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November 22, 2013

Via Email
Original via Mail

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C.
V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Inc. (FBC)

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

Response to the B.C. Sustainable Energy Association and the Sierra Club British Columbia (BCSEA) Information Request (IR) No. 2

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-165-13 setting out the Amended Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCSEA IR No. 2.

FBC notes that the responses to the BCSEA IR No. 2, questions 73.1, 73.2, 73.2.1, and 73.2.2 relate to the PBR Methodology, and will be submitted with the PBR Methodology IR responses.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc: Commission Secretary
Registered Parties (email only)

38.0 Topic: Avoided cost

Reference: Exhibit B-12, BCSEA 1.3.1

38.1 Is it correct to state that FBC's avoided-cost computation is based on the simplifying assumption that the alternative to additional DSM is a series of short-term purchases from the Mid-Columbia energy market?

Response:

Yes.

38.2 If not, please explain how the conceptual basis of the computation differs from that assumption.

Response:

Please refer to the response to BCSEA IR 2.38.1.

39.0 Topic: Avoided GHG emissions

Reference: Exhibit B-12, BCSEA 1.1.2.2; BCSEA 1.3.8

"BCSEA 1.1.2.2 Does FortisBC agree that by increasing relatively carbon-intensive market imports and decreasing zero-carbon DSM savings the proposed 2014-2018 DSM Plan does not support the objective of reducing GHG emissions and would tend to increase rather than reduce GHG emissions?

Response: FBC's purchases of energy at the Mid-C would be sourced from the generation resources available in the region. The following graph obtained from the Northwest Power Planning and Conservation Council illustrates the historical sources of generation. This data can be found at the following link:

http://www.nwcouncil.org/energy/powersupply. [graph showing Historical Energy Production in the Northwest by type and year omitted]

In BCSEA 1.3.8, FortisBC confirms that DSM savings are considered to be GHG neutral.

39.1 The response to BCSEA 1.1.2.2 does not address the question. Please respond to whether FortisBC agrees that by increasing relatively carbon-intensive market imports and decreasing zero-carbon DSM savings the proposed 2014-2018 DSM Plan does not support the objective of reducing GHG emissions and would tend to increase rather than reduce GHG emissions?"

Response:

FBC considers that the combination of the proposed DSM plan and the RCR conservation rates results in an offset of more than 50 percent of load growth and is therefore overall tending to reduce GHG emissions.

40.0 Topic: DSM and electricity self-sufficiency

Reference: Exhibit B-12, BCSEA 1.1.3

Asked why it omitted from Table H-1 the BC energy objective to achieve electricity self-sufficiency, FortisBC says in BCSEA 1.1.3 that "electricity self-sufficiency" means self-sufficiency by BC Hydro; and that s.6(4) of the *Clean Energy Act* requires a public utility such as FortisBC to consider "electricity self-sufficiency" in its long-term planning regarding construction or extension of generation facilities and energy purchases. FortisBC states:

"Thus, the "electricity self-sufficiency" concept can be applied to a public utility in the utility's long-term resource and conservation planning, but in two specified circumstances: "(a) the construction or extension of generation facilities, and (b) energy purchase." <u>DSM programs and expenditures do not fall under either circumstance, and thus are not directly related to the objective of achieving "electricity self-sufficiency."</u> [underline added]

40.1 Does FortisBC agree that its 2014-2018 DSM Plan aims to reduce the amount of electricity served that period? If not, why not?

<u>Response:</u>

Agreed.

40.2 Does FortisBC agree that its 2014-2018 DSM Plan aims to reduce the amount of electricity served at times when FortisBC is receiving power from BC Hydro under the Power Purchase Agreement (PPA) between BC Hydro and FBC? If not, why not?

<u>Response:</u>

No. The objective of FBC's DSM plan is to generally mitigate load growth via DSM measures but does not specifically target times when FBC is purchasing power from BC Hydro under BC Hydro's RS 3808 (i.e. the PPA). Nevertheless, since FBC is taking deliveries of PPA power in most hours, it does follow that any load growth reductions resulting from DSM measures would coincide with times that FBC is taking power from BC Hydro.

40.3 Does FortisBC agree that by reducing the amount of power FortisBC obtains from BC Hydro under the PPA the 2014-2018 DSM Plan directly reduces the amount of power BC Hydro must supply to FortisBC and therefore directly contributes toward the achievement of "self-sufficiency" by BC Hydro?

Response:

No. FBC agrees that if DSM measures result in a reduction in PPA purchases, it may reduce BC Hydro's requirement to acquire other resources to meet its remaining requirements. However the PPA 200 MW capacity limit and the Annual Tranche 1 energy cap of 1041 MWh, already provides a limit on the use of the PPA to meet any future FBC load growth on which BC Hydro will base its long term planning. In particular, given the 200 MW capacity cap, any increase in PPA purchases to meet FBC load growth would be in the shoulder or summer seasons where BC Hydro currently has surplus resources. It is also expected that, given the current forecast of long term market prices, the majority of the time the PPA will not be FBC's marginal resource. Therefore reductions in customer load growth from DSM measures alone most likely will not reduce PPA purchases nor will it directly or indirectly contribute toward the achievement of "electricity self-sufficiency" for BC Hydro as that is defined by the Clean Energy Act.

40.3.1 In the alternative, does FortisBC agree that the 2014-2018 DSM Plan <u>indirectly</u> contributes toward the achievement of "self-sufficiency" by BC Hydro?

Response:

Please refer to the response to BCSEA IR 2.40.3.

41.0 Topic: Avoided costs

Reference: Exhibit B-12, BCSEA 1.3.1

"BCSEA 1.3.1 Please confirm that FortisBC's proposed 2014-2018 DSM Plan assumes an avoided electricity cost based on estimated future Mid-C electricity prices.

Response: The LRMC estimate used by FBC as an input to the TRC and UCT assumes FBC's avoided cost is based on annual average Mid-C market pricing, plus BPA wheeling and losses to deliver it to the BC/US border. ..."

41.1 Please confirm that the Company's LRMC estimate for DSM benefit/cost purposes does not include losses from BC/US border to the customer meter.

<u>Response:</u>

Agreed that the LRMC does not include FBC system losses, however the DSM end-user savings are grossed up by the system losses factor, and the DSM benefits are then calculated at generation and/or bulk transmission point of delivery.

41.2 If confirmed, please explain why the Company's LRMC estimate for DSM benefit/cost purposes does not include losses from BC/US border to the customer meter.

<u>Response:</u>

Please refer to the response to BCSEA IR 2.41.1.

42.0 Topic: Avoided costs

Reference: Exhibit B-12, BCSEA 1.3.2

"BCSEA 1.3.2 Please confirm that FortisBC's proposed 2014-2018 DSM Plan assumes that FortisBC's marginal supply of electric energy is market energy delivered at the Mid-Columbia Hub and wheeled to the FortisBC territory.

Response: Not confirmed. The DSM plan assumes that FBC acquires market energy. Market energy could be acquired from the Mid-Columbia Trading Hub and wheeled to the FBC territory, <u>or it could be market energy acquired from elsewhere</u>, and priced at the FBC's avoided cost (Mid-C plus BPA wheeling and losses)."

42.1 Is FBC making a distinction here between Mid-C pricing and physical delivery from Mid-C?

<u>Response:</u>

Yes. The Mid-Columbia is a general reference to 118 miles of the Columbia River in Central Washington where five hydro projects are located. These projects are owned and operated by Chelan County PUD, Grant County PUD, and Douglas County PUD. Mid-C is also a power trading hub in which physical energy is generated, bought and sold, and is also used as pricing index for other physical (and financial) transactions.

FBC expects that some market purchases will be delivered to the FBC service territory from Mid-C, but they could be delivered from elsewhere, as in the case of Powerex selling surplus BC Hydro power to FBC. FBC assumes for the forecast of its market purchases that pricing will be based FBC's avoided cost, Mid-C market energy delivered to BC.

43.0 Topic: Avoided GHG emissions

Reference: Exhibit B-12, BCSEA 1.3.4

"BCSEA 1.3.4 If FortisBC purchases additional energy at the Mid-Columbia hub in lieu of additional DSM savings, what generation resources (location and type) would FortisBC expect would be the sources of that additional energy?

Response: Please refer to the response to BCSEA IR 1.1.2.2."

The response to BCSEA IR 1.1.2.2 provides a chart showing annual generation by source.

43.1 Is FortisBC suggesting that additional energy purchased at the Mid-Columbia hub in lieu of additional DSM savings should be characterized by <u>annual</u> average generation sources rather than by the <u>marginal</u> generation sources?

<u>Response:</u>

Yes. Please refer to the responses to BCSEA IR 2.45.13 and BCUC IR 1.230.1.2

44.0 Topic: Substitution of imports for DSM savings

Reference: Exhibit B-12, BCSEA IR 1.3.6; BCSEA IR 1.1.2.2

"BCSEA 1.3.6 Would FortisBC agree that incremental energy delivered to FortisBC from the Mid-Columbia hub would be provided primarily by operating additional gas and coal generation? If not, please explain why not.

Response: No, that is an oversimplification. The Mid-C trading hub is complex, and trades surplus electricity generated by various resources, and may include hydro with storage, run of river hydro, wind, nuclear, gas and coal.

The marginal generation mix at any time will be impacted by both time of day as well as season. For example, gas generators typically do not run during freshet when the abundance of hydro and wind resources create Mid-C market prices that may not cover a gas plant's variable operating costs.

There are likely significant periods when thermal generators provide the marginal generation, however even then it typically will be gas plants providing this incremental generation, not coal.

Please also refer to the response to BCSEA IR 1.1.2.2" [quoted above]

44.1 Please provide any data available to FBC regarding the mix of generation that is marginal at Mid-Columbia or other locations in the Pacific Northwest.

Response:

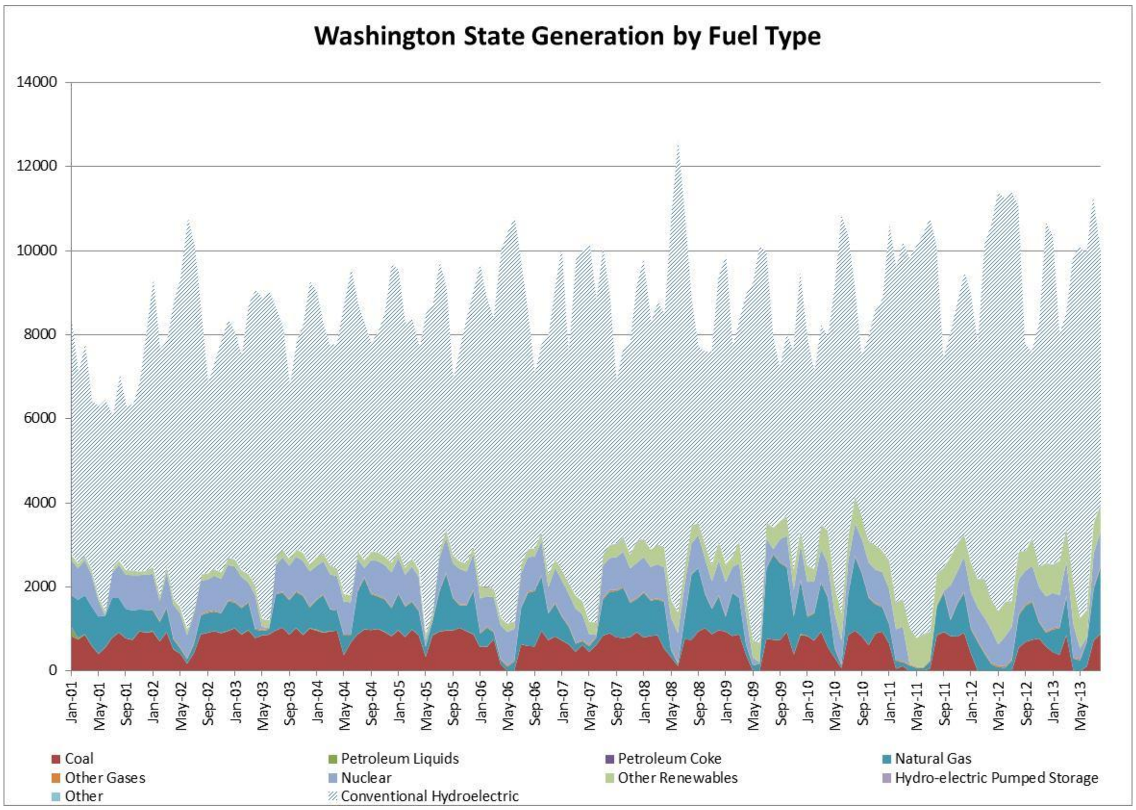
The requested analysis is complex, and the boundaries and assumptions, such as the capacity factor threshold used to differentiate "marginal" and "non-marginal" plants, can produce different results. In 2008, the Northwest Power and Conservation Council attempted to model the Pacific Northwest system marginal resource in every hour.[1] In its modeling, it identifies coal, natural gas biomass and demand response as the regions marginal resource at various times throughout the year, with natural gas CCGT being the marginal resource for most hours in the year, although coal can be the marginal resource during low load hours. FBC believes the study does not consider the impact of the sale of BC Hydro surpluses on the Mid-C marginal generation, so therefore its conclusions on marginal generation may be incomplete.

In recent years the Western Climate Initiative has also spent considerable effort in verifying and validating the carbon content of unspecified power imports from different states as part of its carbon accounting obligations under its cap and trade program. Although FBC does not directly model or monitor the marginal generation in the PNW, BC's *Greenhouse Gas Reduction (Cap*

[1] Northwest Power and Conservation Council, Marginal Carbon Dioxide Production Rates of the Northwest Power System, June 13, 2008.

and Trade) Act Reporting Regulation requires the most recent Western Climate Initiative Final Default Emission Factor Calculator to be used to report the GHG impact of FBC's energy imports.[2] This calculator can be set by state, and calculates marginal or average generation emission factors.

The US Energy Information Administration tracks actual generation in each state by generation type going back to 2001. Attached is a graph based on that data showing historic Washington State generation by fuel type[3].



Bonneville Power Administration also tracks generation on its system by 5 minute intervals going back to 2007[4]. It does not distinguish between thermal generation types, which could include coal, natural gas and biogas.

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2 http://www.westernclimateinitiative.org/document-archives/Electricity-Team-Documents/Default-Emission-Factor-Calculators/2008-Final-Default-Emissions-Factor-Calculator-(Full)/

3 http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=000000000001&sec=g&freq=M&start=200101&end=201308&ctype=linechart&ltype=pin&maptype=0&rse=0&pin=~~~~

4 "#5 Data for BPA Balancing Authority Total Load, Wind Gen, Wind Forecast, Hydro, Thermal, and Net Interchange: 2007; 2008; 2009; 2010; 2011; 2012; 2013. http://transmission.bpa.gov/Business/Operations/Wind/default.aspx

44.2 Please provide any data available to FBC regarding the percentage of the time that the additional energy generated due to an additional sale at Mid-Columbia is from each of the following sources listed in BCSEA IR 1.3.6:

44.2.1 hydro with storage,

44.2.2 run of river hydro,

44.2.3 wind,

44.2.4 nuclear,

44.2.5 gas and

44.2.6 coal.

Response:

FBC does not have detailed information regarding the percentage of time each generation resource is the marginal resource at the Mid-Columbia trading hub. FBC does not have the resources to undertake an independent study. Please refer to the response to BCSEA IR 2.44.1 for the available generation data.

44.3 If a hydro plant with available storage is dispatched to allow a sale to FBC, does FBC agree that the dispatch of such energy would result in less storage and require the dispatch of some other generation at another time, to replace the energy sold to FBC?

Response:

No. There are at least three situations where additional generation will not be required in that scenario:

1. During high water years where the storage is full and that water would otherwise be spilt;

2. Where that water would have been needed to be released otherwise for purposes other than generation, such as for environmental issues related to fish, recreation, flood control, or irrigation; and
3. When there is an energy surplus.

According to BC Hydro's Draft 2013 IRP, BC Hydro is currently in an energy surplus and that surplus is forecasted to last until 2017. To manage this, BC Hydro in the process of trying to trying to reduce its energy supply purchases.[5]

44.3.1 If not, please explain why.

Response:

Please refer to the response to BCSEA IR 2.44.3.

44.3.2 If FBC believes the additional generation of other energy would be required under some conditions, please provide any available information on the frequency of those conditions.

Response:

Generally speaking, this will occur anytime a thermal resource is the marginal resource. Please refer to the response to BCSEA IR 2.44.1 for a discussion of how often this is expected to be the case.

44.4 Regarding the response that "gas generators typically do not run during freshet" [BCSEA 1.3.6], please provide the following data for each spring, 2000–2013:

[5] BC Hydro Draft 2013 IRP dated August 3, 2013, Chapter 4, Section 4.2.5.1, Page 4-10 to page 4-17.

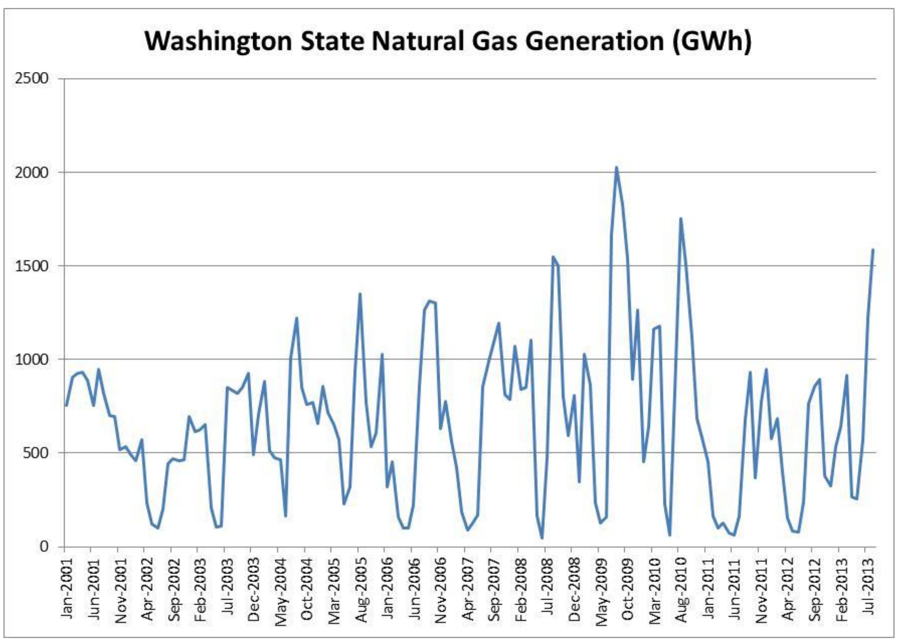
44.4.1 The duration of the period in which no gas generators were run.

<u>Response:</u>

FBC's statement that "gas generators typically do not run during freshet" is specifically responding to the BCSEA inquiring about generation delivered from the Mid-C trading hub. FBC does not have a specific breakdown of Mid-C energy traded at the hub, however the following graph from 2001-2013 quantifying monthly natural gas generation in Washington State[6] is available. Information on natural gas generation in the year 2000 was not readily available.

As can be seen from the graph, the volume of natural gas generation falls significantly during the freshet. FBC interprets that the small amount of residual gas generation in the freshet is related to utility must-run contracts for capacity and not to marginal generation.

The monthly data can be obtained from the US Energy Information Administration[7].



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6 Source: US Energy Information Administration.

7 http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=000000000001&sec=g&freq=M&start=200101&end=201308&ctype=linechart&ltype=pin&maptype=0&rse=0&pin=~~~~

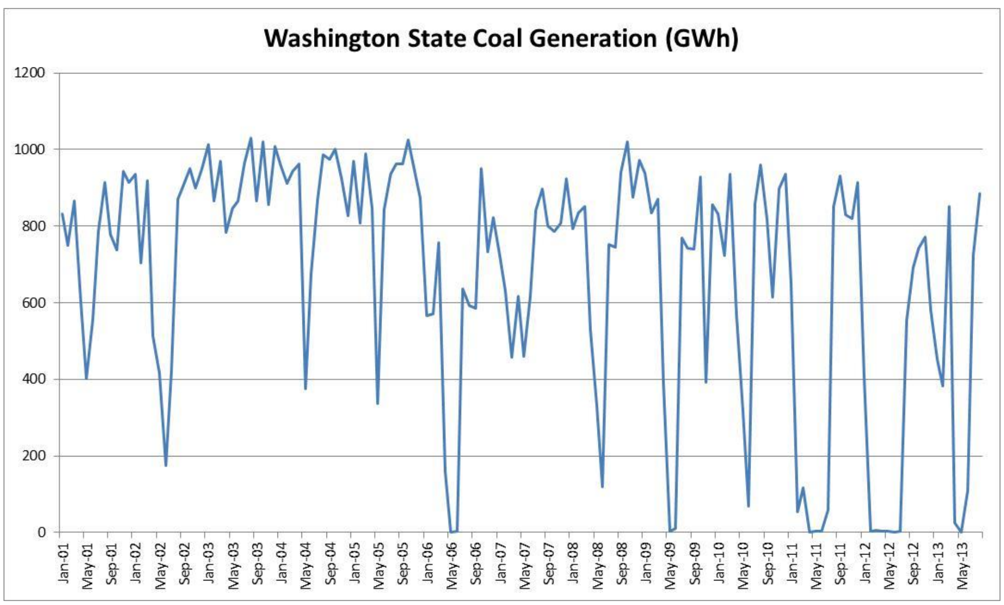
44.4.2 The amount of coal-fired energy generated in the Pacific Northwest during the freshet.

