$54.46
2024	$54.15	$52.41	$50.57	$46.88	$45.14	$46.26	$48.83	$51.79	$51.32	$53.22	$52.93	$55.64
2025	$55.18	$53.43	$51.36	$48.08	$47.42	$47.97	$50.17	$52.77	$52.33	$54.32	$54.13	$56.96
2026	$56.31	$55.01	$52.93	$49.28	$46.87	$49.28	$51.61	$54.10	$53.79	$56.10	$56.01	$58.22
2027	$57.35	$56.43	$54.08	$50.13	$49.27	$50.77	$52.42	$55.60	$54.65	$57.21	$57.43	$59.56
2028	$58.98	$57.93	$55.43	$50.62	$49.61	$51.66	$53.79	$57.31	$55.66	$59.07	$59.13	$61.10
2029	$60.35	$59.54	$57.05	$51.72	$51.39	$52.30	$54.51	$58.65	$57.48	$60.18	$59.75	$62.74
2030	$61.52	$61.18	$58.28	$53.35	$50.94	$53.04	$56.17	$59.74	$59.12	$61.74	$61.46	$64.51
2031	$63.75	$62.77	$59.14	$54.83	$53.53	$54.94	$57.31	$60.61	$60.74	$63.45	$63.10	$66.64
2032	$65.44	$64.99	$61.08	$56.47	$53.33	$56.53	$58.60	$62.28	$62.23	$65.20	$65.79	$68.58
2033	$66.82	$66.79	$63.18	$56.91	$56.49	$58.39	$59.30	$63.86	$63.48	$67.13	$67.51	$70.41
2034	$69.06	$69.04	$64.80	$58.17	$56.27	$59.14	$61.00	$65.69	$65.21	$69.44	$69.63	$72.55
2035	$70.84	$71.18	$67.04	$58.95	$58.38	$59.82	$62.22	$67.45	$67.57	$70.92	$70.77	$74.61

Mid-C Electricity Price Forecast $CAD/MWh 2015 Dollars - High

Adders Included

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	$48.20	$46.57	$45.14	$42.40	$41.89	$42.34	$44.17	$46.96	$46.17	$47.83	$47.91	$49.17
2017	$50.95	$49.14	$47.38	$44.00	$44.93	$44.35	$45.96	$49.18	$48.11	$50.18	$50.03	$51.99
2018	$56.25	$54.84	$52.07	$48.14	$47.03	$47.10	$49.81	$53.86	$53.18	$55.17	$54.49	$57.71
2019	$58.95	$57.30	$54.10	$50.42	$50.47	$49.58	$52.08	$55.77	$55.72	$57.86	$57.31	$59.62
2020	$61.26	$60.24	$56.66	$53.21	$51.30	$52.19	$54.66	$58.26	$58.31	$60.70	$60.87	$63.50
2021	$61.74	$61.03	$57.53	$52.95	$52.27	$53.98	$55.78	$59.24	$58.74	$61.58	$62.17	$64.74
2022	$64.62	$63.83	$60.06	$54.94	$53.49	$56.17	$58.02	$62.03	$60.93	$64.50	$64.72	$67.35
2023	$67.89	$67.05	$63.31	$57.48	$58.37	$59.60	$61.16	$65.18	$63.78	$67.94	$68.26	$70.86
2024	$70.78	$70.07	$66.10	$60.95	$58.42	$60.06	$64.23	$67.95	$67.00	$70.62	$70.21	$73.69
2025	$72.54	$72.24	$67.95	$62.91	$61.56	$62.53	$66.04	$69.35	$68.82	$72.38	$72.44	$76.22
2026	$75.95	$75.57	$71.45	$65.51	$61.82	$65.50	$69.33	$72.54	$72.44	$76.57	$76.65	$80.19
2027	$76.49	$76.53	$72.54	$66.28	$63.82	$67.09	$69.68	$73.34	$72.55	$77.32	$78.07	$81.25
2028	$80.31	$79.95	$75.15	$66.40	$65.07	$69.04	$71.87	$76.62	$75.31	$81.07	$81.36	$84.37
2029	$83.32	$83.61	$79.34	$68.87	$67.93	$70.14	$73.89	$79.55	$78.28	$83.47	$83.31	$87.67
2030	$86.73	$86.43	$81.76	$72.61	$68.03	$71.43	$77.36	$82.22	$81.47	$86.54	$86.81	$91.44
2031	$89.88	$89.91	$83.50	$75.11	$71.91	$75.20	$79.62	$84.50	$84.44	$89.88	$90.23	$94.73
2032	$94.17	$93.81	$86.89	$77.25	$71.96	$78.01	$82.61	$88.10	$87.86	$93.57	$94.89	$99.50
2033	$97.10	$97.65	$91.06	$78.31	$78.63	$81.84	$84.51	$91.42	$90.56	$96.87	$98.06	$103.08
2034	$101.17	$100.80	$93.75	$80.72	$78.44	$83.42	$86.99	$94.68	$93.53	$100.66	$101.98	$107.19
2035	$105.16	$105.35	$97.96	$83.81	$81.61	$84.03	$89.89	$99.02	$98.04	$104.23	$105.33	$110.74

