Wanamaker, Lori FIN:EX

From: Justesen, Josh T FIN:EX
Sent: Wednesday, November 15, 2017 10:15 AM
To: Cochrane, Marlene EMPR:EX
Cc: Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
Subject: RE: Urgent Letter
Attachments: 102700 BCUC Final_Signed.pdf

Hi Marlene,

Please find the signed document attached.

Thank you,
Josh Justesen
Administrative Coordinator | Deputy Minister's Office
Ministry of Finance | Victoria, BC
(250) 387-1660

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 9:33 AM
To: Justesen, Josh T FIN:EX
Subject: Urgent Letter
Importance: High

Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

BRITISH COLUMBIA

November 15, 2017

Ref.: 102700

Mr. David Morton
Chair
BC Utilities Commission

Email: David.Morton@bcuc.com

Re: Inquiry Respecting Site C

The Ministry of Energy, Mines and Petroleum Resources and Ministry of Finance are supporting the government decision process surrounding the future of the Site C project. On behalf of our respective Ministers, we would like to thank the BC Utilities Commission (Commission) for the report *Inquiry Respecting Site C*. Completing an inquiry of this scope over an abbreviated timeframe and with high levels of public and First Nations input is a considerable achievement.

As our ministries analyze the Commission's report, along with other implications associated with government proceeding with or terminating the Site C project, we want to ensure that we fully understand the assumptions and computations that the Commission made in the analysis of potential alternative sources of energy generation and capacity. Accordingly, we are requesting further explanation or additional information on the points listed below and in the Appendix attached to this letter.

1. Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?

   We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not, could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

2. In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects

Ministry of Energy, Mines and Petroleum Resources
Office of the Deputy Minister
Mailing Address: PO Box 9319, Stn Prov Govt Victoria, BC V8W 9N3
Telephone: 250 952-0120
Facsimile: 250 952-0269
Location: 8th Floor, 1810 Blanshard Street Victoria
Website: www.em.gov.bc.ca/

included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

3. Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?

4. If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?

   - Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

   - Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

5. We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:

   - Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?

   - Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?

We sincerely appreciate the Commission's timely response to these questions and requests for clarification. Government has committed to making a decision on the Site C project before the end of the year. The Commission's responses to our questions will assist our ministries in better understanding the report and the assumptions that underlie it as we prepare advice to support government in making a decision that will be in the best interests of British Columbians.

Dave Nikolejsin Deputy Minister Ministry of Energy, Mines and Petroleum Resources	Lori Wanamaker Deputy Minister Ministry of Finance

Attachment

Appendix: Detailed Questions for the Commission

We understand that while BC Hydro modelled over 60 scenarios and tested various assumptions, including a number of alternatives requested by the Commission, the alternative portfolio that the Commission included in the final report was not analyzed using BC Hydro's modelling tools. On this basis, government has asked BC Hydro to provide an assessment of the model used to develop the Commission's final alternative portfolio. BC Hydro will provide the Commission with the results of that assessment separately.

In our initial analysis of the report, our ministries have identified several areas that we would appreciate the Commission's feedback on. Several of our questions relate to the impact of certain assumptions made in the report, and how the costs of those assumptions would be recovered from ratepayers.

We understand that BC Hydro follows standards for rate-regulated utilities in its financial statements and in preparing its applications for review by the Commission. This accounting framework follows a number of principles in relation to the amortization of capital assets and the deferral of other costs for the purpose of matching recoveries from ratepayers to periods over which benefits are provided.

It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.

The Commission's process involved some deliberations on the cost of capital. The alternative portfolio presented in the report assumes that BC Hydro will finance all new resources on its balance sheet. However, other than redevelopment of existing sites and Site C, BC Hydro has, for almost three decades, been primarily procuring new supply from competitive processes or bilateral agreements that are benchmarked to competitive processes. This effectively means that BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.

It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio, and the BC Hydro financing assumption should only be used for the Unit Energy Cost (UEC) analysis. However, on pages 167, 170 and Appendix C (Assumption 2), it appears that the

Commission has used BC Hydro financing (100% debt financing at a cost of 3.43%) for the alternative portfolio. If we are interpreting this correctly, we would appreciate clarification on which cost of capital should be used in analysing rate impacts.

BC Hydro has suggested that recovery in rates of sunk costs in a termination scenario should occur over a 10-year period. If the project were to continue as planned, the sunk costs, as part of the overall project costs, will be recovered over a 70-year period, consistent with the amortization of the Site C asset. The Commission model appears to exclude sunk costs in the termination scenario, and has removed those costs from the completion scenario as well. Effectively this assumes that sunk costs will be recovered through rates over 70 years if the project is terminated. Recovering costs in rates over a shorter period has a material impact on the costs of the alternative portfolio. It would be helpful if the Commission could provide an estimate of the impact on rates of using these two timeframes.

The tables on page 17 of the executive summary and page 170 in the main report include a summary of the Commission's sample scenarios showing the effect of modifying one or more variables to the resulting Net Present Value cost to ratepayers. As noted above, the Commission's alternative portfolio does not appear to include sunk costs, and sunk costs have also been removed on the continue scenario. The tables also include UECs. For the Site C scenario, the UECs reflect costs, including sunk costs, of Site C being either $10 billion or $12 billion depending on assumptions. Our review of the Commission report suggests that the alternative portfolio does not include termination costs. It would be helpful if the Commission could confirm this and provide a version of the UEC portion of the table with termination costs included in the alternative portfolio. This would help provide a consistent basis for comparing costs between the scenarios of completing or terminating the project.

It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis?

We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's *Clean Energy Act* energy objectives of:

- Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;
- Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,
- Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.
It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the *Greenhouse Gas Reduction (Clean Energy) Regulation* under the *Clean Energy Act*. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures.

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

Wanamaker, Lori FIN:EX

From:	Cochrane, Marlene EMPR:EX
Sent:	Wednesday, November 15, 2017 10:23 AM
To:	Justesen, Josh T FIN:EX
Cc:	Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
Subject:	Urgent Letter

Thank you, Josh. The letter has been sent to Mr. Morton.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

From: Justesen, Josh T FIN:EX
Sent: Wednesday, November 15, 2017 10:15 AM
To: Cochrane, Marlene EMPR:EX
Cc: Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
Subject: RE: Urgent Letter

Hi Marlene,

Please find the signed document attached.

Thank you,
Josh Justesen
Administrative Coordinator | Deputy Minister's Office
Ministry of Finance | Victoria, BC
(250) 387-1660

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 9:33 AM
To: Justesen, Josh T FIN:EX
Subject: Urgent Letter
Importance: High

Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

Wanamaker, Lori FIN:EX

From:	Cochrane, Marlene EMPR:EX
Sent:	Thursday, November 16, 2017 9:08 AM
To:	Nikolejsin, Dave MNGD:EX; Wanamaker, Lori FIN:EX
Subject:	Letter from D Nikolejsin and L Wanamaker

Mr. Morton has acknowledged receipt of the letter and mentions a response will come next week. Thanks.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

From: Morton, David BCUC:EX
Sent: Thursday, November 16, 2017 9:01 AM
To: Cochrane, Marlene EMPR:EX
Subject: RE: Letter from D Nikolejsin and L Wanamaker

Thanks Marlene,

We are reviewing the letter and will provide a response to you next week.

Dave

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 10:22 AM
To: Morton, David BCUC:EX
Subject: Letter from D Nikolejsin and L Wanamaker

Good Morning Mr. Morton,

Please see the attached letter from Mr. Dave Nikolejsin, Deputy Minister, Ministry of Energy, Mines and Petroleum Resources, and Ms. Lori Wanamaker, Deputy Minister, Ministry of Finance, regarding the Inquiry Respecting Site C.

Regards,

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

Wanamaker, Lori FIN:EX

From:	Kennedy, Christine PREM:EX
Sent:	Thursday, November 23, 2017 2:30 PM
To:	Foster, Doug FIN:EX
Cc:	Wanamaker, Lori FIN:EX
Subject:	Fwd: BCUC Site C Inquiry - Additional Questions
Attachments:	11-23-2017_MEM MoF Site C_Addition Questions.pdf; ATT00001.htm

Christine

Begin forwarded message:

From: "Sanderson, Melissa EMPR:EX" <Melissa.Sanderson@gov.bc.ca>
Date: November 23, 2017 at 2:07:16 PM PST
To: "Nikolejsin, Dave MNGD:EX" <Dave.Nikolejsin@gov.bc.ca>, "Howlett, Tim GCPE:EX" <Tim.Howlett@gov.bc.ca>, "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>
Cc: "Lloyd, Evan GCPE:EX" <Evan.Lloyd@gov.bc.ca>, "Zadravec, Don GCPE:EX" <Don.Zadravec@gov.bc.ca>, "Haslam, David GCPE:EX" <David.Haslam@gov.bc.ca>, "Kristianson, Eric GCPE:EX" <Eric.Kristianson@gov.bc.ca>, "Gibbs, Robb GCPE:EX" <Robb.Gibbs@gov.bc.ca>, "Kennedy, Christine PREM:EX" <Christine.Kennedy@gov.bc.ca>
Subject: FW: BCUC Site C Inquiry - Additional Questions

Hi all,

The attached response to the clarification request from the DM's just came in to our Minister inbox from the BCUC.

Thanks,

Melissa

From: Minister, EMPR EMPR:EX
Sent: Thursday, November 23, 2017 2:04 PM
To: Sanderson, Melissa EMPR:EX
Subject: FW: BCUC Site C Inquiry - Additional Questions

From: Commission Secretary BCUC:EX
Sent: Thursday, November 23, 2017 1:42 PM
To: Minister, EMPR EMPR:EX; Minister, FIN FIN:EX
Subject: BCUC Site C Inquiry - Additional Questions

Dear Dave Nikolejsin and Lori Wanamaker:

Please see attached correspondence with respect to the above-noted matter.

Original will not follow. A hard copy of the attached is available upon request.

Please call the BCUC Regulatory Services at 604-660-4700 to request a copy.

Regards,

Katie Berezan
Administrative Assistant, Regulatory Services

British Columbia Utilities Commission
P: 604.660.4700 **BC Toll Free:** 1.800.663.1385 **F:** 604.660.1102
bcuc.com

bcuc
British Columbia
Utilities Commission

David Morton
Chair and CEO

David.Morton@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

November 23, 2017

Sent via email

Dave Nikolejsin
Deputy Minister
Ministry of Energy, Mines and Petroleum Resources
PO Box 9319, Stn Prov Govt
Victoria, BC V8W 9N3
EMPR.Minister@gov.bc.ca

Lori Wanamaker
Deputy Minister
Ministry of Finance
PO Box 9417, Stn Prov Govt
Victoria, BC V8W 9V1
FIN.Minister@gov.bc.ca

Re: British Columbia Hydro and Power Authority - British Columbia Utilities Commission Inquiry Respecting Site C – Project No. 1598922

Dear Dave Nikolejsin and Lori Wanamaker:

The Deputy Ministers' letter of November 15, 2017 poses a series of questions to the Commission regarding its Final Report on the Site C Inquiry, which was initiated by the Lieutenant Governor by Order in Council 244. The Commission thanks the Deputy Ministers for their inquiry and sets out its response below, trusting that any additional clarity or amplification of the messages in the Final Report will assist the government in its decision regarding Site C.

Sincerely,

David Morton
Chair and Chief Executive Officer

DM/kbb
Enclosure

Introduction

The Inquiry initiated by Order in Council (OIC) 244 requested that the Commission evaluate the cost to BC Hydro ratepayers of continuing, suspending or terminating construction of the Site C dam. In its Final Report, the Commission drew two overall conclusions:

- The cost to ratepayers of suspending construction would be significantly higher than either continuing or terminating the project, to the tune of $3.6 billion.[1] In addition, there are significant risks that it would not be possible to restart the project due to permitting and other issues.
- The cost to ratepayers of continuing or terminating construction is similar,[2] given the assumptions that the Commission finds to be most reasonable. Both alternatives also have risks which may cause one or the other to be more costly to ratepayers either in the short-term or over a longer period.

Many of the questions posed in the Deputy Ministers' letter, in one way or another, relate to the estimates underlying these conclusions. We believe it will be helpful to provide some background and context before addressing the specific questions.

In reaching its conclusions, the Commission was required to estimate the costs of each of the three options, and in the case of termination, the cost of the alternative energy that might be required. It is important to recognize that each estimate comes with a degree of uncertainty. For example, when considering the cost of terminating the Site C project, the Commission found, based on information from BC Hydro and Deloitte, that costs could range from $750 million to $2.3 billion.[3] In order to make a comparison between the options, the Commission chose a reasonable "point estimate" of $1.8 billion based on BC Hydro's P90 estimate.[4] But it would be quite possible, based on the information available to conclude that the cost of termination could be up to a billion dollars less, or half a billion dollars more. Nonetheless, in spite of this uncertainty, it was quite reasonable for the Commission to conclude that the option of suspending the project, estimated to be $3.6 billion more than either continuing or terminating construction, would be significantly more expensive for ratepayers.

By comparison, the estimated costs to ratepayers of continuing or terminating construction, at $2.852 billion and $3.147 billion respectively,[5] were so close that it would be unreasonable for the Commission to draw a meaningful distinction between them. Given the range of estimates to terminate the project ($750 million to $2.3 billion) an even larger difference between the estimated costs to continue or to terminate would have resulted in the Commission drawing the same conclusion they were similar.

To further illustrate how using point estimates for input assumptions masks the potential variability of assumptions, consider the original Site C completion costs. The original estimate of $8.35 billion was based on a

[1] BCUC Site C Inquiry Respecting Site C Executive Summary (Executive Summary), p. 3.
[2] BCUC Site C Inquiry Respecting Site C Final Report (Final Report), p. 187.
[3] Final Report p. 128.
[4] This is BC Hydro's P90 estimate, which should only have a 10% chance of being exceeded.
[5] Final Report, Errata, p. 10 of 11.

Class 3 estimate, which means that the expected accuracy range is from 20% under the budgeted amount to 30% over the budgeted amount – in this case a variance of $4.2 billion.[6]

Similarly, some of the costs associated with the Illustrative Alternative Portfolio are highly uncertain. Costs of acquiring wind generation equipment post 2025 for example, are estimates of future costs and, as such, may not share the accuracy level of a Class 3 estimate.

Accordingly, in order to rely on a numeric analysis of the costs of various options, the differences in results should be greater than the amount of uncertainty in the input assumptions. In the Inquiry, BC Hydro calculated the incremental cost to ratepayers of terminating the Site C project – including the cost of an alternative portfolio – compared to the cost of completing, to be in the range of $6.2 billion to $11.1 billion. If this amount could be substantiated, it would provide a compelling case to continue. However, based on the evidence available to the Inquiry we were unable to verify these amounts.[7]

That said, the estimates provided in the Final Report are based on many assumptions the Commission was required to make based on the information available to it during the Inquiry. To assist the government in its decision-making, the Commission included in the Final Report some sensitivity analyses to show how the cost estimates would change if different assumptions were applied. An example of this is the forecast for energy demand.

The Commission has found that the forecast of energy demand is most likely to be at BC Hydro's "low load" or lower, based on available information, government policies in place and other factors. Should the government undertake future policy changes resulting in an increase in demand as high as BC Hydro's high load forecast, the cost of Site C would be more attractive by $796 million.[8] Likewise, the Commission estimates that Site C will cost $10 billion to complete. Should the government estimate that the project will end up costing $12 billion, the present value of the overall cost to ratepayers of Site C would be higher by $646 million.