Response:

FBC's statement that "gas generators typically do not run during freshet" is specifically responding to the BCSEA inquiring about generation delivered from the Mid-C trading hub. Therefore, FBC assumes that BCSEA is specifically looking for the amount of coal generation in Washington State during freshet, and has provided the following graph from 2001-2013 quantifying the monthly coal generation[8]. Information on coal generation in the year 2000 was not readily available.

As can be seen from the graph, in recent years the volume of coal generation in Washington State can fall to zero during the freshet.

The monthly data can be obtained from the US Energy Information Administration[9].



8 Source: US Energy Information Administration:

9 http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=000000000001&sec=g&freq=M&start=200101&end=201308&ctype=linechart&ltype=pin&maptype=0&rse=0&pin=~~~~

45.0 Topic: Substitution of imports for DSM savings

Reference: "Marginal Carbon Dioxide Production Rates of the Northwest Power System," Northwest Power and Conservation Council, June 13, 2008 ("NPCC-2008"), at http://www.nwcouncil.org/media/29611/2008_08.pdf;

45.1 Please file a copy of the referenced report NPCC-2008.

Response:

Please refer to Attachment 45.1.

45.2 Does FortisBC agree that the Northwest Power and Conservation Council (NPCC) is a reputable and well-informed source of information about the electrical power system in the Pacific Northwest? If not, please explain.

Response:

The **Northwest Power and Conservation Council** is a regional organization that develops and maintains a regional power plan and a fish and wildlife program to balance the Northwest's environment and energy needs. It is a quasi-governmental organization governed by appointed representatives from states of Oregon, Washington, Montana and Idaho. One of the Council's primary objectives is to promote energy efficiency and conservation while ensuring adequate and reliable energy at the lowest economic and environmental cost. Originally known as the Northwest Power Planning Council, in January 2003 it officially changed its name to the Northwest Power and Conservation Council to emphasize the conservation aspect of its responsibilities.

FBC does believe that the Council is reputable and a well-informed source of information. It is recognized, however, that given the mandate of the organisation, there is an inherent bias in the work performed by the Council in support of conservation and fish and wildlife protection.

NCCP-2008 states:

"The cost of future carbon dioxide (CO2) regulation is a significant factor in utility resource planning in the Pacific Northwest. Failure to properly account for this risk when evaluating resources can result in poor resource decisions and higher costs for the region's ratepayers." [p.1]

45.3 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

Yes. FBC currently addresses this risk by having a carbon adder included in its BC Market Energy Price Forecast.

45.4 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

Yes.

In its utility resource planning, FBC must comply with its legislated greenhouse gas obligations, currently specified by the *Clean Energy Act* and the GHG (Cap and Trade) Reporting Regulation.

When FBC does its portfolio analysis in future resource plans, the impacts of the 2007 Energy Plan's policy actions 18-20, the *Carbon Tax Act*, the *Clean Energy Act* and any other government greenhouse gas policies and laws will be considered.

FBC will continue to consider GHG compliance risks in future resource plans. However, carbon compliance costs and regulatory risk are just one aspect of the resource planning process, and conservation is just one of the resource options that is considered in resource planning.

NCCP-2008 states:

"One of the benefits of conservation is that it avoids CO2 emissions.1"

45.5 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

One would have to look at the entire lifecycle of the conservation measure to verify that it has no GHG footprint. This would including the manufacture, transportation and disposal of any materials associated with the conservation initiative. However, FBC agrees that conservation likely has a very low carbon impact.

45.6 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

The objective of FBC's DSM plan is to generally mitigate load growth via DSM measures. FBC considers that the combination of the proposed DSM plan and the RCR conservation rates results in an offset of more than 50 percent of load growth. Displacement of more intensive GHG generation sources is an ancillary benefit.

Section 2(c) of *the Clean Energy Act* (*CEA*) states one of BC's energy objectives is:

> *"to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity."*

Section 6(4) of the *Clean Energy Act* states:

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

Neither Section 2(c) nor Section 6(4) of the *CEA* directs FBC to meet long-term firm load growth with long-term firm clean BC energy. Nor does the *CEA* prescribe FBC's DSM target levels. However, FBC does consider these issues in its resource planning, and as described in its 2012 Long Term Resource Plan, it does plan to become 100 percent self-sufficient in the long term.[10]

[10] FortisBC 2012 Long-Term Resource Plan, Executive Summary, Page 1, Lines 10-16.

NCCP-2008 states:

"The benefit it [conservation] provides depends on what generating resources would be replaced and how much CO2 they produce."

45.7 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

Yes, FBC agrees that one of the potential benefits of DSM can be displacing more carbon intensive generation.

45.8 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

Please refer to the response to BCSEA IR 2.45.6.

NCCP-2008 continues:

"This requires understanding what generating resources are on the margin; that is, the generation that could be displaced by the conservation. The marginal resource is the last resource brought online to supply power during a given time period (i.e., the highest variable cost resource available and needed during the period)."

45.9 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

Yes.

45.10 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

Please refer to the response to BCSEA IR 2.45.6.

NCCP-2008 continues:

"In the Northwest, the average <u>marginal</u> CO_2 production is substantially higher than the <u>average</u> CO_2 production from all electricity generation. This is because hydroelectricity and wind, which have low operating costs and no CO_2 emissions are brought on-line before coal-fired or natural gas-fired generating units." [p.1, underline added]

45.11 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

Yes, FBC agrees that the average marginal CO_2 production is likely to be higher than the average CO_2 production given the nature of the generation resources in the Pacific Northwest. However FBC does not fully agree with the explanation provided by NCCP because there are other factors in place that sets the marginal generation in any hour that FBC maybe purchasing market power. Indeed there are many hours of the year where coal and gas are generating because they are must-run facilities or contracted to provide baseload supply (i.e. are not dispatched in response to market), and there are many times during which there is significant surplus generation because of wind and run of river hydro conditions. Indeed it is often these times where FBC is able to take advantage of the market because the flexibility of its storage resources allow it to shape the timing of its market purchases. It is not reasonable to assume that FBC market purchases are all being made at times when the marginal generator is thermal.

45.12 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

Please refer to the response to BCSEA IR 2.45.8.

NCCP-2008 continues:

"Because only the marginal plants would be displaced by conservation, it would not be proper to use the average of CO2 emissions from all power generation to estimate the CO2 saved through conservation." [p.1, underline added]

45.13 Does FortisBC agree with this statement by NCCP-2008? If not, why not?

Response:

FBC agrees that it is likely that a decrease in load will result in displacement of whatever generation is the marginal resource at the time. Often, this will be a thermal resource, but the flexibility of the FBC system enables energy to be purchased at times when non-thermal resources such as water and wind are the marginal resource. BCSEA IR 2.45.11 further explains why applying just a thermal marginal rate to FBC conservation is expected to overstate CO2 emission reductions.

As a result, FBC continues to believe that using the average of CO2e emission rate related to its market purchases is the most appropriate measure. This is also consistent with the *Greenhouse Gas Cap and Trade* Reporting Regulation which requires FBC to report the carbon footprint of electricity imports based on the average emissions factor.

45.14 Does FortisBC agree that this statement by NCCP-2008 applies also to utility resource planning by FortisBC? If not, why not?

Response:

Please refer to the response to BCSEA 2.45.13.

46.0 Topic: Avoided GHG emissions

Reference: Exhibit B-12, BCSEA 1.3.7; Exhibit B-7

"BCSEA 1.3.7 Please provide estimates available to FortisBC of (a) the average carbon intensity of market power sold through Mid-C and (b) the carbon intensity of Mid-C market power at the margin. [underline added]

Response: Please refer to the response to BCUC IR 1.230.1.2."

46.1 Please confirm that the response to BCUC IR 1.230.1.2 does not provide an estimate of the carbon intensity of Mid-C market power at the margin; rather the response provides "the Default Emission Factor Calculator ... set to emulate a gas plant for Mid-C hub energy (marginal natural gas = 0.400 tonnes CO2e/MWh)" [BCUC 1.320.2, p.563, lines 33-34].

Response:

Not Confirmed. The 0.400 tonnes CO2e/MWh represents an estimate of the carbon intensity of power at the margin for Washington State, including a factor for line losses, as specifically estimated by the WCI 2008 Final Default Emissions Factor Calculator[11]. The Mid-C trading hub is located in Washington state, so the calculator should represent a good proxy for the carbon intensity of Mid-C market power at the margin.

The calculator forecasts that power in Washington State at the margin is dominated by natural gas generation, but it does include some minor distillate fuel oil generation which does not change the marginal emission factor.

In the response to BCUC IR 1.230.1.2, FBC states:

"...The FortisBC provincial resource stack is zero emission so the graph assumptions indicate only previous US Market Purchases and the "Future Market-Unknown Source", assumed 100% at Mid-C, as GHG emission sources. Since not all future market purchases will be from Mid-C, this likely overstates future emissions." [underline added]

[11] http://www.westernclimateinitiative.org/document-archives/Electricity-Team-Documents/Default-Emission-Factor-Calculators/2008-Final-Default-Emissions-Factor-Calculator-(Full)/

46.2 Please explain why "not all future market purchases [being] from Mid-C [...] likely overstates future emissions."

Response:

FBC makes market purchases from several marketers, including Powerex. Market purchases from Powerex at times will likely include surplus generation directly from the BC Hydro system.

Powerex has been registered in the CARB market as an "asset-controlling supplier"[12], which means that through a calculation and verification of BC Hydro's generation and imports, a marginal carbon emission rate has been approved for BC Hydro system surplus sales into the CARB market. That emission factor is equal to 0.0293mt CO2e/MWh. Market purchases specifically originating from the BC system should have this lower emission factor applied, meaning that the graph overstates future emissions.

46.3 Please provide a table showing all the sources of market energy contemplated by FortisBC for the 2014-2018 period, the average GHG intensity (in tonnes CO2e/MWh) for each source, and the marginal GHG intensity for each source.

Response:

From a planning perspective, FBC is assuming market energy purchased will be from unspecified sources. The GHG intensity from unspecified sources will depend on the location where the power originated. Typically, FBC's market purchases will be sourced from British Columbia and Washington State. Another potential source of market power could be Alberta, although FBC currently does not transact with the Alberta market. The GHG intensities for each of those jurisdictions are provided in the table below:

Jurisdiction	**Average GHG Intensity Factor** metric tons CO2e/MWh	**Marginal GHG Intensity Factor** metric tons CO2e/MWh
British Columbia	0.023	0.0293
Washington	0.102	0.400
Alberta	0.708	0.532

[12] http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm#acs_use

The intensity factors for Washington State and Alberta are sourced from the current WCI 2008 Final Default Calculator, and are after an adjustment for transmission losses.[13] The average intensity factor for the BC Hydro system is for 2010 and was obtained from a BC Hydro website.[14] The intensity factor the for marginal market power sourced from BC Hydro from its British Columbia system is obtained from the CARB Asset-Controlling Supplier System Emission Factor for Data Year 2013 for Powerex.[15]

47.0 Topic: Avoided GHG emissions

Reference: Exhibit B-12, BCSEA 1.3.8

In BCSEA 1.3.8, FortisBC confirms that DSM savings are considered to be GHG neutral. In BCUC 1.230.2, provides a carbon intensity estimate of 0.400 tonnes CO2e/MWh for gas-fired generation at Mid-C, and an estimate 0.102 tonnes CO2e/MWh for average CO2e values for the Mid-C energy hub.

47.1 Does FortisBC agree that obtaining additional energy savings above those proposed in the 2014-2018 DSM Plan would reduce FortisBC's purchases of PPA power and/or market energy?

<u>Response:</u>

Yes.

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13 http://www.westernclimateinitiative.org/document-archives/Electricity-Team-Documents/Default-Emission-Factor-Calculators/2008-Final-Default-Emissions-Factor-Calculator-(Full)/

14 https://www.bchydro.com/about/sustainability/climate_action/greenhouse_gases.html

15 http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm#acs_use

48.0 Topic: Exchange rate

Reference: Exhibit B-12, BCSEA 1.4.3

In response to BCSEA 1.4.3, FBC states:

"**Response:** Confirmed. The Long-Run Marginal cost of market purchases uses the exchange rate forecast from the GLJ January 1st, 2013 Commodity Price Report. This exchange rate forecast is that the Canadian and US dollars will be at par." [underline added]

48.1 Please confirm that the GLJ January 1st, 2013 Commodity Price Report uses an assumption that the Canadian and US dollars will be at par; i.e., that this is an assumption not a forecast.

Response:

GLJ provides the following preamble with its October 2013 Commodity Price Report:

"GLJ Petroleum Consultants has prepared the enclosed price and market forecasts after a comprehensive review of information available through to September 2013. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. The accuracy of all factual data, from all sources has been accepted as represented without detailed investigation by GLJ Petroleum Consultants. The forecasts presented herein are based on an informed interpretation of currently available data. While they are considered reasonable at this time, users of these forecasts should understand the inherent high uncertainty in forecasting any commodity or market. These forecasts will be revised periodically as market, economic and political conditions change. These future revisions may be significant." [16]

The GLJ January 1, 2013 Commodity Price Report forecasted a USD/CDN exchange rate of 1:1. The GLJ October 1, 2013 Commodity Price Report updates the exchange rate forecast to 0.970.[17]

In support of the GLJ exchange rate forecast embedded in its Commodity Price Reports:

1. The BC June 27, 2013 Budget includes the following USD/CDN exchange rate forecast[18]:

16 GLJ Petroleum Consultants, Product Price and Market Forecasts for the Canadian Oil and Gas Industry, October 1, 2013, page 2.

17 GLJ Petroleum Consultants, Product Price and Market Forecasts for the Canadian Oil and Gas Industry, October 1, 2013, page 4.

2013	2014	2015	2016	2017
0.975	0.973	0.990	0.986	0.977

The Ministry of Finance's exchange rate outlook is based on the average of six private sector forecasts including those of IHS Global Insight, CIBC, Bank of Montreal, Scotiabank, TD Economics, and RBC Capital Markets.[19]

2. The BC Hydro 2013 Draft IRP dated August 3, 2013 utilizes a USD/CDN conversion rate of 0.9693.20.

Therefore, FBC is satisfied that utilizing the exchange rate forecast embedded in the GLJ Commodity Price Report is acceptable.

48.1.1 Alternatively, please provide the full documentation of the exchange rate forecast, including the methodology and assumptions not just the result ("at par").

Response:

FBC does not have that information. Please refer to the response to BCSEA IR 2.48.1.

48.1.2 And, please provide any available evidence that supports the view that the GLJ January 1, 2013 use of CAD/USD at par over the forecast period is an actual forecast as opposed to a simplifying assumption.

Response:

Please refer to the response to BCSEA IR 2.48.1.

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[18] BC June Budget Update – 2013/14 to 2015/16 dated June 27, 2013. Table 3.6.5 - Major Economic Assumptions, page 94.

[19] BC June Budget Update – 2013/14 to 2015/16 dated June 27, 2013. Table 3.6.5 - Major Economic Assumptions, page 90.

[20] BC Hydro 2013 Draft Integrated Resource Plan dated August 3, 2013, Chapter 4, Section 4.4.3.4, page 4-61.

49.0 Topic: Avoided energy, price and exchange rate

Reference: Exhibit B-12, BCSEA 1.4.4 and 1.4.5; and Exhibit B-7, BCUC IR1.239.1

"BCSEA 1.4.4 Please explain fully the basis for the change between the 2012 LTAP and the proposed 2014-2018 DSM Plan regarding the forecast foreign exchange rate over the planning period.

Response:

FBC directed Midgard to use the GLJ January 1, 2013 "Product Price and Market Forecasts for the Canadian Oil and Gas Industry" [http://www.gljpc.com/sites/default/files/files/jan13.pdf] for developing its market electricity price forecast update in order to be consistent with the gas price assumptions used by the Company's gas line of business in regulatory proceedings. The GLJ January 1, 2013 forecast also included an exchange rate forecast which Midgard was directed to use because it was an independent publically available forecast. Please refer to the response to BCUC IR 1.239.1."

"BCSEA 1.4.5 Please reconcile the forecast of a constant 1.00 foreign-exchange ratio in Attachment H4 with recent foreign-currency futures.

"Response:

FBC does not understand what is meant by reconciling to recent foreign currency futures as there could be many reasons for differences between today's quoted futures prices and what assumptions drove the rates in a spot rate forecast compiled by an independent third party at January 1, 2013. (http://www.glja.com/commodity-price-forecasts (01JAN2013 version direct link provided in footnote 4)). FBC assumes the question, in simple terms, means to compare foreign-currency futures as of today, to the foreign exchange rates provided in attachment H4 as sourced. Futures contracts do not come in 20 year forecasts; rather contracts settle out to a maximum of 5 years. The December settlement period quotes for each year are shown below:

CAD/USD	
Settlement Date	**Futures Contract[1]**
Dec-13	0.9471
Dec-14	0.9387
Dec-15	0.9319
Dec-16	0.9292
Dec-17	0.9266

[1] Futures contract price Direct method CAD/USD Quotes from CME Group as at August 29, 2013

"

49.1 Please confirm that the futures contract prices cited by FBC in BCSEA 1.4.5 show an annually declining CAD/USD ratio from a high of approximately 0.95 in December 2013 down to about 0.93 in December 2017.

Response:

Confirmed.

49.2 Does Fortis believe that the GLJ January 1, 2013 "forecast" (CAD/USD at par) represents the most likely and most authoritative "independent publically available forecast" for the exchange rate?

Response:

FBC is not aware of any forecast that is considered the 'most likely and most authoritative "independent publically available forecast" for the exchange rate' to quote from the question in BCSEA IR 2.49.2. FBC does believe that GLJ's forecast is reasonable and acceptable for its intended purpose.

49.3 Did Midgard inform FortisBC that it believed that the GLJ January 1, 2013 CAD/USD "forecast" represents the most likely and most authoritative "independent publically available forecast" for the exchange rate?

Response:

No, Midgard did not. Please refer to the response to BCSEA IR 2.48.1.

49.3.1 If not, please describe any opinion that Midgard expressed regarding the most likely future exchange rate.

Response:

In the development of its 2013 update, Midgard did not express any opinion to FBC regarding the most likely future exchange rate. Please refer to the response to BCSEA IR 2.48.1.

49.4 Please provide any documents and describe any communications with GLJ regarding the analysis that supports the GLJ January 1, 2013 forecast of exchange rate.

Response:

The GLJ forecast is an independent, publically available gas price forecast. FortisBC has not had any communications with GLJ regarding the exchange rate component of the forecast. Please refer to the response to BCSEA IR 2.48.1.

49.5 Does Fortis believe that the GLJ January 1, 2013 forecast of exchange rate (1:1) is a better estimate than the contract prices listed in Exhibit B-12, BCSEA 1.4.5 (declining from 0.9471 to 0.9266 CAD/USD over five years). If so, why?

Response:

The contract prices listed in the table provided in response to BCSEA 1.4.5 do not represent a price forecast. They are forward prices that represent the price at which transactions could be entered into at a particular point in time (in this case, on August 29, 2013) for delivery or settlement at some point in the future. The contract prices will change from day to day in response to current spot rates and the cost of financing for the period in question among other things. As discussed in the response to BCSEA IR 2.48.1, the assumptions used by GLJ are used to develop a long term commodity price forecasts based on informed interpretation of various sources of information available at the time of the forecast, including current exchange rates.

FBC does not have a view on which data provides a "better estimate" of future exchange rates on a stand alone basis, but since the avoided cost of market purchases is being determined based on GLJ's natural gas commodity price forecast, it believes that it is appropriate to use the same exchange rate assumptions that are embedded in that forecast.

49.6 Please confirm that if one assumes a CAD/USD exchange rate of less than one over the lifetime (persistence) of DSM savings in the 2014-2018 DSM Plan then the avoided cost of the savings is higher than estimated by FortisBC using a CAD/USD exchange rate of 1:1.

Response:

Confirmed.

50.0 Topic: Mid-C prices

Reference: Exhibit B-12, BCSEA 1.6.1

"BCSEA 6.1 Please provide an up to date version of estimated monthly Mid-C price variations.

Response:

Table 5.1.1-B is based on the BC Hydro "Integrated Resource Plan Technical Advisory Committee Meeting #2 – Meeting Presentation - Day 1" document, from January 2011, on Page. [footnote omitted] The table is reproduced here: [table omitted]

50.1 Has Fortis determined historical or projected Mid-C price variations from sources other than BC Hydro? If so, please provide those estimates.

Response:

No. The derivation of the Mid-C time of use shaping factors would be determined through an assessment of historic Mid-C prices over a period of time. FBC expects BC Hydro has done this and did not believe it was necessary to duplicate the effort. However, with gas plants replacing retiring coal plants in the Pacific Northwest and the amount of wind generation being added to the grid, it is reasonable to consider if historic prices will continue to be a good indicator for future time of delivery factors. FBC plans to review the time of delivery factors as part of its 2016 long-term resource plan.

