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April 11, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1 on FBC Rebuttal Evidence

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On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-10-14 setting out the Amended Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1 on FBC Rebuttal Evidence.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc (email only): Registered Parties

1.0 Reference: Exhibit B-42, p. 1; Exhibit C8-14, 1.6.3; Exhibit C8-9, p.56; BC Hydro IRP, November 2013, Chapter 9, pp. 12, 52-54[1]

Cost-Effective Commercial and Industrial DSM Programs

FBC states in Exhibit B-42, p. 1: "Increasing the "relatively more cost-effective" programs requires higher measure incentives … Mr. Plunkett's suggestion ignores the inequities that may arise as a result of increasing [Demand Side Management] DSM expenditures in the Commercial/Industrial sectors relative to residential customers. In establishing the mix of customer DSM programs, FBC looks at a number of factors, including addressing key end uses, the cost-effectiveness tests, customer payback periods, and the take-up rate of customers. … The FBC commercial/industrial programs already have higher Participant Cost Test [PCT] ratios (7.9 and 6.4 respectively) than the Residential programs (2.9), this disparity is a basis for concern in increasing incentives for commercial or industrial customers."

The British Columbia Sustainable Energy Association and the Sierra Club British Columbia (BCSEA) state in Exhibit C8-14, BCUC 1.6.3: "This assumes that DSM portfolio costs are recovered from customers in proportion to their class sales. If this assumption is not true, then the Commission should consider modifying the current approach so that costs are allocated in rough proportion to the collective electric benefits each class realizes from implementation of the expanded DSM portfolio."

BCSEA state in Exhibit C8-9, p. 56: "We used a 4.93% real discount rate for the program administrators cost (PAC) test and 4.08% for the total resource cost (TRC) test."

1.1 Please explain how FBC interprets "cost-effective" in Exhibit B-42, p. 1.

<u>Response:</u>

FBC uses the TRC/mTRC test prescribed by Regulation.

1.1.1 If FBC places significant reliance on the TRC/mTRC to determine cost-effectiveness, please explain FBC's concern regarding higher incentive levels for commercial/industrial customers as an increase in incentives would not affect TRC/mTRC results.

[1] http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf

Response:

An increase in incentives, which are considered a transfer cost, does not generally impact the TRC/mTRC results. However, the Utility Cost Test is negatively impacted by higher incentive levels and the referenced disparity in the Participant Cost Test would increase.

1.2 Please explain why FBC assumes that increasing "relatively more cost-effective" programs requires higher measure incentives.

Response:

It is a well-known axiom of a market economy that a certain price point, in this case incentive amount, will result in a given level of participation. In order to increase the customer participation rate the incentive amount must be increased, assuming other market barriers remain constant.

1.2.1 Please explain why FBC considers that a high PCT should be a basis for concern in expanding a DSM program. Specifically, does this instead indicate that FBC should investigate whether there are non-cost related market barriers (for example, lack of information or staff resources) that FBC should also be addressing?

Response:

The PCT is a ratio of the customer's benefits (Present Value of electrical savings plus DSM incentive divided by the measure cost). FBC considers that a high PCT is of concern since it indicates the customer may be obtaining too high a benefit relative to the measure cost – which indicates a lower DSM incentive may be appropriate. The higher PCT ratios for commercial/industrial sector programs indicate a strong economic signal for those customers to invest in DSM projects. Conversely, the lower PCT for the residential sector indicates a weaker economic signal, which arguably indicates a higher DSM incentive may be necessary.

In addition to the market barriers mentioned, there are customers' internal limitations including capital rationing and risk appetite (both technological and persistence).

1.2.2 Please describe the efforts FBC has made to identify non-cost related market barriers to efficient consumption and investment decisions by its commercial and industrial customers, and the DSM programs already in place to address those market barriers.

Response:

FBC identifies and addresses a number of non-cost related market barriers as follows:

- Fund and technical support for small business BEA audits;
- Free walk-through audits for medium/large businesses by FBC Technical Advisors;
- Co-fund comprehensive energy assessments for commercial/industrial customers;
- FLIP turn-key direct-install lighting retrofit program for small businesses;
- Promote/sponsor educational workshops, e.g. NRCan Spot the Savings, BCEA Product Knowledge Days, IES Lighting courses, DOE pump assessment software; and
- Co-fund pilot projects and provide Measurement & Verification for new technologies.

However, FBC does not believe it has a role to play in financing commercial and industrial measures, which are better suited to specialized firms with the appropriate risk assessment tools.

1.3 Please explain how DSM costs are allocated between residential/commercial/industrial customers in FBC's Fully Allocated Cost of Service (FACOS) study. If DSM costs related to commercial/industrial programs are allocated to residential customers, please explain why.

Response:

For the most recent Cost of Service Analysis (COSA) undertaken by the Company in 2009, DSM expenditures among the various classes were aggregated. The costs are functionalized as 88 percent for power supply and 12 percent related to transmission and distribution. This split is consistent with the cost/benefit analyses performed for DSM spending evaluations. The power supply component is broken down as 71.6 percent energy-related and 16.6 percent demand-related. The transmission and distribution components are split between demand-related and customer-related components based on the overall transmission and distribution costs. Each of those components is split between customer classes on the basis of the corresponding allocation factors (i.e. the energy-related component as allocated on the basis of the energy for each class).

