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November 1, 2017

BCUC INQUIRY RESPECTING SITE C A-24

Sent via eFile

The Honourable Michelle Mungall, M.L.A.
Minister of Energy, Mines and Petroleum Resources
Parliament Buildings
PO Box 9060 Stn Gov't
Victoria, BC V8W 9E2
EMPR.Minister@gov.bc.ca

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

Dear Minister:

In accordance with Order in Council No. 244 dated August 2, 2017, the British Columbia Utilities Commission hereby submits its Final Report with respect to the Site C Inquiry.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

British Columbia Utilities Commission Inquiry Respecting Site C

Final Report to the Government of British Columbia

November 1, 2017

About the BCUC

Who we are

The British Columbia Utilities Commission (BCUC) is an independent regulatory agency of the Government of British Columbia that operates under and administers the *Utilities Commission Act*. The BCUC is quasi-judicial and makes legally binding rulings.

What we do

The BCUC's primary responsibility is the regulation of BC's energy utilities. In addition to setting rates, the BCUC regulates all franchises, privileges, and concession agreements granted to public utilities.

It is our mission to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities we regulate, while also providing utilities the opportunity to earn a fair return on their capital investments.

bcuc
British Columbia
Utilities Commission

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This report was prepared in response to Order-in-Council No. 244 for the Honourable Michelle Mungall, Minister of Energy, Mines and Petroleum Resources.

Before:
David M. Morton, Panel Chair and Commissioner
Dennis A. Cote, Commissioner
Karen A. Keilty, Commissioner
Richard I. Mason, Commissioner

TABLE OF CONTENTS

Page no.

1.0 Introduction to the Final Report

The British Columbia Utilities Commission (BCUC, Commission) is the independent tribunal of the Government of British Columbia (BC) that is responsible for regulating BC's public utilities, the Insurance Corporation of British Columbia's compulsory automobile insurance rates, intra-provincial pipelines, and the safety and reliability of the bulk electric system. Our mission is to ensure that ratepayers receive safe, reliable and non-discriminatory energy services at fair rates from the utilities we regulate, and that shareholders of those utilities are afforded a reasonable opportunity to earn a fair return on their invested capital. The BCUC is governed by the *Utilities Commission Act* (UCA) and has specific responsibilities under the *Clean Energy Act* (CEA). The Commission also considers all relevant legislation and regulations, as well as government policies and the business environment of regulated companies.

On August 2, 2017, the Commission was requested by the Lieutenant Governor in Council (LGIC), under section 5(1) of the UCA, to advise the LGIC respecting British Columbia Hydro and Power Authority's (BC Hydro) Site C project in accordance with the terms of Order in Council 244 (OIC, or OIC 244).

The Commission issued its Preliminary Report on September 20, 2017 in accordance with the terms of reference set out in OIC 244. The Preliminary Report was based on the Panel's review of BC Hydro's August 30, 2017 filing, two independent reports prepared by Deloitte LLP (Deloitte) and various third-party submissions. The Preliminary Repot identified numerous areas where additional information was required, and requests were made for BC Hydro to provide the additional information and responses requested in the Preliminary Report by October 4, 2017.

BC Hydro responded to the Panel's questions over the course of a number of weeks. These responses have been critical to the Panel in preparing this final report. The Panel commends BC Hydro for its efforts in responding to the large number of questions in such a short time frame. In addition to BC Hydro's responses, the Panel has considered the submissions made by BC Hydro and other parties on the Preliminary Report, the presentations made by the public and First Nations at various input sessions held throughout the province, and comments made by BC Hydro and other parties on an Illustrative Alternative Portfolio developed by Commission staff under the guidance of the Panel.

This report, which is an extension of the Preliminary Report, provides the Panel's analysis and findings on the questions posed in OIC 244.

We first address the Site C Inquiry process undertaken by the Commission, including the results of Commission's consultation through the Community Input Sessions and First Nations Input Sessions held around the province. We then address BC Hydro's ability to meet forecasted load using existing, committed and planned resources, with a discussion of BC Hydro's current load forecast, its existing, committed and planned resources other than Site C, and its handling of any potential surplus in the event Site C energy and capacity is not fully needed once the project has been completed.

In the remaining sections of the Final Report, we address the Site C project options (referred to as "cases") as outlined in section 3(a) of OIC 244. These sections cover issues and questions related to the three cases: (i) completion of the project; (ii) suspension of the project; and (iii) termination of the project. As part of the termination case and in accordance with section 3(b)(iv) of the OIC, we also examine resource and generation alternatives and discuss BC Hydro and Deloitte's portfolio analyses, BC Hydro's Unit Energy Cost (UEC) analysis of Site C and an alternative portfolio, as well as alternative energy and capacity sources. Included in our analysis of the implications of continuing, suspending or terminating the project, we consider other implications of each of the three cases, such as the loss of income to construction workers in a termination scenario or the loss of agricultural land in a continue scenario.

2.0 Background

2.1 Introduction

Site C is a dam and hydroelectric generating station being built by BC Hydro in the province's northeastern Peace River Regional District. According to BC Hydro, five sites between the Peace Canyon and the Alberta border (A, B, C, D and E) were identified in 1958.[1] By 1978, BC Hydro had confirmed that the site identified as "C," approximately 7 kilometers (km) south of Fort St. John, was the optimal location for a third dam to be built on the Peace River, after the W.A.C. Bennett and Peace Canyon dams.

The project comprises an earth-filled embankment dam that creates a new reservoir that will run 83 km along the course of the Peace River. According to BC Hydro's project description, flooding will submerge approximately 5,000 hectares of land when the reservoir is finished, and parts of the reservoir will be two to three times the width of the current riverbanks.[2] Water in the Williston Lake reservoir system is used to generate electricity first in the W.A.C. Bennett dam and then in the Peace Canyon dam. When reused again in the Site C dam, the same water can generate up to 35 percent of the power produced by the W.A.C. Bennett Dam[3] from a smaller area (5 percent) of reservoir.

Site C is forecast to provide a peak capacity of approximately 1,145 megawatts (MW)[4] and 5,286[5] annual GWh of electricity which is the amount of energy needed, per BC Hydro, to power the equivalent of 450,000 homes per year.[6]

2.1.1 Project description

BC Hydro categorizes the project into the following components: dam site area; roads and highways; Peace River/Reservoir Area; transmission lines; Hudson's Hope shoreline protection; and the production and transportation of minerals. BC Hydro's Site C construction includes:

- An earthfill dam about 60 metres above the riverbed and 1,050 metres long;
- Two cofferdams across the main river channel that are needed to build the earthfill dam (these will be removed post-construction);
- Two concrete-lined tunnels (10.8 metres in diameter and between 700–800 metres long) to divert parts of the Peace River;
- A concrete foundation for the dam's generating station and spillways;
- An 800-metre roller-compacted concrete buttress, 70 metres high, to enhance seismic protection;
- Realignment of several sections (up to six) of Highway 29, to include new bridges; and
- Two 77-km transmission lines along an existing transmission line right-of-way, which will connect Site C to Peace Canyon.[7]

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[1] British Columbia Hydro and Power Authority (BC Hydro) Site C Clean Energy Project Website, FAQ – "Why is it called Site C?" retrieved from https://www.sitecproject.com/faq.

[2] BC Hydro Site C Clean Energy Project Website, Information Sheet, July 2017, retrieved from https://www.sitecproject.com/news-and-information/information-sheets.

[3] Ibid.

[4] Submission F1-1, BC Hydro, Appendix Q.

[5] Submission F1-4, BC Hydro, IR 1.4, Attachment 1.

[6] BC Hydro Site C Clean Energy Project, Site C Information Sheet (July 2017), retrieved from https://www.sitecproject.com/news-and-information/information-sheets.

[7] BC Hydro Site C Clean Energy Project, Site C Information Sheet (July 2017), retrieved from https://www.sitecproject.com/news-and-information/information-sheets.

2.1.2 History of Site C

The history of the Site C dam spans over 50 years. BC Hydro began engineering studies in 1971.[8] In 1980, BC Hydro applied to the Commission for an Energy Project Certificate to initiate Site C dam construction. This proposal was not recommended for approval after Commission hearings in 1981 and 1983. While deeming that the Site C project was acceptable, the Commission called for further definition of the future demand for electricity and identification of alternative ways of meeting this demand.[9]

During the 2000s, BC Hydro carried out further engineering and geotechnical studies and refined its project plans to incorporate seismic protection and to optimize the project's hydroelectric potential.[10]

In April 2010, BC Hydro submitted the project plans for regulatory and environmental reviews. The project description was submitted to the BC Minister of Environment as well as the Federal Minister of Environment in May 2011. The Canadian Environmental Assessment Agency (CEAA) commenced their assessment on September 30, 2011, prior to the establishment of the *Canadian Environmental Assessment Act* in 2012. The Federal-Provincial Joint Review Panel (Joint Review Panel) was established in August of 2013[11] and began their review of the Site C project. In May 2014, the Joint Review Panel issued its report on the Site C Clean Energy Project after holding public hearings and receiving submissions from the public, stakeholders and other parties. The CEAA Decision was released in late October of 2014, but then revised and reissued on November 25, 2014.

The Federal and BC environmental approvals came with more than 150 legally binding conditions to be met by BC Hydro.[12] Some of the conditions include: establishing funds to compensate for agricultural lands needed for the reservoir; compensation and mitigation of changes expected in wetland habitat; developing a plan to minimize impacts on infrastructure, water flows and water level conditions during the time that the reservoir is being filled; protecting water and air quality; working with aboriginal businesses and employing aboriginal workers; and managing and minimizing impacts to local archaeological and heritage resources.[13]

In December 2014, the final investment decision from the BC Provincial Government (in the affirmative) was received, and construction began in the summer of 2015.

[8] Submission F28-2, Prophet River and West Moberly First Nations, Tab 2, Report of the Joint Review Panel, Excerpts and Appendix 1: List of Panel's Conclusions and Recommendations (JRP Report), May 1, 2014, p. 8.
[9] Ibid., p. 9.
[10] Ibid.
[11] Submission F28-2, Prophet River and West Moberly First Nations, Tab 2, JRP Report, May 1, 2014, p. iv.
[12] BC Hydro, Site C Clean Energy Project, Site C Fact Sheet (July 2017), retrieved from https://www.sitecproject.com/sites/default/files/site-c-fact-sheet-july-2017.pdf.
[13] Canadian Environmental Assessment Agency, Site C Clean Energy Project, Environmental Assessment Decision Statement, issued under Section 54 of the *Canadian Environmental Assessment Act*, SC 2012, Chapter 19, section 52, re-issued November 25, 2014, retrieved from https://www.ceaa-acee.gc.ca/050/documents/p63919/100567E.pdf.

3.0 Site C Inquiry process

3.1 Legislative framework

The home statute of the Commission is the UCA, which gives the Commission powers to regulate public utilities in BC. In particular, section 45 of the UCA requires that, in most instances, the construction of new electricity generating facilities cannot begin without the Commission issuing a Certificate of Public Convenience and Necessity (CPCN).[14] The Commission issues a CPCN if the proposed facility "is necessary for the public convenience and properly conserves the public interest."[15]

The Commission is also required to comply with the CEA. The provisions of the CEA exempted the Site C dam project, among other projects, from Commission oversight.[16] Specifically, the CEA states that "the Commission must not exercise a power under the *Utilities Commission Act* in a way that would directly or indirectly prevent 'the authority' from doing anything…" related to the Site C project.[17]

Notwithstanding the provisions of the CEA, section 5 of the UCA provides that the Commission has a duty to inquire into "any matter, whether or not it is a matter in respect of which the commission otherwise has jurisdiction."[18] For the Commission to undertake such an inquiry, the Lieutenant Governor in Council must make a request of the Commission, and may specify the terms of reference of the inquiry.[19]

On August 2, 2017, pursuant to section 5 of the UCA, the Lieutenant Governor in Council issued OIC 244, requesting the Commission to "advise the Lieutenant Governor in Council respecting the Site C project in accordance with the terms of reference set out in section 3 of this order"[20] (Inquiry).

OIC 244 provided that: (i) the Inquiry was to start on August 9, 2017; (ii) a Preliminary Report must be submitted by September 20, 2017; and (iii) a Final Report must be submitted by November 1, 2017.[21] Both reports must be submitted to the minister charged with the administration of the *Hydro and Power Authority Act*.

It should be noted that the UCA[22] makes certain provisions of the *Administrative Tribunals Act* (ATA) applicable to the Commission. In particular, the ATA provides that the Commission "has the power to control its own processes and may make rules respecting practice and procedure to facilitate the just and timely resolution of the matters before it."[23] Further, the OIC specifically states that the Commission "may exercise any of its powers under the Act in order to carry out the inquiry in accordance with these terms of reference."[24] Thus, the Commission has the authority, subject to any specific direction provided in the terms of reference in the OIC, to set out processes and rules of practice and procedure that it considers appropriate to the circumstances of this Inquiry.

[14] *Utilities Commission Act* (UCA), RSBC 1996, Chapter 473, section 45(1).
[15] UCA, section 45(8).
[16] *Clean Energy Act* (CEA), SBC 2010, Chapter 22, section 7.
[17] CEA, section 7(3).
[18] UCA ,section 5(1).
[19] CEA, section 5(2).
[20] Order in Council No. 244 (OIC), section 2.
[21] OIC, section 3(g).
[22] UCA section 2.1.
[23] *Administrative Tribunals Act* (ATA), SBC 2010, Chapter 45, section 11.
[24] OIC, section 3(f).

3.2 Scope of the Inquiry

This section presents and explains the scope of the Inquiry. The starting point for the scope is the terms of reference provided in the OIC, which include specific questions to be answered, and activities that the Panel either must or may perform. Here, we further clarify and interpret the scope within the bounds of the OIC.

The OIC does not require or ask the Commission to make recommendations or a decision on the future of the Site C project. The mandate of the Inquiry is limited to providing the information requested in the OIC.

3.2.1 Cases to be considered

The LGIC requested in the OIC that the Commission advise it on the implications of:

(i) completing the Site C project by 2024, as currently planned (Case 1);

(ii) suspending the Site C project, while maintaining the option to resume construction until 2024 (Case 2); and

(iii) terminating construction and remediating the site [25] (Case 3) (collectively, the cases)

The Panel has consequently structured the scope of the Inquiry, the processes to be followed, the Preliminary Report, and the Final Report around these three alternative cases.

3.2.2 Specific questions

The OIC directed that, for further specificity, the Commission address the following questions:

(i) After the commission has made an assessment of the authority's expenditures on the Site C project to date, is the commission of the view that the authority is, respecting the project, currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?

(ii) What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024, and what are the potential mechanisms to recover those costs?

(iii) What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?

(iv) Given the energy objectives set out in the *Clean Energy Act*, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?[26]

Question (i) directs the Commission to inquire into the estimated cost of completing the Site C Project "as currently planned."[27] The Panel's interpretation of this question is to examine whether Site C is currently on budget, and if not, to address the anticipated costs at completion. The Panel considers an answer to this question is required to make a meaningful economic comparison between the three cases. In addition to the direct costs to ratepayers of continuing the project, the Panel considers the broader implications of continuing the project.

[25] OIC, section 3(a).
[26] OIC, section 3(b).
[27] OIC, section 3(a)(i).

Questions (ii) and (iii) explicitly direct the Commission to inquire into the costs to BC Hydro ratepayers of suspending and of cancelling Site C. The Commission interprets "costs to ratepayers" to mean the direct economic cost to BC Hydro ratepayers. This includes items like construction costs and interest on funds used during construction but excludes indirect costs, such as the effects on the economy of construction employment or loss of agricultural land, unless those costs are reflected in the rate that BC Hydro ratepayers pay. While the Panel has excluded the aforementioned indirect costs from its assessment of the "cost to ratepayers," we have provided a discussion of the broader implications of the suspension and termination cases.

Question (iv) directs the Commission to inquire into the alternative generation that would be required should the government decide to suspend or cancel Site C. In these circumstances, at least some of the energy and capacity currently planned to come from Site C would likely need to be sourced elsewhere. The Panel sees no benefit in examining alternative sources of generation in the continue case. The Panel considers any cost of required alternative generation to be a direct economic cost to ratepayers.

3.2.3 Load forecast

The OIC further defined the scope of the Inquiry by directing the Commission to consider a specific forecast of future generation needs:

> c) in making applicable determinations respecting the matters referred to in paragraphs (a) and (b), the commission must use the forecast of peak capacity demand and energy demand submitted in July 2016 as part of the authority's Revenue Requirements Application, and must require the authority to report on
>
> (i) developments since that forecast was prepared that will impact demand in the short, medium and longer terms, and
>
> (ii) other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case.[28]

On August 9, 2017, the Panel, by Order G-121-17, directed BC Hydro to provide a submission on the "developments" and "other factors" as listed above. The Panel considers such developments and other factors that have been identified in submissions to the Inquiry by participants other than BC Hydro.

3.2.4 Consultation

The OIC states: "(d) the commission must consult interested parties respecting the matters referred to in paragraphs (a) and (b)."[29]

The Panel interprets this requirement in a broad sense. Despite the limited time available, the Panel ensured as many opportunities as possible were provided for members of the public and other interested parties to provide input in the Inquiry. A description of the consultation process is provided in section 3.3.

3.2.4.1 First Nations consultation

The Panel solicited submissions from First Nations impacted by the Site C Project.

Although the Panel has the statutory authority to assess the adequacy of consultation in applications before it,[30] the Site C Inquiry is not an application. Further, the OIC does not ask the Panel to make any decisions

[28] OIC, section 3(c).
[29] OIC, section 3(d).

with respect to Site C. Assessing the adequacy of consultation is therefore beyond the scope of this report. Instead, the Provincial Government plans to make a decision on the future of Site C. In the circumstances, it is the Provincial Government who will determine the adequacy of consultation with any particular First Nation. In assessing the adequacy of consultation, the Provincial Government may, in part, rely upon submissions made by First Nations to the Commission in this Inquiry.[31] The Panel has sought submissions from First Nations impacted by Site C and has summarized those submissions received in subsequent sections of this Final Report.

3.2.5 Not a reconsideration

The OIC states that:

> e) in carrying out its inquiry, the commission must be guided by the understanding that the inquiry is not a reconsideration of decisions made in the environmental assessment process or by statutory decision makers or the courts;[32]

This exclusion further clarifies the direction provided in section 3(b) of OIC 244 that the Inquiry is an assessment of the direct economic consequences to ratepayers of each of the three cases described in section 3(a) of OIC 244.

3.2.6 Expert advice

The OIC states that:

> f) the commission may obtain expert advice on any subject related to the inquiry and may exercise any of its powers under the Act in order to carry out the inquiry in accordance with these terms of reference;[33]

The Panel engaged Deloitte to perform an independent analysis and provide independent reports addressing many of the questions set out in the OIC.

3.2.7 Reporting

The OIC states that:

> g) the commission must submit to the minister charged with the administration of the *Hydro and Power Authority Act:*
>
> (i) a preliminary report outlining progress to date and preliminary findings by September 20, 2017, and
>
> (ii) a final report, including the results of the commission's consultations, by November 1, 2017.[34]

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[30] *Rio Tinto v. Carrier Sekani Tribal Council*, [2010], SCC 43.
[31] *Clyde River (Hamlet) v. Petroleum Geo-Services Inc.*, [2017], SCC 40.
[32] OIC, section 3 (e).
[33] OIC, section 3 (f).
[34] OIC, section 3 (g).

3.3 Process

The Commission's process was split into two phases: initial fact gathering, which concluded with the publication of the Preliminary Report, and additional fact gathering, consultation and submissions, concluding with the publication of this Final Report.

3.3.1 Initial fact gathering and the Preliminary Report

During the initial fact gathering phase, the Panel sought submissions, reviewed and analyzed those submissions, and prepared the Preliminary Report.

The Panel directed BC Hydro to provide a submission on all aspects of the Inquiry, including on the questions regarding completing, suspending or cancelling the Site C project. BC Hydro was directed by Order G-121-17 to submit an evidentiary filing updating its load forecast filed in BC Hydro's Fiscal (F) 2017–F2019 Revenue Requirements Application (F17–F19 RRA), on the value of energy and capacity from Site C, and on the questions put forth in the OIC. BC Hydro provided its evidentiary filing on August 30, 2017.

The Panel visited Site C on August 10 and 11, 2017 to inform our deliberations, accompanied by consultants from Deloitte. The Panel toured the Highway 29 realignment area, the dam construction site and the surrounding areas. BC Hydro's on-site team members briefed the Panel on the progress to date and the remaining work.

The Panel engaged Deloitte to perform an independent analysis of many of the questions set out in the OIC, specifically whether the Site C project was on time and on budget, what the anticipated costs would be to suspend or cancel construction, and what alternative source of generation and demand-side management initiatives exist to replace the energy and capacity of Site C.

Deloitte is a qualified and independent consultant that was retained by the Panel to gather information and provide analysis to assist the Panel in answering the questions posed in the OIC. Deloitte is an advisor to the Panel and acts pursuant to the Panel's direction. Deloitte is not a party to the proceeding and does not advocate for or against any issue.

BC Hydro was directed to make available any and all relevant information to assist Deloitte, including but not limited to current Site C project information and current load forecasts. The relevant information included public and confidential documents.

Deloitte submitted their reports to the Panel on August 30, 2017. Subsequently, the Panel worked with BC Hydro to identify confidential information in the Deloitte reports, and to produce a redacted version for publication. Information in Deloitte's final reports that the Panel determined to be confidential was redacted.

Deloitte provided independent estimates of the construction costs to suspend or cancel the Site C project in one of the independent repots. In the other report, Deloitte identified portfolios of alternative generation to replace the energy and capacity of Site C and identified additional demand-side management opportunities, as well as providing an assessment of BC Hydro's load forecast.

In addition to BC Hydro's August 30, 2017 filing and the Deloitte reports, submissions were welcomed from all parties, including the public. The Panel issued public notices in newspapers across the province and online at news websites. An awareness campaign was conducted through media releases, the creation of an Inquiry website, www.siteCinquiry.com, Twitter and email notifications. The Panel did not solicit, receive and evaluate applications for intervener status in this Inquiry. Rather, in the interest of efficiency, the Panel accepted all submissions of data and analysis, and considered each on its own merits in its deliberations. Aspects of submissions beyond the scope of the Inquiry were not considered.

To ensure that the Inquiry was open, transparent and accessible to the public, the Commission set up a toll-free telephone line and a website to provide access to information about the Inquiry. A call centre company was engaged to handle the anticipated volumes of inquiries once the Preliminary Report was published. Back-office processing was also set up to handle a significant volume of comments from the public in response to the Preliminary Report. The Panel accepted submissions electronically via the internet, and also via mail and fax. All submissions are posted on the Commission's website, and are also available for inspection at the Commission's office.

Following the closing date on August 30, 2017, the Panel reviewed the submissions received before the Preliminary Report was issued and deliberated on the questions posed in the OIC. The outcome of these deliberations was documented in the Preliminary Report.

The final step of the initial fact gathering process was the production of the Preliminary Report. This was delivered to the Minister on September 20, 2017, six weeks after the start of the Inquiry.[35] The Preliminary Report was the basis for the subsequent processes, described in Sections 3.3.2, 3.4, 3.5 and 3.6 below.

3.3.2 Additional fact gathering, consultation and the Final Report

Following the publication of the Preliminary Report, the Panel conducted an extensive consultation process inviting submissions on the Preliminary Report. Input was sought from BC Hydro, the public and First Nations.

The Panel acknowledges that BC Hydro has extensive knowledge and a deep understanding of the details related to the Site C project and has a significant stake in the outcome of any decision the BC Provincial Government might make using our analysis and findings. The Panel sought to ensure that BC Hydro has every opportunity to identify potential errors or gaps in the preliminary analysis and provide information relevant to completion of the Final Report.

Based on further evidence and submissions received subsequent to the issuance of the Preliminary Report, the Panel has made further assessments and findings on the questions posed in the OIC. These findings and conclusions are provided in this report.

As an important part of the consultation process, the Commission scheduled and held Community Input Sessions around the province to solicit oral submissions from members of the public. Community Input Sessions were conducted in major population centres in BC and in areas where the Panel considers the Site C project has a higher impact. Specifically, sessions were held in Vancouver, Kamloops, Kelowna, Nelson, Prince George, Hudson's Hope, Fort St. John, Nanaimo and Victoria.

The Panel also sought input from First Nations regarding its Preliminary Report. Treaty 8 First Nations and other First Nations who made submissions in the Inquiry were invited to make further oral submissions on the Preliminary Report. These sessions were held in Prince George, Victoria and Vancouver.

In accordance with Order G-120-17, written submissions on the Preliminary Report from members of the public, BC Hydro and First Nations were accepted by the Commission until October 11, 2017. However, on October 11, 2017, the Commission issued a letter requesting comments specifically on an Illustrative

[35] OIC, section 3(g)(i).

Alternative Portfolio prepared by Commission staff under the guidance of the Panel.[36] The deadline for providing comments on the Illustrative Alternative Portfolio was on or before October 18, 2017.

In total, approximately 600 written submissions were received during the course of the Site C Inquiry.

The Panel also invited specific parties who had made submissions during the Inquiry to present material to the Panel. These presentations were referred to as Technical Presentation Sessions and parties were selected based on the relevance and quality of their submissions, and the degree to which the Panel determined that the party would contribute to its deliberations and conclusions. The sessions were held in Vancouver on October 13 and 14, 2017.

The final step in the Site C Inquiry is the production of this report. In accordance with the OIC, the Final Report must be delivered to the minister charged with the administration of the *Hydro and Power Authority Act* by November 1, 2017, six weeks after the delivery of the Preliminary Report.[37]

The Final Report is available for public review on the Commission's website, and in hardcopy at the Commission's office. With the publication of this report, the Panel has completed the work directed in the OIC. Specifically, within the terms of reference set out in the OIC, the Panel has submitted to the Minister as ordered: "(i) a preliminary report outlining progress to date and preliminary findings by September 20, 2017, and (ii) a final report, including the results of the commission's consultations, by November 1, 2017."[38]

3.4 Community Input Sessions

This section contains a summary of comments made by the public at the Community Input Sessions. A number of the submissions made at the Community Input Sessions have been further expanded upon by the Panel in subsequent sections of this report when discussing other implications of continuing, terminating or suspending Site C.

In total, the Commission hosted 11 Community Input Sessions, beginning in Vancouver on September 23 and ending in Victoria on October 11, 2017. The sessions were well attended throughout the province. There were 963 total attendees. The quantity and quality of submissions was exemplary. Attendees who wished to make submissions were asked to keep their submissions within the scope of the Inquiry and were asked to confine their presentations to five minutes. Generally, each Community Input Session lasted for approximately 3 hours.

In total 290 speakers made submissions at Community Input Sessions. A far greater number of speakers expressed support for the termination of Site C as opposed to favouring completion of the project. In Vancouver, Prince George and Victoria, organized demonstrations were held outside the venue in support of terminating the project. Nonetheless, the Panel is not persuaded the number of people for or against Site C has any statistical reliability. Events of this nature are more likely to attract those with strongly defined views on the subject.

In its review of the transcripts and submissions, the Panel noted a difference between the submissions from people who lived in the vicinity of the project compared to those from other parts of the province. Those who lived near Site C who were against the project had a tendency to augment their submissions with a stronger message about Site C's impact on them personally. Locals who supported Site C tended to be individuals either involved with the project or directly benefiting from the dam's construction. Participants who did not live close to the project and were against the project were more likely to rely on arguments

[36] Submissions A-22; A-22-1.
[37] OIC, section 3(g)(ii).
[38] OIC, section 3(g)(i).

supported by their interpretation of the facts. An exception to this was the concerns expressed related to the project's impact on First Nations.

An analysis of the submissions was conducted and revealed that the highest frequency of comments and submissions fell into one of the following themes:[39]

1. First Nations concerns;
2. The likelihood of Site C being on time and on budget;
3. The likelihood of Site C recovering its costs;
4. Environmental concerns;
5. Alternatives to Site C;
6. Concerns for loss of agricultural land;
7. The impact on jobs;
8. Financial impact on ratepayers;
9. The future demand for electricity; and
10. Social and other unquantified costs.

Each of these themes had a number of sub-themes. A discussion of each of these higher frequency themes and related sub-themes follows.

It is important to note that the following outline of themes and sub-themes is based on submissions from the public and represents their views as understood by the Panel. A number of these themes will be raised again when the Panel examines some of the non-quantifiable costs and the implications of each of the three cases outlined in the OIC.

3.4.1 First Nations concerns

This theme explores public views regarding Site C's impact on First Nations.

Impact on First Nations communities

Major concerns were expressed that Site C would negatively impact First Nations communities by further disrupting their way of life, resulting in a loss of cultural heritage and causing environmental damage. There were a few submissions indicating that new jobs and business development opportunities would be beneficial for communities, but these were relatively rare. Highlighted topics included:

- Environmental damages from flooding prime hunting, fishing and farming land used and relied upon by communities;
- Loss of way of life, damages to sacred sites and burial grounds;
- Health concerns due to loss and contamination of food sources; and
- The potential for Site C to provide jobs and business opportunities for First Nations communities.

Honouring Treaty 8 and fulfilling responsibilities for reconciliation with indigenous peoples

There were significant concerns that both the Government and BC Hydro were ignoring aboriginal and treaty rights and that there has been a lack of sufficient consultation. Several parties referenced the United Nations Declaration on Rights of Indigenous Peoples (UNDRIP) and the fact that First Nations did not give their free, prior and informed consent for Site C. These views were not unanimous as a small number of

[39] Note: a lower frequency of comments and submissions was received on the project approval process, the perception of BC Hydro and the social impact on local communities.

submissions expressed the view that First Nations had been consulted and are supportive of Site C. Highlighted topics included:

- Site C infringes on treaty rights, land title rights, and the self-governance of First Nations;
- The Government must abide by and enforce the treaties and laws which have been established with First Nations;
- Disappointment that the BCUC mandate does not allow BCUC to consider First Nations rights;
- Concerns that some First Nations have explicitly stated they are opposed to Site C but are being consistently rebuffed and ignored;
- Concerns that some First Nations felt pressured into entering into impact benefit agreements with BC Hydro; and
- Comments that some First Nations are supportive of Site C.

Legal issues

The environmental damages, infringement of treaty and indigenous rights, and impact on communities may culminate in extensive legal and settlement costs related to Site C. Highlighted topics included:

- Potential for significant First Nations settlement costs; and
- Concerns that First Nations may lack the financial resources to pursue their rights against the Government and BC Hydro.

The following statements were made at the Community Input Sessions regarding First Nations concerns:

> "The federal-provincial Joint Review Panel concluded that Site C would have significant adverse effects which cannot be mitigated on traditional First Nations' fishing, hunting and other land uses. There are 42 sites of significant cultural or spiritual values that would be flooded. How can we, a nation of newcomers, justify erasing other nations' history of time immemorial? " [40]

> "How do you put a price on the intergenerational destruction and damage that previous dams have brought through the homelessness and the hopelessness that they've inflicted?...Many feel that Treaty 8 has been violated…It is being violated again when B.C. allows clear cutting and destruction of animal habitat to happen without waiting for the courts to decide on treaty rights." [41]

> "I would like to offer as consideration the international reputation and obligations that Canada has to meet with reference to the inherent rights of the indigenous peoples of both BC and right across Canada. This will be a big black mark on our collective reputation if we do not complete the respectful meaningful discussions and get the consent of these First Nations Peoples." [42]

[40] TCI-1, September 23, 2017, Vancouver, p. 43.
[41] TCI-1, September 23, 2017, Vancouver, p. 46.
[42] TCI-1, September 23, 2017, Vancouver, p. 100.

"Apologies are hollow without sincere action. Real reconciliation requires full recognition of First Nations rights to land and self-governance. Treaty 8 nations have yet to be accorded meaningful consultation. A recent UN panel called for Site C to be cancelled on these grounds." [43]

"Though no indigenous communities are located within the planned flood zone, they rely on the valley to hunt, fish, trap and gather berries and plant medicines which provide many of the basic needs of their families and communities while maintaining and revitalizing cultures and traditions that have been undermined and attacked through Canada's history…The valley is prime habitat for moose critical to the traditional diet of indigenous peoples in the region, and for bears and eagles that have cultural and sacred significance. The Site C dam would flood a series of small islands where moose take shelter when calving. Dene Zha elder Lillian Gauthier says she could live without electric lights and a fridge, but she'd be lost if her family could no longer hunt moose." [44]

"When my ancestors entered into a treaty, they did not give up our laws. We still haven't. To this day, I do not find anywhere where we gave up our water rights." [45]

"…it's the largest infraction and infringement on indigenous sovereignty that we have seen…" [46]

3.4.2 Likelihood of Site C being on time and on budget

This theme explores the public's perspective on why the project may or may not be on time and/or on budget. It includes reference to the Deloitte report, Preliminary Report, external studies, experience with projects elsewhere, BC Hydro's track record on major capital projects and recent events regarding Site C construction progress and contractors.

Assessment of current budget and schedule

The public expressed concerns that Site C would be over budget and delayed. These concerns stemmed from the nature of mega projects and the perception of how the Site C project is currently being managed by BC Hydro. Frequently-raised topics included:

- The citing of empirical studies to indicate the majority of mega projects go significantly over budget and behind schedule. This was backed up by Canadian examples such as the Muskrat Falls and Manitoba dams, and previous BC Hydro projects;
- Concerns that BC Hydro is already on track to go over budget due to the large portion of the contingency already used, and expert assessments that prime contract costs are underestimated.

[43] TCI-3, September 25, 2017, Kelowna, p. 204.
[44] TCI-3, September 25, 2017, Kelowna, pp. 209–210.
[45] TCI-8, October 2, 2017, Fort St. John, p. 688.
[46] TCI-9, October 5, 2017, Vancouver, p. 764.

There were requests that cost estimates and schedules be updated to reflect the current situation; and

- Concern around BC Hydro's ability to select, contract and manage contractors to deliver on time/on budget, highlighted by Petrowest entering into receivership, and the slow progress of construction to date.

Geological risks

Concern with geological risks was cited as a major factor impacting unforeseen expenses and delays. These risks were highlighted as becoming increasingly likely. These include:

- Concern over tension cracks that have opened as being indicative of stability issues with the riverbanks and the likelihood of additional time and budget to stabilize being required;
- Concern that the bedrock in the surrounding areas is shale and unsuitable for construction. These concerns included, risks of landslides, dam failure (Taylor bridge collapse), and increased expenses and delays; and
- Claims that BC Hydro is not taking geological reports and geological considerations seriously enough and thus is understating the geological risks.

The following statements were made at the Community Input Sessions regarding the likelihood of Site C being on time and on budget:

> "Site C seems to be hurtling toward significant delay and cost overruns." [47]

> "It will come as no surprise to most watching the project that it's over-budget and over-schedule considering the nature of the geology of the north bank. It's an area that perhaps no amount of money can stabilize and it has been the primary source of delays and cost increases." [48]

> "It is clear as demonstrated through the contracts made, the geological reports ignored, litigations endured, and due process of proper review bypassed, that BC Hydro cannot accurately predict or budget for contingencies, and as such should not be expected to have an accurate financial plan for mitigating future contingencies." [49]

> "…being a steelworker, I've worked on the Port Mann Bridge, I worked on the Kelowna Bridge, and any kind of project, mega-project, like you're calling the Site C dam, it's going to go over cost. Straight out, it's going to go over cost." [50]

[47] TCI-4, September 26, 2017, Nelson, p. 294.
[48] TCI-7, October 1, 2017, Fort St. John, p. 607.
[49] TCI-7, October 1, 2017, Fort St. John, p. 614.
[50] TCI-9, October 5, 2017, Vancouver, p. 788.

3.4.3 Likelihood of Site C recovering its costs

This theme considers whether the Site C project will be able to recover its costs in the long term. This touched on topics including the impact of interest rates over the lifetime of the project, potential demand, technology disruption from lower cost alternatives and the potential to sell surplus power given competitive alternatives elsewhere in North America.

Evolution of energy markets

There were mixed views as to how energy markets would evolve and their impact on Site C. Export opportunities, energy demand, and competing sources were factors discussed by the public with respect to recouping costs. Comments included the following:

- Strong belief around the likelihood that Site C will produce surplus electricity that will be exported at a loss;
- Comments on how Site C will be needed to meet the increase in export demand as other jurisdiction move away from older energy sources and add emission restrictions; and
- Comments that energy demand will be at a high enough level to support Site C by completion time based on new technologies (e.g. electric vehicles) and other increases in energy demand.

Sensitivity of economic viability to changing factors

The public raised a variety of concerns regarding the economic viability of Site C and assumptions on electricity prices, interest rates and construction cost. People were critical of the over reliance on assumptions, and how changes in these assumptions could have a significant impact on Site C's economic viability. Comments included the following:

- BC Hydro's high debt load and the long payback period for the project make it vulnerable to increases market interest rates. There is concern that we will be paying off debt for generations to come;
- Concerns over the extent to which future recovery depends on the market price of electricity increasing. People expressed differing opinions as to whether the market electricity prices would rise or fall;
- Concerns that if construction costs went over budget then Site C costs would not be recoverable over its expected lifespan;
- Comments and criticism related to the overall weakness in the economic viability of Site C and it being a marginal project (high costs, low margins, increasingly competitive industry); and
- Concerns about competition from less costly sources reducing the future demand for electricity, and BC Hydro's ability to sell the surplus.

The following statements were made at the Community Input Sessions regarding the likelihood of Site C recovering its costs:

> "We are trending towards increased energy efficiency, decentralized solar power, and other forms of sustainable energy. As well, our existing dams still have capacity for expansion and added efficiency. I don't believe that there's any justification for building this dam. The excess energy it would produce would have to be sold at a loss, which is ludicrous." [51]

[51] TCI-3, September 25, 2017, Kelowna, p. 242.

> "It's my understanding that BC Hydro currently has enough surplus energy to sell to the United States every year an amount of which roughly adds up to the proposed amount to be produced by the Site C dam itself. From a demand perspective, and from a supply perspective, B.C. doesn't need Site C."[52]

> "Why should I be paying more for the electricity I now use to pay for the production of electricity I do not need, so it can be sold at a loss on the U.S. market? Is this in your best interests? Is this in mine? I don't suspect so."[53]

3.4.4 Environmental concerns

This theme captures public comments on the impact on the environment of continuing with Site C, and the environmental impacts associated with alternative means of electricity production. In particular, it captures changing public views relating to renewable energy versus clean energy production. The main concern of the public was around the negative impacts of the construction of Site C on the environment and downstream impacts of flooding the Peace Valley. These concerns were based on some of the long-term issues arising from the Williston reservoir and the view that Site C is not a clean source of energy.

Renewable versus clean energy generation

Concerns were raised with recent findings concluding that hydroelectricity generation by Site C dam is not a clean source of energy due to the negative environmental impacts in comparison to other energy options (e.g. solar or wind), which were considered as less intrusive on the environment. Highlighted topics included:

- Site C dam has a large carbon footprint due to greenhouse gas emissions produced during construction and the destruction of trees that act as a large carbon sink;
- Site C dam results in the destruction of an ecosystem that provides carbon storage, freshwater supply, air filtration, and flood and erosion control; and
- Site C is a cleaner alternative to natural gas.

Impact on wildlife and rare plant species

Continuing with the construction of Site C will result in the flooding of land that is home to a large and varied population of wildlife. The general public is concerned with the impact flooding has in relation to habitat destruction and wildlife populations. Highlighted topics included:

- BC Hydro has not considered the cost implications of destroying habitat and ecological systems;
- Destruction of this habitat will have negative implications on large mammals due to depletion of forage and loss of calving grounds and migration routes; and
- Site C will destroy habitats for plants, aquatic and land animals, some with populations already endangered, further threatening their existence.

[52] TCI-5, September 29, 2017, Prince George, p. 489.
[53] TCI-5, September 29, 2017, Prince George, p. 490.

Downstream impacts

The public expressed concerns for long-term impacts of Site C construction, often referencing the long-term impacts seen at Williston reservoir and the surrounding area and the resulting health implications. Highlighted topics included:

- Williston reservoir is experiencing high methyl mercury toxicity that is negatively impacting the freshwater quality and fish populations that could be harmful to locals; and
- Concerns that Site C will add to the already impacted Athabasca delta.

The following statements were made at the Community Input Sessions regarding environmental concerns:

> "The loss of unique and irreplaceable values that pertain to the Peace River Valley have not been identified as costs in any of BC Hydro's documents. That does not mean that we as ratepayers, both now and in the future, will not have to bear these costs both environmentally and economically. I ask the BCUC Panel to account for these values as real, but unenumerated costs, of biodiversity loss." [54]

> "There is nothing worse than a hydroelectric project for the environment. It kills the environment. As the previous speaker said, it's dead water behind the dams." [55]

> "An informal analysis suggests that some 1,300 kilometers of biologically rich, productive lowland, river Rhine Valley forests and wetlands associated with former river valleys have been destroyed in B.C. by reservoirs. Site C would consume another 107 kilometers of this kind of habitat, including the Lower Halfway and Moberly rivers…Site C flooding would further wipe out spring calving grounds for moose, deer and elk, and remove prime habitat for a range of wildlife species including grizzly bears, wolves, ungulates, and bull trout, plus many bird species, such as osprey, eagles, and trumpeter swans." [56]

> "…I just want to point that many of the Hudson's Hope losses are of the intangible nature. They're in the eye of the beholder. I don't know how you're going to measure those things but they are costs, nevertheless. So whether it's a drive through the valley to get here, from Fort St. John, or the tiny little cactus plants that we have – pear practice's cactus, I think they're called. They're found along the north bank. Or whether it's the bull trout that are at risk in the river. Those are the things that I know that are not within your terms of reference per se, but they are costs. And how you put a number on it, I don't know." [57]

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[54] TCI-1, September 23, 2017, Vancouver, p. 55.
[55] TCI-1, September 23, 2017, Vancouver, p. 70.
[56] TCI-2, September 24, 2017, Kamloops, pp. 153–154.
[57] TCI-6, September 30, 2017, Hudson's Hope, p. 527.

> "This dam will flood a beautiful valley that supports many lives, both human and animals. There is also a cost to this."[58]

> "There are currently no industrial market gardens in the Peace Valley flood zone. Farmers will not, and do not invest in creating market gardens in the Peace Valley as long as a flood reserve remains on the valley. Over the next five to 10 decades, class 1 and 2 topsoil in British Columbia will probably become more valuable than gold, and certainly more valuable to ratepayers and their families than 75 to 100 years of Site C generated electricity."[59]

3.4.5 Alternatives to Site C

The comments on alternatives to Site C can be broken down into three sub-themes:

- The potential to avoid the need for Site C through more aggressive demand-side management (DSM) initiatives, including peak pricing, industrial demand curtailment, etc.;
- The potential to increase supply from existing infrastructure (e.g. Columbia River Treaty, Burrard Thermal, existing dam retrofits); and
- The construction of alternative renewable supply projects, like wind, solar and thermal, that are timed for when they are needed.

Need for building additional generation capacity

The public expressed opinions on whether building additional generation capacity was needed and took positions both for and against building additional generation capacity. Submissions focused around the existence and efficiency of current additional generation capacity coupled with DSM and energy efficiency. Highlighted topics included:

- Power generated from Site C is not needed due to existing generating capacity from alternatives like re-opening Burrard Thermal which offers existing options for meeting peak demand;
- The potential to explore the Canadian Entitlement for power generated by the Columbia River Treaty;
- Extra generation capacity is not needed due to the increasing efficiency in building techniques, development of better power storage options, and DSM;
- Additional generation capacity will be needed in the future due to increasing demand; and
- Concerns that additional generation capacity is not needed due to the significant amount of power BC Hydro exports/sells outside of BC, especially selling at a loss.

Alternative methods for power generation

Significant interest was expressed by the public on the need to look into alternative options for energy. Alternatives proposed included a heavy focus on emerging renewables along with leveraging existing projects and more localized generation. The pubic frequently proposed alternatives to Site C, which they thought were viable or needed to be explored further. Highlighted topics included:

[58] TCI-6, September 30, 2017, Hudson's Hope, p. 533.
[59] TCI-7, October 1, 2017, Fort St. John, p. 617.

- Smaller scale sites or less ambitious projects with lower risk and commitment than a single megaproject;
- The adoption of renewable energy sources (solar, tidal, geothermal and wind) to deliver electricity locally and at lower cost; and
- Upgrades to and maintenance of existing projects like the W.A.C. Bennett dam or reservoirs.

Effectiveness of alternatives

The public frequently questioned the effectiveness of Site C versus the proposed alternatives. Comments were clustered around suitable generating capacity, investment requirements and effectiveness. Highlighted topics included:

- Risk of committing to long-term projects when renewable technology is advancing at a rapid pace;
- Disruption to the Site C business model as the price of renewables falls;
- Renewables like solar and wind would still require significant land investment;
- Alternatives do not match the consistency, volume and low costs of power generated from hydro; and
- Public funds spent on Site C are better spent on other social projects, healthcare or improving existing energy infrastructure.

The following statements were made at the Community Input Sessions regarding alternatives to Site C:

> "I represent just a few handful of ratepayers, and also I'm doing this in the memory of 45 men and women that built the Heritage System and gave you the downstream benefits. I was director of planning of that group. The reason I'm here is you're worried about the Columbia River Treaty, whether you can count on it. I'm here to tell you why you can count on it until 2040…Now, legally the treaty can be cancelled with ten-years notice…But I'm going to tell you, that it will never be cancelled…" [60]

> "The economics are very clear. This makes no sense. We don't need this power, and if we did we can go to the Columbia River Entitlement Treaty and we can change the Clean Energy Act…Wind and solar have dropped fifty percent in the last five years. So we have options." [61]

> "The second and I think more impactful is just the folly of building a massive industrial mega-dam in 2017, when we know that prices for renewables are falling across the board…we're standing on this precipice of a world that is swimming in cheap, reliable, clean energy, and yet we're reaching back into the 1970s to overhaul this dam that doesn't make sense anymore." [62]

[60] TCI-1, September 23, 2017, Vancouver, pp. 8–11.
[61] TCI-1, September 23, 2017, Vancouver, p. 19.
[62] TCI-1, September 23, 2017, Vancouver, p. 22.

> "If you use wind generation in B.C., we have a distinct advantage. Throughout Europe and so on, there is no place to store that energy except for massively expensive battery banks. But here, you use the wind generation for main generation, which means you're not drawing down the water in reservoirs behind the dams, and you use that as your backup power source."[63]

> "…we would be very pleased if the BCUC considered the flexibility and other values of smaller scale innovative power generation ideas, including conservation as we heard mentioned earlier today, compared to the large scale of Site C and the economic make or break risk that it poses."[64]

> "BC Hydro appears to have fallen off the energy conservation wagon over the past 20 years. British Columbians will benefit if the Crown corporation's resources are redirected from Site C so that it can reclaim the energy conservation leadership role that it held in the 1990s."[65]

> "As I understand it, BC Hydro has been reducing its efforts to address the consumption of electricity it produces through programs like PowerSmart. This is a big problem. We need to be placing more emphasis on managing the demand for energy by households, institutions, and industry before we consider spending money on power projects that have massive ecological footprints like Site C."[66]

> "On a local installation, on buildings, in the future, it will be tied in with batteries…So I think it's reasonable to see that people might even – companies might even start abandoning the grid when the prices come low enough, where you can simply put a bank, an array of PV panels, say, on top of your IKEA building. Storage in the parking lot, which is coming down rapidly, and maybe a generator and some interconnectivity software. And it will be cheaper than what BC Hydro is trying to sell Site C electricity for."[67]

3.4.6 Concerns for loss of agricultural land

This theme describes the public's views over the loss of agricultural land to flooding. A leading concern in this area is the improper value placed on agricultural land and its expected increase in future value due to climate change. The public raised concerns that the value of agriculture is not accurately incorporated into the economic analysis of Site C.

[63] TCI-3, September 25, 2017, Kelowna, pp. 213–214.
[64] TCI-3, September 25, 2017, Kelowna, p. 251.
[65] TCI-4, September 26, 2017, Nelson, p. 289.
[66] TCI-5, September 29, 2017, Prince George, p. 482.
[67] TCI-10, October 5, 2017, Vancouver, p. 808.

Food security and climate change

The public expressed significant concern over how the loss of agricultural land would contribute to a lack of food security, which is seen as an issue of growing importance in BC due to climate change. The most frequently made comment was that the land being flooded at Site C could feed a million people. The public generally expressed the view that climate change would negatively impact farm productivity in places like Mexico and California, but would have a positive impact on farm productivity in BC, especially in the fertile Peace River Valley. Highlighted topics included:

- A million people can be fed from the land being flooded at Site C due to the area's unique and fertile micro-climate;
- Loss of arable land from Site C will be irreversible and negatively impact food security, which is a growing issue in the face of climate change; and
- Farming capabilities in BC will be improved by climate change due to a longer growing season and better weather for farming.

Economic impact

Submissions expressed various ways in which agriculture could provide positive benefits to the economy through jobs in agricultural production and food processing. Highlighted topics included:

- An expanded agricultural industry could create a significant number of long term jobs, as opposed to the temporary jobs from Site C;
- Locally produced food is cheaper and provides economic benefits to the community; and
- The farmland around Site C is not being fully utilized due to the potential for Site C to continue.

The following statements were made at the Community Input Sessions regarding loss of agricultural land:

> "I'm here as a volunteer. I am a professional Agrologist, recently retired. I did the agricultural impact assessment of the Site C dam and made a representation to the Joint Review Panel…I have never become so seized with the importance of defending the public interest in a project as the Site C dam, defending the public interest in why this project should not go ahead…These lands have the capacity to provide the nutritional requirements of over a million people a year…Site C is our plan B for food security. Site C is the commons. These lands have been here for millennia and they are meant to feed generations in the future." [68]

> "…I am also concerned about food security. Climate change leading to drought and the poverty of the north that our previous provincial governments have done nothing to alleviate. As had been pointed out by experts, the Peace River Valley has highly productive agricultural qualities that would be flooded. With high prices of food in the north and elsewhere, I am confused as to why this land isn't being used for food production…Why as a humanitarian society are we not addressing these issues with what we have within our bounders [boundaries], instead of building a dam on futile promises of future unproven need when we can't feed our own children who are our future." [69]

[68] TCI-1, September 23, 2017, Vancouver, 30-32.

"In a time when climate change, both the slow increase of average temperature and the resulting severe weather events is causing havoc to food producers around the globe, it makes sense to pay closer attention to food resiliency here at home and where our food is coming from. We need to be considering the costs of not protecting our farmland."[70]

"The Peace River Valley is a prime agricultural land. Food and water are the main necessities of life. It makes more sense to grow food locally rather than rely on long-distance shipping of produce from areas that are threatened by drought, such as California. As the climate warms, more variety of produce will be able to be grown in the north to supply areas in the south which might be suffering droughts."[71]

3.4.7 Impact on jobs

This theme explores two opposing sub-themes:

- The gain of local jobs directly associated with the Site C project and what would happen to these jobs if Site C was cancelled; and
- The loss of future provincial jobs that might otherwise be created from investment in more intensive agriculture, in alternative energy projects, and in industrial growth if depressed by potentially higher electricity rates.

The impact of Site C on jobs is a divisive issue. The public frequently mentioned the immediate impact of Site C on jobs to local industries, and the long-run impact.

Immediate job impacts

The public was divided on the impacts of jobs attributable to Site C associated with construction or agriculture. Highlighted topics included:

- Job losses to Site C workers due to cancellation of Site C;
- Job losses to the agricultural sector due to completing Site C;
- Support of local economies and municipalities from spending from Site C; and
- The belief that if cancelled, Site C workers should be compensated.

Long-run job impacts

The comments around the long-run impacts on jobs of Site C were focused on the potential for depressed industrial growth if electricity rates rise, as well as missed job opportunities related to DSM activities and renewable energy options. Highlighted topics included:

- Views that loss of Site C construction jobs would be offset by jobs created in remediation, alternative energy projects and other construction projects;

[69] TCI-1, September 23, 2017, Vancouver, p. 43.
[70] TCI-4, September 26, 2017, Nelson, pp. 307–308.
[71] TCI-5, September 29, 2017, Prince George, p. 492.

- Loss of potential jobs in agriculture due to permanent loss of productive land;
- Concerns that the jobs created by Site C are not sustainable in the long-run; and
- Concern that continuation would hinder development of more numerous project and operational jobs in the alternative energy industry.

The following statements were made at the Community Input Sessions regarding impact on jobs:

> "I'd be remiss if I didn't point out that this morning 2500 men and women in construction woke up, and went to work on this very important, and strategic investment in our long term energy future."[72]

> "Don't forget, currently there are over 2500 workers, 2500 families up in the Peace River working, relying on income [from] this project that was decided on long ago."[73]

> "Stopping Site C firmly and permanently will allow the green energy sector to rebound and thrive throughout B.C. Of course, it is necessary to provide retraining and support to displaced workers, but the costs of doing that are minute, compared to the costs to ratepayers, society, taxpayers, the business sector and government of not transitioning."[74]

> "…the workers at Site C, we made a choice to come here. Many uprooted their families to move here. Bought houses, placed their children in school. We just want to be a part of the community. Others are – made the sacrifice of being in Fort St. John without their families and commuting back on their days off. The common thread here is every worker there has made a choice. That choice was made in good faith and that is to integrate ourselves within this community and have a small part providing power for all of British Columbia."[75]

> "Could be 2,000 workers do not have to be concerned about losing their homes or feeding their families because they have a job at Site C today. This megaproject has injected tens of millions of dollars into the municipality and Peace region at the most opportune time when the oil and gas service sector took the worst economic downturn since 1981."[76]

[72] TCI-1, September 23, 2017, Vancouver, p. 29.
[73] TCI-1, September 23, 2017, Vancouver, p. 58.
[74] TCI-4, September 26, 2017, Nelson, p. 306.
[75] TCI-8, October 2, 2017, Fort St. John, pp. 672–673.
[76] TCI-8, October 2, 2017, Fort St. John, p. 678.

> "I think it's way more than just 2,000 workers that are being affected. The local support businesses and the spin-off work that's created by the Site C project is huge…It's not just the supply companies and the rental companies, it's the trucking companies. It's the pile-driving companies. It's the spin-off oilfield businesses. It's the cement companies…And the list is enormous of who this – and what this project is going to affect if it's stopped."[77]

3.4.8 Financial impact on ratepayers

This theme includes the differences (or similarities) that ratepayers see between the financial impacts on themselves as ratepayers versus taxpayers. It includes their perception of the risks they bear, how electricity rates will change, and the impact of electricity rate changes. It also includes concerns with the wasted expense of sunk costs and remediation arising from terminating with no benefit, as well as the opportunity cost of not spending money on other public projects.

Effect on rates and value of project

The public expressed mixed opinions on the effect of Site C on electricity rates. The primary driver behind the differing opinions was due to the cost of Site C. People were concerned over the high cost of continuing the project and the high cost of cancelling project, when compared to the benefits the project would provide. Highlighted topics included:

- Comments were polarized on the potential rate impacts, and the level of government support that should be involved;
- Views that the project will increase BC Hydro rates due to the high costs, large debt levels, and low marginal benefit. This was backed up by examples of other electric projects, like Muskrat Falls;
- Perspectives that the project would lower rates or help support low rates in the future. People mentioned that the building of projects like Site C are why hydro rates are so low in BC compared to the rest of the world;
- Thoughts that potential rate benefits from Site C are not worth it due to the already low price of hydroelectricity, and the willingness to pay a premium to avoid environmental concerns with Site C;
- Concerns over the high costs of remediation associated with cancellation, which would be a waste of money already spent; and
- Value of preserving the environment and avoiding potential First Nations legal costs is enough to justify cancellation costs.

Government involvement with Site C

The public was generally upset with the amount of taxpayer money spent on Site C due to the inefficiency of that spending and the risk of requiring more taxpayer money. Some people believed that the spending was justified. Highlighted comments included:

- Public approval of the Government's support for Site C, as costs to taxpayers will be recaptured from tax revenue from the economic impacts of the project;
- Concerns that the Government's subsidizing of BC Hydro projects is lowering hydro bills at the expense of taxpayers;

[77] TCI-10, October 10, 2017, Nanaimo, p. 924.

- Concerns at the amount of taxpayer dollars being spent on Site C and the future need for further taxpayer support due to budget overruns, interest payments and legal concerns; and
- Views that public funding for Site C is benefiting only private parties, and better investment would be in alternatives such as transport, healthcare and social spending.

The following statements were made at the Community Input Sessions regarding financial impact on ratepayers:

> "The 70 year payback will have a serious effect on opportunity cost implications for B.C., limiting capital availability to support a more sustainable economy for needed infrastructure projects, more cost-effective alternate energy projects, as well as more traditional commercial and industrial businesses."[78]

> "I have a farm north of Fort St. John, and I am a farmer for the last over 30 years. I am all for Site C and I will give you my reasons. Electricity produced from water power is the cleanest and cheapest way…We pay 12.5 cents per kilowatt hour for electricity here. Once a year I go to Germany and every household over there has to pay 60 cents per kilowatt hour. This is over five times as much."[79]

> "The lowest prices for electricity are paid in three provinces: Quebec, Manitoba and British Columbia. The reason Quebec, Manitoba and British Columbia have the lowest electricity prices in Canada is because they run-of-river technology, which is building dams and allowing water to run through a turbine. People call this old technology. It is old technology, and it's proven technology. That's why Quebec makes lots of money selling power into the United States using their run-of-river resources."[80]

3.4.9 Future demand for electricity

This theme includes the historic changes in demand, views on future demand, and the factors that may impact demand. It includes a comparison between historical data and BC Hydro's forecast and methodology, the timing of when more electricity may be required, and the timing of the completion of Site C. There is a particular focus on the relationship between demand and the creation of a competitive LNG industry in BC.

The public expressed concern with the accuracy of the demand forecasts by BC Hydro, criticizing both the methodology and the deviation from the historic trend. There were contrasting opinions on how the demand for power would change over time.

[78] TCI-1, September 23, 2017, Vancouver, p. 81.
[79] TCI-7, October 1, 2017, Fort St. John, p. 603.
[80] TCI-10, October 10, 2017, Nanaimo, p. 917.

Accuracy of BC Hydro's forecasts

The public expressed concerns around BC Hydro's forecast of future energy demand. Concerns ranged between historical growth patterns to invalid assumptions and conflicting incentives. Highlighted topics included:

- Concerns over the fact that BC Hydro is forecasting growing energy demand over the next 15 years, while historical energy demand has been flat for 10 years;
- Concerns that BC Hydro has historically over-estimated the demand for electricity;
- BC Hydro's demand forecasts do not account for changes in demand due to price changes (i.e. price elasticity); and
- Assumptions have been made that the LNG industry would require significant amounts of power. These forecasts are at risk if the LNG industry does not materialize, which is looking increasingly likely.

Need for more power

The public outlined various reasons for why and how electricity demand would change over time. Topics such as the impact of replacing fossil fuel sources of energy with electricity and demand changes from households and industry were focus points. Highlighted topics included:

- The proliferation of electric vehicles was frequently listed as a primary example. There was also some skepticism around how quickly this would occur;
- Power demand is expected to decrease as buildings become more energy efficient and as households increase their uptake of "off the grid" generation;
- Less power is needed as DSM and household batteries will reduce peak power needs;
- There is no proven case that demand will increase due to LNG and other energy intensive industries; and
- Higher prices for electricity will further reduce demand.

The following statements were made at the Community Input Sessions regarding future demand for electricity:

> "…the majority of the power for Site C was intended for an LNG industry which is never going to happen in this province."[81]

> "We are awash in electricity now and at least for twenty years and possibly more. BCUC, other people, we are asking the wrong questions. It doesn't matter if the forecasts are not precise; with incremental least cost projects we can meet demand if and when it materializes. It doesn't matter if Site C is either on time or on budget. We do not need it."[82]

[81] TCI-1, September 23, 2017, Vancouver, p. 21.
[82] TCI-1, September 23, 2017, Vancouver, p. 26.

"Site C dam is needed for the current energy independence of B.C. and the energy dependence of our neighbours who don't have the opportunity to build clean, environmentally renewable energy projects of this magnitude that we have here in B.C." [83]

"…the power from Site C is not needed. It's not needed now, it's not needed ten years from now, it won't be needed 20 years from now. Many speakers have spoken to this and the reason is clear, the consumption of power in B.C. is not going up any more. It stopped rising 12 years ago, and if anything, it is slightly going down." [84]

"…there's real good savings and benefits for integrated systems. However, solar is not a firm generation. And I get very little output from my system in the winter-time. And so, what happens is, I provide all my electricity and hot water for about nine to ten months of the year, and then when the winter comes, I am demanding my energy from a utility. So from a point of view of Site C, we all are going to need energy – more energy in the future…our population will grow eventually in Canada, and we will become more and more of a lifeboat for the world. Site C will go ahead one day…the reality is, battery technology, solar technology will get there, and integrated energy grid internet will get there. But from a point of view of electricity supply, clean, renewable resource, I believe Site C should still go ahead." [85]

"…one statistic that has hit home for me is that the act of converting all of B.C.'s vehicles to electricity would require a power supply equivalent to the capacity of 15 Site C projects. To convert all of our homes, buildings and industry to electricity would require the further capacity of another 15 Site C projects." [86]

"It is becoming clear that it is not possible to forecast the future need for power accurately. The demand for power in B.C. has been essentially flat for the last ten years. That was not forecasted. BC Hydro themselves have said we don't need the power from this dam for ten years after the dam is built. Will we need it then? They haven't been accurate so far." [87]

[83] TCI-1, September 23, 2017, Vancouver, p. 57.
[84] TCI-1, September 23, 2017, Vancouver, p. 69.
[85] TCI-3, September 25, 2017, Kelowna, pp. 207–208.
[86] TCI-4, September 26, 2017, Nelson, p. 322.
[87] TCI-9, October 5, 2017, Vancouver, p. 759.

3.4.10 Social and other unquantified costs

This theme captures the social costs of Site C that are not being taken into account in the economic analysis of Site C. These costs also include the impact of taxpayer support not fully compensated for by BC Hydro. Highlighted topics included:

- Risks of debt and interest rate shocks for British Columbia due to the high debt burden of BC Hydro;
- Government provision of Crown Land at no cost to BC Hydro;
- Financial costs for compensation of First Nations for infringement of their treaty rights and from subsequent environmental damages (Athabasca, Slave River);
- The decrease in land values due to the potential development of Site C;
- Costs to decommission the dam and unbudgeted maintenance on the dam and dam area (i.e. roads and slopes of banks) over its lifespan;
- Costs of maintaining the W.A.C. Bennett dam beyond its planned life; and
- Costs of transmission infrastructure needed to deliver power to end users;

Another important theme that was prevalent among participants in locations near Site C was the social impact on communities of the certainty related to Site C and the fact that it is a divisive issue within the community. Residents spoke about how the uncertainty surrounding Site C has affected land values and how businesses are not willing to invest in the area due to uncertainty about the future. In addition, residents are divided on whether they are for or against the project, which has a social impact on the community as a whole.