Attachment 6.3

FORTISBC INC.

Appendix K

2016 Long Term Electric Resource Plan

Long Run Marginal Cost

Table of Contents

1. INTRODUCTION

Long Run Marginal Cost (LRMC) is a high-level price signal that reflects the cost of prospective future resources required to meet incremental forecast load requirements. In this section, FBC will provide a definition of LRMC, review FBC's previously stated LRMC, review BC Hydro's current LRMC values, and describe the approach used by FBC to determine a LRMC for a specific portfolio.

1.2 *MARGINAL COST DEFINITIONS*

Marginal cost is the change in the total cost of satisfying a permanent increment (or decrement) of demand divided by the magnitude of the increment.[1] The marginal cost can be estimated from either a long-run or a short-run perspective. From a theoretical perspective, the 'Long Run' can be considered a time horizon where all costs are variable. In practice, FBC views the distinguishing differences between the 'short run' and 'long run' as the time horizon considered, specifically the planning horizon of the LTERP.

FBC has previously defined LRMC as "the cost to acquire additional power where existing resources are insufficient to meet load requirements."[2] FBC has updated its definition of Long Run Marginal Cost to be **the incremental cost to build, contract, and/or procure reliable power to meet incremental long term forecast load requirements**. The LRMC is stated in real dollars (2015$)[3] at the point of interconnection to FBC's system. The LRMC includes both an energy and a capacity component.

This definition recognizes FBC's options to build new generation, contract with one or more power providers, further utilize PPA, and/or procure wholesale market power within the planning horizon. The reference to "reliable power" ensures that the power obtained is able to be safely integrated into FBC's system, available at specific times of need, and capable of being scheduled as per industry practices. The use of a portfolio approach recognizes that a combination of existing resources, DSM resources, and incremental supply-side resources will be used to meet the forecast load requirements. It is important to recognize each existing resource contained in the portfolio has a capacity and energy profile. The optimally selected incremental supply-side resources that result in the lowest-cost portfolio will likely complement these existing resource profiles. While a particular resource option may be cost effective relative to a LRMC value, it may not optimally fit the energy or capacity requirements of the portfolio as a whole.

---

[1] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Section 2.0 Cost in the Long Run. Page 4.
[2] FBC. 2012 – 2013 Revenue Requirements and Review of 2012 Integrated System Plan. Response to BCUC IR 1.242.1.
[3] Costing data related to the resource options contained in the portfolio were collected in 2015. Where applicable, other costs in the portfolio were adjusted to 2015$.