In the two examples just described, the difference in the estimates caused by changing the assumptions is less than $1 billion. While this is a significant sum, recall that the estimate of termination costs could vary by that same figure.

The Commission concluded based on its findings, that the cost to ratepayers of continuing or terminating the Site C project is similar. The Commission concedes that the Government might take a different view on one or more of these assumptions, and the sensitivity analysis already provided in the Final Report should allow it to adequately evaluate the consequential effect of a change on the estimated cost to ratepayers. However, the Commission cautions that it would require a very significant difference between the estimates to conclude reliably that one would be more expensive than the other.

In addition to the evaluation of ratepayer costs, the OIC requested that the Commission advise on the broader implications of the three options under consideration. The Final Report stated:

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[6] American Association of Cost Engineers, Cost Estimate Classification System – As Applied in Engineering, Procurement and Construction for the Process Industries.
[7] Exhibit F1-1, pp. 66–67 and 96–97.
[8] Executive Summary, p. 17.

We have not been asked to make recommendations or to identify which option has the highest cost to ratepayers or more significant implications than others. Nevertheless, we have provided our view that not only is the suspension scenario the greatest cost to ratepayers of the three scenarios, it also has other negative implications.

We take no position on which of the termination or completion scenarios has the greatest cost to ratepayers. The Illustrative Alternative Portfolio we have analyzed, in the low-load forecast case, has a similar cost to ratepayers as Site C. If Site C finishes further over budget, it will tend to be more costly than the Illustrative Alternative Portfolio is for ratepayers. If a higher load forecast materializes, the cost to ratepayers for Site C will be less than the Illustrative Alternative Portfolio.

We have provided a discussion of the risk implications of each alternative in order to assist in the evaluation.[9]

We trust that the information in the Final Report, including the discussion of risk, and the results of the province-wide Community Input Sessions and First Nations Input Sessions, will provide useful guidance to the government beyond the question of cost.

[9] Final Report, p. 187.

Question 1: Inclusion of Site C sunk/termination costs

The Deputy Ministers ask:

> *Did the Commission include sunk costs (the estimated $2.1 billion that has been spent to date on the project) and termination costs (the $1.8 billion determined by the Commission) in comparing the costs to ratepayers of completing Site C against the costs of pursuing an alternative portfolio of generation resources?*

Response

The Commission did not include sunk costs in the analysis of ratepayer impact for either Site C or the Illustrative Alternate Portfolio of generation resources. The costs assumed in this analysis were, in both cases, only costs incurred from January 2018 onward. These costs include the termination costs of Site C which are included in the ratepayer impact of the Illustrative Alternative Portfolio.

The Final Report states:

> In order to evaluate the cost to ratepayers of the termination case, and compare that rate impact to the cost of completing Site C, we compare the cost to ratepayers of the energy for the alternative portfolio to the cost of completing Site C from January 1, 2018. The sunk costs of $2.1 billion, which include the Site C regulatory account balance of approximately $0.5 billion, must be recovered in both scenarios. Accordingly, we do not consider the rate impact of the sunk costs in the termination scenario. [10]

The ratepayer impact analysis identifies the present value (PV) of the costs to ratepayers of Site C compared to an Illustrative Alternative Portfolio. The costs are modelled as a cost of service that is recovered in a revenue requirement for the utility. The amounts are calculated annually for seventy years and are discounted (in a net present value [NPV] Analysis) to F2018 dollars. Thus we characterize the cost to ratepayers as the NPV of the seventy-year rate impact.

It is important to note that this does not necessarily reflect the same bill impact as would be faced by an individual ratepayer. That analysis would require further input assumptions, including the number of ratepayers that the revenue requirement is being collected from each year.

[10] Final Report, p. 163.

This treatment is illustrated in the tables on page 167 of the Site C Final Report:

Table 1: Site C Final Report, Tables 39 and 40[11]

Output: Low LF - Alternative Portfolio				
A	Site C Termination Cost (F$18)	$	1,395	million
B	Alternative Portfolio Cost (F$18)	$	2,539	million
C	Surplus Energy Sale (F$18)	$	(788)	million
D	Total Rate Impact (A+B+C)	$	3,147	million

Output: Low LF - Site C				
A	Sunk Costs (F$18)	$	2,100	million
B	Site C Cost to Complete (F$18)	$	4,391	million
C	Flexibility Credit (F$18)	$	(66)	million
D	Surplus Energy Sales (F$18)	$	(1,473)	million
E	Total Rate Impact (B+C+D)	$	2,852	million

In the table above, the $1.395 billion for "Site C Termination Costs" represents the PV of the $1.8 billion of Site C termination costs amortized over 30 years.

Table 2: Rate Impact ($ million) of Site C compared to the Illustrative Alternative Portfolio

	Site C	Illustrative Alternative Portfolio
As provided in the Final Report Errata • Ratepayer impact	$2, 852 million	$3, 147 million[12]

If sunk costs are included, the ratepayer impact of both the continue and terminate options would be affected. If the same amortization period was chosen the effect would be the same for each alternative. We discuss the issue of amortization period for both sunk and termination costs further in our response to question 3.

The Deputy Ministers also ask:

> *We were not able to determine whether the sensitivity analysis included on Page 17 of the report's executive summary includes sunk costs and termination costs consistently. If it does not,*

[11] Final Report, p. 167, as updated by A-25 errata.

[12] In a letter dated November 16, 2017, BC Hydro identified an additional errata related to application of inflation factors and discount rates which would reduce the PV cost of the Illustrative Alternative Portfolio by $60 million. The Final Report was not adjusted for this subsequent errata on the grounds of materiality.

could the Commission advise on how including these sunk and termination costs might change the cost to ratepayers and the unit energy cost (UEC) in both scenarios?

Response

The calculation of the Unit Energy Cost differs from the calculation of cost to ratepayers. The Panel found that there is no generally accepted definition of "unit energy cost." In the Inquiry, BC Hydro stated that "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced." [13]

The term "levelized cost of energy" or "levelized cost of electricity" (both often referred to as LCOE), are in general use in the industry to compare the costs of energy projects. For example, the US Energy Information Administration (EIA) describes LCOE as follows:

> Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. It represents the per-kilowatt hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type. ...[14]

In the Preliminary Report, the Panel defined "unit energy cost" as: ***"Unit Energy Cost*** simply expresses the cost for a resource by its levelized annual cost per unit of energy produced."[15]

There were no submissions received on this issue, and in the Final Report the Panel stated:

> The Panel therefore confirms the unit energy cost definition proposed in the Preliminary Report, that the Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced. ...
>
> **Given the definition of UEC, the Panel finds it inappropriate that the unit energy cost be adjusted for sunk costs** [i.e. that the sunk costs be added to Site C cost to complete or to the Alternative Portfolio costs, as they are sunk so only future costs matter] **and termination costs** [i.e. that the termination costs be added to the Alternative Portfolio cost] **and will not consider these costs in the unit energy cost analysis.** [16]

If sunk and termination costs are included in the UEC analysis:

- The Site C UEC, would increase.
- The UEC of the Illustrative Alternative Portfolio would increase

The quantum of the increases depends upon the assumptions made concerning recovery periods. The following tables provide a sensitivity analysis. Please also refer to our response to question 4 for a more complete discussion about recovery of sunk and termination costs.

[13] F1-1 Submission, p. 61.
[14] EIA Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, p. 1, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[15] Final Report, p. 154.
[16] The wording in the Final Report has been corrected above to clarify that Site C sunk costs are excluded from the unit energy cost comparison.

Table 3: Unit Energy Cost Sensitivity Analysis – Sunk and Termination Costs

Site C			Illustrative Alternative Portfolio[17]			
Sunk costs[18] added?	Amortization period (years)	Unit Energy Cost (F18$/MWh)	Sunk costs added?	Termination costs[19] added?	Amortization period (years)	Unit Energy Cost (F18$/MWh)
No	n/a	$44	No	No	n/a	$31
Yes	70	$57	Yes	No	70	$48
	70	$57			50	$49
	70	$57			30	$50
	70	$57			20	$52
No	n/a	$44	No	Yes	70	$45
		$44			50	$46
		$44			30	$48
		$44			20	$49
Yes	70	$57	Yes	Yes	70	$63
	70	$57			50	$64
	70	$57			30	$67
	70	$57			20	$70

Table 4: Total Rate Impact Sensitivity Analysis – Sunk Costs

Site C			Illustrative Alternative Portfolio[20]		
Sunk costs[21] added?	Amortization period (years)	Total Rate Impact (F18$million)	Sunk costs added?[22]	Amortization period for sunk and termination costs (years)	Total Rate Impact (F18$million)
No	n/a	$2,852	No	30	$3,147
Yes	70	$4,086	Yes	70	$4,399
	70	$4,086		50	$4,530
	70	$4,086		30	$4,775
	70	$4,086		20	$4,969

[17] All scenarios are for the low load forecast, Panel market price assumption, BC Hydro financing, Medium Wind and Geothermal costs.
[18] Sunk costs of $2,100 million (F2018$)
[19] Termination costs of $1,800 million (F2018$).
[20] All scenarios are for the Low load forecast, Panel market price assumption, BC Hydro financing, Medium Wind and Geothermal costs.
[21] Sunk costs of $2,100 million (F2018$)
[22] Note that termination costs were included in the Total Rate Impact for the Alternative portfolio.

Question 2: Financing costs

The Deputy Ministers ask:

In the event that government elects to terminate the Site C project, has the Commission assumed that BC Hydro would develop and finance the projects included in the alternative portfolio (wind, geothermal) rather than independent power producers (IPPs)?

Response

The Commission did not assume that BC Hydro would develop and finance the projects included in the alternative portfolio. Specifically, the Final Report states that "[t]he Panel makes no determination on whether BC Hydro or IPPs should undertake the investments included in the Illustrative Alternative Portfolio."[23]

The Deputy Ministers also ask:

We observe that the Commission has in some cases used BC Hydro's lower cost of capital financing to calculate the cost of the alternative portfolio presented in the report, affecting the valuation of those projects. Could the Commission offer its view of the impact that a higher cost of capital would have on ratepayers if the alternative portfolio were developed by independent power producers rather than directly by BC Hydro?

Response

The Final Report, to assist users in performing sensitivity analysis on the financing cost assumptions, described how users can perform an analysis of the effect of using IPP financing assumptions:

> The updated spreadsheet now allows for the application of different financing costs for wind and geothermal projects. If financing costs are assumed to be the same as BC Hydro's financing cost for Site C (100% debt financing at a cost of 3.43%), the user should select 'BCH rate' in the drop-down menu of the 'Financing Option' variable of the 'Input and Output' tab. If these projects are assumed to be undertaken by IPPs and financed at the IPP financing rate assumed by BC Hydro at 6.4%, the user should select 'IPP rate' instead. If a different rate than 6.4% is assumed, the user can change the value of 'IPP Financing Rate in %' directly.[24]

The Commission notes that selecting the IPP rate in the model results in a financing rate assumption of 6.4% in real terms, whereas BC Hydro's IPP financing rate assumption is 6.4% in nominal terms. In order to model the effect of use of BC Hydro's IPP financing rate, the rate in the model should therefore be set to 8.5 percent.

The table below provides the results of the Illustrative Alternative Portfolio model if changes are made to the Commission financing cost assumptions. Please note that the sensitivity analysis below only reflects the increase in financing costs of IPP financed projects, and does not reflect the corresponding decrease in ratepayer risk:

[23] Final Report, pp. 159–160.
[24] Final Report, Appendix C, p. 2.

Table 5: Sensitivity analysis regarding wind/geothermal financing cost assumption[25]

Load forecast scenario	Illustrative Alternative Portfolio PV Cost: Commission Assumptions[26] (BC Hydro financing rate of 3.43%)	Alternative financing cost assumption (BC Hydro IPP financing rate of 8.5%)	Increase/(Decrease) in Alternative Portfolio PV cost
• High load forecast	$5,121 million	$5,831 million	$710 million
• Med load forecast	$4,618 million	$5,130 million	$512 million
• Low load forecast	$3,147 million	$3,359 million	$212 million

The Deputy Ministers ask:

> *[By procuring new supply from competitive processes] BC Hydro avoids assuming such debt on its balance sheet and only recognizes the incremental costs of new energy purchases which would include the private sector's annual debt servicing costs and equity return within approved purchase contracts.*
>
> *It would be helpful to understand how the Commission assesses the impact on ratepayers of the additional debt associated with the assumptions underlying the alternative portfolio. We would particularly appreciate better understanding the Commission's approach to using BC Hydro's cost of capital for IPP projects and the approach used for the cost of capital faced by an IPP (i.e. what IPPs actually pay) and the resultant rate impacts. For example, on page 159-160, the Commission appears to conclude that IPP financing is the relevant assumption for the alternative portfolio ...*

Response

On page 160 of the Final Report, the Commission stated that "the same financing cost should be assumed for Site C and the Illustrative Alternative Portfolio." The Commission consistently used the BC Hydro financing rate in its comparison between Site C and the Illustrative Alternative Portfolio, for the reasons set out in the Final Report, which are repeated below for convenience. The Final Report goes on to provide an analysis of the effect of using the IPP financing rate for the alternative portfolio, as provided above.

The Commission concluded that an analysis comparing Site C to an alternative portfolio should be agnostic as to the ownership structure used. The rationale for this approach is discussed in the Final Report:

> The question posed in the OIC- whether there is an alternative portfolio that will deliver the benefits of Site C at an equivalent or lesser cost – will yield a different response depending on what assumptions are made regarding whether the alternative portfolio is developed by BC Hydro or by an IPP. ...

[25] Results in this table are based on the revised Illustrative Alternative Portfolio spreadsheet published on Nov. 16 with the A-26 errata.
[26] Final Report, p. 70, footnote 600.

> By contracting for the supply of energy from an IPP, as opposed to developing an energy source directly, BC Hydro will transfer development, construction and operating risk to the IPP. In the Panel's view, the analysis should reflect this transfer of risk. CEABC suggests that the effect of this transfer of risk should be reflected in the discount rate that is applied to each project. BC Hydro submits that it isn't practical to conduct such an analysis on a project to project basis. ...
>
> The Panel makes no determination on whether BC Hydro or IPPs should undertake the investments included in the Illustrative Alternative Portfolio. This Inquiry is not the place to address the question of BC Hydro versus IPP ownership and determine the optimal price/risk allocation in energy purchase agreements between BC Hydro and IPPs. Indeed, this review is agnostic with respect to ownership structure and instead focuses on the inherent cost and performance attributes of the generating assets, and how those assets will meet needs and address risk within the broader generation portfolio.
>
> In order to ensure that the outcome of this review is not biased for or against a particular ownership structure, the Panel therefore determines that an "apples to apples" comparison requires that the same financing costs be assumed for both Site C and the Illustrative Alternative Portfolio. However, to address the concerns raised by BC Hydro, the Panel provides additional scenarios with different financing assumptions. For these scenarios, BC Hydro financing will only be applied to DSM initiatives, and IPP financing costs for all other generation sources. ...[27]

With regards to the reference to "additional debt" associated with the alternative portfolio, the Commission notes that BC Hydro will be financing the Site C project with debt. Therefore, given the similar cost of Site C and the alternative portfolio, the Commission sees no "additional debt" in the event that BC Hydro were to build alternative generating projects instead of Site C.

[27] Final Report, pp. 159, 160.