The following statements were made at the Community Input Sessions regarding social and other unquantified costs of Site C:

> "Whatever your decision is, this uncertainty is not healthy. People, businesses, and community cannot make plans around uncertainty, so we look forward to its end." [88]

> "There is no costing of the lost opportunities that we've had in the valley, and these opportunities might not be in the forefront today. They might be in a hundred years. But if we destroy the valley, they won't there. The community of Hudson's Hope, for example, has withered on the vine. And there will continue to be an escalating demise of that community if this project continues." [89]

3.5 First Nations submissions

The Site C Project is in an area covered by Treaty No. 8. Treaty No. 8 encompasses a landmass of approximately 840,000 square kilometers throughout northeastern British Columbia, Alberta, Saskatchewan and the Northwest Territories. The area is home to 39 First Nation communities, eight of which are located

[88] TCI-8, October 2, 2017, Fort St. John, p. 676.
[89] TCI-8, October 2, 2017, Fort St. John, p. 686.

within British Columbia.[90] Under the treaty, First Nations surrendered title to their traditional territories for, among other things, the right to continue using those territories to maintain their traditional way of life.[91]

Treaty rights are Aboriginal rights set out in a treaty. They are collective rights and shared amongst individual members of the Treaty 8 First Nations. A Treaty 8 First Nation's right to hunt, trap and fish is not established on a treaty-wide basis but in relation to the territories over which a First Nation traditionally hunted, fished, trapped, and continues to do so today.[92] Although Treaty 8 allows the Crown to "take up" land for other purposes, that right is subject to the First Nations being able to meaningfully exercise their rights.[93]

Aboriginal rights are collective rights, which flow from Aboriginal peoples' continued use and occupation of certain areas. They are inherent rights, which Aboriginal peoples have practiced and enjoyed since before European contact.[94] There are areas in British Columbia where First Nation claims to Aboriginal rights and title have not been dealt with by treaty or in any other legal way. Both Aboriginal and Treaty rights are recognized and confirmed by section 35 of the *Constitution Act*, 1982.

First Nations are important stakeholders. An effort was made to provide opportunities for First Nations to comment on Site C and the Panel's Preliminary Report. As noted, First Nations Input Sessions were held at three locations, which were determined in collaboration with those who wished to participate in the Inquiry. First Nations who participated in these sessions as groups or individuals are as follows:

- West Moberly and Prophet River First Nations;
- McLeod Lake Indian Band;
- Mikisew Cree First Nation;
- Sekw'el'was Cayoose and N'Quatqua First Nations;
- Tsilhqot'in National Government and Homalco First Nation;
- Ramona MacDonald; and
- Yvonne Tupper.

Following is a summary of the submissions of each presenting group as well as written submissions provided to the Commission. Where appropriate, any BC Hydro submission addressing an issue raised has been included.

West Moberly and Prophet River First Nations

West Moberly and Prophet River First Nations raised numerous concerns relating to the construction and operation of Site C. Their submissions include the following:

- The existing human footprint in northeastern BC is already large due to the existing hydroelectric infrastructure, reservoirs, oil and gas industry, forestry and mining. As these industries continue to grow there are fewer lands available for Treaty 8 First Nations to exercise their treaty rights to hunt, trap and fish. Site C will significantly add to this footprint.[95]
- The drawdowns on the Williston Reservoir continue to erode the banks and cause slides into the reservoir. In addition, when water is drawn down, beaches along the reservoir edge are exposed

[90] Treaty 8 Tribal Association, retrieved from: http://treaty8.bc.ca/treaty-8-accord/.
[91] *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, [2005], SCC 69 at para 2.
[92] *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, [2005], SCC 69 at para. 48.
[93] *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, [2005], SCC 69 at para 30–31.
[94] *Delgamuukw v. British Columbia*, [1997] 3 SCR 1010.
[95] TFN-1, September 29, 2017, Prince George, p. 354.

and, with wind, cause dust storms. These dust storms, in part, caused the Tsay Keh Dene Nation to be relocated three times since the damming of the Williston Reservoir. [96]

- Fish in the Williston Reservoir and surrounding rivers have elevated levels of methylmercury and are unsafe to eat. These levels have not declined despite the amount of time that has passed since the Williston Reservoir was flooded. West Moberly and Prophet River First Nations are concerned that increased levels of methylmercury will be found in the fish behind the Site C reservoir once it is created.[97]
- Flooding due to Site C will cover the natural fish barrier in the Moberly River, which currently prevents fish travelling up the river and into Moberly Lake. Once this barrier is flooded, the potential for fish contamination by methylmercury within Moberly Lake may occur because there will no longer be an active fish barrier to Moberly Lake. If this occurs, it will directly affect the West Moberly First Nations.[98]
- Current plans to realign Highway 29 will run directly through Bear Flats in the Cache Creek area, a historical gathering spot for the Dene Tha' First Nation for more than 1000 years. In addition, the area includes First Nation gravesites and is currently used for sweat lodges.[99]

More broadly, West Moberly and Prophet River First Nations submit that Site C will have adverse effects on the Treaty 8 Nations' ability to meaningfully exercise their Treaty rights, which cannot be mitigated.[100] Court challenges to date by West Moberly and Prophet River First Nations and the Peace Valley Landowners Association[101] were judicial reviews that addressed the administrative law issues, including the adequacy of the Crown's duty to consult. However, the courts specifically did not address the issue of whether the Crown, by approving Site C, unjustifiably infringed the Treaty 8 rights. Instead, the courts stated that the proper course for West Moberly and Prophet River First Nations is to commence a separate action alleging treaty infringement.[102] Although there are no current lawsuits specifically alleging that Site C is a treaty infringement, West Moberly and Prophet River First Nations and numerous parties submit there still remains a risk to the Crown that the court will find that it has unjustifiably infringed the treaty rights of Treaty 8 Nations and that damages are payable in the event they commence a lawsuit.[103] West Moberly and Prophet River First Nations are unable to quantify the amount of potential damages from this risk, but claim that it is significant given the treaty rights at stake, namely the right to hunt, fish and trap.

West Moberly and Prophet River First Nations submit that Blueberry River First Nations have already commenced litigation against the Province, seeking, in part, to enjoin any new industrial activity within their traditional territory including Treaty 8.[104] While the court determined that Blueberry River First Nations have established irreparable harm, it did not grant the injunction because the trial of the matter is imminent and the balance of convenience favoured not granting such a wide-ranging injunction. The lawsuit does not name BC Hydro as a defendant or third party.

As a result of the recent court case determining the boundary of the western edge of the Treaty 8 lands,[105] there remain potential claims relating to treaty infringements because of the Williston Reservoir, W.A.C. Bennett Dam and Peace Canyon Dam.

[96] TFN-1, September 29, 2017, Prince George, p. 356.
[97] TFN-1, September 29, 2017, Prince George, pp. 369–370, 381.
[98] TFN-1, September 29, 2017, Prince George, p. 370.
[99] TFN-1, September 29, 2017, Prince George, p. 371.
[100] TFN-1, September 29, 2017, Prince George, p. 372.
[101] *Prophet River First Nation v. British Columbia (Environment)*, [2015], BCSC 1682; affirmed [2017], BCCA 58; see also *Prophet River First Nation v. Canada (Attorney General)*, [2017], FCA 15.
[102] TFN-1, September 29, 2017, Prince George, pp. 396–398.
[103] TFN-1, September 29, 2017, Prince George, p. 399.
[104] *Yahey v. British Columbia*, [2017], BCSC 899.
[105] *West Moberly First Nations v. British Columbia,* [2017], BCSC 1700.

West Moberly and Prophet River First Nations state that they have prepared an infringement claim based on the infringement of their Treaty 8 rights because of Site C and the existing dams and reservoirs. This has yet to be filed in any court, although they submit that this is a risk that must be considered in the event Site C is completed.[106]

On a final note, West Moberly and Prophet River First Nations submit there are potential benefits to First Nations resulting from termination of Site C. In West Moberly and Prophet River First Nations' view, all Treaty 8 First Nations are well positioned to provide rehabilitation and remediation work in the Peace River valley. Treaty 8 First Nations have the traditional knowledge regarding plant species that could be applied to any remediation work and, as stewards of the Peace River valley, have a vested interest in rehabilitating it to ensure the continued exercise of their Treaty 8 rights.

BC Hydro response

BC Hydro submits that West Moberly and Prophet River First Nations unsuccessfully challenged the Project approvals in court, which were affirmed by courts of appeal, concluding that the impact from Site C on these First Nations has been meaningfully and reasonably balanced.[107]

BC Hydro responded to the issues related to mercury concentrations and the burial site. Currently, the Fish and Wildlife Compensation Board, a partnership between BC Hydro, BC Fisheries and Oceans Canada and First Nation communities, is undertaking a three-year investigation of mercury in fish in the Williston reservoir watershed. Eight First Nations are involved in the study, including West Moberly and Prophet River First Nations. Initial results of the three-year Fish and Wildlife Compensation Program study have shown that fish mercury concentrations in Williston reservoir and tributary streams, including the Crooked River are currently similar to mercury concentrations in nearby lakes for the species tested and are safe to eat. Further sampling was conducted in 2017 and will continue in 2018. Final results and analysis are not yet available; however, the preliminary report can be found on the Fish and Wildlife Compensation Program website. [108][109]

BC Hydro submits that in March 2017, the First Nations identified the location of what they believe is a burial on the west side of Cache Creek within the highway realignment of Bear Flats. At the request of the First Nations, BC Hydro has not conducted testing to confirm whether or not the site is in fact a burial. However, after learning about the potential burial site, BC Hydro re-designed the bridge over Cache Creek so that the site would not be disturbed.[110]

BC Hydro submits that the lawsuit commenced by Blueberry River First Nation, alleges "that accumulated activities that have already occurred over a very broad area (38,000 km^2) have resulted in an infringement of their Treaty rights. While that broad area includes the area where the Project is being constructed, they identify "critical areas" considerably north of the Project area. The lawsuit does not name BC Hydro or make any claims for damages."[111]

McLeod Lake Indian Band

McLeod Lake Indian Band supports the completion of Site C for two reasons:[112]

1. Site C provided a watershed moment in the relations between McLeod Lake Indian Band and the Crown. It reset the relationships between McLeod Lake Indian Band and the Crown acknowledging

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[106] TFN-1, September 29, 2017, Prince George, p. 399.
[107] Submission F1-12, BC Hydro, p. 6.
[108] Submission F1-12, BC Hydro, Appendix A, pp. 4–6.
[109] Williston-Dinosaur Watershed Fish Mercury Investigation, 2016 Report, prepared for Fish and Wildlife Compensation Program, Peace region (May 2017), retrieved from http://fwcp.ca/app/uploads/2017/06/2016-Data-Analysis-Report-Mercury-Sampling-Program-May-2017.pdf.
[110] Submission F1-12, BC Hydro, Appendix A, p. 7.
[111] Ibid., pp. 10–11.
[112] Submission F274-1, McLeod Lake Indian Band, p. 2.

and accommodating past impacts and establishing a new working relationship by entering into numerous agreements amongst the parties.

2. Suspending or terminating Site C would give rise to financial hardships and lost economic opportunities.

McLeod Lake Indian Band entered a number of agreements with BC Hydro and the Province in relation to Site C. The agreements address and accommodate impacts to McLeod Lake Indian Band title and rights caused by Site C. These agreements include:[113]

1. Renewal Agreement between McLeod Lake Indian Band and BC Hydro;
2. Impact Benefit Agreement (IBA) between McLeod Lake Indian Band and BC Hydro;
3. Contracting Agreement between McLeod Lake Indian Band and BC Hydro; and
4. Tripartite Land Agreement (TLA) between McLeod Lake Indian Band, BC Hydro and the Province.

BC Hydro required McLeod Lake Indian Band to approve the IBA, Contracting Agreement and the TLA before it would enter into the Renewal Agreement. McLeod Lake Indian Band views the IBA, the TLA and the Contracting Agreement as integral to the Renewal Agreement and the renewed relationship amongst McLeod Lake Indian Band, the Crown and BC Hydro. McLeod Lake Indian Band submits that undoing one of the agreements will undo all of them, requiring extensive negotiations and reparations as a result. It will also set back the relationship between McLeod Lake Indian Band and the Crown, impairing reconciliation.[114]

McLeod Lake Indian Band submits the Commission has a legal duty to report to the Lieutenant Governor in Council that:[115]

- the Crown's duty to consult McLeod Lake Indian Band with respect to Site C has been triggered;
- to date, consultation has not yet begun;
- the Crown must provide additional avenues for consultation with McLeod Lake Indian Band with respect to any decision for Site C;
- the Crown is obliged to begin that consultation as early as possible and cannot rely on after-the-fact consultation once the decision has been made;
- the Crown, in discharging the duty to consult, cannot subsume the consideration of the impacts to McLeod Lake Indian Band's title and rights in the consideration of financial impacts – instead it must consider any financial impacts with regard to their potential to adversely affect McLeod Lake Indian Band's title and rights; and
- the Crown, in exercising its discretion with respect to Site C, must consider how that decision will advance or impair reconciliation between the Crown and McLeod Lake Indian Band.

Further, in reporting to the Lieutenant Governor in Council, McLeod Lake Indian Band submits the Commission must identify that suspending or terminating Site C will have the following unaccommodated impacts to McLeod Lake Indian Band's title and rights:[116]

- The basis for entering into the Renewal Agreement will be fundamentally altered, resulting in unravelling reconciliation between the Crown and McLeod Lake Indian Band, and requiring the renegotiation of the Renewal Agreement between BC Hydro and McLeod Lake Indian Band;
- Site C construction has already created impacts to McLeod Lake Indian Band's title and rights;

[113] Submission F274-1, McLeod Lake Indian Band, p. 5.
[114] Submission F274-1, McLeod Lake Indian Band, p. 2.
[115] Submission F274-1, McLeod Lake Indian Band, p. 3.
[116] Submission F274-1, McLeod Lake Indian Band, p. 4.

- If BC Hydro or the Crown suspend or terminate the package of accommodation the Crown agreed to provide McLeod Lake Indian Band (for those impacts), the accommodation for those impacts will no longer be sufficient. The Crown must consult with McLeod Lake Indian Band to reach agreement in relation to new and additional accommodation for the impacts that have already been, and will be, caused by the construction and remediation of Site C; and
- Contracting opportunities that were intended by the Renewal Agreement and the Contracting Agreement to accommodate for physical and economic impacts to McLeod Lake Indian Band's title and rights will need to be replaced.

In addition, McLeod Lake Indian Band submits that the transfer of land under the TLA must occur in spite of whether Site C continues, is suspended or is terminated because the TLA is tied to reparations for previous impacts. McLeod Lake Indian Band submits that any surplus Crown lands available on a termination scenario need to be disposed to McLeod Lake Indian Band to compensate for past impacts to treaty rights and land claims. McLeod Lake Indian Band further submits that BC Hydro will be required to pay any outstanding payments due under the IBA or Contracting Agreement.[117]

In a suspension or termination scenario, McLeod Lake Indian Band expects Crown consultation on how the McLeod Lake Indian Band lands will be remediated. McLeod Lake Indian Band will expect to be awarded contracts to remediate its territory so that it can fulfill its role as steward of the territory.[118]

The McLeod Lake Indian Band asserts that suspension or termination of Site C will affect existing agreements and argue that it cannot be left in a worse position due to the suspension or termination of Site C than it would have been in had the project completed.[119]

McLeod Lake Indian Band wants to be consulted on any decision with respect to Site C to ensure that any decision will uphold the honour of the Crown.[120]

BC Hydro response

BC Hydro submits that the fee simple land transfers that McLeod Lake Indian Band receives under the Tripartite Land Agreement (including three other First Nations) is one of the benefits they are receiving in respect of the Site C but that no reserve lands or land owned by First Nations is being impacted by Site C. BC Hydro responded to the issues related to the cost of termination by stating that the agreements entered into with McLeod Lake Indian Band and with five other First Nations will end if the project is terminated.[121]

Mikisew Cree First Nation

Mikisew Cree First Nation is a Treaty 8 First Nation whose traditional territory is on the Peace River and Athabasca River Delta (PAD). The PAD is also part of the Wood Buffalo National Park and is a United Nations Educational, Scientific and Cultural Organization (UNESCO) World Heritage site.[122]

Mikisew Cree First Nation submits that Site C will further impede the flow of water down the Peace River and into the PAD affecting Mikisew Cree First Nation's exercise of its treaty rights. As such, Mikisew Cree First Nation submits that continuing with Site C will have significant costs to ratepayers. In particular, it submits that ratepayers will incur the following costs:[123]

[117] Submission F274-1, McLeod Lake Indian Band, pp. 4–5.
[118] Submission F274-1, McLeod Lake Indian Band, p. 16.
[119] Submission F274-1, McLeod Lake Indian Band, p. 17.
[120] Submission F274-1, McLeod Lake Indian Band, p. 18.
[121] Submission F1-12, BC Hydro, Appendix A, p. 3.
[122] TFN-3, October 11, 2017, Victoria, p. 1036.
[123] Submission F84-1, Mikisew Cree First Nation, pp. 7–8.

- Existing BC Hydro dams on the Peace River have caused irreparable ecological damage to the PAD and there is a real risk that Site C will cause further ecological damage to the PAD;
- The cost of undertaking an environmental review of the Site C dam as requested by the World Heritage Centre, the International Union for Conservation of Nature and the World Heritage Committee;
- The costs of future ecological impact to the PAD and the associated potential infringements of indigenous treaty rights, including the Mikisew Cree First Nation;
- Potential costs associated with restoring the flow rates of the Peace River as a result of any requirements to maintain and protect the Outstanding Universal Value of the Wood Buffalo National Park which includes the PAD;
- Costs associated with impairments to good will and other assets in the event Wood Buffalo National Park becomes included on the list of World Heritage Sites in Danger; and
- Increased operational costs associated with ongoing assessments, monitoring and/or modifications to address potential impacts from Site C to the PAD.

Mikisew Cree First Nation states that whether or not Site C constitutes an unjustified infringement of Treaty 8 rights of certain First Nations has been left to be determined in future legal proceedings. However, in the event a treaty infringement is found, then the courts may determine that Site C must be decommissioned, its operations significantly altered and/or damages paid. Mikisew Cree First Nation state that these potential costs may be borne directly by ratepayers, taxpayers or both.[124]

Mikisew Cree First Nation submits that terminating or suspending Site C will limit the potential adverse impacts to the PAD and Indigenous communities that depend on the PAD to sustain their Treaty 8 rights. In particular, Mikisew Cree First Nation submits that any termination scenario should consider the economic benefits of doing so to individuals, families and communities from being able to continue with rights-based activities that would otherwise be lost or diminished by continuing with Site C.[125]

Mikisew Cree First Nation requests the Commission take into account potential costs of the Site C dam's effects on the Mikisew Cree First Nation way of life and the PAD.[126]

Sekw'el'was Cayoose and N'Quatqua First Nations

Sekw'el'was Cayoose and N'Quatqua are located in the Seton Portage area and are opposed to the building of the Site C dam. As an alternative, they submit that BC Hydro has existing de-rated facilities that are in disrepair. If refurbished and repaired they could provide additional capacity and energy to meet the future needs as an alternative to Site C. Sekw'el'was Cayoose and N'Quatqua submit that Site C will not only cause permanent and irreversible harm to the natural environment, which people in the northeast rely upon, but will also further destroy the First Nations existence from the land.[127]

BC Hydro built a number of dams and canals in the Stl'atl'imx territory in the 1950s, which are used to generate power and to divert water known as the Bridge-Seton System. Sekw'el'was Cayoose and N'Quatqua submit that the effect of these dams was to wipe out entire stocks of salmon depended upon by Stl'atl'imx people.[128]

[124] Submission F84-1, Mikisew Cree First Nation, p. 8.
[125] Submission F84-1, Mikisew Cree First Nation, p. 11.
[126] Submission F84-1, Mikisew Cree First Nation, p. 12.
[127] TFN-2, October 6, 2017, Vancouver, p. 853.
[128] TFN-2, October 6, 2017, Vancouver, p. 854.

Sekw'el'was Cayoose and N'Quatqua First Nations submit that restoration of BC Hydro's Bridge-Seton System to full capacity provides an alternative source of capacity and energy to the Province than Site C. They claim that in combination with other generational assets and demand-side management initiatives, it will have similar benefits, at similar or lower costs to the production of capacity and energy from Site C.[129]

Sekw'el'was Cayoose and N'Quatqua state that BC Hydro's assets in the Bridge-Seton System are in poor to extremely poor condition.[130] Although, BC Hydro has committed to completing some of the work in 2018, that work represents only a small portion of the capital plan required to bring the Bridge-Seton System up to a good reliable condition. Sekw'el'was Cayoose and N'Quatqua ask the province to provide the following direction to BC Hydro[131]:

- formally update the 10-year capital forecast in the F2017–F2019 RRA to include the forecasted $590 million restoration for the Bridge Seton assets;
- develop a detailed breakdown of expenditures and timing;
- work with St'at'imc collaboratively to determine how their restoration schedule can be accelerated to complete the work by 2028;
- commit the best of BC Hydro resources and personnel to this work; and
- apply the United Nations Declaration of Rights of Indigenous Peoples with respect to water in their territories.

Sekw'el'was Cayoose and N'Quatqua state that if "accelerated investments are not made in the Bridge Seton generation system then the St'at'imc people will continue to experience ongoing destruction of the ecosystem that they rely on for fisheries, wildlife habitat, and our way of life."[132]

BC Hydro response

BC Hydro states that its portfolio analysis does not incorporate specific projects but rather types of alternative resources and leaves open what projects could be developed in those scenarios. Noting that the projects in question do not replace Site C, BC Hydro welcomes discussions with Sekw'el'was Cayoose and N'Quatqua First Nations. [133]

BC First Nations Clean Energy Working Group

The BC First Nations Clean Energy Working Group is an informal working group of First Nations who are involved in the clean energy industry in British Columbia. The BC First Nations Clean Energy Working Group states that Site C negatively affects the economic well-being of BC First Nations who participate in clean energy projects.[134]

A survey completed by the BC First Nations Clean Energy Working Group in partnership with researchers at the School of Environmental Studies at the University of Victoria and Clean Energy BC surveyed First Nations in BC to determine, in part, First Nation involvement in clean energy projects. The survey received responses from 105 of the 203 First Nations in BC and found that respondents overwhelmingly support clean energy initiatives.[135]

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[129] Submission F73-2, Sekw'el'was Cayoose and N'Quatqua First Nations, p. 2.
[130] Submission F73-1, Sekw'el'was Cayoose and N'Quatqua First Nations, p. 5.
[131] TFN-2, October 6, 2017, Vancouver, pp. 876–877.
[132] TFN-2, October 6, 2017, Vancouver, p. 877.
[133] Submission F1-12, BC Hydro, Appendix A, p. 12–13.
[134] Submission F303-1, BC First Nations Clean Energy Working Group, p. 2.
[135] Submission F303-1, BC First Nations Clean Energy Working Group, p. 2.

BC First Nations Clean Energy Working Group submits that the results of its survey clearly show that First Nations are ready, willing and able to provide clean energy alternatives to Site C, which they can complete incrementally as the energy and capacity is required rather than continuing with Site C. The survey found that 30 First Nations are currently involved in 78 operational clean energy projects, while a further 32 First Nations have clean energy projects in development and 15 projects under construction. The survey identified an additional 249 clean energy projects that 105 First Nations had under consideration. The BC First Nations Clean Energy Working Group estimates the value of the projects under consideration to be $3.4 billion. Not all of these projects have agreements with BC Hydro to sell power; however, First Nations continue to enter into and develop clean energy projects in the hopes of selling power to BC Hydro or making their communities' grid independent.[136]

The BC First Nations Clean Energy Working Group submits that Site C is the main reason that First Nations will not be able to develop clean energy projects for economic development opportunities. Once Site C is operational, the demand for power will not require clean energy because Site C will produce more power than is needed by the province. The BC First Nations Clean Energy Working Group submits that the Commission must take into account the loss to First Nations of being unable to participate in the clean energy industry in BC because of Site C, when considering the overall cost of proceeding.[137]

Tsilhqot'in National Government and Homalco First Nation

The Tsilhqot'in National Government and Homalco First Nation submit that Site C should be terminated and instead a joint venture between the Tsilhqot'in National Government and Homalco First Nation should be considered as an alternative.

The alternative joint venture is a hydroelectric project proposed in Bute Inlet projected to produce 3,500 MW from three dams; Moseley, Nude Canyon and Waddington Canyon. The Tsilhqot'in National Government and Homalco First Nation submit the area has deep canyons and is sparsely populated allowing for a much smaller footprint than Site C and minimal flooding. Since there are three dams, working in tandem, the project can be completed in smaller phases as the province requires demand. This project is in the early phases of development and no formal discussions with BC Hydro in respect of this alternative have commenced.[138]

Ramona McDonald

Ms. McDonald is a Metis woman, whose children are members of Prophet River First Nation and business owners within the Fort St. John area. Ms. McDonald supports the continuation of the Site C project and submits that by continuing with projects like Site C in the Treaty 8 territory, it will provide needed employment and economic opportunities for First Nation people, specifically youth, and other First Nation businesses.[139]

Yvonne Tupper

Ms. Tupper is a member of the Saulteau First Nation, one of the Treaty 8 First Nations. Ms. Tupper is opposed to the construction of Site C because the energy is not currently needed. Ms. Tupper submits that the current construction of the Site C dam is already having a significant impact on the wildlife within the Treaty 8 territory due to the clearing of the river banks and islands to be flooded by Site C. Ms. Tupper raised serious concerns regarding negative social and environmental impacts that Site C may have due to the construction, flooding and operation of the dam.[140]

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[136] Submission F303-1, BC First Nations Clean Energy Working Group, p. 3.
[137] Submission F303-1, BC First Nations Clean Energy Working Group, p. 5.
[138] TFN-1, September 29, 2017, Prince George, p. 687.
[139] TFN-2, October 6, 2017, Vancouver, p. 895.
[140] TFN-3, October 11, 2017, Victoria, pp. 1051–1062.

Union of BC Indian Chiefs

The Union of BC Indian Chiefs (UBCIC) submit that Site C, its associated structures, and rights of way unjustly infringe upon the Aboriginal and Treaty Rights of Treaty 8 First Nations by eliminating their ability to continue their way of life and exercise their constitutionally protected Treaty rights.[141]

UBCIC submit that continuing with Site C is a violation of the human rights of Prophet River and West Moberly First Nations by taking away one of the last remaining places where they can exercise their cultures and traditions, which they claim are protected by Treaty 8, the Constitution and international human rights law.[142]

UBCIC claims that Site C may affect the PAD including portions of Wood Buffalo National Park, a UNESCO World Heritage Site, and that keeping the Peace River Valley from further development is important in maintaining First Nations' cultural and spiritual identity. UBCIC submit that further development or flooding of the valley will result in cultural loss to Treaty 8 nations and the loss of opportunities through cultural tourism. UBCIC state that any need for energy and jobs does not outweigh the costs to the Treaty 8 First Nations and therefore support the termination of Site C.[143]

Patrick Michel

Mr. Michel is a member of the Kanaka Bar Band (Kanaka), which has a 50 MW run-of-the-river hydro-electric project on Kwoiek Creek. Revenues used from the sale of power have been used by Kanaka to establish three small solar-energy projects, which are all used by Kanaka to generate electricity. Further, Kanaka is currently looking at developing a wind energy project on its reserve. Mr. Michel submits that Kanaka is an example of using diversification as an alternative to Site C.

Bud Napoleon

Mr. Napoleon is a member of East Moberly First Nation, a former Chief of the East Moberly Indian Reserve and former Tribal Chief of the Treaty 8 Tribal Association. Mr. Napoleon is opposed to the construction of Site C. He claims that Site C is an infringement of the Treaty 8 rights. He argues that the building of Site C undermines the Treaty 8 rights, which are protected under s.35 of the Charter. Due to previous damming along the Peace River, the Treaty 8 First Nations have lost the ability to exercise their Treaty 8 rights to hunt, fish and gather and collect food in the areas affected by the existing dams. As a result, the West Moberly and Saulteau First Nations have had to focus efforts to save a small caribou herd. The impacts of these dams are not only limited to the areas that are flooded but also include the transmission lines running from the generating facilities, which these First Nations did not receive compensation for. Mr. Napoleon argues that Treaty 8 does not allow giving up water rights within the Peace River valley and that Site C is not justified.[144]

Peter Gunville

Mr. Gunville is a First Nation member who spoke in favour of the construction and completion of Site C because it is needed for sustainable growth in northern British Columbia. [145]

Gordon August

Mr. August is a hereditary chief of the Sechelt First Nation. Mr. August submits that Site C is not needed because electricity rates are currently too high. Mr. August submits the loss of plants and trees from Site C

[141] Submission F302-1, Union of BC Indian Chiefs, p. 1.
[142] Submission F302-1, Union of BC Indian Chiefs, p. 2.
[143] Submission F302-1, Union of BC Indian Chiefs, p. 2-3
[144] TFN-1, September 29, 2017, Prince George, p. 687.
[145] TFN-1, September 29, 2017, Prince George, p. 665.

affects not only First Nations but all people and questions why BC Hydro is building Site C at a time when he claims the load is not currently required.[146]

3.6 Technical Presentation Sessions

On October 13 and 14, 2017, technical presentations were made to the Panel by a number of individuals and groups that had previously made submissions in the Inquiry. The following is a list of the presenters:

- Clean Energy Association of BC (CEABC);
- Mr. Robert McCullough, representing the Peace Valley Landowner Association (PVLA) and Peace Valley Environment Association (PVEA);
- Mr. Marc Eliesen (Elisen);
- BC Pulp and Paper Coalition (PPC);
- Canadian Wind Energy Association (CanWEA);
- Allied Hydro Council of BC (AHC);
- Mr. Guy Dauncey;
- Association of Major Power Customers (AMPC);
- Canadian Centre for Policy Alternatives;
- Dr. David Suzuki;
- Mr. Richard Hendriks;
- Mr. Philip Raphals;
- BC Sustainable Energy Association (BCSEA);
- Canadian Geothermal Energy Association (CanGEA);
- Mr. David Vardy; and
- Commercial Energy Consumers Association of BC (CEC).

In addition, BC Hydro made a technical presentation on Saturday, October 14, 2017.

The technical presentations covered a wide variety of topics, often going into great detail. These presentations will not be summarized individually in this report, but the Panel thanks all who took the time to participate. The presenters have provided a great deal of information and explanation which were relied upon by the Panel and were instrumental in assisting the Panel members in reaching their conclusions and preparing this report.

[146] TCI-1, September 23, 2017, Vancouver, p. 61.

4.0 Load forecast and load resource balance

In this section, the Panel reviews BC Hydro's ability to meet the forecasted load using its existing, committed and planned resources without Site C. BC Hydro refers to this as its "load resource balance." The Panel begins by considering the load forecast, or demand, for electricity. The Panel also considers the impacts of developments since the load forecast was prepared. After reviewing the load forecast issues, the Panel identifies the capacity and energy load resource balances and the resulting surplus or deficit using the low, mid and high load forecasts. The Panel then reviews the handling of surplus energy and capacity.

4.1 BC Hydro's Current Load Forecast

4.1.1 Requirements under Order in Council No. 244

In making its applicable determinations set out in the terms of reference established by OIC No. 244, the Commission must use the forecast of peak capacity demand and energy demand (Current Load Forecast) submitted by BC Hydro in July 2016 as part of its F2017–F2019 RRA. In addition, by Order G-121-17, the Commission directed BC Hydro to report to the Commission the following updated demand forecast information by Wednesday, August 30, 2017:

- Developments since the preparation of the peak capacity demand and energy demand forecasts submitted in July 2016 as part of BC Hydro's F2017 to F2019 revenue requirements application that will impact demand in the short, medium and longer terms; and
- Other factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case.

4.1.2 Overview of load forecast issues

4.1.2.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

The Preliminary Report includes a description of BC Hydro's Current Load Forecast methodology. BC Hydro states the Current Load Forecast shows growth even in low load scenarios and presents the following figures to illustrate the current load forecast for energy and capacity within a range of reasonableness:

Figure 1: Current Load Forecast after DSM – Energy[147]

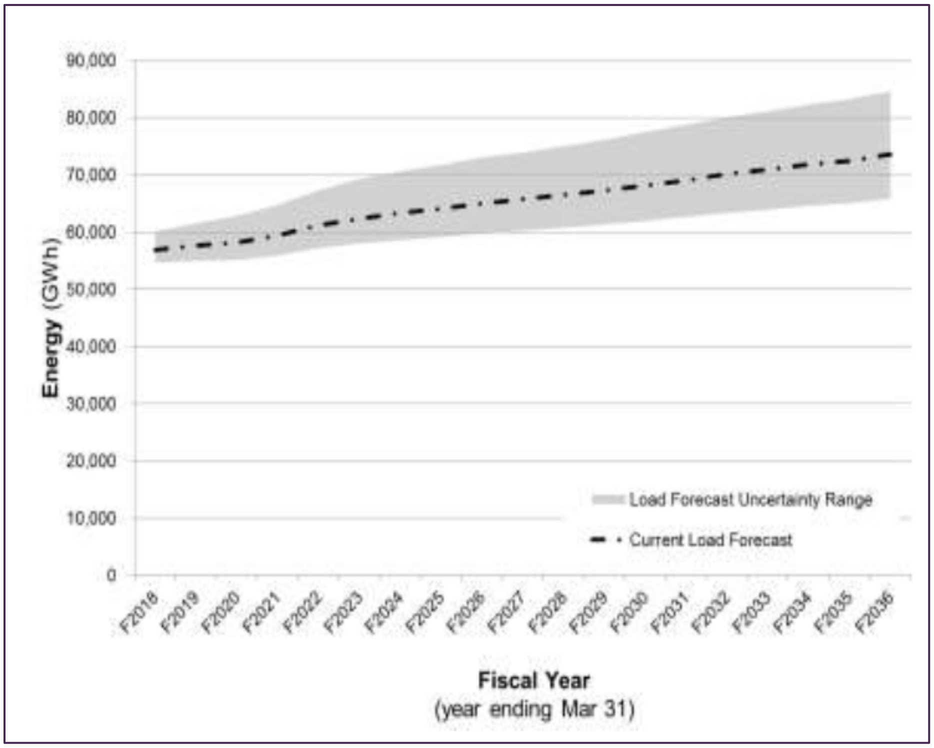
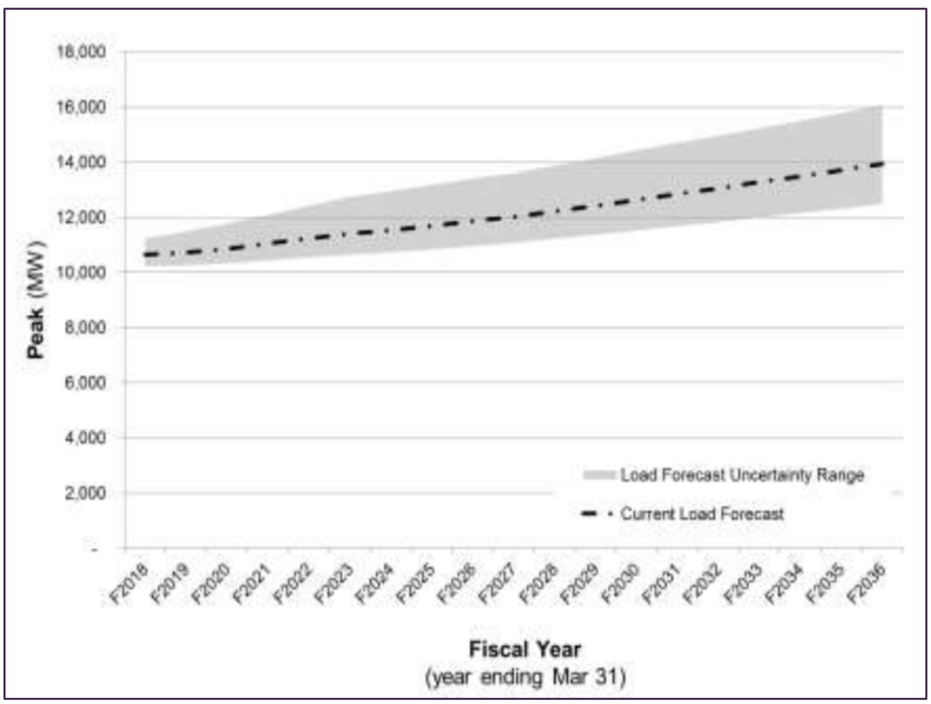


Figure 2: Current Load Forecast after DSM – Capacity[148]



147 Ibid., p. 46, Figure 9.
148 Ibid., p. 46, Figure 10.

It was noted that since load forecasting is an inherently uncertain undertaking with volatile drivers of future requirements, BC Hydro's load forecast approach consists of a high and low band and includes a mid-level projection. In summary, BC Hydro:

- develops its mid-level forecast incorporating models for its three main customer classes (residential, commercial/light industrial and industrial) and adds these model results to other expected load;
- uses the mid forecast for resource planning;
- uses the high and low forecast bands to provide an indication of the magnitude of load uncertainty as well as to develop BC Hydro's contingency resource plans; and
- uses key drivers including projections of economic variables such as Gross Domestic Product (GDP), efficiency of residential and commercial appliances, temperature, commodity prices and electricity rate increases.

The Preliminary Report identified that the large industrial sector contributes to a significant amount of uncertainty in the total system high and low projections since it is the most volatile sector.

BC Hydro states its customer demand for electricity is growing[149] and its Current Load Forecast continues to predict material long-term load growth across residential, light industrial/commercial and large industrial customer groups within a range of uncertainty.[150] BC Hydro notes that while the 2008 recession resulted in a decrease to customer load, since that time load growth has resumed and it continues to expect long-term load growth across all customer classes. BC Hydro notes the provincial economy is growing and BC's population is expected to grow by one million people over the next 20 years. BC Hydro states its studies indicate that demand for power in BC can be expected to grow by almost 40 percent over the next 20 years (before conservation impacts are taken into consideration). [151]

BC Hydro states its current load forecasting methodology has been in place for many years, is consistent with the Commission's resource planning Guidelines, has been presented in a number of Commission proceedings, accepted by the Provincial Government and endorsed by the Joint Review Panel. Further, BC Hydro's consultant GDS Associates Inc. (GDS) did not identify any "critical weaknesses" with load forecasting function at BC Hydro.[152]

BC Hydro summarizes that developments since the Current Load Forecast suggest a net increase in its energy and capacity requirements and have not changed expectations for load growth. In summary, BC Hydro concludes actuals sales to date for fiscal 2017 and fiscal 2018 are tracking reasonably, within one percent of forecast sales; the key economic drivers underpinning the residential and commercial sector continue to be reasonable; and a review of known developments in the large industrial and light industrial sectors suggest an increase in load compared to the forecast, mostly attributable to projects in the oil and gas sector. [153]

[149] Submission F1-1, BC Hydro, p. 3.
[150] Submission F1-1, BC Hydro, p. 46.
[151] Submission F1-1, BC Hydro, pp. 12–13.
[152] Submission F1-1, BC Hydro, pp. 47–48.
[153]Submission F1-1, BC Hydro, pp. 48–50.

With respect to other factors that could reasonably influence demand from the expected mid forecast towards the low or high case, BC Hydro identified the key drivers that influence demand for each customer segment and assessed, where possible, any trends in these drivers. A high-level summary of BC Hydro's key drivers influencing demand by customer class and trends in these drivers is as follows:

- The residential and commercial sectors preliminary analysis shows higher economic drivers (GDP, population growth, disposable income, and employment) and lower offsetting end use intensities (consumption);
- The light industrial sector is driven off GDP trends and preliminary analysis indicates no change from projections in Current Load Forecast;
- The large industrial sector is driven off commodity pricing and there have been some recent increases in commodity prices that are higher than prices used in the Current Load Forecast;
- For LNG, BC Hydro states the level of uncertainly is similar to its previous assessments and that it still anticipates that the three announced LNG projects in its forecast (FortisBC Tilbury LNG Phase 2, Woodfibre LNG and LNG Canada) will proceed, but there is both a timing and completion risk. BC Hydro notes it did not have any load in the Current Load Forecast for the recently cancelled Pacific NorthWest LNG project; and
- In the near-term upstream oil and gas load is not dependent on LNG but in the long-term demand will be lower if the LNG projects do not proceed as expected.[154]

BC Hydro also highlights "significant emerging potential for load growth from initiatives targeting greenhouse gas emission reductions through electrification of fossil-fuel powered end uses (such as electric vehicles or building heating systems) could further increase our requirements for energy and capacity."[155] 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.[156] BC Hydro states that it has not revised the Current Load Forecast upward to account for electrification initiatives directed at reducing greenhouse gas emissions because the timing and magnitude of the increase is uncertain at this early stage.[157]

Deloitte report

In its assessment of the load forecast model, Deloitte focuses on three aspects: historical performance of load forecast model outputs vis-à-vis actuals; inputs to the model; and the model's functional form and statistical features. Deloitte identifies a number of concerns with BC Hydro's Current Load Forecast including:

- Over-optimism in assumptions related to specific LNG projects;
- Over-estimation in the historical performance of the model, especially related to the industrial component;
- Use of higher inputs for GDP and disposable income than the 2016 Conference Board of Canada (CBoC) forecast in some years; and
- Overly simplistic elasticity assumptions that are lower than several alternative estimates.

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[154]Submission F1-1, BC Hydro, pp. 50–52.
[155] Submission F1-1, BC Hydro, pp. 2–3.
[156] Submission F1-1, BC Hydro, p. 52.
[157] Submission F1-1, BC Hydro, p. 54.

Deloitte also notes that BC Hydro's model assumes there will be no future rate increases for the period from 2025 to 2036[158] and states that rate increases introduced between F2025 and F2036 would lower the Current Load Forecast.[159]

As part of its assessment, Deloitte illustrates the impact on the Current Load Forecast (Mid-Load before DSM) of making changes it regards as "plausible" to the input assumptions including:

- Adopting an alternative GDP forecast sourced from the CBoC;
- Removing the assumptions that Pacific NorthWest LNG (now cancelled) and LNG Canada (final investment decision deferred) will proceed; and
- Increasing the adoption of electric vehicles in line with federal commitments.

Deloitte also illustrates the impact of adopting a more intensive DSM approach, consistent with BC Hydro's own submission in the 2013 Integrated Resource Plan (IRP). Deloitte illustrates by F2026, its alternative set of assumptions could result in a reduction of the load forecast in the range of 6,000 to 6,150 GWh, and a reduction in peak capacity in the range of 1,140 to 1,160 GWh [MW] and the corresponding impacts are a reduction in load forecast of 5,950 to 6,100 GWh, and a reduction in peak capacity forecast of 1,110 to 1,130 GWh [MW] by 2036. Deloitte cautions that these projections should be considered as indicative only, since they have adjusted BC Hydro's mid forecast after the fact, rather than conducting a complete rerun of the models that produced the original forecast. Deloitte states its assessment provides estimates of "the direction and order of magnitude of impacts resulting from changes to several key model inputs."[160]

Other submissions

As noted in the Preliminary Report, many participants raised several concerns including:

- An over-estimation bias in BC Hydro's historical load forecasts;
- Lack of support for BC Hydro's assumptions with respect to the LNG and forestry segments;
- Understatement of price elasticity;
- Lower than expected rate increases;
- Population growth being offset by falling per capita demand; and
- The impact of possible disruptive trends.[161]

4.1.2.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In the Preliminary Report, the Panel's analyses highlighted a number of issues and potential concerns identified by Deloitte in its independent report and raised in submissions received from other parties.

The Panel acknowledged there are many uncertainties that make it difficult to forecast future electricity demand given the considerable uncertainty surrounding economic growth, demographic variables, resources acquisition costs, future policy changes, technological and efficiency advancements, changes in customer behaviour and many other factors. The Panel recognized it is in the face of uncertainty that BC Hydro must ensure that there are adequate resources so that the lights go on when ratepayers turn the switch on, while at the same time if BC Hydro acquires or builds more resources than it needs there is a potential for unnecessarily higher rates for customers.

The Panel stated its view that an effective forecast model is one that produces results reasonably close to actual with equal instances of over and under forecasts. The Panel recognized that a utility may view it to be

[158] Submission A-9, Deloitte LLP independent report – Site C Alternative Resource Options and Load Forecast, p. 5.
[159] Submission A-9, p. 75.
[160] Submission A-9, p. 4.
[161] Submission A-13.

better to over forecast rather than to under estimate demand; however, a load forecast model should be designed to be as accurate as possible in order to better inform a decision related to the trade-offs of erring on one side or the other.

In this context, the Panel identified a number of issues in its Preliminary Report and sought further input and analysis of these issues from BC Hydro and other participants. The Panel identified the following issues related to the Current Load Forecast:

- Recent developments in the industrial sectors;
- Accuracy of historical load forecasts;
- GDP and other forecast drivers;
- Price elasticity and future rate increases; and
- Potential disrupting trends.

These issues identified in the Preliminary Report, together with additional responses and submissions, are addressed in the following sections and include other factors impacting forecast demand. The Panel analysis and findings on the load forecast are provided in Section 4.1.9.

4.1.3 Recent developments in the industrial sectors

4.1.3.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

According to BC Hydro, recent developments in its forecasts suggest a net increase in its requirements for energy and capacity. BC Hydro states it expects positive developments in various industrial sectors since the Current Load Forecast was prepared to result in additional load over and above the Current Load Forecast. The 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.[162] BC Hydro provides the following table:

Table 1: Summary of Incremental Load Impacts of Known Developments[163]

Sector	Energy (GWh/yr)			Peak (MW)		
	Short Term (0-3 Years)	Medium Term (4-10 Years)	Long Term (11-20 Years)	Short Term (0-3 Years)	Medium Term (4-10 Years)	Long Term (11-20 Years)
Large Industrial (Transmission)						
Forestry	154	298	299	20	35	35
Oil and Gas	491	688	658	69	89	85
Mining	222	135	102	32	20	11
Others	(71)	(78)	(84)	(16)	(17)	(18)
LNG	(80)	(303)	(7)	(6)	(27)	0
Light Industrial (Distribution)						
Light Industrial	28	7	(3)	0	0	0
Total	745	746	965	99	100	114

Following its analysis of known developments, BC Hydro still anticipates that the three announced LNG projects included in its forecast (FortisBC Tilbury LNG Phase 2, Woodfibre LNG and LNG Canada) will proceed, but adjusts the timing of the load in the medium term. BC Hydro also states that there is both a

[162] Submission F1-1, BC Hydro, Appendix J, p. 1.
[163] Submission F1-1, BC Hydro, p. 50.

timing and completion risk to these projects. With regard to the impact of LNG projects on upstream oil and gas loads, BC Hydro submits that in the near to medium term, most of the projected oil and gas load growth is not dependent on the development of BC-based LNG, but there is a potential for the sector to be lower than expected in the long-term if none of the three BC-based LNG projects proceed as expected. However, BC Hydro also submits that if LNG markets do not materialize in BC, it expects the upstream gas sector to continue to look for new markets and that this sector may continue to grow in response to North American natural gas and liquids markets, including demand from expanding US-based LNG terminals.[164]

Deloitte report

Deloitte comments that BC Hydro's assumptions regarding two specific LNG projects, Pacific NorthWest LNG and LNG Canada, appear optimistic in that the forecast model assumes both will be built (using 100 percent probability). Deloitte points out that the cancellation of Pacific NorthWest LNG and deferral of the final investment decision of LNG Canada occurred after the Current Load Forecast was finalized. Deloitte notes the impact of these assumptions "is magnified via the indirect link to load requirements in the oil and gas industry (i.e. to supply the LNG projects), as well as the GDP forecast, which also assumes that these projects will proceed."[165]

4.1.3.2 Panel analysis, preliminary findings and questions in Preliminary Report

The data and analysis reviewed by the Panel in its Preliminary Report suggested that the most significant developments, since the Current Load Forecast was developed, are in the industrial sector. To assist with further analysis, the Panel requested that BC Hydro:

- Provide a more detailed justification for why it considers it appropriate to continue to include each of the three LNG projects (i.e. FortisBC Tilbury LNG Phase 2, Woodfibre LNG and LNG Canada) in its load forecast. The Panel also asked a number of detailed questions related to the LNG load included in the Current Load Forecast;
- Explain how the completion risk and the timing risk are factored into BC Hydro's Current Load Forecast for both LNG and other industrial projects and customers; and
- Provide further information for each specific development outlined in Appendix J of BC Hydro's August 30, 2017 filing.

The Panel invited further submissions from other parties on BC Hydro's updates to the LNG forecasts and any further data that could assist the Panel in concluding on the implications of developments since the Current Load Forecast was prepared that could impact industrial demand in the short, medium and longer terms.

4.1.3.3 Additional submissions and responses

BC Hydro submission

Regarding the LNG load related questions, BC Hydro stated it adopted a binary approach to including the three LNG projects requesting service from BC Hydro in its load forecast and this approach differs from the probability-based approach it typically uses in developing its industrial load forecast. BC Hydro submitted it is appropriate to continue to include LNG Canada, Woodfibre LNG and FortisBC Tilbury Phase 2 in the Current Load Forecast for both macroeconomic reasons and project-specific reasons.[166]

[164] Submission F1-1, BC Hydro, p. 52.
[165] Submission A-9, p. 5.
[166] Submission F1-6, BC Hydro, IR 2.16.0, p. 2.

BC Hydro stated there are "valid questions as to whether BC LNG has missed the window of opportunity, particularly in light of the recent cancellation of the Pacific Northwest LNG and the more recent announcement that Aurora LNG proponents have decided not to advance their project."[167] However, BC Hydro points to a number of "reputable third party sources"[168] that reflect a range of current market perspectives on the global LNG market and future potential for BC LNG projects. These expert perspectives range from being: unchanged, more pessimistic and more optimistic in terms of indicating higher than expected global LNG growth and earlier supply/demand balance and associated prospects for BC LNG projects.[169] BC Hydro summarizes that while there remains significant uncertainly, global LNG demand will continue to grow and there is opportunity for BC LNG. Further, on balance the market's view remains largely unchanged from when the Current Load Forecast was developed.[170]

In addition to this macroeconomic justification, BC Hydro specifically justified including the three LNG projects, as these projects are requesting electricity service and working with BC Hydro to define requirements. BC Hydro stated service requests from industrial sector customers, including LNG, are generally included in its industrial load forecast. BC Hydro also stated LNG Canada executed a Load Interconnection Agreement, an Electricity Supply Agreement and a Studies Agreement in November 2014.[171] BC Hydro also discussed its ongoing work with the project proponents and referred to the achievement of "significant regulatory and other project development milestones" and recent public statements which demonstrate these proponents continue to expect that these projects will proceed.[172]

BC Hydro outlined other considerations including that the Current Load Forecast is a small portion of the overall BC LNG-related potential load and associated upstream natural gas potential. BC Hydro stated it has risk-adjusted upstream customer-requested load by approximately 40 percent in F2030 and since the forecast was completed there has been increased activity that suggests future growth in the upstream gas production may be less dependent on BC LNG project development.[173] BC Hydro stated that Deloitte overstates the impact to upstream gas (by approximately 276 GWh/35 MW) in the event that LNG projects do not proceed because some of these operations have been in operation for a number of years.[174]

BC Hydro submitted Deloitte's alternative scenario (which removes the LNG Canada load from the Current Load Forecast entirely) is overly pessimistic. However, BC Hydro recognized "there is considerable uncertainty associated with LNG and the associated upstream oil and gas loads." BC Hydro stated that the need without any LNG or LNG-related upstream oil and gas does not materially change the timing of energy shortfall when compared to the "without LNG."[175]

With respect to the developments in the non-LNG industrial load since preparation of the Current Load Forecast, BC Hydro detailed the estimated effect of changes in probability weightings as well as its qualitative rationale for its subsequent assessment of developments. BC Hydro noted that most of the probability adjustments are due to material changes in likelihood or changes in customer productive capacity.[176]

[167] Submission F1-6, BC Hydro, IR 2.16.0, p. 3.
[168] Submission F1-6, BC Hydro, IR 2.16.0, p. 2.
[169] Submission F1-6, BC Hydro, IR 2.16.0, p. 3.
[170] Submission F1-6, BC Hydro, IR 2.16.0, p. 3.
[171] Submission F1-6, BC Hydro, IR 2.16.0, pp. 5–6.
[172] Submission F1-6, BC Hydro, IR 2.16.0, pp. 6–9.
[173] Submission F1-6, BC Hydro, IR 2.16.0, p. 10.
[174] Submission F1-6, BC Hydro, IR 2.16.0, p. 10.
[175] Ibid., p. 19.
[176] Submission F1-6, BC Hydro, IR 2.16.0, pp. 11–17.

BC Hydro responded to the Panel's questions on recent development in the industrial sector as follows:

- Explained each of the probability changes and described the risks that may prevent identified loads from materializing;
- Provided information that demonstrates the aggregate impact of industrial sector developments will result in additional load over and above the Current Load Forecast;
- Supported the conclusion that the Current Load Forecast for each of these subsectors has significantly less uncertainty relative to prior load forecast vintages since approximately 80 percent of the forecasted natural gas load by 2030 is practically already realized due to project advancements identified in its response.[177]

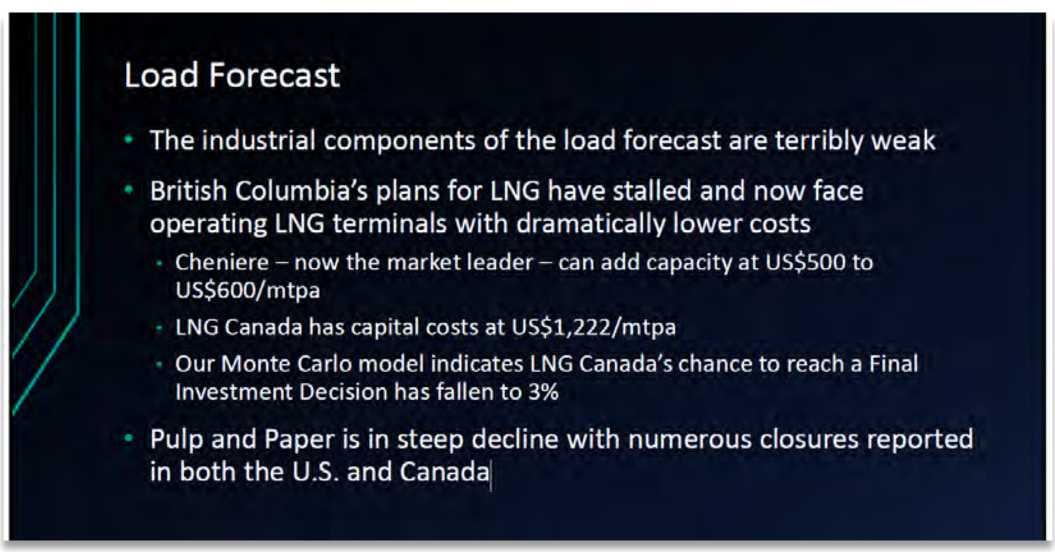
Regarding the comments of other participants on BC Hydro's updates to the LNG forecasts and any further data that could assist the Panel in concluding on the implications of developments since the Current Load Forecast was prepared that could impact industrial demand in the short, medium and longer terms, BC Hydro submits:

- McCullough's analysis on the future of BC's LNG potential and upstream gas supply is limited. BC Hydro's expectations rely on market research undertaken by recognized expert organizations who use a methodology that supports BC Hydro's forecast.[178]
- BC Hydro disagrees with Deloitte's conclusion that BC Hydro's LNG assumptions are above market consensus and, in particular, Deloitte's conclusion that including LNG Canada in the Current Load Forecast is "overly optimistic." BC Hydro states that it has provided "ample evidence" that its LNG assumptions are consistent with expert third party market expectations.[179]

Other submissions

McCullough concludes most of the LNG terminals currently under consideration in BC "won't see the light of day" and the related expected increase in consumption to electrify LNG facilities will not materialize.[180] His view on BC Hydro's Current Load Forecast for LNG is summarized in the following figure:

Figure 3: McCullough's Presentation on Industrial Load Forecast[181]



[177] Submission F1-12, BC Hydro, p. 13.
[178] Submission F1-12, BC Hydro, Appendix C, pp. 5–6.
[179] Submission F1-12, BC Hydro, p. 16.
[180] Submission F35-11, Peace Valley Landowner Association (PVLA) and Peace Valley Environment Association (PVEA), p. 8.
[181] Submission F35-17, PVLA and PVEA, p. 3.

With respect to the likelihood of a BC LNG Industry, Finn states BC Hydro has "not factored into that estimate the probability that the industry – or specifically these three projects requesting grid power- will actually materialize."[182] Finn submits this is a serious error because:

- There is currently a large and growing glut of LNG supply in the target Asia-Pacific market as a result of Japan commencing reactivation of 40 of the 54 nuclear reactors mothballed since the Fukushima disaster of 2011;
- In the wake of that disaster, Japan's power generation needs for LNG fuel sparked an LNG seller's market in Asia. LNG prices spiraled to a peak and this in turn triggered a number of Final Investment Decisions for new LNG plants. The resulting oversupply caused Asian LNG prices to plummet and these lower prices have prevailed since late 2014;
- Unlike the 16 active LNG export projects in the US, the 20+ proposed BC LNG plants are almost all greenfield sites requiring long pipelines from the northeast. Further, BC's shale gas resources are expensive to drill, extract and get to market;
- China was expected to need LNG to assist its switch from using coal as a power generation source, but is instead being served by the construction of two "Power of Siberia" pipelines and is also developing its own extensive shale-gas reserves, the 13th largest in the world compared to Canada's being 21st; and
- The three LNG projects cited by BC Hydro face uphill struggles.[183]

CEC states it is very doubtful that the international LNG markets will lead to a go-forward decision with the Kitimat LNG project in the timeframes BC Hydro is looking at.[184]

BCSEA identified the "greatly diminished" likelihood of a large LNG facility as another factor pushing the load forecast downward.[185]

4.1.4 Accuracy of historical load forecasts

4.1.4.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

In its analysis of load forecast history, BC Hydro concludes:

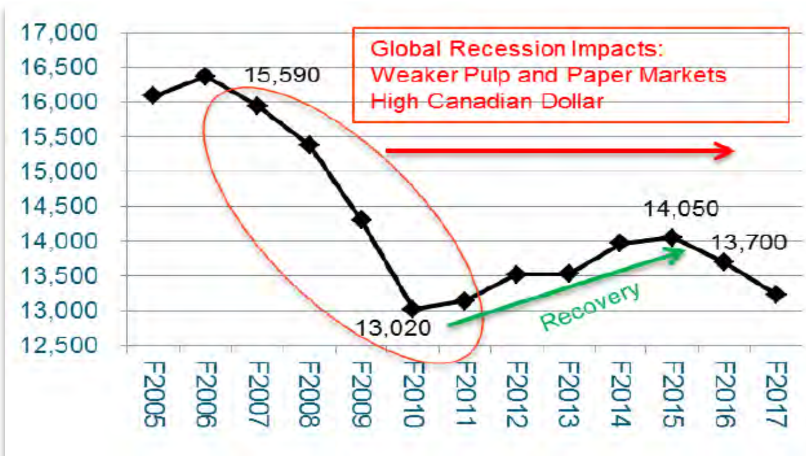
- BC Hydro's load has grown over the last 10 years, even when considering the effects of a significant recession in 2007–2008 and a slower than expected economic recovery following it;
- There is a good rationale for why BC Hydro's load forecasts have been higher than actual load over that period. In particular:
    - Variances in the large industrial sector are the main reasons for variances in the load forecast in recent years; and
    - Variances in the residential, commercial and light industrial sectors have been small;
- BC Hydro, like most other entities, does not, and is not able to, forecast economic recessions or boom cycles;

[182] Submission F44-2, Finn, E. (Finn), p. 3.
[183] Ibid., pp. 3–6.
[184] Submission F82-2, Commercial Energy Consumers Association (CEC), p. 24.
[185] TTP-2, October 14, 2017, Vancouver, p. 1468.

- Fundamental shifts in load growth have occurred and are reflected in the Current Load Forecast, which results in reduced forecast error risk; and
- The Current Load Forecast methodology is still appropriate and has good predictive capability.[186]

BC Hydro states the large declines in industrial load between F2006 and F2010 are attributed to large discrete customer load attrition events including four pulp mills of which the closure of Catalyst (Elk Falls) accounted for about 60 percent of the total decline. BC Hydro presents the following graph showing the impact of what occurred in the large industrial sector:

Figure 4: Large Industrial Load F2005 to F2017 – Actual (GWh)[187]



BC Hydro also notes:

> Over fiscal 2016 and fiscal 2017, Howe Sound Pulp and Paper closed a paper line due to low water levels and negative market outlook. As with the earlier closures of other pulp and paper mills, this closure was not foreseen by industry experts. Until that point the Large Industrial sector was recovering in mining and the oil and gas sector following the declines between fiscal 2007 to fiscal 2010.[188]

BC Hydro's consultant, GDS, concludes its review of prior load forecasts reveal that forecast variances for the Residential and Commercial classifications are within a range of expectancy based on industry benchmarks. GDS provides the comparison shown in Table 2:

[186] Submission F1-1, BC Hydro, Appendix H, pp. 42–43.
[187] Ibid., p. 46, Figure H-3.
[188] Ibid., p. 46.

Table 2: Comparison of BC Hydro Forecast Variances to Industry Benchmarks[189]

Forecast Period	Class	BC Hydro	EIA	Itron
1 yr. out	Residential	1.0%	1.9%	1.7%
3 yr. out	Residential	1.3%	3.9%	na
6 yr. out	Residential	4.6%	8.2%	na
1 yr. out	Commercial	0.9%	1.2%	1.7%
3 yr. out	Commercial	1.8%	2.3%	na
6 yr. out	Commercial	2.3%	8.2%	na
1 yr. out	Industrial	1.3%	1.9%	3.5%
3 yr. out	Industrial	9.5%	6.2%	na
6 yr. out	Industrial	19.6%	11.4%	na

GDS states the higher variances for the industrial class are expected given the volatility of loads and the uncertainties of future economic activity in the forestry, oil and gas, and mining sectors, which comprise a significant portion of total energy sales for the industrial class. GDS notes the variances for the industrial class are higher than industry benchmarks but recommends continued use of the individual customer forecasts.[190]

Deloitte report

With respect to historical performance, Deloitte notes:

- Across model vintages dating back to 1964, the load forecast model has more frequently overestimated load than underestimated (for a total of the 647 forecasted points, 500 [77 percent] were overestimates);
- The forecasts performed better in the short run than the long-run;
- While forecast methodology has changed over time, the magnitude of overestimation does not appear to have decreased; in fact, in the first fully forecasted year and the fifth forecasted year, the magnitude of overestimation appears to have increased;
- The industrial component, representing 29 percent of the revenues between 2000 and 2017, has been the largest contributor to overestimation; and
- The residential and commercial components have performed closer to actuals over both the short and long term.[191]

4.1.4.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In its Preliminary Report, the Panel found 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.

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[189] Ibid., Appendix I, p. 24.
[190] Ibid.
[191] Submission A-9, p. 5.

The Panel invited submissions from BC Hydro and other parties on the implications of the historical over-estimates on the Panel's assessment of the accuracy of the industrial load included in the Current Load Forecast.