The treatment of the DSM costs in the COSA is consistent with the underlying purpose of the DSM programs. From the perspective of FBC, the DSM expenditures are not made for the benefit of the customers implementing the DSM measures; rather they are made as a cost-effective alternative to power purchases and building new T&D facilities. Because the DSM costs allow the utility to avoid costs for power supply and T&D, it is appropriate that those costs are treated in the same manner. The methodology used in the COSA follows this cost causation concept.

1.3.1 Does FBC consider that its FACOS allocation methodology is fair, such that, if a comparison of revenues to allocated costs for each customer class falls within an acceptable range, there should be no inequity concerns between customer classes? Please explain why, or why not.

Response:

FBC considers that the treatment in the COSA is fair and that there is no inequity between the classes.

Whether the DSM spending occurs for commercial/industrial customers or residential customers is irrelevant to the treatment, as long as the commercial/industrial DSM is the most cost-effective option. It is in the interest of all customers to obtain the most cost-effective DSM measures regardless of customer class. If commercial/industrial DSM projects reduce the overall cost to the utility due to the avoidance of power supply and T&D costs, all customers benefit from the program and all customers should contribute to the expense of the program.

1.3.2 Given the responses above, please explain why FBC considers there would be inequity concerns if Commercial/Industrial DSM expenditures were increased.

Response:

In developing the mix of the most appropriate DSM expenditures, several factors are considered, as discussed by FBC in Exhibit B-42 page 1. Expanding the commercial/industrial DSM spending is not appropriate in the context of meeting the objectives discussed. That does not preclude treating the entire DSM cost in the COSA as if it is an alternative to power supply and T&D costs, and allocating the entire cost among all customers.

Please also refer to the response to FBC BCUC Rebuttal IR 1.2.1.

1.4 Please explain why FBC considers customer pay-back periods and the take-up rate of customers in establishing the mix of customer DSM programs - specifically are these not just inputs into the cost-effectiveness tests?

Response:

Customer pay-back periods (and the PCT) represent cost-effectiveness tests on their own, and warrant independent consideration when establishing program mix. The program take-up rate is dependent on a number of factors, including the incentive amount offered, but again is not an input to the TRC test itself.

1.4.1 Please explain why FBC did not include in this list of considerations ensuring that customers within each customer class have a reasonable opportunity to participate in one or more programs (specifically 'hard to reach customers' such as low-income, renters, First Nations etc.)?

Response:

Ensuring the program mix addresses key end-uses within each customer class means that a wide range of customers have a reasonable opportunity to participate in DSM programs. The 'hard to reach customer' segments listed are addressed through adequacy programs mandated by the DSM Regulation.

1.5 Please provide a high level estimate of how much the DSM budget for each of the Commercial and Industrial customer classes could increase for each year of the PBR period (taking into account any ramp up requirements) and yet still pass the TRC and UCT using: (i) FBC's long-run marginal cost (LRMC) of energy estimate; (ii) the LRMC of energy estimate used for the mTRC; and (iii) LRMC of energy at $110/MWh. Please also provide similar estimates for the Residential customer class and any other DSM category.

Response:

As indicated in the response to FBC BCUC IR 1.244.1, the DSM budget estimates using: (i) FBC's long-run marginal cost (LRMC) of energy ($56.61/MWh) is $3 million as filed; and (ii) the LRMC of the mTRC ($111.96/MWh) is approximately $7.92 million. FBC estimates that using (iii) an LRMC of $110/MWh would yield a DSM budget of approximately $7.86 million.

FBC cannot offer a DSM budget by customer class for each year of the PBR period because these are high-level DSM budget estimates and have not been prepared in detail. However, FBC estimates that under these scenarios, the percentage of DSM budget expenditure by sector and year would remain proportional to the filed expenditures as shown below.

Table H1-1a: 2014-18 DSM Plan Expenditures

1		2014 Plan			2015	2016	2017	2018
2	Program Area	Cost	TRC	TRC incl mTRC	Plan Cost	Plan Cost	Plan Cost	Plan Cost
3								
4	**Programs by Sector**	$(000s)	B/C ratio		$(000s)	$(000s)	$(000s)	$(000s)
5	Residential	1,037	1.2	1.3	1,081	1,008	1,015	1,024
6	General Service	1,134	1.4	1.7	1,166	1,195	1,223	1,256
7	Industrial	148	2.8	2.8	150	152	154	156
8	**Sub-total Programs:**	**2,319**	**1.4**	**1.5**	**2,397**	**2,355**	**2,392**	**2,436**
9	Supporting Initiatives	190			190	190	190	190
10	Planning & Evaluation	492	-	-	500	509	518	527
11	**Total (incl. Portfolio spend):**	3,001	**1.2**	**1.4**	3,087	3,054	3,100	3,153

1.5.1 Please estimate how much these budgeted amounts would be expected to change for each scenario above if FBC adopted BCSEA's proposed discount rates for its TRC/mTRC/UCT calculations.