Question 3: Demand-side management

The Deputy Ministers ask:

> *Government will need to consider the total cost of potential demand side management initiatives (rather than just the utility's costs) as it considers the alternatives. Could the Commission advise how the inquiry Terms of Reference led to assessing demand-side measures based on the Utility Resource Cost standard, when Total Resource Cost has been the standard for prior Commission proceedings?*

Response

The Report stated:

> **With regard to what DSM cost should be included in the Alternative Portfolio, the Panel finds that the cost should be the utility cost as section 3(b)(iv) of the OIC [questions] refers to the cost to ratepayers.**[28]

The terms of reference for the Inquiry requested that the Commission evaluate the costs to ratepayers of continuing, suspending or terminating construction of Site C. The Commission interpreted the phrase "costs to ratepayers" as referring to costs that would recovered through BC Hydro's revenue requirement. The Report also stated: "When calculating cost to ratepayers, we calculate the NPV of the incremental revenue requirement of the item in question."[29]

The Commission did not include costs that would be incurred by other parties, such as the government or individuals; neither did the Commission consider broader societal costs or benefits in the financial analysis. Therefore, when considering the costs to ratepayers of the DSM programs, the Commission included only the costs incurred by BC Hydro.

The Deputy Ministers ask:

> *It is our understanding that in previous proceedings the Commission has concluded that the Total Resource Cost (TRC) test is the appropriate way to evaluate demand side management (DSM) in comparison to other resources. In this inquiry, the Commission's model uses the Utility Resource Cost (URC) standard. We believe that using the URC model may underestimate the actual cost of DSM to ratepayers. It would be helpful for us to understand the Commission's rationale in choosing a test methodology that differs from past practice. Could the Commission confirm that the TRC test remains the appropriate metric, and if so, what impact would this have on the analysis.*

Response

The total resource cost test remains an appropriate metric for analyzing whether or not to proceed with DSM programs. As we noted in the final report: "Regarding the use of the utility cost compared to the total resource

[28] Final Report, p. 38.
[29] Final Report, p. 164.

cost, the Panel agrees that BC Hydro should not be undertaking DSM programs that do not pass the total resource cost test."[30]

We also noted that the level of DSM investment included in the Illustrative Alternative Portfolio, a level originally recommended by BC Hydro in the 2013 IRP,[31] could reasonably be considered to pass this test: "However, the illustrative DSM portfolio only includes the first (lowest cost) block of BC Hydro's estimated incremental DSM opportunities. The Panel considers that the Illustrative Alternative Portfolio assumption that the programs in this first block all pass the total resource cost test is reasonable."[32]

The Commission did not use a utility resource cost standard in determining the appropriate level of DSM investment to include in the Illustrative Alternative Portfolio. Therefore, the Commission sees no impact to the analysis.

Once the level of DSM investment in the Illustrative Alternative Portfolio was determined, the Commission then addressed the question of its costs to ratepayers, as set out in the terms of reference. As explained in the answer to the question above, the Commission included only the costs that would be incurred by BC Hydro, and thus passed on to ratepayers. The rationale for this approach is addressed in the Final Report:

> With regard to what DSM cost should be included in the Alternative Portfolio, the Panel finds that the cost should be the utility cost as section 3 (b)(iv) of the OIC refers to the cost to ratepayers, as opposed to the BC cost or the societal cost.
>
> For example, the industrial load curtailment DSM program has a utility cost of $75/kW-year, while BC estimates that the total resource cost (i.e. the cost to the customer of curtailing) is $60/kW-year. The Panel considers it would not be consistent with the treatment of Site C to include in the Alternative Portfolio the cost to the industrial customer of curtailing supply (total resource cost), instead of the cost to the utility of obtaining the curtailment (utility cost).[33]

The Deputy Ministers also ask:

> *The report identifies an aggressive DSM program, coupled with load curtailments as a way to achieve the alternative portfolio scenario. We would appreciate further information from the Commission on how such load curtailments would practically be achieved in the natural resource sector without impairing operations, jobs and economic growth for sectors already facing trade sanctions and pressures*

Response

The Commission would not characterize the DSM plan included in the Illustrative Alternative Portfolio as aggressive. The level of DSM included in the Illustrative Alternative Portfolio is, in fact, the level recommended by BC Hydro in its 2013 Integrated Resource Plan, and was the least aggressive apart from one of the five levels of DSM spending that BC Hydro modelled at that time.[34]

[30] Final Report, appendix A, p. 38.
[31] Final Report, Appendix A, p. 34.
[32] Final Report, appendix A, p. 38.
[33] Final Report, Appendix A, pp. 38, 39.
[34] Final Report, Appendix A, p. 34.

The Commission believes that load curtailment can be a mechanism to retain and attract additional industrial load, and so enhance, rather than impair, operations, jobs and economic growth. The Final Report identifies a desire by industry for higher levels of industrial curtailment opportunities than included in the Illustrative Alternative Portfolio. Specifically, the Association of Major Power Customers (AMPC) has argued for BC Hydro to offer higher levels of load curtailment as being in the interests of its members:

> Curtailable loads have already demonstrated that they can feasibly, cost-effectively and dependably provide system capacity for the necessary duration of peak load events. AMPC's October 11 submission details the specifics of AMPC's position. Once long term curtailable tariffs are established; scalable capacity resources can be delivered in appropriate quantities and at very short notice compared to generation sources. From BC Hydro's forecasts of capacity and energy need, the immediate implementation of curtailable contracts and/or tariffs could provide the necessary time to take a more detailed look at how future energy needs are most reliably and affordably provided. This time is particularly valuable during a period of significant technological development in energy storage, to reduce the risk of adopting a potentially short-lived technology path. Moreover, this provides a non-rate mechanism to retain existing, and attract additional, industrial load.
>
> ...the Commission should, as part of any alternative energy portfolio evaluated, consider the full use of industrial load curtailment to generate needed system capacity, because load curtailment is a well-developed, well-studied program that can be implemented economically and quickly, without the need to speculate on the its potential availability in the future.[35]

[35] Final Report, Appendix A, pp. 72, 74, 75. Emphasis added.

Question 4: Amortization of sunk/termination costs

The Deputy Ministers ask:

> *If the Site C project were terminated, the $4 billion sunk and remediation costs would need to be recovered, and the amortization period of that recovery would affect BC Hydro rates. Could the Commission please clarify whether it assumed that that these costs would be recovered over 10, 30 or 70 years?*

Response

The Commission made no assumptions on the recovery of sunk and termination costs. The Final Report states:

> Regarding the potential mechanisms to recover termination costs, the options available are either from BC Hydro ratepayers, the shareholder or some combination of the two. If these costs are to be recovered from ratepayers a further issue is over what period they should be recovered.
>
> Generally speaking, a regulated utility is entitled to recover from its ratepayers, all prudently incurred expenditures. Therefore, the issue would be whether the costs to terminate the project were prudently incurred and this can only be determined after the expenditures have been made.
>
> In regard to the recovery period, this requires further analysis. Considerations include intergenerational equity – too long a period risks forcing customers who may not benefit from the expenditure to pay for it. If the payback period is too short, there is a risk of rate shock. This Panel takes no position at this time what the recovery period should be and notes that it would be subject to Commission approval.
>
> The same principles apply to the recovery of the sunk costs. There are some that suggest that if the project is terminated, this could be an indicator that the decision to go ahead with the project was not prudent. Others argue that since the project was not approved by the Commission, the costs were, by definition, not prudently incurred.
>
> **The Panel takes no position on the recoverability from ratepayers for sunk and termination costs. Further, we take no position on the recovery period for sunk and termination costs.** However, for the analysis of ratepayer impacts of the termination scenario, we have assumed that termination costs will be recovered from ratepayers over a 10, 30 and 70 year recovery period.
>
> Although we do not consider the rate impact of sunk costs when comparing the continue and termination scenario, the costs must be recovered. In the case of Site C being completed these costs would be included in the project costs, and barring any disallowance, would be recovered from ratepayers over the 70-year amortization period proposed. In a terminate scenario, again assuming the costs are to be recovered from ratepayers, to determine the cost impact to ratepayers requires assumptions regarding the amortization period.

The Deputy Ministers also ask:

Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit. From the Commission's perspective, can recovery of the sunk and remediation costs of Site C over longer periods of 30 to 70 years remain consistent with these inter-generational principles?

Response

The Commission reiterates that we take no position on the recovery period for sunk and termination costs. The recovery period would be the subject of Commission review if, and when these costs are incurred.

When considering the recoverability of any costs, there are a number of regulatory principles considered, including:

- Price signals that encourage efficient use and discourage inefficient use (economic efficiency);
- Fair apportionment of costs among customers (fairness);
- Avoid undue discrimination (fairness);
- Customer understanding and acceptance, practical and cost effective to implement (practicality);
- Freedom of controversies as to proper interpretation (practicality);
- Recovery of the revenue requirement (stability);
- Revenue stability (stability); and
- Rate stability (stability).[36]

The above considerations would apply to the recovery period of both termination costs and sunk costs.

We generally agree with the Deputy Ministers' statement "Fair and appropriate rate-setting principles for rate-regulated utilities typically aim to avoid causing future generations to pay for investments from which they will derive no benefit." Intergenerational equity is an important consideration when considering the deferral of cost recovery. However, in the termination case, both the sunk and termination costs relate to a stranded asset, and it is important to note that no-one benefits from a stranded asset. Therefore there is no more – or less – justification that any particular generation should be more liable than another for the costs related to that stranded asset.

The Deputy Ministers also ask:

Recently it has been stated that recovering the project's sunk and remediation costs over a 10-year period would lead to a 10 per cent hike in BC Hydro rates. Is this assertion consistent with the Commission's thinking?

Response

The table below shows the initial effect on the revenue requirement of amortization of Site C sunk costs, followed by the combined effect when estimated termination costs have been incurred. BC Hydro's F2018 revenue requirement request of $4,626 million has been used to estimate the year one rate impact effect of the

[36] Bonbright principles, BC Hydro 2015 Rate Design Application, Decision dated January 20, 2017, pp. 11, 12

alternative amortization options.[37] BC Hydro real rate increases subsequent to F2018 will result in a lower percentage impact than that indicated on the table below.

Table 6: Rate impact of alternative amortization period for Site C sunk and termination costs

Amortization Period (years)	Year one costs recovered	Revenue requirement impact
Site C sunk costs only ($2.1 billion)		
10	302	6.5%
30	152	3.3%
50	122	2.6%
70	109	2.4%
Total Site C sunk costs and termination costs ($3.9 billion)		
10	560	12.1%
30	282	6.1%
50	226	4.9%
70	203	4.4%

The Panel therefore confirms that the use of a 10-year amortization period for Site C sunk and termination costs have a potential rate impact of 10 percent. However, the actual rate impact of Site C termination will reflect the amortization period selected, which will in turn be driven by intergeneration equity and rate shock concerns, and the degree to which sunk or termination costs prove to have been prudently incurred. The Panel notes that the year one revenue requirement impact of Site C (before export revenues) is estimated at $499 million (F2025).[38]

The scenarios for the total rate impact of the Illustrative Alternative Portfolio as presented in the Final Report[39] include termination costs of $1,800 million. The analysis in the tables above suggests a situation whereby the sunk and termination costs of Site C would be recovered separately from the costs of the Illustrative Alternative Portfolio. To avoid double counting, it is therefore appropriate to present accompanying analysis that demonstrates the impact of removing termination costs from the total rate impact of the Alternative Portfolio. Table XX below indicates that the illustrative Portfolio would be less costly in all load forecast scenarios with termination costs excluded from the rate impact.

[37] BC Hydro F2017-F2019 Revenue Requirement Application, Exhibit B-1-1, p. 1-38
[38] BC Hydro Site C cost calculator (Submission F1-4, BC Hydro, IR 2, Attachment 3), as adjusted to show total Site C costs (including sunk costs) as $10 billion.
[39] Final Report Executive Summary Errata, Corrected Table 43, p.10

Table 7: Total Rate Impact – Termination Costs Excluded from Alternative Portfolio

	Site C– Total Rate Impact (F18$millions)	Illustrative Alternative Portfolio – Total Rate Impact		Difference between Site C and Alternative Portfolio – Termination costs excluded (F18$milllions)
		Termination costs included (F18$milllions)	Termination costs excluded (F18$milllions)	
Low Load Forecast	2,852	3,147	1,752	($1,100)
Medium Load Forecast	3,901	4,618	3,222	($679)
High Load Forecast	4,325	5,121	3,726	($599)

In addition, the Appendix to the Deputy Ministers' letter asks:

> *It would be helpful if the Commission could clarify how the choices of cost amortization and recovery periods in the Termination scenario fit within appropriate utility rate-setting principles that recognize and avoid unnecessarily transferring current utility costs to future user generations when there are clearly no longer directly-related assets or benefits being provided. Such decisions lead rate-regulated accounting practice and use of regulatory accounts, which are areas of particular interest by the provincial Auditor General as well as credit rating agencies.*

Response

The issue of the appropriate period to recover Site C sunk and remediation costs is addressed in the Site C Final Report:

> In regard to the recovery period, this requires further analysis. Considerations include intergenerational equity – too long a period risks forcing customers who may not benefit from the expenditure to pay for it. If the payback period is too short, there is a risk of rate shock. This Panel takes no position at this time what the recovery period should be and notes that it would be subject to Commission approval. ...
>
> **Further, we take no position on the recovery period for sunk and termination costs.** However, for the analysis of ratepayer impacts of the termination scenario, we have assumed that termination costs will be recovered from ratepayers over a 10, 30 and 70 year recovery period.
>
> Although we do not consider the rate impact of sunk costs when comparing the continue and termination scenario, the costs must be recovered. In the case of Site C being completed these costs would be included in the project costs, and barring any disallowance, would be recovered from ratepayers over the 70-year amortization period proposed. In a terminate scenario, again assuming the costs are to be recovered from ratepayers, to determine the cost impact to ratepayers requires assumptions regarding the amortization period.[40]

As noted above, the Commission considers numerous factors in determining the appropriate amortization period to use to recover Site C sunk costs and termination costs.

[40] Final Report, pp. 163–164.

Question 5: Load forecast

The Deputy Ministers ask:

> *We are unaware of prior instances when anything other than BC Hydro's mid-load forecast has been used for planning purposes. For that reason, we would like to clarify:*
>
> > *Did the Commission assume lower demand for electricity (reflected in the low-load forecast used in the report) because it is forecasting a period of lower economic growth for the province in which major power consumers such as mining, forestry, technology and commercial sectors are in decline?*

Response

The Commission did not assume a lower demand for electricity "because it is forecasting a period of lower economic growth for the province." Further, the Report does not state, nor does it suggest, that "major power consumers such as mining, forestry, technology and commercial sectors" are in or are going into "decline". On the contrary, the Report specifically acknowledges that there have been some positive developments in the non-LNG large industrial load, but goes on to conclude that these positive developments are not sufficient to offset the negative developments in the potential BC LNG sector.

The Commission's consideration of the load forecast was based on a holistic assessment of the factors that drive demand for electricity. In our answer to the Deputy Ministers' question below regarding the rationale for the Commission's position, we present a description of the seven factors we considered. These include three factors that are directly related to economic growth: recent developments in the industrial sectors, GDP and other forecast drivers, and flattening electricity demand.