4.1.4.3 Additional submissions and responses

BC Hydro

BC Hydro stated the drivers of historical industrial forecast variances are not relevant to the expected accuracy of the industrial load forecast for the following reasons:

- As illustrated by the fact that previous forecasts reflected future aluminum smelter load which has no relevance today since there is no such sector, the load forecast drivers of the past are not the load forecast drivers of today;
- Load forecast methods and processes have changed over time and the Current Load Forecast is based on in-depth and current market analysis, reliable and supportable sources and a reasonable set of assumptions; and
- Historical variances have been largely due to inherent volatility and uncertainty in global markets which impacts BC's industrial sector. [192]

BC Hydro also commented that its industrial load forecast methodology does not attempt to forecast future recessions but instead it relies on "credible third party experts for their assessments of global supply and demand and market cycles over the near and long term." BC Hydro stated that since these experts project commodity down and up cycles this is already reflected in its large industrial sector forecast.[193]

BC Hydro explained it focused on the most recent ten year history and on mining, pulp and paper and gas (including LNG) sectors as these sectors have the greatest implications for the load forecast.

BC Hydro summarized that its mining sector load forecast is reasonable because:

- The historical variance was largely driven by a commodity boom cycle where several mines requested service and less than half a dozen came into service;
- The risk profile for the sector has diminished since the Current Load Forecast no longer includes services requests from numerous new mining projects. On the other hand the risk associated with existing mine shutdowns has increased due to the current low commodity price environment. BC Hydro assesses this risk to be low given an improved pricing outlook; and
- BC has an abundance of various metal and coal reserves and BC Hydro submits it is likely that these reserves will eventually be developed over the long term.[194]

BC Hydro submitted its pulp and paper load forecast, which represents about 21 percent of total large industrial load over the long-term, is reasonable because:

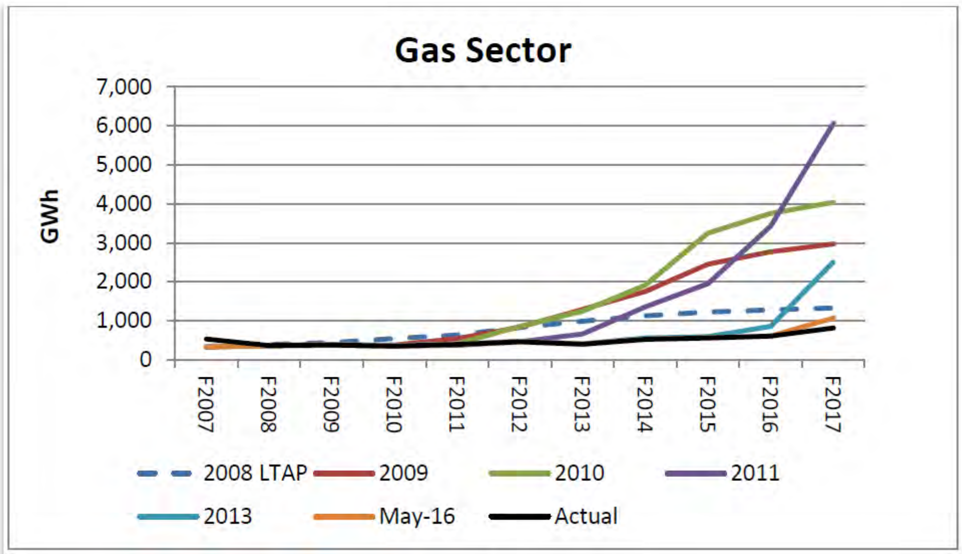
- The probability weights applied to each of the mill production lines are unbiased, balanced and supported by expert consultants, information from customers via BC Hydro key account managers, as well as various BC Ministry analyses contained in industry reports such as the impact of pine beetle on the wood fiber supply; and
- The current pulp and paper load forecast trends downward consistent with actual historical load trend over the past decade. The current forecast, along with recent previous forecasts, are founded

[192] Submission F1-10, BC Hydro, IR 2.17.0, p. 3.
[193] Submission F1-10, BC Hydro, IR 2.17.0, pp. 3–4.
[194] Submission F1-10, BC Hydro, IR 2.17.0, p. 8.

on solid market and mill analysis which factor in the challenges of completion, globalization, digital media substitution, and the potential expansion for some mills into niche markets such as packaging and cardboard containers. BC Hydro believes it has reasonably captured this downward trend in its risk profile analysis of the pulp and paper sector.[195]

BC Hydro acknowledges there was significantly more uncertainty associated with previous gas sector load forecasts and provided the following chart to illustrate the various vintages of BC Hydro's forecasts:

Figure 5: Vintage Gas Sector Forecasts[196]



BC Hydro stated the reasons for the variances in the various forecast vintages can be generally attributed to deferred requests for LNG terminal service, deferred upstream requests for shale gas production to meeting LNG, and North American gas demand.[197]

However, regarding the implications of historical variances in vintage forecasts to its Current Load Forecast, BC Hydro reiterated its reference to current third party expert assessments that continue to expect the development of BC LNG.[198] In summary, BC Hydro stated it is confident with the Current Load Forecast for the following reasons:

- Unlike earlier forecast vintages, there are no generic customer loads included in the Current Load Forecast;
- A number of loads have been reassigned a 100 percent probability due to higher certainty;
- The revised loads reassigned 100 percent probability comprise approximately 80 percent of the new shale gas load forecasted by fiscal 2030;
- The upstream LNG dependent load is small at only 21 per cent of the oil and gas sector component; and
- Recent expert sources are confirming the LNG expectations in the Current Load Forecast suggesting a reasonable likelihood that the LNG dependent upstream gas forecast will be realized.[199]

[195] Submission F1-10, BC Hydro, IR 2.17.0, p. 11.
[196] Submission F1-10, BC Hydro, IR 2.17.0, p. 14
[197] Submission F1-10, BC Hydro, IR 2.17.0, p. 11.
[198] Submission F1-10, BC Hydro, IR 2.17.0, p. 14.
[199] Submission F1-10, BC Hydro, IR 2.17.0, pp. 17–18.

BC Hydro notes GDS's report indicating its overall variances from forecast for the residential, commercial and light industrial sector, which accounts for about two-thirds of the load, are lower than industry benchmarks. BC Hydro also refers to Deloitte's statement that BC Hydro's forecasts of residential, commercial and light industrial sales are close to actuals in both the short and long-run. BC Hydro states its load forecast history from fiscal 2008 to fiscal 2017 confirms that this is the case, with the forecast tracking close to actuals.

BC Hydro submits the load forecast variances that it has experienced are largely associated with the large industrial sector and all parties agree this sector's load forecast is the most volatile and subject to inherent uncertainties.[200]

BC Hydro concludes the pulp and paper, mining, natural gas and LNG subsectors are responsible for most of BC Hydro's load forecast variances since 2007 and the information it has provided demonstrates the aggregate impact of industrial sector developments will result in additional load over and above the Current Load Forecast.
BC Hydro submits the forecast for each of these subsectors has significantly less uncertainty relative to prior load forecast vintages since for example, "approximately 80 percent of the forecasted natural gas load by 2030 is practically already realized due to project advancements identified in our response to BCUC IR 2.16.0 above."[201]

BC Hydro concludes given its experience in load forecasting, its consistency with best practices across North America, and the independent third party endorsement of its methodology, its forecast should be preferred to others submitted in this Inquiry, and submits that its forecast should be used as the basis for the Commission's Final Report.[202]

Other submissions

Regarding the historical variances in the industrial load, David Craig of CEC stated:

> Our industrial sector here has been declining substantially and has been forecast to be declining for over 20 years, but those forecasts rarely find themselves into the BC Hydro load forecasts, and they tend to show up as a surprise. Nobody anticipated this. It's not true. These were anticipated. Up to twenty years ago, I read reports from BC Hydro numerous times from consultants that anticipated all of this coming.[203]

With respect to the implications of historical overestimates on an assessment of the accuracy of the industrial load, CEC submits that BC Hydro has a consistent history of over forecasting industrial loads and attributes this to:

(i) Enthusiasm for new industries, including early stage sign up and studies (recency bias);
(ii) Failure to see and understand the mechanisms working to cause loss of load and loss of customers (unknown bias); and
(iii) Treating a recovery from a recession period as evidence of a rate of growth when it is not or projecting straight line from a dip (continuation bias).

CEC submits that "these problems are often driving rosy forecasts and acquisition of power only to subsequently find that industry is responding to (1) cost pressures or (2) market competition by becoming (a) more efficient or (b) dropping facilities."[204]

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[200] Submission F1-12, BC Hydro, pp. 12–13.
[201] Submission F1-12, BC Hydro, p. 13.
[202] Submission F1-12, BC Hydro, p. 12.
[203] TTP-2, October 14, 2017, Vancouver, p. 1559.
[204] Submission F82-2, CEC, p. 26.

4.1.5 GDP and other forecast drivers

4.1.5.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro presents the main forecast drivers and sources in Appendix C, Section 10 of its August 30, 2017 submission. With respect to developments since the Current Load Forecast was prepared, BC Hydro submits the "key economic drivers underpinning the Current Residential, Commercial and GDP-driven Light Industrial sector load forecasts continue to be reasonable."[205]

Deloitte report

In terms of inputs, Deloitte assesses that the types of variables included in the forecast model appear reasonable. Deloitte notes that BC Hydro's inputs for employment, population, and housing starts, which are provided by Robert Fairholm Economic Consulting (RFEC), appear in line with projections published by independent third parties.

In Deloitte's view, BC Hydro's inputs for GDP and disposable income growth appear higher than the alternative forecast after the first five years. Deloitte notes in the Current Load Forecast, BC Hydro uses an average of 2.3 percent real GDP growth in the first five years, based on the BC Ministry of Finance's forecast. Deloitte also notes this input increases to 3.5 percent over the next five years, based on RFEC projections. Deloitte compares this input to the 2016 Conference Board of Canada forecast which projects that 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. Deloitte notes that by 2025 the RFEC forecast projects the BC economy will be 6 percent larger in real terms.

Deloitte also notes BC Hydro's mid-forecast model does not explicitly incorporate recessionary periods, even though it is likely that such periods will occur over a 21-year horizon, based on the historical record.[206]

4.1.5.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In its Preliminary Report, the Panel noted its concern with the differences between BC Hydro's forecast drivers for GDP and disposable income compared to the CBoC estimates.

The Panel asked BC Hydro to respond to a number of questions related to its forecast drivers for GDP and disposable income, including providing an analysis of the GDP and disposable income projections developed by RFEC compared to the CBoC estimates and to explain the reasons for significant differences in projections. In addition, the Panel requested that BC Hydro quantify the effect on its load forecast of reducing its GDP forecast to align with the CBoC's GDP projections. The Panel also invited submissions from other parties on these inputs to assist the Panel in concluding on the reasonableness of BC Hydro's GDP and other forecast drivers.

4.1.5.3 Additional submissions and responses

BC Hydro

With respect to differences in the GDP estimates, BC Hydro stated that CBoC's work would have been a high level assessment whereas RFEC's estimate is based on more detailed work. BC Hydro stated it can only offer limited comments to compare and explain the differences between RFEC and CBoC GDP and disposable

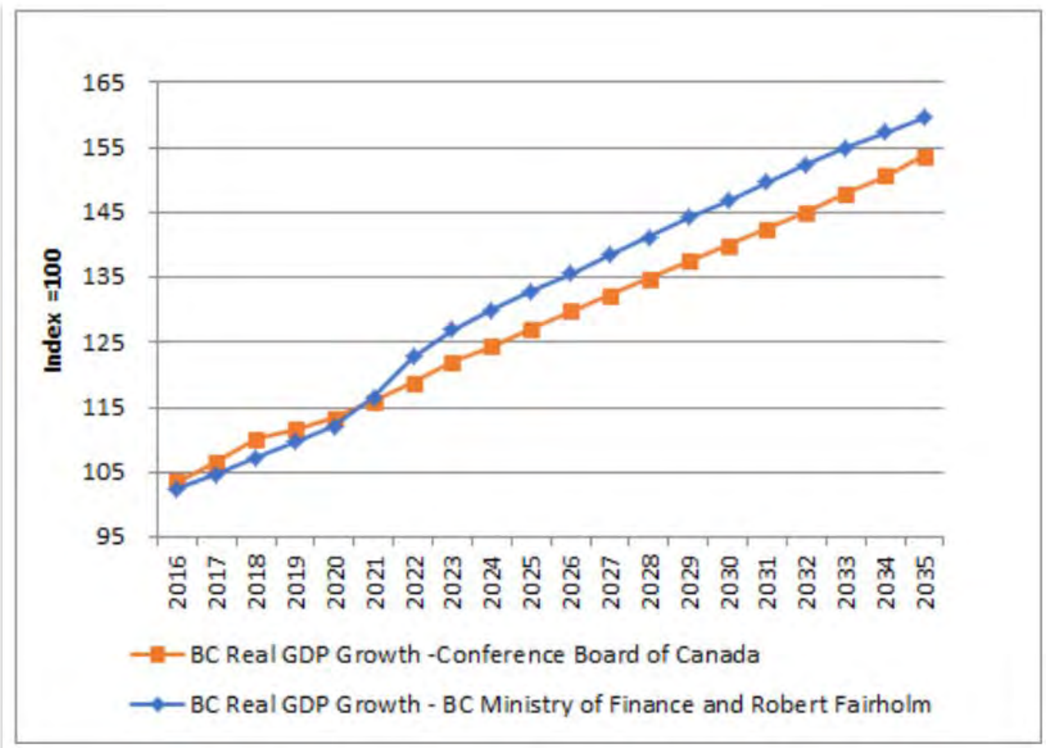
[205] Ibid., Appendix J, p. 6.
[206] Submission A-9, p. 5.

income projections since they outsource these forecasts to RFEC given the specialized expertise and sophisticated models required for the analysis. Further, BC Hydro stated it is not possible to assess the model, assumptions and inputs which generated the December 11, 2015 forecast based on the CBoC report.[207]

In BC Hydro's view, the overall load impact from the varied GDP assumptions is not very significant.[208] BC Hydro stated the forecast of real GDP growth is only used to develop the forecast (mid) light industrial manufacturing sector sales and this sector makes up only 5 percent of the total system sales.[209]

BC Hydro provided the following figure:

Figure 6: Real GDP Growth Forecast from CBoC and BC Ministry of Finance and Robert Fairholm[210]



BC Hydro outlined that differences between the RFEC and CBoC GDP growth projections can arise from various factors, including:

- Difference in model inputs;
- Structural equations;
- Solving methods; and
- Whether the models are a top-down model of the total economy or a series of various regional sub-models that aggregate to a total provincial forecast.

BC Hydro explained the projected increase in real GDP after 2020 in the RFEC economic forecast is due to increased investment growth, particularly in the Northern Region, where it is anticipated most of the LNG export production and upstream gas production will take place.[211]

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[207] Submission F1-6, BC Hydro, IR 2.18.1, p. 1.
[208] Submission F1-6, BC Hydro, IR 2.18.1, p. 1.
[209] Submission F1-6, BC Hydro, IR 2.18.3, p. 2.
[210] Submission F1-6, BC Hydro, IR 2.18.3, p. 2.

BC Hydro describes that only the "other manufacturing" portion of the light industrial sector model, representing only 5 percent of total system sales, uses GDP as a direct input driver and while the residential and commercial models have economic input drivers (e.g., housing starts, employment, commercial GDP) that are related to provincial GDP, none use a single provincial GDP as a direct input driver to develop sales projections.[212]

BC Hydro submitted that Deloitte's top-down adjustment assuming a single load driver (i.e. GDP) and GDP elasticities for the residential and commercial sectors, is an oversimplification compared to the modelling sophistication used to develop those sector forecasts and the results cannot be relied on to develop an alternative load forecast.[213]

BC Hydro submitted that a more realistic sensitivity analysis illustrating the effects of a lower GDP forecast is to look at the load forecast modelling results that were undertaken as part of the F2017–F2019 RRA in which Robert Fairholm was asked to develop a comprehensive regional economic forecast and total GDP forecast assuming no BC LNG plants and associated upstream natural gas production are developed. BC Hydro ran the outputs of that alternative economic forecast in each of its residential, commercial and light industrial models. BC Hydro notes the Deloitte report suggests this may be an appropriate comparison given the similarities between the CBoC's GDP forecast and the Robert Fairholm (No LNG) forecast.

BC Hydro presented the following table to show the difference in domestic sales between the Current Load Forecast and the RFEC (No LNG) economic scenario forecast on a billed basis and after demand side management savings.

Table 3: Current Load Forecast and RFEC, no LNG[214]

Fiscal Year	Difference (GWh)	Difference (%)
F2017	**(21)**	**-0.04**
F2018	**(44)**	**-0.09**
F2019	**(82)**	**-0.16**
F2026	**(265)**	**-0.40**
F2036	**(276)**	**-0.41**

Note:

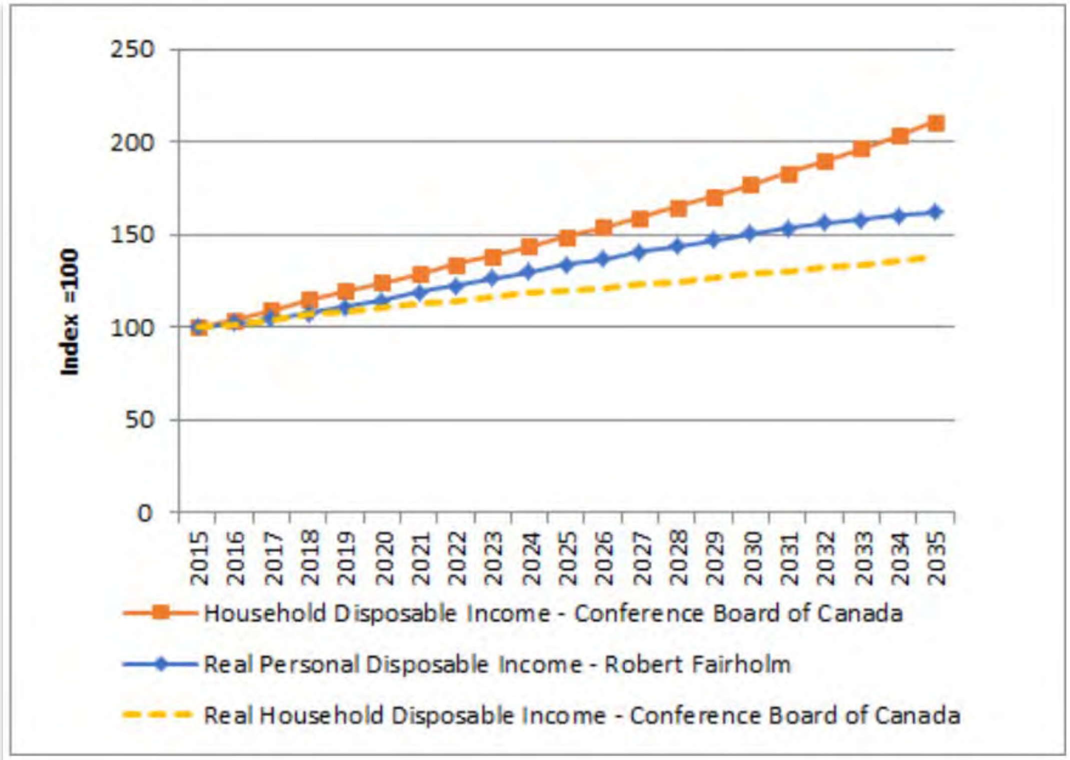
1. **The above differences were prepared with the same residential accounts forecast as that contained in the Current Load Forecast because aside from differences in housing starts in the Northern region, there were not significant differences in other parts of the BC Hydro's service area.**
2. **Aside from the simplifying assumption on residential accounts identified in Note 1, the differences above reflect the difference in the sales projection between the different economic forecasts when applied to the same mid-forecast models.**

BC Hydro submits that Deloitte's reductions for the residential, commercial and light industrial sectors rely on an overly simplistic and flawed methodology for calculating impacts, and as a result Deloitte overestimates the reduction in load associated with a lower GDP by six times.[215]

[211] Submission F1-6, BC Hydro, IR 2.18.3, p. 3.
[212] Submission F1-6, BC Hydro, IR 2.18.3, p. 2.
[213] Submission F1-6, BC Hydro, IR 2.18.3, p. 2.
[214] Submission F1-6, BC Hydro, IR 2.18.3, p. 3.
[215] Submission F1-12, BC Hydro, p. 15.

With respect to disposable income estimate differences, BC Hydro provided the following figure:

Figure 7: Disposable Income Forecasts from the CBoC and Robert Fairholm[216]



BC Hydro stated that if it adjusts the CBoC's nominal dollar forecast of household disposable income-based on the CBoC's Consumer Price Index of annual inflation rate as contained in its report, in its view the CBoC's projected annual growth rate is lower but more in line with that of RFEC's projection for real personal income for BC Hydro's service area.[217]

BC Hydro outlined that it uses the RFEC's forecast of real personal disposable income growth for the four main service regions as inputs into the SAE models in order to develop use per account projections for the residential sector.

While not all of the assumptions on disposable income in the CBoC report are transparent, BC Hydro believes differences can be due to the following reasons:

- differences in the economic modelling of disposable income and differences in the definition of disposable income;
- BC Hydro's forecast of disposable income is specific to BC Hydro service area;
- BC Hydro's forecast of disposable income is in real dollars and CBoC's estimate is in nominal dollars; and
- Deloitte acknowledges that precise comparisons in forecasts are difficult given how they are reported.[218]

[216] Ibid., p. 4.
[217] Ibid., p. 4.
[218] Ibid., pp. 4–5.

BC Hydro provides the following table to show the impact of the difference on the residential sales forecast before DSM when the CBoC's Projection of Household Income is used to develop the load forecast with BC Hydro's forecasting models.[219]

BC Hydro submits the results in the table are "only high level indicative estimates" because of:

- the difference in the definitions in disposable income. Robert Fariholm defines real personal disposable income as labour income, transfers from government and non-labour income less direct personal taxes;
- the CBoC forecast of household income is not defined in its 2016 report;
- The fact that the CBoC forecast is at the provincial level while BC Hydro's forecast is at the service area level; and
- The allocation assumption BC Hydro made to develop the forecast with CBoC's projection of household income.[220]

The results in the table are not additive to the amounts in Table 3: Current Load Forecast and RFEC, no LNG, shown above, since this information was developed with a comprehensive economic forecast from Robert Fairholm that had already considered a reduced real GDP forecast and reduced real personal disposable income projection for the No LNG assumption.

Table 4: Residential Forecast Current vs Forecast Scenario with CBoC Projections of Household Income[221]

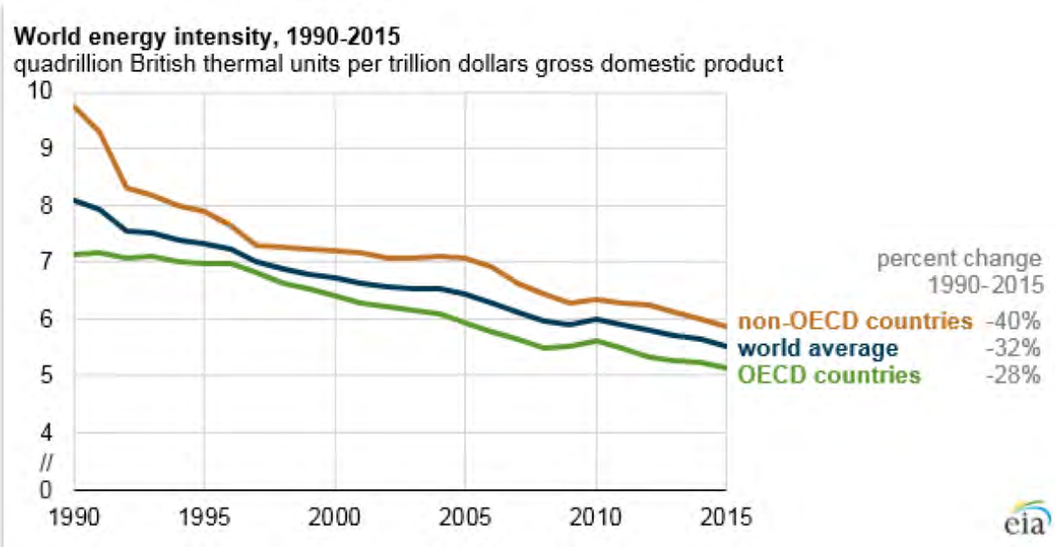
	A	B	A-B	(A-B)/B
	Residential Load Forecast Based on Conference Board of Canada Forecast of Household Income Before DSM (GWh)	May 2016 Residential Load Forecast based on Fairholm Real Personal Disposable Income Before DSM (GWh)	Difference (GWh)	Percentage Difference (%)
F2016	18,292	18,196	97	0.5%
F2017	18,649	18,534	115	0.6%
F2018	18,969	18,854	115	0.6%
F2019	19,321	19,204	118	0.6%
F2020	19,717	19,621	95	0.5%
F2021	20,057	19,985	71	0.4%
F2022	20,486	20,452	34	0.2%
F2023	20,949	20,956	(7)	0.0%
F2024	21,474	21,522	(48)	-0.2%
F2025	21,940	22,025	(85)	-0.4%
F2026	22,436	22,559	(122)	-0.5%
F2027	22,885	23,043	(158)	-0.7%
F2028	23,394	23,588	(194)	-0.8%
F2029	23,819	24,044	(225)	-0.9%
F2030	24,278	24,528	(250)	-1.0%
F2031	24,735	25,007	(272)	-1.1%
F2032	25,223	25,510	(287)	-1.1%
F2033	25,593	25,886	(293)	-1.1%
F2034	25,977	26,267	(290)	-1.1%
F2035	26,340	26,620	(280)	-1.1%
F2036	26,739	26,990	(251)	-0.9%

[219] Submission F1-16, BC Hydro, IR 3.9.0, p. 1.
[220] Submission F1-16, BC Hydro, IR 3.9.0, p. 4.
[221] Submission F1-16, BC Hydro, IR 3.9.0, Table 2, p. 3.

Other submissions

CEC provides evidence that the connection between GDP and load has been dramatically diminished over the last 20 years and submits this world-wide phenomenon shows GDP per quadrillion British thermal units (BTUs) continuing to decline significantly.

Figure 8: GDP per quadrillion BTUs[222]



In addition, CEC refers to Energy Information Administration (EIA) evidence that all countries, including Canada, are increasing energy productivity relative to GDP and that energy intensity is expected to continue to decline.[223] CEC argues:

- BC Hydro's declining use per account statistics confirm that electricity is also declining in intensity; and
- BC's relatively flat electricity consumption for 10 years at the same time that BC's GDP has continued to grow demonstrates a clear disconnect between GDP and electricity energy use.[224]

4.1.6 Price elasticity and future rate increases

4.1.6.1 Key submissions and issues raised in the Preliminary Report

Price elasticity

BC Hydro submission

BC Hydro states it has estimated rate level elasticities in response to general rate increases at -0.05 and has applied those across the rate classes equally. BC Hydro notes it is being challenged that the magnitude of the price elasticity is too low, that it should increase its elasticity assumption and that DSM savings can be directly added to these higher elasticity impacts to determine overall customer load reductions. BC Hydro expressed its disagreement with these assertions and makes the following observations:

[222] Submission F82-2, CEC, p. 28.
[223] Submission F82-2, CEC, pp. 28–30.
[224] Submission F82-2, CEC, p. 31.

- As part of its 2015 Rate Design Application, BC Hydro performed a Residential Inclining Block Rate evaluation where it verified a -0.10 elasticity in response to a Stepped Rate Structure net of DSM program spending. The -0.10 is inclusive of the general rate increase response of -0.05.
- Any empirical price elasticity estimate that was inclusive of DSM would not be comparable with the general rate increase rate level elasticity of -0.05 that BC Hydro uses. BC Hydro references its elasticity inclusive of DSM in its response to Undertaking #1 in the Joint Review Panel hearing.
- If the rate level elasticity had a greater magnitude in the future, BC Hydro would need to review the impacts on the load from rate increases. BC Hydro states it would have to understand what changes in customer loads would be expected to occur as a result of the rate level changes and notes there would be an impact on the volume of DSM savings that would be available to BC Hydro to pursue if the rate level elasticity magnitude were much higher in future than have been the case to date.[225]

Deloitte report

In Deloitte's view, BC Hydro's assumed price elasticity may be an "oversimplification" in three respects:

- Deloitte ignores any DSM impacts and states the magnitude of BC Hydro's elasticity of -0.05 is smaller, in absolute terms (i.e., less negative), than those in some empirical studies (e.g., Alberini and Filippini 2011 and Espey and Espey 2004). Deloitte acknowledges that while location is relevant, these studies suggest that price elasticities for electricity can be at least -0.08 in the short run, and at least -0.45 in the long-run.
- Deloitte notes BC Hydro assumes that short-run and long-run elasticities are identical and refers to the same empirical research that shows long-run price elasticities of electricity demand are larger, in absolute terms, than short-run elasticities, as consumers may respond only gradually to higher prices (e.g., by investing in energy-efficient lighting and appliances).
- Deloitte notes BC Hydro assumes that price elasticity of demand is constant across sectors and refers to some independent studies that have found that commercial and industrial consumers exhibit more price elastic demand than residential consumers (e.g., Griffin and Arent 2006). Deloitte also refers to another other major utility in Canada that uses price elasticities for different customer segments, as well as short- and long-term horizons and notes in the case of the commercial and industrial sectors, the price elasticities used are considerably greater, in absolute terms, at -0.16 in the short run and -0.27 in the long-run. [226]

Deloitte states its assessment does not attempt to model the impact of its observations.[227]

Swain points to long-run price elasticities from sources such as the Joint Review Panel Report and the Hendriks *et al*. report whose estimates of price elasticity ranged from -0.1 to -0.7 with a cluster around -0.4 (Joint Review Panel) and -0.29 to -0.97 with a cluster also around -0.4. [228] Swain contrasts these with BC Hydro's price elasticity of -0.05, which BC Hydro uses uniformly across all sectors. He also states that the trend is that real prices "are on the rise, after a period of relative stability" and that this will affect total, not just marginal, demand. Finally, he states that at expected price elasticities of around -0.4, the effect will overcome population and GDP growth, resulting in continued "static or depressed demand for decades to come."[229]

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[225] Submission F1-1, BC Hydro, Appendix H, p. 3.
[226] Submission A-9, pp. 74–75.
[227] Submission A-9, pp. 74–75.
[228] Submission F36-1, Swain, H. (Swain), pp. 11–12.
[229] Submission, F36-1, Swain, pp. 11–12.

Expected rate increases

BC Hydro outlines its assumption about rate increases in its Base Case analysis. BC Hydro assumes rate increases of 3.5 percent in F2018, 3.0 percent in F2019, and increases of 2.6 percent in each year from F2020 to F2024, consistent with the 10 Year Rates Plan. For years after F2024, BC Hydro has assumed annual rate increases equal to inflation of 2.0 percent.[230]

In the F2017–F2019 RRA, BC Hydro explains that it will be able to meet the targets in the 2013 10 Year Rates Plan by:

- reducing forecast capital expenditures and capital additions;
- employing a debt management strategy, and reducing forecast finance charges;
- implementing operating cost savings in order to limit forecast base operating increases;
- targeting renewal of expiring Independent Power Producer (IPP) contracts at less than what they are currently paid; and
- government changes to significantly reduce pressures on BC Hydro's rates such as eliminating the Tier 3 water rates in F2018, changing the calculation on the ROE and reducing the dividend.[231]

When asked what factors could take BC Hydro "off track" of achieving the 10 Year Rates Plan objective of reducing the Rate Smoothing Regulatory Account balance to zero by F2024, BC Hydro noted that it did not currently anticipate any factors that would put it off track but it would continue to take actions, working with the Provincial Government, to remain on track by adapting to changing circumstances and challenges. However, BC Hydro did note the following factors that could positively or negatively impact it ability to achieve the 10 Year Rates Plan: weather, industrial load, LNG load, interest rates, and energy markets.[232]

In response to AMPC IR 1.1.10 in the F17–F19 RRA proceeding, when asked to calculate the expected average rate increases for each of F2025 and F2026, BC Hydro stated its "current forecasts do not extend past F2024 and BC Hydro is thus unable to perform the requested calculation."

In the F17–F19 RRA intervener final arguments, several interveners expressed concern related to BC Hydro's ability to meet the 2013 10 Year Rates Plan. Among other things, interveners commented on risks related to the industrial load forecast[233] and possible changes in the Provincial Government's approach to the financial management of BC Hydro.[234]

With respect to BC Hydro's assumption that there will be no real rate increases between F2025 and F2036, Deloitte notes that even if electricity demand is assumed to be more price elastic, there will likely be no change to the load forecast over that period as the change in price is assumed to be zero. Deloitte concludes that rate increases introduced between F2025 and F2036 would lower the 2016 load forecast. Deloitte states its assessment does not attempt to model the impact of its observations.[235]

BCSEA notes in its submission that when the Provincial Government announced approval of the Site C project on December 16, 2014, it also announced the 10 Year Rates Plan for BC Hydro. The 10 Year Rates Plan included substantial changes to dividend payments and minor changes to BC Hydro's water rentals that the government said would reduce the cost of Site C to ratepayers.[236]

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[230] Ibid., Appendix R, p. 4.
[231] BC Hydro F2017 to F2019 Revenue Requirements Application (F2017-F2019 RRA), Exhibit B-10, CEA IR 1.3.4.
[232] BC Hydro F2017-F2019 RRA, Exhibit B-10, NAIRG IR 1.1.1.
[233] BC Hydro F2017-F2019 RRA, AMPC Final Argument, para. 2(c).
[234] BC Hydro F2017-F2019 RRA, Mr. McCandless Final Argument, pp. 3–4.
[235] Submission A-9, pp. 74–75.
[236] Submission F29-3, BC Sustainable Energy Association (BCSEA), p. 20.

AMPC reiterates its rate concerns raised in the F2017–F2019 RRA proceeding and states:

> Given the significant capital expenditures associated with the Site C project, the amounts already in the Site C regulatory account, and the fact that the 10-Year Rates Plan does not account for Site C costs, AMPC is obviously concerned that associated rate increases will significantly exceed the currently planned 2.6 percent annual rate increases under the 10-Year Rates Plan.[237]

4.1.6.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel noted the differences in views related to BC Hydro's elasticity assumptions, as well as GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts," which were developed in 2007, need to be updated. [238]

The Panel also noted its concern with the appropriateness of BC Hydro's assumption that there will be no real rate increases between F2025 and F2036 since any rate increases introduced in this period could result in demand being lower than the Current Load Forecast.

Regarding the appropriateness of BC Hydro's assumptions related to price elasticity and future rate increases, the Panel requested that BC Hydro provide a more detailed explanation as to how elasticity is impacted by DSM. The Panel also requested that BC Hydro explain the reasonableness of assumed zero real rate increases as part of its load forecast beyond 2024 and to provide a detailed explanation of the risks which might prevent BC Hydro from achieving its projected zero real rate increases.

The Panel also invited submissions from other parties to assist the Panel in assessing the appropriateness of the assumptions related to price elasticity and future rate increases.

4.1.6.3 Additional submissions and responses

Price Elasticity

As noted in the Preliminary Report, BC Hydro has estimated rate level elasticities in response to general rate increases at -0.05 and has applied those across the residential, commercial and industrial rate classes equally. BC Hydro stated it conducted a number of empirical studies of price elasticity for its customers to support its planning assumptions and these studies set out to estimate price elasticity while controlling for the effects of DSM and other variables that influence electricity consumption in BC. BC Hydro described the results from the studies as follows:

- BC Hydro verified that the Residential Inclining Block Step 2 price elasticity of demand for electricity is between -0.08 and -0.13. These price elasticity estimates include the response to general rate increases – assumed to be -.05 – as well as the response to the Step 2 price increases. BC Hydro's "empirical research indicates that historically, price elasticity for residential customers has been between 0 and -0.13." BC Hydro adopted -0.05 for planning purposes.
- BC Hydro conducted a study to determine price elasticity for a selection of commercial and industrial general service customers, but was unable to detect a price response. BC Hydro concludes its empirical studies indicate that the price elasticity may have been close to zero. However, to be conservative BC Hydro adopted -0.05 for planning purposes.

[237] Submission F81-1, Association of Major Power Customers (AMPC), p. 5.
[238] Submission F1-1, BC Hydro, Appendix I, p. 9.

- BC Hydro evaluated the Tier 2 price elasticity of industrial transmission service rate customers to be -0.16. BC Hydro adopts a bottom up, industrial sector forecast to account for the possible effects of changes to the business environment including prices. In addition to the bottom-up estimates, BC Hydro applies a -0.05 price elasticity for planning purposes. [239]

BC Hydro notes others participants have concerns that its assumption of a -0.05 price elasticity estimate across all sectors is too low. The Deloitte report identified a concern that BC Hydro's overly simplistic elasticity assumptions are lower than several alternative estimates.[240] Hendriks *et al.* in their April 2017 Report counter BC Hydro's elasticity assumptions. [241] Hendriks *et al.* provided the following table summarizing the results of its literature review.

Table 5: Price Elasticity of Electricity Demand – Literature Values[242]

Customer Class	Reference	Short-run	Long-run
Residential	Paul, Myers and Palmer[60]	-0.13 (-0.05 to -0.32)[61]	-0.40 (-0.14 to -1.16)
	Bernstein and Griffin[62]	-0.24	-0.32
Commercial	Paul, Myers and Palmer	-0.11 (-0.01 to -0.22)	-0.29 (-0.02 to -0.70)
	Bernstein and Griffin	-0.21	-0.97
Industrial	Paul, Myers and Palmer	-0.16 (-0.08 to -0.31)	-0.40 (-0.20 to -0.82)

Hendriks *et al.* submit that BC Hydro's determination of price elasticity is at the very low end of the short-run elasticity determined in studies reviewed. In their view, this is relevant given the substantial real increase in electricity rates in the 10 Year Rates Plan – on the order of 19 percent real (46 percent nominal). Hendriks *et al.* conclude given these significant rate increases to come, BC Hydro's low estimate of price elasticity may lead it to overestimate future requirements. Hendriks *et al.* note the studies show that long-run price elasticity is much higher than short-run elasticity in all three sectors.[243]

Swain submits that the relevant measure is long-run price elasticity. He is critical of BC Hydro's use of -0.05 price elasticity across all sectors.[244]

Swain further states DSM is distinct from price elasticity and that BC Hydro confounds the two impacts. He submits DSM involves changes to codes and standards, the introduction of rates that help manage load shedding arrangements with big customers, and the subsidization of more efficient end-use applications like appliances or lighting. Swain concludes that BC Hydro is implicitly assuming that customers require an explicit subsidy or prohibition before any meaningful demand reduction will happen.[245]

AMPC submits its members reflect energy intensive and trade-exposed industries in the natural resources and industrial sectors and as the largest and most price sensitive electricity consumers in the province of BC, they are disproportionately economically affected by changes to electricity rates. AMPC believes that if electricity rates increase by more than 2.6 percent, that will heighten the risk of destroying demand, i.e., existing industrial customers will scale or shut down operations or even transfer production to other jurisdictions. [246]

[239] Submission F1-1, BC Hydro, Appendix I, p. 9.
[240] Submission A-9, p. 74.
[241] Submission F106-1, Program of Water Governance, University of British Columbia (PoWG).
[242] Submission F106-1, PoWG, Table 2, p. 26.
[243] Submission F106-1, PoWG, pp. 26–27.
[244] Submission F36-1, Swain, p. 11.
[245] Submission F36-1, Swain, pp. 12–13.
[246] Submission F81-2, AMPC.

AMPC agrees with the three flaws that Deloitte identified in BC Hydro's price elasticity assumptions: use of a single elasticity factor, failure to distinguish between short-run and long-run elasticities, and BC Hydro's faulty assumption that price elasticity of demand is constant across all sectors. AMPC is also concerned that the use of a low "one size fits all" factor may over-credit utility-funded energy conservation programs, where identified savings may actually be the result of price sensitivities that are greater than assumed. [247]

AMPC submits that BC Hydro fails to recognize that its industrial load forecasting model does not properly account for the risk that new customer requests for service may not fully materialize. AMPC urges the adoption of a more conservative industrial elasticity factor.[248]

BC Hydro does not agree with the approach suggested by some participants in the Inquiry to:

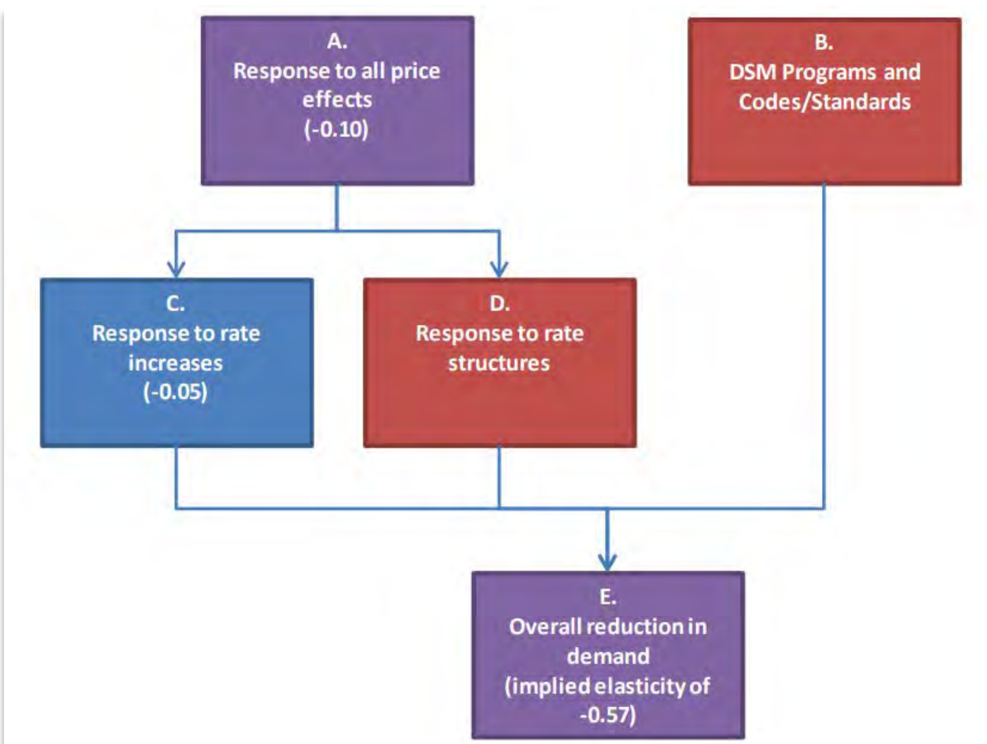
i. Arbitrarily increase the price elasticity used to reduce the forecast load based on an estimate from another jurisdiction and then,

ii. Further subtract BC Hydro's original estimate of DSM savings from the forecast load.

BC Hydro explains studies on elasticities in some other jurisdictions may be better compared to an implied long-run elasticity response that is inclusive of DSM. BC Hydro provided this calculation to the Joint Review Panel using a price elasticity of -0.57 (including estimated rate impacts and DSM savings) for F2033. BC Hydro submits that this is a more appropriate comparison to the empirical elasticity values in studies that did not control for DSM.[249]

The following Figure was presented by BC Hydro to the Joint Review Panel:

Figure 9: Joint Review Panel Treatment of Elasticity[250]



[247] Submission F81-2, AMPC.
[248] Submission F81-2, AMPC.
[249] Submission F1-6, BC Hydro, IR 2.19.0, p. 4.
[250] Canadian Environmental Assessment Agency, Site C Clean Energy Project, BC Hydro's response to Joint Review Panel Undertaking No. 1 (U-001), Doc #2155, December 13, 2013, retrieved from http://www.ceaa-acee.gc.ca/050/documents/p63919/97058E.pdf.

In summary, BC Hydro believes that its current approach to accounting for the effects of elasticity and DSM is appropriate and is supported by the empirical evidence it provides as support. As BC Hydro's elasticity estimate controls for DSM, it is then appropriate to subtract DSM savings. BC Hydro disagrees with adopting price elasticity estimates from studies conducted in regions dissimilar to British Columbia.[251]

BC Hydro concludes:

> Deloitte's first critique relates to BC Hydro's elasticity assumptions, which Deloitte describes as an oversimplification. GDS also recommended that BC Hydro review its elasticity value used to develop its load forecast. We are undertaking the review recommended by GDS, and it is at a very preliminary stage. However, BC Hydro has elasticity studies supporting the values used for the residential and commercial sectors. For the industrial sector, we account for elasticity in two ways. First, there is the -0.05 factor applied to all industrial load. Second, there is an elasticity factor implicit in the customer-specific probability weightings. As explained in the response to BCUC IR 2.19.0, our load forecast is supported by our data.[252]

Expected rate increases

BC Hydro

BC Hydro confirmed it has assumed annual rate increases of 2 percent nominal beyond F2024, which, based on forecast inflation of 2 percent, means rate increases are zero in real terms. BC Hydro also explains any annual real rate increases or decreases over the F2025 to F2036 period could alter the Current Load Forecast.[253]

With respect to future rate increases, BC Hydro stated:

- While it expects new alternative resources to create upward pressure on ratepayer costs, there is a downward impact on ratepayer costs provided by BC Hydro's existing and future heritage assets since the cost of large hydroelectric facilities declines over time as capital investment is paid off and financing costs reduced.[254]
- BC Hydro and Governments, past and present, have taken and will continue to take actions to keep electricity rates among the lowest in North America. These actions include those related to the 2011 Government Review, the 2013 10 Year Rates Plan, and subsequent actions to remain on track with the 2013 10 Year Rates Plan.[255]
- Over the long-term, BC Hydro's residential rates have not increased on a real basis and although future increases in customer rates will not be based on past increases in rates, this historical pattern indicates that, over the very long term, it is not unreasonable to assume that BC Hydro rates will not increase on a real basis.[256]
- BC Hydro estimated that relatively modest rate increases are needed to bring Site C into rates on a smoothed basis (estimated as 0.5 per cent in F2025, an incremental 0.5 per cent in F2026 followed by no further incremental rate increases during the ten-year smoothing period, with rate decreases thereafter). As a result, BC Hydro considers that it is reasonable to assume no real rate increases over the F2025 to F2036 period, despite Site C coming into service.[257]

[251] Submission F1-6, BC Hydro, IR 2.19.0.
[252] Submission F1-12, BC Hydro, p. 12.
[253] Submission F1-6, BC Hydro, IR 2.19.0, p. 5.
[254] Submission F1-6, BC Hydro, IR 2.51.0, pp. 1–2.
[255] Submission F1-6, BC Hydro, IR 2.51.0, pp. 1–2.
[256] Submission F1-6, BC Hydro, IR 2.51.0, pp. 1–2.
[257] Submission F1-16, BC Hydro, IR 3.10.0.

- A comprehensive review of BC Hydro announced by Government will be undertaken and BC Hydro will be working with Government on a "refreshed plan to keep electricity rates low and predictable over the long-term…." As a result, BC Hydro does not have details as to what its revenue requirements will be in the years requested. [258]

BC Hydro provides the table below to show the impact on the Current Load Forecast before DSM of a change in BC Hydro's real rate increase projection by plus or minus 1 percent annually from F2025 to F2036.

Table 6: Impact before DSM of a 1% Change in Real Rates[259]

	A	B	C	B-A	(B-A)/A	A-C	(A-C)/C
	Current Forecast	Current Forecast	Current Forecast				
	Total Integrated	Total Integrated	Total Integrated				
	Requirements	Requirements	Requirements				
	Before DSM	Before DSM	Before DSM	LOWER		HIGHER	
	with LNG	with LNG	with LNG	RATE OF 1 PERCENT		RATE OF I PERCENT	
		With one percent lower	With one percent higer	VS		VS	
		Real Rate Increase	Real Rate Increase	CURRENT		CURRENT	
	GWh	GWh	GWh	GWh		GWh	
F2017	58,395	58,395	58,395	0	0.0%	0	0.0%
F2018	59,162	59,162	59,162	0	0.0%	0	0.0%
F2019	60,561	60,561	60,561	0	0.0%	0	0.0%
F2020	61,624	61,624	61,624	0	0.0%	0	0.0%
F2021	63,574	63,574	63,574	0	0.0%	0	0.0%
F2022	65,974	65,974	65,974	0	0.0%	0	0.0%
F2023	67,557	67,557	67,557	0	0.0%	0	0.0%
F2024	68,856	68,856	68,856	0	0.0%	0	0.0%
F2025	69,957	69,990	69,925	33	0.0%	(33)	0.0%
F2026	71,158	71,225	71,092	67	0.1%	(66)	-0.1%
F2027	72,115	72,217	72,014	102	0.1%	(101)	-0.1%
F2028	73,104	73,242	72,967	138	0.2%	(137)	-0.2%
F2029	74,070	74,246	73,897	176	0.2%	(173)	-0.2%
F2030	75,144	75,358	74,933	214	0.3%	(211)	-0.3%
F2031	76,222	76,475	75,972	253	0.3%	(250)	-0.3%
F2032	77,383	77,678	77,093	294	0.4%	(290)	-0.4%
F2033	78,310	78,645	77,979	335	0.4%	(331)	-0.4%
F2034	79,241	79,619	78,869	378	0.5%	(372)	-0.5%
F2035	80,063	80,483	79,649	420	0.5%	(413)	-0.5%
F2036	80,937	81,400	80,480	464	0.6%	(456)	-0.6%

Other submissions

Many participants in the Inquiry express concerns related to future rate increases especially in the face of the costs of Site C.

Regarding rate increases, Mr. Eliesen stated:

> BC Hydro also underestimates likely rate increases. BC Hydro continues to behave as if it will not be held accountable for the cost of service related to its debt load, deferral accounts and its purchase commitments through independent power producers.
>
> The need to address the impact of these issues is looming, particularly given the Auditor General's recent report and qualified opinion. Any evaluation of the impact of Site C on ratepayers must first be undertaking from the perspective of rate increases needed to cover the cost of service. And then the impact of Site C later on top. It becomes clear that the elasticity of demand for electricity is much more sensitive to an approach that reflects the reality than an approach designed by BC Hydro to mask it.
>
> BC Hydro's costs, rates, and demand approach to forecasting exaggerated the need for Site C and underestimates the negative impact on ratepayers.[260]

[258] Submission F1-16, BC Hydro, IR 3.10.0.
[259] Submission F1-16, BC Hydro, IR 3.11.0, p. 1.

BCOAPO noted that BC Hydro assumes no real rate increases after the 10 Year Rates Plan period. BCOAPO submitted this must be challenged given BC Hydro faces "an aging suite of capital assets and changing business needs."[261]

Hendriks expressed concern with BC Hydro's statement it has had no real rate increases in the last 50 years since the past 50 years may not be the indicative period for concluding that there will be no future real rate increases. Hendriks stated there is a shift due to the decision made as a result of the 2007 BC Energy Plan and other policy since that time, to develop higher cost, low carbon resources. Hendriks questioned:

> Have we entered a new era with respect to price effects? We ask that as a question. We need to understand the low carbon electrification context of the past ten years, as this will also be the context moving forward. We need to understand the price effects of long-term rate increases under electrification.[262]

4.1.7 Potential disrupting trends

4.1.7.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro identified only one trend that it considered could result in a disruptive change to the load forecast – low carbon electrification. BC Hydro considers that electrification of energy loads currently served by fossil fuels (e.g., space and water heating, vehicles and industrial equipment) could reasonably cause demand for electricity to exceed BC Hydro's expected (mid) case in the Current Load Forecast.[263]

Deloitte report

Several participants raised concern that there could be significant changes to the load forecast over the 70 year economic planning life of Site C, and that projections based on historical data could fail to capture the emergence of these new factors. In Deloitte's view, examples of these disruptors include:

- improvements in technology for renewable energies such as solar power;
- the increased use of electric vehicles;
- decentralized power grids;
- the Internet of Things;
- fuel-switching;
- climate change; and
- co-generation. [264]

Similar to other submissions,[265] Deloitte considers that electric vehicle uptake in BC could be greater than BC Hydro has estimated in its load forecast. However, Deloitte was more cautious in its assessment of the potential of space and water heating electrification to further increase load, citing the higher cost of electric heating compared to natural gas. Deloitte considered these price differences would likely prevent customers

[260] TTP-1, October 13, 2017, Vancouver, pp. 1241–1242.
[261] TTP-1, October 13, 2017, Vancouver, p. 1293.
[262] TTP-1, October 13, 2017, Vancouver, pp. 1429–1430.
[263] Submission F1-1, BC Hydro, p. 52; Submission F21-1, King, B. (King), p. 1; Submission F62-1, Dauncey, G. (Dauncey), p. 7; Submission F82-1, CEC, pp. 31–33.
[264] Submission A-9, p. 75.
[265] Submission F60-1, Canadian Centre for Policy Alternatives, p. 2; Submission F82-1, CEC, pp. 28–31.

from switching from natural gas to electric heating for some time, assuming that natural gas prices remain low, and absent strong incentive introduced by policy.[266]

Deloitte also identified trends that could have a downward effect on the load forecast – in particular the use of solar photovoltaic (PV) panels by residential customers. While Deloitte considered that this would not be a significant issue over the 20 year time horizon of the load forecast as solar PV penetration is low (equivalent to 0.02 percent of residential load in 2016), Deloitte noted that projections regarding solar PVs are sensitive to electricity rates, policy and the costs of solar PV equipment.[267]

Other submissions

BC Hydro's online solar PV calculator estimates the payback period for a typical solar PV installation at 23 years. This is based on an assumed cost of $14,500 for 4 kW of installed panels ($3.60 per Watt), an electricity price of 14.2 c/kWh (Tier 2 rate plus 5 percent rate rider and 5 percent GST) and no future electricity rate increases.

Several participants commented that future changes to solar PV costs and BC Hydro rates could affect this payback period (and hence future solar PV uptake):

- **Solar PV cost** - Deloitte references a Northwest Conservation and Electric Power Plan estimate that solar PV costs will decrease by 53 percent between 2012 and 2030.[268] Mr. Dauncey submits that, as BC's solar market matures, there is every reason to expect a fall in solar prices and that rooftop solar PV at $2.00/W would have a levelized cost of 7.2 cents/kWh over 25 years and 6.5 cents over 30 years.[269]
- **BC Hydro's rates** - BC Hydro assumes no increase in its rates (other than for inflation) after the end of the 10 Year Rates Plan in 2024. Mr. Dauncey considers that future BC Hydro rate increases could make a solar PV investment very enticing to customers.[270]

4.1.7.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel noted its 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 has not identified any potential downside risks. The Panel requested that BC Hydro (and any other parties) specifically address:

- The downside risk of a lower load forecast over a 70 year time horizon;
- How this risk could be mitigated (e.g. policy changes to encourage electrification, sale of surplus energy to other markets); and
- To what extent the risk of a lower load forecast over a 70 year time horizon should result in a preference (all else equal) for a portfolio with smaller sized generation/demand components.

[266] Submission A-9, pp. 75–79.
[267] Ibid., pp. 77, 78.
[268] Ibid., p. 78.
[269] Submission F62-1, Dauncey, p. 11.
[270] Submission F62-1, Dauncey, p. 11.

4.1.7.3 Additional submissions and responses

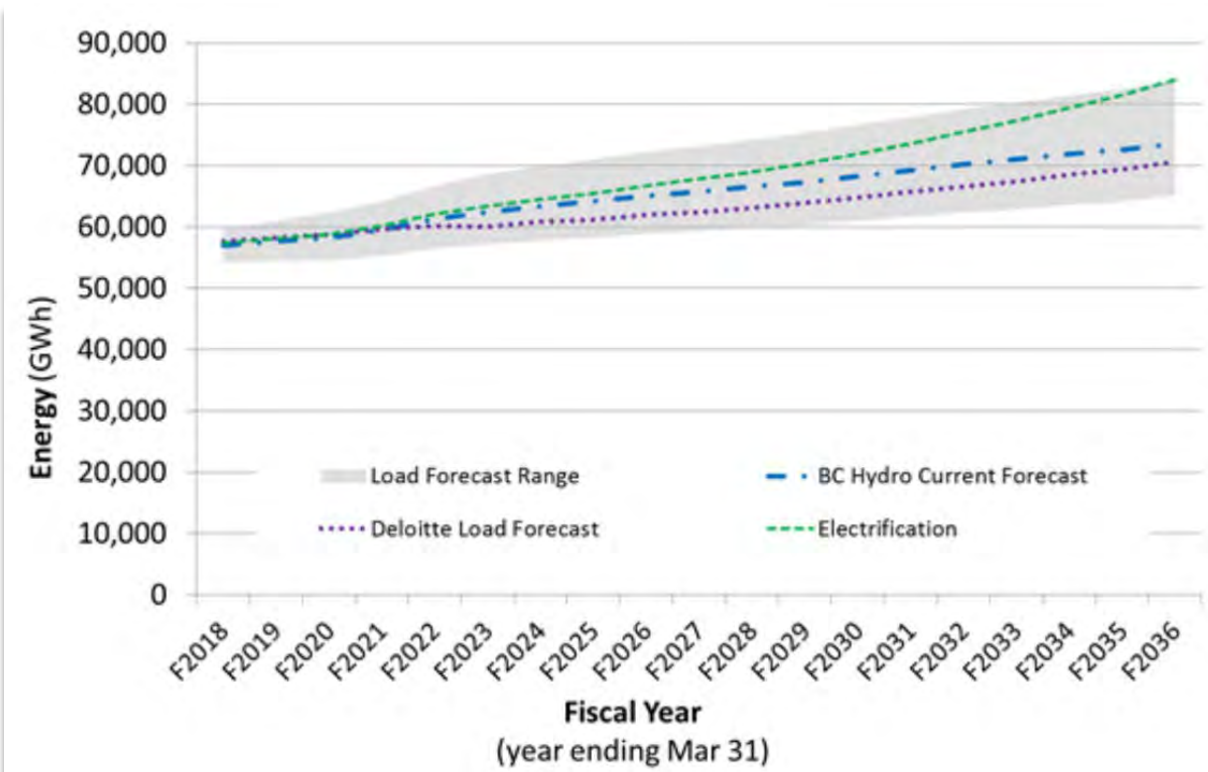
BC Hydro submission

With respect to potential disruptors, BC Hydro states it Current Load Forecast does not reflect the additional load from electrification since such a load represents a paradigm shift rather than a typical economic factor that drives load up or down. BC Hydro submits that combatting climate change will require increased electrification across BC.[271] BC Hydro states:

> In a world in which decarbonisation is becoming more and more important, and the expectation is that policies limiting greenhouse gas emissions will only become more stringent, the need for clean, firm resources is only going to increase. [272]
>
> …As Dr. Jaccard describes, on behalf of BCSEA (Filing F29-6), if the federal and provincial government's deliver on their GHG reduction commitments, the increase in electricity consumption will be substantial.[273]

BC Hydro provides the following figure and states that it depicts the result of the electrification study that BC Hydro undertook for its 2013 Integrated Resource Plan. BC Hydro submits the figure illustrates that by 2036 the mid-load forecast with electrification is equivalent to the high-load scenario and will continue to grow thereafter. The figure also shows where Deloitte's "alternative" load scenario falls in relation to BC Hydro's forecast.[274]

Figure 10: BC Hydro's Load Forecast Range, Impact of Electrification, and Deloitte's "Alternative" Load Scenario[275]



[271] Submission F1-12, BC Hydro, p. 7.
[272] Submission F1-12, BC Hydro, p. 9.
[273] Submission F1-12, BC Hydro, p. 10.
[274] Submission F1-12, BC Hydro, p. 9.
[275] Submission F1-12, BC Hydro, Figure 2-3, p. 10.

The following subsections summarize other evidence and the responses to the Panel's requests for comments on the downside risk of a lower load forecast over a 70 year time horizon and possible mitigation strategies. The information is grouped into factors that may decrease demand and factors that may increase demand.

Factors that may decrease demand

BC Hydro submissions

- Potential for long term economic stagnation to depress load growth.[276]
- A deindustrialization trend that pulls industrial load growth below expected levels.[277]
- Natural conservation of energy driven by technological advances – advances in energy efficiency in terms of lighting, electric motors and customers' choices of end-use products could drive future use at the residential and consumer level far below the expected growth levels.[278]
- Distributed Energy Resources (DERs) remove load from BC Hydro's load resource balance – many energy scenarios extrapolate the trend of decreasing solar PV costs, decreasing wind power costs, and improving battery technologies to envisage an era where reducing reliance on BC Hydro, either partially or totally, becomes a cost effective strategy for individual customers or collections of customers.[279]

Other submissions

- Water heating is difficult to decarbonize, even with a strong carbon price. Heating water with electricity may stay more expensive than heating it with gas. [280]
- In New England the ten-year forecast calls for a 0.6 percent decline in electricity consumption over this ten-year period. New York has similar declines but not as strong. These strong investments in energy efficiency have a cost of USD $35 per megawatt hour.[281]
- Net zero buildings, which means new housing will be built, with very little impact on overall electricity consumption, despite an expanding population.[282]
- Smart meter integration into DSM means up to 18 percent of electricity consumption can be saved using smart meters, while peak demand can be reduced up to 20 percent according to "smartgrid" estimates.[283]
- Hendriks *et al.* critiques the electrification magnitude of two studies, the Deep Decarbonisation Pathways Project (DDPP) and the Trottier Energy Futures Project (TEFP), relied on by the Government of Canada.[284] Some comments and conclusions are as follows:
    - Hendriks *et al.* conclude that lower economic growth (1.7 percent from the Department of Finance rather than the DDPP and TEFP rate of about 2.0 percent) would very likely result in slower growth of emissions, lower electricity requirements and overall less investment in low-carbon electricity to 2050.

[276] Submission F1-8, BC Hydro, IR 2.20.0, p. 4.
[277] Submission F1-8, BC Hydro, IR 2.20.0, p. 4.
[278] Submission F1-8, BC Hydro, IR 2.20.0, p. 4.
[279] Submission F1-8, BC Hydro, IR 2.20.0, p. 4.
[280] TTP-2, October 14, 2017, Vancouver, p. 1435; Submission F106-8, PoWG.
[281] TTP-1, October 13, 2017, Vancouver, pp. 1263–1264.
[282] Submission F6-8, Bryenton, R. (Bryenton), p. 4.
[283] Submission F6-8, Bryenton, p. 4, with reference to https://www.smartgrid.gov/files/The_Smart_Grid_Promise_DemandSide_Management_201003.pdf.
[284] Submission F106-1, PoWG, pp. 34–41.