Response:

FBC understands this IR to request to see the impact of using different real discount rates on DSM budgets for the residential, commercial, and industrial sectors for the 2014-18 PBR period under three LRMC scenarios listed in the previous IR.

Unfortunately, due to the substantial effort required to develop a full DSM budget and plan, FBC is only able to provide this level of analysis for scenario (i) using a long-run marginal cost of energy of $56.61/MWh.

For the 2014 PBR year, a discount rate of 4.93 percent would increase only the commercial DSM budget by a modest 1.9 percent. However using a discount rate of 4.08 percent would increase the commercial DSM budget by 15.3 percent and the residential DSM budget by 13.4 percent. In both cases the industrial budget remains unchanged from the filing. The following table provides the results by sector and PBR year.

Effect of a 4.93% and 4.08% real discount rate on DSM expenditure by sector and year

	2014 Plan			2015	2016	2017	2018
Program Area	Cost	TRC	TRC incl mTRC	Plan Cost	Plan Cost	Plan Cost	Plan Cost
Programs by Sector	$(000s)	B/C ratio		$(000s)	$(000s)	$(000s)	$(000s)
4.08% discount rate							
Residential	1,176	1.6	1.7	1,221	1,150	1,158	1,169
General Service	1,308	1.7	1.7	1,342	1,373	1,404	1,439
Industrial	148	3.3	3.3	150	152	154	156
Sub-total Programs:	2,632	1.7	1.7	2,713	2,675	2,716	2,764
4.93% discount rate							
Residential	1,037	1.6	1.6	1,081	1,008	1,015	1,024
General Service	1,155	1.7	1.7	1,187	1,216	1,245	1,278
Industrial	148	3.2	3.2	150	152	154	156
Sub-total Programs:	2,340	1.7	1.7	2,418	2,376	2,414	2,458
8% discount rate (as-filed)							
Residential	1,037	1.2	1.3	1,081	1,008	1,015	1,024
General Service	1,134	1.4	1.7	1,166	1,195	1,223	1,256
Industrial	148	2.8	2.8	150	152	154	156
Sub-total Programs:	2,319	1.4	1.5	2,397	2,355	2,392	2,436

2.0 Reference: Exhibit B-42, pp. 2-3; BC Hydro Integrated Resource Plan, November 2013, Chapter 9, pp. 52-54; Exhibit C8-14, 1.5.2

Mid-C based LRMC estimate

FBC States in Exhibit B-42, pp. 2-3: "FBC directed Midgard to use the exchange rate assumptions in the January 2013 GLJ Product Price and Market Forecast for the Canadian Oil and Gas Industry. … FBC acknowledges that both exchange rates and exchange rate forecasts are volatile and change with time. … Mid-C prices are an appropriate proxy for market purchase costs. .. For longer-term firm purchases ... power marketers are willing to offer an option of having longer-term market purchases indexed to prices at the Mid-C hub."

British Columbia Hydro and Power Authority (BC Hydro) in its November 2013 Integrated Resource Plan (IRP), states on pages 9-52 to 9-54:

"Chapter 2 demonstrates there is a need for new B.C.-based resources in F2017 and that is why the energy LRMC is not based on spot market price forecasts. …

Energy

... In the process of developing and analyzing the IRP as discussed in Chapters 4 and 6, *the LRMC was reduced from $135/MWh to $100/MWh*. This reduced value informed the levels of DSM modelled and the upper price limit on EPA renewals. ... Depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected, the LRMC may be reduced to about $85/MWh and still provide an adequate supply of resources over the planning horizon. ... [Emphasis added]

Capacity

The LRMC for capacity resources when needed to augment the acquisition of energy and capacity resources is based upon Revelstoke Unit 6, which is lower cost than SCGTs. ...

Energy and Capacity LRMC Summary

The LRMC outlook is as follows:

- Energy: $85 to $100 per MWh F2017 thru end of the planning horizon (i.e., F2033)
- Capacity: $50 to $55 per kW-year F2017 thru F2032. "

BCSEA state in Exhibit C8-14, BCUC 1.5.2: "In any event, BC Hydro includes a separate capacity cost of $50–$55/kW-yr, or roughly another $10/MWh."

2.1 Since FBC filed its PBR Application, BC Hydro Integrated Resource Plan has been approved. Does FBC now consider that it should use the same estimate to determine its LRMC of energy (both for the TRC and the mTRC) as BC Hydro? If no, please explain how, in the absence of transmission constraints between BC Hydro's and FBC's network, the proxy market price for generation should be significantly different between the two utilities (shouldn't price difference just reflect transmission losses?). Also, if BC Hydro is in an energy/capacity shortage position earlier than FBC, wouldn't FBC be able to sell any surplus energy acquired through DSM to BC Hydro resulting in BC Hydro's avoided cost of energy being approximately equal to FBC's)?

Response:

No, FBC does not believe it should use the same LRMC as BC Hydro. FBC's LRMC should be based on an assessment of its unique situation and can be quite different to BC Hydro's LRMC for a number of reasons including the timing and size of any energy or capacity gaps, the available resource options and energy policy directives (e.g. BC Hydro's self-sufficiency directive requires it to meet its requirements with BC based resources).