The Deputy Ministers also ask:

> *Does the Commission include in its load forecast the potential increased electrical power demand of meeting the province's stated objectives to reduce greenhouse gas emissions through greater electrification of our economy?*

Response

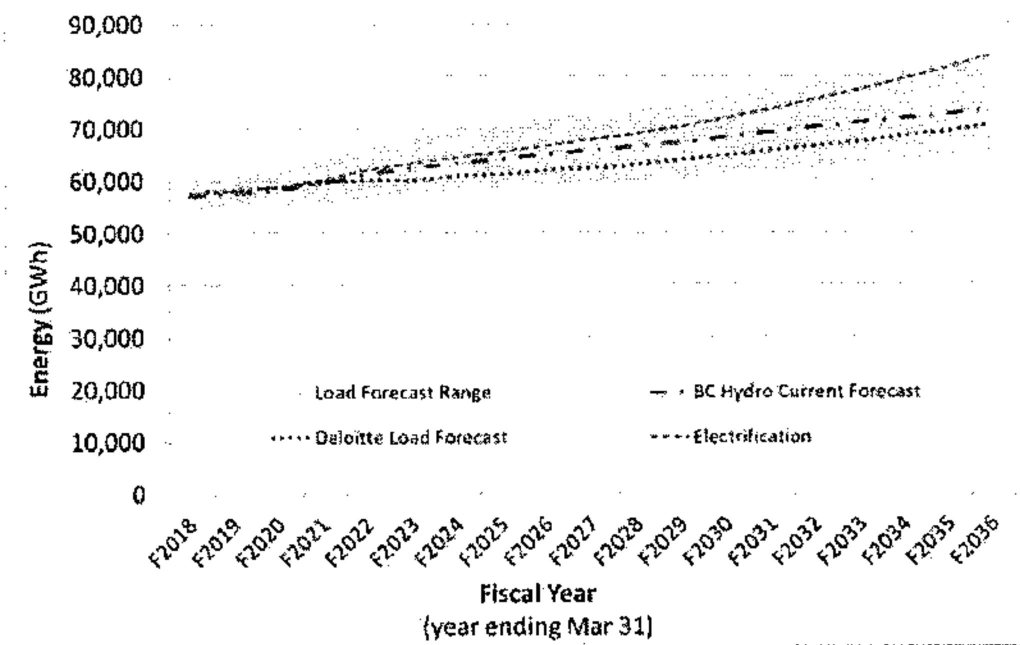
The Commission does not have a load forecast. The terms of reference required us to use BC Hydro's load forecast from the 2016 Revenue Requirements Application, which has a mid-level projection within a high and a low band. We were also required to seek BC Hydro's view on factors which might influence expected demand toward the high or low cases.

The Commission did consider electrification in the Final Report both from the perspective of impacts on the load forecast over the 20-year period and disrupting trends over time. These are considered below.

In its submissions, BC Hydro highlights the emerging potential for load growth from initiatives targeting greenhouse gas emission reductions through electrification of fossil-fuel powered end uses. BC Hydro states "electrification of energy loads currently served by fossil fuels such as space and water heating, vehicles and industrial equipment could reasonably cause demand for electricity to exceed BC Hydro's mid forecast in the Current Load Forecast."

However, BC Hydro does not account for electrification initiatives directed at reducing greenhouse gas emissions in its Current Load Forecast because the timing and magnitude of the potential increase is uncertain at this early stage. BC Hydro presents the potential for electrification to have an upward impact on the load forecast in the figure below.

Figure 1: BC Hydro's Load Forecast Range, Impact of Electrification, and Deloitte's "Alternative" Load Scenario



Although available information indicates that the effects of electrification on BC Hydro's load forecast could potentially be significant, the timing and extent of those increases remain highly uncertain. Given the uncertainty, the Site C Inquiry Panel agreed with BC Hydro that additional load requirements from potential electrification initiatives should not be included in the load forecast for the purpose of resource planning.

The extent and timing of electrification initiatives will be a matter of government policy. In the absence of such policy, it is not appropriate to include any potential additional load requirements from electrification initiatives in the load forecast for resource planning. Should the government set further policy with respect to electrification, BC Hydro would need to prepare an updated load forecast reflecting the impact of such policies.

Although not taken into account in the load forecast, electrification is still an issue for consideration. In its report, the Panel noted that if electrification does materialize in the future, it is possible that some of the higher electricity demand could be offset with aggressive conservation measures, including DSM programs that achieve load reductions similar in magnitude to those experienced in New England.[41]

[41] Page 75 of the Final Report includes the following submission by CanWEA: "These [downside risks] are very real risks that are being realized in many other North American electricity markets. In New England, where I am from, the most recent long-term electricity demand forecast by the Independent System Operator is for a .6% compound annual decline in energy

The Panel also acknowledged numerous submissions identifying disruptive factors that could potentially decrease demand, including the potential impact of expanded distributed generation. However, because these downward impacts on load are uncertain, the Panel did not identify any specific trends that would suggest an adjustment to the Current Load Forecast is required.

The Deputy Ministers further ask:

> *We have noted that the Commission has concluded that BC Hydro's low load forecast was most appropriate for an assessment of the need for the capacity of Site C. It would be helpful for us to further understand the rationale, and whether the assessment includes the load requirements needed to meet the Province's Clean Energy Act energy objectives of:*
>
> - *Reducing greenhouse gas emissions by 2050 by 80% less than 2007 levels;*
> - *Encouraging the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia; and,*
> - *Encouraging communities to reduce greenhouse gas emissions and use energy efficiently.*

Response

To recap the Final Report, the Commission concluded:

> **Overall, the Panel finds BC Hydro's mid load forecast to be excessively optimistic and considers it more appropriate to use the low load forecast in making our applicable determinations as required by the OIC. In addition, the Panel is of the view that there are risks that could result in demand being less than the low case.**[42]

In making findings on BC Hydro's load forecast, the Commission considered the following factors:

1. Recent developments in the industrial sectors
2. Accuracy of Historical Load forecasts
3. GDP and other forecast drivers
4. Price Elasticity assumptions
5. Future Rate increases
6. Potential disrupting trends
7. Flattening electricity demand

Each of the seven items considered by the Commission in arriving at its determination on BC Hydro's load forecast are addressed in detail in the Final Report and are summarized below.

consumption over the next ten years, with no meaningful increase in peak load. New York ISO is also forecasting a decline in energy consumption (-.2% per year)."

[42] Final Report, p. 77.

Recent developments in the industrial sectors

The Panel reviewed recent developments in the industrial sector and concluded:

> **The Panel finds the developments since the Current Load Forecast was prepared, as reported by BC Hydro, can reasonably be expected to reduce demand from the expected case or mid forecast.**
>
> The Panel acknowledges there have been some positive developments in the non-LNG large industrial load that BC Hydro suggests provide a net increase in demand since the Current Load Forecast was prepared (an anticipated positive total variance is approximately 750 GWh/100 MW in the short and medium term and 965 GWh/114 MW over the long-term). However, given the risk and volatility of the industrial load and its susceptibility to cyclical ups and downs, and the risks to the large industrial load set out by AMPC, the Panel is unable to draw any conclusions that these recent developments will result in a permanently positive impact on industrial demand. In any event, in the Panel's view these positive developments in the non-LNG sector are not enough to offset negative developments for a potential BC LNG sector.
>
> **The Panel finds that developments since the Current Load Forecast was prepared have significantly reduced the probability that the majority of BC Hydro's forecast LNG load will materialize.** Regarding the potential LNG industrial load, BC Hydro itself states there are questions as to whether BC has missed the window of opportunity for LNG. While BC Hydro points to certain third-party market views that still show some support for the opportunity to develop LNG in BC, the Panel notes the significant uncertainty expressed in most market views, the recent cancellation and postponement of several large potential BC LNG projects, and the higher costs of potential BC LNG projects compared to existing and potential projects in other jurisdictions. The Panel also agrees with several parties who express concern with the fact that BC Hydro had not made a probabilistic assessment of the likelihood of the LNG load materializing. The Panel agrees with Finn that the three projects cited by BC Hydro face uphill battles, especially given the current poor market conditions. [43]

Accuracy of historical load forecasts

After reviewing the accuracy of BC Hydro's historical load forecasts, the Panel stated:

> As noted in its Preliminary Report, **the Panel finds that the historical instances of over-forecasts are greater than under-forecasts, especially in the industrial load, and that the accuracy of BC Hydro's historical industrial forecasts looking out three and six years has been considerably below industry benchmarks.**
>
> The Panel acknowledges BC Hydro's argument that the drivers of historical industrial forecast variances are not relevant to the expected accuracy of the Current Load Forecast, especially considering the impacts of large discrete customer load attrition between 2006 and 2010 and the steps BC Hydro describes it has taken to ensure its existing industrial forecasts are reasonable. However, as pointed out by CEC, some of these declines in industrial load could or should have been anticipated and may represent a bias towards over-forecasting. Accordingly, while the Panel does not place significant weight on the historical inaccuracies in the load

[43] Final Report, p. 78.

forecast, it does approach the Current Load Forecast with some skepticism, especially as it relates to the industrial load forecast.[44]

GDP and other forecast drivers

After reviewing BC Hydro's GDP growth assumptions, the Panel stated:

> ...The Conference Board of Canada forecast projects the real GDP will grow by 2.6 percent on average between 2016 and 2020 and then drop to an average of 2.3 percent between 2021 and 2025. In contrast, BC Hydro's projection results in an average growth rate of 3.5 percent over the same five years. BC Hydro's forecast results in the BC economy being six percent larger than the CBoC's forecast by 2025. The Panel considers BC Hydro's average growth rate of 3.5 percent to be excessive.
>
> ...
>
> The Panel remains concerned that BC Hydro's GDP and disposable income forecast drivers are higher than other comparable third party estimates, such as the CBoC. Based on the evidence presented in this Inquiry, the Panel can make no definitive finding on the appropriate GDP or disposable income driver to apply. However, considering the historical over-estimates in the load forecast as noted above, the Panel approaches BC Hydro's estimates with skepticism given that these key drivers are both considerably higher than other third party estimates and use of the lower estimates would result in a lower load forecast. **Accordingly, the Panel finds BC Hydro's mid load forecast is higher than if it used the CBoC estimates and adjusting for this could reasonably be expected to influence demand towards the low load case.** [45]

Price elasticity assumptions

With regard to price elasticity, the Panel made the following findings:

> **The Panel finds the -0.05 long-run price elasticity used by BC Hydro for all rate classes to be too low in magnitude to reflect the degree of change in demand for a given change in price. Accordingly, the Panel finds BC Hydro's mid load forecast is higher than would otherwise be the case if it used lower price elasticity factors, and that adjusting for this would reduce demand towards BC Hydro's low load forecast case.**
>
> **The Panel finds that BC Hydro should be using a long-run price elasticity given the long 70 year time horizon of Site C. The Panel also finds that the international literature shows that long-run elasticities are higher than short-run elasticity. It is not clear to the Panel that BC Hydro's empirical studies have appropriately estimated long-run price elasticities since the residential inclining block rate and the transmission stepped rates have not been in place over a long time horizon.**
>
> ...
>
> **The Panel finds the residential long-run price elasticity is likely to be more than -0.05.** BC Hydro's empirical evidence shows a range from 0 to -0.13; however, the zero in the low-end of the range with no price response indicates the study results may not be reliable. The Panel

[44] Final Report, P. 78.
[45] Final Report, pp. 78–79.

> notes the study by Paul, Myers and Palmer shows the low-end of the range to be at -0.14 for residential long-run elasticity.
>
> BC Hydro's empirical evidence shows that the price elasticity for commercial and industrial general service customers is close to zero so BC Hydro adopted -0.05. **The Panel finds that BC Hydro's empirical evidence for the price elasticity of commercial customers is unreliable in determining the long-run price elasticity.** The Panel notes the international literature shows varied results for commercial customers. Paul, Myers, and Palmer had a long-run elasticity average of -0.29 with a range of -0.02 to -0.70. Bernstein and Griffin had a single estimate of -0.97 which suggests the elasticity could be higher than -0.05.[46]

In addition, the Panel noted BC Hydro's consultant GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts," which were developed in 2007, need to be updated.

Future rate increases

BC Hydro assumed no real rate increases beyond the end of the 10 Year Rates Plan (F2024).[47] The Commission concluded with regard to this assumption:

> **The Panel finds BC Hydro's demand forecast is sensitive to rate changes even using BC Hydro's low price elasticity factors. Accordingly, any real increase in rates beyond the rates reflected in the 2013 10 Year Rates Plan and any subsequent real rate increase could reasonably be expected to influence demand towards the low load case.**
>
> **The Panel finds there will be considerable upward pressure on rates for the remainder of the 2013 10 Year Rates Plan and beyond fiscal 2024. The Panel finds the risk associated with this upward pressure on rates is especially concerning given the submissions related to potential "demand destruction" that could result from the impact of real rate increases on already vulnerable industrial customers and the likelihood that even nominal rate increases will increase energy poverty among BC's low income households.**[48]

Potential disrupting trends

The Panel raised as a concern that, given the long life of the Site C asset, BC Hydro has only identified a potential upside risk to the load forecast from electrification, and had not identified any potential downside risk. The Panel concluded:

> **Given the uncertainty, the Panel finds additional load requirements from potential electrification initiatives should not be included in BC Hydro's load forecast for the purpose of resource planning.** Although available information indicates that the effects of electrification on BC Hydro's load forecast could potentially be significant, the timing and extent of those increases remain highly uncertain.
>
> BC Hydro has not included in its Current Load Forecast additional load requirements from electrification initiatives to reduce greenhouse gas emissions. The Panel agrees with BC Hydro and Hendriks *et al.* that the timing and magnitude of the increase is uncertain at this time. However, electrification is still an issue for consideration. The Panel notes that if electrification

[46] Final Report, pp. 79–80.
[47] Final Report, p. 65.
[48] Final Report, p. 80.

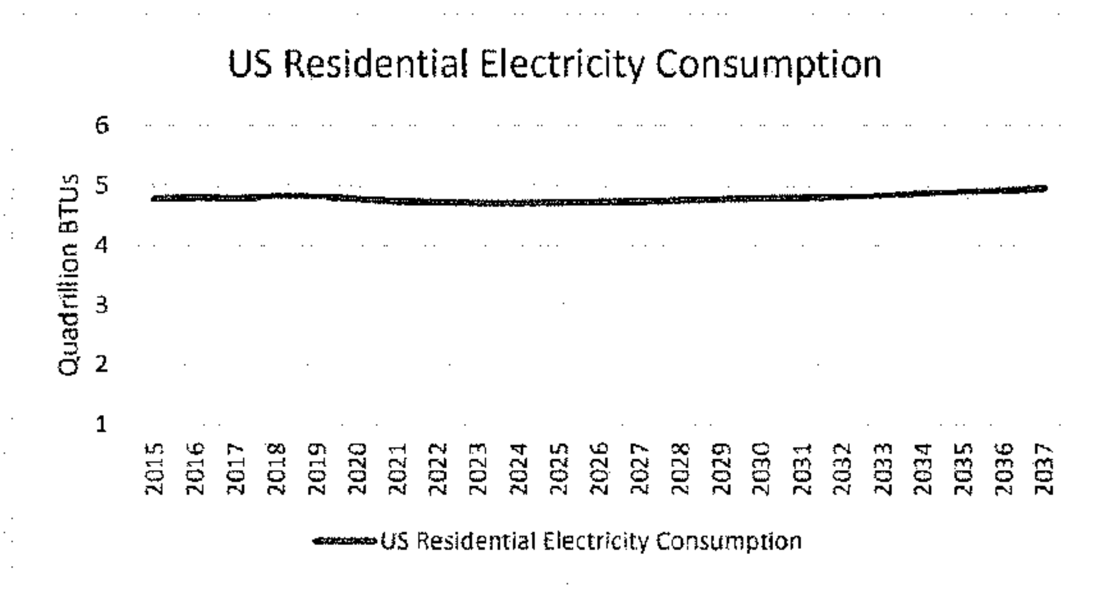
does materialize in the future, it is possible that some of the higher electricity demand could be offset with aggressive conservation measures, including DSM programs that achieve load reductions similar in magnitude to those experienced in the New England states.