2. FBC'S PREVIOUS LRMC VALUE

The LRMC is used for evaluating DSM resources and serves as a point of reference when evaluating power supply options. On July 10, 2014, the BC Government issued BC Regulation 141/2014 that amended the DSM Regulation under the *UCA*. The amended regulation requires FBC to evaluate DSM opportunities using its LRMC of acquiring electricity generated from clean or renewable resources in B.C.[4]

In the 2012 LTRP, FBC has previously used BC Hydro's Standing Offer Program (SOP)[5] to represent the cost of clean or renewable resources in B.C. The levelized cost to acquire additional power from clean or renewable resources was assessed to be $111.96 per MWh[6]. The $111.96 per MWh levelized value was derived from a 2011-2040 price curve stated in table 5.2-A of Appendix B of the 2012 LTRP.[7] This curve was developed using a base price of $101.39 per MWh (2011$) from BC Hydro's SOP and escalated at 50 percent of CPI annually between 2011 and 2040.

The Commission Panel accepted FBC's LRMC for B.C. clean resources as $112 per MWh (rounded up from the $111.96 per MWh value) for the purposes of the 2015-2016 DSM Plan.[8] Since 2015, FBC has evaluated all DSM programs using a LRMC value of $112 per MWh to represent the cost of clean or renewable resources in B.C. FBC has updated the LRMC for purposes of DSM Regulation in Section 9.3.1 of the LTERP.

[4] *Utilities Commission Act* Demand-Side Measures Regulation including amendments up to B.C. Reg. 141/2014, July 10, 2014. Section 4: Cost Effectiveness. Point 1.1.b.i
[5] BC Hydro. Standing Offer Program: Report on the SOP 2-Year Review. January 2011.
[6] FBC. Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Response to BCUC IR 1.3.1. September 18, 2014.
[7] FBC. 2012 Integrated System Plan (Vol. 2) & 2012 Long Term Resource Plan. June 30, 2011. Appendix B: 2011 FortisBC Energy & Capacity Market Assessment. Midgard Consulting Inc. May 26, 2011. Pages 26-28 of 54.
[8] Order G-186-14 concerning FBC Application for Approval of Demand Side Management Expenditures for 2015 and 2016. Section 3.2 Long-Run Marginal Cost. Page 5-6.

3. BC HYDRO'S LRMC

FBC and BC Hydro are frequently compared within various regulatory proceedings. The Commission has also previously compared LRMC values between utilities in its decision-making.[9] Although FBC and BC Hydro both operate within B.C., there are several important differences between the two entities. This section reviews BC Hydro's LRMC definition, stated LRMC values, and highlights some of the key differences between BC Hydro's and FBC's LRMC.[10]

BC Hydro defines the LRMC as "the price for acquiring resources to meet incremental customer demand beyond existing and committed resources."[11]

BC Hydro has stated the LRMC in its 2017-2019 Revenue Requirement Application (RRA) (Section 3.4.4.2) at $85 per MWh (2013$) for the years F2022 to F2033 and $100 per MWh (2015$) for years F2034 and beyond.[12] The Energy LRMC value of $85 per MWh (2013$) is an upper price signal for the acquisition of marginal resources, namely DSM programs and EPA renewals with IPPs. The Energy LRMC of $100 per MWh (2015$) for F2034 and beyond is the cost of greenfield, or new, generation from IPPs. Both of the LRMC values are adjusted for delivery to the Lower Mainland.

BC Hydro has stated the LRMC for capacity resources in its 2017-2019 RRA (Section 3.4.4.3) at $50-$55 per kW-year (2013$) for the years F2020 to F2028 and $115 per kW-year (2015$) for years F2029 and beyond.[13] The capacity value of $50-$55 per kW-year (2013$) is based on Revelstoke Unit 6. The Revelstoke Unit 6 UCC, adjusted for both delivery to the Lower Mainland and energy impacts, is estimated to be $57 per KW-year (2015$). For the years 2029 and beyond, BC Hydro considers a SCGT to be the marginal resource, which has an estimated UCC of $115 per kW-Year (F2015$) after adjustments for delivery to the Lower Mainland. It is important to highlight that the addition of Revelstoke Unit 6 is an expansion of an existing resource and therefore an option that is exclusively available to BC Hydro.