FBC understands that in its 2013 Integrated Resource Plan (IRP), BC Hydro has used a $85-$100/MWh price signal to assess the adequacy of resources that could be acquired to meet its future needs. This price signal was developed differently than BC Hydro's previous LRMCs, which were based on energy calls (e.g. the prior BC Hydro LRMC was based on the 2008 Clean Power Call). The new price signal approach to establishing an LRMC was used because BC Hydro believes that that there is not a need in the near future to acquire additional greenfield IPP resources to meet its self-sufficiency standard. With this price signal as a cap, BC Hydro expects to acquire sufficient DSM savings and will undertake sufficient IPP contract renewals to meet their needs for the next 10 years.

FBC position is that it is also inappropriate to use BC Hydro's LRMC of energy as FBC's LRMC of energy for its TRC and mTRC calculations. The DSM Regulation requires the mTRC to be based on the LRMC of new clean generation resources, which FBC has done using $112/MWh plus 15 percent NEBs. The DSM Regulation is silent on the basis for the TRC benefits per se and FBC uses a market-based price forecast, as was approved in the previous 2012-13 RRA filing. As BC Hydro's new LRMC is not based on new clean generation resources, it would be inappropriate to be used for the first part, and given FBC has different resource options, its LRMC would be different even if the avoided costs of market purchases were excluded.

The final part of this information request also asks: "if BC Hydro is in an energy/capacity shortage position earlier than FBC, wouldn't FBC be able to sell any surplus energy acquired through DSM to BC Hydro resulting in BC Hydro's avoided cost of energy being approximately equal to FBC's?" This question does not appear to take into consideration the characteristics of

FBC's supply portfolio. FBC cannot sell surplus energy unless it is not purchasing supply under its PPA with BC Hydro. If FBC was in an energy surplus situation due to DSM measures (i.e. its load was less than the firm resources available to it), it would first reduce purchases from BC Hydro under the RS3808 (as opposed to selling surplus to BC Hydro), and so the value to FBC would be the avoided cost under BC Hydro's RS3808. The BC Hydro PPA, however, already allows some flexibility to displace a portion of PPA supply (except what is needed for capacity) with market purchases, therefore DSM would likely actually serve to reduce market purchases.

In terms of capacity, with the incorporation of WAX into its supply portfolio in early 2015, FBC will initially have surplus capacity that it will mitigate through a combination of short and medium term sales that could be available to BC Hydro or other market participants. The value of this capacity and the ability to achieve prices higher than market value will depend on the term and duration that it could be made available as a firm resource to another party and that party's the ability to incorporate it into its other resources. FBC does not consider energy savings from DSM measures as firm 'on demand' resources and therefore any additional surplus capacity resulting from these measures would have much lower value.

2.1.1 Please provide a side by side comparison of FBC's LRMC energy estimate (generation and capacity) with BC Hydro`s estimate. For capacity, please provide both a $/kW-year estimate and an equivalent $/MWh estimate (using a reasonable estimate of the coincident load factor of DSM acquired energy).

Response:

	BC Hydro ($2013) F2017-F2033	FBC ($2013) 2014-2043
Energy - $/MWh	$85-100/MWh	$56.61**
Capacity - $/KW-yr	$50-$55	N/A
Capacity Equivalent $/MWh	$10*	N/A

Notes:

* As FBC does not have the data to convert BC Hydro's capacity value to an equivalent $/MWh value, this is the BCSEA estimate provided in the preamble to this series of questions referring to BCSEA response to BCUC 1.5.2. FBC cannot verify the accuracy of this figure, and in addition is uncertain whether it is appropriate to add it to BC Hydro's energy value as BCSEA has done in its IR response.

** The FBC energy LRMC of $56.61 already contains all associated capacity, so the capacity value is not applicable. This also reflects the fact that FBC has sufficient capacity resources to meet its forecasted load requirements.

2.2 Does FBC consider that its gas price and exchange rate forecast used to derive the FBC LRMC estimate will result in a forecast that is as stable over time as the approach used by BC Hydro to derive its LRMC estimate? Please explain why, or why not.

Response:

FBC does not have an opinion on which approach would result in a more stable forecast. FBC recognizes that natural gas commodity prices and exchange rates change over time. However, BC Hydro has also indicated that its marginal cost estimates are expected to change over time, as noted in the referenced excerpt copied below:

> *"In the process of developing and analyzing the IRP as discussed in Chapters 4 and 6, the LRMC was reduced from $135/MWh to $100/MWh. This reduced value informed the levels of DSM modelled and the upper price limit on EPA renewals. ... Depending on the amount of LNG load that BC Hydro ultimately serves and whether non-LNG load growth occurs as expected, the LRMC may be reduced to about $85/MWh and still provide an adequate supply of resources over the planning horizon."*

2.3 Does FBC consider that the market value of new incremental generation should be different from the market value of existing generation (assuming no obligation to serve requirements)? If yes, please explain why.