51.0 Topic: Short-term market energy purchases

Reference: Exhibit B-12, BCSEA 1.7.6; BCSEA 1.8.3

In response to BCSEA IR 1.7.6, FortisBC provides a table showing the monthly market purchases segregated by purchases from entities in BC, US entities through BC Hydro, US entities through Teck Metals Line 71 and from Alberta.

"BCSEA 1.8.3 ...

Purchasing capacity in the wholesale market is a strategy that FortisBC has historically employed. The Company can purchase these products directly from the US electricity market or from BC Hydro's trading subsidiary Powerex. Typically this can only be done on a short term basis and is achieved by <u>contracting for short-term supplies of firm power to be delivered to FortisBC during the peak demand months of December, January, and/or February.</u> The advantage of this procurement method is that FortisBC has flexibility with regard to contract timings, quantity of contracts and contract durations. ..." [underline added]

51.1 Please specify the amount of purchases in each month that were "short-term supplies of firm power" in the sense that FortisBC uses that term in BCSEA 1.8.3.

<u>Response:</u>

Greater than 99 percent of the market purchases shown in BCSEA IR 1.7.6 were short-term supplies of firm power. A very small amount of non-firm market purchases make up the remainder. FBC does not track these purchases separately, and therefore the only way to identify them would be to pull and do an analysis all of the hourly logsheets over the period. This would be a very time consuming process and therefore has not been done.

51.2 To the extent possible, please provide the amount of the purchases in each month that were in HLH.

<u>Response:</u>

The table below shows an approximation of the amount of monthly purchases in the heavy load hours and light load hours from 2010 to 2012.

Date	Heavy Load Hour (HLH)	Light Load Hour (LLH)	Total
Jan-10	4,038	-	4,038
Feb-10	-	-	-
Mar-10	-	701	701
Apr-10	2,710	-	2,710
May-10	36,299	-	36,299
Jun-10	42,466	-	42,466
Jul-10	-	15,202	15,202
Aug-10	27,992	2,323	30,315
Sep-10	20,185	-	20,185
Oct-10	37,235	60	37,295
Nov-10	42,059	12,840	54,899
Dec-10	28,290	18,995	47,285
2010 Total	**241,274**	**50,121**	**291,395**
Jan-11	35,719	21,048	56,767
Feb-11	31,324	21,820	53,144
Mar-11	43,705	22,456	66,161
Apr-11	38,465	8,204	46,669
May-11	24,725	805	25,530
Jun-11	35,492	12,541	48,033
Jul-11	24,351	7,495	31,846
Aug-11	18,903	4,260	23,163
Sep-11	11,010	262	11,272
Oct-11	44,830	350	45,180
Nov-11	36,620	11,296	47,916
Dec-11	15,412	18,790	34,202
2011 Total	**360,556**	**129,327**	**489,883**
Jan-12	35,466	19,605	55,071
Feb-12	35,891	17,965	53,856
Mar-12	19,812	30,343	50,155
Apr-12	28,432	330	28,762
May-12	19,898	3,471	23,369
Jun-12	22,509	8,643	31,152
Jul-12	27,810	13,798	41,608
Aug-12	15,344	3,804	19,148
Sep-12	38,491	6,264	44,755
Oct-12	21,741	27,953	49,694
Nov-12	31,791	22,707	54,498
Dec-12	71,975	210	72,185
2012 Total	**369,160**	**155,093**	**524,253**

51.3 To the extent possible, please provide the amount of the purchases in each month that were in LLH.

Response:

Please refer to the response to BCSEA IR 2.51.2.

52.0 Topic: Delivery of Mid-Columbia Energy to FortisBC

Reference: Exhibit B-12, BCSEA 1.8.2; FortisBC 2012 Long Term Resource Plan, Appendix B – Midgard 2011 FortisBC Energy & Capacity Market Assessment, p. 18 of 54 (pdf 122)

The 2011 Energy & Capacity Market Assessment states that "interconnections are often at their maximum transmission limit," "wheeling additional power between utilities in the region is frequently not possible," "these constraints…restrict access to the energy and capacity from the US market," and "transmission constraints between British Columbia and the United States will become ever more restrictive" (underline added).

Similarly, in BCSEA 1.8.3, FBC states: "The consequences of transmission congestion are highest for FBC and its customers during on peak hours during the winter peak." [p.25, lines 31-32]

The response to BCSEA 1.8.2 states FBC's belief that "it does not seem possible to 'quantify current and future restrictions'."

52.1 Please explain how FBC can conclude that some event [i.e., transmission congestion] occurs "often" and "frequently," if it cannot quantify the frequency of the event.

Response:

The statement from the response to BCSEA IR 1.8.2 was that current and future restrictions cannot be quantified—meaning that there is an element of uncertainty as to what exactly will happen from year to year. For example, while FBC believes that the 2011 Midgard statement quoted above that transmission constraints between BC and the US will become ever more restrictive is most likely correct in the long run, 2012 saw the lowest number of hours of restrictions over the last 10 years. It is very possible to quantify the frequency of transmission restrictions on a historical basis.

The following table shows the number of hours, including the number of heavy load and light load hours, that the transmission path through BPA has been greater than 90% capacity flowing south to north to the BC/US border. FBC believes that the 90% level is an acceptable proxy for a level where the transmission is congestion, and there is uncertainty on whether or not additional transmission can be obtained. This information is calculated from public information on BPA's website[21].

[21] http://transmission.bpa.gov/Business/Operations/Intertie/default.aspx

Number of Hours S to N > 90% Capacity

Year	HLH	LLH	Grand Total
2003	123	85	208
2004	635	268	903
2005	136	118	254
2006	783	389	1,172
2007	78	59	137
2008	196	128	324
2009	371	83	454
2010	545	94	639
2011	197	142	339
2012	61	10	71
Grand Total	3,125	1,376	4,501

As shown in the table, transmission congestion can change greatly from year to year. In addition to the annual changes in the total hours of transmission congestion, the available transmission changes on an hourly, daily and weekly basis. As such, it is difficult to estimate future transmission congestion and FBC cannot forecast the annual amount of hours that the transmission will be congested, nor the timing at which those hours will occur.

52.2 Please provide any data available to FBC regarding the number of hours per year that the interconnections have been at their maximum transmission limit, for each of the last 10 years.

Response:

Please refer to the response to BCSEA 2.52.1.

52.3 Please provide any data available to FBC regarding the number of high-load hours (HLH hours) per year that the interconnections have been at their maximum transmission limit, for each of the last 10 years.

Response:

Please refer to the response to BCSEA 2.52.1.

52.4 Please provide any data available to FBC regarding the number of low-load hours (LLH hours) per year that the interconnections have been at their maximum transmission limit, for each of the last 10 years.

Response:

Please refer to the response to BCSEA 2.52.1.

52.5 Please provide any studies or reports available to FBC regarding the rate at which the "transmission constraints between British Columbia and the United States will become ever more restrictive."

Response:

Please refer to the Path 3 report in the publicly available WECC path reports[22]. Path 3 is considered historically congested, but that can change from year to year. Future analysis indicates that increasing congestion could occur.

52.6 Please provide the data, studies or analyses that demonstrate that the only time that "it is risky to rely on the market to meet energy and capacity needs" is "during periods of peak demand."

Response:

If the Company is buying power from the Mid-C market outside of periods of peak demand it is to allow energy to be stored from the Company owned generation for later use, or to restrict the

[22] http://www.wecc.biz/committees/BOD/TEPPC/PathReports/TAS_PathReports_Combined_FINAL.pdf

use of PPA power from BC Hydro. In effect this generation is being held in reserve and can step in at any time it is required to maintain reliability. FBC has flexibility in the timing of these purchases, and if there are transmission restrictions outside of periods of peak demand, it does not impact reliability.

52.7 Please define the "periods of peak demand" in the response to BCSEA 1.8.2. (e.g., whether this means 20 hours a year, HLH in winter months, HLH in all months, or something else).

Response:

The periods of peak demand over the winter months can vary greatly from year to year and are mainly driven by weather. The colder the winter, the more peak hours FBC will have. On an average winter, the number of peak hours over the winter months would likely be between 15 to 30 hours spread out over three or four days. In a particularly cold winter, the number of peak hours could be a lot higher than 30 hours, and in a mild winter, the number of peak hours could be lower than 15.

52.8 Please provide the data, studies or analyses that demonstrate that "the availability of energy at times when capacity is not of concern is very reliable and secure."

Response:

Please refer to the response to BCSEA IR 2.52.6.

53.0 Topic: Delivery of Mid-Columbia Energy to FortisBC

Reference: Exhibit B-12, BCSEA 1.8.3

53.1 Please provide a detailed description of FBC's "strategy" of "purchasing capacity in the wholesale market," including a description of the timing of the "contracting for short-term supplies of firm power to be delivered to FortisBC during the peak demand months of December, January, and/or February."

Response:

It is FBC's practice to have firm resources to meet expected loads. FBC has relied upon the PPA capacity and energy combined with winter capacity blocks from Powerex along with owned and long term contracted generation to provide this firm resource. In addition, over the past couple of years FBC has contracted a winter block of market power to cover all hours of the winter. This has resulted in savings compared to relying upon PPA capacity and energy and also created a reserve, in that the displaced PPA capacity was still available if required. While FBC has normally completed these purchases in the fall, this year they were completed in the spring, in order to comply with the new PPA Annual Energy Nomination deadline. This included a purchase for the winter of 2013/2014 as well as a purchase for the winter of 2014/2015. Since the date of winter peaks cannot be forecast in advance, additional purchases are required on a shorter term basis in order to meet peak demand requirements. These may include purchasing blocks of power on the day ahead market when colder weather is forecast and making additional purchases on the hourly market in order to ensure sufficient resources.

Going forward, FBC will continue to evaluate the winter conditions annually, prior to nominating an Annual Energy Nomination under the new PPA, and will continue to make winter purchases depending on load forecasts, resource availability and market prices. Please also see Tab C Section 2.5 of the Application (Exhibit B-1, pages 101-103).

53.2 Specifically, does FortisBC typically contract for those supplies one month before delivery, in the preceding summer, or with some other lead time?

Response:

Please refer to the response to BCSEA IR 2.53.1.

53.3 Please provide the amount of short-term firm power that was contracted for delivery in each "peak demand" month from January 2010 through February 2013.

Response:

The following table shows the amount of short-term firm power that was contracted for delivery in each peak demand month from January 2010 through February 2013. FBC also considers that November is a peak demand month, since the winter peak can occur in November, and did occur in November as recently as 2010 with a peak of 707 MW.

Date	Total (MWh)
Jan-10	4,038
Feb-10	-
Nov-10	54,899
Dec-10	47,285
Jan-11	56,767
Feb-11	53,144
Nov-11	47,916
Dec-11	34,202
Jan-12	55,071
Feb-12	53,856
Nov-12	54,498
Dec-12	72,185
Jan-13	72,777
Feb-13	36,789

53.4 Does FortisBC consider the "strategy" of "purchasing capacity in the wholesale market" to be risky, since "it is risky to rely on the market to meet energy and capacity needs during periods of peak demand." (BCSEA 1.8.2)

Response:

As stated in the response to BCSEA IR 1.8.2 and referenced in the question, FBC agrees that it is risky to rely on the market to meet energy and capacity needs during periods of peak demand. However, for the winter of 2013/14 and 2014/15 the Powerex capacity blocks are very reliable and, as explained in the response to BCSEA IR 2.53.1, the supplemental blocks mainly displace PPA capacity and energy which remains available if needed, such that reliability of service to customers during periods of peak demand is not at risk. For the winter of 2015/16 and beyond, WAX CAPA capacity is expected to be available to meet peak demand.

As stated in the response to BCSEA IR 1.8.2, for periods outside of peak demand the market is considered very reliable and secure and FBC's main requirement from the market at this time (particularly after WAX CAPA is available) is energy, not capacity.

54.0 Topic: Delivery of Mid-Columbia Energy to FortisBC

Reference: Exhibit B-12, BCSEA 1.8.3; BCSEA 1.8.6.1

In BCSEA 1.8.3, FortisBC states: "...Given DSM is a broad measure to generally reduce load…, transmission congestion was not included in the assessment of FBC's avoided cost."

In BCSEA 1.8.6.1, FortisBC states: "transmission congestion does not change FBC's avoided cost assessment for DSM."

54.1 Is it FBC's position that DSM does not avoid any energy requirement in the hours in which transmission is congested?

Response:

No. DSM is primarily an energy resource. To the extent that DSM reduces FBC's overall energy requirements, it will also reduce FBC's energy requirements at times of US transmission constraints.

The FBC system has sufficient native generation and contracted capacity to meet peak loads. If it should occur that BC needs market energy at times of US transmission congestion, it is likely that market power will be available from Powerex through the BC Hydro system.

Therefore potential transmission congestion on the US system does not change FBC's avoided cost assessment for DSM.

54.1.1 If so, please explain why.

Response:

Please refer to the response to BCSEA IR 2.54.1.

54.1.2 If not, please explain why "transmission congestion does not change FBC's avoided cost assessment for DSM."

Response:

Please refer to the response to BCSEA IR 2.54.1.

54.2 Does FBC agree that increased transmission congestion would increase the avoided cost for DSM (regardless of whether FBC has chosen to ignore that additional cost)?

Response:

No. Please refer to the response to BCSEA IR 2.54.1.

54.2.1 If not, please explain why.

Response:

Please refer to the response to BCSEA IR 2.54.1.

55.0 Topic: Teck Metals Line 71 wheeling charges

Reference: Exhibit B-12, BCSEA 1.8.6

55.1 Please provide the "wheeling cost per MWh of energy delivered" to which "energy delivered to the FBC service area through Teck Metals Line 71 is subject."

Response:

The wheeling rate is $0.2 per MWh.

55.2 Please explain what agency reviews and determines the wheeling rate on Teck Metals Line 71.

Response:

The wheeling rate on Teck Metals Line 71 is a negotiated rate between the parties.

55.3 Please explain how the wheeling rate on Teck Metals Line 71 is determined.

Response:

Please refer to the response to BCSEA IR 2.55.2.

55.4 Please state the period of time into the future for which the wheeling rate on Teck Metals Line 71 has been determined, and when that rate is subject to review.

Response:

The wheeling rate on Line 71 has not changed, nor is any review of the rate planned to the best of FBC's knowledge.

56.0 Topic: Transmission capacity from Mid-C to Teck Metals Line 71

Reference: Exhibit B-12, BCSEA 1.8.7; BCSEA 1.8.3

"BCSEA 1.8.7 Please provide any data available to FortisBC regarding the firmness of BPA's capacity for delivery to the Teck Metals Line 71."

"**Response:**

The firm transmission from Mid-C to the BC/US border (which includes Teck Metals Line 71) is fully subscribed. However, BPA routinely makes additional transmission available on a non-firm basis. It is a fully accepted practice in the Pacific North-West to carry firm Generation on non-firm transmission and refer to the combined product as firm. <u>On an hourly basis</u>, it is expected that there will be a certain amount of this non-firm transmission available, but <u>no guarantee that there will be enough to fully meet the demand</u>. In addition, purchases can be arranged through the holders of the firm transmission if longer term deals are desired.

Therefore, <u>if transmission can be obtained, it is expected that BPA will deliver the power but there is no guarantee of this.</u>" [underline added]

56.1 If there is "no guarantee that there will be enough [non-firm transmission available] to fully meet the demand" [BCSEA 1.8.7], how can FBC depend on a strategy of "contracting for short-term supplies of firm power to be delivered to FortisBC during the peak demand months of December, January, and/or February" [BCSEA 1.8.3, quoted above]?

<u>Response:</u>

Please refer to the response to BCSEA IR 2.53.4.

56.2 Please provide any available comparison of the prices that FBC paid for its purchases from the US (delivered at Teck Metals Line 71) to the contemporaneous price at Mid-C.

<u>Response:</u>

FBC does not have a direct comparison of the price it paid for purchases from the US to the contemporaneous price at Mid-C, but it can provide a comparison of FBC's hourly market cost, including purchases from BC and the US, to the hourly Mid-C spot price. The following table shows the average hourly difference between the price FBC paid and the hourly Mid-C price, for the hours that FBC was purchasing market power.

Average Hourly Difference Between the Price FBC Paid and Hourly Mid-C Price

Month	2011	2012	2013	Total
1		$ 5.45	$ 2.69	**$ 4.09**
2		$ 6.69	$ 1.56	**$ 4.37**
3		$ 13.56	$ 3.79	**$ 8.76**
4		$ 0.81	$ 2.35	**$ 1.67**
5		$ 6.55	$ 0.72	**$ 2.78**
6		$ 8.61	$ 6.63	**$ 7.50**
7		$ 7.90	$ 8.84	**$ 8.39**
8		$ 7.55	$ 4.30	**$ 5.87**
9		$ 2.14	$ 3.67	**$ 2.91**
10	$ 6.54	$ 4.18	$ 3.82	**$ 4.66**
11	$ 5.38	$ 5.36		**$ 5.37**
12	$ 2.22	$ 5.85		**$ 4.00**
Total	**$ 4.51**	**$ 6.25**	**$ 3.82**	**$ 5.04**

As shown in the table above, between October 2011 and October 2013 FBC has paid an average of $5.04/MWh more than the hourly Mid-C price. FBC estimates approximately $4/MWh would be related to the transmission charges and other ancillary services. The remainder would be mainly due to the difference between actual spot prices and the fixed price agreed to at the time the transaction was entered into in advance.

56.3 Please provide a list of all US purchases for delivery at Teck Metals Line 71, with the following data for each: the date of the purchase, the delivery date, the MWh purchased, the price, and whether the purchase was for HLH or LLH energy.

<u>Response:</u>

FBC does not have this information easily accessible. The power market relies on hourly trading and FBC sometimes enters into multiple deals for any one hour and therefore can have between 0-40 deals per day. As such, FBC aggregates its deals for record keeping. In order to provide segregated data, it would require a detailed analysis of hourly records and phone calls. Please refer to the response to BCSEA IR 1.7.6 for a summary of the purchases made through Teck Metals Line 71.

57.0 Topic: Modified TRC

Reference: Exhibit B-7, BCUC 1.236.1

57.1 Please provide the LRMC that FortisBC applies in the Modified TRC.

<u>Response:</u>

Please refer to the response to BCUC IR 1.244.1.

57.2 Please identify the 10% of the portfolio to which FortisBC applies the Modified TRC.

<u>Response:</u>

Programs that do not pass the TRC test but do pass the mTRC test are included in the mTRC portfolio. If the mTRC portfolio exceeds 10 percent of the DSM budget, only programs with better TRC ratios are included in the mTRC portfolio to fit within the mTRC budget.

58.0 Topic: LRMC

Reference: Exhibit B-7, BCUC 238.1; Exhibit B-12, BCSEA 1.11.2

BCUC "1.238.1 ... In this filing FBC has used an LRMC which is inclusive of capacity costs, and added a Deferred Capital Expenditure factor, based on plan kW savings, to represent incremental Transmission & Distribution capital costs."

58.1 Please demonstrate that "FBC has used an LRMC which is inclusive of capacity costs" by specifying the generation capacity costs included in the LRMC for each year.

Response:

Spot market power is only sold on a dollars per MWh basis and the value of the capacity is not broken out from the value of the energy. Therefore, the LRMC used by FBC includes the value of the capacity as part of the dollar per MWh price.

58.2 If "The LRMC is a levelization of the 30 year Midgard BC Energy Market Price Curve" (BCSEA 1.11.2), how does the LRMC include capacity?

Response:

Please refer to the response to BCSEA IR 2.58.1.

59.0 Topic: Deferred Capital Expenditure

Reference: Exhibit B-7, BCUC 238.1, BCUC Attachment 248.02 p. 34

59.1 Please provide the derivation of the Deferred Capital Expenditure value.

<u>Response:</u>

The $35/kW-year figure is used by FBC as a proxy to represent the value of avoided transmission and distribution capital expenditures due to energy conservation. The Deferred Capital Expenditure value of $34.81 is the net present value in 2013 of the avoided system costs identified below, using the assumptions stated.

Assumptions (as per 2012 Integrated System Plan load forecast and long-term capital plan)

Peak Load Growth	279 MW
Lifetime	30 Years
Inflation	2.00%
Borrowing Rate	6.00%

T&D SYSTEM COSTS

	2013	2014	2015	2016	2017	2018	2019	TOTAL
Transmission Growth	$ 11,832	$ 8,847	$ 17,287	$ 27,537	$ 15,265	$ 51,293	$ 63,474	$ 195,535
Distribution Growth	$ 13,646	$ 13,759	$ 16,300	$ 14,320	$ 19,172	$ 13,744	$ 15,770	$ 106,711
(Subtract) New Connects	$ (11,057)	$ (10,780)	$ (11,446)	$ (11,536)	$ (12,076)	$ (11,298)	$ (11,226)	$ (79,419)
Total Growth	$ 14,421	$ 11,826	$ 22,141	$ 30,321	$ 22,361	$ 53,739	$ 68,018	**$ 222,827**

59.2 Please provide a list of the projects or categories of capital projects that were included in the computation.

<u>Response:</u>

For the purposes of this calculation the Transmission Growth and Distribution Growth categories (excluding new connects) were included.