    - The omission of distributed generation from the analysis represents a major shortcoming in the TEFP, calling into question the findings with respect to future electricity requirements that would be met by large-scale hydroelectric development.
    - The finding in the TEFP of less generation from solar PV in Canada in 2050 than today is not credible.
    - The assumption in the TEFP that real wind costs remain unchanged between 2012 and 2050 is without merit. Further cost declines in wind energy alter the balance of future low-carbon electricity resources towards combinations of energy storage and wind, and away from conventional large-scale hydroelectric resources.
    - The omission in the TEFP of the potential for capacity upgrades at existing hydroelectric facilities substantially overstates the need for large-scale hydroelectric development.
- Hendriks *et al.* comments on the BC Hydro 2013 IRP electrification potential MK Jaccard and Associates Study (MKJA study). [285]
    - Hendriks *et al.* notes notwithstanding the potential for electrification to contribute to substantial increases in electricity requirements, several factors influencing the analysis in the MKJA study have evolved since the study was completed, including the following: low GHG prices tracking closer to the low case, much lower natural gas prices well under the low case, and electrification in the transportation sector would require less than 1,000 GWh/year by 2030, much less than anticipated in the MKJA study. [286]
- Hendriks *et al.* concludes: Though available information indicates that the effects of electrification on BC Hydro's load forecast are likely to be significant, the timing and extent of those increases remain highly uncertain. The preponderance of information points to a significant effect from electrification beginning not sooner than the 2030s. The possible exception concerns the electrification of natural gas production, processing, transmission and liquefaction, which is currently underway and already included in BC Hydro's Current Load Forecast. [287]

Factors that may increase demand

BC Hydro

- Climate change
    - The Municipal City of Vancouver Renewable City Strategy Results indicates that net electricity demand after efficiency measures would almost double by 2050.[288]
    - Federal-Provincial: Pan-Canadian Framework
        - Reduction in emissions from natural gas activities: British Columbia and the Government of Canada will work together to bring clean grid electricity to natural gas operations in northeast BC. They will co-fund the construction of new transmission lines and other public electrification that could avoid up to 4 mega tonnes (Mt) of emissions per year.[289]
        - Electricity grid interconnection: British Columbia and the governments of Canada and Alberta will work together to restore the capability of the existing high-voltage electricity grid interconnection with Alberta. This project will improve access to

[285] Submission F106-1, PoWG, pp. 42–46.
[286] Submission F106-1, PoWG, pp. 42–46.
[287] Submission F106-1, PoWG, p. 53.
[288] Submission F1-8, BC Hydro, IR 2.20.0, p. 2.
[289] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 5.

clean electricity in Alberta and will result in lower GHG emissions and air pollution, and improved grid reliability in both provinces.[290]

- Published studies on electrification and GHG Reductions
    - In BC Hydro's 2013 Integrated Resource Plan, the 2011 MK Jaccard and Associates Study concluded achievement of deep reductions in GHG emissions would require significant electrification. Electricity demand could grow significantly, by between 7,000 and 13,000 GWh/year in 2030, and by between 17,000 and 28,000 GWh/year by 2050, relative to the reference scenario.[291]
    - Clean Energy Canada Electrification Study (2016) concludes the leading provincial electrification policies across Canada reduce greenhouse gas emissions by shifting energy consumption from fossil fuels towards electricity while at the same time ensuring that electricity generation comes from zero emission sources.[292]

- Impacts on energy requirements in key sectors
    - Electrification of natural gas production, processing and transmission: The BC Climate Leadership Plan includes electrification of natural gas production as the largest component of low-carbon electrification in the Plan and the Pan-Canadian Framework has commitments to fund transmission infrastructure to support electrification of the BC natural gas sector.[293]
    - BC Climate Leadership Plan of avoiding 1.6 million tonnes per year through electrification will require approximately 2,700 GWh/year of electricity, depending on the emissions intensity of gas production. This level of load growth is consistent with BC Hydro's May 2016 load forecast.[294]

4.1.8 Other factors impacting forecast demand

In addition to the issues identified by the Panel in its Preliminary Report, this section includes other factors impacting forecast demand identified in additional submissions considered since the Preliminary Report. The other factors include:

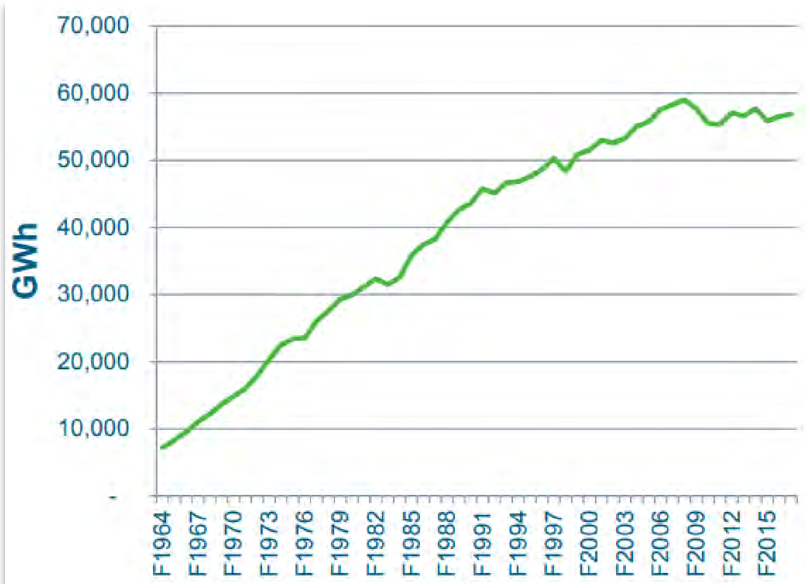
1. flattening of electricity demand;
2. concerns about BC Hydro's financial situation; and
3. risk of increasing energy poverty.

Flattening electricity demand

BC Hydro stated two thirds of its load – residential, commercial and light industrial - is steady and increasing.[295] BC Hydro presented actual total gross requirements and noted the figure reproduced below shows the impact of the 2008 recession and reflects a major shake-out in the pulp and paper sector. BC Hydro also attributed another major drop in the 2016 timeframe to Howe Sound Pulp and Paper.[296]

[290] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 5.
[291] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 6.
[292] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 6.
[293] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 7.
[294] Submission F1-1, BC Hydro, Appendix J, Attachment 1, p. 8.
[295] Submission F1-14, BC Hydro, p. 15.
[296] TTP-2, October 14, 2017, Vancouver.

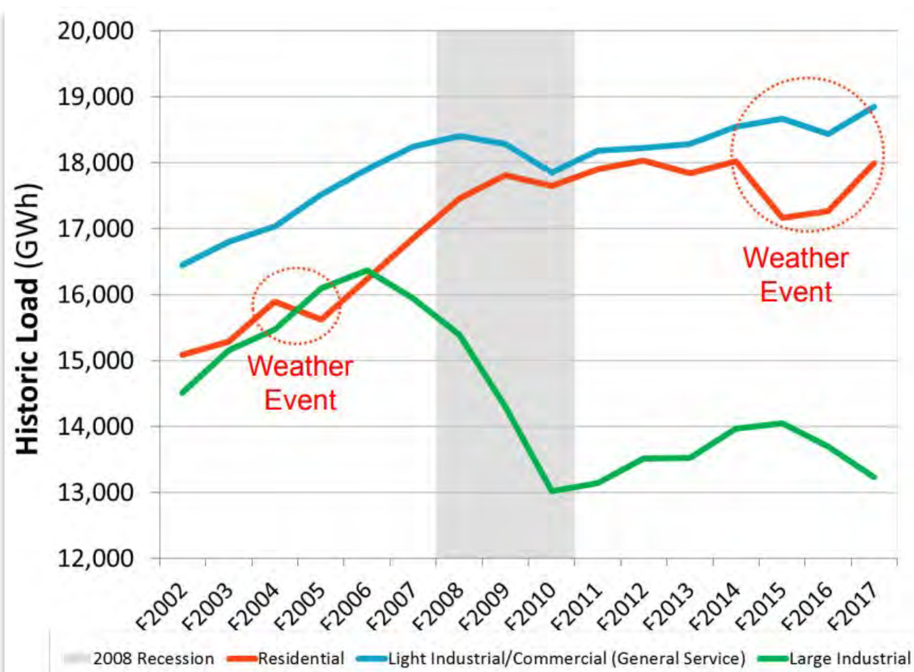
Figure 11: Total Gross Requirements[297]



BC Hydro stated that recessions have historically not stopped load growth and in years subsequent to 2007 the underlying sectors outside of pulp and paper have continued to grow.[298] Regarding the figure presented below, BC Hydro states:

> But if you take it from after the effects of the recession and then start looking off to the right, so outside of that grey band it is more modest growth than what we saw before, but both the blue and the red lines, residential and commercial, are growing, albeit slowly. And we have reflected that slower rate of growth, that's being seen now post-recession onto our low [sic] forecasts.

Figure 12: Historic Load (Not Weather Adjusted)[299]



[297] Submission F1-14, BC Hydro, p. 15.
[298] TTP-2, October 14, 2017, Vancouver, p. 1610.

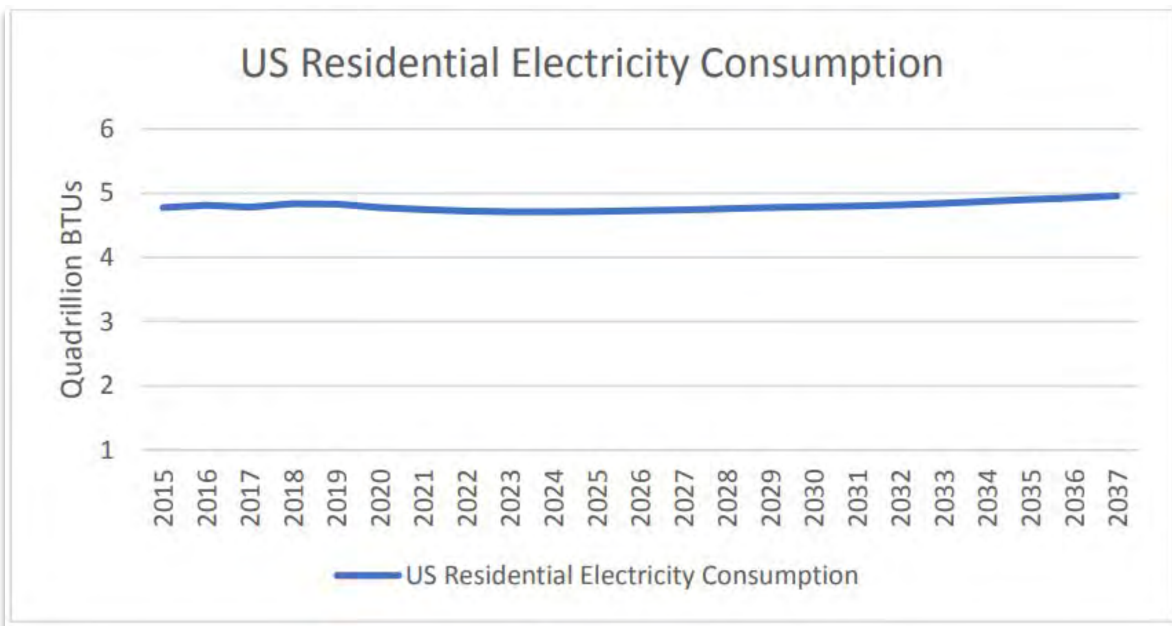
BC Hydro agreed that since the recession demand has not returned to the same growth rate and BC Hydro's growth rate is now down to 1 percent and maybe a little bit less and this is what it has reflected in its forecast going forward.[300]

Commercial Energy Consumers Association

CEC explained that as loads have flattened out in the last 10 years, 200,000 new customers have been added to the BC Hydro system with no requirement for increased electricity and this includes all of the additional commercial businesses in support of all of that activity. CEC attributes this to DSM spending, changing demographics and declines in baby boom spending, and declines in the industrial sector and North American manufacturing moving overseas.

CEC takes exception to GDS's comments on BC Hydro's residential and commercial forecasts and provides the following US residential demand projections "demonstrating a substantially different picture than provided by GDS":

Figure 13: US EIA Electricity Demand Projection[301]



CEC states the US has been experiencing flat electricity load growth and is now projecting flat load growth until the late 2020s and modest growth thereafter. CEC submits the "evidence is that the BC Hydro projections are out of alignment with other key jurisdictions."[302]

In its submission on the load forecast, CEC states:

> The BC Hydro submissions have one key failure, they do not acknowledge the declining use per account change and its continuation. Rather they prefer to say the recession caused the flat loads and their models now predict growth.

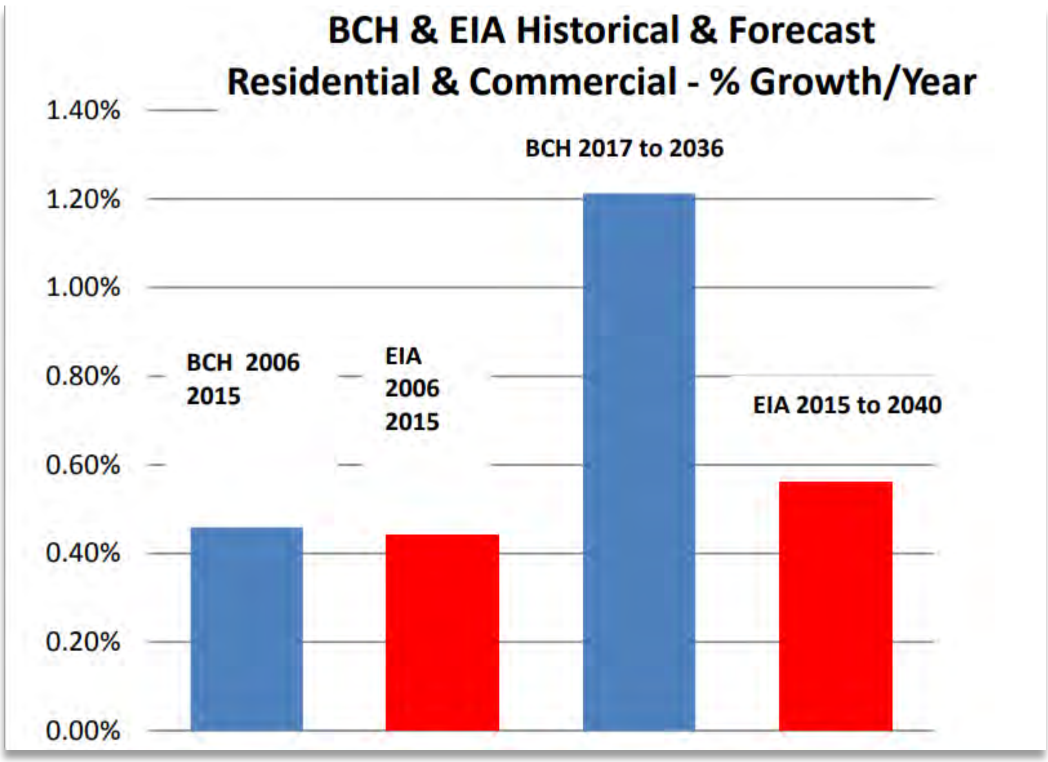
[299] Submission F1-14, BC Hydro, p. 14.
[300] TTP-2, October 14, 2017, Vancouver, p. 1616.
[301] Submission F82-2, CEC, p. 24.
[302] Submission F82-2, CEC, p. 25.

…The CEC is concerned that the Panel has not seen in these submissions the acknowledgement that BC has declining use per account trends, which have propelled lower load forecasts.[303]

Surplus Energy Match

Surplus Energy Match provides the following graph taken from EIA data and BC Hydro's F2017–F2019 RRA. The figure below compares the US historical trends and the EIA forecast with BC Hydro's historical trend and projections with respect to the residential and commercial sectors.

Figure 14: BC Hydro & EIA Historical & Forecast Residential & Commercial - % Growth/Year[304]



Surplus Energy Match notes the historical trends for BC and the US have been quite similar for the last 10 years, with BC at 0.46 percent per year compared to 0.44 percent per year for the US. Surplus Energy Match also notes BC Hydro is projecting more than twice the annual growth rate than the EIA for the next 20 years and questions why there should be this much difference in projections since historically the trends have been quite similar and given BC Hydro has such a strong conservation program in place.[305]

Canadian Wind Energy Association

CanWEA states:

> 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 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). Interestingly, my assessment regarding these risks is consistent with that provided by

[303] Ibid., p. 35.
[304] Submission F288-1, Surplus Energy Match, p. 3.
[305] Submission F288-1, Surplus Energy Match, p. 3.

> Powerex which last month noted that "demand is not growing in most places in North America."
>
> These are not markets in which one makes large investments in baseload resources that require a 70-year payback (like Site C).
>
> So what's driving this decline in energy consumption? Two things: First, investments in energy efficiency and conservation, which are commonly understood to be the lowest cost energy resource.
>
> … The second factor that is contributing to this decline in electricity demand is the growth of behind-the meter solar PV such as rooftop solar projects.[306]

BC Hydro's financial situation

A number of participants in this Inquiry raise concerns about BC Hydro's growing debt load and what impact this might have on future rate increases. The following is an outline of points Eliesen raises:

- Even if real market interest rates stay unchanged, any increase in debt costs will increase the cost of service to ratepayers;
- Given the weak financial position of BC Hydro, Site C costs will exacerbate an already precarious financial situation which could lead to a downgrade in credit ratings and an increase interest costs;
- BC Hydro's regulatory accounts, debt level and off-balance sheet liabilities to IPPs also place a significant burden on ratepayers;
- The BC Auditor General's qualification with respect to regulatory accounting is a serious issue;
- Ratepayers have not been charged rates that are reflective of their cost of service and the need for rate increases has compounded; and
- Site C costs and subsidized rates for LNG will add to this burden.

Swain described BC Hydro's financial condition as:

> …an artifact of previous public policy more than BC Hydro management, cannot continue, or worse, be allowed to deteriorate further. Its debt equity ratio is perilously high at 4.55 to 1, its deferral accounts are enormous, it's equity very oddly defined, and its free cash flow a long way from being free.
>
> If it were a regular publicly-owned company, its stock would be delisted by now and its credit rating below investment grade.[307]

Energy poverty

A number of parties raised issues with respect to the impact of rate increases on low-income customers. Dauncey stated:

> An aspect of that which is rate impacts causing energy poverty, which is a subset of demand-side management. It's a dimension of debate not being covered at all, which I firmly should be included. The impact of rate risers on low income households, including the evictions of households for non-payment of utility bills and people's children being taken into care because their homes are too cold and pose a risk to the children's health. Energy

[306] Submission 104-2, Canadian Wind Energy Association (CanWEA) and Clean Energy Association of BC (CEABC).
[307] TTP-2, October 14, 2017, Vancouver, pp. 1405–1406.

> poverty is a real concern for issues that affect the health, standard of living, living environment and children of British Columbians.[308]
>
> … So, price elasticity becomes so extreme at the low-income level that it's down to, you know -- the elastic band breaks, and demand is down to zero. Because, you know, you can't afford to pay. [309]

The Canadian Center for Policy Alternatives (CCPA) noted that neither the Preliminary Report nor the Deloitte Report, comment on energy poverty, and submitted:

> …completing Site C will lead to higher debt for BC Hydro and higher rates for all BC Hydro customers. This will increase energy poverty among B.C.'s low income households.
>
> …My research has previously analyzed energy poverty in B.C. and finds that steep residential rate increases disproportionately impact lower income households that are already facing major affordability challenges.[310]

4.1.9 Panel analysis and findings

In the Preliminary Report, the Panel noted that a number of participants point out that sections 3(c)(i) and (ii) of the OIC provide flexibility for the Panel to identify factors that may cause the load forecast to deviate from the mid-level load forecast (the expected case). The Panel also agreed with BCSEA's submission that the requirement to have BC Hydro report on adjustments and the factors that may move demand higher or lower than the mid-level forecast does not preclude us from receiving and taking into account information from participants on these topics in developing our findings on the load forecast.

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.

The Panel agrees with BC Hydro that we should not use an alternative load forecast such as the one put forward by Deloitte. However, while it is not appropriate to use Deloitte's alternative forecast for resource planning purposes, in the Panel's view, Deloitte's analysis is useful for considering the order of magnitude of the effect that changing certain variables has on the demand estimates.

The Panel acknowledges BCSEA's submission:

> Now, the Commission in my submission does not have enough evidence, let alone enough time, to redo and approve a whole new BC Hydro load forecast. The Commission will have to focus on the factors that will push load downward compared to the load forecast, and the factors that will push load upward compared to the current load forecast. The fact is that there are genuine, realistic factors that push down, and that push up.[311]

However, while the Panel cannot precisely determine the adjustments necessary to the mid load forecast, we can, based on our view of the issues and factors impacting demand, place more weight on an estimate elsewhere within the range of uncertainty set out by BC Hydro. It is in this context the Panel considers the load forecast issues. The Panel focuses on those issues and factors that could reasonably be expected to influence demand from the expected case (mid load forecast) to the high-load and low-load case.

[308] TTP-1, October 13, 2017, Vancouver, pp. 1327–1328.
[309] Ibid., p. 1330.
[310] Ibid., p. 1364.
[311] TTP-2, October 14, 2017, Vancouver, pp. 1467–1468.

As described below, an overwhelming majority of the Panel's findings set out below suggest the mid load forecast is not the most probable outcome. Weighing the Panel's findings on the identified issues and other factors impacting demand, the Panel identifies that there is significant downward pressure on demand that indicates the low load forecast is the most probable forecast within BC Hydro's Current Load Forecast range of uncertainty. In addition, there is risk that demand could be even lower than the low load forecast.

Recent developments in the industrial sectors

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.

Accuracy of historical load forecasts

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

GDP and other forecast drivers

The Panel finds the GDP and disposable income estimates used by BC Hydro in its Current Load Forecast are higher than similar Conference Board of Canada estimates, and these differences have not been fully explained. 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.

Accepting BC Hydro's argument that the sensitivity analysis presented in Table 3 is preferable to the one prepared by Deloitte, the Panel notes that directionally adjusting for the differences in GDP results in a 265 GWh and 276 GWh reduction in load for F2026 and F2036, respectively.[312] The Panel also notes that BC Hydro's "high level indicative only" calculation of the impact of the estimate of using the CBoC disposable income estimates a 122 GWh and 251 GWh reduction in load for F2026 and F2036, respectively. The Panel accepts BC Hydro's caution that these amounts are not additive to the GDP adjustment noted above.

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.**

The Panel also notes CEC's evidence that the connection between GDP and load has been dramatically diminished over the last 20 years and submits this world-wide phenomenon shows GDP per quadrillion BTUs continuing to decline significantly. The Panel is concerned if load growth is decoupled from GDP, relying on optimistic GDP forecasts could have implications for demand later in the forecast period.

Price elasticity

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. Additionally, it is not clear if BC Hydro appropriately calibrated its empirical results with other long-run studies to calculate the estimated long-run price elasticity.

The Panel concurs with Swain that BC Hydro confounds DSM and price elasticity. The Panel also shares AMPC's concern that a low "one size fits all" factor may over-credit utility funded energy conservation programs, where the identified savings may actually be the result of price sensitivities that are greater than assumed. The Panel is concerned that BC Hydro confounds the calculated impacts of the actual price elasticity from rate increases, resulting in too much attribution being given to DSM and too little to the impact of real price increases.

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

[312] Submission F1-6, BC Hydro, IR 2.18.3.

response indicates the study results may not be reliable. The Panel 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.

BC Hydro's empirical evidence shows that historically large industrial customers have been more sensitive than other customer segments, but it applies a -0.05 price elasticity. **The Panel agrees with AMPC that a higher industrial elasticity factor should be used.** The Panel considers BC Hydro's evidence of a -0.16 price elasticity in Tier 2 industrial transmission service rate customers as indicative that the long-run price elasticity is above -0.05. As noted above it is not clear to the Panel that the empirical study for industrial customers measured the long-run price elasticity since the industrial tiered rates have not been in place for a long period of time. The Paul, Myers and Palmer study shows the low-end of the range to be at -0.20. This is directionally consistent with the views articulated by AMPC regarding the particular price sensitivity of its energy intensive and trade-exposed customers who operate in a global competitive market.

The Panel finds the appropriate "apples to apples" starting reference point is the international literature on long-run price elasticities, followed by consideration of BC Hydro's results in its empirical studies. The National Renewable Energy Laboratory (NREL) conducted a study on regional differences in the US for both short-run and long-run price elasticities.[313] BC Hydro's empirical studies' results and the NREL results with US states geographically close to British Columbia indicates that BC Hydro may be near the low-end of the international range for long-run price elasticity. The Panel is not convinced that the international price elasticities have any material utility DSM component embedded that may confound the results.

The Panel notes GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts," which were developed in 2007, need to be updated and we acknowledge that BC Hydro is in the preliminary stages of undertaking the review recommended by GDS.

Future rate increases

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.

BC Hydro presents the rate impact before DSM of a 1.0 percent change in real rates (Table 6), illustrating a 67 GWh and 464 GWh change in load for F2026 and F2036, respectively. The issue for the Panel is whether it is appropriate to accept BC Hydro's assumption of zero real rate increase post 2024 for the purpose of making our assessment on the load forecast. In the Preliminary Report, the Panel discussed that future rates

[313] Originally referenced in Submission F106-1, PoWG, p. 26, footnote 62, Bernstein, M.A. and Griffin, J. 2005. Regional Differences in the Price-Elasticity of Demand for Energy. Prepared for the National Renewable Energy Laboratory. Retrieved from https://www.nrel.gov/docs/fy06osti/39512.pdf.

could be impacted by changes to government policy with respect to proceeding with the elimination of the Tier 3 water rates, changes to the calculation of the ROE, reducing the dividend, and other policies in the 2013 10 Year Rates Plan and beyond. The Panel also recognized that achievement of the targets in the 2013 10 Year Rates Plan are subject to risk with respect to policy changes, weather, industrial load, LNG load, interest rates, energy markets and Site C budget uncertainties, among other things.

In the Panel's view, the fact that BC Hydro's residential rates have not increased on a real basis over the very long term does not provide adequate support for the reasonableness of the assumption of no real increases going forward. Future rate increases are more likely to be impacted by more recent experience and expected changes going forward rather than by the long-term history of increases in real rates. The Panel agrees with Hendriks *et al.* that there has been a shift in BC Hydro's costs in the last 10 years, partially as a result of the 2007 Energy Plan which increased rates due to the policy to decarbonize electricity generation (e.g. IPPs and decommissioning of Burrard Thermal). The Panel is concerned that the size of increases in revenue requirements in the last 10 years (before the imposition of mandatory rate caps and rate smoothing regulatory accounts), the requirement for BC Hydro to clear out regulatory accounts periodically, the considerable future capital expenditures that will be needed to maintain heritage assets, and the costs to complete Site C (including interest carrying costs and the risk of any further cost overruns) can reasonably be expected to have upward pressure on real rates. With respect to the rate impacts to bring Site C into rates, the Panel is not convinced that even on a smoothed basis it is reasonable to assume no real rate increases. In addition to these considerable pressures on rates, the ability to meet the 2013 10 Year Rates Plan and keep real rates flat beyond the 10 Year Rates Plan will be impacted if actual demand is less than the 2016 mid forecast.

The Panel acknowledges BC Hydro's submission that in the past it has worked with government to take actions to keep rates low and the Government's recent announcement that a comprehensive review of BC Hydro will be undertaken. Considering information presented by BC Hydro in its F2017–F2019 RRA related to its past effort to manage costs resulting from the 2011 Government Review, the 2013 10 Year Rates Plan, and subsequent actions including the deferral of some capital project as part of its effort, the Panel considers there is risk related to BC Hydro's ability to keep electricity rates low and predictable over the period of the Current Load Forecast and the 70-year life of the Site C project.

The Panel also notes the submissions from participants who raise concerns that future rate increases could also be impacted by real interest rate changes and the impact of any changes in credit rating that could result from BC Hydro's higher debt load, its high level of regulatory account balances and off-balance sheet IPP commitments. Both the Provincial Government and BC Hydro's credit rating could potentially be impacted by these factors and by the Auditor General's report qualification.

Potential disrupting trends

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 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.

Flattening electricity demand

Many participants, including BC Hydro, recognize that since the recession demand has not returned to what it was. 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.

The Panel acknowledges BC Hydro's submission that the total electricity demand for the residential, commercial and light industrial sectors is growing, albeit slowly at 1.0 percent or a bit less. However, the Panel calculates the compound annual growth rate over the last 10 years, excluding the large industrial load, to be less than 0.4 percent. In addition, the Panel notes that BC Hydro's after-DSM compound growth rate for these customer segments included in the mid load forecast approximates 1.4 percent. **The Panel finds BC Hydro's expected compound growth rate for the residential, commercial and light industrial sectors to be significantly higher than the flat or declining growth rates forecast in other North American jurisdictions.**

In the Panel's view, a likely explanation for this is the result of lower DSM spending and DSM program differences, in that BC Hydro has not implemented time-of-use and other load curtailment measures that have been broadly adopted elsewhere in North America.

4.2 Load resource balance

4.2.1 Key submissions and issues raised in the Preliminary Report

Existing/current production

In the Preliminary Report, the Panel considered BC Hydro's existing and committed or total electricity supply without Site C and the resulting surplus or deficit using the low, mid and high load forecast.

BC Hydro summarized its existing and committed (those in development but not in service) resources in Appendix K of its August 30, 2017 filing. Tables K-1 and K-2 within Appendix K (in addition to other items) present BC Hydro's total energy and capacity supply for the period 2018 through 2036 without Site C. These provide an outline of the total energy and capacity that BC Hydro will have available if it does not complete Site C or add energy or capacity from other sources.

BC Hydro categorizes its energy and capacity supply as follows:

- Existing and committed Heritage resources
  - existing facilities owned and operated by BC Hydro
- Existing and committed IPP resources
  - including run-of-river and other alternative energy sources
- Planned supply side resources
  - inclusive of IPP renewals and those related to the standing offer program

BC Hydro does not explain how it determines the amount of energy and capacity its existing and committed Heritage resources can supply. However, public information can be found in BC Hydro's 2013 Integrated Resource Plan.[314] Ruskin questions how BC Hydro determined these amounts.[315]

Heritage resources are currently the largest part of BC Hydro's energy supply, accounting for approximately 75 percent. IPP resources and anticipated or planned renewals, accounting for 24 percent, are the next largest group with the standing offer program at approximately one percent, providing only a small amount of energy. By 2036, excluding Site C and Revelstoke 6, BC Hydro expects the contribution of heritage resources to remain unchanged at approximately 75 percent but expects IPP (including planned renewals) energy to drop slightly to 21 percent with a greater reliance on the standing offer program anticipated.

With respect to capacity, heritage resources currently account for approximately 87 percent with almost all of the balance attributed to IPPs and anticipated renewals. Little change is expected by 2036 with only minor changes in these percentages and a slight increase in reliance on standing offer program capacity.

Load resource balance

As noted in the Preliminary Report, BC Hydro summarizes that without Site C, it would need new energy and capacity resources on the timeline shown in Figure 15. BC Hydro emphasizes that accessing dependable capacity will be one of its most pressing concerns for years to come.[316]

4.2.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel noted that Revelstoke 6 was not included in the load resource balances in BC Hydro's August 30, 2017 filing (submission F1-1) and asked BC Hydro to confirm that there are no other planned resources that have been excluded from these tables. The Panel also asked BC Hydro to comment on Ruskin's submission and further explain how BC Hydro determined the amount of energy and capacity available from existing and committed Heritage resources.

4.2.3 Additional submissions and responses

BC Hydro confirmed that other than Revelstoke Unit 6 and Site C there are no other currently planned resources that have not been included in the tables provided in Appendix K of BC Hydro's August 30, 2017 filing or in the subsequently updated Appendix K tables provided in BC Hydro's response to IR 1.4.0.

Ruskin argues that BC Hydro should not be planning based on what BC Hydro's facilities have generated, but what capacity they have to generate. Ruskin submits this amount is approximately 53,000 GWh/year.[317]

BC Hydro responded that it already uses the approach suggested by Ruskin and explains that its assessment of long term system energy capability considers average water conditions over a 70-year inflow record and includes a comprehensive model to simulate its system's multi-year storage capability. BC Hydro submitted its average energy capability is consistent with the CEA and is 48,500 GWh/year and its Firm Energy Load Carrying Capability is 44,400 GWh/year in critical water conditions.[318]

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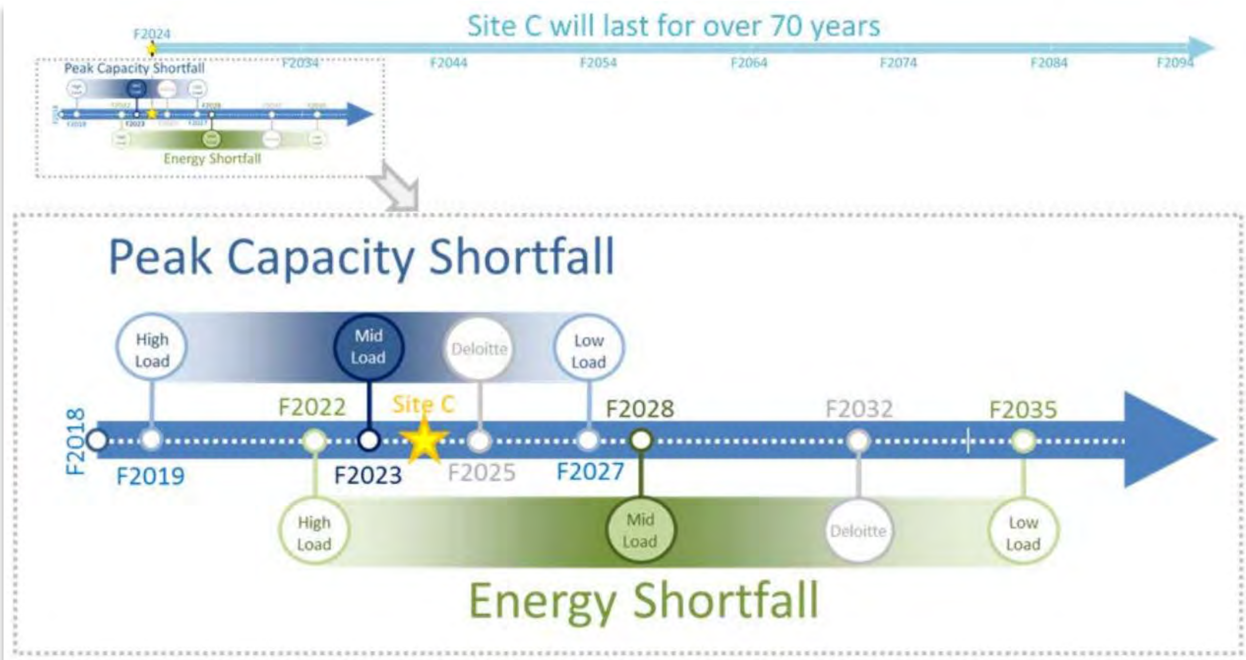
[314] BC Hydro Integrated Resource Plan: Meeting BC's Future Electricity Needs (2013 IRP), dated November 2013, Chapter 2: Load-Resource Balance, retrieved from https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0002-nov-2013-irp-chap-2.pdf.
[315] Submission F26-1, Ruskin, V. (Ruskin); Submission F26-2, Ruskin; Submission F26-3, Ruskin.
[316] Submission F1-1, BC Hydro, p. 3.
[317] Submission F26-7, Ruskin, Attachment 1, p. 4; Submission F26-8, Ruskin.
[318] Submission F1-6, BC Hydro, IR 2.21.

BC Hydro submits that both Deloitte's and its own load scenarios demonstrate a future need for capacity and energy and that it is only a questions of when, not if, there is a need for the electricity. BC Hydro also points to the Joint Review Panel's observation that "[t]he timing of need is necessarily uncertain." BC Hydro forecasts a need for new capacity by F2023 and for new energy in F2028. Under its low load scenario, BC Hydro submits capacity is still needed by F2027, and under its high load scenario, capacity is needed by F2019. BC Hydro depicts this in Figure 15:[319]

Figure 15: Timing of Energy and Peak Capacity Shortfall (Without Site C and Without Electrification)[320]



However, BC Hydro notes that the figure above does not reflect low carbon electrification initiatives, which are not yet reflected in BC Hydro's Current Load Forecast. These initiatives would advance each of the low, mid and high load scenario dates for new supply. [321]

In response to a supplemental question from the Panel, BC Hydro added Revelstoke 6 into the planned energy and capacity supply. With Revelstoke 6 included (Site C excluded), the energy and capacity load resource balances are provided below:[322]

[319] Submission F1-12, BC Hydro, p. 8.
[320] Submission F1-12, BC Hydro, p. 8.
[321] Submission F1-12, BC Hydro, p. 8.
[322] Submission F1-20, BC Hydro, Supplemental IR 2.21.1, Attachment 1, Tables K1-a, K2-a.

Table 7: Energy Load Resource Balance after Planned Resources without Site C

Table K-1a: Energy Load Resource Balance after Planned Resources without Site C

(GWh)		F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																				
Heritage Resources (excluding Site C)	(a)	46,895	46,014	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491	48,491
Existing and Committed IPP Resources	(b)	14,592	14,337	14,364	14,097	13,782	13,547	13,210	12,814	12,414	12,307	11,983	11,467	10,720	10,259	10,203	10,163	10,015	9,476	8,295
Planned Supply-Side Resources																				
IPP Renewals		280	571	647	779	936	1,114	1,349	1,628	1,951	2,032	2,223	2,617	3,328	3,788	3,828	3,863	4,011	4,549	5,515
Standing Offer Program		130	291	419	546	674	801	929	1,056	1,184	1,311	1,439	1,566	1,694	1,821	1,949	2,076	2,204	2,320	2,448
Revelstoke Unit 6		0	0	0	0	0	0	0	0	0	26	26	26	26	26	26	26	26	26	26
Sub-total	(c)	410	862	1,066	1,325	1,609	1,916	2,278	2,684	3,135	3,370	3,688	4,209	5,048	5,635	5,803	5,966	6,241	6,895	7,988
Total Supply (Operational View) **	(d) = a + b + c	61,897	61,213	63,922	63,913	63,883	63,954	63,979	63,989	64,041	64,168	64,163	64,167	64,259	64,386	64,497	64,620	64,747	64,863	64,774
Demand - Integrated System Total Gross Requirements																				
2016 May Mid Load Forecast Before DSM*		-59,013	-60,413	-61,371	-62,309	-63,675	-64,836	-66,008	-67,109	-68,310	-69,267	-70,256	-71,222	-72,296	-73,374	-74,535	-75,462	-76,393	-77,215	-78,089
Expected LNG Load***		-148	-148	-252	-1,265	-2,299	-2,721	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848	-2,848
Sub-total	(e)	-59,162	-60,561	-61,624	-63,574	-65,974	-67,557	-68,856	-69,957	-71,158	-72,115	-73,104	-74,070	-75,144	-76,222	-77,383	-78,310	-79,241	-80,063	-80,937
Existing and Committed Demand Side Management & Others Measures																				
SMI Theft Reduction		83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83	83
Voltage and VAR Optimization		152	171	188	219	240	254	259	263	268	285	290	295	300	305	310	315	320	325	331
2016 DSM Plan F16 savings		970	939	940	935	926	923	917	912	885	863	855	848	844	807	770	760	758	757	736
Planned Demand Side Management Measures																				
2016 DSM Plan F17 to F19 savings		988	1,679	1,896	1,931	1,969	1,956	1,935	1,917	1,908	1,896	1,853	1,787	1,694	1,613	1,547	1,462	1,300	1,224	1,190
2016 DSM Plan F20+ savings		0	0	292	904	1,454	1,897	2,310	2,637	2,946	3,229	3,500	3,758	4,006	4,248	4,473	4,690	4,908	5,116	4,976
Sub-total	(f)	2,192	2,873	3,399	4,072	4,672	5,112	5,502	5,811	6,089	6,356	6,581	6,770	6,927	7,055	7,183	7,310	7,368	7,505	7,317
		F2018	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) (Operational View) **	(g) = d + e + f	**4,928**	**3,524**	**5,697**	**4,411**	**2,582**	**1,509**	**626**	**-157**	**-1,029**	**-1,591**	**-2,360**	**-3,132**	**-3,958**	**-4,780**	**-5,703**	**-6,379**	**-7,126**	**-7,696**	**-8,846**
Surplus / Deficit as % of Net Load (Planning View) **		**115%**	**115%**	**114%**	**111%**	**108%**	**106%**	**104%**	**103%**	**101%**	**101%**	**99%**	**98%**	**97%**	**96%**	**95%**	**94%**	**93%**	**92%**	**90%**
Small Gap Surplus/(Deficit) (Operational View) **		7,487	6,536	9,087	8,279	6,967	6,275	5,665	5,184	4,607	4,254	3,731	3,220	2,660	2,064	1,480	1,060	493	-24	-1,045
Large Gap Surplus/(Deficit) (Operational View) **		2,036	*-70*	1,293	*-601*	*-3,171*	*-5,130*	*-6,378*	*-7,533*	*-8,792*	*-9,517*	*-10,614*	*-11,768*	*-13,062*	*-14,158*	*-15,375*	*-16,318*	*-17,346*	*-18,333*	*-19,833*

* 2016 Integrated System Load Forecast with losses
** For a description of Operational versus Planning view please refer to section 3.4.2 of BC Hydro's F2017-F2019 Revenue Requirements Application.
*** Including losses.

Table 8: Capacity Load Resource Balance after Planned Resources without Site C

Table K-2a: Capacity Load Resource Balance after Planned Resources without Site C

(MW)		F2018	F2019	F2020	F2021	F2022	F2023	F2024	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034	F2035	F2036
Existing and Committed Heritage Resources																				
Heritage Resources (excluding Site C)	(a)	11,410	11,416	11,416	11,416	11,480	11,480	11,480	11,066	11,066	11,066	11,066	11,066	11,066	11,480	11,480	11,480	11,480	11,480	11,480
Existing and Committed IPP Resources	(b)	1,673	1,621	1,572	1,490	1,461	1,167	1,132	1,069	1,025	1,025	975	938	806	806	802	796	771	747	683
Planned Supply-Side Resources																				
IPP Renewals		23	55	79	120	135	419	441	450	486	488	514	538	671	671	674	680	705	862	901
Standing Offer Program		18	24	31	39	46	53	61	68	76	83	91	98	106	113	120	128	135	142	150
Revelstoke Unit 6		0	0	0	0	0	0	0	0	0	488	488	488	488	488	488	488	488	488	488
Sub-total	(c)	41	78	110	159	181	472	502	519	562	1,057	1,092	1,124	1,264	1,272	1,283	1,296	1,328	1,492	1,539
Total Supply	(d) = a + b + c	13,124	13,115	13,098	13,065	13,122	13,120	13,113	12,854	12,652	13,148	13,134	13,128	13,136	13,557	13,564	13,572	13,579	13,719	13,702
14% of Supply Requiring Reserves***	(e)	-1,809	-1,808	-1,805	-1,801	-1,809	-1,808	-1,807	-1,750	-1,750	-1,819	-1,817	-1,817	-1,818	-1,877	-1,878	-1,879	-1,880	-1,899	-1,897
Effective Load Carrying Capability	(f) = d + e	11,315	11,307	11,293	11,264	11,313	11,311	11,306	10,904	10,902	11,328	11,316	11,312	11,318	11,681	11,687	11,693	11,699	11,820	11,805
Demand - Integrated System Peak																				
2016 May Mid Load Forecast Before DSM*		-11,021	-11,209	-11,374	-11,541	-11,737	-11,930	-12,119	-12,313	-12,515	-12,708	-12,943	-13,155	-13,386	-13,614	-13,840	-14,074	-14,303	-14,542	-14,774
Expected LNG Load****		-19	-19	-72	-222	-329	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361	-361
Sub-total	(g)	-11,039	-11,228	-11,447	-11,763	-12,066	-12,291	-12,480	-12,674	-12,876	-13,069	-13,304	-13,516	-13,747	-13,975	-14,201	-14,435	-14,664	-14,903	-15,135
Existing and Committed Demand Side Management & Others Measures																				
SMI Theft Reduction		11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Voltage and VAR Optimization		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2016 DSM Plan F16 savings		214	210	211	210	207	204	201	198	193	189	185	183	180	174	168	165	165	165	162
Planned Demand Side Management Measures																				
2016 DSM Plan F17 to F19 savings		167	272	310	314	316	311	305	299	295	290	282	272	259	247	237	225	207	198	195
2016 DSM Plan F20+ savings		0	0	47	170	285	358	421	468	514	554	593	629	663	696	725	753	788	822	808
Sub-total	(h)	392	494	578	706	818	884	938	977	1,013	1,045	1,072	1,095	1,114	1,128	1,142	1,154	1,171	1,196	1,176
Small Gap Surplus/(Deficit) (Operational View) **		**F2018**	**F2019**	**F2020**	**F2021**	**F2022**	**F2023**	**F2024**	**F2025**	**F2026**	**F2027**	**F2028**	**F2029**	**F2030**	**F2031**	**F2032**	**F2033**	**F2034**	**F2035**	**F2036**
Surplus / (Deficit) **	(i) = f + g + h	**668**	**573**	**424**	**206**	**65**	**-96**	**-236**	**-794**	**-561**	**-696**	**-915**	**-1,109**	**-1,315**	**-1,167**	**-1,373**	**-1,587**	**-1,793**	**-1,887**	**-2,154**
Small Gap Surplus / (Deficit) **		1,136	1,121	1,041	908	856	765	675	174	61	369	203	63	-88	108	-32	-189	-356	-390	-591
Large Gap Surplus / (Deficit) **		118	-105	-403	-737	-1,013	-1,334	-1,536	-2,159	-2,393	-2,157	-2,440	-2,705	-2,999	-2,902	-3,162	-3,430	-3,696	-3,856	-4,175

* 2016 Integrated System Load Forecast with losses
** Planning View is shown in this table. Capacity load resource balances are only shown in Planning View. See section 3.4.2 of BC Hydro's F2017-F2019 Revenue Requirements Application
*** This is also referred to as the Planning Reserve - the system generating capacity beyond that required to meet peak demand that is necessary to meet reliability criteria. See section 1.2.2 of the 2013 Integrated Resource Plan for more details on the criteria
**** Including losses.

4.2.4 Panel analysis and findings

BC Hydro defines Revelstoke 6 as a planned resource. **Accordingly, the Panels finds it appropriate to include Revelstoke 6 as a planned resource in determining the energy and capacity load resource balances after planned resources without Site C** . Excluding Revelstoke 6 gives the impression that there are larger and/or earlier needs for additional capacity and energy resources than would otherwise be needed without Site C. The Panel notes that Revelstoke 6 is an exempt project under the *Clean Energy Act*.

With respect to Ruskin's submissions, the CEA defines heritage energy capability as "the maximum amount of annual energy that the heritage assets that are hydroelectric facilities can produce under <u>prescribed water conditions</u>" [Emphasis added]. Pursuant to section 35 of the CEA, the Lieutenant Governor in Council may make regulations prescribing water conditions for the purposes of the definition of "heritage energy capability." After OIC 36 replaced "critical water conditions" with "average water conditions," which are defined as "the average stream flows occurring within the authority's historical record," the water conditions prescribed for the purposes of heritage energy capability became the average water conditions, and, consistent with this definition, BC Hydro is relying on this amount of energy for energy planning purposes.

Based on the above analysis, the Panel finds the capacity and energy load resource balances provided in Tables K1-a and Table K1-b in IR 2.21.0 (submission F1-6) contain the appropriate information to determine the capacity and energy gaps or the load resources balance which will need to be supplied by either Site C or an alternative portfolio.

4.3 Value of surplus energy and capacity

Once Site C is in operation there is potential for surplus energy and capacity. The Panel addresses some of the options to handle any unplanned surplus of energy and capacity as well as expectations for the pricing of any such surpluses at this time that BC Hydro is exploring. For clarification, energy refers to the total amount of electricity that the utility supplies throughout the year and is usually measured for all customers in GWh, and capacity is the maximum output, commonly expressed in MW that generating equipment can supply to system load, adjusted for ambient conditions. Peak demand is the maximum load during a specified period of time and is also measured in MW.

The Panel will address the issue of Site C flexibility in section 6.3.

4.3.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submissions

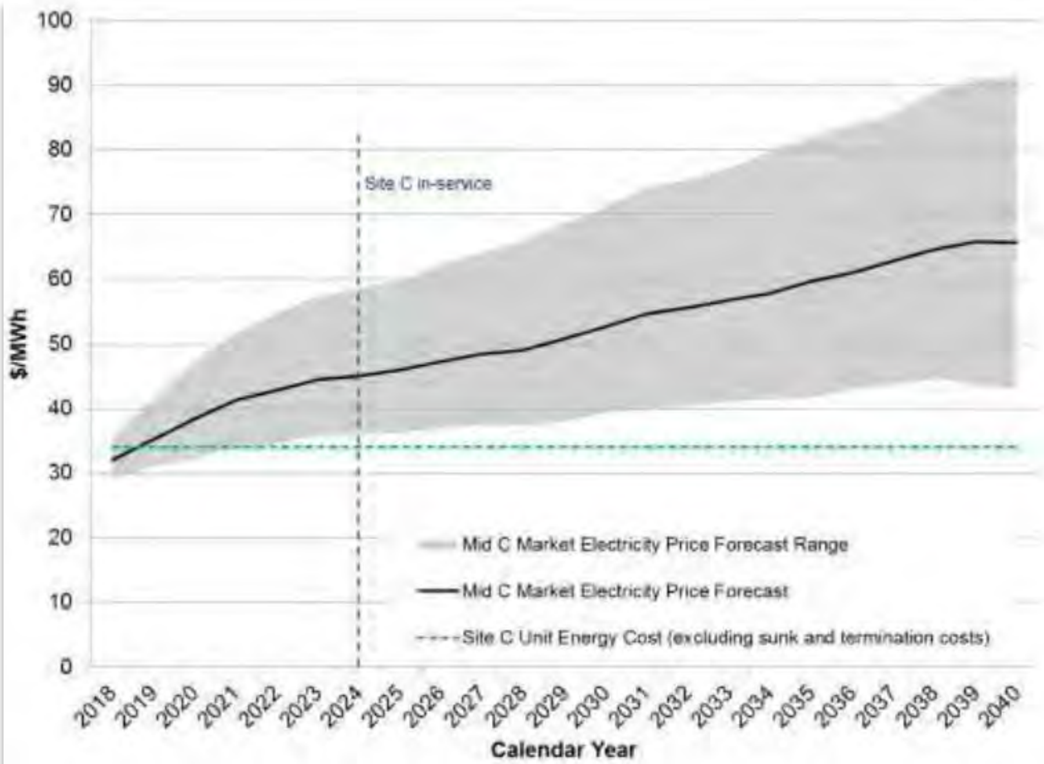
BC Hydro acknowledges the extensive lead times associated with new generation additions combined with challenges related to forecasting demand years into the future could potentially result in Site C not being immediately needed to serve domestic load when it comes on line. In these circumstances surplus energy could be sold in the short-term wholesale energy markets outside of BC to mitigate the associated costs.[323]

BC Hydro asserts that its unit energy cost analysis demonstrates there is potential to profit from a short-term surplus. Figure 16 shows BC Hydro's market electricity price forecast[324] in comparison to its estimate of the incremental cost for completion of Site C "net of sunk costs and the termination and remediation credit

[323] Submission F1-1, BC Hydro, Appendix S, pp. 1–3.
[324] Based on BC Hydro's response to IR 2.22.1 (Submission F1-8, IR 2.22.1, p. 8), it appears this is the ABB 2016 Mid C Price Forecast.

at a unit energy cost of $34/MWh." Based on these market price estimates, BC Hydro states that if Site C temporarily had surplus energy it could be sold at a profit enhancing the case for completing Site C.

Figure 16: Comparison of Site C Energy Cost to Mid C Market Electricity Price (F2018$/MWh) [325]



BC Hydro estimates prices for 2024 to 2030 short-term energy sales to be in the CAD $48/MWh range. BC Hydro explains that electricity markets are currently over built but are returning to a more balanced position, but acknowledges this recovery may take some time as clean energy subsidies and Renewable Portfolio Standards continue to create a surplus in the market. This scenario is represented by the lower band of the price curve as outlined in Figure 16. BC Hydro reports that a sensitivity run on this lower band shows the value of its portfolio with a completed Site C relative to termination would decrease by $0.2 billion but would still retain a $7.1 billion benefit.[326]

Deloitte report

Deloitte reports a higher wholesale price of energy outlook than BC Hydro and states the annual average price of energy will rise from $45/MWh in 2018 to $94/MWh in 2036. Deloitte asserts that this projection is a function of assumptions and what actually occurs may differ from this projection and "care must be taken to understand that assumptions as well as approaches, methodologies, and other differences can account for a wide variation in forecasts."[327] The information relied upon for this scenario is based upon a set of three cases used by FortisBC Inc. (FBC) as part of its 2016 Long Term Electric Resource Plan (LTERP). The assumed Mid C market prices in this scenario are generally between the high and base cases utilized by FBC in its LTERP, reflecting estimates to purchase energy in the market (rather than sell it) and including adders for transmission costs and delivery losses.[328]

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[325] Submission F1-1, BC Hydro, p. 64.
[326] Submission F1-1, BC Hydro, p. 104.
[327] Submission A-9, p.109.
[328] Submission A-9, p. 116. FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan and Long Term Demand Side Management Plan Application, Exhibit B-1.

Other Submissions

Allied Hydro Council of British Columbia

The Allied Hydro Council of British Columbia (AHC) generally agrees with BC Hydro, stating that the availability of surplus power could be a benefit rather than a negative factor and noting that with Alberta taking a policy position to phase out coal-fired power soon, the feasibility of a new transmission line from Site C to Alberta has been discussed. AHC also raises the possibility of an opportunity for power exports to Alaska as it has minimal power generation but the state is not connected to the North American grid. The Northwest Transmission Line runs close to the Alaska border and there is a potential for the two systems to be connected.

Program of Water Governance

With reference to the Mid C price forecast provided by BC Hydro in the F2017–F2019 RRA proceeding, Dr. Karen Bakker (Bakker), co-director of the Program on Water Governance (PoWG) at the University of British Columbia, makes the following observations:

> In reality there is considerable uncertainty respecting the potential value of surplus energy sales from the Site C Project. Specifically, these forecasts are very sensitive to the future evolution of the USD/CAD exchange rate, to electricity prices, to natural gas prices, and to carbon prices, among other factors.

Bakker recommends BC Hydro use a Monte Carlo simulation approach to ensure the risk is captured for future exchange rate variations as well as for electricity and natural gas prices.[329]

Clean Energy Association of British Columbia

CEABC asserts that the majority of energy exports are likely to be during off-peak periods when demand for BC electricity is low. Off-peak Mid C futures prices in 2024 are approximately $26/MWh and are expected to increase to about $27/MWh in 2025 and $28/MWh in 2026.

CEABC also notes that there are constraints to capacity sales revenue, stating “that amount of capacity can’t be sold to the neighbouring jurisdictions because there isn’t enough capacity in the transmission system to deliver it.”[330]

BC Hydro in its 2013 IRP also comments on transmission constraints pointing out that:

> Current transmission lines are fully subscribed by firm transmission rights holders. Furthermore, the availability of non-firm transmission capacity has been dwindling due to increasing competition from power producers.[331]

4.3.2 Panel analysis, preliminary findings and questions in the Preliminary Report

BC Hydro outlined how it may handle surplus energy and capacity in the event it is not required when Site C is online and appears confident it has the ability to optimize the trade benefits through its subsidiary, Powerex.

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[329] Submission F106-2, PoWG, pp. 58–59.
[330] Submission F18-3, Clean Energy Association of BC (CEABC).
[331] BC Hydro 2013 IRP, dated November 2013, Chapter 5: Planning Environment, p. 5-47, retrieved from https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0005-nov-2013-irp-chap-5.pdf.

BC Hydro and Deloitte provided forecasts for Mid C market price estimates going forward through 2036. Noting that these estimates differed decidedly, the Panel found there was common agreement that there is always potential for projections to differ from what actually occurs. The Panel agreed and noted its concern as to the reliability of future forecasts, finding it premature to reach any conclusions on future surplus energy demand.

The Panel noted that both AHC and CEABC raised the issue of transmission of power to neighbouring jurisdictions, with CEABC questioning whether there is sufficient capacity remaining in the transmission system to deliver it. The Panel requested BC Hydro address whether there is a need for additional transmission capability to move surplus energy from Site C to other utilities.

The Panel also noted that BC Hydro made a number of statements with respect to the potential for export sales in the 2012 Draft IRP including the following: “the prospects of export sales of renewable energy in excess of that required to meet self-sufficiency requirements have diminished considerably.” BC Hydro cited a number of reasons for this situation which it did not expect to materially improve over the short term. The Panel requested that BC Hydro update this information and provide an explanation as to the impact these issues could have on export sales.

In addition to the specified information requests, the Panel asked a number of questions concerning BC Hydro’s submissions on market price forecasts. These covered a range of topics including:

- Details of BC Hydro’s market price forecast for F2025 and F2034;
- Mid C pricing over the past 20 years and the $/MWh price BC Hydro received in the most recent years;
- Description of the energy and capacity markets in the US and Alberta where BC Hydro expects to participate;
- Details on the transmission lines to the US and Alberta (maximum rating for exports, firm and non-firm transmission capacity generally available and percentage of the time the transmission line is on average constrained); and
- Potential for the sale of Site C surplus energy and capacity within BC.

4.3.3 Additional submissions and responses

BC Hydro submission

BC Hydro provided Table 9 in response to IR 2.22.1, which shows its ABB Spring 2016 Mid C market price forecast for calendar year 2025 and 2034 in Canadian and US dollars converted to BC Buy and BC Sell prices.

Table 9: ABB Spring 2016 MID C Price Forecast, converted to B.C. Buy and B.C. Sell Prices

	Mid C 2016 USD/MWh			Mid C 2016 CAD/MWh			Losses (1.9%) 2016 CAD/MWh			Wheeling 2016 CAD/MWh	B.C. Buy 2017 CAD/MWh			B.C. Sell 2017 CAD/MWh		
Calendar Year	On Peak	Off Peak	Average	On Peak	Off Peak	Average	On Peak	Off Peak	Average	-	On Peak	Off Peak	Average	On Peak	Off Peak	Average
2025	36.46	35.76	36.16	45.70	44.82	45.32	0.87	0.85	0.86	6.28	53.58	52.68	53.20	39.09	38.22	38.72
2034	45.53	45.41	45.47	57.06	56.91	56.99	1.08	1.08	1.08	6.28	65.32	65.17	65.26	50.39	50.24	50.33

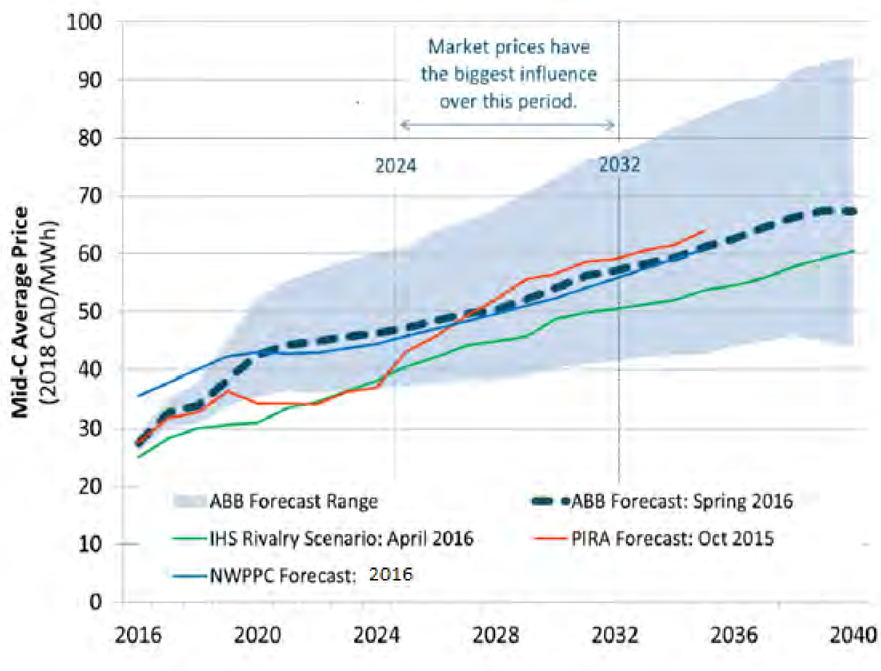
Exchange rate assumption: ***Rates based on updates provided by the Treasury Board of the Province of B.C.-May 30, 2017. 1USD = 1.2533CAD***

Inflation assumption: ***CPI from Statistics Canada - updated 2017-01-20. CPI increase in 2016 = 1.4 per cent.***

BC Hydro reports that over the past five years the actual Mid C prices seem to reflect the estimated variable cost production of Combined Cycle Gas Turbines (CCGT) in most hours, but in cases like spring freshet and periods of high wind generation Mid C prices were below this level. BC Hydro subscribes to the ABB reference case database and explains that the market price is "determined from the ABB PROMOD model, which simulates the operation of each region in North America in order to determine the market clearing price (MCP) at hundreds of locations (referred to as nodes) on an hourly time step." [332]

BC Hydro provided the following figure showing a comparison of Mid C Average Price Forecast:

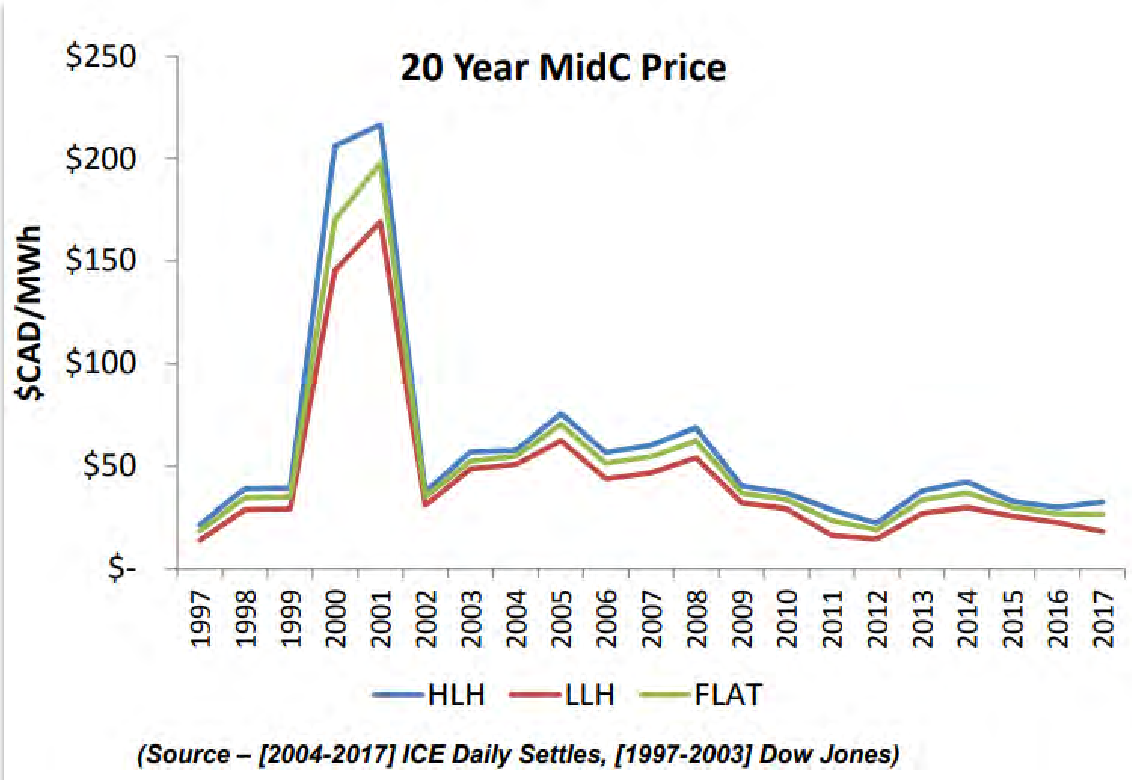
Figure 17: Mid C Average Price Forecast Comparison[333]



BC Hydro also provided a table detailing the average annual Mid C price for on-peak, off-peak and all hours for the past 20 years. This is illustrated in graphical form in Figure 18. This shows that after a period of moderately high prices from 2003 through 2008, there was a significant drop in prices for the period covering 2009 to the present with on-peak prices in the low $30 range for 2015 through 2017.[334]

[332] Submission F1-8, BC Hydro, IR 2.22.1, pp. 7–10.
[333] Submission F1-17, BC Hydro, p. 23 as adjusted per BC Hydro to correct the date of the NWPP forecast from 2017 to 2016.
[334] Submission F1-17, BC Hydro, IR 2.22.2.