The Panel acknowledges the numerous submissions identifying disruptive factors that could potentially decrease demand, including the potential impact of expanded distributed generation. However, because these downward impacts on load are uncertain, the Panel did not identify any specific trends that would suggest an adjustment to the Current Load Forecast is required.[49]

Flattening electricity demand

CEC, Surplus Energy Match and CanWEA all provide evidence that total demand is not growing in most jurisdictions in North America – in most cases it is flat or declining. In British Columbia the declining use per customer over the last 10 years has largely offset the effects of population growth.[50]

Figure 2: US Residential Electricity Consumption



The Deputy Ministers ask:

It has been government's assumption that electrification with low carbon electricity would be a key initiative to achieve greenhouse gas reductions. The provincial government is working with the Government of Canada on electricity system infrastructure investments to reduce and avoid greenhouse gas emissions, and has enabled BC Hydro to pursue electrification initiatives under the Greenhouse Gas Reduction (Clean Energy) Regulation under the Clean Energy Act. It would be helpful for our ministries to understand if the Commission has a different outlook, and if the

[49] Final Report, pp. 81–82.
[50] Final Report, p. 82.

Commission could further describe the impact on its analysis of electrification initiatives to meet greenhouse gas reduction objectives.

Response

The Commission's outlook on electrification and its effects on the load forecast are provided in the Final Report. We refer the Deputy Ministers to our previous answer for a summary of the material.

The Deputy Ministers also ask:

We understand that BC Hydro has provided the Commission with a description of its view of what BC's economic environment would look like under a low load outlook scenario. It would [be] helpful if the Commission could further describe its interpretation of the low load outlook. We observe that the Commission's view is that the outlook could be even lower than that presented in BC Hydro's low-load scenario, and we are interested in understanding how that outlook is based on realistic economic sustainability around which the alternative portfolio would be premised.

Response

The Commission's consideration of the load forecast was based on a holistic assessment of the factors that drive demand for electricity. In our answer to the question above regarding the rationale for the Commission's position, we have included a description of the seven factors we considered. These include three factors that are directly related to economic growth: recent developments in the industrial sectors, GDP and other forecast drivers, and flattening electricity demand.

Additional question: Dispatchability

The Deputy Ministers ask:

> *It would also be useful to know if the Commission examined the value of "dispatchable" resources versus intermittent resources, particularly as applied to the goal of moving industrial energy requirements now and in future to low carbon electricity.*

Response

The Commission examined the value of "dispatchable" versus intermittent resources in its selection of generation options in the Illustrative Alternative Portfolio, and concluded that "increasingly viable alternative energy sources such as wind, geothermal and industrial curtailment could provide similar benefits to ratepayers as the Site C project with an equal or lower Unit Energy Cost."[51]

Appendix A of the Final Report contains the Commission's analysis of each generation option in the Illustrative Alternative Portfolio, and the degree to which they provide "dispatchable" energy. With regards to wind energy, for example, the largest single contributor to the Illustrative Alternative Portfolio, the Commission stated:

> BC Hydro states that Site C (capacity 1,145 MW) can integrate 900 MW of wind. However, the Panel notes that BC Hydro's existing modest level of wind penetration (780 MW) and high levels of hydro generation providing reserves (GM Shrum, Mica and Revelstoke with a combined capacity around 8,000 MW) means that BC Hydro would not be expected to need Site C to integrate these additional wind farms.[52]

In comparison, the Illustrative Alternative Portfolio includes 444 MW of wind generation in the low load forecast and 729 MW in the high load forecast.[53]

[51] Executive Summary, p. 3.
[52] Final Report, Appendix A, p. 32.
[53] Final Report, Errata, p. 6.

Towner, Erin FIN:EX

From:	Foster, Doug FIN:EX
Sent:	Thursday, November 16, 2017 6:14 AM
To:	MacLaren, Les EMPR:EX
Subject:	FW: Urgent Letter
Attachments:	BC Hydro on reserve margin.pdf

Do you recall if or how the BCUC and or Hydro addressed this?
d.

From: Dunn, Jonathan FIN:EX
Sent: Wednesday, November 15, 2017 11:57 AM
To: Foster, Doug FIN:EX
Subject: RE: Urgent Letter

Thx – looks good, well done.

s.13

Kind regards
Jon

From: Foster, Doug FIN:EX
Sent: Wednesday, November 15, 2017 10:28 AM
To: Gonzalez, Selina FIN:EX; Hopkins, Jim FIN:EX; Dunn, Jonathan FIN:EX
Subject: FW: Urgent Letter

keeping you in loop.
how last 10 days spent. d.

From: Justesen, Josh T FIN:EX
Sent: Wednesday, November 15, 2017 10:15 AM
To: Cochrane, Marlene EMPR:EX
Cc: Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
Subject: RE: Urgent Letter

Hi Marlene,

Please find the signed document attached.

Thank you,
Josh Justesen
Administrative Coordinator | Deputy Minister's Office
Ministry of Finance | Victoria, BC
(250) 387-1660

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 9:33 AM
To: Justesen, Josh T FIN:EX
Subject: Urgent Letter
Importance: High

Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

BC Hydro Provincial Integrated Electricity Planning Committee
Meeting 2 (February 22-23, 2005)

Information Sheet #3
Planning Criteria

BC Hydro's Planning Criteria is used to ensure that BC Hydro has a reliable system. Reliability is a complex subject and can be viewed from different perspectives. We understand that, from the customer's point of view, reliability usually means "do the lights stay on?" regardless of the cause of an outage. Usually for customers, the frequency and duration of outages is important. We understand that some customers may tolerate a number of outages as long as they last no more than a few hours. Other customers, such as hospitals, can tolerate no outages, and these customers usually install their own backup generation.

From the utility's perspective, reliability is examined for the different components of the electric system: generation, transmission, and distribution. While examining the reliability of the system as a whole is important, utilities tend to have different planning criteria for each of the three major components. One reason why the systems are looked at differently is that the consequence of a failure can be very different. Failures in generation adequacy and the transmission system are more severe, but occur infrequently compared to outages on the distribution system.

Here are some examples of the different types of outages:

- One example of a distribution outage is trees falling on the distribution lines knocking out power for a local area. Almost all outages that BC Hydro's customers experience are due to problems on the distribution system.
- A good example of a failure of the transmission network is the Northeastern North American Blackout in August 2003. Instability on the transmission in one area cascaded and ended up leaving millions of customers without power for days.
- An example of a failure in generation reliability, or *resource adequacy*, is the California Crisis in 2000/2001 (which was exacerbated by legal and regulatory issues). California did not have enough generation to meet its load, and this resulted in rolling brownouts and high electrical prices for consumers.

In the 2004 IEP, all portfolios were built to meet the reliability planning criteria for generation and transmission (see below). Therefore reliability was not an attribute that was used to distinguish differences between portfolios. A similar approach is proposed for the 2005 IEP. Additional analysis could examine the cost and benefit of changing the planning criteria. This proposed approach will be discussed in more detail at the meeting.

BC Hydro's Planning Criteria is presented briefly in the sections below. For more context about reliability and planning criteria, please refer to the attached Electric Reliability Primer.

Generation Energy Planning

BC Hydro uses a Loss of Load Probability (LOLP)[1] of one-day-in-10-years for capacity planning. This LOLP criterion translates into a 14% capacity reserve. BC Hydro assumes that 400 MW of that capacity can be reliably met though imports, so the net capacity reserve actually maintained on our physical system is about 10%.

BC Hydro assesses the reliability of energy supply based on the firm energy capability of available resources. The firm capability of the hydroelectric resources is the energy that is reliably available at any time during the historical analysis period.

The generation reliability criterion is an input common across all portfolios. The Provincial Committee can highlight this as one of the issues they would like to see addressed in the modelling process.

Transmission

British Columbia Transmission Corporation (BCTC) is responsible for planning the transmission system. The transmission system is planned and operated in accordance with the industry-wide standards defined by the North American Electric Reliability Council (NERC). Generally, this reliability standard is met by applying the "single-contingency planning criterion" under which firm supply must serve demand with the largest element (such as a transmission line, cable circuit, transformer or generator) out of service.

In building portfolios, the supply and demand side management resource options are first scheduled to meet customer demand. The portfolios are then given to BCTC, who add the required transmission upgrades required for each portfolio in order to meet the transmission reliability criterion. Therefore, the transmission reliability standard is the same across all portfolios and so ought not to play a large role in discussions.

Distribution

Distribution reliability is currently undertaken based on historical performance of the distribution system combined with performance targets for improvement or maintenance of current performance. The system performance is measured in terms of frequency and duration of outages including the resulting Customer Hours Lost metric. Based on actual performance, distribution targets areas where frequent, long and high number of customers impacted outages have occurred.

Distribution reliability is not modelled in the IEP, as the IEP focuses on the overall system requirements.

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[1] LOLP is defined as the expected number of days in the year when the daily peak demand exceeds the available generating capacity.

Electric Reliability Primer

The attached Electric Reliability Primer was prepared by a consultant from Energy and Environmental Economics in September 2004. This paper was prepared for BC Hydro to document methodologies used by other utilities, and was not prepared specifically with the Provincial IEP Committee in mind.

As a result, BC Hydro has made some changes to this document, with permission by Energy and Environmental Economics, in order to focus the information on areas more pertinent to the 2005 IEP. Parts removed include an economics-based approach to reliability planning and "whole utility" planning, will be discussed briefly at the meeting. If committee members are interested in reading more information about these topics, BC Hydro would be happy to provide the full report.

Electric Reliability Primer

1. Introduction

This primer describes the reliability planning standards used by electric utilities and other control area operators in North America. The focus of this report is on *generation* reliability planning, but it also includes sections on transmission and distribution reliability planning, as reliability is best considered in the context of the interaction of these three areas to deliver energy to the end-user. This primer is meant to be an introduction to the topic, rather than a detailed tome. The primer was pulled together with "off the shelf" information, as the short timeframe did not allow for a detailed phone survey of utilities. However, given that generation planning and integrated planning efforts were largely put on hold because of market restructuring, the methods and techniques of the past are still in widespread use today.

Definition of Electric Reliability

For the purpose of this primer, we are focusing on investment decisions so our use of the term *reliability* refers to **adequacy**. Adequacy is the ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

General Findings

1. To assure that there is adequate energy to meet its existing commitments, BC Hydro uses the driest water year in its historical record to define the firm energy capability of its hydro resources. This practice is commonly found in large energy constrained hydro systems and is identical to the standard used by BPA.

2. BC Hydro also plans to maintain adequate capacity using a commonly used loss of load probability (LOLP) approach with a standard designed to provide 1 day with an outage over a 10 year period. The 1 in 2 day forecasting

standard for capacity and 1-day-in-10-years LOLP combination are common practices. Nearly half of the utilities in the survey discussed in the primer used a 1-day-in-10-years LOLP criterion.

3. BC Hydro's reliability criteria are consistent with the utilities reviewed, although it should be noted that differences in input assumptions can result in utilities planning for different levels of risk despite the use of the same criterion, such as 1-day-in-10-years LOLP.

4. Prior to the 1990's, vertically integrated utilities typically maintained 20% to 30% capacity margins (average 25%). Since 1992, the U. S. margin has declined to less than 15 percent.[1] BC Hydro's reserve margin of 14% is in the 12-18% range of reserve margin targets currently utilized in the Northwest and California.

5. Some utilities have utilized more sophisticated methods that attempt to more directly measure the potential impact of generation inadequacy on customers. PG&E's adoption of such a method in the 1990s resulted in a reduction of their target reserve margin from 22% using LOLP to 16% using the Shortage Value method.

Organization of the remainder of the primer.

Section 2 describes the measures of generation reliability used by the industry as it progressed from the simple operating rules commonly used in the 1960's (e.g., 20 percent planning reserve margins), to more sophisticated measures that include a customer's value of reliability.

[1] "Western System Power Crisis: Imperatives and Opportunities" EPRI, June 25, 2001. http://www.epri.com/WesternsStatesPowerCrisisSynthesis.pdf.

In Section 3, we describe the generation reliability standards used by BC Hydro; in Section 4 we compare these standards to those used by other utilities. Finally, Sections 5 and 6 provide overviews of transmission and distribution planning standards.

2. Evolution of Generation Reliability Planning

Generation reliability planning, like utility resource planning in general, is a relatively new practice born out of the need to justify "prudently incurred" expenditures. For much of the history of the electric utility industry, this pressure did not exist. From the invention of Thomas Edison's Pearl street station in downtown Manhattan in 1882, until roughly the time of the first oil crisis in the mid-1970's, increasing economies of scale and scope minimized the importance of careful attention to cost control in utility planning. This *Golden Era* of electric utilities occurred as prices declined from over $2 per KWh in 1900 to about 4 cents per kWh in 1972.[2] These remarkable cost decreases were fueled by technological advances in production efficiencies, rapid growth, and new high voltage transmission, allowing utilities to transport inexpensive sources of power, like hydro-power, to distant load centers.

During this time of rapid growth and declining costs, utilities did not need to carefully manage generation adequacy to minimize cost. Adding a new generator was a win-win situation, in the sense that it both increased the adequacy of the system to meet load, and reduced costs by augmenting or replacing older, less efficient sources of generation with newer, more efficient sources. The utility was, in effect, protected from making imprudent expenditures. If the new generation was in excess of what was needed to reliably meet load, it could simply be used to replace older, more costly generation. If the new generation

[2] 1984 USD

was necessary to meet new load, it proved to be not only a necessary expenditure, but one that also had the benefit of reducing average costs. With 8% annual growth rates, the utility could be sure that any excess generation capacity would not remain so for long.

These trends disappeared in the early 1970's. The rate of technological advancement slowed, reducing the cost savings that could be achieved by replacing older generation sources. The oil crisis caused fuel prices to skyrocket and brought increasing scrutiny on utility spending. Inflation drove utilities' cost of capital to double digit figures. Annual growth rates declined from nearly 8% to less than 3%. The confluence of these factors meant that utilities could no longer automatically and rapidly grow generation. To do so would mean high carrying costs for unused generation resources, rising average costs, and upward rate pressure. As a result, utilities began to devote effort to generation reliability planning, with the intent of building enough generation to reliably meet load, without incurring drastic cost increases due to overbuilding.

Traditional Generation Reliability Planning Methods

Generation reliability planning has typically been focused on planning to meet peak *capacity,* rather than planning based on total *energy* requirements. This is because the binding constraint is typically peak capacity, particularly in systems dominated by thermal generation sources, where energy requirements can be met by simply increasing fuel usage. However, for systems with significant amounts of hydroelectric resources and storage, the binding constraint could be annual energy (see

Figure 1). For example, the Federal Columbia River Power System (the source of energy marketed by the Bonneville Power Administration) is energy limited, and historically BC Hydro has been considered energy limited.

Figure 1: Generation Constraints by System Type

System Type	Capacity	Energy
Binding Constraint	Machine Limited (Thermal systems)	Fuel Limited (Hydro Systems)
Adequacy Metric	Peak Hour Capacity	Annual Energy

With transmission interconnection and the development of Open Access systems, energy limits are becoming less constraining. For example, hydro-dominated systems can purchase from the market to cover energy shortfalls during dry hydro years. However, because of the risk of high market prices, the energy planning criteria remains relevant --- but more from a price risk than an adequacy standpoint. This report therefore focuses on generation capacity planning methods.