59.3 Please provide a list of the projects or categories of T&D capital projects that were excluded from the computation, and for each, explain why it was not considered deferrable.

<u>Response:</u>

All Transmission Sustainment, Distribution Sustainment and Distribution New Connects projects were excluded from the calculation. Sustainment category projects are considered necessary to maintain adequate levels of safety and reliability for the existing T&D system. The Distribution New Connects program was excluded on the basis that these costs are still necessary to physically connect new customers (regardless of whether the load growth resulting from their addition is offset by energy efficiency initiatives).

59.4 Please specify the period of years over which capital expenditures were compared to load growth to determine a value for deferrable capital expenditures.

Response:

The calculation was carried out over a period of 30 years.

60.0 Topic: Avoided cost

Reference: Exhibit B-12, BCSEA 1.10.3.1

"BCSEA 10.3.1 Please explain why Midgard considers it important to confirm that the "forecast is not meant to represent the cost of importing power."

Response: The factors that impact the supply, demand and price of electricity within the Mid-Columbia electricity trading hub are similar, but not necessarily identical, to the factors that that impact supply, demand and price of electricity within the British Columbian context. Consequently, the Mid-C price index is a proxy for the average price of electricity within the British Columbian context, not the cost of importing power because power imports would not occur on an average basis."

This explanation is difficult to understand.

"BCSEA 10.3.3.1 Is there some guideline or rule that requires determination of DSM avoided cost using "the average price of electricity within the British Colombian context"? If so, please provide it.

Response: No. The underlying principle FortisBC uses in determining <u>its DSM avoided cost</u> is that the cost <u>should reflect FBC's LRMC of incremental supply</u>. Based on FBC's specific circumstances and needs, FBC's avoided cost of power over the long term is the cost of market purchases. ..."

60.1 Is FBC making a distinction between <u>prices</u> (set at Mid-C or with reference to Mid-C prices) and <u>physical acquisition</u> of market power (that may or may not be physically through Mid-C)?

<u>Response:</u>

No. In the first response FBC is making the distinction between a forecast of average annual BC market prices and hourly spot prices. To meet its forecasted energy resource gap, FBC will not be acquiring a fixed amount of energy every hour of the year. So the annual average Mid-C price, factoring in costs of delivery to BC, is a proxy for BC's market price. A more sophisticated analysis would identify specifically when the energy resource gaps would be expected, and apply Time of Delivery shaping factors to the annual average price, to arrive at a forecast of FBC's annual average market cost. In order to be comparable, a similar sophisticated analysis would be needed on DSM avoided cost savings. FBC has not done that.

The second response just emphasizes the point that FBC's LRMC is the avoided cost of market purchases.

60.1.1 Is FBC saying that "the cost of importing power" is not the same as 'the cost of purchasing market power,' e.g., because some FBC purchases are not physical imports?

Response:

No. Please refer to the response to BCSEA IR 2.60.1.

60.2 By "power imports would not occur on an average basis" is FBC referring to power imports by FBC? If not, please explain.

Response:

Yes. Please refer to the response to BCSEA IR 2.60.1.

60.3 FBC says that the fact that "power imports [by FBC] would not occur on an <u>average</u> basis" explains why "the Mid-C price index is [not] a proxy for ... the cost of importing power." If that explanation holds, then doesn't the fact that "power imports [by FBC] would not occur on an <u>average</u> basis" mean that "the Mid-C price index is" <u>not</u> "a proxy for the <u>average</u> price of electricity within the British Columbian context"?

Response:

No. The forecast of the annual Mid-C price, delivered to BC, is an appropriate proxy for the annual average price of market energy in BC. However, depending on the time of procurement and volumes procured, it may not be a good representation of the annual average cost of energy for FBC.

60.4 In BCSEA 1.10.3.3.1, FBC says that its DSM avoided cost is its avoided cost of power over the long term which is the “cost of market purchases.” If the “cost of market purchases” is the basis for the DSM avoided cost, why does Midgard not produce an estimate of FBC’s cost of market purchases?

Response:

Please refer to the response to BCSEA IR 2.60.1.

61.0 Topic: LRMC

Reference: Exhibit B-12, BCSEA 1.11.1; Exhibit B-7, BCUC 1.236.1

"BCSEA 1.11.1 Does FortisBC use the term Long Run Marginal Cost (LRMC) as being synonymous with "avoided cost" for the purpose of determining the "total resource cost" (TRC) ratio of DSM programs and portfolio (setting aside the modified TRC in the DSM Regulation)?

Response: Please refer to the response to BCUC IR 1.236.1."

The response to BCUC IR 1.236.1 does not address whether FBC uses LRMC as synonymous with "avoided cost."

61.1 Does FBC use LRMC as synonymous with "avoided cost"?

Response:

Yes, typically they are used interchangeably. Strictly put, the LRMC only refers to the avoided cost of power purchases. The complete "avoided cost" primarily consists of the LRMC benefits but also includes adders, specifically the $35.60/kW-yr DCE (Deferred Capital Expenditure).

62.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.20.2.2

"The current DSM tracking system does not accurately track *participant numbers* (please refer to the response to BCSEA IR 1.25.2.2), and it is [sic] *not a metric in the DSM Plan*."

62.1 Does FBC agree that the number of participants is a primary determinant of total program electricity savings, i.e., total program savings over any period is the product of the number of participants and per-participant electricity savings?

Response:

FBC disagrees, since the primary determinants for total electric savings are the number of installed measures and the unit savings per measure, which can either be per qualifying product (e.g. EnergyStar refrigerator, Compact Fluorescent, Heat Pump etc.) or per unit area (e.g. insulation, times the number of units incented).

A participating customer will typically install only one Heat Pump or one refrigerator in which case the number of participants are easily known, but other measures may be in multiples e.g. a dozen CFLs, or 1200 ft^2 of insulation – in which case the number of participants is not easily tracked.

62.2 Please explain what FortisBC means when it states that "participant numbers" are "not a metric in the DSM Plan."

Response:

Please refer to the response to BCSEA IR 2.62.1. The key DSM Plan metrics are the kWh targets and budget line items (incentive and administration). To reiterate, the program kWh targets are the number of installed measures and the unit savings per measure.

Participant numbers can be difficult to determine. An example is the current EnergyStar lighting product campaign at retail stores. Customers receive "instant" rebates through discounted product pricing. The energy savings are data-based by processing the invoices from the participating retailers, which report the number of qualifying EnergyStar lighting products but not the number of individual customer transactions.

62.2.1 Is FBC suggesting that it need not track numbers that are not reported directly in its DSM plan?

Response:

No. The DSM database contains a wealth of information on the various projects that have been data-based, but not all the data points kept are noteworthy or complete enough to warrant reporting.

63.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.20.3

63.1 While FBC says it did not reallocate resources to areas of relatively greater cost-effectiveness, did it investigate or analyze the potential impact on total portfolio savings and cost-effectiveness of doing so?

Response:

No, since it was considered important to maintain a range of programs across the customer classes.

63.2 If so, please provide the results of any such analysis, including functioning MS Excel files containing all inputs, assumptions, equations, and documentation thereof.

Response:

Please refer to the response to BCSEA IR 2.63.1.

63.3 If not:

63.3.1 Does FBC agree that an alternative DSM plan with higher spending and savings than FBC proposes could be cost-effective, i.e., produce higher net benefits under either the TRC, MTRC, or the Utility Cost test? If not, why not?

Response:

FBC agrees that it is a possibility, but such an alternative plan could also increase the rate impact and could restrict the range of programs across the customer classes.

63.3.2 If FBC did not analyze the potential impact on total portfolio savings and cost-effectiveness of reallocating resources to areas of relatively greater cost-effectiveness, does FBC concede that it has not demonstrated that its proposed 2014-2018 DSM plan would capture all cost-effective electricity savings? If not, why not?

<u>Response:</u>

FBC disagrees.

FBC has programs for most of the measures identified as cost-effective in the CPR, with the exception of end-uses (e.g. consumer electronics that are better addressed through other means, such as codes & standards). This is different from capturing *all* of the cost-effective energy savings potential over the PBR period (which is an unattainable goal, regardless of the level of DSM funding).

The DSM Plan addresses major end-uses in all customer sectors, with program take-up subject to market response.

64.0 Topic: DSM

Reference: Exhibit B-12, Attachments 20.1 and 20.1.1 MS Excel spreadsheets that are part of FBC's response to BCSEA IR 1.20.0.

Attachment 20.1 appears to represent the cost-effectiveness analysis representing the FBC proposed DSM, with reduced spending and savings compared to the previous year. Attachment 20.1.1 appears to represent the "Original" DSM spending and savings (similar to the previous year's spending and savings) but using the new and lower avoided costs.

64.1 Please confirm the above statement with regard to what Attachments 20.1 and 20.1.1 represent. If not true, please clarify.

Response:

FBC confirms that the word "Original" would have been better phrased as "Prior" DSM spending and savings level, wherein "Prior" specifically refers to the 2012-13 DSM Plan.

64.2 Attachment 20.1 (proposed DSM) excludes (via a flag in column AD of the "TRC" tab) several TRC cost-effective measures from inclusion in the DSM portfolio that are included in Attachment 20.1.1 (original DSM). For example, refrigerators and freezers were included in Attachment 20.1.1, but excluded from Attachment 20.1.

64.2.1 Please explain for each excluded measure why it was excluded from Attachment 20.1, but included in Attachment 20.1.1.

Response:

As per the response to BCSEA IR 1.21.1, FBC considered the cost effectiveness of "continuing at the approximate level of expenditures previously approved". This scenario, referred to as the $7 million scenario, was included as Attachment 21.1.1 provided in the response to BCSEA IR 1.21.1.1.

Attachment 20.1.1, provided in response to BCSEA IR 1.20.1.1 represents a hypothetical scenario that included measures that would not be viable in a filed DSM plan. These measures were excluded from Attachment 20.1 (the DSM plan as filed) because their inclusion leads to the total mTRC expenditure exceeding the 10 percent cap on the mTRC portfolio. These measures are included in Attachment 20.1.1 to simulate the 2012/2013 level of DSM expenditures. However, as noted in the response to BCSEA IR 1.21.1, this level of expenditure is not considered viable and exceeds 10 percent cap on the mTRC portfolio.

64.2.2 Does FBC agree that if only TRC non-cost-effective measures were excluded from Attachment 20.1, that each of the customer classes would be cost-effective and the portfolio would be considerably more cost-effective, while producing significantly more savings than in Attachment 20.1 and the proposed DSM savings?

Response:

FBC understands BCSEA IR 2.64.2.2 to ask if the customer and portfolio would be more cost effective if all TRC cost effective measures were pursued in Attachment 20.1 – FBC's proposed DSM expenditure level. While cost effectiveness is the governing test, FBC also uses other criteria to determine whether or not to run a DSM program. Please refer to the response to BCUC IR 1.248.8.1 for a discussion of circumstances where FBC has opted not to offer a DSM program.

If all cost-effective measures are included (including all programs that pass the TRC, not mTRC, test) only the industrial customer class becomes more cost effective overall, which leads to a 5 percent improvement in the overall portfolio TRC (including 7.4 percent of programs that qualify under the mTRC) and a modest 12 percent increase in DSM target savings. Thus, adding measures to the DSM plan does not have a significant effect on the customer sector or portfolio level TRC cost effectiveness.

64.2.2.1 If affirmative, please explain why this approach was not taken for the proposed DSM?

Response:

Please refer to the response to BCSEA IR 2.64.2.2.

64.2.2.2 If not, why not?

Response:

Please refer to the response to BCUC IR 2.64.2.2.

64.3 Some of the per unit measure kWh savings are different in Attachment 20.1 than Attachment 20.1.1 in the "TRC" tab Column "E." For each measure with different savings assumptions, please explain the reason for the difference.

Response:

Only three residential programs were identified to have different kWh savings: Solar Thermal, Direct Install – Lighting and Behavioural. These three programs were not included in the DSM budget as filed in Attachment 20.1. Thus, the kWh savings estimates were not required. When these programs were added to the DSM budget in Attachment 20.1.1, the kWh savings estimates were inserted.

64.4 Cells C23 and C24 on the "Inputs" tab of the above referenced spreadsheets appear to contain the avoided cost values used for calculating the DSM TRC and MTRC benefits, respectively. Please confirm.

Response:

Confirmed.

64.4.1 At what point in the system are these avoided costs expressed? (e.g., customer meter, generation, or somewhere in between).

Response:

The LRMC, and applicable adders such as DCE or NEB, are applied to the energy savings at generation or the equivalent point of delivery i.e. transmission interconnection in the case of power purchases.

64.4.1.1 If not at generation, please indicate what percentage of line losses are included (please indicate if percent of generation or percent of customer meter).

Response:

FBC used the current estimate of line losses: 8.8 percent, which is applied to the energy savings achieved at the customer meter.

64.4.1.2 If at generation what line loss percentage would be needed to express at the customer meter? (please indicate if percent of generation or percent of customer meter)

Response:

Please refer to the response to BCSEA IR 2.64.4.1.1.

64.5 Column “E” of the “TRC” tab of the above referenced spreadsheets appear to contain the per unit measure kWh savings used for generating the DSM benefits. Please confirm.

Response:

Confirmed.

64.5.1 At what point in the system are these kWh savings expressed? (e.g., customer meter, generation, or somewhere in between).

Response:

These kWh savings are expressed at generation. As per the response to BCSEA IR 2.64.4.1.1, FBC estimates line losses at 8.8 percent of gross load.

64.5.1.1 If not at the customer meter level, please indicate what percentage of line losses are included (please indicate if percent of generation or percent of customer meter).

Response:

Please refer to the response to BCSEA IR 2.64.5.1.

64.5.1.2 If not at generation what line loss percentage would be needed to express at the generation level? (please indicate if percent of generation or percent of customer meter)

Response:

Please refer to the response to BCSEA IR 2.64.5.1.

64.5.1.3 If not at the same level as the avoided costs in cells C23 and C24 on the "Inputs" tab, please indicate what system losses would need to be added or subtracted to express at the same level as the avoided costs (please indicate if percent of generation or percent of customer meter).

Response:

Both the DSM savings and avoided costs are expressed at generation.

64.6 Is the discount rate in cell C37 of the "Inputs" tab of the above referenced spreadsheets a real or nominal discount rate?

Response:

The rate in cell C37 represents a real discount rate.

64.6.1 If the discount rate in cell C37 is a nominal discount rate, does FBC consider it appropriate to use a nominal discount rate for calculating the present value of savings (benefits) based on a single value avoided cost?

Response:

Please refer to the response to BCSEA IR 2.64.6.

64.6.1.1 If affirmative, please explain rationale.

Response:

Please refer to the response to BCSEA IR 2.64.1.

64.6.1.2 If negative, does FBC agree that calculations of benefits in the above referenced spreadsheets should be using a real discount rate? If not, why not?

Response:

FBC disagrees. Please refer to the response to BCSEA IR 2.64.6.1.

65.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.21.1

Based on its analysis of continuing portfolio spending and savings levels at previously-approved levels, FBC states:

"This expenditure level is not considered viable by FortisBC, in part because the residential program fails the cost-effectiveness test and in part because of the 2.2 per cent rate impact it creates."

65.1 Confirm that FBC did not investigate residential program alternatives that would have increased penetration of measures found to be cost-effective by increasing financial incentives and/or other approaches to raise participation.

Response:

Confirmed.

65.2 What level of residential program cost-effectiveness does FBC believe would render the portfolio "viable", separate and apart from the cumulative rate impact?

Response:

FBC defers to the cost-effective test to establish the viability of the DSM portfolio. In other words, residential programs must have a TRC or mTRC value greater than 1.

65.2.1 Please provide the basis for this criterion, including any analysis or studies that substantiate it.

Response:

Please refer to Section 4 of the DSM regulation for the cost-effectiveness criteria.

65.3 What level of cumulative rate impact over the period does FBC consider "viable," separate and apart from residential program cost-effectiveness?

Response:

FBC has not established such a threshold, but carefully considers the rate impact of any initiative.

65.3.1 Please provide the basis for this criterion, including any analysis or studies that substantiate it.

Response:

Please refer to the response to BCSEA IR 2.65.3.

65.4 If FBC believes that the two factors (cost-effectiveness and rate impact) are not separable, then provide a table that indicates what level of cumulative rate impact FBC considers "viable" for a any given level of residential program and portfolio cost-effectiveness.

Response:

Please refer to the response to BCSEA IR 2.65.3. Ultimately, the Commission must decide what level of cumulative rate impact is "viable" within the context of the entire Application.

65.4.1 For example, what level of program cost-effectiveness would be required in order for a 2.2% cumulative rate impact to be considered "viable"?

Response:

FBC has not established such a criterion. Please refer to the responses to BCSEA IRs 2.65.3 and 2.65.4.

65.4.2 Please provide the basis for this criterion, including any analysis or studies that substantiate it.

Response:

Please refer to the responses to BCSEA IRs 2.65.3 and 2.64.4.

65.5 How does FBC reconcile its rejection of a residential program even though the portfolio TRC was 1.0 with section 4(4) of the DSM Regulation which states:

"4(4) The commission must determine the cost-effectiveness of a specified demand-side measure proposed in a plan portfolio or an expenditure portfolio by determining whether the portfolio is cost effective as a whole."

Response:

FBC has not rejected any "specified demand-side measure" in the residential sector, but claims the residential program "area" or sector fails the cost-effectiveness test on the whole.

65.6 How does FBC reconcile its reliance on a 2.2% rate increase as the rationale for rejecting an otherwise cost-effective DSM portfolio with section 4(6) of the DSM Regulation which states:

"4(6) The commission may not determine that a proposed demand-side measure is not cost effective on the basis of the result obtained by using a ratepayer impact measure test to assess the demand-side measure."

Response:

FBC did not rely on the RIM test to discontinue individual measures as per section 4(6); but instead used the governing TRC cost-effectiveness test as the primary determinant of whether a measure or program would be included. Secondary determinants may have included status of market transformation, free-rider rate, persistence, etc.

The 2.2 percent rate impact benefit is a byproduct of the condensed DSM Plan.

66.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.21.3

"BCSEA 1.21.3 Did FortisBC analyze the differential impact on <u>total</u> customer bills of continuing with previously-approved expenditure levels as compared with the reduced expenditures proposed now?" [underline added]

"Response: Please refer to the response to BCSEA IR 1.21.2. <u>Non-participant</u> bills would be expected to be 2.2% higher over the PBR term if the previously-approved DSM expenditure levels were maintained." [underline added]

66.1 Please respond to the original IR BCSEA 1.21.3, which asked about "total customer bills" (i.e., revenue requirement), not about non-participants as a subset of total customers.

<u>Response:</u>

Please refer to the response to BCSEA IR 2.66.5.

66.2 Is it a 2.2% cumulative rate impact on <u>non-participants</u> that FBC says renders the level of expenditures under the previously-approved plan not viable, as opposed to the differential rate impact on <u>all</u> customers combined, including participants?

<u>Response:</u>

The reduction in the LRMC was the principal driver of the proposed DSM plan, and the 2.2 percent rate impact benefit was a byproduct of the reduced DSM expenditure schedule (as compared to the previously approved expenditure levels). Note the 2.2 percent rate impact applies to all customers, however FBC wanted to emphasize the benefit to non-participants.

66.3 Would FBC consider the DSM plan to be viable if (a) it passed the TRC cost-effectiveness test and (b) the rate impact on all customers combined, i.e., including participants, was zero, even if average rates to non-participants would increase by 2.2% cumulatively over the period?

Response:

The primary tests for DSM plan viability are cost-effectiveness and adequacy, as defined by the DSM regulation. Rate impacts to customers, although important, are a secondary consideration.

66.4 If the answer to 66.2 is affirmative and the answer to 66.3 is negative, does FBC concede that in effect it is using the non-participant test for DSM cost-effectiveness to restrict DSM resource acquisition that could be cost-effective under the TRC or Utility Cost tests?

Response:

No. FBC believes the proposed DSM plan, as-filed, is cost-effective and adequate per the DSM regulation. Furthermore, as indicated in the response to BCSEA IR 2.63.3.2, the plan includes all DSM measures identified as cost-effective (with some small and prudent exceptions).

66.4.1 If so, please explain how FBC's 2014-2018 DSM Plan does not violate the DSM Regulation, s.4(6), barring the use of the ratepayer impact measure to restrict DSM investment.

Response:

FBC believes that the DSM plan as proposed is fully compliant with the DSM Regulation. Please also refer to the responses to BCSEA IRs 2.66.2 and 2.66.4.

66.4.2 If not, please explain why not.

Response:

Please refer to the response to BCSEA IR 2.66.4.1.

66.5 Please provide a table showing average rates and average bills for all customers for both a continuation of the 2013 DSM spending levels and the 2014-2018 DSM Plan annually over 20 years (i.e., including 15 years following the 5-year performance period.)

Response:

The Tables below provide average rates (Cents/KWh) and average bills ($/Customer) per year for all customers for both a continuation of the 2013 DSM spending levels (DSM Original Level) and the 2014-2018 DSM Plan (per the July 5, 2013 Application).

Forecast data beyond 2018 is not available at this time.