Figure 18: Average Annual Mid C Price – On-Peak, Off-Peak and All Hours



With reference to the F2013 to F2017 $/MWh prices received after transaction costs, BC Hydro stated that they may not be directly comparable to the value they may receive with the addition of Site C. BC Hydro explained that this is because surplus energy sales were impacted by the inclusion of "substantial amounts of surplus sales due to generation resources with limited flexibility and/or storage. Site C generation, by contrast, benefits from the upstream storage of Williston reservoir and surplus Site C energy could be stored for sale in more valuable hours."[335]

Regarding transmission constraints, BC Hydro asserted that any concerns are unfounded; stating that the BC to US export path is 3,159 MW and the rating of the BC to Alberta path is 1,200 MW. While the operational export capability is below these amounts, the combined operational export capability is well above the amount necessary to support a large volume of surplus energy. BC Hydro further stated that even in a very high water year, existing transmission capability is sufficient to allow Powerex to export 9,000 GWh out of its system during the higher-priced 50 percent of the hours. Additionally, Powerex has in place long term US transmission agreements for, 2,500 MW of transmission rights between the Pacific Northwest and California.[336]

In response to BCUC IR 3.14.0, BC Hydro stated that existing capacity of interties to the US and Alberta is sufficient to move surplus energy from Site C to those markets and Site C energy can be scheduled into high value periods and avoid transmission constraints that occur periodically.[337]

BC Hydro was asked to comment on whether it had analyzed selling Site C surplus energy and capacity within the province of BC at rates designed to incent incremental consumption. In response, BC Hydro referred to the recently approved pilot industrial freshet rate which offered industrial customers access to

[335] Submission F1-8, BC Hydro, IR 2.22.3
[336] Submission F1-8, BC Hydro, IR 2.22.1, pp. 5–6.
[337] Submission F1-16, BC Hydro, IR 3.14.0.

market prices for surplus energy for incremental purchases during the spring freshet. While its preliminary evaluation of this recently introduced program indicated success with respect to customer participation, incremental energy sales and positive ratepayer impact, "a key concern with surplus rates is accurately determining the surplus, or incremental consumption." BC Hydro continues to assess this issue and notes that if it were to pursue "any other such surplus rates, revenues earned would be similar to the modelled market recoveries and would not impact the analysis although this may have ancillary economic development benefits for B.C."[338]

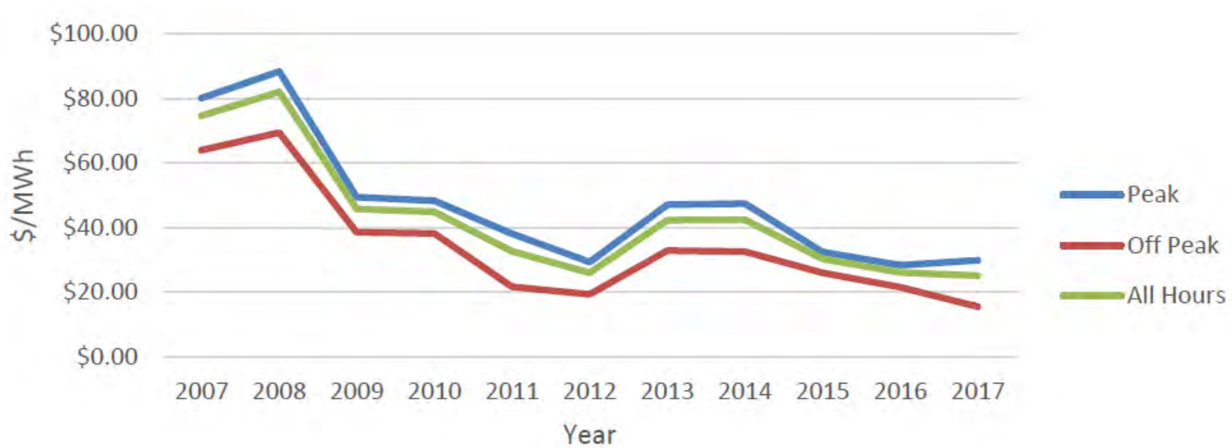
McCullough

McCullough disagrees with BC Hydro's assessment of the Mid C market price forecast stating that "it is a relatively poor forecast since it diverges from actual market prices."[339] McCullough submits that the 2025 Mid-C forward market price is US $30.51/MWh.[340]

BC Hydro takes issue with the assertion that electricity is being purchased seven years out, as claimed by McCullough, stating that it is common to purchase power three years out with purchases four and five year out being sporadic with no evidence that electricity is being purchased seven years out. In addition, BC Hydro questions the validity of taking a snapshot of the forward curve (real short term transactions to lock in price) on a particular day and comparing this against a market forecast done back in time. A snapshot taken six months from now might look completely different and depending on external circumstances like weather and spot prices might move up or down depending on these circumstances.[341]

Regarding participation in energy and capacity markets in the US and Alberta, McCullough states that the vast majority of BC Hydro's export market is in the US and for nearly a decade market prices have undergone a steady decline. He states that he expects these prices will continue to decline as more renewable sources come online. The Mid-C average peak, off-peak and all hours prices by year are provided in Figure 19.

Figure 19: Mid-C (Can$/MWh) Average Peak, Off-peak and All Hours Prices by year[342]



Noting that the nominal value of BC's electricity exports to the US fell by 21 percent from July 2016 to July 2017, McCullough is of the view that BC Hydro will have difficulty making a profit through sales of electricity from projects like Site C. From the perspective of capacity sales, he asserts that Powerex reported only one capacity transaction at Mid C and that was at a price that was de minimis. According to McCullough, exports

[338] Submission F1-8, BC Hydro, IR 2.22.13.
[339] Submission F35-7, PVLA and PVEA, p. 2.
[340] Submission F35-6, PVLA and PVEA, p. 2.
[341] TTP-2, October 14, 2017, Vancouver, pp. 1657–1658.
[342] Submission F1-8, BC Hydro, IR 22.2.

to Alberta are negligible and even if the market is favourable, a shift in the status quo would need to take place in order for interprovincial trade to be comparable with trade to the US.[343]

Clean Energy Association of British Columbia

CEABC states that price expectations for surplus energy are optimistic. CEABC takes BC Hydro's estimates of lost sales revenue from 2025 through 2029 if Site C were terminated, as a function of the projected surplus energy available for sale. This allows for the calculation of an implied price for these sales ranging between approximately $64 and $102. CEABC observes that these amounts seem high given the extra GWh/year because of Site C and a considerable portion of Site C's production must occur during spring freshet.[344]

BC Hydro states that it has no expectation that it will be limited by transmission capacity in its ability to export any surplus. It further explains that the operational capacity of export lines from BC to Alberta and the US allows approximately 26,000 gigawatt hours of annual surplus to be exported while Site C's annual energy averages 5,286 gigawatt hours.

Other Submissions

Numerous other parties offered their thoughts with regard to the handling of surplus and the efficacy of BC Hydro's Mid C market price forecasts. Most of these questioned the Mid C market forecast was prepared by BC Hydro. However, none of these submissions provided any specific analysis shedding any additional light on why these forecasts are either reasonable or unreasonable.

4.3.4 Panel analysis and findings

The Preliminary Report outlined and discussed BC Hydro's expectations for the handling and sale of surplus energy from Site C. From the outset, BC Hydro has and continues to be optimistic that in the event of a surplus it will be able to cost effectively transfer it out of the province to customers in Alberta or in the US. In providing its analysis and findings on this issue, the Panel considers surplus energy sales and the potential for the sale of capacity and/or flexibility sale options to be distinct and decidedly different, and will therefore discuss each in turn. This section addresses surplus energy sales. The value of Site C's flexibility is addressed in Section 6.3.

As outlined in Figure 16, BC Hydro has taken an optimistic view regarding the potential for energy market sales prices with its Mid C market electricity forecast, which shows steady growth in prices from 2018 onward through 2040, peaking in the $60 MWh range in 2040. In addition to this forecast BC Hydro has also provided its estimate of the Mid C market price range which could occur over this period. This range is quite wide and encompasses a low end option with limited price growth and a high-end option where Mid C prices would grow at an accelerated pace over the next 22 years. McCullough takes exception to BC Hydro's Mid C market price estimate characterizing it as a poor forecast as it diverges from actual market prices. McCullough asserts that prices have been in decline for the past decade, a trend that is expected to continue.

The Panel notes that BC Hydro has not disputed McCullough's characterization of current market prices. They are quite low and in the near future they are likely to stay low. However, the issue is not what prices are today or even what they will be in two or three years. What is at issue is what market prices are likely to be in 2024 and beyond. The Panel is not persuaded that a reliance on a forward curve at a specific point in time is an accurate indicator of future long-term prices as postulated by McCullough.

[343] Submission F35-7, PVLA and PVEA, pp. 7–8.
[344] Submission F18-5, CEABC, p. 18.

What we do know is what spot prices are today as well as some of the market forces likely to be at play tomorrow. For instance, we know that the current price for electricity has been low for the past few years and it is anticipated it is unlikely to change in the short term. We also know that renewables such as wind and solar are increasingly coming on-stream in the Pacific Northwest and other export markets at increasingly lower prices and this has the potential to impact future market prices and be disruptive. Further, the Panel has made findings with regard to BC Hydro's load forecast which indicate that under the low load scenario, surplus energy may be available up to and including F2034.

With respect to export transmission capacity, the Panel finds there is insufficient evidence to support the concern that BC Hydro has inadequate transmission capacity to meet potential future export requirements.

Given the current low market prices and the likelihood of increasing supply, the Panel is persuaded that a conservative approach for the estimation of future market pricing is warranted and finds that BC Hydro's proposed Mid C forecast should not be relied upon. Accordingly, the Panel finds that for the purposes of this assessment the future market price for 2024 and beyond should be considered to be at a point mid-way between BC Hydro's proposed Mid C forecast and the low end of the ABB range.

In the following sections, the Panel addresses the implications of the three cases identified in the OIC terms of reference – completing the Site C project; terminating the Site C project and remediating the site; and suspending the Site C project. Within each of these sections the Panel also addresses the specific questions posed by the OIC for each of the cases.

5.0 Case 1 – Continue Site C

5.1 The question posed under the OIC

Section 3(a)(iii) of the OIC states that the Commission must advise on the implications of completing the Site C project by 2024, as currently planned.

Section 3(b)(i) asks: "After the commission has made an assessment of the authority's expenditures on the Site C project to date, is the commission of the view that the authority is, respecting the project, currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?"

5.2 Construction costs, including possible budget overruns

The OIC requests that the Panel assess whether the Site C project is "currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)."[345] For the purposes of the Preliminary Report, the Panel established that "currently" was to be interpreted as referring to the date of June 30, 2017, this being the date of BC Hydro's most recent quarter-end report. For this report, the Panel deems that "currently" shall be interpreted as September 30, 2017, since BC Hydro's responses to the Panel's questions from the Preliminary Report were received in early October, and refer to material events that took place in late September 2017.

The Panel has also considered, regardless of whether or not the project is currently on time and within the budget, what the eventual in-service date might be and what the final project costs might be. In the Panel's view, this is required for a meaningful comparison of the costs to ratepayers of the three alternatives presented in the OIC.

The Panel has first addressed the question of whether the project is on time, then subsequently whether the project is on budget. By choosing to address the question of the project schedule first, the Panel is able to explore more clearly the budget impacts of any possible delays to the project schedule.

5.2.1 Is the Site C project currently on time and what is the likelihood it will remain on schedule?

The Panel notes that there are two schedules for the Site C project that might be relevant to answering the question posed in the OIC. The Final Investment Decision (FID) schedule shows an in-service date of the final generation unit in November 2024.[346] BC Hydro also created an internal Performance Measurement Baseline (PMB) schedule, which was last updated in June 2016.[347] The PMB schedule shows an in-service date of the final generation unit in November 2023. BC Hydro is presently using the PMB schedule to "control, monitor, and report progress" on the Site C project.[348] Deloitte presents a comparison between the two schedules:[349]

[345] OIC, section 3(b)(i).
[346] Submission F1-1, BC Hydro, p. 34.
[347] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 19.
[348] Ibid., p. 23.
[349] Ibid., p. 20.

Table 10: Key PMB Milestones Compared to FID Milestones

Milestone	FID Dec 2014	PMB Jun 2016	PMB Critical Milestone	Diff. (months)
Early Works				
Commence Dam Site Clearing	1-Aug-15	27-Jul-15		-
Worker Accommodation Operational	1-Mar-16	1-Mar-16		-
Main Civil Works				
Complete all Civil Work for Diversion	28-Feb-20	1-Mar-19		-12
Complete Testing of Diversion Gates (Dry)	10-May-19	1-Jun-19		1
Start River Diversion	1-Sep-20	1-Sep-19	✓	-12
Highway 29 Realignment				
Highway 29 in service	30-Sep-21	30-Sep-21		-
Transmission and Distribution				
5L5 500kV Transmission Line in service	16-Oct-20	22-Nov-19		-11
5L6 500kV Transmission Line in service	10-Jul-23	25-Aug-22		-10
Site C Substation in service	3-Nov-20	10-Dec-19		-11
Turbines and Generators				
Unit 1 in service	8-Dec-23	7-Dec-22	✓	-12
Unit 6 in service	25-Nov-24	24-Nov-23	✓	-12

However, the OIC specifically asks the Panel to consider the case where the Site C project is completed "by 2024, as currently planned."[350] The Panel takes this to mean that it is the FID schedule against which the schedule progress should be measured. The subsequent analysis therefore uses November 2024 as the final in-service date against which to determine whether or not the project is on schedule.

The Panel will also assess the likelihood of remaining on schedule by looking at the current risks to the schedule, taking into account the prior experience of BC Hydro in managing large projects, and the experience of others in building large hydropower dams.

5.2.1.1 Key submissions and issues raised in the Preliminary Report

For the Preliminary Report, the Panel reviewed BC Hydro's submission and the independent report prepared by Deloitte to assess whether the project is currently on schedule.

BC Hydro submission

BC Hydro asserted that the project is currently on schedule, and that "the November 2024 in-service date is not at risk."[351] BC Hydro also stated that the individual in-service dates of the transmission lines, sub-stations and generating units were all "on track":[352]

Table 11: Project In-Service Dates

Description/ Status	Final Investment Decision Planned ISD[26]	Status
5L5 500 kV Transmission Line	October 2020	On Track
Site C Substation	November 2020	On Track
5L6 500 kV Transmission Line	July 2023	On Track
Generating Unit 1 (First Power)	December 2023	On Track
Generating Unit 6 (Final Unit)	November 2024	On Track

[350] OIC, section 3(a)(i).
[351] Ibid., p. 34.
[352] Ibid.

In support of the claim that the project is on schedule, BC Hydro provides a summary of the interim milestones it has completed to date:[353]

Table 12: Completed Interim Milestones

Description/ Status	Final Investment Decision Plan Date	Completed
Site Prep, North Bank Complete	February 2016	October 2016
Peace River Temporary Bridge Complete	May 2016	March 2016
Worker Accommodation – Phase 3	July 2016	August 2016
Main Civil Works – Commence Mobilization to Site	September 2016	March 2016
Main Civil Works – Commence North Bank Excavations	January 2017	June 2016
Main Civil Works – South Bank Stage 1 Cofferdam Complete	May 2018	April 2017
Main Civil Works – Powerhouse Excavation Complete	April 2018	July 2017

BC Hydro stated that by February 2017, it had recovered the three months of slippage that occurred as a result of the main civil works contract delays in 2016.[354] However, it noted that challenges with the main civil works contract on the left bank were "currently forecast to result in the use of 3 months of float for this component of the work."[355] BC Hydro stated that it had identified opportunities to recover this schedule float.

BC Hydro provided a summary of the major project work components and their current status:[356]

Table 13: Work Component Status

Work Component	Status	Notes
Early Works	Complete	
Worker Accommodation	Construction Complete Operations on track	Camp is in operation
Main Civil Works	Managing construction challenges and claims (see below)	Schedule and cost pressures identified
Turbine-Generator	On track	Contract awarded
Transmission and Substation	Schedule on track; Procurements underway	Cost pressures being monitored
Highway 29 Realignment	Procurements on hold (see below)	Schedule mitigation under investigation
Generating Station and Spillways	Procurements underway	Impact of Main Civil Works delays being monitored; Potential cost pressures

BC Hydro reported that a 400-metre tension crack had appeared on the left bank of the dam site in February 2017, which temporarily stopped some construction activities, although the issues had since been resolved.[357] BC Hydro then went on to report that another tension crack had been observed on the same

[353] Ibid.
[354] Submission F1-1, BC Hydro, pp. 36–37.
[355] Submission F1-1, BC Hydro, p. 37.
[356] Submission F1-1, BC Hydro, pp. 36–37.
[357] Submission F1-1, BC Hydro, pp. 36–37.

bank in May 2017, but that it had identified opportunities to "recover the schedule and maintain the overall project schedule for diversion in 2019." Deloitte noted that Peace River Hydro Partners (PRHP), the main civil works contractor, had made slow progress in its excavation of the left bank, and added that according to PRHP's latest schedule revisions "the Start of River Diversion milestone would not be achieved in 2019 as planned."[358] According to Deloitte, BC Hydro had not accepted this revised schedule and expected that some months of lost schedule could be regained through re-sequencing of work and acceleration measures, but despite this Deloitte concluded that "PRHP's ability to meet the critical milestones poses a major risk to the Project."[359]

BC Hydro also noted that "progress in 2017 on the right bank associated with preparation for placement of specialized concrete and the Right Bank Drainage Tunnel works has started to fall behind schedule,"[360] and this had the potential to impact the work of the Generating Station & Spillways Contractor. However, the effects on the project schedule were not quantified, nor was there any indication of whether this work was on the critical path for the river diversion or the overall project. Deloitte observed that PRHP had also made slow progress in its excavation of the right bank, but did not quantify the effect on the project schedule of these delays.

According to BC Hydro, on August 11, 2017, Petrowest Corporation, a 25 percent partner in PRHP, "announced that it received a notice of termination"[361] from one of the two other partners, ACCIONA, and Petrowest was subsequently "placed into receivership on August 15, 2017." BC Hydro stated that this was "not expected to affect BC Hydro or construction of Site C in any major way," since "BC Hydro's contract is with the partnership; the contractor's equipment on site is owned by the partnership; and the labour agreements for on-site workers are with the partnership, not Petrowest." BC Hydro had one contract directly with Petrowest which it has since engaged an alternate contractor to perform. However, Deloitte was of the view that the termination of Petrowest from the partnership "will create a period of instability that may impact PRHP's ability to meet its planned work schedule in the short to medium term,"[362] although Deloitte does not quantify the possible impacts to the schedule specifically as a result of this period of instability.

BC Hydro described its work to realign six segments of Highway 29, which connects Hudson's Hope to Fort St. John,[363] to avoid flooding by the Site C reservoir. This work was scheduled to commence in summer 2017, in anticipation of the river diversion in fall 2019, but in June 2017, BC Hydro was requested to "delay the start of this work to allow further discussions with local property owners and consultation with Aboriginal Groups." This postponement would have risked delaying the river diversion. However, the Ministry of Transportation and Infrastructure, under whose jurisdiction the road lies, had since advised that they were "willing to discuss the implementation of mitigation measures that would manage the risk of flooding while allowing River Diversion to continue."[364] BC Hydro stated that this development would allow the river diversion to proceed despite the postponement of highway work.

Deloitte Report

Deloitte stated that "today the Project remains on time,"[365] and identified the start of the river diversion, planned for September 2019 in the PMB schedule and September 2020 in the FID schedule, as a critical milestone on the way to achieving the overall in-service date. Deloitte added that should BC Hydro not

358 Submission A-8, p. 37.
359 Ibid., p. 37.
360 Submission F1-1, BC Hydro, pp. 37–38.
361 Submission F1-1, BC Hydro, p. 38.
362 Submission A-8, p. 38.
363 Submission F1-1, BC Hydro, p. 38.
364 Submission F1-1, BC Hydro, p. 38.
365 Submission A-8, Deloitte LLP independent report – Site C Construction Review, p.3.

achieve the start of the river diversion by September 2019, and the project subsequently delayed by one year, the in-service date of November 2024 could still be achieved.[366]

Deloitte further stated that, according to the more aggressive PMB schedule, there were three months of schedule contingency between the end of the work required for the start of the river diversion and the start of the diversion in September 2019.[367] Despite challenges owing to the delayed start of work required prior to river diversion[368] and two tension cracks appearing on the left bank slopes, Deloitte assessed that the project was "still on track to meet the September 2019 diversion date, as well as the overall target completion date of 2023."[369]

Notwithstanding the above, Deloitte noted that the current progress report from BC Hydro is showing the three-month contingency prior to the start of the river diversion "will be consumed, putting the river diversion at risk."[370] Deloitte explained that the latest schedule update is showing three months of delay to work required prior to diversion, the same amount of schedule contingency in the PMB for crucial work pre-diversion.

In addition, Deloitte stated the most recent report from PRHP showed "completion of work related to diversion tunnels on March 30, 2020."[371] While it added that BC Hydro has not approved this updated schedule from PRHP, this schedule would result in "delaying the overall completion of the Project by 12 months to November 25, 2024."

Deloitte further cautioned that it "has not observed a clear method the Project utilizes to measure percent complete."[372] According to Deloitte, BC Hydro plans to implement earned value methodology (EVM) by December 2017[373] to assess the degree of completion of project activities. Deloitte added that this is "common practice" for large projects, and "if developed and executed properly"[374] provides an assessment of both current project status and future trends.

Other submissions and BC Hydro response

Ansar submitted an academic study published in 2013 addressing the question "Should we build more large dams? The actual costs of hydropower megaproject development."[375] In the cover letter to his submission, he states that he and his colleagues (i.e. co-authors) examined "a representative sample of 245 large dams (including 26 major dams) built between 1934 and 2007 on five continents in 65 different countries."[376] With respect to schedule slippage, Ansar observed that "Eight out of every 10 large dams suffered a schedule overrun" and that the "Actual implementation schedule was on average 44% (or 2.3 years) higher than the estimate with a median of 27% (or 1.7 years)." He added that "the evidence is overwhelming that implementation schedules are systematically biased towards underestimation," and "Large dams built everywhere take significantly longer than planners forecast," although "North America with a 27% mean schedule overrun is the best performer." Ansar concluded that "longer time horizons and increasing scale are underlying causes of risk in investments in large hydropower dams."[377]

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[366] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p.3.
[367] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 25, section 5.4.4.
[368] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p.23.
[369] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p.24.
[370] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 25, section 5.4.4.
[371] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 25.
[372] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 28.
[373] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 28.
[374] Submission A-8, Deloitte LLP independent report – Site C Construction Review, p. 22.
[375] Submission F64-1, Ansar, A. / Flyvbjerg, B. / Budzier, A. / Lunn, D. (Ansar).
[376] Submission F64-1, Ansar, p. 3.
[377] Submission F64-1, Ansar.

BC Hydro submitted that Ansar's study is flawed, since many of its data points are outside North America, and the conclusions are "heavily influenced"[378] by outliers. BC Hydro adds: "Only 40 of the projects in the article were located in North America, and only two were located in Canada (the report does not specify which two)." BC Hydro also notes that while the majority of projects studied by Ansar suffered schedule slippage, "the average length of time to construct a project was 8.6 years," adding that "this is just under BC Hydro's projected schedule for Site C."[379]

BC Hydro quoted Hollman[380] as saying that a statistically controlled study[381] of Canadian hydroelectric projects shows that, under certain circumstances, "the outcomes can be reasonably reliable." The Panel observed that two of the six authors of the statistically controlled study (Hollman) referred to by BC Hydro are employed by BC Hydro.[382]

Eliesen[383] stated "the notion that Site C will be completed on time…is illusionary." He cited the examples of the Wuskwatim Dam in Manitoba, which took six years to build, two more than originally scheduled, and Keeyask Generating Station and Muskrat Falls which are both currently two years behind schedule.[384]

Deloitte noted that Keeyask, a dam under construction by Manitoba Hydro, is 21 months behind schedule,[385] and Muskrat Falls is at "61% actual completion versus a plan of 63%." The Panel noted that Deloitte's submission on Muskrat Falls appears to be in contradiction to Eliesen's observation that the in-service date is "delayed to 2020" from the in-service date of 2018 when the project commenced in 2013.

5.2.1.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In the Preliminary Report, the Panel found Site C project was, as of June 30, 2017, on time for a final in-service date of November 2024. Both BC Hydro and Deloitte agreed on this assessment, notwithstanding Deloitte's concern that the project is not using EVM to measure its progress.

However, the Panel found that it was not yet in a position to determine whether the project would remain on schedule for completion by November 2024.

The Panel asked BC Hydro to provide additional information related to the current challenges with the main civil works contract, and to assess the likelihood that the planned start of the river diversion in September 2019 would be achieved. While a one-year delay in the start of the river diversion still permits an on-time completion, the Panel is concerned that such a delay has significant budget implications and increases the risk that subsequent delays will put the final in-service date of November 2024 at risk.

The Panel was concerned about the ability of BC Hydro to achieve the completion of the river diversion in September 2019, and the effect that losing the one-year schedule contingency would have on the risks of subsequent delays to the project. The Panel asked BC Hydro to provide more information on the risks to the schedule of activities that are slated to start after the river diversion, whenever it was to take place.

The Panel acknowledged the work done by Ansar to identify possible systematic problems with estimating schedules for large dam projects. However, the Panel gave more weight to the evidence specific to the Site C project than to the conclusions drawn by the Ansar study, which the Panel views as providing general

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[378] Submission F1-1, BC Hydro, Appendix T, p. 6.
[379] Submission F1-1, BC Hydro, Appendix T, p. 7.
[380] Submission F1-1, BC Hydro, Appendix T, p. 7.
[381] Submission F1-1, BC Hydro, Appendix T, pp. 11–12.
[382] Submission F1-1, BC Hydro, Appendix T, pp. 11, 12.
[383] Submission F13-1, Eliesen, M. (Eliesen).
[384] Submission F13-1, Eliesen, p. 7.
[385] Submission F1-7, BC Hydro.

guidance rather than specific evidence. In the absence of more specific information from BC Hydro, the Panel was not willing to make findings about the Site C project solely on the basis of the Ansar study.

5.2.1.3 Additional submissions and responses

On October 4, BC Hydro submitted a letter in the Inquiry from its president, Mr. O'Riley.[386] In this letter, BC Hydro acknowledges that due to geotechnical and construction challenges, the river diversion target of September 2019 will not be met. BC Hydro added that this will increase the project budget, but that the final in-service date of November 2024 will still be achieved.

In its responses to Panel questions, BC Hydro provided a revised table of milestones against which to compare its progress:[387]

Table 14: Completed Interim Milestones

Description / Status	Final Investment Decision Plan Date	Performance Measurement Baseline Plan Date	Completed
Site Prep, North Bank Complete	February 2016	June 2016	October 2016
Peace River Temporary Bridge Complete	May 2016	March 2016	March 2016
Worker Accommodation – Phase 3	July 2016	August 2016	August 2016
Main Civil Works – Commence Mobilization to Site	September 2016	January 2016	March 2016
Main Civil Works – Commence North Bank Excavation	January 2017	April 2016	June 2016
Main Civil Works – South Bank Stage 1 Cofferdam Complete	May 2018	April 2017	April 2017
Main Civil Works – Powerhouse Excavation Complete	April 2018	April 2017	July 2017

The Panel notes that, when measured against the PMB schedule, the main civil works mobilization, north bank excavation and powerhouse excavation were all completed late, whereas the information presented by BC Hydro in this table in its earlier submission shows all three milestones being achieved early when compared to the FID schedule.

BC Hydro also submitted an earned value analysis for its main civil works activities:[388]

Table 15: Main Civil Works – Pmb Earned Value Analysis

Component	PMB Planned Value ($ million)	PMB Actual Cost at June 30, 2017 ($ million)	PMB Earned Value ($ million)	Cost Performance Index	Schedule Performance Index
Main Civil Works	**520.3**	**441.7**	**~~456.4~~433.5**	**.98**	**.89**

[386] Submission F1-7, BC Hydro.
[387] Submission F1-8, BC Hydro, IR 2.1.0.
[388] Submission F1-8, BC Hydro, IR 2.6.0.

The table above demonstrates that, when compared to the PMB schedule BC Hydro uses to manage the Site C project, by June 30, 2017 it has earned $433.5 million of value, compared to the plan to earn $520.3 million. BC Hydro states that it is not able to perform an earned value analysis of progress compared to the FID schedule, since its FID schedule lacks sufficient detail.[389]

BC Hydro submits that it is now no longer expecting to be able to achieve the river diversion in 2019.[390] It adds that the cause of the delay is a matter of dispute between BC Hydro and the main civil works contractor, PRHP. However, BC Hydro is still "confident" it can deliver the project on time, according to the FID schedule, by November 2024.[391]

In response to Panel questions, BC Hydro provided information on the status of its project activities compared to the PMB plan, rather than simply providing the amount of work completed. The sections of the table with material adverse variances are produced below:[392]

Table 16: Moberly River Clearing Progress of Work to June 30, 2017

					Complete (%)		
Moberly River Clearing		**Unit**	**Contract Quantity**	**Complete to Date**	**Actual**	**PMB Plan to Date**	**FID Plan to Date**
Moberly River Clearing (Season 1)	Clearing and removal of merchantable timber	ha	100	77	77	100	100
	Construction and deactivation of access roads	m	5,149	5,149	100	100	100
	Construction and deactivation of ice bridges	m	276	276	100	100	100
	Disposal of non-merchantable timber	ha	123	-	0	0	0
Moberly River Clearing (Season 2 - not started)	Clearing and removal of merchantable timber	ha	150	-	0	0	0
	Construction and deactivation of access roads	m	TBD	-	0	0	0
	Construction and deactivation of ice bridges	m	TBD	-	0	0	0
	Disposal of non-merchantable timber	km	TBD	-	0	0	0

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Moberly River Clearing: BC Hydro postponed the start of clearing of the Moberly River in response to First Nations concerns raised during an injunction application regarding a number of Site C permits. The variance also includes areas left uncleared due to slope stability concerns, worker safety concerns, and delays related to early onset of warm weather. The schedule impact on other scopes of work is minimal. The remaining work will be completed at the same time as the second season of Moberly clearing, currently planned for November 2018 through March 2019.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Moberly River Clearing: Refer to the explanation above.

[389] Submission F1-8, BC Hydro, IR 2.6.0.
[390] Submission F1-8, BC Hydro, IR 2.3.0.
[391] Submission F1-7, BC Hydro, p. 1.
[392] Submission F1-8, BC Hydro, IR 2.2.0.

Table 17: Main Civil Works Progress of Work to June 30, 2017

					Complete (%)		
Main Civil Works		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Excavation	Left Bank	m^3	8,858,889	4,754,268	54	52	In progress
	Approach Channel	m^3	8,200,000	2,454,665	30	28	In progress
	Right Bank Powerhouse	m^3	845,000	738,488	87	100	0
	Right Bank Stilling Basin	m^3	347,844	347,844	100	100	n/a[1]
	Right Bank Spillway	m^3	1,242,156	265,531	21	2	0
	Right Bank Dam	m^3	544,000	381,653	70	0	0
Tunnels	Right Bank Drainage Tunnel	M	1,089	26	2	100	In progress
Cofferdams	Stage 1 Right Bank Cofferdam Slurry Wall	M	1,570	1,570	100	100	0
	Inlet Cofferdam Slurry Wall	m^2	5,755	470	8	100	100
Tension Crack, including mitigation	Left Bank Toe Buttresses	m^3	160,000	160,000	100	n/a	n/a

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Excavation - Right Bank Powerhouse: Work was completed on target. The contract quantity was estimated higher than the actual quantity ultimately required. There is no impact on other scopes of work.

Excavation – Right Bank Spillway: Excavation commenced earlier than planned in order to increase Right Bank Powerhouse slope stability.

Excavation – Right Bank Dam: Excavation commenced earlier than planned in order to increase Right Bank Powerhouse slope stability.

Right Bank Drainage Tunnel: work on the Right Bank Drainage Tunnel has been delayed since February 2017 as the contractor's methodology for controlling silica on site didn't meet WorksafeBC's control requirements.

Cofferdams – Inlet Cofferdam Slurry Wall: Work on the Inlet Cofferdam Slurry Wall was delayed due to the left bank tension crack. The impact of the delays to the construction of the left bank cofferdam slurry walls has been minimal and has been offset by the delays to excavation of the left bank slope, Inlet and outlet portals..

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Most of the Main Civil Works scope commenced significantly earlier than the FID plan contemplated.

Table 18: Transmission Progress of Work to June 30, 2017

					Complete (%)		
Transmission		Unit	Contract Quantity	Complete to Date	Actual	PMB Plan to Date	FID Plan to Date
Clearing	East	ha	270	181	67	100	100
	West	ha	300	0	0	0	0

Variances (Actual to Performance Measurement Baseline Schedule Percentage Complete):

Transmission Clearing – East: Percentage complete is less than planned as the contract was awarded two months later than planned and the vendor experienced resourcing challenges. Clearing has been further delayed by BC Hydro commitments not to undertake clearing during this inquiry. If the clearing delay is not recovered there is potential impact to the start of the transmission line construction. BC Hydro is assessing options to recover the clearing schedule.

Variances (Actual to Final Investment Decision Schedule Percentage Complete):

Transmission Clearing – East: Percentage complete is less than planned. See explanation of variance above.

As noted in section 5.2.1.3 above, BC Hydro now believes that it will achieve the river diversion in September 2020, rather than September 2019 as had been planned.393 This delay is reportedly a result of the tension cracks that appeared on the left bank of the river during the slope stabilization activities. BC Hydro submits that a "constructability review" conducted jointly between itself and PRHP identified options that would have maintained the September 2019 river diversion schedule, but that the parties were unable to agree on the "schedule, options and allocation of cost."[394]

In response to the Panel's inquiry as to how BC Hydro intends to work with PRHP to recover its schedule for the main civil works, BC Hydro stated:

> Although the parties are in dispute over the cause of some of the delays, BC Hydro proposed taking a lead in developing a response to address the challenges for construction to proceed. Such a response could include design modifications, changes to construction methodologies and development of shared metrics to track progress going forward. The parties have agreed to work together on this issue. In addition, BC Hydro has outlined steps to enable work to continue over the winter months.[395]

BC Hydro asserted that there is a "high probability" that it will still achieve the November 2024 scheduled in-service date, since it had planned a one-year float, or schedule contingency, in advance of the river diversion.[396] It continued by identifying elements of infrastructure that are now in place, including the right bank coffer dam, most of the left bank coffer dam, the key batching, crushing and washing equipment, and substantially all of the road access and laydown areas on the right bank.

However, BC Hydro also described the moderate impact scenario set out by Deloitte as "possible," and explains that this could occur "due to an additional one year delay."[397] BC Hydro further described the possibility of a two or more year delay from their current expectations as having "very low likelihood."

In response to further Panel questions, BC Hydro provided a list of major outstanding risks to the activities scheduled to happen after the river diversion, a sample of which is provided below:[398]

Table 19: Post Diversion Schedule Risks

Risk Event Description	Risk and Response Summary	Risk Quantification		
		Severity ($ million)	Probability (%)	Score
Dam Site Construction				
Construction	**Spillway gate construction is delayed due to equipment installation delays (gate guides, anchors, lifting beams, power components and other embedded parts) impacting the turbine and generator Unit 1 in-service date. To mitigate, BC Hydro and the contractor(s) to monitor and expedite equipment deliveries.**	**10-100**	**10**	**10**

[393] Submission F1-8, BC Hydro, IR 2.3.0.
[394] Submission F1-8, BC Hydro, IR 2.3.0.
[395] Submission F1-8, BC Hydro, IR 2.3.0.
[396] Submission F1-8, BC Hydro, IR 2.15.0
[397] Submission F1-8, BC Hydro, IR 2.15.0.
[398] Submission F1-10, BC Hydro, IR 2.5.0.

Construction	**Spillway and intake gates are not water tight requiring re-work and delaying Unit 1 commissioning. To mitigate, BC Hydro to monitor manufacturing quality, installation work and add schedule float around key gate installation dates.**	**10-100**	**10**	**10**
Construction	**Turbine and Generator Unit 1 commissioning is delayed due to manufacturing, installation and/or safety issues. To mitigate, BC Hydro to actively manage technical and schedule contractor requirements.**	**10-100**	**10**	**10**
Risk Event Description	**Risk and Response Summary**	**Risk Quantification**		
		Severity ($ million)	**Probability (%)**	**Score**
Contractor Interfaces	**Roller compacted concrete powerhouse buttress and spillways buttress hand-over delay impacts the powerhouse and spillways construction and ultimately delaying the reservoir impoundment and the Unit 1 in-service date. To mitigate, add schedule float around hand-over dates; proactively manage the contract; and if required handover the lower buttress to the contractor prior to the upper buttress being completed. This risk is unrelated to river diversion and may occur both pre- and post-diversion.**	**10-100**	**10**	**10**
Contractor Interfaces	**A contractor delays another contractor due to poor planning or execution of the work causing a contractor schedule delay. To mitigate BC Hydro and the contractors to identify interface points, track interfaces in log, include interface hand-over dates in contracts, and add schedule float around key hand-off dates. BC Hydro to monitor interfaces to ensure contractor performance.**	**10-100**	**10**	**10**
Diversion Tunnel	**Poor tunnel hydraulic performance to accommodate water flows causing cofferdam overtopping and/or failure in a flood event. To mitigate, increase tunnel design capacity to be greater than expected water flows to allow fluctuations in water flows.**	**10-100**	**10**	**10**

Risk Event Description	Risk and Response Summary	Risk Quantification		
		Severity ($ million)	Probability (%)	Score
Quality	**Equipment manufacturing and design (turbines, generators, gates, cranes, elevators, and other plant equipment) errors and omissions result in re-design or re-manufacturing causing schedule delays and costs increases. To mitigate, contract specifications to include quality assurance and quality control contractor requirements. BC Hydro to complete contractor design and manufacturing reviews to ensure specification adherence.**	**10-100**	**10**	**10**
Transmission and Substation Construction				
Construction	**No or poor road access along transmission right-of-way's resulting in contractor construction delays. To mitigate, upgrade existing access roads, construct new roads, and transfer risk of on-going access and maintenance to the line construction contractor. Line contractor may choose to mitigate further by using helicopters, rig matting or rescheduling work to take advantage of frozen ground conditions.**	**10-100**	**10**	**10**
Geotechnical Conditions	**Poor Transmission right-of-way geotechnical conditions impacting transmission tower foundations. To mitigate, pre-design and construction geotechnical investigations and tower contract to include several foundation designs based on a range of ground conditions encountered during construction.**	**10-100**	**10**	**10**
Highway 29 Construction				
Geotechnical Conditions	**Significant settlement of the highway causeways approaching several new bridges due to unstable layer of shale bedrock; design does not meet Ministry of Transportation and Infrastructure design safety requirements. Options to mitigate: revise the causeway design with shear keys excavation/backfilling, flatten the causeway slope and investigate alternate design extending the length of the bridge crossings to full spans and eliminate the need for causeways.** **This risk may occur both pre- and post-diversion.**	**10-100**	**60**	**11**

Risk Event Description	Risk and Response Summary	Risk Quantification		
		Severity ($ million)	Probability (%)	Score
Reservoir Filling				
Reservoir Filling	**Reservoir fill is delayed, takes longer or the diversion tunnel or gates fail requiring dewatering of the river to repair the tunnel/gates impacting the reservoir fill schedule. To mitigate, prepare reservoir filling plan that includes what-if options that can be executed should an issue arise.**	**10-100**	**10**	**10**
Strategic and General Risks				
Regulatory	**During construction unanticipated permits are required and changes to the Environmental Management Plans are needed. This can add unplanned scope, schedule and cost to the project. To mitigate, BC Hydro to proactively works with regulatory agencies to establish clarity to the scope of the mitigation and compensation program.**	**10-100**	**10**	**10**

However, BC Hydro has only quantified the effect of these risks on the budget, and has not quantified their effect on the schedule should they arise.

5.2.1.4 Panel analysis and findings

The Panel finds that, on September 30, 2017, the Site C project is currently on schedule for completion by November 2024. However, BC Hydro was working towards an in-service date of 2023, and with regard to that in-service date, the project is one year behind BC Hydro's PMB schedule.

In addition, the Panel finds there are significant risks that could prevent the project from remaining on schedule and we are not persuaded that it will remain on schedule for a November 2024 in-service date. In the Panel's view, the fact that the project is still on schedule should not be interpreted as suggesting that the project is expected to remain on schedule.

At the time the Preliminary Report was prepared, the Panel was not able to determine whether the river diversion was on schedule for September 2019, and was concerned that a one-year delay was possible. BC Hydro now states definitively that this date will not be achieved. However, the Panel agrees with BC Hydro that this one-year delay does not mean that the November 2024 date cannot be met, since there was a one year "float" built into the FID schedule.

If the current problems with the main civil works activities are not resolved in a timely manner, or if further problems arise prior to the river diversion, which has recently been delayed until September 2020, then the project may be delayed a further full year. Even if the river diversion does take place in 2020, BC Hydro has lost its one-year schedule contingency and problems arising in subsequent activities may delay the November 2024 in-service date.

The primary cause of the delay in completing the river diversion is reportedly the left-bank tension cracks. The Panel is concerned that BC Hydro has not provided sufficient explanation regarding how it will work with PRHP to address the current challenges.[399] Asserting that the approach "could include" design modifications and other responses does not inspire confidence.[400] However, as noted in the Preliminary Report, PRHP has submitted to BC Hydro a revised schedule showing that the main civil works activities can be completed for a river diversion in 2020, which would allow the final date of November 2024 to be met. Further, the Panel notes that the earned value analysis does show significant progress being made, although not sufficient to maintain the PMB schedule.

There are several other activities that were planned to be complete, but are currently incomplete. Work on the right bank drainage tunnel has been suspended since February 2017, and only 2 percent of the work has been completed to date. Work on the inlet cofferdam slurry wall is only 8 percent complete, while the eastern clearing for the transmission line is only 67 percent complete. Further, clearing and removing the timber from the Moberly River has been postponed in response to First Nations concerns raised during an injunction application, and other concerns with slope stability and worker safety. While it is not clear that any of these activities are on the critical path, all activities become critical at some point if not addressed.

On the basis of these concerns, the Panel does not share BC Hydro's confidence that the river diversion will be achieved by September 2020. Should the river diversion not be achieved until 2021, the Site C project would be delayed for another full year until November 2025.

As shown in Table 19, even if the river diversion were to take place in 2020, significant risks remain associated with the subsequent activities. While BC Hydro has not quantified the schedule effect of the outstanding risks, the list contains 12 risks, all with probabilities of occurrence of 10 percent, except the geotechnical risk to Highway 29 construction which has a 60 percent probability of occurring. The likelihood is that one or more of these risks will occur. BC Hydro has schedule contingency built into each of its main contracts. However, the one-year schedule contingency built into the plan has now been consumed as a result of the delay to the river diversion. Any delays in these post-river diversion activities beyond the contingency built into specific contract-schedules risks delaying the project beyond November 2024.

The Panel recognizes that delays to activities scheduled subsequent to the river diversion do not imply full-year delays in the schedule. However, in the absence of more specific information on the risks to the subsequent activities, and in light of the risks that still remain to the 2020 river diversion, the Panel is left to conclude that further delays are more likely than an in-service date of November 2024.

5.2.2 Is the Site C project currently on budget and what will be the final cost of the project?

In this section, the Panel examines the question of whether the Site C project is currently within the proposed budget, as posed by the OIC. As noted in the previous section, there are two schedules for Site C. The FID schedule, with an in-service date of November 2024, is the schedule against which the project is measured for the purposes of this report. The PMB schedule, with an in-service date of November 2023, is the schedule against which BC Hydro is currently measuring its progress.

There are also two budgets for the Site C project, one associated with each of the FID and PMB schedules. While the total budgets are the same in each case ($8.335 billion), the timing of expenditures for each schedule matches their respective activities, and hence is different for the FID and PMB schedules. Both the FID and PMB budgets exclude the $440 million project reserve established and held by the province.[401]

For the Panel to assess the cost impact to ratepayers of completing, suspending or cancelling the Site C project, it is necessary to know what the expected cost of the project will be at completion. Accordingly, this

[399] Submission F1-8, BC Hydro, IRs 2.3.0, 2.4.0.
[400] Submission F1-8, BC Hydro, IR 2.3.0.
[401] OIC, section 3(b)(i).

section also explores what the total cost may be to complete the project. Additionally, the Panel explores current risks to the project budget and the experience of BC Hydro and others in managing similar projects.

5.2.2.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro stated that the project is on budget.[402] It further stated the expected total cost of the Project is $8.335 billion, and it does not expect to use the additional $440 million project reserve established and held by the BC Government.[403]

BC Hydro stated it has spent $1.8 billion to June 30, 2017,[404]representing 22 percent of the budget of $8.335 billion.[405] BC Hydro compared the $1.8 billion spent to date with the FID planned spending to June 30, 2017 of $1.321 billion, and showed that it is $479 million higher than planned.[406] BC Hydro claimed that this variance between planned and actual spending to date relates to timing differences of expenditures, specifically that expenditures related to worker accommodation, main civil works and early works were incurred earlier than planned.

BC Hydro noted there are claims associated with the main civil works activities in 2016 which are being managed “within existing contingency funds” [407], although BC Hydro does not quantify these claims.

BC Hydro stated it “expects to complete Site C…on budget”[408] and did “not expect to use the additional $440 million project reserve.” BC Hydro supported this by adding that it has an “appropriate level of…cost contingency,”[409] and it has “more unused contingency now than at the time of the Final Investment Decision.”[410]

BC Hydro stated the Site C budget prepared in 2014 (the FID budget) was “a product of a robust process and appropriate approximations.”[411] It described how the work was broken down into work areas corresponding to the “major contract packages” for procurement; two teams independently created the estimates for the two largest packages of work (major civil works, MCW and generating station and spillway, GSS), and the results were compared. A Monte Carlo model was used to understand the variability of possible estimates based on the risk areas of design uncertainty, labour, estimate accuracy, contractor markups, and economic conditions.

Further, BC Hydro described three independent assessments that were performed on the estimates. According to BC Hydro, “KPMG verified that both the methodology for developing the assumptions and the construction of the financial model were appropriate”[412]; a panel of experienced independent contractors “completed an additional review of the estimate of direct construction costs,”[413] and Marsh Canada reviewed the risk management approach, and “concluded that BC Hydro had developed a strong foundation for risk management for the Site C project.”

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402 Ibid., p. 24.
403 Ibid., p. 2.
404 Ibid., Appendix D, p. 3.
405 1,800 / 8,335 * 100%
406 Ibid., Appendix D, p. 3.
407 Ibid., p. 37.
408 Submission F1-1, BC Hydro, p. 2.
409 Submission F1-1, BC Hydro, p. 2.
410 Submission F1-1, BC Hydro, p. 24.
411 Submission F1-1, BC Hydro, p. 25.
412 Submission F1-1, BC Hydro, p. 25.
413 Submission F1-1, BC Hydro, p. 26.

BC Hydro also noted that its hydro-electric generation facilities are "a mature technology with well-established estimating practices and techniques."[414] It added that the main technical risks are geotechnical in nature and "A number of site investigations over the past several decades have helped BC Hydro and its contractors better understand and mitigate these risks, and take them into account in cost estimates."

BC Hydro presented the following analysis of its current cost contingency, showing that it has grown from the original FID budget of $794 million to the present figure of $1.195 billion:[415]

Table 20: Changes in Contingency Since Final Investment Decision

Description	$ million (Nominal)
Original Contingency Budget, at Final Investment Decision	794
Identified Savings on Forecast Interest-During-Construction:	
2015	89
2016	76
2017	150
Total identified Savings on Forecast Interest-During-Construction	**315**
Other Cost Savings identified, to June 30, 2017	86
Total identified Cost Savings	**401**
Total Contingency, June 30, 2017[24]	**1,195**

The primary reason for the increase in total contingency since the start of the project is that estimates of interest during construction have fallen by $315 million, due to lower forecast interest rates. BC Hydro added that it has locked in "historically low interest rates by hedging 50 percent ($4.4 billion) of its forecast future debt issuances from fiscal 2017 to fiscal 2024."[416]

BC Hydro went on to state that it has committed $356 million of contingency to date, and its unused cost contingency was $839 million, over and above the $440 million project reserve:[417]

Table 21: Contingency Remaining

	As at June 30, 2017 ($ million)
Total Contingency Budget	1,195
Less Contingency Committed to June 30, 2017	(356)
Contingency Remaining	**839**
Project Reserve Held by Treasury Board	**440**
Total Remaining Contingency, Including Project Reserve Held by Treasury Board	**1,279**

414 Submission F1-1, BC Hydro, Appendix T, p. 3.
415 Submission F1-1, BC Hydro, p. 31.
416 Submission F1-1, BC Hydro, p. 31.
417 Submission F1-1, BC Hydro, p. 32.

BC Hydro in summary stated "the remaining $839 million of contingency is sufficient to manage such risks." However, BC Hydro did note that if the river diversion is delayed from the current schedule of 2019 to 2020, "it would likely trigger a draw on the Treasury Board reserve."[418] That is, the one-year delay in the project would cause the project to exceed its budget of $8.335 billion before Treasury Board reserve. BC Hydro added that "delaying River Diversion for one year would cost approximately $630 million."[419] BC Hydro also presented a table of "material project risks."[420] This table contained no quantification of the effect should any of the risk events listed come to pass.

BC Hydro claimed "a history of delivering projects on budget,"[421] with projects coming in at "0.94 per cent less than budget on a total of $6.36 billion of spending," based on data reported in 2016/17.[422]

Deloitte report

Deloitte summarized its position by stating: "As the project continues to operate within…the existing budget (and unallocated contingency), today the Project remains…on budget."[423] Deloitte reported that the project had expended $1.8 billion to June 30, 2017.[424] However, it noted this "is based on spent cost only and does not represent actual progress on the site to date." Deloitte went on to say it had "not observed a clear method the Project utilizes to measure percent complete," and the "use of earned value reporting on other mega-projects is a common practice."[425]

Deloitte then compared the $1.8 billion costs incurred to date with the figure of $2.104 billion that the PMB schedule expected to have been spent to date,[426] yielding a discrepancy of "$305 million or 14% behind its planned spend as of June 30, 2017."[427] In Deloitte's view, this underspend could be explained by lower-than planned spending on main civil works due to schedule delays and problems encountered; shifting of expenditures on property purchases, royalties, and mitigation and compensation into future periods; and lowering of the expenditures on turbines and generators due to timing differences.

Deloitte further noted the total contingency of $356 million committed to date represents 45 percent of the budgeted cost contingency of $794 million, a percentage "significantly higher than the 22% of total budget spent to date."[428]

Deloitte noted that "PRHP plans to submit a claim to BC Hydro"[429] for the delay caused by the first tension crack on the left bank in February 2017. Also, Deloitte reported that discussions were underway between BC Hydro and PRHP regarding how the delays caused by the second left bank tension crack, in May 2017, could be mitigated, and that PRHP had "suggested that more claims are to come."[430]

Deloitte confirmed many of the details of BC Hydro's submission. It also noted that the budget of $7.96 billion, developed in 2010, was a Class 3 estimate which became the basis for the FID budget of $8.335 billion, increased "to account for HST and PST changes in addition to an adjusted project completion date of

418 Submission F1-1, BC Hydro, p. 35.
419 Submission F1-1, BC Hydro, p. 39.
420 Submission F1-1, BC Hydro, Appendix D, p. 9.
421 Submission F1-1, BC Hydro, Appendix D, p. 24.
422 Submission F1-1, BC Hydro, Appendix T, p. 2.
423 Submission A-8, p. 3.
424 Submission A-8, p. 28.
425 Submission A-8, p. 23.
426 Submission A-8, p. 27.
427 Submission A-8, p. 28.
428 Submission A-8, p. 32.
429 Submission A-8, p. 25.
430 Submission A-8, p. 34.

2024."[431] Deloitte added that the budget was subsequently "identified as having a P50 value, meaning that the Project had a 50% chance of being over and 50% chance of being under the budgeted value."

Deloitte noted the contingency of $794 million "represented 11.5% of the total construction and development costs of $6.928 billion and 9.5% of the total project costs of $8.335 billion," whereas when the project reserve of $440 million "combined with the contingency of $794 million, resulted in an overall contingency of $1.234 billion, which represented 14% of the overall total project costs." Deloitte stated that, in its experience reviewing large complex capital projects, it would expect the contingency (including project reserve) would be "in the range of 15% - 20% of total project costs,"[432] and noted the Site C project contingency was "just below the low end of that range."

Deloitte went on to describe three scenarios for the outcome of the Site C project with respect to cost: low, moderate, and high impact, as described in the following table:[433]

Table 22: Site C Project Scenarios – Cost and Schedule Performance

	Meet Start of River Diversion milestone	Miss Start of River Diversion milestone
Existing cost contingency *sufficient* to cover further consumption of MCW contingency, uncertainties in other major contracts, increases in interest rates, and geotechnical issues	• One-year schedule contingency maintained, sufficient to cover other potential schedule risks, Final Investment Decision(FID) schedule maintained • Cost pressures of additional 0–10% to FID budget • **Overall impact: Low**	• Loss of one-year schedule contingency due to continued issues with MCW, loss of ability to absorb other schedule slippage, potential for up to one-year delay • Cost pressures of additional 10–20% to FID to reduce schedule impact, including one year of additional Interest During Construction (IDC) and indirect costs • **Overall impact: Moderate**
Existing cost contingency *insufficient* to cover further consumption of MCW contingency, uncertainties in other major contracts yet to be awarded, increases in interest rates, and geotechnical issues	• One- year schedule contingency maintained, sufficient to cover other potential schedule risks • Cost pressures of additional 10–20% to FID to cover shortfall in contingency • **Overall impact: Moderate**	• Loss of one-year schedule contingency due to continued issues with MCW, other schedule issues result in >1 year delay • Cost pressures of additional 20–50% to FID to reduce schedule impact, including one to two years of additional IDC and indirect costs • **Overall impact: High**

Deloitte's view was that the best case, or low impact scenario, would have the project come in somewhere between the original budget of $8.335 billion and $9.169 billion, a ten percent overrun. The worst case identified by Deloitte was a 50 percent overrun, leading to a project cost of $12.503 billion. These outcomes are presented in the table below:

[431] Submission A-8, footnote 19.
[432] Submission A-8, pp. 19, 20.
[433] Submission A-8, p. 2.

Table 23: Possible Impact Scenarios (Nominal $ Million)

Impact	Schedule Delay to FID Nov 2024 ISD	Cost Impact to FID Budget ($8.335B)		Final Cost Range at Completion	
		low	high	low	high
Low	On time	0%	10%	$ 8,335	$ 9,169
Moderate	One year delay	10%	20%	$ 9,169	$ 10,002
High	More than 1 year delay	20%	50%	$ 10,002	$ 12,503

Deloitte noted that BC Hydro is currently projecting to use $1 billion of cost contingency by the end of the project,[434] a 26 percent increase over the $794 million planned cost contingency, and 84 percent of the total available contingency of $1.195 billion. Deloitte observed that such an increase within only the second year of an eight-year contract "calls into question the accuracy of the Project's initial estimates."

Deloitte expressed concern about the main civil works being performed by BC Hydro's contractor PRHP. In addition to the schedule risks noted in previous sections from a budget perspective, Deloitte stated that PRHP "has issued several claims to BC Hydro, the latest of which is dated August 24, 2017."[435]

Deloitte was also concerned about the risks BC Hydro had under-estimated the cost of its major contracts. BC Hydro under-estimated the cost of the main civil works contract,[436] which caused cost contingency to be committed when the contract was awarded. Two other large contracts, generating station and spillways (GSS) and transmission, had yet to be awarded, and "Should these contracts have similar discrepancies between planned versus actual values, the Project contingency may be insufficient to cover them."[437]

Deloitte stated the geotechnical risks appear to "have been investigated" and the "design has been adapted to the conditions."[438] It adds that issues might arise "if conditions deviated from the assumptions made," but does not quantify the effect if those risks came to pass.

Deloitte estimated that a one-year delay in the river diversion, currently planned to start on September 1, 2019, would incur "additional costs, on the order of $382 million, excluding inflation impacts and potential delay claims."[439] The largest single component of this cost would be additional interest during construction of $252 million, being $21 million per month for twelve months, based on figures provided to Deloitte by BC Hydro.[440] The remaining $130 million would be for "additional indirects."

Other submissions

Eliesen[441] observes that "the most recent major hydro dam constructed in BC was the Revelstoke dam completed in 1984."[442] He adds: "The vast majority of people with internal utility expertise in hydro project construction management have retired or no longer work for the company. Consequently, there is a lack of professional and management expertise at BC Hydro with respect to large scale construction

[434] Submission A-8, p. 30.
[435] Submission A-8, p. 38.
[436] Submission A-8, p. 39.
[437] Submission A-8, p. 39.
[438] Submission A-8, p. 40.
[439] Submission A-8, p. 42.
[440] Submission A-8, p. 42, footnote 63.
[441] Submission F13-1, Eliesen.
[442] Ibid., p. 6.

projects." Eliesen concludes that "there is a high probability that the final Site C capital cost will be about $12 billion, well above currently estimated costs of $9 billion."[443]

Bakker[444] provided information on recent hydro and transmission projects, showing cost overruns of three hydro projects in Canada ranging from 40 percent to 78 percent. She observes that, with respect to Site C, "the extent of eventual cost overruns, if any, cannot be fully determined at this point."[445] However, she adds: "it is reasonable to expect that there may be cost overruns for the Site C Project, based on recent experience with greenfield hydroelectric and transmission projects across Canada, including BC Hydro projects."

Deloitte presented the same data originally included in Bakker's submission,[446] but with updated data.[447] Three transmission projects identified by Deloitte were managed by BC Hydro and had cost overruns varying from 16 percent to 82 percent. There is no data on BC Hydro's performance building recent, large hydropower projects; as Eliesen notes,[448] BC Hydro's last project of this nature was in 1984. Deloitte added that it had not conducted a review of these projects in order to draw specific parallels to the Site C project.

Eliesen observes that the budget for Site C has increased from $6.6 billion in 2010 to $8.8 billion in 2016, and notes this is an increase of $2.2 billion, or 33.3 percent.[449]

Vardy[450] provides information on the Muskrat Falls hydro project being built by Nalcor Energy in Newfoundland and Labrador, showing its capital costs increasing from $6.2 billion in 2010 to $12.7 billion in 2017.[451] He then identifies the similarities and differences between Muskrat Falls and Site C, and concluded that "Nalcor Energy is leading a project that is beyond its capacity and the same may be true of BC Hydro's capacity to build Site C."[452]

5.2.2.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In the Preliminary Report, the Panel was unable to determine whether the project was currently on budget.

The Panel therefore asked BC Hydro to provide additional information regarding the current progress to date. The Panel was particularly concerned that the risk of a one-year delay in the river diversion would lead to a significant increase in the cost of the project, even if the overall schedule of November 2024 continued to be achievable.

BC Hydro was also asked to provide information on the possible budget impact of outstanding claims against the company.

The Panel also found that if the river diversion is not achieved in September 2019, the project will not remain within its budget of $8.335 billion. BC Hydro has subsequently acknowledged it will miss the river diversion in 2019, and that it currently expects the final budget for the Site C project to be $8.945 billion, an increase of $610 million or 7.3 percent over the budget of $8.335 billion.

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443 Ibid., p. 11.
444 Submission F106-1, PoWG, p. 60.
445 Ibid., p. 64.
446 Submission F106-1, PoWG, p. 60.
447 Submission A-8, p. 36.
448 Submission F13-1, Eliesen.
449 Ibid., p. 6.
450 Submission F52-1, Vardy, D. (Vardy).
451 Ibid., p. 10.
452 Ibid., p. 7.

However, the Panel did not have sufficient information at the time of preparing the Preliminary Report to assess total budget overruns for the Site C project, and consequently posed a series of questions. The Panel asked BC Hydro why it had chosen to allocate a contingency of only 9.5 percent of project costs, what its anticipated use of contingency would be for the remainder of the project, and how much of its new-found contingency based on low interest rates would remain in the event that interest rates rose. BC Hydro was also asked questions on the expected cost of its outstanding large procurements, and its revised approach to realigning Highway 29. Finally, BC Hydro was asked to quantify the budget impacts of risks that it had previously identified.

The Panel acknowledged the work done by Ansar to identify possible systematic problems with estimating costs for large dam projects. However, the Panel gave more weight to the evidence specific to the Site C project than to the conclusions drawn by the Ansar study, which the Panel viewed as providing guidance rather than specific evidence.

5.2.2.3 Additional submissions and responses

BC Hydro submission

BC Hydro submits it currently expects to spend $8.945 billion to develop Site C, an increase of $610 million or 7.3 percent over the budget of $8.335 billion.[453] BC Hydro does not state whether it expects the $440 million Treasury Board reserve to be allocated to the costs of this overrun, or retained for possible further cost overruns. In its technical presentation, BC Hydro stated that it will be working with the Provincial Government to revise its budget in November.[454]

BC Hydro was asked to comment on the likelihood of the three budget outcomes considered by Deloitte: low impact (0 – 10 percent budget overrun), moderate impact (10 – 20 percent), and high impact (20 – 50 percent). BC Hydro responded by stating it believes there is a “reasonable probability” that the budget overruns will be in the low or moderate categories (i.e. that the budget overrun will be between zero and 20 percent). It described the likelihood of the high impact scenario to be “very low” in its estimation.[455]

BC Hydro added that the moderate impact scenario is “possible” [456]. In addition to the 7.3 per cent overrun recently acknowledged, BC Hydro noted that large procurements not yet completed may be impacted by the change to the river diversion schedule, and that further changes are possible to the Highway 29 realignment.

BC Hydro provided an analysis of the cost of its recent acknowledgement that the river diversion will be delayed until 2020:

[453] Submission F1-7, BC Hydro, p. 1.
[454] TTP-2, October 14, 2017, Vancouver, p. 1600.
[455] Submission F1-8, BC Hydro, IR 2.15.0, p. 4.
[456] Submission F1-8, BC Hydro, IR 2.15.0.

Table 24: BC Hydro Cost Impacts of Postponing River Diversion [457]

Description	Explanation	Amount ($ million)	
		Current	IR 2.8.0
Ongoing project costs	Incremental indirect costs	[redacted]	[redacted]
Site and environmental maintenance	Incremental site and environmental maintenance costs	[redacted]	[redacted]
Main Civil Works	Incremental costs	[redacted]	[redacted]
Turbines & Generators	Storage of components and equipment	[redacted]	[redacted]
Generating Station & Spillways	Incremental costs (primarily inflation)	[redacted]	[redacted]
Worker Accommodation	Fixed worker accommodation costs	[redacted]	[redacted]
Total Direct Costs		**$397**	**$325**
Inflation	Increase in nominal dollar cost of expenditures incurred after 2019 due to inflation increases	Included above	105
Interest During Construction	Increase in finance carrying charges	162	200
Contingency	Increase in contingency	51	-
Total Cost of Postponing River Diversion to 2020		**$610**	**$630**

The table above indicates that BC Hydro considers the cost of the delay to the river diversion to be $610 million, compared to an earlier estimate of $630 million. The Panel observes that the $51 million of contingency included in the total of $610 million is 9.1 percent of all costs,[458] or 12.8 percent of the $397 million total direct costs.[459]

BC Hydro also provided an analysis of the effect on the budget of the material risks to the project subsequent to the river diversion. This was provided previously in Table 19.