Deterministic Planning

Generation reliability criteria can be divided broadly into two types of measures: *deterministic* and *probabilistic*. Deterministic criteria are calculated with known system parameters and provide a static look at the system. They offer the advantage of being easy to calculate and intuitive to understand. The disadvantage is that they only provide a limited representation of the adequacy of the generation system. *Reserve Margin* is a common deterministic criterion.

Reserve Margins

Reserve margin is the percentage by which supply capability exceeds demand. Planning reserve refers to the amount of generation capacity kept in excess of peak load to meet generation contingencies. Planning reserve was a common metric of utility generation reliability standards in the early days of reliability planning, and is still in use today.

Operating reserve margin is smaller than the planning reserve margin and reflects the generation capacity that is required to reliably meet peak demand on a real time basis. Operating reserve margins and other transient operating criteria are established by NERC and regional planning councils, as discussed in Section 6 of this document.

The advantage of the reserve margin criterion is that it is straightforward, easy to understand, and easy to compute. In some cases, the reserve margin can be based largely on professional judgment. In other cases, the reserve margin can be the byproduct of more comprehensive probabilistic analyses.

Probabilistic Planning

Probabilistic criteria recognize and model the dynamic nature of the generation system. Statistical methods are used to model the future uncertainties in system components. Since the 1980's the most common probabilistic criterion for generation reliability has been the Loss of Load Probability (LOLP).

LOLP

LOLP is defined as the expected number of days in the year when the daily peak demand exceeds the available generating capacity. It is obtained by calculating the probability of peak demand in a period exceeding the available capacity and adding these probabilities for all periods in the year. Typical periods used for LOLP studies are individual days or months. BPA is unique in using the entire winter season as its LOLP period of concern.

Because utilities have historically planned generation reliability such that the expected number of days in a year with inadequate generation to meet load is well under one day, LOLP is typically expressed as 1-day-in-X-years; for example 1-day-in-10-years or 1-day-in-20-years. Note that "1-day-in-10-years" in this case does not mean that there is an expectation of 24 hours of outages in ten years. Rather, the metric indicates that there is a 1 in 10 chance that during the year there will be an outage during one of the 365 days.

While LOLP is a probabilistic method, uncertainty in the peak demand forecast is typically not accounted for. LOLP also is problematic in that it only indicates the frequency of generation inadequacy, but does not indicate the duration or the magnitude of those generation shortages. Fortunately, LOLP is relatively easy to calculate, especially if only daily analyses are performed.

Hourly Loss of Load Expectation

Hourly Loss-of-Load-Expectation (LOLE) is similar to LOLP, with hourly demands used in the calculations. The use of hourly load data provides information on the duration of the outages in addition to the frequency. This type of analysis provides an estimate of the total expected outage minutes, although the magnitude of the outage is still lacking.

LOLE can be more computationally demanding than LOLP, as there are 8760 hours in the year, requiring 8760 iterations.

Expected Unserved Energy

Another reliability metric that is being more frequently used by utilities is Expected Unserved Energy (EUE). EUE measures the amount of energy demanded that exceeds the available supply (assuming that loads could be shed to bring demand down to the available supply at every hour). We are unaware of any widely accepted target for EUE. EUE indicates generation inadequacy in kWh per year.

Expected Duration of Emergency Actions

A related measure is Expected Duration of Emergency Actions (EDEA). EDEA is defined with the assumption that emergency actions are taken as long as available reserves are below a critical level. Therefore, EDEA is the expected duration of a having a reserve margin below the specified critical level. EDEA differs from LOLE only in that is measures duration at the reserve margin, rather than duration at supply demand balance.

Shortage Value

Finally, the shortage value metric combines the EUE estimate with the value of that unserved energy to customers. In economic terms, the cost of any action to reduce EUE should not exceed the value of that EUE reduction. Shortage value is an emerging criterion and does not have a pre-determined target value. Rather, the economically optimal value would vary with differences in customer value of service (VOS) and differences in generation supply option costs. Where customer VOS is higher, more generation reliability would be warranted. Conversely, where generation supply options are more expensive, the VOS would justify less generation reliability.

Taking into consideration the value of reliability to customers, as well as the cost of providing that reliability, often results in a lower level of planning reserves than would be obtained through a historically-used deterministic or probabilistic industry standard. For PG&E in the late 1980's / early 1990's, the planning reserve margin required based on shortage value was only 16%, as compared to 26% using the 1-day-in-10-years LOLP criterion. Table 1 summarizes the differences in the various generation capacity metrics. It shows that shortage value captures all of the different aspects of generation reliability.

Table 1: Generation Capacity Adequacy Metrics

Adequacy Aspect	LOLP	LOLE	EUE	Shortage Value
Frequency	☑	☑	☑	☑
Duration		☑	☑	☑
Magnitude			☑	☑
Value				☑

An example of shortage-value-based planning is included later in Section ***Error! Reference source not found.***.

Planning for Energy Limited Systems

Resource planning for energy limited systems is straightforward. The system is considered adequate as long as the annual energy output of the system exceeds the annual energy demand. This criterion can be refined to include energy imports, exports, and nonfirm loads so that the final criterion seeks resources such that:

(Output + Imports - Exports) >= (Energy Demand – Nonfirm Energy)

Risk tolerance of the system planner is incorporated through the selection of values for these inputs. For example, Bonneville Power Administration (BPA) uses the following assumptions:

Input	Assumption
Output	Hydro output for "critical water" year (OY 1937). This is nearly 4,000 aMW less energy than under average water condition.
Imports	No spot market imports, despite strong winter surplus capacity in the Southwest.
Energy Demand	Average year (1 in 2), based on input from customers.
Nonfirm Energy	Agreement to curtail Direct Service Industry Loads.

Despite the historical Northwest Planning criteria, load resource balance was allowed to go significantly negative beginning in the early 1990's --- basically the criteria was viewed as being too conservative, given the restructuring of the electricity markets in the West. This is an example of the role of judgment in selecting input assumptions for deterministic planning criteria.

Generation Reliability Planning for Pool Markets

In the 1990's, generation reliability planning was restructured to fit into redesigned markets for both capacity and energy. The challenge was met with a different response in different markets, as can be seen by the examples of California and New York discussed below.

California

In California, the assumption was that generation adequacy would be met by the market. Utilities were given incentives to sell off large portions of their generation and 100 percent of their net power needs was to be purchased through hourly spot markets. The California Independent System Operator (CAISO) was responsible for matching supply and demand bids for capacity related products, and market restructuring assumed that new generation supply would be provided in anticipation of, or response to, rising market prices as generation surplus declined. The only market or requirement for generation capacity was the Reliability Must Run (RMR) market established to provide certain capacity in load pockets. Load pockets are transmission-constrained areas that the ISO deems to have insufficient transmission transfer capability to provide adequate reliability without the operation of key in-area generators. The California Energy

Commission (CEC) was responsible for developing long-term forecasts of supply and demand by scenario, but these forecasts do not require any action by market participants.

Recently, the California Public Utilities Commission (CPUC) issued a decision that utilities should maintain a 15% reserve margin, in their long-term procurement plans. Discussions are currently underway between the CPUC and utilities with regard to how to meet these reserve requirements.

New York

The New York market differs from California in that it has an installed capacity (ICAP) market, separate from the generation energy market. The NYISO determines the amount of capacity that Load Serving Entities (LSEs) must procure, based upon the New York State Reliability Council's (NYSRC) Installed Reserve Margin. The NYISO uses an Unforced Capacity methodology to determine the amount of Capacity that each Resource is qualified to supply to the New York Control Area. The Unforced Capacity methodology estimates the probability that a Resource will be available to serve Load, taking forced outages into account. LSE's may procure adequate Unforced Capacity from Installed Capacity Suppliers either bilaterally or through ISO-administered auctions, to meet their requirements.

The NYCP Installed Reserve Margin is established annually by the NYSRC and is based on the NPCC standard for Resource adequacy. The NPCC Resource Adequacy Standard requires an LOLE of no more than once in ten years after due allowance for:

- Scheduled and forced outages and scheduled and forced derating;
- Assistance over interconnections with neighboring control areas and regions; and
- Capacity and/or load relief from available operating procedures.

For the Long Island and New York City zones, a specified portion of the total Unforced Capacity must be procured from suppliers electrically located within the transmission constrained areas. Because each LSE's load growth forecast is translated into a financial obligation to purchase ICAP, the NYISO evaluates each regional load growth forecast to determine consistency with historic growth rates, economic indicators, and the NYISO's own forecasts. The load forecasts can be weather normalized, but the NYISO Load Forecasting manual does not specify a design weather standard.

3. BC Hydro Generation Reliability Planning Standards

BC Hydro considers both the peak demand and the annual energy demand on its electrical system. The capacity planning criterion ensures that sufficient resources are acquired to provide a high reliability of serving the annual peak demand. The energy planning criterion ensures that sufficient resources are available to satisfy the annual energy requirements of the system. Both criteria act to ensure that BC Hydro's own supplies are adequate to meet the probable demands on its system and, as a result, BC Hydro limits its exposure to having to purchase high-priced spot market energy.

Generation Capacity Planning

LOLP Analysis

BC Hydro uses numerous generation adequacy criteria, including LOLP of 1-day-in-10-years. The LOLP is calculated using daily peaks (365 data points for the year). The critical assumptions for the LOLP analysis are 1) the demand forecast, and 2) the available resources.

Demand Forecast

BC Hydro's load forecasting group prepares a monthly peak forecast (12 data points) based on 1 in 2 year weather (50th percentile) from 30 years of meteorological data. The forecast starts with forecasts of the single hour peak demand for each of the 4 regions. The forecast uses the 50th percentile of the coldest annual temperatures over 30 years for each region. These regional forecasts are then combined into a single system peak after adjusting for peak load diversity. The single system peak is then converted into 12 monthly peaks using historical ratios. Finally, the generation planning group takes the 12 monthly peaks and converts each into 28 to 31 daily peaks using historical peak daily load duration curves for each month.

Resource Availability

BC Hydro uses Dependable Capacity, which is for 3 hours in the peak load period of weekday during the continuous two weeks of cold winter. Dependable capacity is calculated based on an 85% confidence level of assumed 50 year stream flows.

Equivalent Capacity Reserve Target

The 1-day-in-10-years LOLP criterion translates to a 12% capacity reserve margin if a 2% Forced Outage Rate (FOR) is assumed for the large hydro units, or 14% is 3% FOR is assumed for those units. BC Hydro assumes that 400MW of that capacity can be reliably met through imports, so the net capacity reserve target is only 8% to 10% of dependable capacity. BC Hydro's capacity reserve margin is comparable to the two largest units out of service, which BC Hydro reports is one way that many utilities meet their 1-day-in-10-years criterion.

Generation Energy Planning

The energy generation that a resource can reliably sustain is frequently referred to as its firm energy capability. The firm energy capability of the various resources available to BC Hydro is determined as follows:

Hydroelectric resources: The annual generation that can be sustained in all water conditions within the entire historical record (worst case) is considered the firm energy capability of the system.

Burrard and other thermal: The firm energy capability of Burrard and other thermal projects is determined from their installed capacity, maintenance requirements and unit forced outage rates. (Note that Burrard is no longer fuel limited)

Energy Purchase Contracts: BC Hydro has energy purchase contracts with numerous independent power producers and other suppliers. The firm energy capability of such acquisitions may be identified in the contract (eg. Alcan) or may require an assessment of the characteristics of the resource (eg. a contract to purchase the output of a hydroelectric IPP project).

4. Comparison to Other Utilities

We consider two points of comparison for BC Hydro's reliability planning standards. The first is based on a survey of major U.S. utilities conducted in the 1980's. The second is a brief review of the current practices in the Northwest and California. Each is described below.

1980's Survey of Reliability Planning Practices

In the mid-1980's, PG&E surveyed 16 major U.S. utilities on their generation reliability planning criteria. This survey remains a useful benchmark for BC Hydro. Since research into generation reliability planning methods was largely suspended with the restructuring of electric markets in the 1990's, practices today are not significantly different from those that were in place at the time of the survey. The results of the survey are shown Attachment A. For comparison, we have also included BC Hydro's and Bonneville Power Administration's (BPA's) current planning criteria in this table.

LOLP

Of the 16 utilities, 10 use an LOLP metric as one of their generation reliability criteria. Of the remaining 6, Duke Power ran LOLP as a comparative measure, FP&L and Houston were considering the use EUE, and SDG&E was considering reverting back to LOLP.

Of those utilities using LOLP, 80% use the same 1-day-in-10-years standard as BC Hydro. It should be noted, however, that LOLP criteria are not always directly comparable across utilities. One confounding factor is the number of days in the analysis. For example, PG&E's original LOLP analysis based its calculation on 1-day-in-10-years of "Julys" (where July is understood to mean a peak summer month). So they interpreted 1 day in ten years to mean one generation deficiency event in 120 dry Julys. Since there are 3 peak summer months in each year, PG&E's criterion could have been interpreted to have been a 1-day-in-40-calendar-years (120 months divided by 3 peak months per calendar year). On the other hand, BPA uses a 1-day-in-20-years LOLP, but their unit of concern is the entire winter season, as contrasted with the daily period used by BC Hydro.

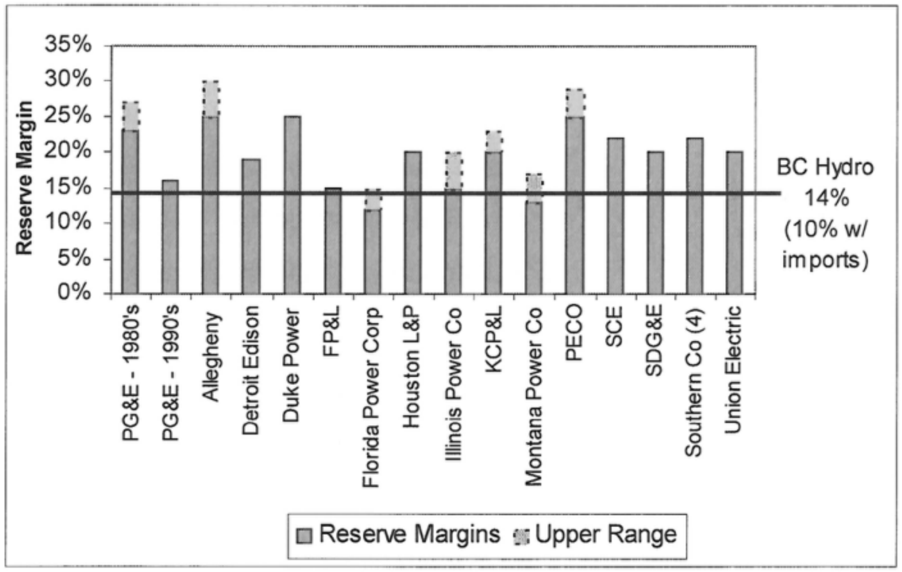
A second confounding factor is the extent of reliance on trade in multi-area reliability analysis. The key assumptions used by utilities in taking trade into consideration may differ, having a critical impact on LOLP calculations. For example, BC Hydro provides reserve margin figures that assume either zero or 400 MW of imports at the time of system need. BPA assumes 1,000 MW of imports in the summer and 3,000 MW of imports in the winter. Other utilities like Houston Light & Power assumed no support from trade at the time of the survey.