Response:

No, based on the caveat provided in the question. If there is no obligation to serve, then value of both new incremental generation and existing generation would be set by the market. On the other hand, if there is an obligation to serve requirement, the buyer should be willing to pay a premium for access to a long term incremental resource to ensure it can reliably meet its load requirements. Likewise, the buyer may be willing to pay a premium to market for new incremental generation to the degree it is required to meet policy directives (e.g. BC Hydro's self-sufficiency standard).

2.4 Does FBC consider that the Mid-C based methodology adopted by FBC in setting its LRMC will provide a good indicator of the need to build new capacity in the wider Mid-C region over time?

Specifically, will FBC's methodology result in LRMC values that reflect the cost to build new generation at times when new generation is required in order to meet reliability requirements in the wider Mid-C region? If yes, please explain how. If no, please explain if this indicates that Mid-C can only be used to provide a proxy market value for energy imbalances within the broader Mid-C market, but not to value DSM supplied energy.

Response:

FBC does not believe a market based solution is an appropriate long-term solution and if new generation were required it would not be appropriate to use a market based LRMC. The 2016 Resource Plan will reexamine FBC's resource requirements.

In general, FBC does not believe that the Mid-C market provides long-term price signals for the need to build new capacity except in extreme events such as the 2000/01 Western Energy Crisis. Capacity projects in the Pacific Northwest are typically built for utilities either directly or through successful bids in utility calls for power, such as those recently held by Puget Sound Energy and Portland General Electric. Prices are generally determined through a competitive bid process, and may be capped by the utility's avoided cost of building a SSGT gas plant.

The DSM Regulation requires the mTRC to be based on the LRMC of clean or renewable generation resources in British Columbia, for which FBC has used $112/MWh plus 15 percent for Non-Energy Benefits. The DSM Regulation is not prescriptive with respect to the LRMC value to be used for calculating the TRC benefits and FBC has opted to use a market-based price forecast, consistent with the previous 2012-13 RRA filing. FBC is not currently looking to acquire resources and therefore a market-based number is an appropriate indicator of LRMC. .

2.4.1 Does FBC consider that its Mid-C LRMC estimate correctly values its own generation? For example, if FBC no longer had an obligation to serve its customers, would it be willing to sell the output from its own generation plant, entitlement and contracts to a third party under a long-term firm contract at its estimated LRMC value? If no, please explain if this indicates that Mid-C based estimates are not appropriate to value DSM supplied energy.

<u>Response:</u>

A long range marginal cost is a marginal cost for marginal generation. As such it is inappropriate to consider the costs or benefits of the existing plant in a LRMC calculation. What FBC would sell electricity from existing assets for is not relevant to the calculation.

If FBC had no existing means of meeting customer load, the Company believes it would be inappropriate to use the proposed LRMC as the situation would be completely different. However, given the Companies much more limited needs at this time, the proposed LRMC is prudent and reasonable.

The DSM Regulation requires the mTRC to be based on the LRMC of new clean generation resources, which FBC has done using $112/MWh plus 15 percent NEBs. The DSM Regulation is silent on the basis for the TRC benefits per se and FBC uses a market-based price forecast, as was approved in the previous 2012-13 RRA filing.

2.5 Is it FBC's position that power marketers would offer a long-term (15 to 20 years) firm energy contract (delivered to FBC's network) sufficient to meet any gap between FBC's firm generation resources (plant owned, energy entitlements and firm energy purchase agreements) and expected load over the next 15 to 20 years at FBCs Mid-C based levelized cost? If no, please explain if this indicates FBC`s Mid-C based methodology is not appropriate to value DSM supplied energy.

<u>Response:</u>

No. Marketers may be willing to offer a long-term firm energy contract based on flow through of the Mid-C index price, but any long-term fixed price contract of that duration based on market purchases, if even available, would likely have a significant risk premium built into it. FBC's avoided cost calculation is based on a forecast of spot prices so it does not have a similar risk premium built into it.

However, considering the flexibility of the FBC's capacity resources, principally its storage capability and the BC Hydro PPA, combined with the modest nature of its energy needs, firm energy is not required. (For example, the flexibility of FBC's resources allows FBC to take delivery of market power during lower value periods for use during peak periods.) As a result, FBC believes it may be possible to negotiate a long-term contract covering FBC's energy needs over the next 20 years at or close to FBC's avoided cost based on the Mid-C methodology.

3.0 Reference: Exhibit B-42, p. 4

Transmission congestion risk

FBC States in Exhibit B-42, p. 4: "… the primary risk of congestion on the transmission system is that power will not flow and it is therefore a reliability risk. … With respect to FortisBC purchasing costs for energy due to congestion of the transmission system, Mr. Plunkett's concern is irrelevant, as FBC simply defers its purchases until another hour."

3.1 Please provide an estimate as to how over how long a period FBC could be expected to remain indifferent to transmission congestion restricting access to the Mid-C market, for example, how many days, weeks, months, or years could the line remain restricted before transmission congestion could cause either reliability issues on FBC's network or significant increases in incremental energy purchase costs.