BC Hydro explained that the risk severity is post-mitigation and not all of the risks identified would be expected to happen. It added that project contingency would be expected to cover some of the costs should these risk events occur.

In a partially-redacted submission, BC Hydro provided details of claims submitted by its contractors. The most significant budget impact of claims submitted to date relates to the main civil works contract. BC Hydro provided the following information related to the claims which have been settled to date:

[457] Submission F1-8, BC Hydro, IR 2.15.0.
[458] $610 million - $51 million = $559 million, $51/$559 = 9.1%
[459] $51/397 = 12.8%

Table 25: BC Hydro Peace River Hydro Partners Claims Summary[460]

Claim Description	Contractor Claims: Number	Contractor Claims: Amount ($ million)	BC Hydro Accepted Amount ($ million)
2016 Right Bank Delay and Acceleration Claims	[redacted]	[redacted]	[redacted]
Accepted Claims for Change	[redacted]	[redacted]	[redacted]
Rejected Claims for Change	[redacted]	[redacted]	[redacted]
Subtotal	60	105.3	25.3

This table shows that, on average, BC Hydro has settled for 24 percent of the amounts claimed to date. The amounts claimed, but not resolved, are significantly higher than those settled to date. The Panel accepts that these figures should remain confidential, since their disclosure would prejudice both BC Hydro and its ratepayers. However, the Panel has taken the figures into account when considering its assessment of the total project overrun.

In the Preliminary Report, the Panel asked BC Hydro to explain why it chose the contingency amount that it did for the project. BC Hydro submitted that the Site C project contingency was calculated as follows:

Table 26: Final Investment Decision, Site C Project Budget[461]

	Element	Estimated Cost ($ million)[1]
1	Direct Construction Costs	$4,468
2	Indirect Costs:	
3	BC Hydro Personnel and Consultants	315
4	Other and Sunk[2]	815
5	**Total Indirect Costs**	**$1,130**
6	**Total Construction Cost Without Contingency *($2014, real)***	**$5,598**
7	Contingency	679
8	**Total Construction Cost *($2014, real)***	**$6,277**
9	Inflation	651
10	Interest During Construction	1,407
11	**Total Project Cost Loaded ($ nominal)[3]**	**$8,335**
	Contingency (line 7) as percentage of lines 1 and 3	**14.2%**

Notes:
1 – Refer to Appendix D, Table D-1, column C, "Board Approved Plan (2014$)
2 – Excluded from the calculation of contingency as a percentage of project costs
3 – Totals may not add exactly due to rounding

BC Hydro added that the contingency figure of $679 million in the table is in 2014 dollars, and becomes $794 million in nominal dollars when adding inflation.[462] For the purpose of the analysis in this section, the Panel has used the figure of $679 million for contingency.

[460] Submission F1-10, BC Hydro, IR 2.7.0.
[461] Submission F1-10, BC Hydro, IR 2.9.0.
[462] Submission F1-16, BC Hydro, IR 3.4.0.

In Note 2 in the table above, BC Hydro pointed out that the figure of $679 million did not include a contingency allowance for the “other and sunk” costs, since sunk costs have no risk of variance. It further clarified that the entire $815 million figure represents sunk costs, and have been incurred in the past.[463]

The Panel notes the figure of $679 million is calculated before the addition of inflation and interest during construction (IDC), the latter being $1.407 billion. BC Hydro acknowledges its improved contingency position on June 30, 2017 is almost entirely due to favourable changes to the forecast of the IDC figure. In response to Panel questions, BC Hydro stated that IDC can vary based on changes in the timing of expenditures, interest rates and total project costs.[464]

BC Hydro stated the contingency of $679 million represents approximately a P48 value, meaning there is a 48 percent probability of the eventual budget coming in at less than $8.335 billion, and a 52 percent probability that the budget of $8.335 billion will be exceeded. The P90 contingency assessment as prepared prior to the final investment decision budget update was $1.7 billion.[465]

BC Hydro also provided a partially redacted analysis of the amount of contingency currently forecast to be allocated until the end of the project:

Table 27: BC Hydro Contingency Committed to Contracts [466]

Contingency Category	Contingency Committed by Management, June, 2017 ($ million)	Forecast Allocation of Contingency		
		June, 2017[1] ($ million)	August, 2017 ($ million)	Variance ($ million)
Main Civil Works	[redacted]	[redacted]	[redacted]	[redacted]
Generating Station and Spillway	[redacted]	[redacted]	[redacted]	[redacted]
Rights, Taxes and Grants	[redacted]	[redacted]	[redacted]	[redacted]
Highway 29 Relocation	[redacted]	[redacted]	[redacted]	[redacted]
Clearing	[redacted]	[redacted]	[redacted]	[redacted]
Early Civil Works	[redacted]	[redacted]	[redacted]	[redacted]
Turbines and Generators	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]
Miscellaneous	[redacted]	[redacted]	[redacted]	[redacted]
Worker Accommodation	[redacted]	[redacted]	[redacted]	[redacted]
BC Hydro Construction Management	[redacted]	[redacted]	[redacted]	[redacted]
Indirect Costs	[redacted]	[redacted]	[redacted]	[redacted]
Insurance Savings	[redacted]	[redacted]	[redacted]	[redacted]
Total Contingency Budget before Interest During Construction	355.8	999.7	1,051.3	51.6
Savings on Interest- During- Construction / Other Unallocated Budget	N/A	194.9	143.3	51.6
Total Contingency	355.8	1,194.6	1,194.6	0.0

463 Submission F1-16, BC Hydro, IR 3.2.0.
464 Submission F1-16, BC Hydro, IR 3.7.0.
465 Submission F1-15, BC Hydro, IR 3.15.0, Attachment 1.
466 Submission F1-10, BC Hydro, IR 2.11.0.

The table above shows that, as of August 2017, BC Hydro currently expects to allocate a total of $1.051 billion contingency, a figure which has grown by $51.6 million since June 2017.

In the Preliminary Report, the Panel also asked BC Hydro to estimate the total price of its two major outstanding procurements, and the degree to which possible cost overruns in this area are already included in anticipated contingency. BC Hydro provided a partially redacted response, indicating it anticipates budget overruns for each of its outstanding major contracts, and these overruns are included in the currently anticipated contingency figure. BC Hydro added there are both procurement and post-procurement risks to the budget for these contracts, but provided no substantiation of whether the anticipated contingency will be sufficient to cover either category of risk.

BC Hydro responded to another Panel question by providing a partially redacted analysis of its new approach to realigning Highway 29.[467] It noted the expected budget overrun is included in the forecast allocated contingency amount.

BC Hydro had previously noted the available Site C Project contingency had increased due to interest rates being lower than forecast, with a corresponding reduction in the forecast allowance for interest during construction. In response to Panel questions, BC Hydro submitted analysis of the effect of possible interest rate rises on its available contingency:

Table 28: Impact of Market Interest Rates[468]

	Forecast rate of Interest During Construction					Increase in Site C Interest During Construction ($ million)
	F2018 (%)	F2019 (%)	F2020 (%)	F2021 (%)	F2022-F2025 (%)	
Forecast Interest During Construction Rate (current)	3.93	3.83	3.78	3.66	3.43	0
Change in Market Interest Rates:						
Impact of +0.5% interest rates	+0.07	+0.08	+0.10	+0.12	+0.14	32
Impact of +1.0% interest rates	+0.15	+0.17	+0.21	+0.23	+0.28	65
Impact of +2.0% interest rates	+0.30	+0.35	+0.44	+0.48	+0.58	136

BC Hydro noted that the impact of possible interest rate increases is mitigated by the amount of debt it has already issued or hedged.

Other submissions

Eliesen[469] submits the current budget should be considered to be $8.16 billion rather than $8.335 billion. He observes that BC Hydro has been managing to an in-service date of 2023 rather than 2024, and hence BC Hydro should not include the interest and inflation that take the budget from 2023 dollars to 2024 dollars. Instead, Eliesen calculates a budget of $8.16 billion by taking BC Hydro's original budget of $7.96 billion and

[467] Submission F1-10, BC Hydro, IR 2.14.0.
[468] Submission F1-5, BC Hydro, IR 2.12.0.
[469] Submission F13-2, Eliesen, p. 13.

adding $200 million for PST, but adding nothing for interest or inflation since the original figure was for an in-service date of 2023.

Flintoff[470] observes that a Class 3 estimate for Site C could have an accuracy range of -20 percent to +30 percent, and using the upper end of that range would predict a final cost of $11.408 billion. He adds that there may be merit in using the P90 figure for contingency calculated in BC Hydro's Monte Carlo analysis of the project costs. In response to a Panel question, BC Hydro submitted that its P90 value for the Site C construction cost contingency is $1.7 billion.[471]

In CEC's oral submission to the Panel, it described analyzing BC Hydro's cost performance building dams, and quotes a range of 25 percent to 75 percent overruns when compared to pre-construction budgets.[472]

5.2.2.4 Panel analysis and findings

The Panel finds that the project is not within the proposed budget of $8.335 billion. Further, the Panel finds that the total cost at completion may be in excess of $10 billion as there are significant risks remaining that could lead to further budget overruns.

BC Hydro states in its October 4, 2017 submission that it presently expects to spend $8.945 billion on Site C. This differs from BC Hydro's August 30, 2017 filing in which it stated that the project was on budget. The Panel understands that BC Hydro has not completed its work with the Province on a revised budget and that the disposition of the $440 million Treasury Board reserve is not known at this time.

Since BC Hydro has not yet completed an updated budget estimate, which the Panel expects will be a more refined estimate, it is necessary for the Panel to consider if there are other probable budget impacts that it should take into account in making its other findings required under the OIC.

Site C is currently at an early stage in its construction period. To date, significant risk events have occurred, including tension cracks and contractor issues that have caused BC Hydro to delay the timing of the diversion of the Peace River. At this point in time, none of these issues have been resolved and the estimated costs for the project have already grown by $610 million. There is no certainty that the river diversion will be completed in 2020. Given that the project is still at a relatively early stage in construction and the lack of certainty around the resolution of issues that led to the delay, the additional $610 million may just be the first in what could be a continuing series of additional risk events occurring, resulting in further cost overruns.

BC Hydro's latest estimate of expenditures for Site C is $8.945 billion, which is $610 million more than the $8.335 billion budget and the project is still only two years into a nine-year construction schedule. The Panel notes BC Hydro's response that it believes there is a "reasonable probability" that the budget overruns will be in the low or moderate categories (i.e. that the budget overruns will be between zero and 20 per cent) and the likelihood of the high impact scenario to be "very low" in its estimation.

A number of participants have suggested alternative approaches to estimating the cost at completion including adjusting the amount of contingency. The Panel considers BC Hydro's pre-FID P90 contingency estimate is a reasonable starting point for estimating a cost at completion until BC Hydro completes its new budget estimate. This P90 contingency assessment as prepared prior to the FID budget update was $1.7 billion, compared to the original approved contingency of $679 million plus $440 million in project reserve. It was developed by BC Hydro using a Monte Carlo contingency analysis and provides an estimate of the contingency which would have been required to have confidence that the budget estimate would be

[470] Submission F212-1, Flintoff, D. (Flintoff), p. 7.
[471] Submission F1-15, BC Hydro, IR 3.15, Attachment 1.
[472] TTP-2, October 14, 2017, Vancouver, p. 1546, lines 4–11.

exceeded only 10 percent of the time. The Panel considers that, when estimating a budget for a project of this nature, a Monte Carlo-based P90 contingency assessment would have been appropriate. The Panel also understands BC Hydro frequently uses a Monte Carlo-based P90 estimate for budget authorization from its Board of Directors, including contingency and project reserves.

In addition to adjusting the contingency to a P90 estimate, in the Panel's view it is necessary to adjust IDC and inflation to account for the higher estimated budget. BC Hydro acknowledges that the estimate of IDC changes with the timing of project costs and interest rates. Further, the Panel notes that BC Hydro has estimated that a 1.0 percentage point increase in the interest rate would increase its project costs by $65 million.[473]

BC Hydro has also provided a table of risks, indicating that all but one of the risks has a probability of occurrence of 10 percent and that all of them have a budget impact of $10 million - $100 million if they were to occur. Given the similarity of the estimates despite the diversity of the possible risks (from geotechnical to regulatory risks by way of reservoir filling), the Panel concludes that these assessments are not refined and further overruns could materialize.

Finally, BC Hydro has provided confidentially to the Panel amounts of contractor claims that have been received but not accepted. The Panel accepts that these amounts should remain confidential.

There is a high degree of uncertainty at this time. As such the Panel is persuaded by the analysis performed by Deloitte, which indicated that in a "high impact" scenario the budget may be exceeded by between 20 and 50 percent. The first of the possible events described by Deloitte in the high impact scenario, the delay in the river diversion, has already become a reality. While this has only so far caused BC Hydro to increase its expected costs for the project to $8.945 billion, the project is only two years into a nine-year construction schedule. Other challenges, and a further one-year delay in the river diversion are still possible, and other increases in budget are likely.

The Panel notes that Eliesen concludes that the final Site C capital costs will be about $12 billion. Others have submitted that large hydro projects are subject to large cost overruns and provided some examples to support this. The Panel is not persuaded there is sufficient evidence to support the finding of an estimated cost overrun of this magnitude. However, given the nature of this type of project and what has occurred to date, total costs for the project may be in excess of $10 billion and there are significant risks that could lead to further budget overruns. The Panel considers this amount is a reasonable point estimate to use in making its other findings required under the OIC.

5.3 Other implications of continuing Site C

In addition to the directs costs for continuing with Site C, there are a number of potential and actual indirect costs which are difficult to determine whether they will actually occur and, if so, how to quantify them. Many of the implications were identified by the Joint Review Panel in its report, including the following findings by the Joint Review Panel:

> The Panel concludes that the Project would likely cause a significant adverse effect on other traditional uses of the land for the First Nations represented by Treaty 8 Tribal Association, Saulteau First Nations, and Blueberry River First Nations, and that some of these effects cannot be mitigated[474]

[473] Submission F1-5, BC Hydro, IR 2.12.0.
[474] Submission F28-2, Prophet River and West Moberly First Nations, Tab 2, JRP Report, May 1, 2014, p. 113.

> …Site C would seem cheap, one day. But the Project would be accompanied by significant environmental and social costs, and the costs would not be borne by those who benefit. The larger effects are:
>
> - Significant unmitigated losses to wildlife and rare plants, including losses to species under the Species at Risk Act and to game and plant resources preferred by Aboriginal peoples;
> - Significant unmitigated losses to fish and fish habitat, including three distinct sub-groups of fish preferred by Aboriginal peoples, one of which is federally listed as a species of special concern;
> - Losses of certain archaeological, historical and paleontological resources
> - Social costs to farmers, ranchers, hunters, and other users of the Peace River valley; and
> - Forced changes to the current use of lands and waters by signatories to Treaty 8, other First Nations and Métis, whose rights are protected under article 35 of the Constitution Act, 1982.
>
> These losses will be borne by the people of the Valley, some of whom say that there is no possible compensation. Those who benefit, once amortization is well underway, will be future electricity consumers all across the province.[475]
>
> …Justification must rest on an unambiguous need for the power, and analyses showing its financial costs being sufficiently attractive as to make tolerable the bearing of substantial environmental, social, and other costs.[476]

Many of these were issues were raised by the public in Community Input Sessions or by First Nations in their input sessions. These submissions have been described in depth in Sections 3.4 and 3.5.

In this section, the Panel outlines some of the other implications of continuing Site C to allow the issues to be further investigated or examined prior to a final decision being made with respect to Site C.

Potential First Nations settlement costs

The West Moberly and Prophet River First Nations submit that Site C will have adverse effects on Treaty 8 First Nations to meaningfully exercise their treaty rights and these rights cannot be mitigated. The courts have addressed administrative law issues including the Crown's duty to consult but have not addressed whether the Crown, by approving Site C has unjustifiably infringed the Treaty 8 rights. West Moberly and Prophet River First Nations submit that the Crown bears the risk that in the event a lawsuit is commenced, the court will find in favour of Treaty 8 First Nations. The amount at stake cannot be determined at this time.

As noted, the Blueberry First Nation has already commenced litigation against the Provincial Government, which sought, in part, to enjoin the new industrial activity within their traditional territory; a trial is reported to be imminent.

The Mikisew Cree First Nation traditional territory is on the Peace River and the Athabaska River Delta. It submits that Site C will further impede the flow of water into its area thereby affecting its Treaty 8 rights. Mikisew Cree First Nation states that whether the building of Site C is an infringement of its Treaty 8 rights will be left to be determined in future legal proceedings.

[475] Submission F28-2, Prophet River and West Moberly First Nations, Tab 2, JRP Report, May 1, 2014, p. 307.
[476] Submission F28-2, Prophet River and West Moberly First Nations, Tab 2, JRP Report, May 1, 2014, p. 308.

Impact of the loss of agricultural land if Site C is built

This issue was raised by individuals throughout the Community Input Sessions. The basis of the issue is that when Site C is completed the flooding required will cover valuable agricultural land that, because of the many micro climates along the Peace River Valley, might be used to grow produce that cannot be grown elsewhere in the region.

The claim made by many, is that the land being flooded could feed a million people. As best as the Panel is able to ascertain, this claim is made on the basis of a study commissioned by BC Hydro titled "Peace River Site C Hydro Electric Development: Vegetable Industry Study," where the primary objective was to "review the land base of the entire valley from Hudson Hope to the Alberta border and to determine the impact of Site C on future development of vegetable production." The study stated that the land base with vegetable potential would be reduced from 22,174 acres to 16,625 acres and sand alluvial soil from 10,724 acres to 6,254 acres as a result of the Site C reservoir. [477]

The report also states that a processing plant for vegetables in the Peace River Valley did not appear to be economic as it would require a market area with a population of roughly 1,200,000 and a land base of approximately 5,500 acres. Thus, it appears that while the market was not big enough to support a processing plant, there was sufficient land to support the growing of the vegetable product. The conclusion reached with respect to its land based analysis was that "the Site C project would not appear to preclude the future development of a vegetable industry in the Peace River Valley. The study also makes the following observation:

> Returns to growers from processing vegetables do not appear to be any better than returns from traditional crops such as grain and alfalfa. Existing farmers and landholders are unlikely to switch to processing vegetables as vegetable production would not improve their incomes.[478]

The Panel notes that this study was completed in 1980 and is most certainly out of date, but based on the study the conclusion can be reached that while significant acreage capable of growing vegetables will disappear with Site C's reservoir, there still remains ample land in the Peace River Valley to develop a vegetable industry if it is considered viable.

Potential for a change in BC Hydro or the Provincial Government's credit rating

This was an issue that was also raised numerous times in the Community Input Sessions held across the province. Many people made submissions that BC Hydro's accounting practice, use of deferral accounts and growing debt may have an impact on BC Hydro or the Provincial Government's credit rating. At least one such presenter asked the Commission to review this issue. While out of scope for this review, if this concern were to become a reality, there would be an impact on either ratepayers or taxpayers.

Impact on the environment

Submissions from First Nations were replete with the impact that Site C and projects like it have on the natural habitat. West Moberly and Prophet River First Nations have raised the issue of elevated levels of methylmercury in fish resulting from foliage emissions in the Williston reservoir and fear a similar occurrence once the Site C reservoir is created with potential impacts on their food sources. Sentiments concerning the loss of habitat, game and the ability to hunt and fish were noted throughout the First Nations presentations and were echoed by many in the Community Input Sessions.

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[477] Peace River Site C Hydro Electric Development: Vegetable Industry Study, March 1980, issued by BC Hydro, pp. 104–106.
[478] Peace River Site C Hydro Electric Development: Vegetable Industry Study, March 1980, issued by BC Hydro, pp. 112–113.

The David Suzuki Foundation (DSF) has studied the Peace River Region extensively and asked the Commission to consider the impacts of Site C on the natural capital in the region. DSF contends that this natural capital related to the Peace River Valley and associated ecosystems are worth hundreds of millions of dollars annually in non-market benefits. Specifically, DSF estimates the annual value to be in the billions through the ecological services provided by farmland and the nature in the Peace River Watershed "through the cumulative contribution of services such as water supply, air filtration, flood and erosion control, habitat for wildlife and agriculture pollinators, carbon storage and other benefits."[479]

[479] Submission F87-1, David Suzuki Foundation (DSF), cover letter.

6.0 Case 2 – Terminate Site C

6.1 The question posed under the OIC

Section 3(a)(iii) of the OIC states that the Commission must advise on the implications of terminating construction and remediating the site.

Section 3(b)(i) asks: "What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?"

6.2 Remediation and contract termination costs

For the purposes of this analysis, the Panel has assumed that the project would be terminated on December 31, 2017. BC Hydro notes: "Variations in the termination date of a few months earlier or later would not be material to the outcome."[480]

6.2.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro estimates costs of $1 billion to demobilize the project and remediate the site, which consists of $300 million to terminate the project and $700 million to remediate the site. The figure of $700 million is converted to a present value cost of $600 million by BC Hydro in the subsequent portions of its analysis.[481] BC Hydro states that its estimates of $300 million to terminate the current project and $600 million (in present value costs) to remediate the site[482] are Class 5 estimates, accurate to within a range of +100 percent and -35 percent,[483] and include a contingency of 30 percent.[484]

BC Hydro explains that its $300 million estimate of termination costs includes paying construction contractors for work completed and for stopping work and demobilizing from the site, and the amounts required to "terminate other contracts including environmental consulting, engineering and benefit agreements it has entered into with respect to the Project."[485] The benefit agreements BC Hydro refers to are further explained as being community benefit agreements and First Nation benefit agreements.[486]

According to BC Hydro, the remediation work estimated at $600 million would bring the site "to a condition that does not create a risk to public safety and reduces future environmental impacts,"[487] but BC Hydro has "not assumed that the site will be restored to pre-project conditions – such a standard would significantly increase" the cost estimate and timeline.

BC Hydro adds that it has included costs to maintain a project team to manage the termination work, but does not state whether these costs are included in the $300 million figure or the $600 million figure. BC Hydro has prepared a detailed list of the activities required to cancel the project, but these have not been costed individually.[488]

480 Submission F1-1, BC Hydro, p. 67.
481 Submission F1-1, BC Hydro, pp. 68, 73.
482 Submission F1-1, BC Hydro, p. 73, Table 13.
483 Submission F1-1, BC Hydro, p. 68.
484 Submission F1-1, BC Hydro, p. 69.
485 Submission F1-1, BC Hydro, p. 70.
486 Submission F1-1, BC Hydro, Appendix O, pp.29–30.
487 Submission F1-1, BC Hydro, p. 70.
488 Submission F1-1, BC Hydro, Appendix O.

BC Hydro also notes it will have incurred $2.1 billion in costs prior to a potential termination of Site C and that if Site C were terminated there would be approximately $4.2 billion of additional costs related to higher costs of alternative supply.[489]

BC Hydro goes on to explain that the figure of $2.1 billion in costs incurred prior to termination consists of $500 million already in the Site C regulatory account and $1.6 billion in capital project costs incurred to December 31, 2017.[490] BC Hydro adds that the balance in the Site C regulatory account includes accrued interest charges.

Deloitte report

Deloitte estimated that the incremental cost of terminating the Site C project is "approximately $1.2 billion, excluding inflation impacts and interest costs."[491] Deloitte included the activities of "Management of existing contracts and commitments" and "Creation of a new project (the Termination Project)" in its estimates. Deloitte does not comment on the sunk costs of the Site C project.

Deloitte estimated the termination and remediation costs to be $1.203 billion, to a Class 5 accuracy of +100 percent/-35 percent, including 30 percent contingency.[492] Deloitte included in its estimates figures of $320 million for cancelling existing contracts and benefit agreements and $50 million for demobilization. Deloitte identified the contracts to be cancelled as: main civil works, turbines and generators, and worker accommodation.[493] It added that benefit agreements include First Nation and community agreements. In addition to contract termination costs, Deloitte estimated that $50 million will be required to cover demobilization activities by contractors.[494]

Deloitte explained that its costs of remediation include work to "return the site to natural conditions capable of supporting natural vegetation and wildlife."[495] It adds that this work "is extensive enough to require independent project planning for control of budget and schedule" and includes "environmental appraisal, permitting, and planning for construction and contracting." Deloitte provided details on the remediation activities, although detailed costs are not presented.[496]

6.2.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The analysis in this section considered only the costs to terminate the project and to remediate the site.

The Panel presented its preliminary findings in the following table:

Table 29: Preliminary Panel Findings – Termination and Remediation

Findings	Cost
Termination costs	$391 million
Remediation costs	$662 million
Total	$1.1 billion

[489] Submission F1-1, BC Hydro, p. 66.
[490] Submission F1-1, BC Hydro, p. 67.
[491] Submission A-8, p. 66.
[492] Submission A-8, pp. 66, 83.
[493] Submission A-8, pp. 47–50.
[494] Submission A-8, p. 53.
[495] Submission A-8, p. 66.
[496] Submission A-8, pp. 76–82.

6.2.3 Additional submissions and responses

BC Hydro presents a summary of its and Deloitte's earlier submissions of termination and remediation costs:

Table 30: Comparison of Termination Cost Estimates

Cost Component[1]	Deloitte Estimate[2] (F2018$, million)	BC Hydro Estimate[3] (F2018$, million)
Cost to terminate	370	182
Cost impact of site remediation	555	650
Contingency	278	249
Total including Contingency	1,203	1,081

BC Hydro states that the Panel must consider financing and alternative energy costs in addition to the figure of $1.1 billion in termination and remediation costs arrived at for the Preliminary Report.[497] It added that the P90 value of its estimate of these costs would imply an additional $700 million for a total of $1.8 billion, and that there is a 10 percent likelihood of this occurring.

Similarly, BCSEA[498] submits that the Class 5 accuracy of the estimate for termination and remediation yields a range of $700 million to $2.2 billion.

6.2.4 Panel analysis and findings

The Panel finds that termination and remediation costs would likely be in the range of $750 million to $2.3 billion.

BC Hydro's estimate for combined termination and remediation costs with contingency is $1.081 billion based on a Class 5 estimate (accuracy range is -35 percent to +100 percent), yielding a range of $703 million to $2.162 billion. Likewise, Deloitte's estimate with contingency is $1.203 billion, and the same Class 5 accuracy yields a range of $782 million to $2.406 billion. **The Panel finds it reasonable to take an approximate mid-point between each of the lower and upper bounds, yielding a range of $750 million to $2.3 billion.**

The Panel notes that a P90 value for the termination and remediation costs would provide a reasonable budget estimate at this point in a project's life, considering the level of project definition, the inherent uncertainties and the effort and time available to prepare the estimates. As such, **the Panel finds a reasonable budget estimate for termination and remediation of Site C is BC Hydro's P90 value of $1.8 billion.**

The Panel agrees with BC Hydro that financing and alternative energy costs must be considered when looking at the total ratepayer impact of termination. Those factors are considered in Section 6.3 below.

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[497] Submission F1-12, BC Hydro, p. 31.
[498] Submission F29-9, BCSEA, p. 37.

6.3 Alternative portfolio to Site C

6.3.1 The question posed under the OIC

Section 3(b)(iv) of the OIC asks:

> Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?

British Columbia's Energy Objectives

Section 2 of the CEA defines "British Columbia's energy objectives":

a) to achieve electricity self-sufficiency;

b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;

d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;

e) to ensure the authority's ratepayers receive the benefits of the heritage assets and to ensure the benefits of the heritage contract under the *BC Hydro Public Power Legacy and Heritage Contract Act* continue to accrue to the authority's ratepayers;

f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;

g) to reduce BC greenhouse gas emissions

   i. by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,

   ii. by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,

   iii. by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,

   iv. by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and

   v. by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;

h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;

i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

j) to reduce waste by encouraging the use of waste heat, biogas and biomass;

k) to encourage economic development and the creation and retention of jobs;

l) to foster the development of first nation and rural communities through the use and development of clean or renewable resources;

m) to maximize the value, including the incremental value of the resources being clean or renewable resources, of British Columbia's generation and transmission assets for the benefit of British Columbia;

n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

o) to achieve British Columbia's energy objectives without the use of nuclear power;

p) to ensure the commission, under the *Utilities Commission Act*, continues to regulate the authority with respect to domestic rates but not with respect to expenditures for export, except as provided by this Act.

The question set out in the OIC states that "[g]iven the energy objectives set out in the *Clean Energy Act*, what, if any, other portfolio of commercially feasible generating projects and demand side management initiatives could provide similar benefits" to Site C. However, the question stops short of requiring a comparison of how the alternative portfolio meets the objectives compared to Site C.

6.3.2 Key submissions and issues raised in the Preliminary Report

For the purpose of addressing OIC 3(b)(iv), BC Hydro undertook a "block unit energy cost" and portfolio present value cost analysis (Portfolio PV analysis) to compare the cost of Site C with an alternative portfolio of energy and capacity resources (BC Hydro Alternative Portfolio).

Appendix A contains a review of alternative sources of generation and capacity that have been presented by BC Hydro, Deloitte and other parties. Although not directly available to BC Hydro, many parties (including BC Hydro) commented on the availability and appropriateness of the Columbia River Treaty Entitlement. We provide comments on these submissions in Appendix B.

The analysis of the alternative energy sources provided in Appendix A informs the development of alternative portfolios and the comparative costs of those portfolios. Alternative portfolios and the comparison of their costs to Site C costs are discussed in the following sections.

BC Hydro's "block unit energy cost" analysis

BC Hydro used a "block unit energy cost" or "Block UEC" to compare the estimated unit energy cost of Site C to what BC Hydro described as a similarly sized blocks of energy and capacity from other sources. BC Hydro stated: "While Portfolio PV Analysis is BC Hydro's preferred approach to making resource acquisition decisions, looking at resources' Unit Energy Costs can help explain the results of Portfolio PV Analysis. Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced."[499]

BC Hydro presented the following comparison:

[499] Submission F1-1, BC Hydro, p. 61.

Table 31: Comparison of BC Hydro Site C and Alternative 'Block Unit Energy Cost'

BC Hydro Site C 'Block Unit Energy Cost'	
Cost Factor	**Unit Energy Cost $/MWh**
Site C Cost To Ratepayers in 2013 Integrated Resource Plan (November 2013) at Point of Interconnection in F2013$	**$83**
Change to project capital and operating costs	+1
Debt Finance as per OIC No.590-2016 Net Income Frozen	-26
Site C Cost To Ratepayers at Final Investment Decision (December 2014) at Point of Interconnection in F2013$	**$58**
Updated financing rates and conversion to F2018$	-10
Adjustment for Delivery to Lower Mainland and annual shape adjustment	+10
Site C Cost To Ratepayers Today Delivered to Lower Mainland in F2018$	**$58**
Adjustment For Sunk Costs	-15
Site C Cost To Ratepayers Today Less Sunk Costs	**$43**
Delivered to Lower Mainland in F2018$	
Credit for avoiding termination and site remediation costs	-9
Site C Cost To Ratepayers Today Less Sunk Costs and Credit for Termination / Remediation Costs Delivered to Lower Mainland in F2018$	**$34**

BC Hydro Alternative 'Block Unit Energy Cost'	
Cost Factor	**Unit Energy Cost $/MWh**
Energy Resources (Generally Wind)	
Total Cost - Point-of-Interconnection	**$85**
Annual shape adjustment	-2
Levelized Firm Energy Price (values annual shape)	**$83**
Add Adjustments to reflect cost to Lower Mainland	
Cost of Incremental Firm Transmission	+2
Cost of Required Network Upgrades	+6
Line Losses	+9
Wind Integration Costs	+5
Wind Adjusted UEC – Delivery To Lower Mainland	***$105***
Capacity Resources (Pumped Storage)	
Fixed Costs	+31
Costs of Energy Loss (30% Pump/ Generation Cycle)	+17
Combined Clean Alternative Block	**$153**

BC Hydro stated: "[t]he resources that would be the long-term alternative to Site C are expected to be wind combined with pumped storage to provide firming and shaping services. These are the marginal resources in the portfolio analysis, and are thus the resources shown in the simplified Block UEC Analysis."

To arrive at the “final” unit energy cost, BC Hydro stated that it started with a plant gate wind unit energy cost ($85/MWh) and made adjustments with various “adders.” These include adjustments for shape, transmission, line losses, wind integration and pumped storage and increased the unit energy cost to $153/MWh.

CEABC submits that the fundamental concept of adders is simple - to estimate the economic impact of different project attributes on BC Hydro’s overall system. However, it submits that although the underlying purpose for these adders is well-intentioned, every item in the list is fraught with uncertainties and judgments that are well beyond the project’s ability to control. Most of these do not represent actual cash outlays from ratepayers’ pockets, but rather hypothetical contingency allowances for future events that might possibly occur (or may not occur at all).[500]

BC Hydro’s portfolio PV analysis

BC Hydro describes its Portfolio PV Analysis as its main tool to compare resource options, and submits that it is standard utility practice for resource planning. BC Hydro states that this tool is the proper method for comparing the costs associated with a portfolio that includes completing Site C to the costs associated with portfolios based on (a) terminating the Project, remediating the site, recovering sunk costs and building an alternative portfolio, or (b) suspending the Project for a number of years. [501]

BC Hydro describes the benefits of Portfolio PV Analysis as including the following:

- It compares the cost of alternative supply options in the context of how the electricity system is built and operated;
- It times the addition of resources to the portfolio to match customer need. BC Hydro states that this is important because alternative resources (which provide smaller increments than Site C) would not all be brought in at once. The portfolio therefore analysis recognizes the potential benefit of the smaller and more incremental introduction of these alternative resources;
- It models the different levels of supply and the resulting trade with neighbouring electricity markets, which allows BC Hydro to include the value of surplus energy in the markets as an offset to costs;
- Present value calculations reflect the time value of money – i.e., that costs or benefits in the future are worth less than costs or benefits today. BC Hydro uses a time-value of money (or “discount rate”) equal to our weighted average[502] cost of capital of 6 percent (in nominal dollars);
- The Terms of Reference require the Commission to consider the “costs to ratepayers” of suspending or terminating Site C. The PV analysis is performed based on costs to ratepayers; and
- The Terms of Reference also require consideration of reliability and greenhouse gas emission (“the energy objectives set out in the *Clean Energy Act*,” “maintenance or reduction of 2016/17 greenhouse gas emission levels”). These are considerations included in the Portfolio PV Analysis.[503]

BC Hydro proposed a number of alternative portfolios, all consisting of a combination of wind and pumped storage. BC Hydro states that other potential sources were screened out of the analysis due to unsuitability, commercial immaturity or some other factor(s). Further, the portfolio optimization tool used by BC Hydro selected a combination of wind energy and pumped storage for all the portfolios. A sample is shown below:

[500] Submission F18-3, CEABC, p. 63.
[501] Submission F1-1, BC Hydro, pp. 60–61.
[502] Submission F1-1, BC Hydro, p. 60.
[503] Submission F1-1, BC Hydro, pp. 60–61.

Table 32: BC Mid load forecast with current DSM plan transitioning to IRP DSM. Site C completed on current schedule[504]

UECs and UCCs are shown for energy and capacity resources respectively. The UEC/UCC shown includes wind integration costs and network upgrade costs where applicable.

Resources Selected

Year	Zone	Resource	Capacity - MW Installed	Capacity - MW Dependable	Energy - GWh Firm	Energy - GWh Total	UEC / UCC $/MWh or $/kW-year
2023	BCH_PR	Site C	1145	1,145	5,286	5,286	34
2025	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2027	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2034	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2035	BCH_PR	Wind_PC20	156	41	594	594	92
2037	BCH_NC	Wind_NC09	333	87	1,074	1,074	101
2038	BCH_PR	Wind_PC18	138	36	524	524	92
2039	BCH_PR	Wind_PC28	153	40	641	641	94
2040	BCH_PR	Wind_PC14	144	37	570	570	92
2040	BCH_LM	2017 Load Curtailment	85	85	0	0	77
2041	BCH_PR	Wind_PC48	150	39	538	538	95
2041	BCH_KN	Wind_SI16	660	172	1,814	1,814	111

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2023	Increase series compensation of 5L1, 5L2, 5L7 from GMS to WS	PR to CI	360
2023	Increase series compensation of 5L11, 5L12, 5L13 from WSN to	CI to KN	390
2023	Static VAr compensation at WSN	PR to KN	650
2025	Nicola-Vaseux Lake Compensation (NVLC)	SEL to KN	147
2026	Shunt compensation at NIC and MDN	KN to LM	570

However, we note that BC Hydro did not identify a specific output of its PV Portfolio tool as the basis of its block UEC analysis in Table 31.

Some of the assumptions used in the portfolio analysis are similar to the assumptions in similar analyses presented previously in the 2012 and 2013 IRP. Parties had a number of comments and concerns with these assumptions including:

- The 70 year planning horizon;
- The life of the upstream W.A.C. Bennett dam;
- The discount rate used;
- The pricing of alternative energy sources;
- The pricing of "Natural Capital"; and
- The economic impact of the dam's effect on the Athabasca delta.

Deloitte's portfolio analysis

Deloitte used a different model (MarketBuilder) to determine the Net Present Value (NPV) cost of resources which could replace Site C. The portfolio selected by the MarketBuilder model comprises a range of existing facilities and new alternative resources. These include:

- BC Hydro hydroelectric facilities (existing and committed);
- BC Hydro natural gas facilities – CCGT and SCGT;
- EPA contracts (existing and renewals) – biogas, biomass, cogeneration, hydroelectric, MSW, solar, onshore wind (Okanagan and Peace River regions);

[504] Submission F1-1, BC Hydro, Appendix Q, pp. 4–14.

- BC Hydro hydroelectric facilities (new endogenous);
- Biogas (new);
- Geothermal (new); and
- Onshore wind – Vancouver Island (new).

The portfolio selected by the MarketBuilder model included new capacity hydroelectric facilities beginning in 2018, with additional geothermal added in 2027. Biogas and wind begin to add capacity later in the planning period, in 2029 and 2034, respectively. Capacity from biomass decreases in 2018 and 2019 due to the expiration of existing EPAs that are assumed to not be renewed. Deloitte state that total annual capital costs from the development of new biogas, geothermal, hydroelectric and wind facilities reach $951,484 by 2036, with annual O&M costs of $583,839.[505]

Financing costs

CEABC raises concerns with BC Hydro's debt financing. It states: "Even though the 'zero return on equity' policy was apparently adopted for the Site C project, in [the 2017 to F2019 Revenue Requirements Application CEABC IR 1.12.4], a BC Hydro response to a CEABC Information Request ("IR") unequivocally confirmed that an entirely different approach is being used in BC Hydro's financial evaluations of all other projects. The 70/30 weighted average cost of capital ("WACC") approach (including an 11.84% return on equity), was still the method being used."

Swain comments that:

> [i]n corporate finance, equity is the buffer between unexpected realities and bankruptcy. BC Hydro is merely outsourcing this risk to the general BC taxpayer. They are not making it go away. And as for financing billions at current rates, the risk is overwhelming that refinancing costs during a 70-year term will be significantly higher than they are at present. Transferring these risks to the taxpayer owners of the company without compensation is irresponsible financial sleight-of-hand.[506]

West Moberly and Prophet River First Nations submit that even though the government of British Columbia proposes to charge BC Hydro less than cost for its equity for a number of years, the actual cost, however, is a real cost and will be paid by taxpayers and ratepayers.[507]

Discount rate

CEABC provided a commentary from the CD Howe Institute regarding "[f]our mistakes [that] are commonly made when evaluating public and private investments." CEABC further stated that the second mistake identified in the CD Howe report is: "Using a cost of capital for the business as a whole (e.g. the weighted average cost of capital, or WACC, corresponding to the cost of financing) in the assessment (usually the NPV) of all its investments rather than using a specific cost of capital for each project, properly assessed against the risk of that particular project."[508]

Site C flexibility

BC Hydro's considers Site C's "'dispatchability' or dependable operational flexibility" as having more value to a utility than generation from intermittent resources, such as wind, which generates only when the wind is blowing, or solar, which generates only when the sun is shining.

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[505] Submission A-9, p. 105.
[506] Submission F36-1, Swain, pp. 18–19.
[507] Submission F28-2, Prophet River and West Moberly First Nations, Tab 7, Site C Business Case Assumptions Review, McCullough, R., dated May 25, 2015, p. 5.
[508] Submission F18-3, CEABC, pp. 9–10.

BC Hydro explains that new market opportunities to monetize surplus capacity and flexibility in its system are expected to arise in coming years. As an example, it points out that utilities with coal base-load generation in Alberta and the Pacific Northwest are developing plans to replace coal generation and expect most of it to be retired by the mid-2020s. BC Hydro believes that this coal-based generation will be partly replaced with local renewable generation such as wind, but doing so will reduce the current capacity and there will be an increased need for flexibility. BC Hydro acknowledges that these utilities will likely replace the coal capacity by installing natural gas fired generation, thereby creating the flexibility to integrate new wind and solar installations. However, given the high capital cost of gas-fired generation, they may find the procurement of flexible hydro capacity attractive from both a cost and environmental perspective. BC Hydro speculates that a 10 to 20 year commitment for clean, flexible generation would let these utilities either displace or delay the significant capital costs of building new gas fired generation.[509]

BC Hydro also explains that as a direct result of California's aggressive environmental policies driving change in the state's resource mix, there is a need for flexibility and capacity products in California. In addition to the growing requirement for flexible resources to balance and backstop solar production, the state is increasingly seeking clean alternatives to natural gas generation for its capacity and flexibility needs. BC Hydro considers there to be increasing potential to monetize its surplus hydro capacity and flexibility by selling these products in the California market. If it becomes clear there will not be a requirement for Site C's full generation, Powerex will seek sales to maximize the value of the surplus capabilities.[510]

6.3.3 Panel analysis, preliminary findings and questions in the Preliminary Report

Definitions

In the Preliminary Report the Panel adopted the following definitions of *firming, shaping, storage and Unit Energy Cost* for the purpose of section 3(b)(iv) of the OIC:

> ***Firming capability*** is the ability of resources to quickly change output in response to changes in customer demand and output from variable generation resources that fluctuate within the hour (e.g. wind or solar). The best resource for this capability is large hydro, but it can also be also supplied by pumped storage and gas-fired generation. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors, do not have this capability;
>
> ***Shaping capability*** is the ability of resources to reduce their generation supply within the day to allow the electricity system to absorb variable resource electricity (e.g., wind, run-of-river, solar) when its customers do not need it and then to release that energy later in the day when it is required. Large hydro and pumped storage have this ability and other storage methods are being developed such as batteries or compressed air; and
>
> ***Storage capability*** is the ability of resources to adjust their generation supply at certain periods within the year to respond to seasonal changes in variable generation resources (e.g., run-of river hydro output is highest during the spring freshet and lower in the late summer). Only large hydro resources have the capability to store electricity seasonally.
>
> ***Unit Energy Cost*** (UEC) simply expresses the cost for a resource by its levelized annual cost per unit of energy produced. [511]

[509] Submission F1-1, BC Hydro, Appendix S, pp. 1–2.
[510] Submission F1-1, BC Hydro, Appendix S, pp. 1–3.
[511] Submission A-13, pp. 75–76.

In addition, the Panel invited comment on its interpretations of commercially feasible, grid reliability and maintenance or reduction of 2016/2017 greenhouse gas emission levels. For ease of reference, the Panel's interpretations are repeated below:

> ***Commercially feasible*** means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time. Publicly verifiable data exists on technical and financial performance. Regulatory challenges (e.g. safety certifications, lack of standards) have been addressed in multiple jurisdictions.
>
> ***Grid reliability*** means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards.
>
> ***Maintenance or reduction of 2016/2017 greenhouse gas emission levels*** means that the alternative portfolio must not increase the greenhouse gas intensity of BC Hydro's greenhouse gas emissions, as measured in CO2 tonnes equivalent per GWh generated.

BC Hydro "Block Unit Energy Cost" analysis

In the Preliminary Report, the Panel found that, for a portfolio, the usefulness of BC Hydro's "block unit energy cost" methodology is limited as a comparison methodology because it does not appear to take into account when the energy sources come on line or that the costs of many clean energy technologies are decreasing over time. In addition, the Panel found that the adjusted "block unit energy cost" of the BC Hydro Alternative Portfolio is too opaque to be of value in a comparison of costs of Site C to an alternative portfolio and that adjustments to the Site C UEC financing costs result in an "apples to oranges" comparison to the alternative block. [512] These concerns were also expressed by several submitters.[513]

BC Hydro PV Portfolio Analysis

The Panel found that the assumptions used by BC Hydro in the Portfolio PV Analysis were not as well documented as they needed to be to allow the Panel to make any findings regarding the appropriateness and cost of alternative portfolios, in particular in the development of the assumptions of energy sources (a similar concern as expressed in regard to the derivation of the "block unit energy cost"). For example, there are no capital, O&M, tax, etc. cost assumptions provided for these sources.

BC Hydro was requested to clarify the portfolio assumptions and to model different scenarios which included changed assumptions regarding the load forecast, DSM, and different alternative energy sources and costs. BC Hydro was also requested to explain whether it has considered the relative risk of the projects in the alternative portfolio. Parties were also requested to provide comment on the approach to the discount rate recommended by the CD Howe Institute.

Site C flexibility

In the Preliminary Report, the Panel stated that BC Hydro has demonstrated the potential value of capacity and flexibility as compared to an intermittent wind or solar source but has not provided evidence to support the notion that there are potential customers actively seeking to purchase this capability now or in the future. The Panel, noting that BC Hydro currently forecasts a capacity surplus prior to completion of Site C for 2018 through 2022, raised the question as to whether BC Hydro has pursued the sale of this surplus in other jurisdictions and the results or whether this potential is speculative at this point in time.

In addition to the specified information requests, the Panel asked a number of questions concerning BC Hydro's submissions on market price forecasts. These covered a range of topics including:

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[512] Submission A-13, pp. 86, 92.

[513] Submission F28-2, Prophet River and West Moberly First Nations, Tab 7, Site C Business Case Assumptions Review, McCullough, R., dated May 25, 2015, p. 5., p. 10; Submission F106-4,PoWG, p. 118.

- Details on the transmission lines to the US and Alberta (maximum rating for exports, firm and non-firm transmission capacity generally available and percentage of the time the transmission line is on average constrained);
- Impact of future technical advances on market value of flexibility benefits; and
- Potential implications and impact of joining or not joining the Energy Imbalance Market (EIM).

6.3.4 New submissions and responses

Definitions

BC Hydro generally agreed with the Panel's interpretation of "commercially feasible." However, in its view consideration of resource viability should be added to the definition as follows:

> Publicly verifiable data exists that confirms the viability of the resource in terms of its energy source (e.g. the availability of adequate volumes of hot water should be confirmed prior to a geothermal site being described as commercially available).[514]

BC Hydro submitted that resources, such as geothermal, that have no verified energy source in BC, are not viable and should not be relied upon.[515]

BC Hydro submits the Panel should interpret "maintenance or reduction of 2016/17 greenhouse gas emission levels" to mean greenhouse gas emission levels, rather than greenhouse gas emission intensity.[516]

CEABC submits that, if there is a capacity shortage, an alternative is to increase DSM curtailment or to add SCGTs. CEABC states that SCGT GHGs can be the same as Site C, and if GHGs are high, one could move to biogas or offsets. It also submits that Site C's GHG emissions were enormous in the early years, as rotting vegetation emits methane. It also submits that SCGTs can easily compete until at least 2040, allowing more time for battery technology/cost to advance.[517]

BC Hydro stated that its interpretation of "grid reliability" in this context refers to the reliability of an integrated power system grid consisting of generation, transmission and distribution. It further states that cost and reliability of the integrated grid needs to be considered in portfolio analysis and that it follows Commission-approved Mandatory Reliability Standards to ensure adequate transmission with generation resources are planned to meet the widely used "one day in ten years Loss of Load Expectation" criterion.[518]

BC Hydro 'Block Unit Energy Cost' analysis

Regarding the use of BC Hydro's Block UEC cost analysis as an approach to respond to the question posed by OIC 244, BC Hydro states:

> BC Hydro agrees with the Panel that the usefulness of the simplified "Block UEC Analysis" described in section 5.6 is limited as a comparison tool. … We continue to believe that portfolio analysis is the most comprehensive analysis and should be used for comparing resource options.[519]

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[514] Submission F1-6, BC Hydro, IR 2.23.0.
[515] Submission F1-6, BC Hydro, IR 2.23.0.
[516] Submission F1-12, BC Hydro, Appendix F, p. 3.
[517] Submission F18-6, CEABC, p. 6.
[518] Submission F1-6, BC Hydro, IR 2.23.0.
[519] Submission F1-5, BC Hydro, IR 2.78.0.

BC Hydro PV portfolio analysis

BC Hydro was requested to clarify the portfolio assumptions and model different scenarios which included changed assumptions regarding the load forecast, DSM, and different alternative energy sources and costs. BC Hydro was also requested to explain whether it has considered the relative risk of the projects. BC Hydro provided the following portfolio sensitivity results:[520]

Table 33: BC Hydro PV model – portfolio sensitivities

Commission Portfolio Sensitivities	Benefit Site C Portfolio vs. Alt. Resources Portfolio (PV - $ billion)	Site C Portfolio Unit Energy Cost ($/MWh)	Alternative Resources Portfolio UEC ($/MWh)
Mid Gap - UEC Sensitivities	6.2	73	96
+10% Site C Project Cost	5.8	75	96
+20% Site C Project Cost	5.4	76	96
+50% Site C Project Cost	4.3	81	96
Mid Gap - UEC Sensitivities + Low Market Prices	6.0	75	99
Mid Gap - UEC Sensitivities + BCH Financing of Alternates	4.7	62	79
Mid Gap - UEC Sensitivities + BCH Financing of Alternates + Low Cost Wind Renewals	4.6	61	78
Mid Gap - UEC Sensitivities + BCH Financing of Alternates + Low Cost Wind Renewals + Low Market Prices	4.1	65	81
Small Gap – UEC Sensitivities	6.1	35	73
Small Gap – UEC Sensitivities + Low Market Prices	4.7	38	70
Small Gap – UEC Sensitivities + Low Market Prices + BCH Financing of Alternates + Low Cost Wind Renewals	3.8	34	59
+10% Site C Project Cost	3.4	35	59
+20% Site C Project Cost	3.0	37	59
+50% Site C Project Cost	1.9	43	59
Large Gap – UEC Sensitivities	9.7	128	154

BC Hydro submitted that the risk assessment demonstrates that:

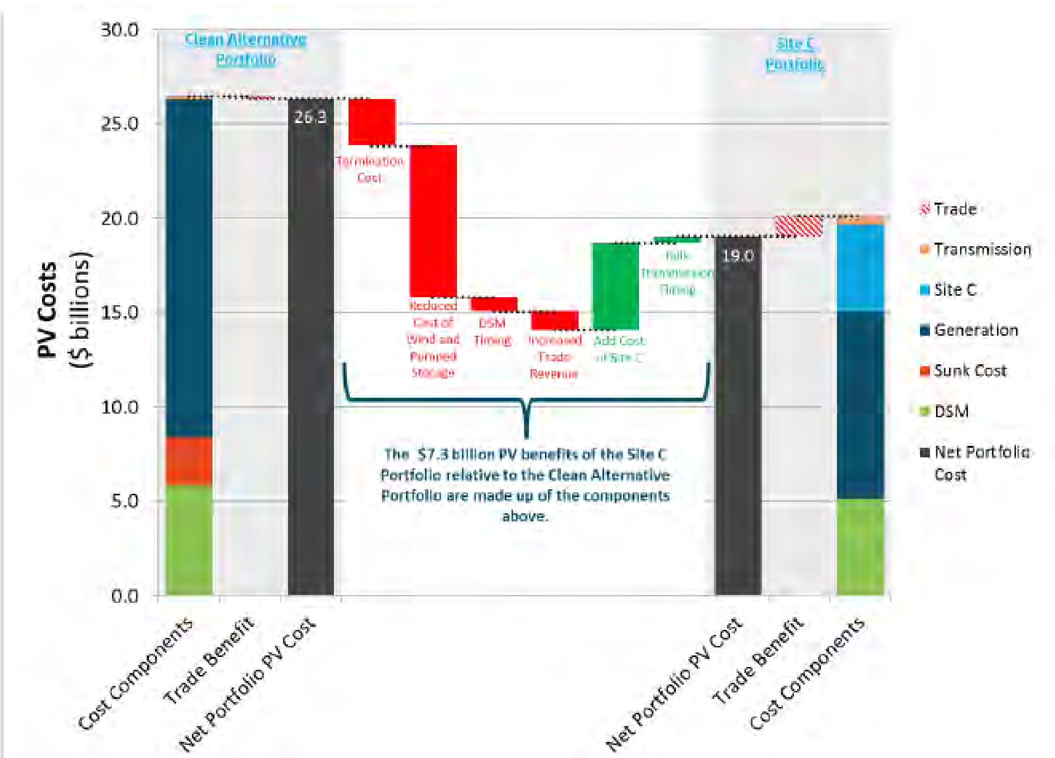
- There are risks associated with the development of any resource project. Site C has residual construction risk (although this has been reduced given the progress to date) but once completed the costs to ratepayers are predictable and will decline over the 100-plus year life of the assets;
- While Site C may have the potential to create a comparatively larger surplus than a portfolio of IPP contracts, the capacity and flexibility-rich nature of Site C generation makes it a more valuable market asset;
- An alternative portfolio with BC Hydro's expected alternatives (wind and pumped storage) has a higher overall risk portfolio than Site C, but that risk is still tolerable; and

[520] Submission F1-12, BC Hydro, p. 40.

- The alternative portfolio proposed by Deloitte (consisting primarily of geothermal, upgrades to BC Hydro facilities, wind and biomass) relies on a combination of low probability assumptions. These assumptions make the risk to ratepayers associated with this portfolio very high.[521]

BC Hydro provided the following analysis of the cost differences between BC Hydro's PV of the cost of proceeding with Site C compared to the PV of the cost of termination.[522]

Figure 20: BC Hydro PV of Site C vs. Alterative Portfolio (Mid Load)



BC Hydro further stated:

> As shown, the major difference in net portfolio PV costs results from:
>
> - The cost of Site C net of termination costs; and
> - The cost of wind and pumped storage resources.
>
> As a result, wind and pumped storage are the true alternatives to Site C over the long term. The other three effects are DSM timing, trade revenue and transmission resources, all of which are relatively small. With respect to DSM, the Site C portfolio has a reduced DSM cost because by delaying the DSM ramp-up, the costs are also delayed. Therefore, the difference is largely the effect of discounting the incremental DSM cash flows over the DSM planned ramp up period.[523]

With regard to the difference between BC Hydro's PV comparison of Site C and the BC Hydro Alternative Portfolio, Bakker stated:

[521] Submission F1-12, BC Hydro, p. 41.
[522] Submission F1-17, BC Hydro, p. 8.
[523] Submission F1-17, BC Hydro, pp. 8, 9.

The $630 million benefit of the Site C Project in the Clean portfolio is largely the result of the relatively high cost of pumped storage hydroelectricity. In the absence of Site C and simple cycle gas turbines (SCGTs), pumped storage hydroelectric meets the bulk of BC Hydro's capacity needs in the Clean portfolio without Site C.[524]

… while BC Hydro affirms that it has carried out a System Optimizer portfolio analysis, it has deleted from the scenario outputs the specific results that permit an economic comparison amongst the options[525]

Bakker further stated:

While BC Hydro suggests that it has carried out a present value analysis comparing portfolios with and without the Site C Project, nowhere in its Submissions does BC Hydro present results or the supporting detail of that present value analysis. In Appendix Q of BC Hydro's Submissions, System Optimizer outputs are presented for 11 scenarios, but (unlike the similar outputs presented in the 2013 IRP) the key result of each one — the present value of its incremental costs — is not shown. Figure [18] compares the System Optimizer outputs presented in the Integrated Resource Plan (above) and the present inquiry (below). The actual present value costs are conspicuously absent from the outputs provided to the Commission. [526]

Figure 21: Portfolio PV model information excluded from Site C submissions

Input Assumptions	Load	DSM	Market Scenario
	Mid Load & No LNG	Mid DSM Option2(constant)	Scenario 1
		Discounted to January 2013 (F2013 $) - Jan DSM TRC	
PV of G& T Resource cost -$ millions		5,607	
PV of Trade Revenue -$ millions		(1,977)	
PV of DSM Option cost - $ millions		**2,986**	
PV of Total Portfolio Cost -$ millions		6,615	

The British Columbia Sustainable Energy Association proposed approach

BCSEA submits that the response to s. 3(b)(iv) requires a portfolio analysis, and that at a high level, this involves:

a) identifying and estimating the attributes of potentially available, qualifying supply-side and demand-side energy and capacity resources that are not already committed (other than Site C),

b) determining the forecasts of before-DSM energy and peak capacity requirements,

c) determining the "stack" of committed supply-side and demand-side resources that will contribute to providing energy and capacity,

[524] Submission F106-4,PoWG, p. 121.
[525] Submission F106-5, PoWG, p. ii.
[526] Submission F106-5, PoWG, p. 8.

d) defining the planning requirements a portfolio must meet, such as meeting after-DSM energy and peak capacity needs in each year over a defined period of years,

e) determining assumed values for parameters, such as forward interest rates, exchange rates, gas prices, electricity prices, and more, not already implicitly defined by the attributes of the resource options, such as the cost of capital, or by the load forecast, such as population and GDP growth,

f) creating at least two portfolios, one with and one (or more) without the Site C project, that contain available supply-side and demand-side resources that meet the planning requirements,

g) optimizing each portfolio to minimize its net present value (NPV) while still meeting the planning requirements,

h) comparing the NPV of the Site C portfolio with the NPV of the Without- Site C portfolio (and with a Suspended-Then-Completed-Site C portfolio if one is examined),

i) identifying and quantifying the sensitivity of the results of the portfolio analysis to changes in input values within reasonable ranges, and (j) discussing and providing qualitative interpretation of the portfolio analysis results in the context of model limitations and input sensitivities.[527]

BCSEA further states:

> The fundamental output of the portfolio analysis is the NPV of the subject portfolios. For presentation purposes, this can be expressed as a unit energy cost and a unit capacity cost of each portfolio.
>
> … actual and projected sunk costs up to the deemed decision date are excluded from both the Site C portfolio and the Without-Site C portfolio, and the costs of termination are added to the Without-Site C portfolio.
>
> Having insight into the strength and reliability of the financial information will allow the Government to give the financial information appropriate weight in comparison with the other important factors it will have to consider when it decides which Site C option (completion, suspension or termination) to pursue.
>
> … creating a Without-Site C portfolio with benefits similar to those of the Site C portfolio in terms of firming, shaping, storage, grid reliability and GHG emissions will require some judgment and flexibility. While no new GHG emissions and probably grid reliability can be treated as constraints, the ways in which the two portfolios will meet the energy and capacity planning requirements are different by definition and this will necessitate differences in terms of firming, shaping and storage[528]

BC Hydro's capacity needs

At issue is the nature of BC Hydro's capacity requirements. How long are the periods that BC Hydro needs maximum capacity and when in the day do those periods occur?

BC Hydro states that its load is "peaky on an annual basis in that the highest demand happens in the winter with demand in other times of the year being relatively lower," and that in F2014 "demand was only higher than 8000 MW 10 per cent of the time." It further states that "[w]hile there are not a large number of peak

[527] Submission F29-3, BCSEA, pp. 12–13.
[528] Submission F29-3, BCSEA, pp. 13–14.

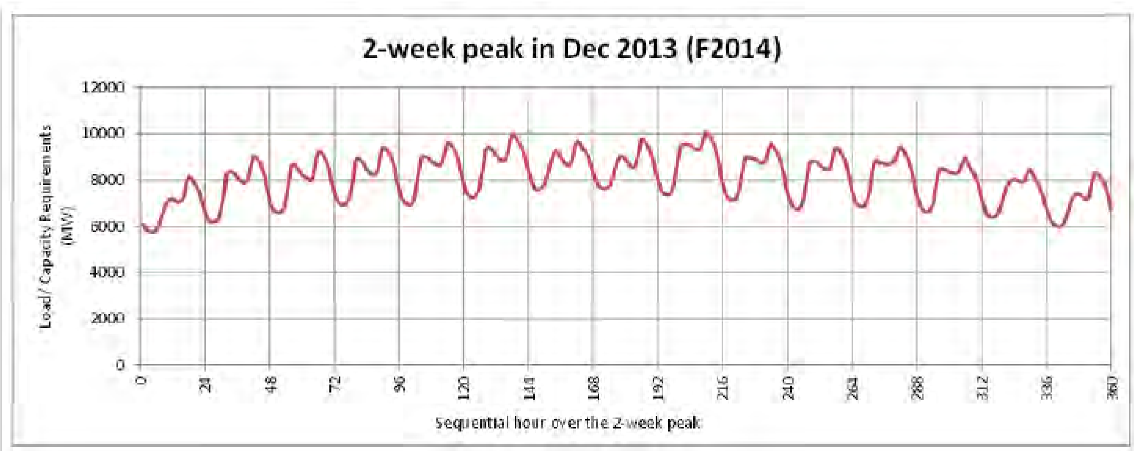
hours in a year, they tend to occur in clusters during winter cold-snaps. These cold snaps can last about two weeks at a time and can occur multiple times during a winter season." [529]

BC Hydro states that it has assessed system need and has determined it,

> Require[s] capacity resources that are available in aggregate to generate or curtail load for 16-hours peak per day for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months…..The 36-day requirement is derived from past weather records, and assumes three two-week cold snap periods with 6 days of heavy load hour periods per week."

BC Hydro also provided the figure below to demonstrate the impact of a cold snap:

Figure 22: BC Hydro 2-week peak in December 2013 (F2014) [530]



In Clean Balance Power's (CBP) view:

> Optimal capacity alternatives to Site C can only be determined by a more granular understanding of the quantum, profile and location of load and generation spikes within the BC Hydro system. At this time, without this information, CBP can only simplistically opine that Site C represents is a very expensive, energy-rich capacity alternative to address system imbalances which are most likely predominant in the Lower Mainland between the hours of 6:00 am and 10:00 am and 4:00 pm and 8:00 pm, 6 days per week."

The Panel notes that a number of submissions, including Bryenton,[531] McCullough,[532] CanWEA and CEABC,[533] Bakker[534] and Bryenton *et al.*[535] have provided models related to portfolios comprising alternative generation and demand side options to Site C.

[529] Submission F1-16, BC Hydro, IR 3.19.0.
[530] Submission F1-16, BC Hydro, IR 3.11.0.
[531] Submission F6-1-1, Bryenton; Submission F6-6-1, Bryenton.
[532] Submission F35-5, PVLA and PVEA, Appendix A.
[533] Submission 104-1, CanWEA and CEABC, pp. 23–27.
[534] Submission F106-1, PoWG, pp. 124–146; updated in Submission F106-2, pp. 35–46 and Submission F106-5, pp. 32–41.
[535] Submission F315-1-1.