Reserve Margins

The PG&E survey also reported target planning reserve margins for each utility; those values are shown in the figure below. Some utilities reported a range of reserve margins. Those cases are indicated by the shaded box with dotted outline. The figure also shows BC Hydro's current reserve margin as the thick black horizontal line at 14%, assuming a 3% large hydro forced outage rate and no imports. As noted earlier, up to 400 MW can be reliably met through imports. When this is taken into consideration, BC Hydro's reserve margin falls to 10%.

EPRI reports that until the 1990's US utilities maintained a comfortable capacity margin of 20-30% (25% average), but between 1992 and 2001 the margin declined to less than 15%. This is borne out by Figure 2, which reflects the reserve margin targets utilities in the 1980s. BC Hydro's 10% reserve margin (14% without imports) is quite a bit lower than the reserve margins in the 20+% range from the 1980s, but consistent with the reserve margins currently observed in the U.S. on average, and the 15% target reserve margin recently decreed by the California Public Utilities Commission for the state. This decline in the US reserve margins is consistent with higher reliance upon transmission interconnections for system support. Moreover, given the higher than average reliability of hydro systems, we would expect that the BC Hydro target reserve margin would be lower than the US average.

Figure 2: Target Planning Reserve Margins



Reserve margins are circa 1980's unless otherwise noted.

Economic-based Planning

Four of the utilities in Attachment A take economic criteria into consideration when establishing their reliability criteria. Duke Power, Allegheny Power, and the Southern Company derived their reserve margins using an "Over/Under" framework, which makes explicit trade-offs between the costs of "over capacity" (primarily excess capital costs) and "under capacity" (including the costs of power outages). PG&E in the 1990s uses target planning reserve margins that are based on Shortage Value based planning. The use of economic-based criteria is discussed in more detail in Section 5.

Review of Current Practices in the Northwest and California

A review of current practices in the Northwest and California confirms the notion that the practice of reliability planning has not changed significantly since the time of the PG&E survey in the 1980's. Generation adequacy planning is still widely discussed in terms of LOLP and reserve margin. Target reserve margins today have declined from the 20% plus range observed in earlier years to levels in the 12-18% range, largely due to the increased reliance upon transmission and the expansion of planning regions to facilitate larger pooling of resources[3].

California

In California, 3 state energy agencies, including the Public Utilities Commission, collaborated to produce a state Energy Action Plan, in 2003.[4] The plan stated that "current information" suggested the WECC LOLP criteria of 1-day-in-10-years could "be met with approximately 15 – 18 percent reserve margins."

The CPUC subsequently adopted this standard in D.04-01-050. The decision applies to Load Serving Entities (LSEs) within the service territories of the states 3 investor-owned utilities, including Energy Service Providers (ESPs), Community Choice Aggregators, and the utility itself. The decision:

- Adopts a reserve margin of 15 – 17% and directs that the reserve margin must be fully phased in by 2008, with incremental steps beginning in 2005.

---

[3] Ironically, this increased reliance on transmission can introduce its own reliability issues. While it certainly reduces the need for each individual load serving entity (LSE) to own generation resources to maintain generation adequacy, the higher reliance on the bulk transmission system can place LSEs at risk for regional outages from stability problems.

[4] Adopted by the Consumer Power and Conservation Financing Authority, the Energy Resources Conservation and Development Commission, and the California Public Utilities Commission in April and May of 2003.

- Directs that for each summer month (May through September), 90% of requirements (peak load plus reserve margin) must be covered by forward contracts one-year in advance, with utilities allowed to request exception to this rule on a case-by-case basis.
- Continues the 5% limitation for utilities' reliance on the spot market to meet their energy needs.

Though the 15-18% reserve margin recommended by the Energy Action Plan was suggested to meet a 1-day-in-10-years criterion, parties to D.04-01-050 agree that the reserve standard would actually result in an LOLP of closer to 1-day-in-50-years.

A series of workshops were held on the subject of how to assess compliance with the requirements of D.04-01-050. A workshop report identified areas where CPUC decisions are needed in load forecasting rules, resource eligibility to be count toward the 90% measure, assignment of load to LSEs, and other areas.[5]

Pacificorp

In its 2003 IRP Pacificorp used a 15% reserve margin, in the middle of the 12-18% range in FERC's Standard Market Design.

Pacificorp evaluated the reserve margin associated with various levels of LOLP. An 18% reserve margin is equivalent to an LOLP of 1-day-in-10-

[5] Workshop Report on Resource Adequacy Issues, prepared by Administrative Law Judge Michelle Cooke, June 15, 2004.

years. A 15% reserve margin is equivalent to an LOLP of 2-days-in-10-years.

Recently, Pacificorp has turned to a more value-based metric, measuring Expected Unserved Energy (EUE) and taking into account both the cost of the EUE and the cost of reducing EUE by increasing reserve margin (see prior discussion of *Shortage Value* metric). The analysis is performed through a simulation-based approach. The analysis provided no compelling reason to change from the 15% reserve margin.

Portland General Electric (PGE)

PGE uses a 12% reserve margin (6% planning reserve margin on top of the 6% operating reserve margin required by WECC). PGE's demand forecast is based on a 1 in 2 standard – forecasting the maximum demand based on conditions that occur, on average, 1 in every 2 years. PGE proposes, in its 2004 Action Plan, to plan for average hydro conditions. PGE would then hedge against poor hydro conditions through the use of options.

PGE is a member of the Northwest Power Pool Contingency Reserve Sharing Operating Agreement. This agreement requires that control area operators carry contingency reserves against their generation and provides for a reciprocal right that allows members to call upon the reserve capacity of other members in the event of a disruption in generation for a maximum of 60 minutes. Beyond this time period, the member requesting reserve capacity is responsible for remedying its own loss of generation. For longer-term outages, PGE must compare market costs with those of holding capacity and energy reserves.

Northwest Power & Conservation Council (NWPCC)

The NWPCC has defined system adequacy as having an LOLP of 5%, or 1-day-in-20-years, though this is not an enforceable standard.

The NWPCC concludes in its Draft 5th Power Plan that there are two kinds of resource adequacy: physical and economic. While there may be sufficient resources to prevent the involuntary loss of load and meet physical adequacy, unacceptably high power prices may ensue. There is a need to plan for both physical and economic adequacy.

Planning for a critical water year (lowest hydro in historical record) and requiring that, under these conditions, loads could be met without import, is too conservative and costly. Instead, planning can look at the effect of a deficit of internal resources under a critical water year, and reliance on imports to make up the difference.

For example, analyses carried out using GENESYS, the Council's reliability model, indicate that the region can maintain a 5% LOLP (1-in-20-years) with an annual critical water deficit of somewhat over 1,000 MWa if it can count on 1,500 MW of imports across the winter season. Assessments of the likely seasonal availability of resources in the Western System suggest this amount should be available, given the seasonal load diversity that exists between the Northwest and the Southwest. The modeling measures curtailment at a threshold of 1,200 MW-days; in other words, the 5% LOLP standard means there is a 5% chance of a curtailment of 28,800 MWh or more.

5 Transmission Reliability Planning

While transmission reliability planning is no longer in the purview of BC Hydro, it bears discussion here because, ultimately, an ideal planning process would integrate generation, transmission, and reliability planning. With 90% of outages related to distribution disturbances, and only about 3% related to generation adequacy, it may not be economically rational to spend a great deal of money to make a small improvement in generation reliability if the same reliability improvement could be realized with far fewer dollars devoted to transmission or distribution work.

Standard Planning Criteria

Typically transmission planning is done using deterministic criteria such as "n-1." "N-1" is shorthand for transmission equipment emergency ratings not being exceeded during any loading period under a large single contingency, such as the sudden loss of a large generator or high voltage transmission circuit. Similarly, "n-2" refers to the transmission system being able to withstand the simultaneous occurrence of two contingencies. In the deterministic analysis, the system either passes or fails the criterion. The probability of the single or double contingency is not considered. However, the likelihood of an event could be considered when choosing the standards for the criteria --- only those events that occur often enough to warrant system reinforcements would be analyzed. (See Attachment B for a brief discussion of NERC, and its associated planning standards)

The deterministic n-1 criteria have a natural application for transmission planning. Transmission equipment have failure rates far lower than generation, so a complete enumeration of all combinations of transmission equipment failures is of limited value. Moreover, in the past, the computational requirements for modeling the transmission system and solving complex load flow network models would have made the consideration of any more than a few contingency scenarios overly burdensome. With the rapid advancements in computing power of workstations and even PCs, however, transmission owners and overseers are considering more comprehensive evaluation methods.

EUE and Economics-based Planning

While generation planning research slowed in the 1990s, some transmission planners continued to develop models to incorporate probabilities of outages as well as duration, magnitude (EUE analyses), and costs of those outages (Shortage Value analyses). Both the EUE and Shortage Value methods would allow transmission reliability projects to be compared directly with generation projects in terms of the expected value provided to customers.

6. Distribution Reliability Planning

Distribution reliability planning is generally less sophisticated than its counterpart in bulk system reliability planning. The outages on the high voltage system are less frequent, but affect significantly more customers and broader areas. High-voltage outages make newspaper headlines and affect millions of customers such as the Northeast blackout in August, 2003. On the other hand, individual distribution system outages only affect a relatively small number of customers. In addition, the majority of distribution outages are caused by uncontrollable events such as falling trees, automobiles, and ice-storms.

Because of these distinctions, the most common approaches to planning distribution are a deterministic single contingency 'N-1' standard, or an 'N-0' or 'Normal' standard.

Deterministic Industry Standard

Almost universally, distribution systems are built with a radial design to meet the highest forecasted load in each year with either a) all equipment in service at their normal ratings (the Normal limit), or b) any single component of the system out of service, and all other equipment at their emergency ratings (the N-1, or emergency limit). If load is forecasted to exceed either the Normal or Emergency limit, typically it would be exceeded for relatively few hours of the year during the peak days with the most extreme temperatures (coldest days in winter peaking areas, hottest days in summer peaking areas).

Within the deterministic standards, variations in reliability between distribution utilities relate to how the load carrying capability of the existing system is determined and how the load forecast is prepared. For example, if a more extreme temperature is used for forecasting future peak load, the peak load forecast will be higher and the utility will build earlier. If the nameplate rating of a transformer is used rather than a 'dynamic' rating based on equipment loadings and temperatures, the load carrying capability will typically be lower and the utility will build earlier.

Attachment A: Comparison of Generation Reliability Criteria

	Reliability Criteria	Reserve Margin[6]	Load Model	Specification of Hydro	Includes Tie-Line Assistance
PG&E (Circa 1985)	LOLP of 1-day-in-10-years, for each month	23-27% reserve margin	Daily peak loads for each day in month	Extreme dry year	Yes
PG&E (Circa 1990)	Shortage Value	16%	Hourly loads (average)	Extreme dry year	Yes
Allegheny Power System	Minimum reserve margin of 25% based on median peak load. 40-60 days/year dependence on outside capacity resources	25-30%	Daily peak loads for each of 365 days	Seasonally adjusted expected values	No
Detroit Edison	25 days/year dependence on outside resources LOLP of 1-day-in-10-years on an interconnected basis	*Capacity* margin of 19%	Daily peak loads: 252 highest daily peaks per year (21 days/mo x 12 months)	Not applicable	Yes, for LOLP calculation
Duke Power	25% reserve margin (LOLP used for comparison only)	25%	LOLE calculation based on PROMOD which uses 3 load duration curves for each month	Median	Yes
Florida Power & Light	15-25% reserve margins	15-25%	Daily peak loads for each of 365 days	Not applicable	No
Florida Power Corp (FPC)	6 days/year dependence on outside resources LOLP of 1-day-in-10-years on an interconnected basis	12-15% reserve margin	Daily peak loads for each of 365 days	Not applicable	No
Houston Light & Power	20% reserve margin	20%	Daily peak loads for each of 364 days	Not applicable	No

[6] Where reserve margin is not specifically required, the table reports an implied reserve margin based on the LOLP requirements given the utility's generation ownership at the time of the study.

Attachment A: Comparison of Generation Reliability Criteria

	Reliability Criteria	Reserve Margin[6]	Load Model	Specification of Hydro	Includes Tie-Line Assistance
Illinois Power Co.	LOLP of 1-day-in-10-years after tie-line assistance to MAIN Minimum reserve of the lesser of 15% or single largest unit reserve	15-20%	Daily peak loads for 250 working days	Not applicable	Yes
BC Hydro - Capacity	LOLP of 1-day-in-10-years	14% capacity reserve	Daily Peak Loads	Dependable capacity from 85th percentile of assumed 50 year stream flows. Dependable capacity is three hours in the peak load period during continuous 2 weeks of cold winter .	Up to 400 MW of capacity from import
BC Hydro – Energy	Expected unserved demand less than 0.8% of total. Equivalent to 2500GWh of nonfirm			Firm Energy: Hydro in worst water year on record	NA. Tie-line part of the better hydro or imports that make up the nonfirm allowance.
BPA – Capacity	> 10MW deficit LOLP of 5% for winter seasons		1 in 2 year	Severe OY 1937 water conditions	1000MW in Smr, 3000MW in Wtr
BPA - Energy	Annual energy load resource balance of zero.		1 in 2 year	Sustained peaking level of 50 hours per week using severs OY 1937 water conditions	No, but can "borrow" future water energy and exercise DSI curtailment agreements.
Kansas City Power & Light	LOLP of 1-day-in-10-years	20-23%	Daily peak loads 5 days/week x 52 weeks	Not applicable	Yes
Montana Power Co	LOLE of 1 hour in 20 years. In addition, pool requirements of 13-17% reserve margin		LOLE calculation using PROMOD	Critical water	Yes
Philadelphia Electric Co.	Pool criteria of 1-day-in-10-years	25-29% reserve margin	Daily peak loads 6 days/week x 52 weeks	Not applicable	Yes

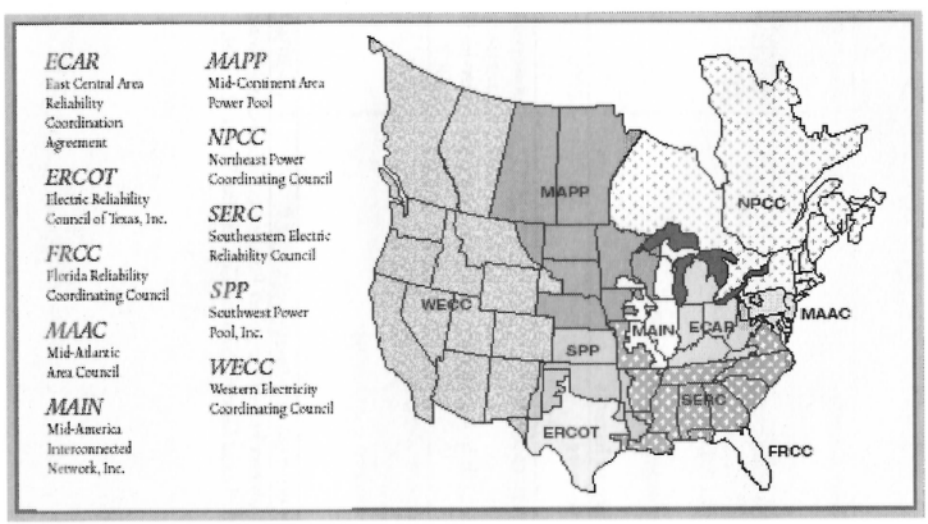
Attachment A: Comparison of Generation Reliability Criteria

	Reliability Criteria	Reserve Margin[6]	Load Model	Specification of Hydro	Includes Tie-Line Assistance
Southern California Edison	16-20% reserve margin LOLE of 0.05 hours/year Single largest hazard plus 7% Two largest hazards	22% based on LOLE	8736 hourly loads	Expected	Yes
San Diego Gas & Electric	Reserve margin	20%	36 PROMOD load duration curves, 3 for each month	Not applicable	No
Southern Company*	20% reserve margin 0.02% EUE in the absence of tie-line assistance	Reserve margin criteria implies 1-day-in-10-years LOLP	Daily peak loads 5 days/week x 52 weeks	Probability distribution	No
Texas Utilities **	20% reserve margin Single largest contingency	20%	Daily peak loads for 250 working days	Not applicable	Yes
Union Electric	MAIN criterion of 1-in-10-years LOLP	18-20%	250 working days	Not applicable	Yes

* Georgia Power Co., Alabama Power Co., Gulf Power Co., Mississippi Power Co.
** Texas Power & Light, Texas Electric Service Co., Dallas Power & Light,

Transmission reliability planning in North America is overseen by the North American Electric Reliability Council (NERC) and the ten regional reliability councils. Generally, the standards established by NERC are adopted by each regional council, with each regional council making the standards more stringent or adding new standards in accordance with regional conditions. The standards may be further refined by state or local reliability organizations. Figure 3 shows the geographic span of the regional reliability councils, and Attachment B provides some additional information about NERC.