<u>Response:</u>

The reliability aspect of the question was addressed in the portion of the reference to Exhibit B-42, p. 4 that was omitted from the quote in the question. For reference, it is included here, "With WAX, FortisBC's peak loads are not at risk at this time or in the near future…". While there is never a guarantee that supply shortages will not result in a loss of reliability, with WAX, the chance of transmission congestion impacting reliability in any material manner is very low. Therefore, FBC is not proposing any additional resources to enhance reliability at this time. This will be examined again in the 2016 Resource Plan.

As also indicated in Exhibit B-42, p. 4, "Further, FortisBC typically has flexibility around the timing of these market purchases due to its ability to use its CPA storage account to work around transmission constraints." The impact of prolonged congestion will depend upon the time of year and the amount of energy in storage at the time. With a total storage ability of over 60,000 MWh of energy, the Company has ample energy reserves to ride out short term transmission system congestion. However, in the event of prolonged congestion during a cold snap, there will be an impact since the Company is energy short. In approximately 3 to 4 weeks, depending exactly on the load and resources available, the Company would likely start becoming a price taker for energy.

3.2 Does FBC consider that, if transmission congestion resulted in power outages on FBC's network, the proxy market value of energy should reflect the affected customers' Value of Lost Load (VOLL) during those hours? If no, please explain if assuming a lower value of energy could result in sub-optimal FBC decisions on the value of reliability to customers on its network.

Response:

FBC believes that if transmission constraints are expected to materially impact reliability, then the addition of incremental resources to preserve reliability must be considered. At this time, FBC believes that, due to the flexibility of its resources, this risk is currently very low. Please also refer to the response to FEI BCUC Rebuttal IR 1.3.1.

4.0 Reference: Exhibit B-42, p.4; BC Hydro IRP, November 2013, Chapter 9, p. 54

Transmission marginal costs

FBC states in Exhibit B-42, p. 4: “The $233/kW-year figure advanced by Mr. Plunkett [for the marginal cost for transmission and distribution] is not adequately supported … ”

BC Hydro states on page 9-54 of its November 2013 IRP: “The energy and capacity LRMCs relate to the cost of procuring annual firm energy and dependable capacity delivered to the Lower Mainland; hence, adjustments as described in section 3.4.3 and Appendix 3A-34 (such as the costs of transporting the energy and capacity to the Lower Mainland, including line losses) are included in the LRMCs.”

4.1 Does FBC consider that the LRMC of transmission and distribution should reflect the incremental network costs over the LRMC period that could be avoided if there was a significant decrease in load growth? Please explain why/why not.

Response:

Yes, by definition the LRMC of transmission and distribution should reflect the next increment of network costs over the LRMC period. Therefore, it gives a price signal to consider for planning purposes.

4.2 In calculating the network LRMC, please explain the period used by FBC for: (i) determining avoidable network growth related investments; (ii) determining load growth; and (iii) arriving at a levelized annual cost. If the time periods used in these three cases were different, please explain why.

Response:

The periods used for calculating the Deferred Capital Expenditure (DCE) cost are (by order of sub-question):

i. 7 years (2013 – 2019) – which includes the period of the PBR term and these are the years for which detailed T&D capital costs related to growth are available
ii. 30 years (as this is the period of the load forecast planning horizon)
iii. 30 years (approximate period for which the investments would be amortized)

4.3 Please explain how FBC arrived at its estimate of growth-related transmission and distribution investments for the purpose of estimating the network LRMC. Please provide both FBC's $/kW-year estimate of the network LRMC and an equivalent $/MWh estimate (using a reasonable estimate of the coincident load factor of DSM acquired energy).

Response:

Please refer to the response to BCSEA IR 2.59.1 for FBC's derivation of the $35/kW-year Deferred Capital Expenditure (DCE) factor used in the DSM benefits calculations.

Assuming an approximate load factor of 0.55, this results in an estimated Deferred Capital Expenditure cost of approximately $7.27/MWh-year.

4.4 Please identify and explain any differences between the approach used by FBC to determine its network LRMC and the approach used by BCH in its most recently approved IRP.

Response:

BC Hydro appears to calculate a "Cost of Incremental Firm Transmission" (CIFT) as a proxy for avoided transmission investment due to DSM. This is a transmission-only cost and appears to only account for costs related to energy delivery to the Lower Mainland load centre. The FBC calculation of the Deferred Capital Expenditure included both transmission and distribution and included all system growth costs.

5.0 Reference: Exhibit B-43, p. 4; International Financial Reporting Standards (IFRS) Status Update Report, Manitoba Hydro, April 30, 2012, p. 21[2]

Accounting for DSM Expenditures

FBC States in Exhibit B-43, p. 4: "This issue of the appropriate treatment of DSM expenditures was analyzed in depth in a report prepared by Deloitte & Touche, entitled "Accounting for DSM Expenditures" (February 1991) (the "Deloitte Report")." Further, FBC states that the Deloitte Report concludes that "Where there is reasonable assurance that a DSM expenditures will result in future benefit, it should be deferred and amortized as the future benefit is realized.

Manitoba Hydro (MH) states on page 21 of an April 30, 2012 IFRS status update report: "The new standard 3064 and IFRS specifically identify research, selling/promotion and indirect expenditures as ineligible costs for capitalization as an intangible asset. New DSM programs typically include research activities as well as promotional activities to introduce the DSM programs. Thus, upon adoption of section 3064, MH retrospectively adjusted unamortized DSM related balances for ineligible research and promotional related balances."