Customer Average Rates (DSM at Original Level)		2014	2015	2016	2017	2018
Residential	Cents / KWh	12.21	12.69	13.18	13.67	14.19
General Service	Cents / KWh	8.90	9.24	9.58	9.94	10.30
Wholesale	Cents / KWh	7.47	7.76	8.06	8.36	8.68
Industrial	Cents / KWh	7.97	8.25	8.53	8.83	9.16
Lighting & Irrigation	Cents / KWh	10.75	11.09	11.43	11.77	12.19

Average Yearly Bill / Customer (DSM at Original Level)		2014	2015	2016	2017	2018
Residential	$/Customer	1,510	1,555	1,599	1,648	1,696
General Service	$/Customer	5,250	5,394	5,534	5,670	5,844
Wholesale	$/Customer	7,213,921	7,494,114	7,778,447	8,073,028	8,381,979
Industrial	$/Customer	645,801	667,817	688,679	709,542	732,975
Lighting & Irrigation	$/Customer	2,023	2,043	2,060	2,076	2,115

Customer Average Rates (DSM at RRA 5th July Filing Level)		2014	2015	2016	2017	2018
Residential	Cents / KWh	12.19	12.61	13.04	13.48	13.94
General Service	Cents / KWh	8.89	9.19	9.50	9.82	10.15
Wholesale	Cents / KWh	7.46	7.71	7.97	8.24	8.52
Industrial	Cents / KWh	7.95	8.18	8.43	8.70	8.99
Lighting & Irrigation	Cents / KWh	10.77	11.14	11.53	11.93	12.34

Average Yearly Bill / Customer (DSM at RRA 5th July Filing Level)		2014	2015	2016	2017	2018
Residential	$/Customer	1,511	1,553	1,597	1,646	1,694
General Service	$/Customer	5,266	5,422	5,580	5,735	5,926
Wholesale	$/Customer	7,223,910	7,506,849	7,801,769	8,108,611	8,429,096
Industrial	$/Customer	644,729	664,634	684,285	704,087	726,337
Lighting & Irrigation	$/Customer	2,048	2,112	2,177	2,245	2,315

66.6 Please indicate the portion of the 2.2% cumulative rate impact that is attributable to the recovery of the DSM expenditures, as distinct from the portion due to the reduction in sales volume leading to higher fixed costs per unit sold. The response to this request should include all supporting analysis, including inputs, assumptions, equations, and documentation, in a functioning MS Excel file.

Response:

The Revenue Variance components that are attributable to the recovery of the DSM expenditures and the differential power purchase cost due to load variance are shown separately in the Table below. Please also refer to Attachment 66.6 for the functioning spreadsheet.

Sales & Revenue Parameters	Forecast				
	2014	**2015**	**2016**	**2017**	**2018**
Sales Volume (GWh) Variance	8	24	39	54	69
Rate Base Variance	(1,482)	(4,343)	(7,006)	(9,565)	(12,031)
Revenue Deficiency Variance:					
Power Purchases Cost Increase:	**448**	**925**	**1,772**	**2,694**	**3,513**
Financing & Income Tax Variance					
Income Taxes Variance	(18)	(119)	(217)	(317)	(417)
Cost of Debt Reduction	(23)	(91)	(177)	(258)	(346)
Cost of Equity Reduction	(54)	(159)	(256)	(350)	(440)
Amortization Reduction	-	(198)	(395)	(600)	(810)
	(95)	**(568)**	**(1,045)**	**(1,525)**	**(2,013)**
Total Revenue Requirement Variance	**352**	**358**	**726**	**1,169**	**1,500**
Rate Impact Variance	**-0.20%**	**-0.50%**	**-0.40%**	**-0.40%**	**-0.40%**
Cumulative Rate Impact Variance			**-2.2%**		

Note: All cost data in "$000s".

67.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.22.1.1

"BCSEA 1.22.1.1 Please trace how specific 2012 program results were used to project outcomes from the 2014-2018 DSM Plan, such as program cost per kWh saved, and/or savings per participant.

Response: Please refer to the response to BCSEA IR 1.22.1. Past program results and trends were used to inform the 2013 CPR Update scenarios and make decisions on level of incentives paid and participation rates in the DSM Planning process."

The referenced response to BCSEA IR 1.22.1 states:

"Please refer to the response to BCSEA IR 1.28.4.4.

The 2012 actual results are provided in certain tables, e.g. Appendix H Table H-4, for information and comparative purposes, but are not directly linked to the 2014-18 DSM Plan."

67.1 Please explain and document which "past program results and trends were used to inform the 2013 CPR Update scenarios and to make decisions on level of incentives paid and participation rates" and specifically how these are reflected in the proposed DSM Plan.

<u>Response:</u>

The past program results are used to adjust the baseline for assessing the potential in the 2013 CPR and developing the DSM plan moving forward. Significant research was conducted through sector surveys for the 2010 CDPR, the program achievements since 2010 are used to update the baseline for the 2013 CPR by subtracting the number of units achieved. The participation rates of programs are used to establish initial program area ramp rates. Program areas with low past participation but significant potential, could be considered for higher incentives, while programs areas with high past participation and lower future potential could be considered for reduced incentives.

68.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.25.2.2

In response to the request for information on the number of participating customers, by year, projected in the programs contained in its DSM Plan, FBC states:

"FBC does not have this analysis. The DSM Plan estimates the number of unit measures (for instance, the number of CFL or LED light bulbs or the square feet of insulation incented), which is different from the number of participating customers.

There are two primary issues that make accurate customer participation statistics problematic. First, the LiveSmartBC program does not currently provide sufficient information for FortisBC to be able to automatically link incentive payments to specific customers in our CIS system. Second, some incentive programs (for example, speciality light bulbs) pay incentives to retailers or wholesalers in bulk and FortisBC cannot identify the end user..."

68.1 Given that FBC cannot count the number of participants in its programs, please explain how FBC is able to identify or count the number of non-participants.

Response:

FBC does not count the number of non-participants *per se*. If a survey of non-participants is undertaken, as was the case with the LiveSmart BC evaluation study, a mail-out is done to a sample of qualifying customers. At the beginning of the survey form respondents are asked to identify whether or not they were participants in the LiveSmart program. Only the non-participant survey returns were used to determine the characteristics of said group.

68.2 If FBC cannot determine the numbers of customers considered non-participant, then please explain why rate impacts to such a nebulous category of customers is a reasonable basis for restricting acquisition of DSM resources that would be cost-effective under the TRC?

Response:

Although FBC's tracking system cannot accurately count the number of participants, in 2011 FBC undertook an exercise that estimated the DSM count to be roughly 14 thousand participants. Considering the total customer count of approximately 162 thousand, there are approximately 148 thousand non-participants.

FBC believes that the equity principle requires this large sub-set of customers be considered in determining the appropriate level of DSM expenditures.

69.0 Topic: DSM Evaluation Reports

Reference: Exhibit B-12, BCSEA 1.29.1; 1.30.1; Exhibit B-1-1, Appendix H DSM, Attachment H-2, Semi-Annual DSM Report Year Ended December 31, 2012, Sub-Appendix C

BCSEA asked FBC to provide the full evaluation reports for industrial programs, and commercial lighting programs. FBC responds:

"Past practice, in alignment with a BCUC directive to BC Hydro, is to file executive summaries of M&E reports only, except if a program has ended. Additionally FBC wishes to safeguard the confidentially of the participants as the full report includes detailed site visit reports of named customers who expect their industrial processes and program experiences to remain confidential."

69.1 Please provide the full evaluation reports for industrial programs and for commercial lighting programs to the Commission on a confidential basis.

Response:

FBC points out that the key findings and recommendations of said evaluation reports, including the Net-to-Gross ratio calculations, can be found in the Executive Summaries that are already in the public domain. By releasing executive summaries rather than full reports, FBC is acting in a manner consistent with the precedent established by the Commission's with respect to BC Hydro evaluations.

As per good evaluation practice, FBC maintains the confidentiality of participant information and other program related feedback provided to the consultants during the process of the evaluation. Submitting the full evaluation reports would, in our opinion, undermine the basis for these important relationships.

Furthermore FBC notes there were no IRs submitted concerning the content of the executive summaries already filed. At this point, there is insufficient justification or rationale for the release of full evaluation reports.

69.2 Please indicate if FortisBC has any objection to BCSEA-SCBC personnel who have signed confidentiality undertakings from having access to these particular confidential filings. If FBC object, please state why.

Response:

Please refer to the response to BCSEA IR 2.69.1.

70.0 Topic: DSM

Reference: Exhibit B-12, BCSEA 1.31.1

When asked “what percentage of customers to whom FBC made incentive offers went on to complete retrofit projects?”, FBC answered:

“This metric is not tracked by FBC. FortisBC does not generally “offer” incentives to individual customers, but instead responds directly to customer questions regarding incentives and programs or simply processes rebates for purchases that have already been made.”

70.1 Confirm that neither FBC’s general service programs aimed at commercial and industrial customers nor its residential retrofit programs attempt to diagnose and recommend comprehensive efficiency retrofit investment opportunities to individual customers using customized financial incentives for the package of measures.

Response:

Not confirmed. FBC strongly disagrees with this statement.

For both the Commercial (formerly General Service) and Industrial customers, FBC Technical Advisors provide a no-cost walk-through energy assessment that identifies both behavioural (O&M) actions and DSM investment opportunities to save energy. FBC also offers to pay 50 percent of the cost of a consultant’s comprehensive audit of the customers’ facilities and/or processes. Larger commercial, institutional and industrial customers are encouraged to sign a PiE (Partners-in-Efficiency) agreement, which provides for periodic reviews of the customers’ capital plans in order to identify DSM opportunities. Finally FBC has a long-established policy of bundling a customer’s project (both fast and long payback retrofit measures) to encourage the customer to maximize their DSM project.

For residential customers FBC has long promoted EnerGuide energy assessments that provide a whole-home energy assessment of the building envelope and major systems (furnace & hot water). Customers are actively referred to the LiveSmartBC program – which requires a pre/post EnerGuide audit energy assessment to access multi-layer matching government incentives (while they were in market); and more recently through the community Energy Diets.

Having identified the EnerGuide homeowner fee ($150 normally paid by the customer) as a major market barrier, FBC RFP’d the Service Organizations and sought co-funding from participating local governments, in order to bring the customers’ portion of the audit assessment cost down to as low as $35. This was coupled with the direct install of measures (CFLs and low-flow showerheads). Recent NRCan stats show that over half of BC’s EnerGuide audits energy assessments are occurring in the FBC service area.

FBC staff are is also consulting with NRCan on the revised EnerGuide labeling scale to be released in 2014, and on the home energy report redesign to improve its understandability to better prompt action by the homeowners.

70.2 Please reconcile the response to the preceding question with the LiveSmart program's design and implementation, in which customers obtain energy audits, and a fraction of these customers end up following audit recommendations and implementing measures.

Response:

LiveSmart BC has shown a high degree of completion – up to 85 percent - of customers making improvements to their homes after having an EnerGuide energy assessment, with the rate of completion varying upon the incentive levels offered. However, the majority of home owners only install a single measure. Efforts to encourage multiple measures, including awarding Silver and Gold incentives premiums, have met with limited success.

FBC efforts to improve the readability and "action"-ability of the EnerGuide report is in the hope that it will encourage customers to follow the energy efficiency continuum (from small DIY measures such as draft-proofing, to must-do insulation upgrades, to major measures such as furnaces or heat pumps). FBC has also implemented a number of pilot projects testing ways to improve program uptake, including:

- FBC financing: On-bill financing and Credit Union financing (promoted through community Energy Diets); both encourage customers to install multiple measures. The financing rules also require customers to install measures in order, i.e. insulation & draft-proofing must be done first, before more costly (but popular) measures such as furnace replacement or heat pump installation. Last and least, customers are allowed to use the financing for window replacements;
- Special bonus offer rebates to encourage customers to make more than one-measure improvements are made; and
- Energy Diet marketing campaigns which "blitz" communities and provide lower-cost energy assessments.

Recently FBC was involved in a two-day workshop in Vancouver, co-sponsored by FEU and BC Hydro, that brought together stakeholders, including service organizations (who perform the EnerGuide audits), contractors and renovators and utility EEC/DSM staff, to brain-storm solutions that would continue and improve the LiveSmartBC home retrofit program going forward.

71.0 Topic: DSM

Reference: Exhibit B-7, BCUC IR 1.229.3

BCUC "1.229.3 Does FBC consider that customers benefit overall where DSM programs result in lower overall bills, even if rates increase? Please explain.

Response: It is not possible for rates to increase and for non-participants to have lower bills (all else being equal), and therefore customers cannot benefit overall."

71.1 Please explain how and why it logically follows that "customers cannot benefit overall" if rates and bills increase for non-participants.

<u>Response:</u>

FBC's statement that "customers cannot benefit overall" indicates not all customers will have a lower bill as a result of DSM programs (all else being equal). FBC does not believe that non-participant customers would consider their higher bills an "overall benefit" from increased DSM spending.

71.1.1 Specifically, if DSM expenditures have the effect of lowering the total cost of service and thus lowering the sum of bills across all customers combined, how can it be true that customers as a group – participants and non-participants together – do not benefit overall?

<u>Response:</u>

Please refer to the response to BCSEA IR 2.71.1.

71.2 Suppose FBC implemented a portfolio of programs over the next 20 years that successfully got the vast majority of customers to participate in DSM programs so that those customers who end up not participating constitute a small minority of all customers. Suppose further that the result is that rates are 10% higher but average bills (for all customers, participating and non-participating) are 20% lower than they would have been with less DSM and more supply. Explain how this outcome would not "benefit customers overall."

Response:

In this highly improbable scenario, FBC agrees that customers would benefit overall.

The scenario is highly improbable for two reasons. First, a DSM program that results in participation of the approximately 148,000 non-participants (please refer to the response to BCSEA IR 2.68.2) would be extremely expensive due to the high incentives that would need to be paid.

Second, a volume reduction of this magnitude would reduce the Company's operating margin by an equivalent amount, but only the power purchases would fall proportionately. The remaining lost margin, that recovers mostly fixed costs (O&M, amortization of assets etc.) that remain in place to serve the reduced load, would still need to be recovered.

Both of these issues would likely result in much more than a 10 percent rate increase.

FBC agrees that, where cost effective, DSM can benefit customers overall. FBC is proud of its long history of delivering cost effective DSM programs to customers.

71.3 What percentage of "non-participation" in a DSM portfolio would be low enough for FBC to consider a rate increase of 2.2% over 5 years to be "viable" if average bills across all customers declined?

Response:

FBC does not have a threshold percentage of DSM program non-participation below which it would consider a DSM program resulting in higher rates and lower average bills "viable".

72.0 Topic: DSM, Balanced Scorecard

Reference: Exhibit B-12, BCSEA 34.4

"FBC currently does not have any specific success measures on its Scorecard related to DSM performance. Instead, DSM related key success measures are included in individual employee objectives and performance plans, where applicable." [underline added]

72.1 Please provide details of the "DSM related key success measures [that] are included in individual employee objectives and performance plans."

Response:

Employee objectives related to DSM success measures differ by individual employee and are dependent on their role and responsibilities.

The example below shows a financial objective for a DSM Manager for 2013:

Category	Objective	Anticipated results			Weighting
		Developing	Achieved objectives	Exceeds	
Financial	Implement PS activity to 100% of approved budget - kWh savings and costs	PS budget + 10% costs and -10% kWhrs	PS budget (kWh and costs)	PS budget + 10% kWh and -10% cost	30 %

In the above example, 30 percent of this employee's short-term incentive pay is determined by their meeting the DSM budget and savings targets.

72.2 How many individual employees have DSM related key success measures?

Response:

There are five employees with DSM related individual objectives.

72.3 For the individual employees who do have DSM related key success measures, are all the measures the same?

Response:

Individual objectives are employee-specific, dependent on their role and responsibilities related to DSM.

All of the individual employee objectives related to DSM are structured in a similar fashion to the example shown in the response to BCSEA IR 2.72.3, but their weightings differ, ranging from 10-30 percent of the total score.

72.3.1 If so, what is the measure(s)?

Response:

Please refer to the response to BCSEA IR 2.72.1.

72.3.2 If not, what are the different measures?

Response:

Please refer to the response to BCSEA IR 2.72.3.

72.4 How will the DSM related key success measures [that] are included in individual employee objectives and performance plans be affected, if at all, by the proposed reduced DSM spending?

Response:

If DSM spending is reduced as proposed, the specific targets in the individual employee objectives and performance plans will change, but because they are structured in relation to regulatory approved budgets (whatever that regulatory approved budget happens to be), they will be structurally the same.

72.5 Is (are) there any employee(s) whose key success measures include a measure of the amount of energy (and capacity) saved by the Company's DSM spending?

Response:

Please refer to the response to BCSEA IR 2.72.1.

72.5.1 If so, please indicate the employee(s) position(s), the measure, and the results in up to five previous years.

Response:

As demonstrated in the responses to BCSEA IRs 2.72.1 through 2.72.5, the management and exempt (M&E) employees who manage the DSM programs have the annual DSM savings target and/or DSM budget included as an integral part of their individual objectives plans. There are five M&E employees with DSM measures included in their individual objectives. Respecting personal privacy regarding compensation is a consideration in the release of the requested information. The release of the results of individual employee objective and performance plans into the public domain given the small number of M&E would be inappropriate.

For FBC employees, individual objectives have been part of the short-term incentive program since 2012, when the STI program was modified to include individual targets as well corporate targets.

72.5.2 If not, why not?

Response:

Please refer to the response to BCSEA IR 2.72.5.1.

72.6 Please use redactions and/or confidential filings if necessary.

Response:

Please refer to the response to BCSEA IR 2.72.5.1.

73.0 Topic: PBR performance review

Reference: Exhibit B-12, Attachment BCSEA 35.2, "Review of FortisBC Performance under PBR, 1996 to 2004," prepared by Elenchus Research Associates Inc., August 2, 2005

"The incentive mechanism (or PBR plan) implemented for FortisBC is essentially an indexed cost-of-service plan rather than a full-fledged performance-based regulation plan. The incentive mechanism is a non-litigious, streamlined way of setting revenue requirement and rates using a traditional cost-of-service approach." [p.14, underline added]

73.1 Does FortisBC accept Elenchus Research Associates' characterization of the 1996 to 2004 PBR plan? If not, why not?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

73.2 In FortisBC's view, is the proposed 2014-2018 PRB plan accurately described as "essentially an indexed cost-of-service plan rather than a full-fledged performance-based regulation plan"?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

73.2.1 If so, please comment on how and whether this characterization affects the merits of the 2014-2018 PRB plan.

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

73.2.2 If not, why not?

Response:

This IR has been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

73.3 If the Company considers that this information request belongs in the PBR Methodology stream, please so indicate and BCSEA-SCBC will ask the question in that phase.

Response:

BCSEA IRs 2.73.1 and 2.73.2 have been identified as relating to the PBR Methodology and will be submitted with the PBR Methodology IR responses.

Attachment 45.1

Northwest Power and Conservation Council

MARGINAL CARBON DIOXIDE PRODUCTION RATES OF THE NORTHWEST POWER SYSTEM

JUNE 13, 2008

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Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

The cost of future carbon dioxide (CO_2) regulation is a significant factor in utility resource planning in the Pacific Northwest. Failure to properly account for this risk when evaluating resources can result in poor resource decisions and higher costs for the region's ratepayers.

One of the benefits of conservation is that it avoids CO_2 emissions.[1] The benefit it provides depends on what generating resources would be replaced and how much CO_2 they produce. This requires understanding what generating resources are on the margin; that is, the generation that could be displaced by the conservation. The marginal resource is the last resource brought on-line to supply power during a given time period (i.e., the highest variable cost resource available and needed during the period). In the Northwest, the average marginal CO_2 production is substantially higher than the average CO_2 production from all electricity generation. This is because hydroelectricity and wind, which have low operating costs and no CO_2 emissions are brought on-line before coal-fired or natural gas-fired generating units. Because only the marginal plants would be displaced by conservation, it would not be proper to use the average of CO_2 emissions from all power generation to estimate the CO_2 saved through conservation.

This paper evaluates what resources are on the margin in every hour and what the CO_2 reduction would be as a result of conservation. The analysis is an extension of the Council's recent interim wholesale power market price forecasts.[2] In the base case for that analysis, natural gas-fired combined-cycle plants are on the margin most of the time so conservation would avoid the CO_2 emission of a gas-fired combined-cycle power plant for most of the hours in a year. When the marginal CO_2 emissions for each hour are averaged over all of the hours in a year, the average of these hourly CO_2 emissions is about 0.8 pounds per kilowatt-hour. This increases the value of conservation by up to $5.60 per megawatt-hour (in constant 2006 dollars) under the base case CO_2 price assumption of $14 per ton in 2025.

The value of conservation can be significantly higher for measures, such as city street-lighting programs, that target load reduction during weekend nighttime hours. This is because coal-fired generation is typically the region's marginal resource during these low load hours. Since coal-fired generation has higher CO_2 emissions than natural gas combined-cycle plants, more CO_2 is displaced by each unit of conservation.

In addition to the Interim Base Case, this analysis tests two alternative assumptions about future resource costs. First it looks at a case of higher capital costs for generating resources, similar to recent experience. This case produced no change in the resources that were expected to be developed in the Northwest, but it did eliminate significant coal development in other parts of the West. Fewer coal resources reduce Westwide annual CO_2 production. Interestingly, the annual

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[1] Similarly, the value of other low-CO_2 resources including many types of demand response and most renewable resources should include the value of the CO_2 production displaced by the resource.