Figure 3: Regional Reliability Council Members



NERC was founded in 1968. Its existence is mainly a response to the need to coordinate transmission reliability planning as local and regional transmission system interconnection became more common. A set of standards was required to ensure that one system did not adversely affect another system to which it was interconnected.

NERC and the regional councils were established as voluntary organizations. Changes in the electric industry in recent years have led many in the U.S. to believe that a *mandatory* system of reliability standards is required. This would require creation of a reliability organization with the statutory authority to enforce reliability standards among all market participants. Legislation currently pending in Congress would allow NERC to apply to become that reliability organization. Participation in a U.S.-sanctioned transmission reliability system would obviously remain voluntary for Canadian utilities.

NERC reliability standards are currently divided into *planning standards* and *operating policies*, though it plans to replace these with a single set of reliability standards.

Planning standards define the reliability of the bulk electric system in terms of its ability to supply the aggregate electrical requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements; and its ability to withstand sudden disturbances.

Operating policies provide standards for operation of interconnected systems, so that control areas operate in a reliable manner and do not burden other entities within their interconnection.

NERC Planning Standards

NERC Planning Standards define the reliability of interconnected bulk electric systems using the following two terms:

Adequacy. The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security. The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

NERC and the regional councils provide for system adequacy and security through a series of standards. For example, WECC specifies that each control area shall maintain minimum operating reserves such that the system can meet demand variations and replace capacity and energy lost due to forced outages or curtailment of imports. One well known element of these operating reserves is *Contingency reserve*, which is the greater of:

> Capacity loss due the most severe single contingency; or
> The sum of 5% of the load served by hydro generation and 7% of the load served by thermal generation

In either case, at least half of the Contingency reserve must be spinning reserve. Along with Contingency reserve, WECC also includes Regulating reserve, interruptible import reserve, and on-demand obligation reserve in its total operating reserve requirement.

In addition to the operating reserve specifications discussed above, NERC establishes many technical operating standards that are beyond the scope of discussion for this primer.

Towner, Erin FIN:EX

From:	Kennedy, Christine PREM:EX
Sent:	Thursday, November 23, 2017 2:30 PM
To:	Foster, Doug FIN:EX
Cc:	Wanamaker, Lori FIN:EX
Subject:	Fwd: BCUC Site C Inquiry - Additional Questions
Attachments:	11-23-2017_MEM MoF Site C_Addition Questions.pdf; ATT00001.htm

Christine

Begin forwarded message:

From: "Sanderson, Melissa EMPR:EX" <Melissa.Sanderson@gov.bc.ca>
Date: November 23, 2017 at 2:07:16 PM PST
To: "Nikolejsin, Dave MNGD:EX" <Dave.Nikolejsin@gov.bc.ca>, "Howlett, Tim GCPE:EX" <Tim.Howlett@gov.bc.ca>, "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>
Cc: "Lloyd, Evan GCPE:EX" <Evan.Lloyd@gov.bc.ca>, "Zadravec, Don GCPE:EX" <Don.Zadravec@gov.bc.ca>, "Haslam, David GCPE:EX" <David.Haslam@gov.bc.ca>, "Kristianson, Eric GCPE:EX" <Eric.Kristianson@gov.bc.ca>, "Gibbs, Robb GCPE:EX" <Robb.Gibbs@gov.bc.ca>, "Kennedy, Christine PREM:EX" <Christine.Kennedy@gov.bc.ca>
Subject: FW: BCUC Site C Inquiry - Additional Questions

Hi all,

The attached response to the clarification request from the DM's just came in to our Minister inbox from the BCUC.

Thanks,

Melissa

From: Minister, EMPR EMPR:EX
Sent: Thursday, November 23, 2017 2:04 PM
To: Sanderson, Melissa EMPR:EX
Subject: FW: BCUC Site C Inquiry - Additional Questions

From: Commission Secretary BCUC:EX
Sent: Thursday, November 23, 2017 1:42 PM
To: Minister, EMPR EMPR:EX; Minister, FIN FIN:EX
Subject: BCUC Site C Inquiry - Additional Questions

Dear Dave Nikolejsin and Lori Wanamaker:

Please see attached correspondence with respect to the above-noted matter.

Original will not follow. A hard copy of the attached is available upon request.

Please call the BCUC Regulatory Services at 604-660-4700 to request a copy.

Regards,

Katie Berezan
Administrative Assistant, Regulatory Services

British Columbia Utilities Commission
P: 604.660.4700 **BC Toll Free:** 1.800.663.1385 **F:** 604.660.1102
bcuc.com

Towner, Erin FIN:EX

From:	Layton, Ryan <ryan.layton@bchydro.com>
Sent:	Wednesday, November 15, 2017 11:04 AM
To:	Foster, Doug FIN:EX
Cc:	Yaremko, Cheryl
Subject:	Re: Urgent Letter

Hi Doug - I tried you just now but got your voicemail. In a meeting now for about 15 mins - will try you again after.

Ryan

Sent from my iPhone

On Nov 15, 2017, at 10:48 AM, Foster, Doug FIN:EX <Doug.Foster@gov.bc.ca> wrote:

> give me a call when able. d.
>
> ---
>
> **From:** Justesen, Josh T FIN:EX
> **Sent:** Wednesday, November 15, 2017 10:15 AM
> **To:** Cochrane, Marlene EMPR:EX
> **Cc:** Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
> **Subject:** RE: Urgent Letter
>
> Hi Marlene,
>
> Please find the signed document attached.
>
> Thank you,
> **Josh Justesen**
> Administrative Coordinator | Deputy Minister's Office
> Ministry of Finance | Victoria, BC
> (250) 387-1660
>
> ---
>
> **From:** Cochrane, Marlene EMPR:EX
> **Sent:** Wednesday, November 15, 2017 9:33 AM
> **To:** Justesen, Josh T FIN:EX
> **Subject:** Urgent Letter
> **Importance:** High
>
> Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.
>
> **Marlene Cochrane**
> Executive Coordinator | Deputy Minister's Office
> Ministry of Energy, Mines and Petroleum Resources
> Victoria | British Columbia
> Phone (778) 698 7254
>
> <102700 BCUC Final_Signed.pdf>

Towner, Erin FIN:EX

From: Foster, Doug FIN:EX
Sent: Wednesday, November 15, 2017 10:28 AM
To: Gonzalez, Selina FIN:EX; Hopkins, Jim FIN:EX; Dunn, Jonathan FIN:EX
Subject: FW: Urgent Letter
Attachments: 102700 BCUC Final_Signed.pdf

keeping you in loop.
how last 10 days spent. d.

From: Justesen, Josh T FIN:EX
Sent: Wednesday, November 15, 2017 10:15 AM
To: Cochrane, Marlene EMPR:EX
Cc: Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
Subject: RE: Urgent Letter

Hi Marlene,

Please find the signed document attached.

Thank you,
Josh Justesen
Administrative Coordinator | Deputy Minister's Office
Ministry of Finance | Victoria, BC
(250) 387-1660

From: Cochrane, Marlene EMPR:EX
Sent: Wednesday, November 15, 2017 9:33 AM
To: Justesen, Josh T FIN:EX
Subject: Urgent Letter
Importance: High

Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.

Marlene Cochrane
Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

Towner, Erin FIN:EX

From: Foster, Doug FIN:EX
Sent: Thursday, November 23, 2017 9:12 PM
To: Gonzalez, Selina FIN:EX
Subject: RE: Response from BCUC
Attachments: Fwd: BCUC Site C Inquiry - Additional Questions

s.13

d.

From: Gonzalez, Selina FIN:EX
Sent: Thursday, November 23, 2017 9:00 PM
To: Foster, Doug FIN:EX
Subject: Response from BCUC

I haven't read through this yet. You may be aware already, but the BCUC has posted their response to the Nov 15th DMs' letter:
http://www.bcuc.com/Documents/NewsRelease/2017/11-23-2017_InformationRelease_BCUC-responds-to-Site-C-Additional-Questions.pdf

Have a good night.

Selina Gonzalez, MA Econ
Treasury Board Analyst
Performance Budgeting Office
Ministry of Finance
P: 250-953-4429
C: 250-580-7438

Towner, Erin FIN:EX

From:	Kennedy, Christine PREM:EX
Sent:	Thursday, November 23, 2017 2:30 PM
To:	Foster, Doug FIN:EX
Cc:	Wanamaker, Lori FIN:EX
Subject:	Fwd: BCUC Site C Inquiry - Additional Questions
Attachments:	11-23-2017_MEM MoF Site C_Addition Questions.pdf; ATT00001.htm

Christine

Begin forwarded message:

From: "Sanderson, Melissa EMPR:EX" <Melissa.Sanderson@gov.bc.ca>
Date: November 23, 2017 at 2:07:16 PM PST
To: "Nikolejsin, Dave MNGD:EX" <Dave.Nikolejsin@gov.bc.ca>, "Howlett, Tim GCPE:EX" <Tim.Howlett@gov.bc.ca>, "MacLaren, Les EMPR:EX" <Les.MacLaren@gov.bc.ca>
Cc: "Lloyd, Evan GCPE:EX" <Evan.Lloyd@gov.bc.ca>, "Zadravec, Don GCPE:EX" <Don.Zadravec@gov.bc.ca>, "Haslam, David GCPE:EX" <David.Haslam@gov.bc.ca>, "Kristianson, Eric GCPE:EX" <Eric.Kristianson@gov.bc.ca>, "Gibbs, Robb GCPE:EX" <Robb.Gibbs@gov.bc.ca>, "Kennedy, Christine PREM:EX" <Christine.Kennedy@gov.bc.ca>
Subject: FW: BCUC Site C Inquiry - Additional Questions

Hi all,
The attached response to the clarification request from the DM's just came in to our Minister inbox from the BCUC.
Thanks,
Melissa

From: Minister, EMPR EMPR:EX
Sent: Thursday, November 23, 2017 2:04 PM
To: Sanderson, Melissa EMPR:EX
Subject: FW: BCUC Site C Inquiry - Additional Questions

From: Commission Secretary BCUC:EX
Sent: Thursday, November 23, 2017 1:42 PM
To: Minister, EMPR EMPR:EX; Minister, FIN FIN:EX
Subject: BCUC Site C Inquiry - Additional Questions
Dear Dave Nikolejsin and Lori Wanamaker:
Please see attached correspondence with respect to the above-noted matter.
Original will not follow. A hard copy of the attached is available upon request.
Please call the BCUC Regulatory Services at 604-660-4700 to request a copy.
Regards,
Katie Berezan
Administrative Assistant, Regulatory Services
British Columbia Utilities Commission
P: 604.660.4700 **BC Toll Free:** 1.800.663.1385 **F:** 604.660.1102
bcuc.com

Towner, Erin FIN:EX

From:	Yaremko, Cheryl <Cheryl.Yaremko@bchydro.com>
Sent:	Wednesday, November 15, 2017 11:02 AM
To:	Foster, Doug FIN:EX
Subject:	Re: Urgent Letter

Will call you at noon

Sent from my iPhone

On Nov 15, 2017, at 10:48 AM, Foster, Doug FIN:EX <Doug.Foster@gov.bc.ca> wrote:

> give me a call when able. d.
>
> ---
>
> **From:** Justesen, Josh T FIN:EX
> **Sent:** Wednesday, November 15, 2017 10:15 AM
> **To:** Cochrane, Marlene EMPR:EX
> **Cc:** Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
> **Subject:** RE: Urgent Letter
>
> Hi Marlene,
>
> Please find the signed document attached.
>
> Thank you,
> **Josh Justesen**
> Administrative Coordinator | Deputy Minister's Office
> Ministry of Finance | Victoria, BC
> (250) 387-1660
>
> ---
>
> **From:** Cochrane, Marlene EMPR:EX
> **Sent:** Wednesday, November 15, 2017 9:33 AM
> **To:** Justesen, Josh T FIN:EX
> **Subject:** Urgent Letter
> **Importance:** High
>
> Hi Josh. As per our conversation, please find attached a joint letter from Lori and Dave to the BCUC. This letter will be sent by email to the Chair of BCUC. Please return the letter to me once her signature is applied and I can email to Mr. Morton. Thanks very much.
>
> Marlene Cochrane
> Executive Coordinator | Deputy Minister's Office
> Ministry of Energy, Mines and Petroleum Resources
> Victoria | British Columbia
> Phone (778) 698 7254
>
> <102700 BCUC Final_Signed.pdf>

---

collect call or return email to notify us of this error. Thank you for your cooperation.

Towner, Erin FIN:EX

From: Foster, Doug FIN:EX
Sent: Thursday, November 16, 2017 6:59 AM
To: Dunn, Jonathan FIN:EX
Subject: FW: Urgent Letter

From: Foster, Doug FIN:EX
Sent: Thursday, November 16, 2017 6:59 AM
To: MacLaren, Les EMPR:EX
Subject: RE: Urgent Letter

Thanks. D.

From: MacLaren, Les EMPR:EX
Sent: Thursday, November 16, 2017 6:39 AM
To: Foster, Doug FIN:EX
Subject: RE: Urgent Letter

s.13

Les

From: Foster, Doug FIN:EX
Sent: Thursday, November 16, 2017 6:15 AM
To: MacLaren, Les EMPR:EX
Subject: FW: Urgent Letter

Do you recall if or how the BCUC and or Hydro addressed this?
d.

From: Dunn, Jonathan FIN:EX
Sent: Wednesday, November 15, 2017 11:57 AM
To: Foster, Doug FIN:EX
Subject: RE: Urgent Letter

Thx – looks good, well done.

s.13

s.13

Kind regards
Jon

From: Foster, Doug FIN:EX
Sent: Wednesday, November 15, 2017 10:28 AM
To: Gonzalez, Selina FIN:EX; Hopkins, Jim FIN:EX; Dunn, Jonathan FIN:EX
Subject: FW: Urgent Letter

keeping you in loop.
how last 10 days spent. d.

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Cc: Foster, Doug FIN:EX; Wanamaker, Lori FIN:EX
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Administrative Coordinator | Deputy Minister's Office
Ministry of Finance | Victoria, BC
(250) 387-1660

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Executive Coordinator | Deputy Minister's Office
Ministry of Energy, Mines and Petroleum Resources
Victoria | British Columbia
Phone (778) 698 7254

Towner, Erin FIN:EX

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