BC Hydro suggested in its RRA Evidentiary Update that including a generation capacity value with the energy LRMC of $85 per MWh could increase the LRMC from $95 per MWh (based on $85 per MWh in 2013$ adjusted for distribution losses and inflated to 2017$) to $106 per MWh[14]

[9] BCUC. FBC Self-Generation Policy Application, Stage 1. Decision and Order G-27-16. Section 6.1.3. March 4, 2016
[10] FBC has consulted with BC Hydro and has reviewed BC Hydro's public Commission filings regarding its LRMC. However, the content of this section of the LTERP should not be in any way attributed to BC Hydro; it solely represents FBC's understanding of BC Hydro's LRMC.
[11] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.1. Page 3-45
[12] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.2. Table 3-10 Marginal Energy Resources and Related Costs. Page 3-49
[13] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 3.4.4.3. Table 3-11 Marginal Capacity Resources and Related Costs. Page 3-50
[14] The $106/MWh (2017$) energy with capacity inclusive value is only applicable to BC Hydro's residential load shape.

in 2017$, although this figure is still being explored through the BC Hydro 2017-2019 RRA proceedings at the time of this document publication.[15]

While BC Hydro and FBC both investigate B.C. generation opportunities, it is not possible to draw a direct comparison between BC Hydro and FBC's stated LRMC values. There are notable timing differences for required resources, locational differences in load and generation, volume differences in capacity and energy requirements, and differences in governing policy that can cause BC Hydro and FBC to consider different resource options. BC Hydro has indicated that resources are required in the near to medium term to meet forecast load[16] and has identified specific resources, both demand side and supply side, that will be used to address this requirement. In contrast, FBC's resource needs are further into the future, as identified in the LTERP, Section 9. To identify prospective future resources, FBC developed a collection of resource options and performed portfolio analysis, which is a fundamentally different approach from BC Hydro.

[15] BC Hydro. 2015 Rate Design Application. Evidentiary Update on Load Resource Balance and Long Run Marginal Cost. Conclusion Section. February 18, 2016.
[16] BC Hydro. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. July 28, 2016. Section 2.4.2 BC Hydro's Load-Resource Balances.

4. FBC'S LONG RUN MARGINAL COST APPROACH

Consistent with the BCUC Resource Planning Guidelines[17] and a Commission directive from the 2012 LTRP decision (G-110-12, Directive 54), FBC has adopted a portfolio analysis approach to assessing resource options. FBC investigated a series of scenarios and therefore a series of potential resource portfolios with different characteristics. The LRMC is calculated as a by-product of a given portfolio scenario. Correspondingly, FBC has stated multiple LRMC values with each LRMC being reflective of the optimal combination of resources used to meet the forecast load requirements and PRM requirements of the specific portfolio scenario. The portfolio analysis description and LRMC values are discussed in more detail in the LTERP, Section 9.

There are three standard approaches to determining LRMC values: the Levelized Unit Energy Cost (LUEC) approach, the Perturbation approach (also referred to as the Turvey approach), and the Average Incremental Cost (AIC) approach.

The LUEC approach is a resource-specific calculation and therefore not appropriate for providing a portfolio LRMC. The Perturbation and AIC are the two portfolio approaches that were considered by FBC.[18] Both the Perturbation and AIC approaches involve similar steps, but differ in how they measure the effect of changes in load requirements on future costs. The Perturbation approach considers the impact on cost of a fixed change in load from the forecast load requirements. In contrast, the AIC approach considers the average incremental cost of meeting the forecast load requirements above current load requirements.