5.1 Given that FBC has been approved to report under US GAAP, please provide the specific US GAAP codification that FBC relies on to defer DSM costs.

Response:

Whether it is DSM costs, non-controllable variance account balances or regulatory compliance costs, if there is Commission approval to defer such costs, these costs can be deferred pursuant to US GAAP Accounting Standards Codification (ASC) 980-340-25-1 for the recognition of a regulated asset as follows:

Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall capitalize all or part of an incurred cost that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

[2] http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_5_5.pdf

> *A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.*

Additionally, the preamble refers to Manitoba Hydro's position that certain DSM expenditures should be expensed rather than deferred, while referencing Canadian GAAP and IFRS, both of which are accounting standards that FBC is not using for rate-setting purposes. The preamble fails to mention that Canadian GAAP will not be an available option for rate-setting purposes in the future, while IFRS does not have a long-term, established rate-regulated standard that allows for the option to defer expenditures, even with regulatory approval. The primary reason why FBC, along with several other Canadian rate-regulated utilities, adopted US GAAP for rate-setting purposes is to allow for deferrals, such as DSM costs, to continue to be recognized in a manner that is appropriate and well-established.

5.1.1 Are there any restrictions under US GAAP as to which DSM costs are eligible for amortization, or guidance regarding amortization periods? If yes, please explain.

Response:

Provided that the regulatory approval to defer and fully recover the DSM costs is consistent with the recognition criteria in ASC 980-340-25-1, which were stated in the response to FBC BCUC Rebuttal IR 1.5.1, there are no explicit restrictions under US GAAP for the amortization period of DSM costs.

5.1.2 Does FBC consider that there is any judgment involved in interpreting US GAAP as it relates to deferral and amortization of DSM expenses? If yes, please explain

Response:

If the Commission approves the deferral of DSM costs and a recovery period, consistent with what it has done for the last 20 years, FBC considers that very little judgment, if any, is required to be applied as the recognition criteria under ASC 980-340-25-1 will have been satisfied.

5.1.3 Is it FBC's position that the Commission should allow deferral and amortization of DSM expenditures in order to comply with US GAAP, or that US GAAP gives the Commission the option to allow deferral and amortization? Please explain.

Response:

US GAAP does not explicitly require the deferral and amortization of DSM costs, rather the adoption of US GAAP allows for the Commission to continue with the accepted practice to defer and amortize DSM costs. FBC's position is that the Commission should continue to approve deferral and amortization of DSM expenditures as it supports the principle of matching the costs with the benefits of demand side management, is consistent with the approved FBC regulatory treatment for the last 20 years, is practiced within the rate-regulated utility industry, is consistent with the treatment of similar expenditures for BC Hydro as confirmed by the March 5, 2014 Order in Council 97, item 7(d) and is permitted under US GAAP ASC 980-340 Regulated Operations. As part of the Application for Approval of a Multi-Year PBR Plan for 2014 to 2018, in the response to BCUC IR 2.97.3 FBC elaborated on its view that the deferral of DSM expenditures is well-established and appropriate, and in the response to BCUC IR 2.97.6 provided multiple examples of North American utilities who have deferred some type of DSM costs.

5.1.4 Please explain whether the findings of the 1991 Deloitte Report have any inconsistencies with US GAAP principles.

Response:

The 1991 Deloitte Report is consistent with US GAAP principles as it, in part, bases its conclusions on Financial Accounting Standard No. 71 (FAS71), "Accounting for the Effects of Certain Types of Regulation" which is the codification predecessor to ASC 980-340 Regulated Operations. Accordingly, the same regulated asset recognition criteria to support deferring and amortizing DSM costs, which were referred to in the response to FBC BCUC Rebuttal IR 1.5.1, are also included in the findings of the 1991 Deloitte Report.

5.1.5 Has FBC undertaken any more recent third party evaluation to determine the eligibility of DSM costs for capitalization and amortization under US GAAP? If yes, please provide. If no, please explain why not.

Response:

FBC has not undertaken a third party evaluation since such a study would not provide any additional clarification or understanding on the appropriateness of FBC continuing to defer and amortize DSM costs under US GAAP. Rather than seeking a third party evaluation, FBC continues to defer and amortize its DSM costs as it is consistent with the approved regulatory treatment for FBC over the last 20 years, is consistent with the principle of matching the benefits of DSM with costs, is practiced within the rate-regulated utility industry, and is in compliance with US GAAP ASC 980-340 Regulated Operations.

When the Deloitte Report was published in 1991, FBC and many other Canadian electric utilities reported under Canadian GAAP, which had less specific accounting guidance around rate-regulated operations. FBC has now adopted US GAAP and the regulated operations guidance of ASC 980-340 is more explicit than Canadian GAAP in supporting the deferral and amortization of costs, such as DSM expenditures, based on the regulator’s decision. Accordingly, there is not the current requirement to seek clarification or understanding of deferring DSM costs today as there would have been over 20 years ago in a Canadian GAAP environment.