[2] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf

CO_2 emissions in the Northwest increase since Northwest resources run more frequently to meet regional and Western loads. This is because fewer new resources are constructed in this high capital cost case. The increased use of Northwest resources means that coal-fired generation is used less often as the region's marginal resource. So, even though the region's annual CO_2 emissions increase, its marginal CO_2 production rate decreases to about 0.7 pounds of CO_2 per kilowatt-hour.

The second case adds higher CO_2 allowance prices (the possible future costs of CO_2 emissions) of $43 per ton of CO_2 beginning in 2012 to the high capital cost case. This results in much higher average marginal CO_2 emissions, up to 1.8 pounds per kilowatt-hour, and raises the value of conservation to as high as $38.00 per megawatt-hour. The high CO_2 prices increase the operating cost of coal plants more than they increase the operating cost of natural gas combined-cycle plants. This differential is enough to cause natural gas plants to be dispatched before coal-fired plants. With natural gas plants now operating first, coal plants are forced to the margin. This increases the region's average marginal CO_2 production rate and, therefore, the value of conservation to lower CO_2 emissions.

The other side of this change is that with higher CO_2 prices, natural gas-fired plants provide more baseload generation and therefore reduce the use of coal-fired generation as a share of total electricity production. As a result, total CO_2 emissions in this case are greatly reduced. Whereas, total CO_2 emissions in the region continued to grow in the Interim Base Case and the High Capital Cost Case, total CO_2 emissions are reduced to near or below 1990 levels in the High CO_2 Price Case. This is a direct result of the reduction in generation from existing coal-fired plants.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Marginal Carbon Dioxide Production Rates of the Northwest Power System

INTRODUCTION

During any given hour of the year, there are numerous generating units supplying power to the Pacific Northwest power system. Some of these units will be hydroelectric units or wind generating units that do not emit CO_2 into the atmosphere. At the same time, some of these units will likely be coal-fired or natural gas-fired generating units that do emit CO_2 into the atmosphere. Each type of generating unit has a distinct rate at which it emits CO2. For example, a contemporary natural gas-fired combined cycle unit emits roughly 0.8 pounds (lbs.) of CO_2 per kilowatt-hour. A typical conventional coal-fired steam unit emits roughly 2.3 lbs. of CO_2 per kilowatt-hour.

One way to measure the CO_2 production rate of the Northwest Power system is to average the rates of all the generating units operating during a given time period. In this paper, we use the term, *average CO_2 production rate*, to refer to an average across *all resources* operating during a given time period.

Another way to measure the CO_2 production rate of a power system is to determine the CO_2 emissions rate of the last resource (or marginal resource) brought on-line to supply power during a given time period. In wholesale power markets, generating resources are typically brought on-line in the order of their operating costs. In other words, resources with low operating costs are used before resources with higher costs. In general, hydroelectric, nuclear and wind generating units will be brought on-line before coal-fired or natural gas-fired generating units. It is the CO_2 emissions of the marginal resource that can be avoided by adding energy-efficiency measures to the system.

This paper estimates the Pacific Northwest power system's marginal resource, and its CO_2 production rate, during each hour for four separate years: 2010, 2015, 2020, and 2025. Because there are typically 8,760 hours during a year, we summarize our results by providing *average marginal CO_2 production rates* for each year. In this paper, we use the term *average marginal CO_2 production rate* to refer to an average across *only the marginal resources* operating during a given time period.

The major findings and conclusions of this new analysis are:

- For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Power system planners and resource analysts should use the marginal CO_2 production rate to quantify and evaluate the ability of energy-efficiency and other resources with low CO_2 emissions to reduce emissions.

- Marginal CO_2 production rates for the Northwest power system, under our Interim Base Case assumptions, are forecast to range between 0.7 lbs. of CO_2 per kilowatt-hour (kWh) and 0.9 lbs. of CO_2 per kWh over the period 2010 through 2025.

- The region's average marginal rate of CO_2 production and its overall level of CO_2 production tend to move together, but in opposite directions. For example, under our combined High Capital Cost and High CO_2 Price Case assumptions, the region's marginal CO_2 production rate is forecast to jump as high as 1.8 lbs. of CO_2 per kWh. Carbon regulation, while decreasing overall CO_2 emissions, also increases the region's marginal CO_2 production rate since coal plants become the marginal resource.

- The type and amount of generating resources added to the Western power system outside our region influence the Pacific Northwest's CO_2 production. For example, although the Interim Base Case and the High Capital Cost Case forecasts have essentially the same resource mix for the Pacific Northwest, the High Capital Cost Case forecasts less overall new plant development, and no new conventional coal-fired plant development, in the Western power system over the planning period. This results in lower annual CO_2 emissions for the Western power system. At the same time, however, annual CO_2 production increases in the Pacific Northwest (and marginal CO_2 production rates decline) as Northwest resources are operated more intensely to meet loads both inside and outside the region.

METHODOLOGY

The methodology we use to estimate the Pacific Northwest power system's marginal resource is an extension of the modeling described in the Council's recent Interim Wholesale Power Price Forecast paper.[3] In this paper, we provide further analysis of two scenarios presented in the interim forecast paper: the Interim Base Case and the High Capital Cost Case. Each of these cases incorporates the same fuel price forecasts, estimates of the future costs of CO_2 allowance prices, and schedule of renewable resource additions to achieve state renewable portfolio standards. The only difference between these cases is the estimated costs of constructing new generating resources.[4] The Interim Base Case assumes construction costs from the "2006 Biennial Monitoring Report of the Fifth Power Plan." Since the release of the monitoring report, construction costs have increased significantly. The High Capital Cost Case was developed to better reflect current estimates of the future cost of building new generating resources and is being used in the preliminary studies for the Sixth Power Plan. We also present new results for a combined High Capital Cost/High CO_2 Price Case. The resource mix underlying each of these forecasts affects the choice of the marginal resource, and therefore, the marginal CO_2 production rate for the Pacific Northwest power system. These effects are discussed in the results section of this paper.

Council staff uses the AURORA$^{xmp®}$ Electric Market Model to develop its wholesale power price forecasts.[5] This model simulates hourly supply and demand to determine a marginal resource and market-clearing price for every hour of the simulation period for each of the load-resource zones in the model. The Council's configuration of AURORA^{xmp} uses 18 load-resource zones to represent the Western power system. The Pacific Northwest power system is

[3] The "Interim Wholesale Power Price Forecast" paper is available at: http://www.nwcouncil.org/library/2008/2008-05.pdf
[4] For a description of our current estimates of new resource capital costs see the "Interim Wholesale Power Price Forecast" paper (pp. 10-13).
[5] Available from EPIS, Inc. (www.epis.com).

represented by 6 of these zones.[6] Therefore, for each hour of a simulation period, AURORA^{xmp} identifies 6 marginal resources for the Pacific Northwest, one for each zone.[7]

In order to identify a single Pacific Northwest marginal resource, and marginal CO_2 production rate, for each hour of the simulation period, Council staff conducted additional analysis on the AURORA^{xmp} hourly output databases. The hourly output databases contain statistics summarizing the simulated operation of each generating unit located in the Pacific Northwest.[8] Staff performed a series of filtering steps to arrive at a single marginal resource for each hour. First, staff removed any units considered to be must-run resources. Must-run resources are those that are operated regardless of wholesale power market prices. For the Northwest, must-run resources include: wind plants, municipal solid waste facilities, industrial co-generation facilities, geothermal steam plants, and landfill gas energy recovery and other biogas facilities. Second, for each hour, any unit that did not generate electricity was removed from consideration. Finally, of the remaining units, the unit with the highest dispatch cost was selected as the region's marginal resource for each hour.[9] This process resulted in a single marginal resource for the Pacific Northwest for each hour of the simulation period.[10]

This methodology for identifying the region's marginal resource is analogous to the resource stacking approach depicted in Figure 1. The figure is a snapshot of our forecast of the region's supply and demand during the peak hour of demand in 2020.[11] The vertical axis of the figure is dispatch cost--the cost that can be avoided by curtailing operation of a resource. For any resource, the dispatch cost comprises the variable operating and maintenance costs (including integration costs for intermittent resources), variable fuel cost, CO_2 allowance cost, any unit cycling premium, and a dispatch premium representing the "profit" over cost demanded by a plant owner to dispatch the resource.

The horizontal axis represents cumulative generating capability for the hour. The supply curve for this hour starts with the region's lowest-cost resource, hydroelectric generation, and adds supply in order of increasing dispatch cost. The forecast demand for electricity in this hour is 38,081 megawatts, shown as the vertical black line. The region's marginal resource for this hour is the generating unit that is situated at the intersection of the region's supply and demand curves.

[6] The Pacific Northwest zones are identified as PNW Westside North, PNW Westside South, PNW Eastside North, PNW Eastside South, Idaho South, and Montana East.

[7] This is equivalent to 52,560 marginal resources in the Pacific Northwest on an annual basis (8,760 hours * 6 load-resource zones = 52,560 marginal resources).

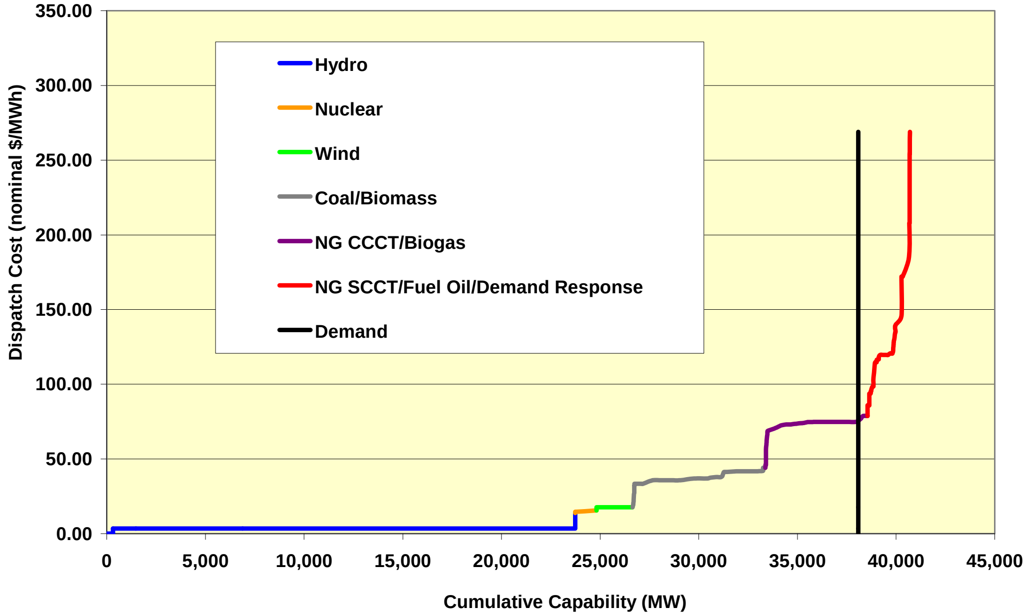
[8] The annual databases contain roughly 7.4 million records (844 generating units * 8,760 hours = 7.4 million records)

[9] If two or more units tied for the highest dispatch cost in an hour, the unit operating farthest from its maximum capability (or closest to its minimum capacity) was chosen as the marginal resource.

[10] For an annual simulation period, this results 8,760 marginal resources in the Pacific Northwest.

[11] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 1: Illustration of the marginal resource selection methodology (High Capital Cost Case)



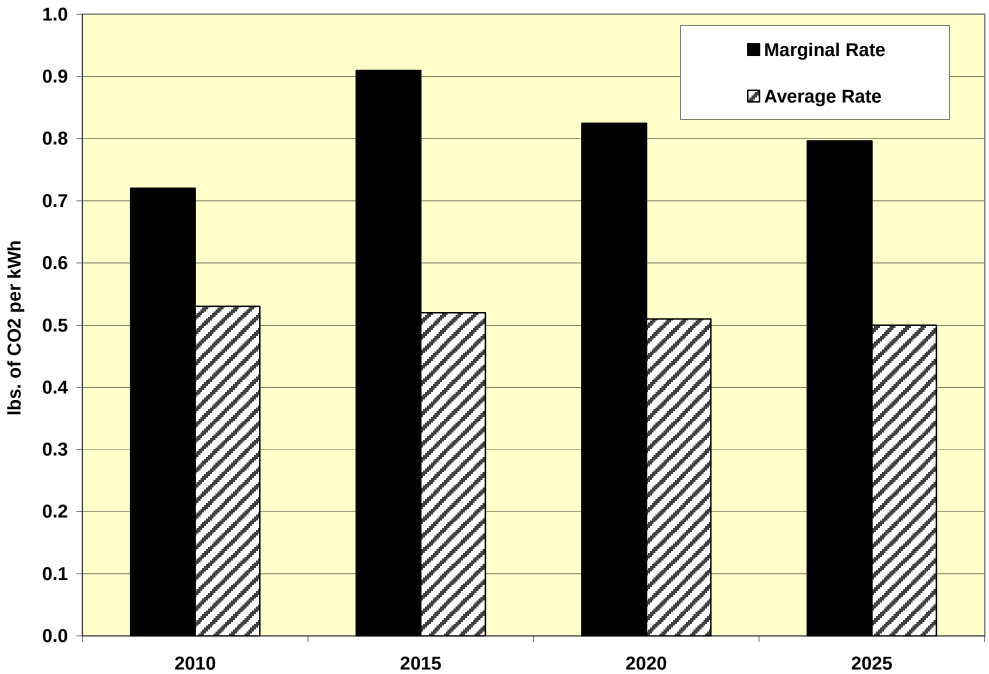
The region's marginal resource will change not only from season to season as the region's water supply, loads, fuel prices, and resource availability varies, but also from hour to hour as demand changes. The filtering methodology described in the previous paragraph is roughly analogous to performing this resources stacking for each hour of the forecast year.

RESULTS

Interim Base Case

For the Northwest power system, with its large amount of hydroelectric, nuclear and wind generating resources, the *marginal CO_2 production rate* is considerably higher than the *average CO_2 production rate*. Figure 2 compares these two rates for the Interim Base Case.

Figure 2: Northwest marginal and average CO_2 production rates (Interim Base Case)



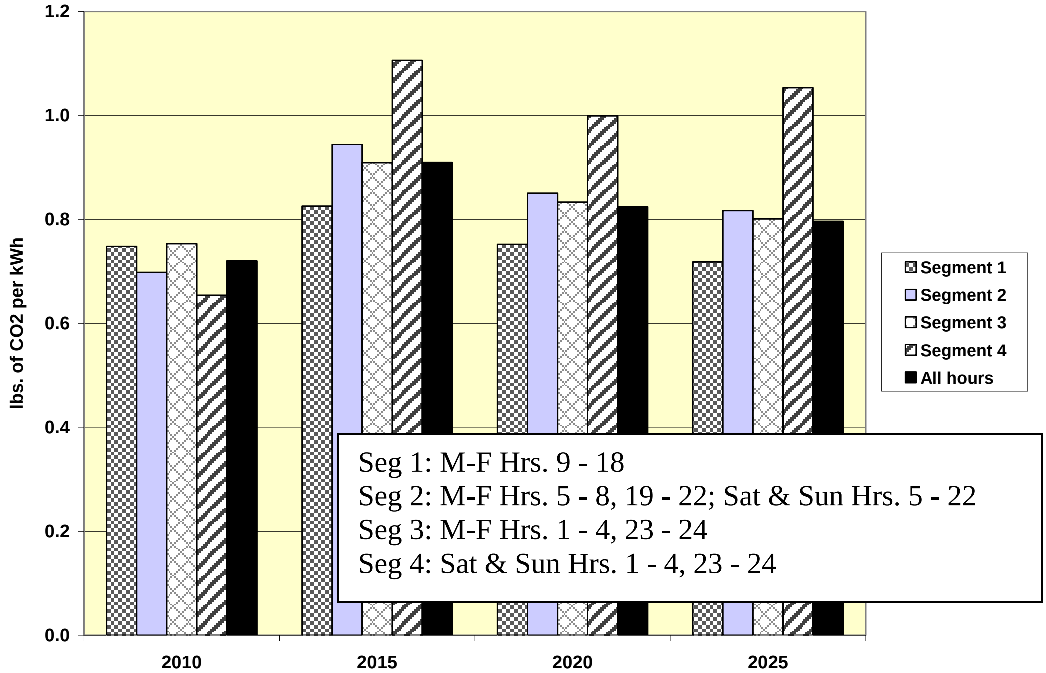
Power system planners and resource analysts should use the marginal CO_2 production rates to evaluate the CO_2 cost associated with future purchases of power from the wholesale power market and the relative benefits of energy-efficiency measures and other resources with lower CO_2 emissions. For example, given the Council's current interim forecast of future CO_2 emissions prices (i.e., \$11.12 per ton in 2015, \$12.55 per ton in 2020, and \$14.15 per ton in 2025), the estimated CO_2 cost included in future purchases from the wholesale power market would be \$5.06 per megawatt-hour (MWh) in 2015, \$5.17 per MWh in 2020, and \$5.63 per MWh in 2025.[12]

Marginal CO_2 emission rates (pounds of CO_2 per kWh) vary by time of day and day of week because the marginal generating resource changes with load. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours, whereas coal-fired plants with lower variable costs can be on the margin during nighttime and weekend light load hours. Therefore, both the physical quantity, and dollar value, of avoided CO_2 emissions vary with time. The Council and the Regional Technical Forum use four load

[12] The calculation of the market CO_2 cost in 2015 is: (0.9 lbs. of CO_2 per kWh) / (2000 lbs. per ton) * (1000 kWh per MWh) * (\$11.12 per ton of CO_2).

segments to assess the cost-effectiveness of conservation measures. Figure 3 shows the average marginal CO_2 emission rates for the four segments for the four future years.

Figure 3: Northwest marginal CO_2 production rates by load segment (Interim Base Case)

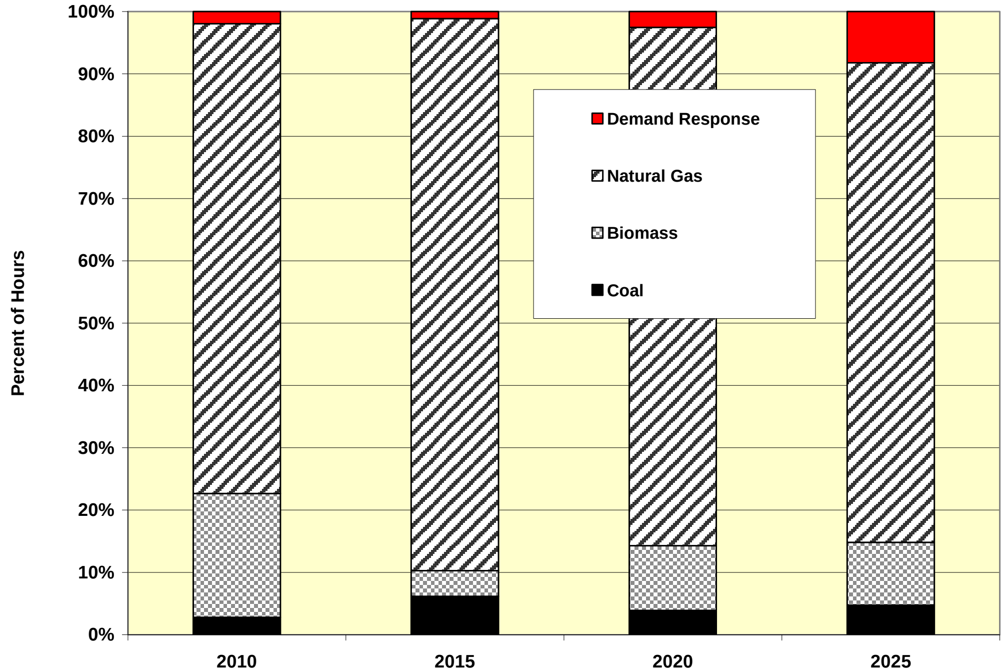


The pronounced increase in the marginal CO_2 production rate during weekend nighttime hours (i.e., during Segment 4 hours) is due to coal-fired units being the marginal resource during these low-load hours. This is consistent with the recent and expected addition of significant amounts of wind generation to the Northwest power system, which pushes coal-fired resources up toward the margin.[13] After 2015, there is a slight downward trend in the Northwest's marginal CO_2 production rates. This downward trend reflects the changing fuel mix of the region's marginal resources over time.

Figure 4 shows the percentage of hours in each year that resources of various fuel types are on the margin. The percentage of hours that coal-fired resources are the marginal resource declines from 6.2 percent in 2015 to 4.7 percent in 2025. As regional loads continue to grow, there is also an increase in the number of high load hours during which demand response is the region's marginal resource. Both of these changes have the effect of lowering the region's marginal CO_2 production rates.

[13] An open issue at this time is whether the coal-fired resources operating at the margin during these light load hours can provide the operational flexibility needed to integrate intermittent resources into the power system.