6.3.4.1 Commission staff Illustrative Alternative Portfolio

At the request of the Panel, Commission staff prepared an Illustrative Alternative Portfolio (based on BC Hydro's high, mid and low forecasts) using information submitted in the Site C Inquiry (Illustrative Draft Alternative Portfolio).[536]

The Panel invited comments from BC Hydro and other parties on the Illustrative Draft Alternative Portfolio; in particular:

- The underlying assumptions regarding the Illustrative Draft Alternative Portfolio (see the Key Assumptions table for descriptions of all key assumptions); and
- The calculations, inputs and assumptions used in the Illustrative Draft Alternative Portfolio Spreadsheet.

The summary of the results of the Illustrative Draft Alternative Portfolio are shown in the table below:

Table 34: Summary Results of the Illustrative Draft Alternative Portfolio (2018$)

Summary Results of the Illustrative Draft Alternative Portfolio (2018$)			
	High Load Forecast	**Medium Load Forecast**	**Low Load Forecast**
Alternative Portfolio composition	• 588MW of wind projects starting in F2025, 297MW in F2026 • DSM initiatives (energy efficiency, optional time of use (TOU) rate, capacity focused DSM, industrial curtailment) • 150MW of batteries in F2025	• 591MW of wind projects starting between F2028 and F2031 • DSM initiatives (energy efficiency, optional TOU rate, capacity focused DSM, industrial curtailment) • 400MW of batteries starting between F2025 and F2026	• 444 MW of wind projects starting between F2039 and F2041 • DSM initiatives (energy efficiency, optional TOU rate, capacity focused DSM, industrial curtailment)
Rate Impact of Illustrative Draft Alternative Portfolio	$3,411 million	$2,889 million	$1,851 million

The NPV of incremental revenue requirements reflects not when the cost outlays are incurred, but when they impact ratepayers.

A full description of the model and the key assumptions used were included in A-22.

Comments on the Illustrative Draft Alternative Portfolio

BC Hydro raised the following issues with the Illustrative Draft Alternative Portfolio:[537]

1. Treats DSM as an alternative when it is included in all portfolios. This effectively assumes we cease DSM if we build Site C, which is not correct;
2. BC Hydro builds and finances all alternative resources. As BC Hydro has stated, we do not believe this is a realistic assumption;
3. Battery costs used in the analysis omitted the following:

[536] Submission A-22.
[537] Submission F1-17, BC Hydro, pp. 4–30.

- Capital costs other than balance of system (i.e. batteries, power conversion system, construction and permitting).
- Operating costs of approximately $10M per year for a 100MW installation.
- Operating energy losses of approximately 7%;

4. Capacity-focused DSM estimates are dated with significant deliverability risk;
5. Wind cost declines are optimistic;
6. Assumes Site C has less flexibility than a portfolio of alternative resources because of the size of Site C's reservoir. This is incorrect. The analysis fails to recognize Site C's flexibility is derived from Williston storage given Site C will be downstream with integrated operations;
7. Issues with assumptions regarding market pricing:
    - Uses the market forwards for pricing energy surplus rather than market forecast. Market forwards are not appropriate for this purpose.
    - Assumes any Site C surplus has same export value as alternative portfolio. This fails to recognize the additional value we expect to receive for flexible generation products in external markets; and
8. Other methodological issues:
    i. Double-counting of loss savings associated with DSM;
    ii. Use of Total Utility Cost rather than Total Resource cost to estimate costs to ratepayers;
    iii. Application of a 14% reserve requirement to DSM energy savings;
    iv. Failure to recognize Site C sunk and termination cost recovery in the alternative portfolio;
    v. Failure to recognize Site C surplus trade value over the period of analysis;
    vi. Does not account for the overlap between credits for energy and capacity;
    vii. Contains errors related to calculation of timing of DSM costs;
    viii. Does not include network upgrade costs for wind resources; and
    ix. Assumes availability of cost-effective geothermal resources.

Energy and capacity resource assumptions (wind, solar etc.)

New evidence related to alternative energy and capacity sources (such as wind, solar, and DSM) is included in Appendix A.

Financing cost assumptions

The Illustrative Draft Alternative Portfolio model calculates the annual depreciation and financing costs of the alternative resources. As a result, the cost of financing these investments is a key input assumption. The Illustrative Draft Alternative Portfolio's financing cost is the same as BC Hydro's financing cost for Site C (100 percent debt financing at a cost of 3.43 percent). Grants in lieu of taxes and school taxes were assumed to be the same as those used by BC Hydro for Site C.

BC Hydro acknowledges that it has applied different financing costs to different resources. In its view, this is appropriate in light of the different developers of different projects. BC Hydro submits that its approach recognizes that the terms of reference of the OIC focus on ratepayer impact. Therefore it uses the financing costs that would actually be paid by ratepayers for particular resources. Specifically:

- IPPs have a materially higher cost of capital than BC Hydro, and customers will pay that higher cost of capital when BC Hydro acquires the resources. Where resources are likely to be developed by

IPPs, we have used an IPP's cost of capital. This is true for the portfolio including Site C and the portfolios without Site C; and

- BC Hydro is regulated to finance Site C with debt, rather than a mix of debt and equity. This is the cost that will be recovered from ratepayers, and the Commission is required to look at the impact on ratepayers.

BC Hydro is of the view that "[a]rtificially assuming all resources can be financed at the same rate as BC Hydro is effectively assuming that BC Hydro will develop all future resources in the portfolios. In other words, the Commission would be assuming that there is no real place for the IPP industry in British Columbia for some time into the future. As described above, we regard this to be a highly unrealistic assumption given it is at odds with the current approach to resource development." [538]

BC Hydro submits that making assumptions that are unlikely to reflect real ratepayer impacts would be inconsistent with the OIC's terms of reference, and would introduce significant risk of understating the cost of an alternative portfolio to Site C. [539]

Further, BC Hydro submits that it does not have a mandate to explore and develop alternative energy resources:

> The role to develop other sources of clean and non-clean energy is that of Independent Power Producers. In the 1980s, BC Hydro acquired its first run-of-river hydro contracts. In the 1990s, BC Hydro acquired gas-fired generation contracts and biomass contracts. BC Hydro's role was formalized in the 2000s with the 2002 and 2007 Energy Plans. The 2002 Energy Plan Policy Action #13 states that 'the private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants.' This was later confirmed in the 2007 Energy Plan that built upon the framework of the 2002 Energy Plan. [540]

At the Technical Input session, Mr. Reinmann stated that since the 2000s,

> We've had open calls, biomass calls, so we haven't been in this game for decades. And so our belief about this is that resource exploration and development is something that's well-suited to IPPs. They have innovative concepts and they're willing to run around and invest their money and try to explore it. And if they can get a contract, then away they go. And if they don't, they made their bet, they've lost their money.[541]

BC Hydro further states that:

> The IPP industry has played a useful role in the development of these many varied resources in B.C. The innovation and exploration that has been undertaken by the IPP industry has provided B.C. with a broad range of clean resources and is increasingly expected to deliver those resources on a cost-effective basis. The benefit of the IPP industry undertaking these exploration and development activities is their ability to raise capital where investors are willing to assume those risks for the return of an EPA with a reasonable return on equity. If IPPs pursue a risky undertaking that does not become a project, the costs do not flow to ratepayers. [542]

[538] Submission F1-8, BC Hydro, IR 2.42.0.
[539] Submission F1-8, BC Hydro, IR 2.45.0.
[540] Submission F1-8, BC Hydro, IR 2.42.0.
[541] TTP-2, October 14, 2017, Vancouver, p. 1644.
[542] Submission F1-8, BC Hydro, IR 2.42.0.

BC Hydro submits that it "is not well positioned to undertake the risks associated with the exploration and development activities for the many smaller resources and believes the IPP industry should continue to play a similar role. Were BC Hydro to undertake those activities, normal financial processes would have those costs be recovered from ratepayers." Conversely, BC Hydro submits it "is well able to undertake the development of large hydro facilities in terms of the longer term approach to development and to spend the time and effort to obtain the necessary permits and approvals. BC Hydro submits that large utilities are best able to develop large projects of this nature and take on the associated risks on behalf of ratepayers, that it has the historical perspective of large hydro development and has been developing significant projects such as the John Hart Refurbishment." [543]

BC Hydro states that past attempts (including the geothermal development attempts at South Meager Creek) have been costly failures, and so the best option for the ratepayer is for BC Hydro to seek these alternative resource options from IPPs. BC Hydro states that it has undertaken all of its recent planning and acquisitions on that basis and continues to be of the view that those relative roles are appropriate and largely beneficial for the ratepayer.

However, CEABC submits:

> BC Hydro is actually assuming that Site C will be financed using 100% debt at a rate of 3.4%, fixed for 77 years (until 2094). On the other hand, the alternative projects are assumed to pay 8.5%, and to have to completely rebuild themselves every 25 years. So in the ratepayer impact analysis, at least, BC Hydro has imposed a 5 percentage point differential in cost of capital.

CEABC further pointed out that modern financial theory and practice completely rejects this sort of differential in cost-of capital as entirely inappropriate for making efficient economic investment decisions, and it offered a commentary from the CD Howe Institute, in support.[544]

In response to the Panel's request for clarifications regarding the cost of capital issues, CEABC has commissioned Dr. Marcel Boyer (the lead author) to provide a paper aimed more specifically at the issues surrounding the Site C financial analysis as presented by BC Hydro.

Boyer comments specifically on the "pretense" of 100 percent debt financing, and on how it is an artificial illusion, potentially saddling both ratepayers and taxpayers with huge risks for which they are uncompensated. He states:

> These errors expose BC citizens to potentially large losses of value, possibly hundreds of millions of dollars, if not more, without any compensation for the risks they are being asked to bear.

He derives a more realistic weighted average cost of capital (WACC) at around 8.8 percent, which employs risk premiums on both the debt and the government's 40 percent equity share, in order to compensate for the risks inherent in such a large, lengthy and complex project as Site C. He also comments on the use of a 70 year amortization period and gives guidelines for reference periods used in other jurisdictions. He points out the difficulties that can arise in properly reflecting the renewal costs of shorter-term projects in order to arrive at useful apples to apples comparisons[545]

[543] Submission F1-8, BC Hydro, IR 2.42.0.
[544] Submission F18-3, CEABC, Appendix 2.
[545] Submission F18-5, CEABC, pp. 2, 3.

In addition, Eliesen submits:

> Given the weak financial position of BC Hydro, there is a cost of continuing the project because Site C exacerbates an already precarious financial situation. There is reason to believe that continuing Site C will bring with it higher debt financing charges. Higher financing costs related to credit worthiness concerns, not only increases the debt financing costs for Site C, but for all BC Hydro and provincial government debt. The cost to ratepayers of a downgrade(s) because of Site C would need to be applied to all debt BC Hydro intends to incur, not simply debt related to Site C. …
>
> Avoiding a downgrade(s) in BC's credit rating by cancelling Site C is a benefit to BC Hydro ratepayers in the amount of interest expense related to Site C financing that would otherwise be payable if the continuation of the project triggers such a downgrade.[546]

Discount rate

The Illustrative Draft Alternative Portfolio model calculates the discounted NPV of the annual costs of the portfolio. As a result, the discount rate used is a key input assumption. The Illustrative Draft Alternative Portfolio uses the same discount rate proposed by BC Hydro for Site C (6 percent nominal, 3.9 percent real).

BC Hydro submits:

> The CD Howe article is premised on the use of a discount rate adjustment to account for risks that impact the profitability or economic viability of a project. As described earlier, BC Hydro has explicitly considered many factors that could negatively impact Site C including capital cost overruns, lower demand, and lower market electricity prices. To address risks through a discount rate adjustment as well as through different sensitivities would be double counting the risks of the project. BC Hydro believes that the sensitivity approach provides a more transparent view of the risks to the projects and the impact of each as opposed to a subjective and blanket change in the discount rate.

Boyer's report also addressed project management risks and market risks:

> Project management risks are risks that managers can mitigate through better resource and schedule planning, better inventory management, better surveillance of construction and operations, and more generally through better incentives and incentives alignment fostering proper cooperation and exchange and use of information throughout the chain or network of operators, clients and suppliers, and stakeholders.
>
> …
>
> Market risks are different. They relate to the impact of the overall economic outlook on the financial results of the project. The economic outlook, with alternating periods of favorable conditions (expansion) and unfavorable ones (slowdown or recession) will affects more or less severely the benefits and costs of the project.
>
> …
>
> It appears that the preference of BC Hydro for sensitivity analysis to account for risk is misplaced. Sensitivity analysis allows to illustrate how different factors may affect the value of projects. As such it is a complement illustrative tool but not a substitute for the risk adjusted discount rate in project evaluation. The confusion is clear when BC Hydro writes: "BC Hydro believes that the sensitivity approach provides a more transparent view of the

[546] Submission F13-2, p. 43.

> risks to the projects and the impact of each as opposed to a subjective and blanket change in the discount rate."[547]

Bakker states:

> BC Hydro further indicates that it, for its discount rate, it "chose to use the Generic Cost of Capital as set out in Order G-129-16." This order, regarding FortisBC Energy Inc., adopts an equity rate of 8.75% and a common equity component of 38.5%.[548]

Flexibility of Site C versus flexibility of the Illustrative Draft Alternative Portfolio

Section 3(b)(iv) of the OIC asks what, if any, other portfolio of commercially feasible projects and DSM initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?

As a result, the Panel compared the quality of energy produced by the Illustrative Draft Alternative Portfolio with that produced by Site C.[549]

BC Hydro' position is that there will be additional capacity and flexibility resulting from Site C ,which in addition to meeting peak and annual load requirements, will increase surplus capacity and flexibility when less than peak loads are required. BC Hydro stated its surplus capacity and flexibility is monetized through different market opportunities including surplus energy sales in higher priced hours and selling short term energy in high priced periods while purchasing a similar amount in lower priced hours. In addition, BC Hydro stated there are several initiatives it is considering that will facilitate new markets for capacity and/or flexibility, asserting that there will be expanded opportunities to monetize capacity and flexibility in the near future. These include:

- The exploration of a redesign of California's Flexible Resource Adequacy Criteria and Must Offer Obligation program to potentially allow external participation.
- The recent implementation in California of an enhancement allowing the California Independent System operator (CAISO) to procure flexible capacity on a short time basis.
- Alberta is designing a capacity market to be in place by 2019 (external participation in this capacity market cannot be confirmed).

BC Hydro confirmed that Powerex expects to participate in the Energy Imbalance Market (EIM) located in the US by April 2018. However, BC Hydro noted that Powerex's level of participation will be limited by the level of market opportunities and transmission capability in the EIM. Because of this, BC Hydro does not see a direct connection between Site C and Powerex's participation in the EIM.

BC Hydro submitted that there are developments, which by the mid-2020's are likely to impact capacity and flexibility opportunities. These include:

- 4,500 MW of US Western Interconnect coal generation capacity being shut down by 2025;
- 6,000 MW of coal generation to be shut down by 2030 in Alberta; and
- 7,500 MW of California natural gas and nuclear generation capacity planned to be shut down by 2025.

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[547] Submission F18-5, CEABC, Appendix, p. 13.
[548] Submission F106-5, p. 6.
[549] Submission A-22, p. 8.

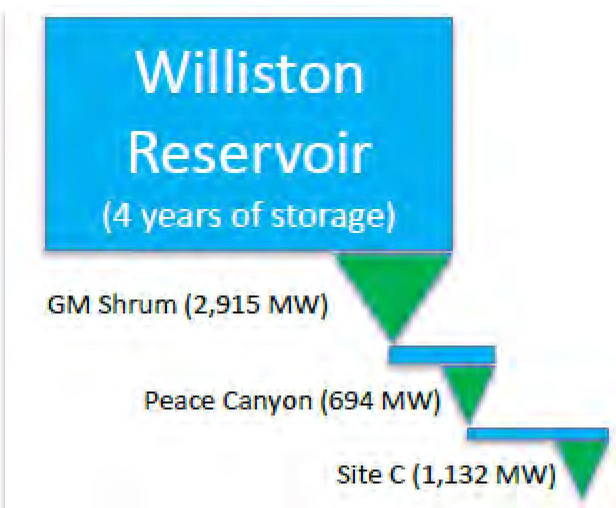
BC Hydro stated that much of the energy produced from these plants is likely to be replaced by wind or solar, which have less capacity, increasing the need for flexible resources. In addition, the availability of surplus capacity could provide potential opportunities to displace or defer new gas generation resources. BC Hydro also pointed out the significant hurdles and challenges that stand in the way of such transactions but noted that Powerex continues to pursue confidential discussions with its customers.[550]

BC Hydro further submits:

> The Project reservoir, with a normal operating range of 1.8 m and an active storage volume of 0.4 per cent of the active storage volume of Williston Reservoir**,** does not have sufficient storage volumes to provide seasonal shaping of generation. The upstream regulation at Williston Reservoir allows the Project to generate electricity to match the timing of BC Hydro customer demand without the need to establish another large multi-year storage reservoir similar to Williston Reservoir. [551]
>
> Site C has seasonal shaping and firming capabilities, primarily due to its location downstream of Williston Reservoir (rather than due to the Site C reservoir itself). Figure 7 shows that Williston Reservoir provides over four years of storage capability and can be used for seasonal shaping of generation at Site C. Outflows from Williston go through Peace Canyon and will go through Site C, with only minor delays (refer to the response to BCUC IR 2.22.6 for the Site C monthly generation profile). As a result, the seasonal shaping benefits of the Williston Reservoir will also apply to Site C.

BC Hydro provides the figure below, which compares the storage volume of the Williston Reservoir to Site C:

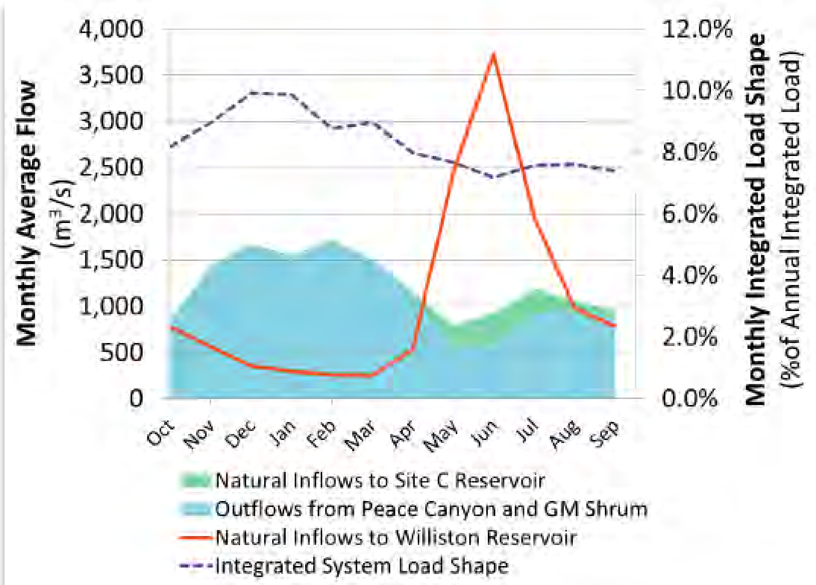
Figure 23: Peace River System[552]



[550] Submission F1-8, BC Hydro, IR 2.22.1, pp. 1–5; IR 2.22.14.
[551] Submission F1-1, BC Hydro, Appendix F, pp. 2, 3.
[552] Submission F1-17, BC Hydro, p. 20.

BC Hydro provides the figure below to illustrate the seasonal shaping provided by the Williston Reservoir:

Figure 24: Monthly Inflows to the Site C Reservoir[553]



BC Hydro further submits that Site C generation enhances the value of the storage in Williston Reservoir and adds to overall system seasonal firming and shaping capability and that the Site C reservoir provides both daily and multi-day firming and shaping benefits that can be used to integrate intermittent wind and solar resources.[554]

BCSEA's expert, Dr. Mark Jaccard, agrees that energy from Site C (or any dispatchable source, including nuclear, coal and natural gas) has more economic value than energy from wind or solar sources. In Jaccard's view, "[a]s non-dispatchable wind and solar increase in neighbouring jurisdictions, the market value of Site C's dispatchable capacity is likely to increase." However, he also points out that since the BC electricity system is currently dominated by dispatchable large hydro facilities, the within-province incremental benefit of adding Site C may be limited. Jaccard considers that this possible concern, however, would likely be moderated by the fact that value can also be captured through sales to neighbouring jurisdictions.[555]

Jaccard argues that:

> An economic evaluation of Site C should account for the full value of its dispatchable capacity. Since current wholesale spot prices in most cases do not capture the full value of dispatchable capacity, these should not be used as an indicator of the future value of dispatchable capacity from a generator like Site C. As the penetration of intermittent renewables increases, it will become increasingly important for markets to incentivize dispatchable capacity for its full value, and thus the revenue earned for dispatchable capacity will exceed current spot prices, perhaps substantially.[556]

CEC agrees that the Site C energy and capacity will be qualitatively more firm and reliable than the Illustrative Draft Alternative Portfolio.[557] CEC submits that Site C shaping capabilities will be greater than

[553] Submission F1-17, BC Hydro, p. 21.
[554] Submission F1-17, BC Hydro, pp. 19–21.
[555] Submission F29-8, BCSEA, p. 9.
[556] Ibid.
[557] Submission F82-4, pp. 6–7.

that of the Illustrative Draft Alternative Portfolio.[558] CEC further submits that Site C's seasonal shaping profile is provided by the Williston Reservoir. It states the Illustrative Draft Alternative Portfolio does not have seasonal shaping for the wind component, but the DSM components will have the seasonal profile of its savings reduction profile. It concludes that there is a distinct difference in quality of the products, meaning that the Illustrative Draft Alternative Portfolio will need compensating shaping capacity from another source to enable reliable delivery of the energy.[559]

BCSEA states: “The [Site C] facility does not need storage to be fully dispatchable. It simply needs to receive a reliable flow of water sufficient to run at full capacity when most needed.” [560]

CEABC states that Site C is not a “rock star” project in terms of capacity or flexibility. CEABC notes the limitations of Site C, relying on a quote from BC Hydro, taken from the Joint Review Panel hearing process, stating that “its high sensitivity of generation to hydraulic head (water pressure) would lead to the project being used for shaping in lower preference over other facilities.” CEABC points out that Site C does not have a high head or dam height and it is the third in a series of dams. In most cases, Site C will be operated in tandem with the other dams making it essentially a run-of-river project. CEABC concludes that in spite of BC Hydro’s responses to the Panel’s Preliminary Report questions, concerning export opportunities for capacity and flexibility related to Site C, it is not going to add appreciably to export potential.[561]

In addition, CEABC submits that the following approach should be taken when considering the value of Site C flexibility:

i. What firming, shaping and storage capability, often referred to in general terms as “capacity” can Site C provide?
ii. How much firming, shaping and storage does BCH require?
iii. Is transmission available to market excess firming, shaping and storage?
iv. What is the value of firming, shaping and storage? …[562]

CEABC also submits that Site C will not come into commercial operation until 2024 at the earliest and as currently proposed, won’t be fully paid for until 2094. CEABC states that this time frame creates enormous difficulties in allowing for a proper analysis of Site C, and the alternatives, as the farther out in time, the less likely any analysis will have any meaning. [563]

McCullough submits that the argument that Site-C can serve as storage for future alternative sources of energy is highly questionable given its lack of reservoir capacity.[564]

In addition, McCullough submits that the only BC resources that qualify for California’s renewable portfolio standard (RPS), the largest market for renewable resources, are B.C. wind resources (despite considerable efforts to gain eligibility as renewable resources for other types of B.C. resources).[565]

[558] Submission F82-4, p. 7.
[559] Submission F82-4, p. 7.
[560] Submission F29-8, BCSEA, p. 9.
[561] Submission F18-5, CEABC, pp.7–8; TTP-1, October 13, 2017, Vancouver, pp. 1206–1207.
[562] Submission F18-5, CEABC, pp. 5–13; F18-6, pp. 5, 6.
[563] Submission F18-5, CEABC, pp. 5–13; F18-6, pp. 5, 6.
[564] Submission F35-5, PVLA and PVEA, pp. 24–25.
[565] Submission F35-15, PVLA and PVEA, p. 4.

Surplus Energy Sales

The Illustrative Draft Alternative Portfolio model treats revenue received from energy exports as a credit to the cost of the portfolio (for both Site C and the Illustrative Draft Alternative Portfolio). As a result, the value of surplus energy is a key input assumption.

BC Hydro further provided the following table outlining the Mid-C forecast assumptions in its F17-F19 RRA:

Table 35: BC Hydro F2017-F019 Revenue Requirement Application Mid-C Forecast[566]

Calendar Year	Mid-Columbia Market Prices in 2016 USD/MWh (Refer to page B-6 of Appendix B of the ABB Report)	Apply USD/CAD FX Rate (U.S. $ per $1 CAD)	Mid-Columbia Prices Converted to 2016 CAD/MWh	Apply (Subtract) Wheeling/loss Adjuster ($/MWh)	Sell price at the B.C. Border in 2016 CAD/MWh	FY[1]	Sell Price at the B.C. Border in 2016 CAD/MWh – Fiscal Year Values
	Average		Average		Average		Average
2016	19.5	0.74	26.5	6.3	20.2	F17	21.4
2017	23.2	0.78	31.4	6.3	25.1	F18	25.0
2018	24.1	0.8	31.0	6.3	24.7	F19	25.5
2019	27.2	0.82	33.9	6.3	27.7	F20	28.4
2020	30.2	0.82	36.8	6.3	30.5	F21	31.3
2021	32.5	0.82	39.7	6.3	33.4	F22	33.7
2022	33.7	0.82	41.1	6.3	34.8	F23	35.2
2023	35.0	0.82	42.7	6.3	36.4	F24	36.5
2024	35.4	0.82	43.2	6.3	36.9	F25	37.1
2025	36.2	0.82	44.1	6.3	37.8	F26	38.1
2026	37.2	0.82	45.3	6.3	39.0	F27	39.3
2027	38.1	0.82	46.4	6.3	40.1	F28	40.3
2028	38.6	0.82	47.0	6.3	40.7	F29	41.2
2029	39.9	0.82	48.7	6.3	42.4	F30	42.9
2030	41.4	0.82	50.5	6.3	44.3	F31	44.7
2031	43.0	0.82	52.5	6.3	46.2	F32	46.4
2032	43.8	0.82	53.4	6.3	47.1	F33	47.4
2033	44.7	0.82	54.5	6.3	48.2		
			Average for the period F2017 to F2033				$36/MWh

BC Hydro also provided a table below showing the annual value of the assumed sale of surplus Site C energy over the life of the project. BC Hydro submits these amounts may be conservative as they have not specifically considered capacity sales.[567] In the table below, Commission staff has used this information to calculate an annual $/MWh estimate for the value of export sales assumed by BC Hydro for the Site C project.

[566] Submission F106-1, PoWG, p. 67; BC Hydro F2017-F2019 RRA, Exhibit B-14, BCUC IR 310.1.
[567] Submission F1-18, BC Hydro, IR 3.20.0.

Table 36: BC Hydro Surplus Site C sales [568]

	F2025	F2026	F2027	F2028	F2029	F2030	F2031	F2032	F2033	F2034
Surplus Site C Energy (GWh)	3,072	5,286	4,467	3,239	2,745	2,013	1,777	1,364	1,030	409
Surplus Sales Revenue($'m)	$140	$256	$243	$183	$162	$124	$117	$96	$77	$32
$/MWh	**$46**	**$48**	**$54**	**$56**	**$59**	**$62**	**$66**	**$71**	**$75**	**$78**

The Panel notes that there is no clear linkage between the $/MWh revenue estimates provided in the table above, those provided in the F17-F19 RRA and BC Hydro's ABB based Mid-C forecast graph provided in the BC Hydro's initial submission.[569]

6.3.5 Panel analysis and findings

Definitions – portfolio attributes

The Panel confirms the definitions for firming (hourly shaping), shaping (daily shaping) and storage (seasonal shaping) adopted in the Preliminary Report:

> ***Firming capability*** is the ability of resources to quickly change output in response to changes in customer demand and the output from variable generation resources that fluctuate within the hour (e.g., wind or solar). The best resource for this capability is large hydro, but it can also be also supplied by pumped storage and gas-fired generation. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors, do not have this capability;
>
> ***Shaping capability*** is the ability of resources to reduce their generation supply within the day to allow the electricity system to absorb variable resource electricity (e.g., wind, run-of-river, solar) when its customers do not need it and then to release that energy later in the day when it is required. Large hydro and pumped storage have this ability and other storage methods are being developed such as batteries or compressed air; and
>
> ***Storage capability*** is the ability of resources to adjust their generation supply at certain periods within the year to respond to seasonal changes in variable generation resources (e.g., run-of river hydro output is highest during the spring freshet and lower in the late summer). Only large hydro resources have the capability to store electricity seasonally.[570]

The Panel also adopts the definitions for commercial feasibility and grid reliability used in the Preliminary Report:

> ***Commercially feasible*** means full-scale technology demonstrated in an industrial (i.e. not R&D) environment for a defined period of time. Publicly verifiable data exists on technical and financial performance. Regulatory challenges (e.g. safety certifications, lack of standards) have been addressed in multiple jurisdictions.

[568] Submission F1-18, BC Hydro, IR 3.20.0.
[569] Submission F1-1, BC Hydro, p. 64.
[570] Submission A-13, pp. 75–76.

> ***Grid reliability*** means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards.

The Panel declines to add to the commercially feasible definition BC Hydro's proposed wording: "Publicly verifiable data exists that confirms the viability of the resource in terms of its energy source (e.g. the availability of adequate volumes of hot water should be confirmed prior to a geothermal site being described as commercially available)." The Panel considers that such wording would be overly restrictive given the OIC request, the objective of section 2(d) of the *Clean Energy Act*, and the timing of new generation resources required.

As for the definition for maintenance or reduction of 2016/2017 greenhouse gas emission levels, the Panel agrees that the alternative portfolio must not increase the greenhouse gas intensity of BC Hydro's greenhouse gas emissions, as measured in CO2 tonnes equivalent per GWh generated. **The Panel finds that levels should mean levels, and not intensities, and as such adopts the following definition:**

> ***Maintenance or reduction*** of 2016/2017 greenhouse gas emission levels means that the alternative portfolio must not increase the level of BC Hydro's greenhouse gas emissions relative to 2016/2017.

The Panel notes that this interpretation of the requirement in the OIC of no increase in GHG levels is more restrictive than the provisions of the *Clean Energy Act.* **The Panel therefore finds it is not possible to include any natural gas fired gas turbines to provide for capacity deficits unless alternative means are used to offset BC GHG emissions (for example, a reduction in the use of BC gas fired generation used for export).** Natural gas fired generation using biogas would be a way to make use of these resources and also satisfy section 2(j) of the *Clean Energy Act*.

Regarding GHG emissions, the Panel finds that the Illustrative Alternative Portfolio (comprised of energy efficiency, geothermal and wind) should maintain or decrease BC GHG emissions compared to 2016/17 levels. In addition, the Panel notes that Site C increases BC GHG emissions compared to 2016/17 levels , and, unlike wind energy, does not qualify for California's renewable portfolio standard market. [571]

Definitions - Unit Energy Cost

The OIC asks what, if any, other portfolio of commercially feasible generating projects and DSM initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower *unit energy cost* as the Site C project.

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.[572]

There were no submissions received on this issue. Therefore, the Panel considers that although there is no generally accepted definition of unit energy cost, there is a well-accepted definition of "levelized cost of energy" or "levelized cost of electricity" (LCOE). BC Hydro states that "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced."[573]

The US Energy Information Administration describes LCOE as follows:[574]

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[571] Submission F106-6, PoWG, p. 6.
[572] Submission A-13, pp. 75–76.
[573] Submission F1-1, BC Hydro, p. 61.
[574] US Energy Information Administration, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017, April 2017, p. 1, retrieved from https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

> 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-kilowatthour 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.
>
> The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (see text box), can also impact the calculation of LCOE. As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change. [575]

In addition, BC Hydro uses the following formula in its Block UC analysis to develop the "unadjusted" UEC:

Equation 1: Unadjusted Unit Energy Cost

$$\frac{\text{sum of costs over lifetime}}{\text{sum of electrical energy produced over lifetime}}$$

This is consistent with the way that LCOE is typically calculated. It is also consistent with the way the Panel calculates the UEC of the Illustrative Draft Alternative Portfolio. **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.**

However, the LCOE is typically applied to a specific generating asset (such as a solar or wind farm, or a nuclear or gas plant), rather than a portfolio. In this case, it applies to a portfolio of generation assets and demand side management measures. An additional consideration is what adjustment (if any) should be made for export revenues, Site C sunk costs and Site C termination costs.

BC Hydro submits that the unit energy cost should include an adjustment for the sunk and termination cost of Site C (either as a reduction in Site C costs or an increase in the Alternative Portfolio cost).[576] BC Hydro's PV portfolio costs for Site C also includes a credit for export revenues. [577]

With regard to the adjustments for export revenues/volumes, Site C sunk costs and Site C termination costs, BC Hydro states that these adjustments can be considered as either:

- A sunk or committed cost reducing the costs needed to complete Site C; or
- An additional cost to the Clean Alternative Block if Site C were to be terminated.

BC Hydro argues that:

> One of these approaches must be adopted otherwise the analysis does not account for the significant costs spent to date and the costs of termination and site remediation. We chose

[575] The specific assumptions for each of these factors are given in the Assumptions to the Annual Energy Outlook 2017, July 18, 2017, retrieved from http://www.eia.gov/outlooks/aeo/assumptions/.
[576] Submission F1-5, BC Hydro, p. 28.
[577] Submission F1-18, BC Hydro, IR 3.20.0.

> to put it as an avoided cost on the Site C UEC rather than as an additional cost on the Clean Alternative Block to allow the comparison of the Site C cost to the current market electricity price forecast.[578]

Given the definition of UEC, the Panel finds it inappropriate that the unit energy cost be adjusted for sunk costs and termination costs and will not consider these costs in the unit energy cost analysis. Similarly, the unit energy cost will not be adjusted for export revenues and associated export volumes. Consideration of these costs is appropriate in a rate impact analysis, and we will address these costs in the following section.

The Panel notes that the Site C Joint Review Panel also arrived at a similar conclusion:

> The Panel concludes that methodological problems in the weighing and comparison of alternatives render unitized energy costs only generally reliable as a guide to investment. The Panel is more confident about the ranking of BC Hydro's projects, or IPP projects, or DSM projects considered as separate lists.[579]

An additional issue relates to adjustments for the quality of the energy produced by an alternative portfolio compared to Site C. Jaccard expressed concerns that the UEC ignores differences in the market value of electricity. He explains that energy from a dispatchable source has more economic value, because it can be produced and sold into a market when prices are higher, whereas energy supplied by wind and solar is not dispatchable and therefore may only be sold when market prices are lower. [580]

The Panel refers back to the OIC request that an alternative portfolio should provide similar benefits to Site C (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels). The Panel considers it may be reasonable to adjust the UEC for any significant differences in the quality of energy produced by the BC Hydro Alternative Portfolio compared to Site C. However, for an adjustment to be required, it is important that not only should there be a demonstrated difference in the quality of energy produced between Site C and the BC Hydro Alternative Portfolio, it must also be a quality that has value.

BC Hydro's Block Unit Energy Cost

BC Hydro's unit costs of energy are summarized in the below:

Table 37: BC Hydro's Unadjusted and Adjusted UEC[581]

Source	UEC Before Adjustments ($/MWh)	Adjusted UEC ($/MWh)
Site C	$83	$34
Alternative Block	$85	$153

The Panel questions why the entire cost of a 1,200 MW pumped storage facility is allocated to the BC Hydro Block UEC for the Alternative portfolio when only a smaller facility is needed to provide the required capacity required in the load forecast. Further, the Panel questions whether pumped storage, as opposed to capacity focused DSM programs such as optional time based rates, is an appropriate approach to address peaking requirements that amount to approximately 16 hour shortfalls for a limited number of days during the winter.

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[578] Submission F1-5, BC Hydro, IR 2.28.0.
[579] Tab 2 p. 324 (JRP extract):
[580] Submission F29-8, pp. 3–4.
[581] Submission F1-1, BC Hydro, pp. 62–63.

Table 38 provides the results of the Panel's adjustments to the UEC, including removing the pumped storage adder:

Table 38: BC Hydro's Unadjusted and the Panel-adjusted UEC[582]

Source	UEC Before Adjustments ($/MWh)	Panel-adjusted UEC ($/MWh)
Site C	$83	$58
Alternative Block	$85	$105

It is difficult to draw any conclusion from this analysis as it isn't clear what portfolio is being modelled, how the pumped storage costs are modelled and the assumptions underlying the wind integration costs. However, notwithstanding these issues, even without the pumped storage adder, the Block UEC of BC Hydro's alternative portfolio is substantially more than the UEC of Site C.

The Panel continues to find that the usefulness of the UEC , as calculated by BC Hydro, is limited as a comparison methodology because:

- It doesn't take into account when the energy source comes on line and therefore doesn't capture the declining costs of many clean energy technologies are decreasing over time.
- Utilizes adders and credits for sunk costs, termination costs, transmission costs, network upgrade and line losses.
- The $85/MWh for the alternative portfolio is only an illustrative starting point for wind (it does not map to a particular wind project), and also is not a portfolio UEC as it only includes wind.
- It assumes the need for a pumped storage facility without demonstrating that BC Hydro will need to incur this cost.

As a result, the Panel rejects the use of the BC Hydro's Block Adjusted UEC methodology as a basis for responding to the OIC question and places and places little weight on these results.

Portfolio Model selection

BC Hydro describes its Portfolio PV Analysis as its main tool to compare resource options, and submits that it is standard utility practice for resource planning. BC Hydro states that this tool is the proper method for comparing the costs associated with a portfolio that includes completing Site C to the costs associated with portfolios based on (a) terminating the Project, remediating the site, recovering sunk costs and building an alternative portfolio, or (b) suspending the Project for a number of years." [583]

BC Hydro submits that its Portfolio PV analysis demonstrates that Site C has a lower NPV than the alternative in all scenarios the Commission asked BC Hydro to model.[584] However, the Panel continues to find BC Hydro's Portfolio PV analysis to be opaque in its assumptions, and finds that key input assumptions are insufficiently robust to be able to be relied upon for this analysis. Key concerns related to the alternative energy and capacity options are discussed in Appendix A and are summarized below:

- Outdated Resource costing data: The model appears to use out of date cost estimates for wind and solar, and does not anticipate any future decline in prices.

[582] Submission F1-1, BC Hydro, pp. 62–63.
[583] Submission F-1, BC Hydro, pp. 60–61.
[584] Submission F1-12, BC Hydro, p. 40.

- For example, at the start of this proceeding BC Hydro submitted that it has screened out solar energy on the basis of a solar cost estimate in F2025 of $97/MWh (for Cranbrook), with a range of $82 - $114. [585] In response to a Commission question, BC Hydro provided updated cost estimates of $48/MWh in F2025 (decreasing to $44/MWh in 2035). [586] This represents a substantial decrease in costs.

- <u>Lack of adequate consideration of capacity focused DSM</u>: The alternative portfolio generated by the Portfolio PV analysis does not include demand side capacity response other than for 85MW of industrial load curtailment.
  - BC Hydro identified in the 2013 IRP that there was 382 MW of expected capacity savings from industrial load curtailment, and 193 MW of expected capacity from capacity focused programs. BC Hydro is now half way through the F2017 – F2019 funding request of $38 million to understand the dependability/reliability of capacity focused programs, and yet only included 85MW of Industrial load curtailment as a demand side capacity option.
- <u>Assumed need to build three $1.3 billion pumped storage facilities</u>: BC Hydro's alternative portfolio model output includes, as the only other capacity resource that is not already committed, 1,000 MW of pumped storage facilities at a cost of $1.32 billion with fixed annual operating costs of $12.5 million, with storage sufficient for only 6 hours of continuous generation. As the model forecasts increases in load growth, it adds more of these pumped storage facilities, reaching three such facilities in the mid-load forecast scenario.
  - BC Hydro's model is opaque as to whether the portfolio is charged with the full cost of this facility the moment a small capacity gap appears. The Panel also considers that the lack of consideration of demand side options is a key driver of the difference between BC Hydro's model results and that of the Commission.
- <u>Market value of surplus assumptions</u>: The model is unclear with regard to assumptions on the market value of surplus energy. For example, information provided by BC Hydro on surplus energy sales and volumes included in the model appear to reflect a different market price assumption than provided by BC Hydro elsewhere in this proceeding or provided in the F17-F19 RRA. In addition, charts previously included in the 2013 IRP showing the export revenues by scenario, which could have improved transparency, were removed from the worksheets provided for this proceeding.
- <u>Wind integration costs</u>: BC Hydro's 2010 wind integration study has not been updated, despite BC Hydro starting a wind integration update project in 2015. The 2010 study appeared to assume that BC Hydro is selling all of the surplus flexibility in its system into the market at price based on the F2003 – F2008 California market prices.

Therefore, the Panel finds that while BC Hydro's Portfolio PV model may be effective at optimizing system costs, its lacks transparency regarding the inputs, calculations and outputs. In addition, insufficient focus has been given to ensuring that the inputs are reasonable. Further, the lack of consideration of demand side management options results in questionable outputs. **The Panel finds that it cannot rely on BC Hydro's Portfolio PV model results for the purpose of this Inquiry.**

Similarly, the Deloitte portfolio also does not include capacity focused DSM as a supply side option, and its generation alternative input assumptions are not transparent and in some cases do not give sufficient focus on the BC context. The Panel has also reviewed models prepared by other submitters and considered their results. While they have helped in obtaining a better understanding of the alternative approaches that can be used and the key assumptions, the Panel does not consider that the input assumptions in these models have been sufficiently tested during this Inquiry to be able to be relied upon as the primary source of evidence to address OIC 3(b)(iv).

[585] Submission F1-1, BC Hydro, Appendix L, pp. 4, 39, 50.
[586] Submission F1-8, BC Hydro, IR 2.68.1.

The Panel notes the approach suggested by BCSEA to address the OIC request, and considers that this is generally consistent with the approach used in the Illustrative Draft Alternative Portfolio model. While Commission staff's approach is simplified and illustrative compared to the resource optimization of BC Hydro's Portfolio PV model, it has key advantages of including capacity-focused DSM within the portfolio and being transparent with regard to the key input assumptions. In addition, unlike other models provided by submitters along similar lines, comments on the Illustrative Draft Alternative Portfolio have been both solicited and received which further enhances its transparency.

The Illustrative Draft Alternative Portfolio model, as adjusted in response to submissions received (Illustrative Alternative Portfolio), is the model that the Panel will use to answer the question posed in the OIC: whether any other portfolio of commercially feasible generating projects and demand-side initiatives could provide similar benefits to ratepayers at a similar or lower unit energy cost as Site C.

Financing Cost Assumptions

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.

One significant assumption is the cost of capital. In BC Hydro's alternative analysis, Site C is financed at the cost of debt, while the alternative portfolio is financed at an assumed WACC for an average IPP – as a proxy for the cost of financing for an IPP. However, every project is different, and it is not possible to make general assumptions about different IPP's cost of debt, nor what return the IPP's shareholders require, or are willing to accept.

According to the evidence presented to the Panel, BC Hydro is financing the construction costs of Site C at the BC Governments cost of debt. Further, BC Hydro does not propose to develop any other form of generation, or to finance the cost of such development.

At this time the Panel takes no position on what projects BC Hydro should or should not develop. We note the comments made by BC Hydro that they have little or no expertise in the development of alternative energy but do have experience with large storage hydro projects. Although BC Hydro has considerable experience maintaining large storage hydro projects, as evidenced by recent refurbishments to the Ruskin Dam and the W.A.C Bennett dam, the most recent storage hydro new construction was Revelstoke dam over 30 years ago. The work on both that project and Site C was contracted to third parties. – BC Hydro does not retain teams of experienced dam construction personnel on staff, its expertise is related to the oversight of the project. In our view this contributes to the risk of the Site C project. The Panel has commented further on the risks inherent in Site C. However, here we are concerned that the financial analysis that compares Site C to the Alternative Portfolio adequately reflects this risk.

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. We will discuss project risk further in the next section.

Therefore, for the purpose of rate impacts the Panel agrees that the cost of capital faced by an IPP may be a more appropriate value to use than the government cost of debt when evaluating the impact on ratepayers, although a more accurate analysis should consider the actual contract price that would be paid by BC Hydro to acquire such energy.

Notwithstanding the comments above, the Panel accepts BC Hydro's position that the cost to ratepayers can only be evaluated by considering the costs that ratepayers will actually pay and the Panel applies these financing assumptions when we evaluate the impact on ratepayers.

By assuming that BC Hydro will only develop Site C and no other energy generation project, the Panel finds that this results in an apples-to-oranges comparison. For the purpose of responding to the question of whether another portfolio of commercially feasible generating projects and DSM initiatives could provide similar benefits to ratepayers at similar or lower unit energy cost as the Site C project, the Panel finds that the same financing cost should be assumed for Site C and the Illustrative Alternative Portfolio.

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.

The second issue raised is whether the assumption of 100 percent debt financing at a cost of 3.43 percent is appropriate for the Site C versus the Illustrative Alternative Portfolio analysis. The Panel notes submitters concerns that (i) financing costs are at historic lows and could increase over the 70 year time horizon, and (ii) an assumption of 100 percent debt financing may change over the 70 year time period.

The Panel considers the risk of higher financing costs as part of the overall consideration of project risk.

Discount rate

The Illustrative Alternative Portfolio use the same discount rate proposed by BC Hydro for Site C (6 percent nominal, 3.9 percent real). For the purpose of this Inquiry only, the Panel agrees with BC Hydro that it is appropriate to use the generic cost of capital as the discount rate and address project and market risks through sensitivity analysis.

Market value of surplus

In modelling the "Energy surplus to BC Hydro" the Illustrative Draft Alternative Portfolio used a fixed forward market F2025 Mid-C price of US $30/MWh adjusted for exchange rate, line losses, wheeling to US/Canada border, transmission losses to Site C, and other adjustments to arrive at CAD $25/MWh.

Earlier in this report, the Panel found that the Mid-C Average Price forecast should be between the BC Hydro proposed Mid-C Market Price and ABB's low range forecast. The Panel has therefore changed the market priced assumption in the Illustrative Alternative Portfolio to align with this latter assumption.

This results in a Mid-C Market Price of (F2018) CAD $32/MWh in 2018 with real escalations to (F2018) CAD $55/MWh in 2040. Approximately the Mid-C Market Price rises each year by CAD $1/MWh in real terms. After adjusting for line losses at 1.9 percent, wheeling at CAD $6.3/MWh, and transmission losses to Site C at 11 percent, the market price for energy surplus is (F2018) CAD $22.3/MWh in 2018. The market price for energy surplus rises to (F2018) CAD $42.4/MWh in 2040.

Two other scenarios were modelled: (a) a Low Scenario based on the ABB low end of the forecast of BC Hydro's market price forecast[587] and (b) a scenario based on the BC Hydro Requirement Requirements Application.[588]

Attributes of Site C vs. Illustrative Alternative Portfolio (flexibility, reliability, GHG)

The Panel agrees with BC Hydro, CEC and Jaccard that dispatchable energy has potentially more economic value than non-dispatchable energy. However, the Panel also agrees with CEABC that a key issue is whether, and to what extent, this is needed in BC, and if not needed, whether it has a demonstrated value in the export market.

BC Hydro has provided a detailed explanation of why the timing may be optimal for the introduction of such products and make effective use of available surplus. The closure of coal generation plants in the Western US and Alberta in the mid to late 2020's and similar shut downs for nuclear and natural gas in California indicate that there will be a need to fulfill capacity requirements. However, what is less clear is whether BC Hydro through Powerex can be successful in reaching agreements to supply this capacity and flexibility. BC Hydro has acknowledged there are significant hurdles standing in the way of such transactions. It is reported that Powerex is pursuing these types of commercial opportunities actively and to date has at least one sale of this product type and is involved in discussions with others. This would indicate there is some potential for development for some sales of this capability but it is too early to be able to determine whether there is an opportunity to backstop other jurisdictions with surplus capacity and flexibility on an as required basis.

BC Hydro submits that Site C has the flexibility (i.e. firming and shaping capacity) to integrate 900 MW of wind, while the BC Hydro Alternative Portfolio (which includes intermittent renewable resources) will instead require firming and shaping. In Appendix A, the Panel considered BC Hydro's proposed cost of wind integration and found that:

- Although Site C can provide wind integration, BC Hydro already has significant wind integration capacity. As a result, BC Hydro values wind integration at the lost opportunity of providing firming/shaping into the export market.
- In the proceeding, BC Hydro estimated its lost opportunity cost of firming wind at $5/MWh. However, in Appendix A the Commission found that a more reasonable lost opportunity cost estimate would be $1/MWh.

In addition, the Panel notes that BC Hydro would have to first exhaust all the firming/shaping export opportunities from its existing hydro generation before it would incur any lost opportunity costs related to Site C.

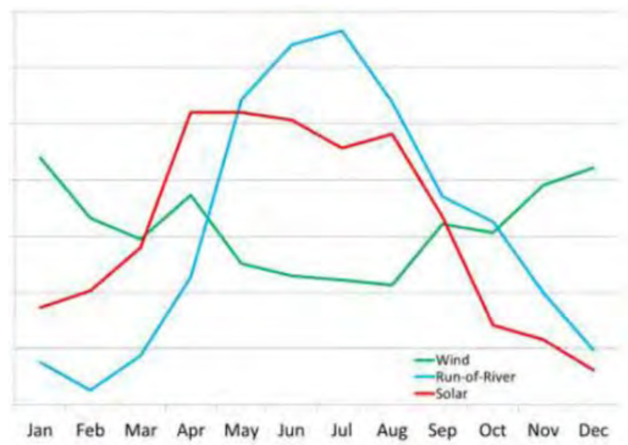
In Appendix A, the Panel also determined that, as wind projects are charged $1/MWh for the cost of wind integration, Site C should be provided a similar credit to reflect the potential export of this service into neighbouring jurisdictions. Based on BC Hydro's submission that Site C can integrate 900 MW of wind, the Panel estimates that this will result in a Site C "wind integration credit" of $3.36 million a year. **The Panel finds that an adder for wind integration in the Illustrative Alternative Portfolio, and a credit for wind integration for Site C, result in the portfolios having similar levels of firming and shaping.**

The OIC also referred to storage capability which is the ability to adjust generation supply within the year to respond to seasonal changes in variable generation resources. Site C cannot itself shape energy, although it does have a beneficial load shape as a result of shaping by the upstream Williston reservoir. However, the Illustrative Alternative Portfolio also has a beneficial load shape:

[587] Submission F1-1, BC Hydro, p. 64.
[588] Submission F106-1, PoWG, p. 67; BC Hydro F2017-F2019 RRA, Exhibit B-14, BCUC IR 310.1.

- The load shape of energy efficiency DSM would be expected to be similar to that of BC Hydro's load, and also adjust to year-on-year changes in weather (a customer who undertakes home insulation would benefit from greater energy reductions during a cold winter month compared to a warm winter month);
- Capacity focused DSM (such as utility controlled water heaters, bill credits for load curtailment during peak periods) can be very beneficial in responding to seasonal changes in energy demand; and
- Wind generation output is greater during the winter months as seen in the graph below. [589]

Figure 25: Monthly Energy Profile for Wind, Run-of-river and Solar



As a result, the **Panel considers that the seasonal shape of energy generated from Site C is similar to the Illustrative Alternative Portfolio (comprised of energy efficiency DSM, capacity focused DSM and wind energy).** The Panel also notes that energy efficiency and capacity focused DSM can provide financial benefits to BC Hydro's ratepayers.

Regarding grid reliability, the Panel finds that the addition of a cost adder to the Illustrative Draft Alternative Portfolio to account for network upgrades results in the Illustrative Alternative Portfolio (as discussed in Appendix A) having similar levels of grid reliability as Site C.

In Appendix A the Panel finds that geothermal energy is commercially viable and includes it in the Illustrative Alternative Portfolio, and that the quality of geothermal energy (with regards to firming, shaping, storage and grid reliability) is similar to that of Site C.

Regarding GHG emissions, the Illustrative Alternative Portfolio (comprised of energy efficiency, geothermal and wind) maintains or decreases BC GHG emissions compared to 2016/17 levels and is below Site C's GHG emission levels in the short term.

The Panel finds that the Illustrative Alternative Portfolio indicates that it is possible to design an alternative portfolio of commercially feasible generating projects and demand-side management initiatives that could provide similar benefits to ratepayers as Site C.

Termination, sunk costs and cost to ratepayers

The OIC asks: "What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?"

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[589] Submission F1-1, BC Hydro, Appendix L, p. 28.

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.

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.

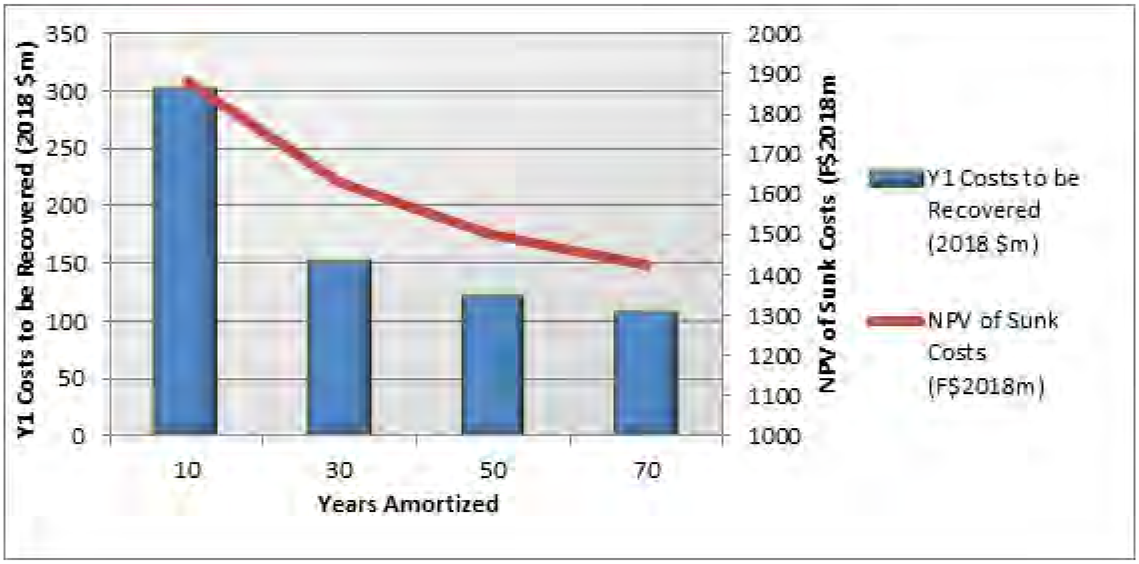
In regard to the recovery period, this requires further analysis. Considerations include intergenerational equity – too long a period risks forcing customers who may not benefit from the expenditure to pay for it. If the payback period is too short, there is a risk of rate shock. This Panel takes no 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.

Figure 26: Effect on revenue requirement (Year 1) sunk cost amortization periods in the Illustrative Alternative Portfolio



When calculating cost to ratepayers, we calculate the NPV of the incremental revenue requirement of the item in question. This does not equate to bill impact as that would require, among other things, assumptions about the increase or decrease in the number of ratepayers over time.

Illustrative Alternative Portfolio results and sensitivity analysis

Section 3(b)(iv) of the OIC asks:

> Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?

The Panel presents here the results of the Illustrative Alternative Portfolio model developed to assist in answering the OIC question above. The outputs of the model are:

- An estimate of the PV of the costs to ratepayers of Site C and the Illustrative Alternative Portfolio. This PV estimate includes all costs (less export revenues) associated with each option. Incremental costs associated with terminating site C are included in the cost of the Illustrative Alternative Portfolio. A credit is given to Site C to reflect the additional flexibility of Site C compared to the Illustrative Alternative Portfolio.
- An estimate of the unit energy cost (UEC) of each portfolio. Consistent with the Panel's previous finding, this represents the PV of the cost of each option divided by the energy produced.

The Panel is mindful of the comments by BC Hydro and other parties that resource planning is a complex exercise. This exercise is not a substitute for BC Hydro's planning process. We consider that the Illustrative Alternative Portfolio presented in this report is illustrative only, and were developed as a way to answer the questions posed in the OIC. They were informed by the evidence available, including portfolios presented by BC Hydro that were produced by its PV Portfolio Analyzer.

Key assumptions

Appendix C describes the revised key input assumptions that are now used in the updated model, and provides a description of the model itself and its functionality. The model is being published together with this report in order to increase the transparency of the approach used by the Commission to answer the OIC question, and to assist users in understanding the sensitivity of the model output to key input assumptions.

Illustrative Alternative Portfolio results

The composition of the Illustrative Alternative Portfolio is shown below:

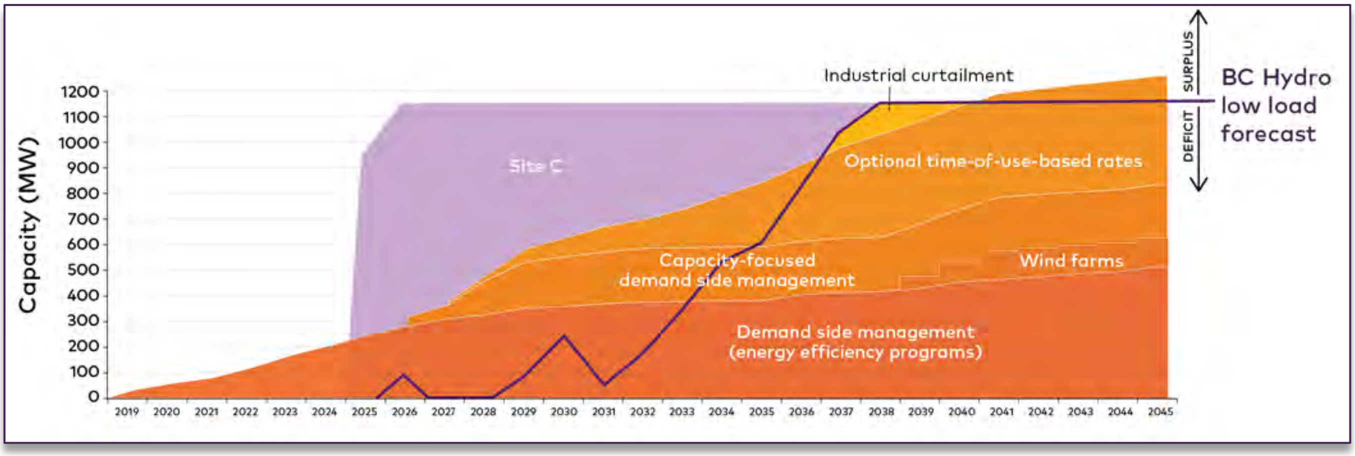
Summary Results of the Illustrative Alternative Portfolio (2018$)			
	High Load Forecast	**Medium Load Forecast**	**Low Load Forecast**
Illustrative Alternative Portfolio composition	• 441 MW of wind projects starting in F2025, 288MW in F2026 • DSM initiatives (energy efficiency, optional time of use (TOU) rate, capacity focused DSM, industrial curtailment) • 81 MW of geothermal projects starting in F2025[590]	• 438 MW of wind projects starting between F2029 and F2031 • DSM initiatives (energy efficiency, optional TOU rate, capacity focused DSM, industrial curtailment) • 81 MW of geothermal projects starting in F2025[591]	• 444 MW of wind projects starting between F2039 and F2041 • DSM initiatives (energy efficiency, optional TOU rate, capacity focused DSM, industrial curtailment)[592]
Cost to ratepayers Illustrative Alternative Portfolio[593]	$ 5,121 million[594]	$ 4,618 million[595]	$ 3,234 million[596]

In the low load forecast scenario, the load can be met with BC Hydro's existing assets until 2034. This results in all of the energy and capacity produced from Site C from its commissioning date of 2024 until 2034 to be surplus and available for export sales by Powerex. In addition, there continues to be surplus available for sale through 2041. This has the effect of reducing the cost to ratepayers of the Site C project.

A key difference between the Illustrative Alternative Portfolio and Site C is the incremental nature of the Illustrative Alternative Portfolio. Layering in DSM with smaller scale renewable projects provides flexibility to better match generation with demand. DSM and smaller scale IPP projects have project completion times in the range of months to a few years, and each project (or energy contract if it is contracted through an IPP) is much lower in price than Site C.

[590] Appendix H – Commission Illustrative Alternative Portfolio, Tab 'High LF – portfolio', with costs in Tab 'High LF - portfolio costs'.
[591] Ibid., Tab 'Med LF – portfolio', with costs in Tab 'Med LF - portfolio costs'.
[592] Ibid., Tab 'Low LF – portfolio', with costs in Tab 'Low LF - portfolio costs'.
[593] Discount rate of 4% real, 6% nominal; export revenues valued at Panel's Mid C Forecast (at plant gate location), Site C $1.8 billion termination costs amortized over 30 years and assuming all resources are financed at BC Hydro's financing rate.
[594] Appendix H – Commission Illustrative Alternative Portfolio, Tab 'Input and Output', Cell O26.
[595] Ibid., Tab 'Input and Output', Cell O17.
[596] Ibid., Tab 'Input and Output', Cell O8.

Figure 27: Capacity Gap Surplus



The Commission, in its 1983 Decision on Site C, also raised similar concerns regarding the need to consider the timing of investment decisions in an economic analysis:

> The Commission recognizes that undersupply can impose serious consequences and therefore should be avoided if possible. But it also recognizes that, under current circumstances, overbuilding can entail the significant economic costs to the province associated with a mistimed investment. Given the softer export market conditions forecast to prevail throughout the balance of the decade, overbuilding can result in the commitment of a large amount of capital yielding a relatively low rate of return. This return might be sufficient to cover Hydro's borrowing costs (i.e. 3%), but it would not be sufficient to cover the social opportunity cost of capital (i.e. 8% to l0%). Overbuilding could also result in significant upward pressure on domestic customer rates, as discussed in the next chapter. In light of this, the Commission concludes that overbuilding should be avoided.[597]

The following tables show the cost to ratepayers and UEC for Site C and the Illustrative Alternative Portfolio, based on the following assumptions (referred to as “Commission Assumptions” below):

- **Low** load scenario;
- The **Panel Mid-C** market electricity price forecast;
- Site C total costs of **$10 billion;**
- Termination costs of **$1,800 million** amortized **over 30 years; and**
- **BC Hydro financing for all** resources in the Alternative Portfolio

The Panel is of the view that assuming BC Hydro financing for all resources results in an “apples to apples” comparison.

[597] BC Hydro Application for an Energy Project Certificate for the Peace River Site C Project, Site C Report and Recommendations to the Lieutenant Governor-in-Council, British Columbia Utilities Commission report dated May 3, 1983, p. 99.

Table 39: Cost to ratepayers and UEC of the Illustrative Alternative Portfolio

Output: Low LF - Alternative Portfolio				
A	**Site C Termination Cost (F$18)**	$	1,395	million
B	**Alternative Portfolio Cost (F$18)**	$	2,627	million
C	**Surplus Energy Sale (F$18)**	$	(788)	million
D	**Total Rate Impact (A+B+C)**	$	3,234	million
E	**Alt. Portfolio Volume (F18)**		83,017	
F	**UEC (F$18) (B/E)**	$	31.64	per MWh

Table 40: Cost to ratepayers and UEC of Site C

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)**	$	(1,137)	million
E	**Total Rate Impact (B+C+D)**	$	3,188	million
F	**Volume (F18)**		98,993	
G	**UEC (F$18) (B/F)**	$	44.35	per MWh

The comparison in the tables above show that the cost to ratepayers Illustrative Alternative Portfolio has a lower UEC than Site C ($31.64/MWh compared to $44.35/MWh) but a cost to ratepayers slightly higher ($3.234 billion compared to $3.188 billion for Site C).