In the opinion of FBC, the Perturbation approach, although aligned with the theoretical definition of LRMC, has some significant drawbacks for practical application, namely:

(1) The Perturbation approach requires a demand increment (or perturbation) to be assumed for the analysis. It is difficult to determine the appropriate size and shape of the demand increment. Furthermore, slightly varying the characteristics of this assumption could potentially yield a significantly different LRMC value.

(2) The Perturbation approach does not necessarily reflect the average incremental costs over the full planning horizon, but rather the incremental cost associated with the assumed perturbation in demand.

(3) The Perturbation approach would be more sensitive to the size and type of the resource options considered in the portfolio, which may vary over time.

(4) The nature of the Perturbation approach provides a greater possibility for large variances in the LRMC over time depending on when the LRMC is updated and the supply-demand balance at the start of the analysis.

[17] BCUC. Resource Planning Guidelines. December 2003. Points 4-6.
[18] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Section 2.1 Measures of LRMC. Page 4.

To derive the LRMC value, FBC has selected the AIC approach. FBC's position is that the AIC approach is more intuitive to interpret and better able to reflect the general level and trend of future costs as well as addresses the unique attributes of FBC's resources (e.g. flexibility of the PPA and market access). The AIC approach is more likely to yield a steady price signal and therefore better guide long term decisions.

4.2 AVERAGE INCREMENTAL COST OVERVIEW

The AIC approach to estimating the LRMC takes the present value of the incremental costs expected to be incurred over the planning horizon and divides the incremental costs by the present value of the incremental load requirements expected to be served by marginal resources within the same period. The AIC approach does not directly link a particular increment of load with the resulting change in cost, but rather expresses the LRMC as the average incremental cost of satisfying the forecast load requirements over the planning horizon.

The AIC approach to estimating LRMC can be summarised as follows:[19]

1. Establish a long-run load forecast (e.g. reference case load forecast with a 20 year planning horizon);
2. Gather information regarding the characteristics and costs of resource options considered available to meet demand;
3. Determine the optimal combination of resources given a set of constraints (the levelized least cost capital program plus the change in operating costs), in present value terms, which can satisfy the forecast requirements at each point in the planning horizon and meet reliability standards;
4. Determine the present value of the load that is in excess of the current load requirements, and
5. Calculate the LRMC by dividing the present value (PV) of the cost of servicing the additional demand by the size of that demand increment, where:

$$\mathbf{LRMC}_{AIC} = \frac{PV(cost\ to\ satisfy\ additional\ demand\ over\ planning\ horizon)}{PV(additional\ demand\ served\ over\ planning\ horizon)}$$

[19] Market Surveillance Administrator (MSA). A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta. December 10, 2012. Appendix A.2: The average incremental cost approach. Page VI.

4.3 *FBC AVERAGE INCREMENTAL COST CALCULATION*

The following steps were taken by FBC to calculate the LRMC:

1. Established a long-term load forecast *(Labelled* L_1*)*
    - For each month, in each year of the planning horizon
        - Determine the expected peak demand requirement within the month
        - Determine the expected total energy requirements for the month.
2. Create a resource 'profile' for each existing resource as well as each potential new resource option considered available to meet future load
    - For each resource:
        - For each month, in each year of the planning horizon, estimate the capacity and energy capabilities as well as define other relevant resource attributes (e.g. environmental attributes such as GHG emissions, etc.)
        - Establish estimates of unit capital costs, incremental operating expenditures, and other relevant costs (e.g. system interconnection costs).
3. Determine an optimal (lowest-cost) portfolio of resources, in present value terms, that can satisfy the current load, assuming no load growth (referred to as the benchmark load), while adhering to the portfolio constraints and variable settings of the given portfolio scenario[20] [*Labelled* P_0]
    - Assume the load is constant at the benchmark level (2016 forecast load) for the full planning horizon [*Labelled* L_0]
    - Set variables and apply constraints to the portfolio optimization routine based on the characteristics of the portfolio scenario
    - Set the DSM to considered minimum (Low DSM)
    - Find the least cost portfolio that meets the benchmark load requirements and adheres to the constraints of the portfolio scenario.
4. Using the same variable settings and same set of constraints used to represent the characteristics of the portfolio scenario, find the optimal combination of resources that satisfies the forecast load requirement for the planning horizon [*Labelled* P_1]
    - Set the DSM to scenario level (e.g. High DSM)