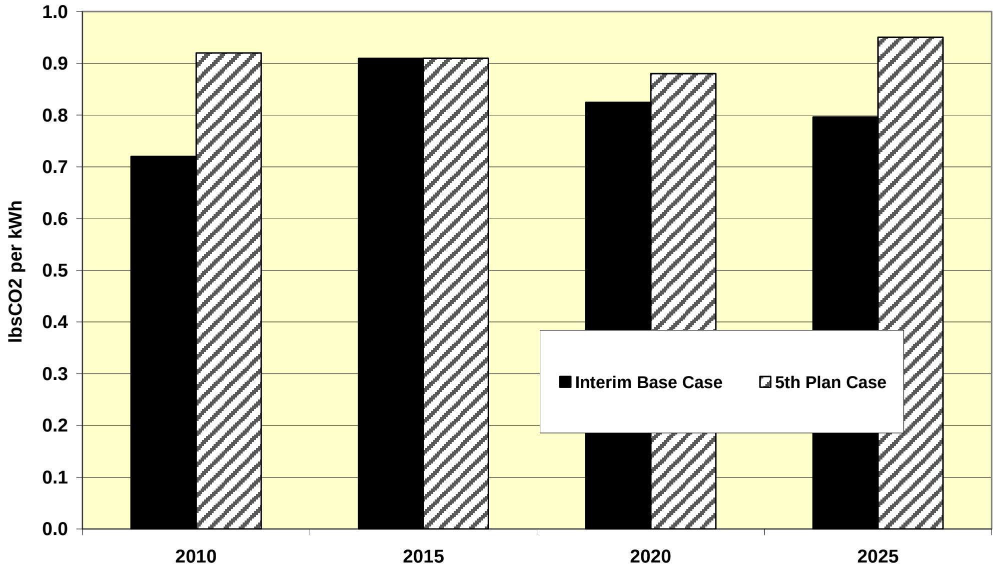
Figure 4: Percentage of hours resources of various fuel types are the marginal resource (Interim Base Case)



The low percentage of hours that coal-fired resources are the region's marginal resource is a significant change from the Council's previous forecast of the marginal rate of CO_2 production in April, 2006.[14] At that time, coal-fired resources were forecast to be the marginal resource in 16 percent of the hours in 2010, declining to 12 percent of the hours in 2025. This difference in marginal resource mix is evident in a comparison of the two forecasts of marginal CO_2 production rates (see Figure 5).

[14] Staff presented, "Power System Marginal CO_2 Production Factors" to the Council's Power Committee on April 11, 2006, in Whitefish, Montana.

Figure 5: Comparison of marginal CO_2 production rates (Interim Base Case vs. 5th Plan Case)



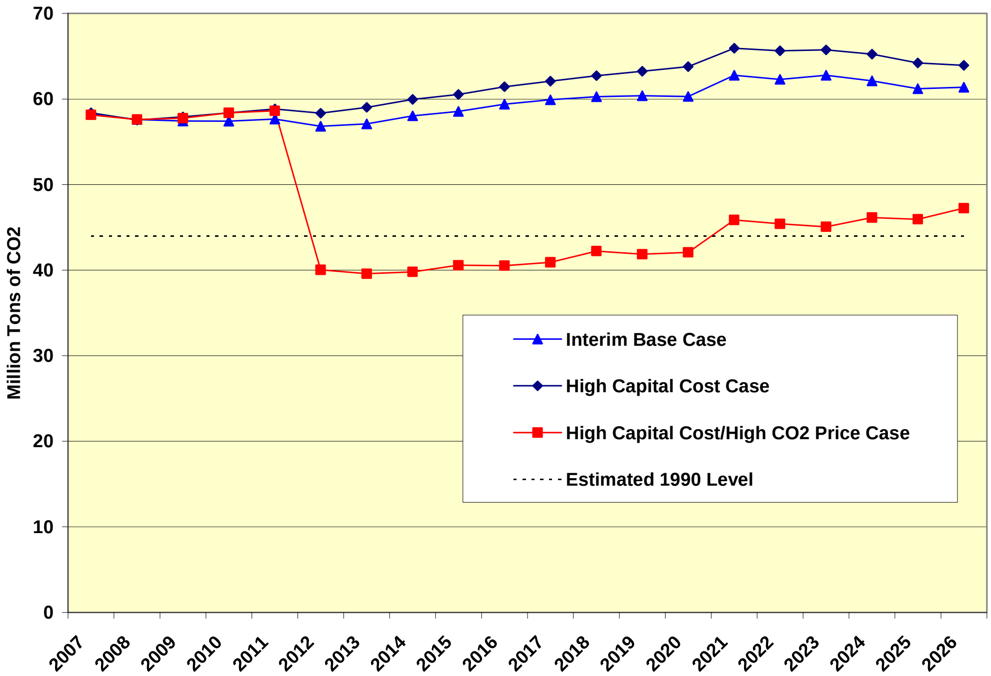
The decrease in coal-fired generation on the margin can be partly attributed to the improved methodology for selecting the region's marginal resource.[15] However, this difference is also partly explained by differences in forecast assumptions and the forecast, or recommended, resource mix for the Pacific Northwest. For example, the Interim Base Case uses higher CO_2 allowance prices than the 5th Plan Case.

It is important to place the declining trend in the Northwest power system's marginal CO_2 production rates, and the underlying changes in its marginal resource mix, within the wider context of the overall power system CO_2 production. In the Interim Base Case, Northwest power system CO_2 emissions are forecast to total 57 million tons in 2010, and to increase to 61 million tons in 2025. For comparison, we previously estimated that the Northwest power system's CO_2 production was 44 million tons in 1990 and that it would have been 57 million tons in 2005 (had normal hydro conditions prevailed).[16] Figure 6 shows our CO_2 emissions forecasts for the Northwest power system under the three future scenarios discussed in this paper.

[15] The previous methodology selected a single regional marginal resource during each hour of the year by starting with the units that AURORA^xmp identified as the marginal resource in each of the six Northwest load-resource zones. Starting with only one resource in a load-resource zone, and then removing it from further consideration if it is a must-run resource, has the effect of removing all the resources in that zone from consideration as the region's marginal resource. In some hours, this method could erroneously select an intra-marginal resource as the region's marginal resource. The prior method had the potential to overstate the occurrence of coal-fired units and hydroelectric units as the region's marginal resource. The methodology presented in this paper avoids this problem by starting with all of the generating units dedicated to serving loads in the Pacific Northwest.

[16] We also estimated that with implementation of the recommended resource portfolio of the 5th Power Plan, CO_2 emissions would total 67 million tons in 2024. These estimates are from the Council's paper titled, "Carbon Dioxide Footprint of the Northwest Power System." This paper is available at: http://www.nwcouncil.org/library/2007/2007-15.htm

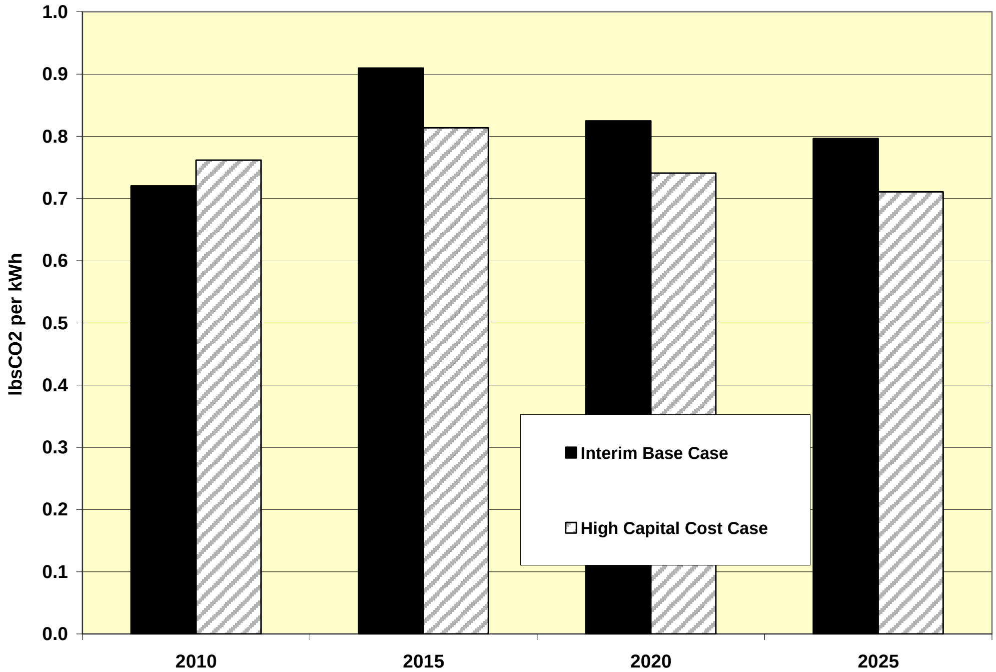
Figure 6: Forecasts of the Northwest power system's CO_2 emissions



High Capital Cost Case

It is also important to describe the sensitivity of our results to changes in key input assumptions. Figure 7 shows the effect of our revised forecast construction costs for new generating resources on marginal CO_2 production rates. The higher construction costs in the High Capital Cost case reduce the level of forecast resource additions in other regions of the West. This leads to more intense use of power resources in the Pacific Northwest, and to lower marginal CO_2 production rates.

Figure 7: Comparison of marginal CO_2 production rates (High Capital Cost Case and Interim Base Case)



The portfolio of Northwest generating resources is essentially the same in both the High Capital Cost Case and Interim Base Case. In both cases, Northwest generating resources consist of existing resources and the forecast addition of renewable resources to meet state renewable portfolio standards. The reduction in marginal CO_2 production in the Northwest is primarily driven by a change in the amount and type of new resources added to meet load in areas outside of the Northwest. The High Capital Cost Case results in more new natural gas-fired resources and fewer new coal-fired resources being added to the Western power system over the planning period.[17] This change in incremental resource mix results in Northwest resources being dispatched more often to serve loads, both inside and outside the region. This increase in the dispatch of regional resources increases the occurrence of natural gas-fired resources on the margin and reduces the Northwest's marginal CO_2 production rates.

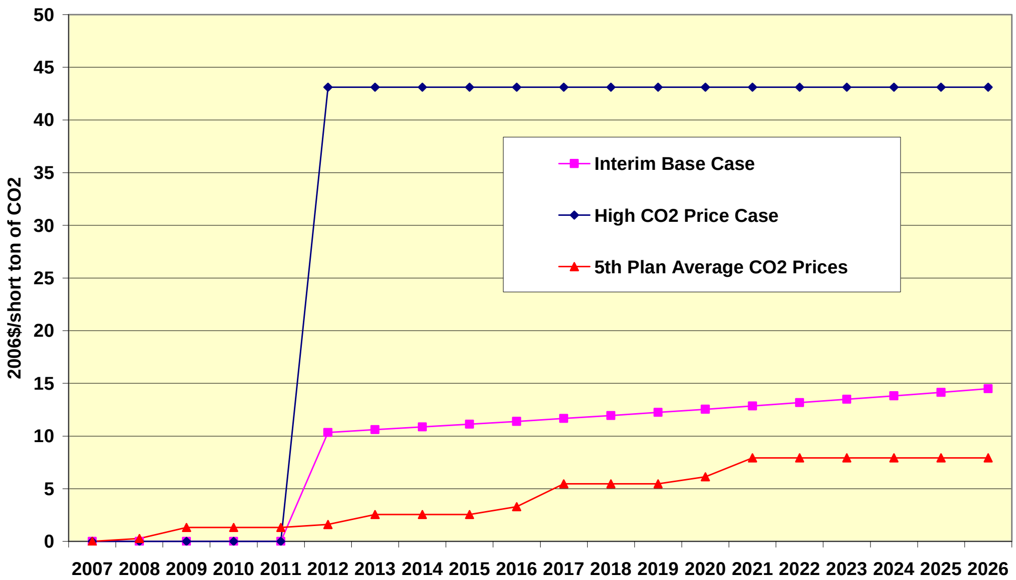
The increased utilization of the Northwest's resources also leads to higher total CO_2 production in the Northwest (see Figure 6). For example, total Northwest CO_2 production is 64 million tons in 2025 in the High Capital Cost Case compared to 61 million tons in 2025 in the Interim Base Case. However, from the perspective of the interconnected-West, the higher resource use in the Northwest contributes to the reduction in total Western CO_2 production to 461 million tons in 2025 in the High Capital Cost Case from 519 million tons in the Interim Base Case.[18]

[17] See "Interim Wholesale Power Price Forecast" paper, p. 26, for a detail description of this change in incremental resource mix.
[18] See "Interim Wholesale Power Price Forecast" paper, p. 24, for a detail description of annual Western Electricity Coordinating Council (WECC) CO_2 production.

Combined High Capital Cost and High CO_2 Price Case

The following figure shows the difference between the CO_2 allowance prices used in the Interim Base Case (and High Capital Cost Case), and the higher CO_2 allowance prices used in the High Capital Cost/High CO_2 Price case.[19] It also shows the average of the 750 possible future trajectories of CO_2 emissions prices used in the Fifth Power Plan.

Figure 8: Base and high CO_2 emission prices



The higher CO_2 emissions prices used in the High Capital Cost/High CO_2 Price Case significantly reduce the forecast annual CO_2 production of the Western power system. Forecast Westwide CO_2 production drops from 461 million tons in the High Capital Cost Case to 384 million tons in the High Capital Cost/High CO_2 Price Case. The higher CO_2 emissions prices also drive a dramatic decline in the forecast of annual CO_2 production from the Northwest power system (see Figure 6).[20]

The higher CO_2 prices also have a significant effect on the forecast of the Northwest's marginal CO_2 production rates. These marginal rates are dramatically higher (see Figure 8). This increase occurs because the higher CO_2 prices drive heavy CO_2 producing resources to the less frequently dispatched end of the region's supply curve and puts them on the margin during more hours of the year.

[19] For a description of the rationale underlying our CO_2 emission price assumptions see the "Interim Wholesale Power Price Forecast" paper (pp. 8-10).
[20] The higher CO_2 emissions prices result in 1,200 megawatts (MW) of new wind resources being added to the Northwest power system over the planning period (i.e., 500 MW in 2016, 200 MW in 2024, and 500 MW in 2025). This is installed wind capacity above the amount forecast to be added to meet state renewable portfolio standards.

NORTHWEST
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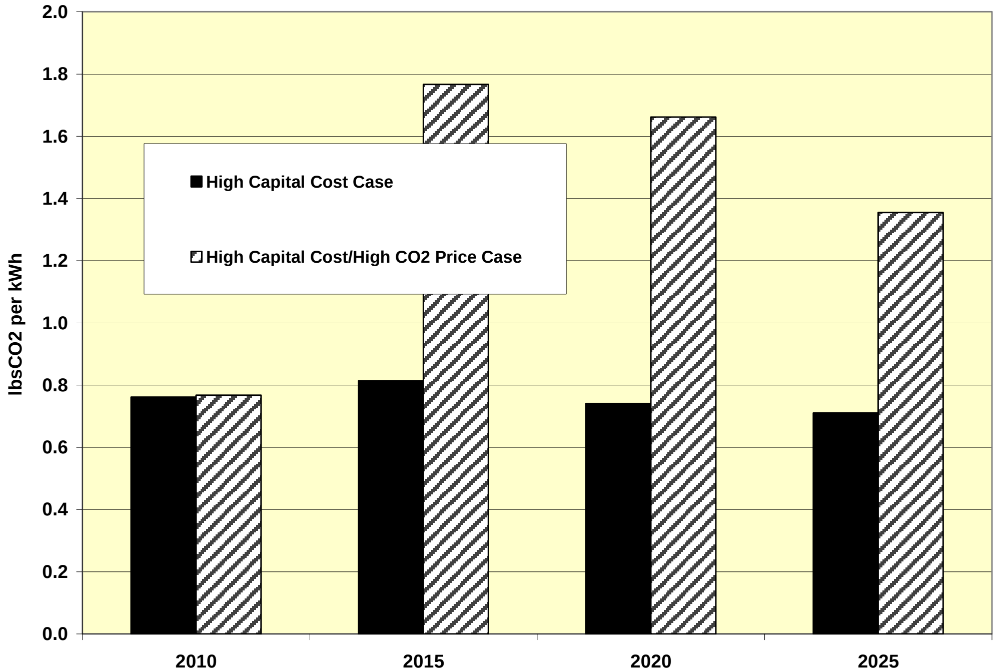
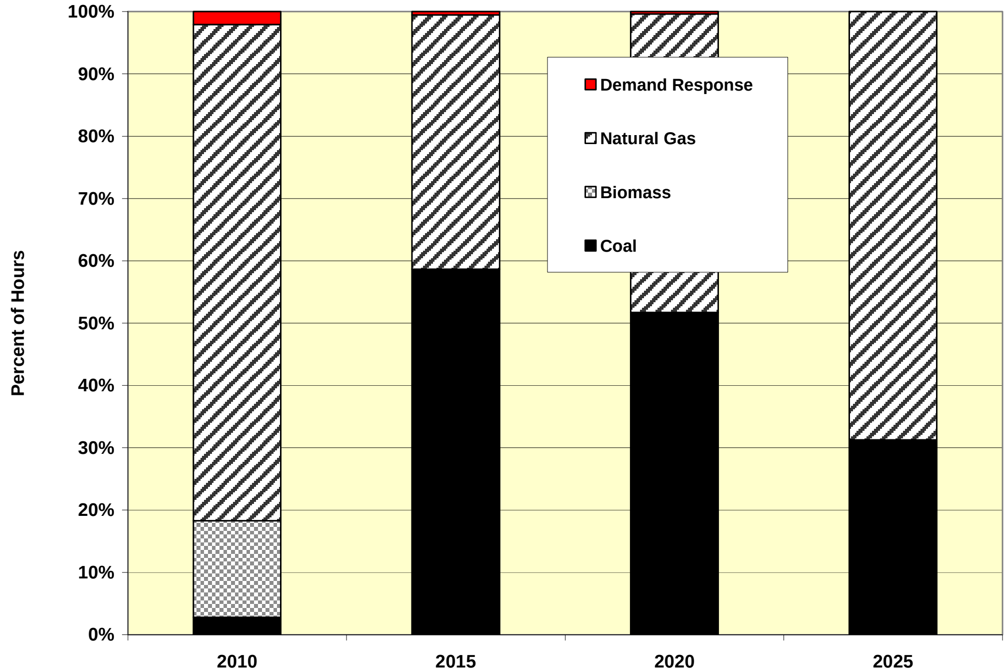
POWER PLAN

Figure 8: Comparison of marginal CO_2 production rates
(High Capital Cost Case vs. High Capital Cost/High CO_2 Price Case)



Under the High Capital Cost/High CO_2 Price Case assumptions, coal-fired resources are the marginal resource during 59 percent of the hours in 2010, 52 percent of the hours in 2015, and 31 percent of the hours during 2025. Figure 9 shows the increased role of coal as a marginal resource mix for this sensitivity case, compared to the base case shown in Figure 4.

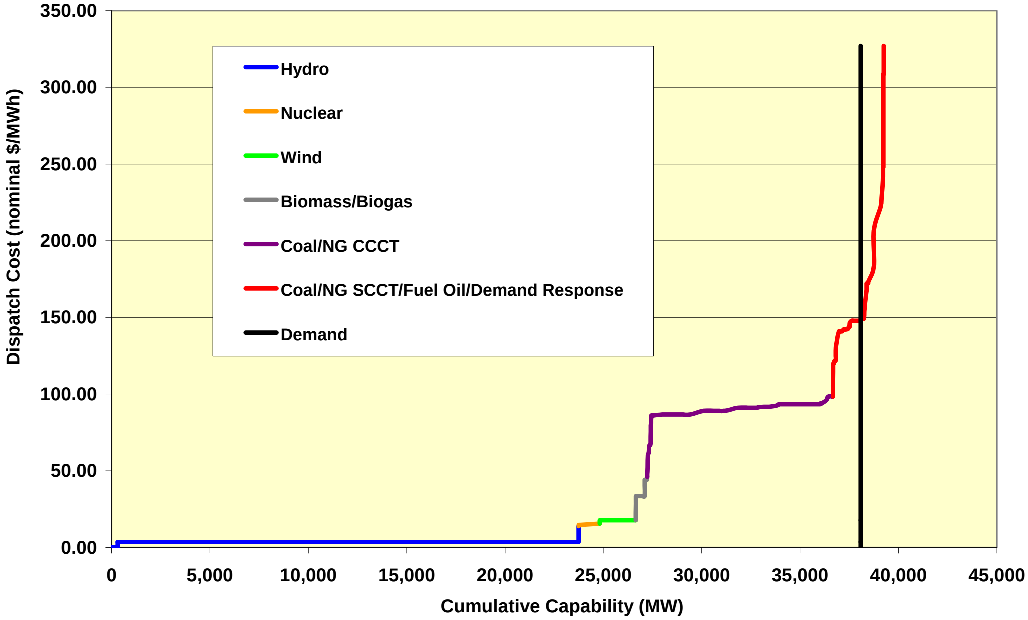
Figure 9: Percentage of hours resources of various fuel types are the marginal resource (High Capital Cost/High CO_2 Price Case)



Again, stated differently, the increase in the percentage of hours that the Northwest's coal-fired resources are on the margin is due to their higher dispatch cost because of emission charges. Their dispatch cost increases to, and in some cases surpasses, the dispatch cost of the Northwest's natural gas-fired combined cycle units. This "leveling" effect of the higher CO_2 emission prices is illustrated in the following snapshot of the region's supply and demand during the peak hour of demand in 2020.[21]

[21] The snapshot shown is for hour ending 7:00 P.M. on January 15, 2020.