It should be further noted that the original 1991 Deloitte Report was prepared by Deloitte for the Canadian Electrical Association which represents a multitude of Canadian electric utilities. Since there is an established regulatory pattern of approving the deferral of DSM costs for FBC and is supported under US GAAP for regulated operations, the incremental costs for FBC to independently seek a third party evaluation on this matter would be costly and provide minimal benefit.

5.2 Does FBC have any capitalized DSM expenditures which could be categorized as research, selling/promotion or indirect expenditures? If yes, please explain their currently treatment and if this is in compliance with US GAAP.

Response:

A portion of FBC's deferred DSM costs would include promotional and indirect costs which, pursuant to the regulator's approval, are in compliance with US GAAP as described in the response to FBC BCUC Rebuttal IR 1.5.1.

5.3 FBC states that: "…in recommending that the Commission order FBC to cease capitalizing certain DSM-related expenditures, Mr. Pullman has ignored the very sizable rate impact that would result from expensing FBC's forecast 2014 $3.0 million (net of tax) DSM expenditures." (Exhibit B-43, p. 5) Please provide the 2014 rate impact of expensing (instead of capitalizing) the $3.0 million DSM expenditure.

Response:

The 2014 rate impact for expensing (instead of capitalizing) the $3.0 million DSM expenditure would be approximately an additional 1 percent (i.e., 2014 forecast Customer Rate will increase from 3.3 percent to 4.3 percent).

Please note that the above response assumes no increase of Capitalized Overhead volume in 2014 as a result of expensing the DSM cost as per above.

6.0 Reference: Exhibit B-43, Appendix C, p. 35

Total DSM Spend

FBC includes a January 2013 Public Utilities Fortnight article titled "DSM in the Rate Case" as Appendix C to its Rebuttal Evidence. The article states on page 35:

"The utility frequently owns the plant and earns a return on investment supplied by shareholders. … [DSM programs] don't typically create a regulatory asset booked on the utility's balance sheet. And without such treatment, there's no return on investment for shareholders. … to ensure a level playing field for both demand- and supply-side resources, regulators must address … shareholder expectations.

Recently the U.S. Energy Information Administration (EIA) indicated that $5.5 billion was spent on electric DSM programs in 2011, representing 1.5 percent of total electric retail revenues."

6.1 Over the next 15 to 20 years, to what extent (if any) does FBC plan to meet load growth by building generation assets, compared to purchasing energy under energy purchase contracts or from the spot market?

<u>Response:</u>

As discussed in detail in FBC's 2012 Long Term Resource Plan[3], after WAX is completed in Q1 2015, FBC plans to meet any remaining energy supply gaps to meet load through the wholesale electricity market at least through the next decade. However, the Company will continue to assess cost and reliability risks and over the longer term, expects to acquire new resources to address these risks. This is consistent with the preferred Buy-Build strategy discussed in the 2012 Resource Plan (pages 84 through 88). Future resource options will be re-evaluated as part of the full portfolio analysis the Commission directed FBC to include in its 2016 Long Term Resource Plan.

6.1.1 If no significant generation asset (rate base) investments are anticipated over the next 15 to 20 years, please explain if, in FBC's case, any DSM shareholder incentive is required to ensure a level playing field for both demand and supply side resources.

[3] Exhibit B-1-2, FBC 2012-13 RRA and ISP proceeding.

Response:

The rate base treatment of DSM expenditures creates the shareholder incentive to ensure a level playing field between demand side and supply side resources by providing for a rate base rate of return on both types of investment. Given the nature of DSM investments in comparison to the magnitude and infrequency of supply side resource investment, the comparability of demand side and supply side alternatives is only maintained when all investments in both are treated in the same manner, regardless of the respective timing of demand side versus supply side decisions.

If the Company were not incented to invest in demand-side measures, it could accelerate the need for supply-side investments.

6.2 Please provide FBC's annual DSM spend (actual/projected) since 2010 to the end of the PBR period as a percentage of revenues. Please explain any significant difference between FBC's actual and projected DSM spend as a percentage of revenues and the 1.5 percent EIA US industry average spend in 2011.

Response:

Year:	2010	2011	2012	2013	2014	2015	2016	2017	2018
	Actual ($000s)				Plan ($000s)				
DSM Spend:	3,712	5,918	7,300	6,855	3,001	3,087	3,054	3,100	3,153
FBC Revenue:	246,791	277,090	282,943	308,532	323,403	336,898	351,061	366,051	382,083
per cent DSM:	1.5%	2.1%	2.6%	2.2%	0.9%	0.9%	0.9%	0.8%	0.8%

FBC's actual DSM spend has ranged from 1.5 to 2.5 percent of revenues, it's plan (projected) spend is just under one per cent, whilst the overall average for the entire 2010-18 period is 1.4 percent - which is close to the 1.5 percent EIA US industry average.

The DSM expenditure, expressed as a percentage of revenue, is an outcome and is not a metric by which FBC determines its DSM plan budget. The difference between EIA US industry average and the FBC planned DSM spend has been set forth in the 2014-18 PBR filing and discussed at length in these proceedings.