[20] For the purpose of this portfolio, FBC assumes the "Low-DSM" scenario against which the incremental costs associated with higher levels of load growth offset due to DSM are compared in the various other portfolios.

- Using the load forecast from step 1, the same set of resources established in step 2, and the variable setting and portfolio optimization constraints applied in step 3, find the least cost portfolio that meets the forecast load requirements of the planning horizon.

5. The LRMC is calculated by dividing the net change in the present value of the lowest-cost portfolios by the net change in load requirements, in present value terms.

$$\mathbf{LRMC}_{\boldsymbol{AIC}} = \frac{PV(Portfolio_{\text{Forecast Load}}) - PV(Portfolio_{\text{Benchmark Load}})}{PV(Forecast\ Load) - PV(Benchmark\ Load)} \qquad \mathbf{LRMC}_{\boldsymbol{AIC}} = \frac{PV(P_1) - PV(P_0)}{PV(L_1) - PV(L_0)}$$

5. CONSIDERATIONS WHEN APPLYING THE LRMC

The characteristics of each portfolio, and therefore the characteristics of the LRMC, are largely formed by the constraints applied within the optimization routine, the level of DSM, and the variables settings assumed (e.g. high commodity prices versus low commodity prices, varying PPA costs, etc.). For example, within a portfolio including 100 percent clean or renewable B.C. resources, the portfolio optimization routine constrains (i.e. excludes) resource options that are not considered to fit the definition of a B.C. clean or renewable resource in the *CEA*. The result is a different set of resource options considered available when compared to a portfolio scenario that allows gas-fired generation as a potential resource.

DSM is a component of FBC's preferred resource portfolio. The cost of DSM in the portfolio scenarios, and correspondingly the preferred portfolio, is based on the Total Resource Cost (TRC) as discussed in the LTERP, Section 8.1.

The LRMC assumes that all electricity generated is of equal value. This assumption does not hold true in practice. FBC's resource requirements vary at different times of the year and the value of energy in the market varies at different times.

The timing of when resources are required, the selection of resource options, and the optimal operation of the preferred portfolio strategy is contingent on a number of dynamic factors that will change over time including load forecasts, market pricing, changing customer behavior, macro-economic conditions, governing policy, and technological advancement. In future long term resource plans, FBC intends to revisit and update the LRMC with the most current information available at that time.

6. SUMMARY

FBC considers the long run marginal cost to be a price signal and is one of many considerations when assessing the cost-effectiveness of different resource options. FBC does not expect to acquire all available resources up to the LRMC, nor should the LRMC be viewed as a clearing price in isolation from other prudent resource planning considerations, such as energy or capacity profiles or environmental factors. It is important to note that inappropriate applications of the LRMC can lead to negative customer impacts.

FBC has selected the AIC approach to determining the LRMC. Correspondingly, the LRMC is driven by the incremental costs in the portfolio required to supply incremental demand. The AIC approach is easier to understand, reflects changes in cost and demand over the full planning horizon, and is more likely to produce a stable price signal than the alternative Perturbation approach.

FBC has investigated multiple portfolio scenarios, and correspondingly, has stated multiple LRMCs, which are provided with the analysis in the LTERP, Section 9. The characteristics of the LRMC align with the characteristics of the source portfolio. There are considerations associated with applying the LRMC. Examples of these considerations include selecting the correct LRMC value for the intended purpose, and understanding the LRMC is a price signal without reference to when the power will be required.