Figure 10: Illustration of the change in the regional supply curve (High Capital Cost/High CO_2 Price Case)[22]



With high CO_2 emissions prices, most of the region's coal-fired units move up to share the same relative position on the region's supply curve with natural gas-fired combined cycle units (some of the less efficient coal-fired units move beyond this level to mix with natural gas-fired simple cycle units and other "peaking" resources). This leveling of the costs of coal-fired generation and natural gas-fired generation creates a "high plateau" in the region's supply curve near $90 per MWh. A quick comparison of Figure 10 and Figure 1 also highlights this effect. The resources lying along this plateau would likely clear the market during many hours of the year.

This analysis confirms that high CO_2 emission prices can drive significant reductions in total CO_2 emissions, both Westwide and in the Pacific Northwest. The analysis also shows that high CO_2 emissions prices increase the region's marginal rate of CO_2 production, and therefore, likely increase the value of energy-efficiency measures that reduce CO_2 emissions.

CONCLUSION

This paper forecasts the marginal CO_2 production rates for the Pacific Northwest power system to be between 0.7 lbs. per kilowatt-hour and 0.9 lbs. per kilowatt-hour for the period 2010 through 2025, under interim base case assumptions. The Council and the Regional Technical Forum can use these marginal CO_2 production rates to quantify the value of CO_2 emissions avoided by conservation and to evaluate the cost-effectiveness of energy-efficiency measures and other resources with lower CO_2 emission rates. These marginal CO_2 production rates are

[22] Coal purposefully appears in two places on the legend. With high CO_2 emissions prices most of the Northwest's coal units have dispatch costs similar to natural gas-fired combined cycle combustion turbines (NG CCCT), however, some of the less efficient coal units have even higher dispatch costs, similar to natural gas-fired simple cycle combustion turbines (NG SCCT) and other peaking resources.

very sensitive to changes in the future regulation, and cost, of CO_2 emissions. Because of this sensitivity, the marginal CO_2 production rates may change significantly if the assumptions regarding CO_2 allowance prices change during development of the Sixth Power Plan.

The effectiveness of the higher CO_2 prices in reducing CO_2 emissions also appears to be very sensitive to fuel costs. At $43 per ton of CO_2, the variable cost of most existing coal plants is slightly higher than the variable cost of gas combined-cycle plants. However, any increase in the cost of natural gas would favor the dispatch of coal and return combined-cycle plants to the margin. A higher CO_2 price would be needed to restore coal to the margin. The Council intends to further explore this issue during development of the Sixth Power Plan.

Sensitivity to Higher Natural Gas Price Assumptions

Addendum to Marginal Carbon Dioxide Production Rates of the Northwest Power System

SUMMARY

An important result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," indicated that with carbon dioxide (CO_2) allowance prices of $43 per ton the Northwest power system's annual CO_2 emissions could be reduced to its1990 level. This result was achieved at the Council's medium fuel price forecast.

Results presented in this addendum indicate that:

- With the Council's high fuel price forecast the $43 per ton CO_2 allowance price assumption fails to produce the same dramatic reduction in annual CO_2 emissions that were shown for the medium fuel price forecast.

- With the Council's high fuel price forecast CO_2 allowance prices would need to increase to nearly $70 per ton in order to achieve annual reductions in CO_2 emissions similar to those achieved under the medium fuel price forecast.

INTRODUCTION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual carbon dioxide (CO_2) emissions can be driven below its 1990 level with CO_2 allowance prices of $43 per ton of CO_2 (in constant 2006 dollars). This CO_2 allowance cost would bring about a significant reduction in annual emissions by changing the dispatch order of coal-fired and natural gas-fired generating units. Coal-fired units would become more costly to operate than natural gas-fired units and would dispatch to meet load less often. The reduced operation of coal-fired units would lower the Northwest power system's annual CO_2 emissions.

The result presented in the marginal CO_2 assessment was achieved at the Council's medium fuel price forecast. Higher natural gas prices would be expected to increase the CO_2 allowance prices required to change the dispatch order of coal-fired and natural gas-fired plants. This addendum examines how higher fuel prices might affect this result. How sensitive is the modeled reduction in annual CO_2 emissions to increased natural gas prices? With high fuel prices how high would CO_2 allowance prices need to climb in order to reduce the Northwest power system's annual CO_2 emission to its 1990 level?

METHODOLOGY

The High Capital Cost/High CO_2 Price Case presented in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper serves as the reference case for the analysis presented in this addendum. This case serves as the point of reference because it showed that with CO_2 allowance prices of $43 per ton the region's annual total CO_2 emissions could be reduced to its 1990 level. For ease of reference, we refer to this case as the Medium Fuel/$43 CO_2 Price Case in this addendum.

In this addendum, we also model three high fuel price sensitivity cases. This modeling is an extension of the modeling presented in the Council's recent "Interim Wholesale Power Price Forecast" paper.[23]

The first sensitivity case is a combined high fuel price and $43 per ton CO_2 allowance price case (referred to as the High Fuel/$43 CO_2 Price Case). This case is designed to test the sensitivity of the modeled reduction in the Northwest power system's annual total CO_2 emissions to high fuel prices.

The second sensitivity case is a combined high fuel price and $70 per ton CO_2 allowance price case. This is an intermediate case. The only difference between this case and the first sensitivity case is that the CO_2 allowances prices are increased to $70 per ton (in 2006 dollars). Importantly, the forecast resource mix of the Western power system is held constant in this sensitivity case. The $70 per ton CO_2 allowance price was determined to be the level needed to drive the forecast of the Northwest power system's annual CO_2 emissions below its 1990 level. We refer to this case as the High Fuel/$70 CO_2 Price/Fixed Mix Case.

The third sensitivity case expands on the second sensitivity case by using the AURORA^xmp model to forecast a new incremental resource expansion for the Western power system under the $70 per ton CO_2 allowance price assumption. In other words, the underlying resource mix is allowed to change in response to the increased forecast of CO_2 emissions costs. We refer to this case as the High Fuel/$70 CO_2 Price/New Mix Case.

The Council's current set of fuel price forecasts were developed in the summer of 2007.[24] The low, medium-low, medium, medium-high, and high fuel price forecasts cover a wide range of possible future price trends. Figure 1 compares the medium and high price forecasts for natural gas and coal delivered to electricity generators located in the western load-resource zones of the Pacific Northwest. For natural gas, the high price forecast is approximately $3 per million British thermal units (MMBtu) higher than the medium price forecast over most of the planning period.

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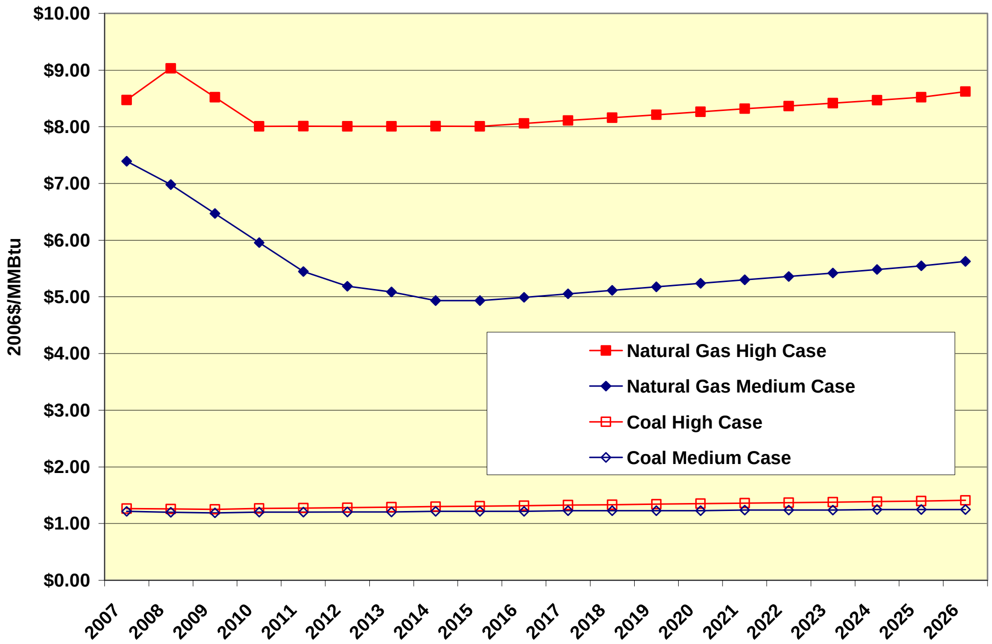
[23] The "Interim Wholesale Power Price Forecast" paper available at: http://www.nwcouncil.org/library/2008/2008-05.htm

[24] The "Revised Fuel Price Forecasts" paper is available at: http://www.nwcouncil.org/library/2007/2007-14.htm

Figure 1: Comparison of medium and high fuel price forecasts



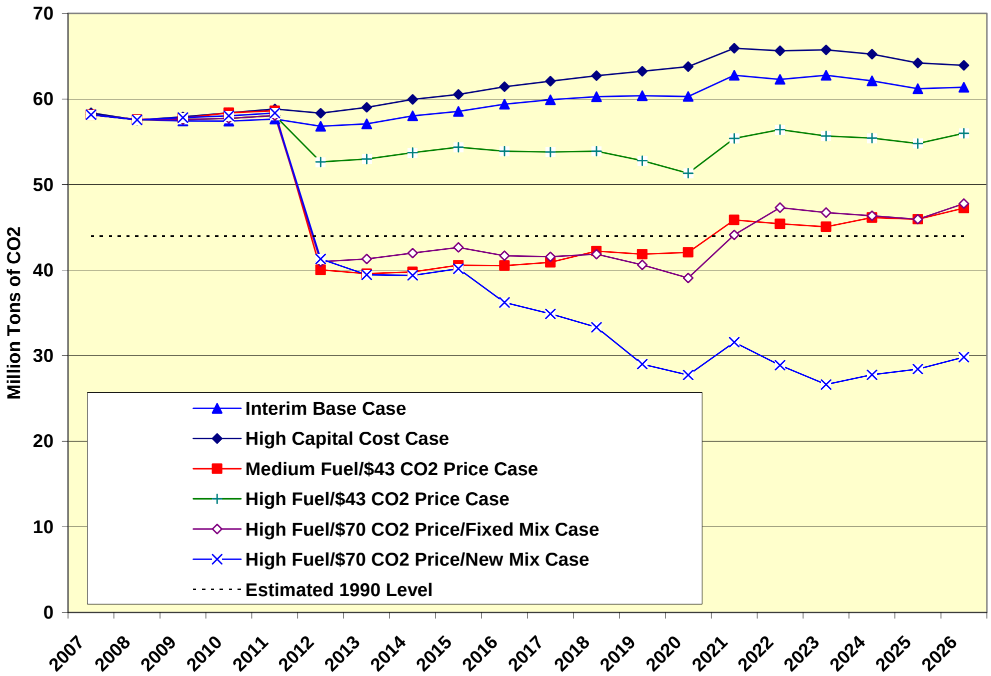
RESULTS

Figure 2 shows the Northwest power system's annual total CO_2 emissions for the reference case and the three high fuel price sensitivity cases. For continuity with the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper, it also shows the annual total CO_2 emissions for the Interim Base Case and High Capital Cost Case of that paper.[25]

In the reference case the significant reduction in annual total CO_2 emissions is driven by a switch in the dispatch order of coal-fired and natural gas-fired resources.[26] The results of the High Fuel/$43 CO_2 Price Case show that this reduction in total emissions is sensitive to high natural gas prices. While some reduction in CO_2 emissions is achieved, with natural gas prices in the $8 to $9 per MMBtu range the $43 per ton CO_2 allowance price fails to reduce CO_2 emissions to the 1990 level. This is because the higher cost of natural gas favors the dispatch of coal-fired generating resources. With the higher natural gas prices the $43 per ton CO_2 emission cost is not sufficient to move coal-fired generation to the margin during a significant number of hours each year.

[25] See Figure 6, p. 11, in the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper.
[26] See the "Marginal Carbon Dioxide Production Rates of the Northwest Power System" paper (pp. 7 - 16).

Figure 2: Forecasts of the Northwest power system's total CO_2 emissions

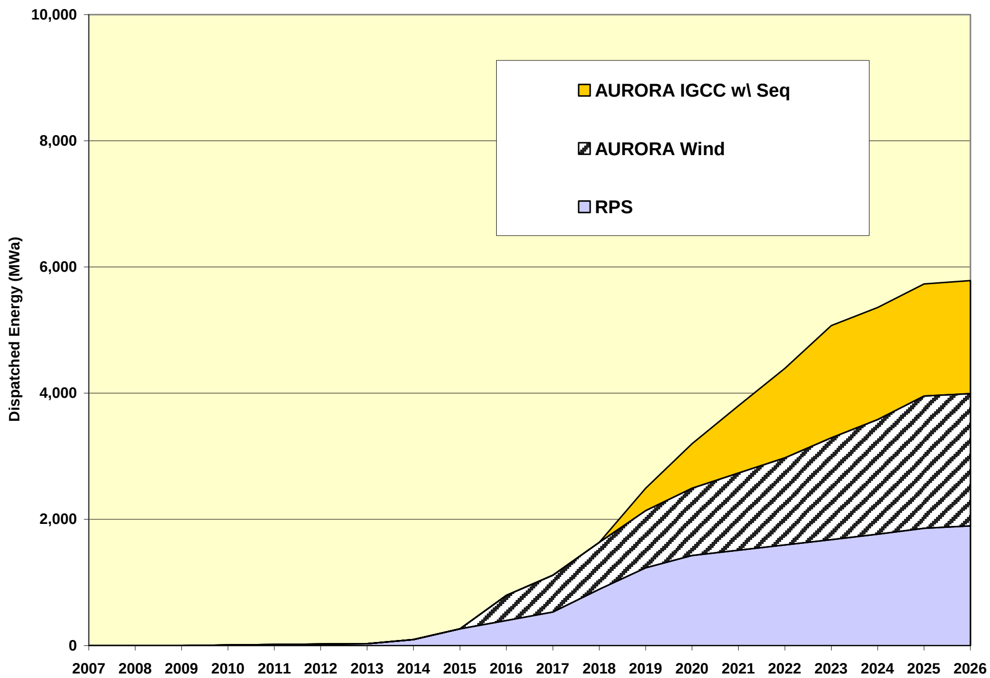


The results for the High Fuel/\$70 CO_2 Price /Fixed Mix Case show that under the Council's high fuel price assumptions the price of CO_2 emissions allowances would need to climb to as high as \$70 per ton of CO_2 in order for the Northwest power system to reach its 1990 level of CO_2 production with the resource mix of the reference case. The high natural gas prices work against efforts to reduce Northwest CO_2 emissions by forcing the cost of CO_2 allowance prices to climb in order to achieve the same targeted reduction in emissions.

The results for the High Fuel/\$70 CO_2 Price /New Mix Case easily achieve 1990 levels of CO_2 emissions and show a continued decline in annual total CO_2 emissions after 2015. This is because additional wind generation (beyond Renewable Portfolio Standard requirements) and integrated gasification combined cycle (IGCC) generation with carbon capture and sequestration become economic additions to the power system. In addition, two large coal-fired generating units, Boardman and Valmy 1, become uneconomic to operate under these assumptions and are and retired in 2013 and 2020 respectively.[27] Figure 3 shows the energy output of the incremental resources added to the Northwest power system over the planning period. The continuing decline of CO_2 emissions observed in this case suggest that over the long-term, CO_2 allowance prices of less than \$70 per ton of CO_2 may be sufficient to maintain emissions below 1990 levels, even with high natural gas prices.

[27] The Boardman unit is also retired in the reference case in 2012.

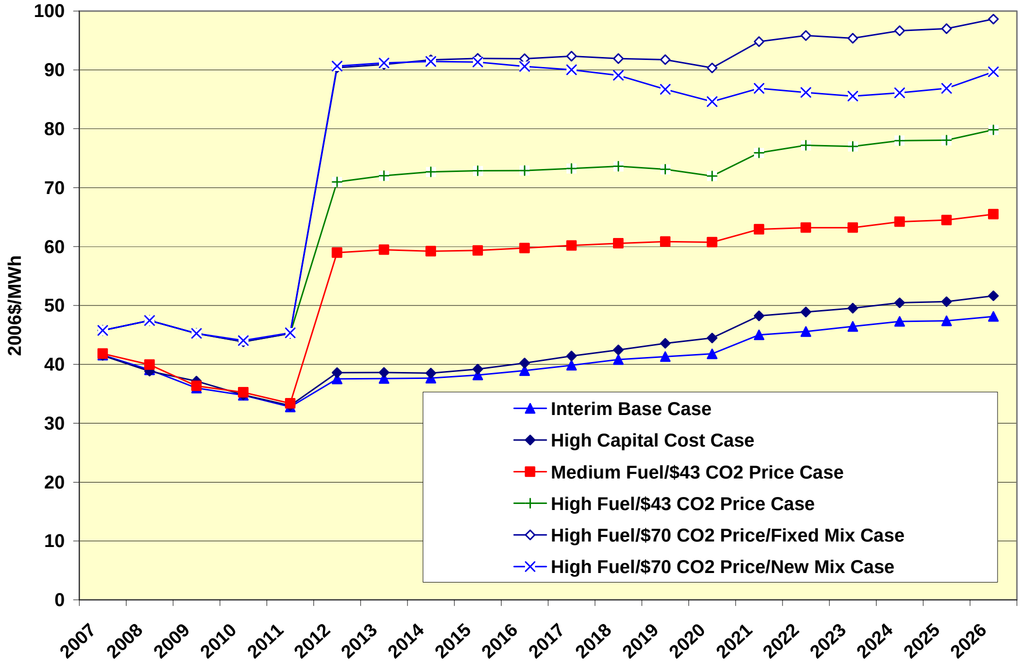
Figure 3: Forecast Pacific Northwest incremental resource mix based on dispatch energy (High Fuel/\$70 CO_2 Price/New Mix Case)



In its Fifth Power Plan the Council assumed that IGCC plants with CO_2 capture and sequestration using unconventional sequestration media (i.e., other than enhanced oil or gas recovery) could be in service in the region in the 2015 - 2020 period. Because of disappointingly slow development of the technologies involved it is uncertain whether five IGCC plants with carbon capture and sequestration could be built in the Northwest between 2019 and 2026. Moreover, because of the absence of relevant plant construction experience, the cost and risk of carbon sequestration is difficult to estimate. The Council will continue to improve its assumptions regarding this technology as it develops the Sixth Power Plan.

Whether CO_2 allowance prices of \$70 per ton of CO_2 would be politically sustainable for a prolonged period of time is also an open question. Many of the cap-and-trade proposals introduced in the 110th Congress call for “safety valve” options designed to release the CO_2 emissions cap if the cost of compliance becomes unacceptably high. Figure 4 shows the forecast wholesale power prices for each of the scenarios studied. The high fuel price sensitivity cases with \$70 per ton CO_2 allowance prices have the highest forecast power prices. For example, the High Fuel/\$70 CO_2 Price/New Mix Case had a levelized wholesale power price of \$73.70 per megawatt-hour (MWh). This is \$20.90 per MWh higher than the levelized price of the reference case. The High Capital Cost Case presented in the Council’s “Interim Wholesale Power Price Forecast” paper had a levelized wholesale power price of \$41.30 per MWh. However, a \$70 per ton of CO2 allowance price appears to be more than sufficient to reduce CO2 emissions to 1990 levels, raising the possibility that somewhat lower allowance prices may suffice to achieve this objective, even with high natural gas prices. Moreover, a portion of the allowance revenues would likely be redirected to energy efficiency measures and low carbon generation, partly offsetting the overall cost of power system operation.

Figure 4: Forecasts of Northwest wholesale power prices



CONCLUSION

An important modeling result presented in the Council's paper, "Marginal Carbon Dioxide Production Rates of the Northwest Power System," is that the Northwest power system's annual CO_2 emissions can be driven below its1990 level with CO_2 allowance prices of $43 per ton. This result was achieved at the Council's medium fuel price forecast.

The findings presented in this addendum demonstrate that this modeling result is sensitive to higher natural gas price forecasts. At the Council's high fuel price forecast the $43 per ton CO_2 emission cost is insufficient to achieve the same dramatic reduction in the total annual emissions of the Northwest power system.

The higher natural gas prices tend to work against efforts to achieve significant reductions in total CO_2 emissions. This is because higher natural gas prices favor coal-fired generation by making natural gas-fired units more costly to operate. Our modeling indicates that with the Council's high fuel price forecast, CO_2 allowance prices would need to climb to a level between $43 and $70 per ton of CO_2 in order to reduce the Northwest power system's annual total emissions to its 1990 level.

The Council will continue to explore these issues as it develops its Sixth Power Plan. While a wide range of uncertainties regarding both fuel prices and CO_2 allowance prices will be incorporated in the Sixth Power Plan portfolio risk analysis, CO_2 reduction objectives can only be indirectly considered by subsequent examination of the CO_2 production implied by the resulting preferred resource portfolio.

Attachment 66.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)