The Panel undertook a sensitivity analysis to identify the key variables that could have a material effect on the results. To analyze the sensitivity of the cost to ratepayers, a base case must first be defined for which a cost to ratepayers is calculated. Then each variable is varied one by one, to a lower or higher value than its value in the base case and the rate impact is re-calculated. It should be noted that the base case is not the same as the "Commission Assumptions" as each base case had to have a higher and lower variable. Specifically, the base case for the sensitivity analysis was the mid load forecast (whereas the "Commission Assumption" is the low load forecast) and IPP financing for wind and geothermal resources (whereas the "Commission Assumption" is for BC Hydro financing). The assumptions and results of these assumptions are shown below:

Table 41: Sensitivity Analysis of Illustrative Alternative Portfolio

Illustrative Alternative Portfolio Base Case Rate Impact: $4,918 million

Input Variable	Low Value	Difference from Base Case	High Value	Difference from Base Case	Low Value	Base Case	High Value
Load	$ 3,360	$ (1,558)	$ 5,537	$ 619	Low LF	Med LF	High LF
Termination costs	$ 4,106	$ (812)	$ 5,306	$ 388	$750 million	$1.8 billion	$2.3 billion
Financing costs	$ 4,618	$ (300)	$ 5,120	$ 202	BCH financing for wind-geo, 3.4%	IPP financing for wind-geo, 6.4%	IPP financing for wind-geo, 8.4%
Termination costs amortization	$ 4,745	$ (173)	$ 5,134	$ 216	70 years	30 years	10 years
Wind costs	$ 4,860	$ (58)	$ 5,115	$ 197	Base case less 5.9% (CanWEA/EABC F104-3)	A-22 Assumption No. 13	Base case plus 20%
Geothermal costs	$ 4,862	$ (56)	$ 5,025	$ 107	CANGEA (F66-4)	NREL flash	NREL binary
Market price of surplus	$ 4,881	$ (37)	$ 4,949	$ 31	BC Hydro RRA	Panel Mid C	Panel Mid C ABBLow

The table above shows that the cost to ratepayers of the Illustrative Alternative Portfolio defined as the Base Case (see Base Case column for the values taken by each of the key input variable) is $4.918 billion. Then, each variable can be changed to a low or high value, in the right-hand side of the table, and the cost to ratepayers of that single change (while holding the other inputs constant) is shown in the left-hand side.

For example, if the Load is changed to Low instead of Medium, the cost to ratepayers would be reduced by $1.558 billion from $4.918 billion to $3.360 billion, while all the other inputs remained as defined in the Base Case. This estimate of $3.360 billion is higher than the Illustrative Alternative Portfolio result of $3.234 billion as the base case in the table above uses IPP financing costs rather than BC Hydro financing costs. However, this analysis serves to illustrate how sensitive the PV cost to ratepayers analysis is to changes in key input assumptions.

The cost to ratepayers of any combination of changes can be calculated from the table above, by starting with the Base Case and adding the “Difference from Base Case” value associated with the change in the input variable. The results are shown graphically below:

Figure 28: Illustrative Alternative Portfolio Cost to ratepayers Sensitivity

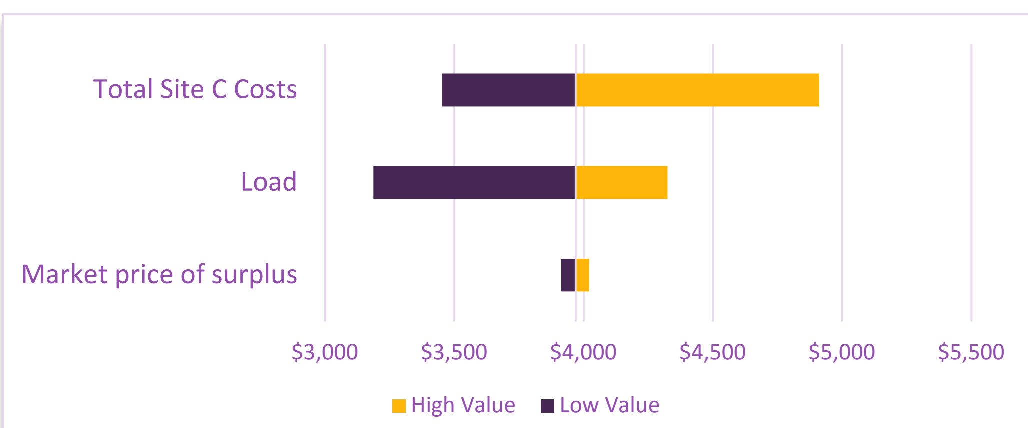
As can be seen in the graph above, the inputs and assumptions that have the greatest impact on the cost to ratepayers in the Illustrative Alternative Portfolio are the magnitude of the load and Site C termination costs. These are followed by the assumption regarding the financing of IPP projects and the length of the amortization period for the Site C termination costs. The wind and geothermal energy capital and O&M costs, as well as the market price of surplus energy have the least impact on the results.

The analysis of the effect of the input assumptions into the Site C cost to ratepayers is shown below:

Table 42: Sensitivity Analysis of Site C

Input Variable	Low Value	Difference from Base Case	High Value	Difference from Base Case	Low Value	Base Case	High Value
Total Site C costs	$ 3,452	$ (517)	$ 4,911	$ 942	$8,900 M	$10,000 M	$12,000 M
Load	$ 3,188	$ (718)	$ 4,325	$ 356	Low LF	Med LF	High LF
Market price of surplus	$ 3,914	$ (55)	$ 4,021	$ 52	BC Hydro RRA	Panel Mid C	Panel Mid C ABBLow

Figure 29:Site C Cost to ratepayers Sensitivity



For Site C, the inputs and assumptions that have the greatest impact on rates are the Site C total costs and the magnitude of the load. As with the Illustrative Alternative Portfolio, the market price of surplus energy has much less impact on the costs to ratepayers.

In addition, the Illustrative Alternative Portfolio model has been designed to allow the user to analyze the sensitivity of the cost to ratepayers of both the Illustrative Alternative Portfolio and Site C to changes of the following input assumptions:

- Magnitude of load
- Termination costs
- Financing costs for IPP projects
- Amortization period of termination costs
- Wind costs
- Geothermal costs
- Market price of surplus energy

A summary of some sample scenarios is shown below:

Table 43: Summary of Sample Scenarios

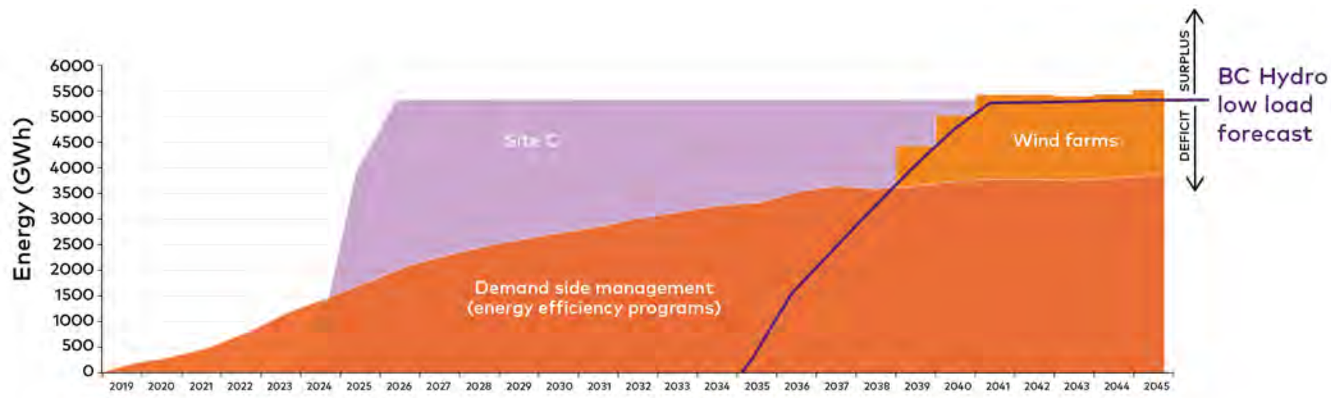
	Cost to ratepayers ($'m)			Unit energy cost ($/MWh)	
Scenarios	**A. Illustrative Alternative Portfolio**[598]	**B. Site C**[599]	**Difference (A - B)**	**Illustrative Alternative Portfolio**	**Site C**
Commission Assumptions[600]	$3,234	$3,188	$46	$32	$44
Scenarios[601] Medium load forecast	$4,618	$3,969	$649	$34	$44
Medium load forecast + $12 billion Site C cost	$4,618	$4,129	$489	$34	$54
Low load forecast, $12 billion Site C cost	$3,234	$4,129	($895)	$32	$54
Low load forecast + higher wind-geothermal financing	$3,360	$3,188	$172	$33	$44
High load forecast	$5,121	$4,325	$796	$31	$44
High load forecast, $12 billion Site C cost	$5,121	$5,266	($145)	$31	$54

[598] Illustrative Alternative Portfolio cost plus Site C termination costs minus exports revenues.
[599] Site C cost to complete less flexibility credit and export revenues.
[600] Low Load Forecast, Panel Mid C market electricity price forecast, Site C total costs of $10 billion, $1.8 billion in termination costs amortized over 30 years, and BC Hydro financing for all resources in the Illustrative Alternative Portfolio.
[601] The five scenarios presented in this table start with using the "Commission Assumptions" and modifying one or two variables as described therein.

Surplus Energy

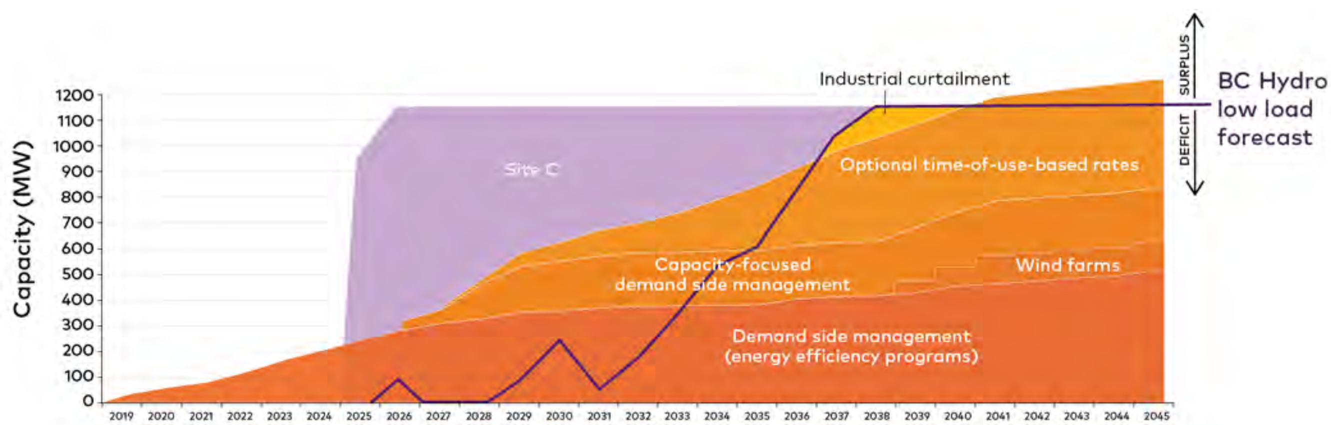
As shown in the graph above, in the low load forecast, there are fewer surplus sales from the Illustrative Alternative Portfolio.

Figure 30: Energy Gap/Surplus: Site C Compared to Illustrative Alternative Portfolio



Any surplus energy produced by Site C or the Illustrative Alternative Portfolio is assumed to be sold for export at the market price. BC Hydro and some parties in this proceeding argue that the ability to sell surplus energy is a benefit to Site C. Others describe selling surplus energy as selling below cost. The view you take depends on assumptions about the market price of energy and the domestic need for Site C energy. BC Hydro modelled approximately $1.5 billion in sales of surplus energy from Site C between 2024 and 2034.

Figure 31: Capacity Gap/Surplus: Site C Compared to Illustrative Alternative Portfolio



To illustrate the effect of market sales, we examine an extreme case. We have modelled the cost to ratepayers of a zero-load growth. In this scenario all Site C energy is surplus and an alternative portfolio is not required. With the Panel Mid-C Forecast, the cost to ratepayers is $1,638 million:

Figure 32: Cost of Site C to Ratepayers of a Zero-Load Growth

Output				
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)**	$	(2,686)	million
E	**Total Rate Impact (B+C+D)**	$	1,638	million
F	**Volume (F18)**		98,993	
G	**UEC (F$18) (B/F)**	$	44.35	per MWh

This illustrates that under current market value assumptions, not all of the costs of Site C would be recovered and that the surplus energy is therefore being sold "below cost." However, if ratepayers need Site C energy, but don't need it immediately, as with the low load forecast scenario and higher, surplus sales actually lower the cost to ratepayers of Site C.

On the face of it, the suspend scenario would delay the completion of Site C until demand "catches up" with supply. However, as we have previously discussed, the costs associated with the suspension case result in a higher cost to ratepayers.

6.4 Other implications of terminating Site C

In addition to the directs costs for terminating Site C, there are a number of potential and actual indirect costs which are difficult to determine whether they will actually occur and, if so, how to quantify them.

Many of these were issues were raised by the public in Community Input Sessions or by First Nations in their input sessions. These submissions have been described in depth in Sections 3.4 and 3.5.

In this section, the Panel outlines some of the other implications of terminating Site C to allow the issues to be further investigated or examined prior to a final decision being made with respect to Site C.

Potential First Nations concerns

McLeod Lake Indian Band submits that suspension or termination of the Site C project will have numerous unaccommodated impacts to its title and rights and will affect existing agreements with BC Hydro and the Provincial Crown. McLeod Lake Indian Band submits it cannot be left in a worse position due to the termination or suspension of Site C than it would have been had the project been completed.[602]

The Panel acknowledges that it would be reasonable to expect that all other First Nations that entered into similar agreements with BC Hydro or the Provincial Government would have similar claims.

Loss of Site C jobs and financial impact on the community

The termination of Site C will have a dramatic effect on employment in the Peace River Region. The construction of Site C is estimated to provide jobs to 2,500 people. Many of the people who have been engaged stay on site but others have moved into the area, purchased homes and become members of the community. A termination of Site C would likely provide temporary employment for some over the remediation period but after this employment would be severely reduced or eliminated. The loss of employment would have many impacts on both individuals and the community as a whole. Workers who

[602] Submission F274-1, McLeod Lake Indian Band, pp. 17–18.

purchased homes would likely sell their homes and move elsewhere, potentially creating a surplus in housing with resultant impacts on saleability and house prices.

Perhaps even more important is the effect on the community of terminating the project. Many local businesses rely either directly or indirectly on Site C as a source of business. If this were to dry up suddenly, the impact on the business community would be significant.

Impacts on the environment

The Community Input sessions were replete with concern for the impact on the environment if Site C were completed. A cancellation of this project would have the opposite impact. To the extent that damage to the environment will occur in the event of Site C being completed, this will not occur.

First Nations reconciliation

A major sub-theme in the Community Input sessions was the honoring of Treaty 8 and fulfilling responsibilities for reconciliation with indigenous peoples. The termination of Site C would be interpreted as a positive and meaningful step in the reconciliation process for those First Nations who did not reach an agreement with BC Hydro.

Agricultural land

A natural consequence of termination of Site C is a cancellation of any flooding of the Peace River Valley to allow for the reservoir. This would leave open the option for other uses for this land and would also over time allow the heavily logged areas to reforest. This would in turn allow for the land that has been logged to return to a more natural state over time.

7.0 Case 3 – Suspend the project

7.1 The question posed under the OIC

Section 3(a)(ii) of the OIC states that the Commission must advise on the implications of suspending the Site C project, while maintaining the option to resume construction until 2024.

Section 3(b)(ii) of the OIC asks: "What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024, and what are the potential mechanisms to recover those costs?"

7.2 Costs to suspend Site C

7.2.1 Key submissions and issues raised in Preliminary Report

BC Hydro submission

BC Hydro separated its analysis into two sections: (i) the costs to suspend and maintain the site allowing for remobilization in 2024; and (ii) the costs of restarting and completing the project after suspension. BC Hydro noted that while working under the assumption it is possible to restart the project, there are substantial risks with this assumption and while some of the assets could be maintained in suspension, others would be lost resulting in substantial risk to restarting.

Suspension and maintenance during the suspension period

Based on a Class 5 estimate (+ 100 percent/-35 percent) BC Hydro's estimate of direct costs of suspension and maintenance for a seven-year period totals $1.1 billion inclusive of a 30 percent contingency with the key cost areas identified as:

- construction and other contracts;
- activities to remediate the site to a safe and environmentally sound state; and
- indirect costs like project team staffing for work arising from suspension.

BC Hydro conducted a Monte Carlo analysis to help understand the risks and uncertainty associated with the estimates and retained Hemmera Envirochem Inc. for advice on environmental and regulatory requirements for remediation.[603]

As prepared by BC Hydro, a summary of suspension and maintenance costs are outlined in Table 44.

Table 44: Breakdown of Suspension and Maintenance Costs[604]

Cost to put the Project site into a state of suspension and render safe	$0.9 billion
Cost to maintain the Project site for the period of suspension to preserve the option to resume	$0.3 billion
Total	$1.1 billion*

* Total is different than the sum numbers above due to rounding effects.

BC Hydro reports that work associated with suspending and rendering the project safe would take two years and cost $0.9 billion to cover costs related to contract termination, rendering the site safe and environmentally sound and retaining a project team to manage the suspension work (a detailed list of these

[603] Submission F1-1, BC Hydro, p. 68.
[604] Submission F1-1, BC Hydro, p. 84.

activities are outlined in the appendix to Exhibit F1-1). Once suspended and rendered safe, the site requires ongoing maintenance costs to continue monitor and maintain it at an estimated cost of $0.3 billion.[605]

Restarting and completing the project

BC Hydro states it would take approximately two years to restart the project prior to the recommencement of construction as it would require re-establishing a project team, re-procurement of major contracts, re-permitting construction activities and remobilization of major contractors to the site requiring a spring of 2023 restart.[606]

BC Hydro estimates that restarting the project after a seven-year delay would result in completing the project in 2031. This would represent significant risk to the schedule and completion costs and be subject to the circumstances existing at the time for items like equipment availability, labour markets and regulatory timelines. Added to this are risks related to changes in cost drivers such as market conditions, regulatory requirements and increased design standards over time. BC Hydro estimated an amount of $1.7 billion for these additional costs but provided limited detail as to the specific costs and how the quantum of $1.7 billion in additional costs was calculated.[607]

BC Hydro explains that a restart to the project would also have a significant impact on interest charges. BC Hydro estimates that interest charges from 2018 through the 2031 completion date would result in an additional $1.8 billion. Therefore, taking all of the aforementioned costs into account, BC Hydro estimates the costs to be recovered from ratepayers under the suspension scenario would total $12.9 billion. These are summarized as:

- $2.1 billion in sunk costs through the end of 2017;
- $1.1 billion for suspension and maintenance of the site;
- $7.9 billion for completion of the project (inclusive of the additional $1.7 billion); and
- $1.8 billion in additional interest costs from 2018 through 2031.[608]

Deloitte report

Deloitte estimated the suspension scenario to cost approximately $1.4 billion with an accuracy range of -35 percent to +100 percent. Its estimates do not include incremental interest costs related to the suspension nor account for any inflation impacts on post suspension costs to complete the project.

Deloitte's suspension scenario triggers two sets of BC Hydro's project team activities: the management of existing contracts and commitments and the creation of a new "suspension project." Accordingly, it would need to decide whether to retain or terminate the existing contracts and commitments and how to close out existing active contracts. In Deloitte's view, creating a suspension project would be significantly different from the current project to justify independent project planning and implementation to meet the objective of the new scope of work. Accordingly, it would be executed with its own scope, budget and execution schedule.[609]

In Deloitte's view, the decision to suspend the project changes the current scope of work as well as the schedule and budget, triggering the closeout of the current Site C project and definition of a new project. The resultant new project would require a project setup phase to establish the conceptual design and to

[605] Submission F1-1, BC Hydro, pp. 84–85; a detailed list of these activities are outlined in Submission F1-1, Appendix O.
[606] Submission F1-1, BC Hydro, pp. 86–87; Appendix O, p. 19.
[607] Submission F1-1, BC Hydro, pp. 87–89.
[608] Submission F1-1, BC Hydro, pp. 89–90.
[609] Submission A-8, p. 42.

perform tasks related to an environmental appraisal, permitting, design for construction and contracting. The new project would have its own scope, budget and schedule. [610]

A summary of Deloitte's estimated costs are outlined in Table 45.

Table 45: Summary of Cost Estimate – Suspension Scenario[611]

#	Suspension Scenario	Cost Impact ($ millions)
1	The cost to suspend the Site C Project	
	• Contract cancellations	331
	• FNs, community and archeological impacts	Included above[65]
	• Demobilization	50
2	The cost to maintain the Site C Project in a state of suspension	
	• Engineering (site), permitting, and procurement	25
	• Site preservation activities	445
	• Care and maintenance	40
3	The cost to remobilize the Site C Project to begin construction in 2025	
	• Engineering (design + site), permitting and procurement and site mobilization	195
	• Revalidating site	5
	Total	**1,091**
	Contingency (30%)	327
	Grand Total	**1,418**

Deloitte's total cost for suspending, maintaining and remobilizing the project is estimated to be $1.418 billion. This does not include any provision for additional interest costs nor does it include the impact of inflation on post suspension costs to complete the project. The major cost areas include contract cancellation at $331 million, site preservation activities at $445 million, $195 million for engineering, permitting, procurement and site mobilization activities and $327 million (or 30 percent) for contingency.

7.2.2 Panel analysis, preliminary findings and questions in Preliminary Report

The Panel found that $1.1 billion is a reasonable estimate of the costs for suspension and maintenance of the project. The estimates provided by BC Hydro at $1.1 billion and that of Deloitte at $1.143 billion are very similar. The Panel noted there was a degree of comfort with respect to these estimates in that two separate and independent processes have provided a similar result. However, this was tempered by the fact that the estimates completed by both parties are based on Class 5 estimates that have a broad accuracy range.

The Panel found there is significant variance between BC Hydro and Deloitte's estimates with respect to costs related to restarting the project. Deloitte has provided an estimate of $200 million plus contingency to remobilize the Site C project and begin construction again in 2025 while BC Hydro has estimated costs of $1.7 billion. There are significant differences between what has been contemplated in each of the two estimates as Deloitte has estimated only those costs for engineering (design and site), permitting and procurement and site mobilization. It has neither considered nor estimated the impact of inflation on post suspension costs due to it maintaining there would be a need to establish a completely new project with its own unique scope budget and schedule.

[610] Submission A-8, pp. 3, 46–63.
[611] Submission A-8, p. 64.

Given the lack of clarity with respect to some of the costs, the Panel found it premature to reach a conclusion as to the total costs for the project in the event it is suspended and restarted at a later date. The Panel further found that BC Hydro's inclusion of estimated costs for increased interest costs and "for escalation and some of the incremental risk to complete the Project due to the period of suspension"[612] accounts for much of the variance between the two estimates. The Panel noted its concern with the lack of information that BC Hydro has provided to support the additional $1.7 billion in restart costs.

The Panel requested BC Hydro to readdress its estimate of $1.7 billion to restart the project providing a more fulsome description of the costs and assumptions made. BC Hydro was also asked to address whether it believed there to be any circumstance restricting its ability to complete the project and to comment on the costs and benefits installing fewer generators initially at Site C, followed by more generators at a later date to perhaps better match energy and capacity needs. Subsequently, BC Hydro was asked to provide its calculation for the estimated $1.8 billion in additional interest charges associated with suspending and restarting the project.

7.2.3 Additional submissions and responses

BC Hydro submission

Explanation for the $1.7 billion to restart the project following suspension

BC Hydro stated that its total estimated cost for the project suspension scenario is $2.75 billion, inclusive of the resumption of activities at $2.25 billion plus a provision of $0.5 billion to cover risks of restarting the project. These costs are outlined in Table 46 which compares at a high level the estimates of both BC Hydro and Deloitte for the scenario.

Table 46: Comparison of Estimated Costs for Project Suspension: BC Hydro and Deloitte[613]

Description	BC Hydro ($ million)	Deloitte ($ million)[1]	Variance ($ million)
Reactivation Costs			
Direct Costs	341	195	146
Indirect costs	66	5	61
Contingency	168	327	(159)
Reactivation Costs before Inflation and Management Reserve	**575**	**527**	**48**
Inflation (both during suspension and required to complete construction)	585	-	585
Management Reserve (risk provision)	500	-	500
Project Reactivation Costs (Including Management Reserve)	**1,660**	**527**	**1,133**
Project Suspension Costs, including Maintenance of Site until F2023	1,090	891	199
Total Estimated Costs for Project Suspension	**2,750**	**1,418**	**1,332**

BC Hydro stated that Site C suspension costs vary by 18 percent or $199 million from Deloitte's estimate, and reactivation costs are relatively close with a variance of 8 percent or $48 million. In calculating these figures, BC Hydro has applied all of Deloitte's estimated $327 million contingency to the reactivation costs

[612] Submission F1-1, BC Hydro, p. 87.
[613] Submission F1-8, BC Hydro, IR 2.81.1.

and none to the project suspension costs. In addition, BC Hydro's $341 estimate for direct costs related to reactivation is almost double that of Deloitte. BC Hydro provided no further comment on this.

The most significant difference in the estimate of $1.418 billion prepared by Deloitte and BC Hydro's estimate of $2.750 billion relates to two factors that Deloitte does not address: Deloitte has specifically excluded expected inflation impacts of post-suspension costs to complete Site C and has not included a management reserve or risk provision to cover items such as the potential for higher inflation or interest costs, regulatory condition changes or a change in the engineer of record. These factors, when combined, total $1.085 billion. [614]

BC Hydro provided explanations for a number of the cost items. Some of the key items are as follows:

Remobilization costs

BC Hydro explained that contractors will be required to re-perform work on items already completed under existing contracts. These include development of plans and submissions, the hiring of the management team and workforce, deployment of personnel, vehicles and equipment to the site and the process of reactivating the fixed infrastructure left on site for future use at an estimated cost of $180 million.[615]

Construction management, engineering and project management and other

There would be a need to engage a new construction management team to undertake the task of managing the reactivation of the site. This is estimated to cost $14 million. In addition, the engineering team (at a cost of $26 million) would need to be reconstituted and plans put in place to provide for assessment of the current site conditions, design of any remediation requirements and participate in the new construction planning, regulatory activities and contractor submission reviews. Cost estimates for the reactivation period for construction management and engineering were calculated based on an analysis of the current burn rate and imputed Full Time Equivalent (FTE) staff factoring in the incremental effort required and recognizing that these costs would be lesser than the current burn rate. Overall, these costs represent 30 percent of the current monthly construction management expenditures and 29 percent of the current engineering expenditures. In addition, there would be a need to reconstitute the project management team at an estimated cost of $31 million. This represents a burn rate of approximately 79 percent of current expenditures by month.[616]

Contingency

BC Hydro budgeted a contingency of $168 million split between the suspension period (at 29.9 percent) and the reactivation period (at 70.1 percent). The contingency associated with suspending the project is 33.7 percent; an amount BC Hydro states, "is relatively high due to the fact this is a Class 5 estimate."[617]

Inflation

BC Hydro stated that the total cost of inflation based on the inflation calculation model maintained by its Estimating Department is $624 million. Of this amount, $39 million is for maintaining the site during the suspension period and $585 million for the reactivation work. This amount covers the remaining construction work and the cost of deferral of all remaining works by seven years. BC Hydro stated the anticipated inflation was based on "two percent per year, compounded annually, in accordance with BC Hydro's corporate rate assumptions and the annual MMK Consulting report on projected inflation."[618]

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[614] Submission F1-8, BC Hydro, IR 2.81.1, p. 2.
[615] Submission F1-8, BC Hydro, IR 2.81.1, pp. 3–4.
[616] Submission F1-8, BC Hydro, IR 2.81.1, pp. 5–7.
[617] Submission F1-8, BC Hydro, IR 2.81.1, p. 8.
[618] Ibid., p. 8.

Risk provision

BC Hydro included a provision of $500 million to cover additional risks. While acknowledging these may have a low likelihood of materializing, BC Hydro considered making an assumption that all such costs would be avoided would not be prudent. It has identified a number of scenarios where any one has the potential to cause the $500 million estimate as a special provision to be exceeded. Among these are the following:

- Escalation beyond the assumed 2 percent rate of inflation.

  Given the seven-year delay, the project is highly sensitive to small differences in inflation. If, for example, the inflation rate were one percent greater than forecast, the impact would be greater than the $500 million.[619]

- Constant interest Rates

  Due to the lengthy construction period, the project is subject to interest rate fluctuations. Currently, BC Hydro benefits from historically low interest rates which it may forego if the project is suspended. BC Hydro currently has a hedging program to mitigate the risk of an increase in interest rates but would not enter into new hedges without certainty on restarting the project. BC Hydro noted that project suspension "has the potential to forego this benefit, and may impact the economic rationale to complete the project in the future."[620]

- Project engineer change

  A change in the project engineer will likely require various technical works to be done in order to satisfy their design accountability. BC Hydro noted that this could result in further delays in the expected timeline.

- Regulatory requirements

  BC Hydro pointed out that laws and regulations with respect to safety, environmental protection and consultation and engagement with First Nations may be amended provincially or federally. This could affect a variety of factors such as the means and methods of construction, requirements for environmental and safety mitigation and ultimately impact schedule performance.[621]

Installing generators at a later date

BC Hydro stated that "potential savings associated with deferring installation of one or more generating unit (s) could be expected to be minimal at best." Specifically, BC Hydro made the following assertions:

- Construction costs making up a significant part (approximately 50 percent) of completing the generator unit bays would still be incurred;
- The maximum potential of any savings would not be expected to be realized;
- Incremental savings would be offset by new costs related to leaving the bays empty; and
- The operational flexibility and outage management benefits related to the deferred generating units would not be realized.

BC Hydro further explained that if a downstream plant such as Site C were to be built with less hydraulic capability than those upstream, the downstream plant restriction will cascade to upstream plants resulting in more frequent operational impacts at these upstream facilities.[622]

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[619] Submission F1-8, BC Hydro, IR 2.81.2, p. 8.
[620] Submission F1-8, BC Hydro, IR 2.81.2, p. 2.
[621] Submission F1-8, BC Hydro, IR 2.81.1, p. 8.
[622] Submission F1-5, BC Hydro, IR 2.82.2.

Estimated $1.8 billion in interest charges

BC Hydro has more accurately calculated this interest charge at $1.73 billion and supported these calculations with a spreadsheet. BC Hydro stated that its total direct costs in the Site C Regulatory Account before interest will amount to $3.247 billion made up of the following components:

- $0.465 billion already in the Site C Regulatory Account; plus transfers of
- $1.635 billion for capital costs between FID and the suspension date;
- $0.891 billion for suspension related costs; and
- $0.257 billion for maintenance costs.

BC Hydro's assumptions call for the amounts in the Site C Regulatory Account to assume interest based on its forecast weighted average cost of debt and estimated through the end of 2031. For suspension costs, the full liability is assumed to be recognized at December 31, 2017 and transferred to the Site C Regulatory Account at that time but will not assume interest paid until the expenditure has been made. Similarly, maintenance costs will not incur interest until the expenditure is made.[623]

Other submissions

Allied Hydro Council of BC

The AHC states that it agrees with the suspension costs as shown in the Preliminary Report. The Council adds that the Commission "should not ignore the cost of finding replacement energy supplies which will likely be equal to or a higher cost than Site C and without all the benefits and likely with delivery delays."[624]

Philip Raphals

Raphals conducted an analysis of the termination and project completion options with a reliance on present value analysis but concluded that this was not appropriate to use in comparing termination versus suspension for the eight years option due to a timing mismatch. Because of this, he used present value analysis for the terminate and complete options only and dropped the suspension option from his analysis suggesting that it should be considered as an insurance policy. In effect, it would provide at an incremental cost, an additional variant in relation to the terminate option. Raphals recommends the Commission first reach a conclusion with regard to the comparison between completion and termination of the project before considering the desirability of the suspension option. He explains the reasons for this recommendation as follows:

> Comparing the costs determined by Deloitte for the Terminate and Suspend options, we note that the initial costs are remarkably similar: $370 million for Termination, and $381 million for Suspension. In other words, according to Deloitte, it would cost just $11 million more to suspend the Project than to terminate it. Still according to Deloitte, the cost to maintain the site in a state of suspension is estimated at $510 million for six years — around $85 million per year. This amount includes $445 million for "Site preservation activities." This can thus be thought of as the "insurance" cost, in order to maintain for several years the option of restarting construction. Should that decision be made within, say, two years (e.g., at the conclusion of BC Hydro's 2018 IRP process), the additional costs would be limited to two years of maintenance costs ($85 * 2 = $170 million). Should the Project be recommenced, there would in addition be remobilization costs of $200 million, for a total of $381 million additional.[625]

[623] Submission F1-5, BC Hydro, IR 2.83.0.
[624] TTP-1, October 13, 2017, Vancouver, p. 1305.
[625] Submission F106-5, PoWG, p. 25.

British Columbia Sustainable Energy Association

BCSEA submits the Commission should reject BC Hydro's working assumption that after a suspension period, it would be possible to restart the project. It believes that after a period of suspension of up to seven years, a decision to recommence the project would be subject to full regulatory approval at both the provincial and federal levels which in the case of the federal review would be more rigorous and broader in scope than at the time of the Site C Joint Panel Review. BCSEA believes BC Hydro's response to the Panel question regarding circumstances that would restrict its ability to complete the project severely understates the likelihood the project would require new regulatory review and approvals following a period of suspension. In conclusion, BCOAPO submits that it foresees the probability of a recommenced Site C receiving regulatory approval as low.[626]

Commercial Energy Consumers Association

CEC submits BC Hydro's assertion that many of the assets would be lost in the event of suspension could become increasingly costly. Concerning suspension and maintenance cost estimates, CEC submits that such estimates are prone to underestimation risk and need to be augmented by adjustments. CEC recommends a range of $1.1 billion (the current estimate) to $1.35 billion. CEC recommends the Panel advise government that it could drop this option from further consideration.[627]

BC Hydro submission

BC Hydro points out that its and Deloitte's evidence is that suspension, maintenance and recommencement costs alone are in excess of $1.4 billion. This amount does not take into account the additional costs for inflation and risk adjustments for completing the project which BC Hydro estimates at close to $1.1 billion and Deloitte has not considered in its estimate.[628]

Deloitte's and BC Hydro's estimates are generally consistent with the exception that Deloitte does not take into account the impacts of inflation or risk adjustments. BC Hydro has acknowledged that it incorrectly attributed Deloitte's entire contingency to reactivation costs thereby sharply reducing the amount it attributed for reactivation costs. As a result, reactivation costs for Deloitte now stand at $260 million while BC Hydro's reactivation cost estimate totals $575 million. BC Hydro is unable to provide an explanation for this variance.[629]

BC Hydro states that in addition to the direct costs and the associated inflation and risk-related costs there are three additional costs that Deloitte has not included in its analysis:

- Financing costs between the date of expenditure and date of recovery from ratepayers;
- Impacts on BC Hydro's import and/or export position for the period of suspension; and
- Additional costs due to the higher cost of alternative energy and capacity costs to replace Site C.

These costs are significant and need to be accounted for.[630]

BC Hydro points out that significant cost risks exist with the estimates for suspension and maintenance costs as they are based on a Class 5 estimate that is asymmetrical. This means that there is considerable risk that costs will be higher than estimated and "the risk that refined estimates will be higher is greater than the potential for a revised estimate to be lower." BC Hydro notes that at the upper end of the estimate (+100

[626] Submission F29-9, pp. 34–35.
[627] Submission F82-2, p. 58.
[628] Submission F1-12, p. 24.
[629] Submission F1-15, BC Hydro, IRs 3.12.1, 3.12.3.
[630] Submission F1-12, p. 26.

percent), costs would double Deloitte's estimate and exceed $2.8 billion. BC Hydro also reemphasized that once the project was suspended, there was considerable risk it could not be restarted.[631]

Restarting the project would result in significant cost increases to the completed project and have significant deliverability risk. BC Hydro states that with the addition of costs related to the impact of adding a year to the completion of the river diversion, the total cost to complete the project increases to $13.6 billion in the event the suspension option is decided upon.[632] This amount is based on a P50 estimate for suspension, maintenance and restarting the project.

7.2.4 Panel analysis and findings

The suspension and restart scenario at BC Hydro's estimated $3.6 billion is the most expensive of the three scenarios being considered. In addition, it appears to be the most risky.

BC Hydro states that a suspension of seven years would not only result in additional costs for suspending and maintaining the site for future redevelopment but the costs of restarting the project would be substantial yet very difficult to estimate. Suspension and maintenance costs are based on a Class 5 estimate which has a broad accuracy range and is skewed to the high side. Because of this it can be expected that if a variance occurs it will likely be to underestimate rather than over-estimate costs. The costs related to starting a project after a seven-year suspension are uncertain. Deloitte recognizing the challenge deferred on providing a complete estimate and restricted its estimate to initial start-up costs. In the Preliminary Report the Panel noted that in Deloitte's view a suspension of the project "would change the scope of work as well as the schedule and budget triggering the closeout of the current Site C project and definition of a new project." Thus, the Site C Project would be separated into two separate projects, the work done to date and the suspension costs in one and a new project with its own plan, schedule and budget.

BC Hydro has attempted to lay out a cost estimate for the restart part of the project and has endeavoured to provide as much detail as it can. However, because the restart is seven years away, there is little that can be projected with any certainty. In its estimate of $1.7 billion to restart the project, BC Hydro has estimated the impact of inflation and risks. BC Hydro has outlined a number of risks which cause the special risk provision estimate of $500 million to be exceeded. These risks include: (i) changes in inflation, where given the seven-year delay a change of only one percent over the two percent projected increase could result in an additional cost impact; (ii) the potential change of the project engineer which could result in delays to the timeline; and (iii) changes in regulatory requirements, potentially resulting in further time delays, costs or failure to obtain approvals.

Given the magnitude of the costs involved, the uncertainty of the cost estimates and the risks of suspending the project for seven years, the Panel finds that the most expensive of the three construction scenarios is to suspend and restart the project in 2024.

In the event the suspension scenario is to be given further consideration, the Panel agrees with Raphals that such consideration should only occur after a conclusion is reached with respect to either going forward with the project or terminating it. The activities related to terminating the project or suspending it while not identical are similar to the extent that reinstatement could be maintained as a variant of the termination scenario.

If the decision is made to proceed with a suspension of the project for a seven-year period the Panel finds that BC Hydro's estimate of $13.6 billion is not an unreasonable basis for an estimate of the construction-related costs given the level of detail provided for this analysis. However, since $13.6 billion is based on an assumed cost to complete of $8.945 billion, and the Panel has found that the cost to complete Site C is $10

[631] Submission F1-12, p. 27.
[632] Submission F1-12, p. 28; Submission F1-16, IR 3.8.0.

billion, the cost to suspend Site C must be adjusted. **The Panel finds the cost to suspend, restart and complete Site C is $14.812 billion.** However, before making a final decision to suspend the project, the Panel recommends that BC Hydro be required to produce a Class 3 estimate which will provide much greater confidence in the estimates provided.

7.3 Cost to ratepayers of suspending Site C

As described in section 6.3.5, the cost to ratepayers - the NPV of incremental revenue requirements – for the suspend case under the low load forecast scenario is $5.359 billion. For the medium and high load forecast scenarios, additional energy would be required from an alternative energy portfolio. This would increase the costs beyond $5.359 billion.

The $5.359 billion does not consider the effects of inflation incurred by delaying the completion of the project for seven years. Further, this number is based on the cost, as of January 1, 2018, to complete the project by 2024. Both BC Hydro and Deloitte have indicated the cost to complete beginning in 2024 will likely be higher.

Since the suspension case has a substantially higher cost for ratepayers and since the Panel has found the low load forecast is the most probable scenario, we have not calculated the cost to ratepayers of acquiring energy from the alternative portfolio under the medium or high load forecast scenarios.

7.4 Other implications of suspending Site C

As noted, suspension of the Site C project and restarting it seven years later will result in a significant increase in the costs related to its completion. However, not unlike the continue and termination cases, there are costs which are not easily quantifiable in the event Site C is suspended. Included among these are issues raised in the other cases like the impact on BC Hydro and Government credit ratings as well as First Nation issues. With respect to credit ratings, it is reasonable to expect that any risk to either BC Hydro or the Provincial Government's credit rating would not diminish but would be increased due to the increased costs of suspending the project and then restarting it again seven years later.

As outlined in the termination scenario, there is a potential for litigation if the project is suspended. However, the suspending the project for seven years would provide additional time for First Nations consultation to occur.

The suspension of Site C would also have similar impacts on jobs in the Peace River Valley region as under the termination case. Many people involved in the Site C project would lose their jobs after the suspension project has been completed, with a much smaller number of jobs remaining to maintain the project over the seven year suspension period.

Perhaps the biggest non-financial impact of suspending the Site C project is the uncertainty it would cause. This was brought up numerous times in the Community Input Sessions that were held in the Peace River Valley area. In particular, the mayor of Fort St. John summarized her concerns as follows: "Whatever your decision is, this uncertainty is not healthy. People, businesses and community cannot make plans around uncertainty, so we look forward to its end."[633] Clearly, in the minds of most residents of the Peace River Valley, suspending the project would be the worst of outcomes. The message being conveyed is to move forward and the community will find a way to deal with it regardless of the outcome.

[633] TCI-8, October 2, 2017, Fort St. John, p. 676.

8.0 Conclusion

On August 2, 2017, the Provincial Government issued an Order in Council (OIC) No. 244 requesting the BC Utilities Commission undertake an inquiry into certain aspects of BC Hydro's Site C project. The OIC asked the BCUC to report on the implications of the scenarios — continuing, terminating, or suspending construction with the option to resume by 2024.

In addition, we were specifically asked what the costs are to ratepayers of the suspend and terminate scenarios.

We were also asked, given the energy objectives set out in the Clean Energy Act, what, if any, commercially feasible generating projects and demand side management initiatives could provide similar benefits to ratepayers with an equal or lower unit energy cost as the Site C project.

In order to provide a fulsome response to the questions laid out above, we have also considered the costs to ratepayers of completing Site C.

The suspension scenario

The suspension scenario results in the highest cost to ratepayers as well as various other implications. The cost of putting the Site C project in a state of suspension, awaiting future remobilization in about five years, would be just as costly as terminating the project. In addition, there are the remobilization costs and the costs to complete the project beginning in 2024. There is no certainty that the remaining project budget would be adequate to complete the construction following remobilization in 2024. Contracts would have to be retendered and First Nations' benefit agreements may have to be renegotiated. Environmental permitting would have to begin anew upon resumption of construction.

The completion scenario

The project is not within the proposed budget of $8.335 billion. Further, the total cost at completion may be in excess of $10.0 billion as there are significant risk remaining which could lead to further budget overruns. There is a high degree of uncertainty at this time. As such the Panel is persuaded by the analysis performed by Deloitte, which indicated that in a "high impact" scenario the budget may be exceeded by between 20 and 50 percent. In addition there are significant risks that could prevent the project from remaining on schedule and the Panel is not persuaded that it will remain on schedule for a November 2024 in-service date.

The termination scenario

In the event the Site C project is terminated, the construction site must be remediated. We estimate this cost to be $1.8 billion. In addition to this remediation cost, depending upon the load, a portfolio of commercially feasible generating projects and demand side management initiatives may be required. Therefore, to answer this question requires assumptions about the load forecast. We were directed to use the forecast of peak capacity and demand submitted by BC Hydro in July 2016 as part of its Revenue Requirements Application. We reviewed submissions related to BC Hydro's mid forecast, the low and high bounds representing the range of uncertainty and key assumptions underlying that forecast. The mid load forecast is overly optimistic, and we consider it more appropriate to use the low-load forecast for resource planning purposes. We note there are also risks that could result in demand being less than the low case.

Comparison of costs to ratepayers for the completion and the termination scenarios

Evaluation of the cost to ratepayers is not straightforward in either the completion or termination scenarios. To be competitive, an alternative portfolio must provide sufficient savings to account for the $1.8 billion in expected termination costs. Many alternative types of energy such as wind are not dispatchable so they do not provide the same benefit to ratepayers as Site C energy. The Panel discusses this issue in the Report and concludes that because BC Hydro has substantial existing dispatchable energy, energy from the alternative portfolio (which has a relatively small amount of wind) would effectively have the same value as that from Site C.

During this Inquiry, Commission staff developed a draft Illustrative Alternative Portfolio using BC Hydro's output from its PV Portfolio Analyzer, additional assumptions and input from BC Hydro and other parties. The resultant Illustrative Alternative Portfolio included in our report indicates that it is possible to design an alternative portfolio of commercially feasible generating projects and demand-side management initiatives that could provide similar benefits to ratepayers as Site C, with a similar unit energy cost.

As can be seen in the table below, the cost to ratepayers of Site C and the Illustrative Alternative Portfolio are virtually equivalent, within the uncertainty inherent in the assumptions.

Table 47: Cost to Ratepayers of Site C and the Illustrative Alternative Portfolio

	Rate Impact ($million)			**Unit energy cost ($/MWh)**	
Scenarios	**A. Illustrative Alternative Portfolio**[634]	**B. Site C**[635]	**Difference (A - B)**	**Illustrative Alternative Portfolio**	**Site C**
Commission Assumptions[636]	$3,234	$3,188	$46	$32	$44

The table above incorporates the following assumptions (Commission Assumptions):

- Low load scenario
- The Panel Mid-C market electricity price forecast
- Site C total costs of $10 billion
- Termination costs of $1.8 billion amortized over 30 years
- BC Hydro financing for all resources in the Illustrative Alternative Portfolio

The Panel undertook sensitivity analysis to identify the key variables that could have a material effect on the results. The results are discussed later in this Conclusion.

Other implications

Regardless of the comparative costs, there are also other issues to consider when comparing the completion and termination cases. Both scenarios involve risk that is not easy to quantify. The major risk of Site C in the short term is whether there will be further construction cost overruns. Site C is a major construction project and therefore inherently at risk of larger cost overruns than a smaller project. It has already exceeded its budget, only two years into a nine-year schedule. There are tension cracks and disputes with its contractors both of which remain unresolved. Although the project is currently expected to be completed by the publicly announced date of 2024, it is one year behind the schedule to which it was actually being managed. At this time, ratepayers are at risk for the known over budget amount, as well as further overages.

[634] Illustrative Alternative Portfolio cost plus Site C termination costs minus exports revenues.
[635] Site C cost to complete less flexibility credit and export revenues.
[636] Low Load Forecast, Panel Mid C market electricity price forecast, Site C total costs of $10 billion, $1.8 billion in termination costs amortized over 30 years, and BC Hydro financing for all resources in the Illustrative Alternative Portfolio.

In the longer term, a disruptive technology such as affordable utility – or home – scale storage technology could reduce the anticipated benefits of Site C, by allowing the production of non-dispatchable energy from renewables at declining prices. Combined with a continued glut in North American energy markets, this could make it increasingly difficult to sell Site C surplus energy. In addition, disruptive storage technology could incent customers to generate their own electricity. This is more likely to be the case if BC Hydro's rates continue to increase as a result of the requirement for BC Hydro to clear regulatory accounts periodically, the considerable future capital expenditures that will be required to maintain heritage assets, and the costs to complete Site C (including interest costs and the risk of any further cost overruns) and other upward pressure on rates.

While battery storage technology has been raised as part of a possible alternative to Site C, we note that a similar discussion is being held in many other jurisdictions in North America. In Appendix A of the Final Report, the Panel found that utility scale battery storage has reached the early stage of commercial feasibility. We are aware of a pilot test installation and at least one application for other installations. Further, as noted in Appendix A, numerous firms are planning battery production facilities. There is no guarantee that battery storage will reach full commercial feasibility or, if it does, at what price. However, if it were to happen, demand for Site C's flexible energy could be reduced and BC Hydro and Powerex may not be able to realize any "flexibility premium."

In addition, BC Hydro's financing cost assumption that the cost of debt will not change over 70 years may not be supportable. This period far exceeds the current life span of Provincial Government issued debt instruments.

Some of these risks can be mitigated. For example, prudent oversight of the Site C construction project can keep budget overruns to a minimum. However, some risks, such as the adoption of disruptive technologies and interest rate fluctuations are inherent in such a long-term project.

The assumptions used in the Illustrative Alternative Portfolio are not without risk. Estimates of the amount of load curtailment available could be overly optimistic. The cost of wind may be higher than estimated. There may actually be no geothermal potential. In any of these cases, Site C would have a lower cost to ratepayers, provided it avoided the risks it faces, which are outlined above.

Some risks in the assumptions used in the Illustrative Alternative Portfolio can be mitigated. For example, BC Hydro could implement time based rates for residential customers and hot water shut offs during peak times could be encouraged. Time of use rates can be introduced on an optional basis, by providing a credit on the residential customer's bill if they voluntarily curtail usage during peak periods.

Other ways to mitigate risk and meet future energy needs include changes to government policy. While the Panel takes no position on these mitigation strategies, the evidence received in this process suggest that the following options are available to government:

- Repatriate some or all of the Columbia River Treaty entitlement. This energy is generated from water stored behind BC Hydro dams in British Columbia and is as firm and flexible as the energy from Site C.
- Remobilize Burrard Thermal and reduce the use of Island Cogen for export to provide capacity for the limited number of 16-hour winter peaks.
- Increase reliance on the market to provide capacity for the limited number of 16-hour winter peaks.

In addition to the risks outlined above, other factors to be considered include:

1. Potential cost to ratepayers related to infringement of First Nation treaty and aboriginal rights if Site C is completed.

2. The impact of the loss of valuable agricultural land due to flooding.
3. Possible down-stream impact on the Peace-Athabasca Delta in the event Site C is completed.
4. The potential for a change in either BC Hydro or the Provincial Government debt or bond rating.
5. The impact of termination to First Nations that have entered into agreements with BC Hydro and the Province.
6. The impact of continuing with Site C on those First Nations that have not entered into agreements with BC Hydro and the Province.
7. The impact of termination on McLeod Lake Indian Band will have unaccommodated impacts to its rights.
8. The effect the termination of Site C may have on employment and other economic impacts in the Peace River Region.

Actual load may be higher than the low load forecast. Further, government policy regarding electrification could impact the load forecast to the higher side. The sensitivity analysis shows that although Site C's cost to ratepayers rises with the load, it rises less quickly than does the Illustrative Alternative Portfolio's costs to ratepayers.

Summary

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.

DATED at the City of Vancouver, in the Province of British Columbia, this *first* day of November 2017.

David M. Morton
Panel Chair / Commissioner

K. Keilty

Karen A. Keilty
Commissioner

Dennis A. Cote
Commissioner

Richard I. Mason
Commissioner

1.0 Appendix A – Alternative energy and capacity sources

1.1 Upgrade of existing BC Hydro assets

1.1.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submits that there is some opportunity to modestly increase the energy and/or capacity within BC Hydro's existing fleet of 30 hydroelectric Heritage assets. These opportunities are commonly referred to as Resource Smart opportunities.[637]

BC Hydro also states that energy and/or capacity increases can be realized as stand-alone investments planned specifically to satisfy an energy and/or capacity need identified through the long-range planning process, or the opportunities can be realized at the time of reliability refurbishment or replacement investments associated with the major generating components. The capability of all of the major generating components (generator, turbine, unit transformer, circuit breaker, exciter, governor, water passage) and auxiliary equipment have to be able to facilitate the increased energy and capacity requirements so in some cases it can take a long time to fully realize the uprated potential of the Heritage assets if combined with reliability improvements. Environmental, First Nation consultation and water licencing considerations are also required.[638]

Deloitte, Swain and Cayoose Creek First Nation commented on the opportunity to utilize BC Hydro's existing fleet.

Comments received regarding opportunities for upgrading BC Hydro's existing assets are summarized in the following table:

Table 48: Comments Regarding Opportunities for Upgrading BC Hydro's Existing Assets

Project name	BC Hydro	Deloitte	Comments
Revelstoke Unit 6	488 MW, 26 GWh/year, UCC = $46/kW-yr, $F2018. Revelstoke 6 is selected in all resource portfolios in BC Hydro's analysis regardless of the decision on Site C.[639]	500 MW, $591million – $398 million. All committed BC Hydro expansion is included in the Deloitte model as firm supply, that is, it is included regardless of economic performance.[640]	Similar project, but different capacities and potentially different costs. Swain provides comment.[641]
John Hart replacement, Ruskin upgrade, Clowhom	Not identified.	All committed BC Hydro expansion is included in the Deloitte model as	Sekw'el'was Cayoose Creek Band (CCB) provide comment on the Bridge

[637] Submission F1-1, Appendix L, p. 43.
[638] Submission F1-1, Appendix L, p. 43.
[639] Submission F1-1, Appendix L, p. 44.
[640] Submission A-9, pp. 40, 96.
[641] Submission F36-1, p. 19.

rehabilitation, Cheakamus units 1 and 2 replacement, Bridge River 2 upgrade units 5, 6, 7, 8, and Bridge River 1 upgrade unit 4 generator and governor		firm supply, that is, it is included regardless of economic performance. [642]	River system.[643] Swain provides comment on John Hart and Ruskin. [644]
GMS units 1-5 capacity increase	100 MW, $66/kW-yr, $F2018. Not considered in the analysis. BC Hydro explains that subsequent study showed that the dependable capacity available from this project is lower than originally estimated (reduced from 220 MW to 100 MW). BC Hydro decided to not to pursue the project because it submits it would increase reliability risk during implementation phase (over a four-year period) as each of the five major units (~275 MW) at GMS would need to be taken out of service in order to get the total 100 MW gain at the end of the project. [645]	220 MW, $71 million. Additional potential is included in the model as a supply option.[646]	Similar project, but different capacities and potentially different costs and energy.
GMS - install 2 new generating units	Not identified.	No additional costs or capacity identified. Deloitte provided the following comments: "The purpose of the project is to install 2 new generating units. A resource opportunity had	The additional potential from this project does not appear to be included as a supply option in either party's models.

[642] Submission A-9, p. 40.
[643] Submission F73-1.
[644] Submission F36-1, p. 19.
[645] Submission F1-1, Appendix L, pp. 44–45.
[646] Submission A-9, pp. 43, 45.

		been identified in the 1970's to potentially add two new generating units in the low level outlets. This was predicated on a future diversion of water into the Williston Reservoir (The McGregor Diversion). There is no opportunity in the foreseeable future for this additional resource, and if one arises in the future, any new units would require a separate, new water passage."[647]	
Falls River redevelopment	24 MW, 170GWh/yr, \$550/kW-yr.[648]	Incremental 9 MW (25 MW – 7 MW) for \$165 million, or incremental 18 MW (25 MW – 7 MW) for \$260 million.[649]	Similar project, but different capacities and potentially different costs and energy.
Alouette redevelopment	21MW, 61GWh/yr, \$51/MWh, \$121 million.[650]	9.7MW and \$100 million, or 21MW and \$160 million.[651]	Similar project, but different costs and potentially different energy.
Elko redevelopment	20.8 MW, 118.5 GWh/yr to 124.9 GWh/yr, \$180.1 million, \$105/MWh (\$95/MWh net of a \$29 million decommissioning credit).[652]	20 MW, \$225 million.[653]	Similar project, but slightly different capacities, different costs and potentially different energy.
Kootenay Canal Grohman Narrows	0 MW, 89 GWh/yr, \$68 million[654]	Not identified.	
Seven Mile turbines upgrade	48 MW, 89GWh/yr, \$137 million.[655]	32 MW, \$100 million.[656]	Similar project, but different capacities, different costs and

647 Submission A-9, pp. 45–46.
648 Submission F1-1, Appendix L, p. 45.
649 Submission A-9, p. 44.
650 Submission F1-1, Appendix L, p. 45.
651 Submission A-9, p. 43.
652 Submission F1-1, Appendix L, pp. 45–46.
653 Submission A-9, p. 44.
654 Submission A-9, p. 46.
655 Submission F1-1, Appendix L, p. 47.
656 Submission A-9, p. 43.

			potentially different energy.
Strathcona additional unit	31 MW, 0 GWh/yr, $98/kW-yr $F2018.[657]	31.3 MW, $37 million.[658]	Similar project, very similar capacities. Unclear if there are cost or energy differences.
Duncan Dam new generation	30 MW, 103 GWh/yr, $98/MWh ($F2018), $336/kW-yr ($F2018).[659]	22 MW, $250 million, $114/MWh.[660]	Similar project, but with different capacities and potentially different costs and energy. Swain provides comment.[661]
Lajoie additional unit	30 MW, 80GWh/yr, $108/MWh ($F2018), $288/kW-yr ($F2018).[662]	30 MW, $340 million.[663]	Potentially same project, same costs and same energy, but could not be confirmed. CCB comments on Lajoie.[664]
Ladore additional unit	9 MW, 8 GWh/yr, $272/MWh ($F2018), $242/kW-yr.[665]	9 MW, $11 million.[666]	Potentially same project, same costs and same energy, but could not be confirmed.
Ash River additional unit	9 MW, 30 GWh/yr, $84/MWh ($F2018), $279/kW-yr.[667]	9 MW, 36 GWh/yr, $101 million.[668]	Similar project, but with different energy and potentially different costs.
Ash River refurbishment of the powerhouse	Not identified.	8 MW, $57 million.[669]	
Puntledge additional unit	10 MW, 18 GWh/yr, $69/MWh ($F2018), $126/kW-yr.[670]	10 MW, $115 million.[671]	Potentially same project, same costs and same energy, but could not be confirmed.

[657] Submission F1-1, Appendix L, p. 48.
[658] Submission A-9, p. 46.
[659] Submission F1-1, Appendix L, p. 48.
[660] Submission A-9, p. 43.
[661] Submission F36-1, p. 19.
[662] Submission F1-1n, Appendix L, p. 48.
[663] Submission A-9, p. 47.
[664] Submission F73-1.
[665] Submission F1-1, Appendix L, p. 48.
[666] Submission A-9, p. 47.
[667] Submission F1-1, Appendix L, p. 48.
[668] A-9 Submission, p. 45.
[669] A-9 Submission, pp. 44-45.
[670] F1-1 Submission, Appendix L, p. 48.
[671] A-9 Submission, p. 47.

Seton unit upgrade	Not identified.	2 MW, $20 million.[672]	CCB comments on Seton.[673]
Shuswap refurbishment of generating unit	Not identified.	3 MW, $6 million.[674]	
Wahleach turbine replacement	Not identified.	14 MW, $5.8 million.[675]	
Whatshan transformer replacement	Not identified.	4.7 MW, $3.6 million.[676]	

1.1.2 Panel analysis, preliminary findings and questions in the Preliminary Report

BC Hydro was requested to provide further comment on the table above. In particular, the Panel wanted to know its assessment of the cost of any potential refurbishments and upgrades that were not otherwise planned for the next twenty years, the UEC and UCC, and the resultant amount of capacity and energy should these refurbishments be completed.

1.1.3 Relevant new information or submissions

In response to the question above, BC Hydro explained that the John Hart, Ruskin, Cheakamus, Bridge River and Clowhom projects are existing and committed resources and expected to be built with or without Site C. In addition, the Whatshan transformer has already been replaced and Revelstoke Unit 6 is selected in all resource portfolios regardless of the decision on Site C. In other words, BC Hydro submitted these projects cannot be considered as Site C alternatives.

BC Hydro submitted that apart from the GMS capacity increase project, the remaining opportunities to increase energy and capacity from BC Hydro's existing assets are relatively small, individually. BC Hydro explained that it tested the cost effectiveness of these resources by modeling the GMS capacity increase project as one option and the sum of all other potential facility upgrades as another. Only the GMS capacity increase project was selected as a cost-effective resource in the portfolios modelled.

BC Hydro explained that the GMS capacity increase project requires units to be taken out of service to undertake the upgrades which results in a net decrease in capacity of 275 MW for a period of approximately four years. Other capacity resources would be required to offset this decrease.

BC Hydro summarized the latest cost estimates of these opportunities and submitted the most economic time to evaluate and pursue these opportunities is when major refurbishment/replacement work is required, the timing of which is driven by the degrading condition of aging assets. BC Hydro also noted that a number of these opportunities are under consideration in Facility Asset Plans (i.e. Alouette redevelopment, Seven Mile turbines upgrade, Ash unit refurbishment, Seton unit upgrade and Wahleach turbine replacement) and could be in-service in the 20-year planning window.

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672 A-9 Submission, p. 46.
673 F73-1 Submission.
674 A-9 Submission, p. 46.
675 A-9 Submission, p. 47.
676 A-9 Submission, p. 47.

BC Hydro submitted that some of the analysis is based on high level scoping studies that are more than a decade old. Consequently, many of these opportunities have a high degree of uncertainty associated with the costs and feasibility. BC Hydro explained that the lead time for realizing these energy and capacity gains could be significant depending on certain factors. In addition, the implementation phase of some projects might increase the reliability risk if they require taking existing units out of service, such as the GMS Units 1 to 5 capacity increase project.

Table 49: Cost and Technical Summary of Remaining Opportunities[677]

Project Name	Energy (GWh)	UEC @ POI[2] ($/MWh, $F2018)	Capacity[3] (MW)	UCC at POI ($/kW-year, $F2018)
GMS – install 2 new generating units	BC Hydro agrees with Deloitte's assessment not to include this as a supply option. We also note that McGregor River Diversion is one of the prohibited projects per Schedule 2 of the Clean Energy Act; and installing new generating units in the low level outlets could pose dam safety concerns.			
Strathcona additional unit	It is no longer feasible to add a unit to the existing Strathcona powerhouse, because generation at the current powerhouse will not be possible once seismic risks associated with the Dam have been addressed.			
Seven Mile turbines upgrade	89	65	48	120
Wahleach turbine	Uncertain		14	21
Ash River refurbishment of the unit [5]	Uncertain		8	284
Seton unit upgrade	Uncertain		2	420
Alouette redevelopment	61	35 (incremental to decommissioning)	21 (replaces existing plant that is out of	103
GMS Units 1 – 5 capacity	Uncertain		100	39
Falls River redevelopment	170	54	24 (replaces existing plant)	381
Elko redevelopment	125	66 (incremental to decommissioning)	21 (replaces existing plant that is out of	395
Kootenay Canal Grohman	89	38	Uncertain	
Duncan Dam new generation	103	68	30	234
Lajoie additional unit	80	79	30	211

677 Submission F1-5, IR 2.59.

Ladore additional unit	8	170	9	151
Ash River additional unit	30	56	9	188
Puntledge additional unit	18	49	10	89
Shuswap refurbishment of	Uncertain		3	85
Total	773	n/a	**334**	**n/a**

Other submitters (for example, Swain, Ruskin, and Sekw'el'was Cayoose and N'Quatqua First Nations) in part advocate for upgrades, improvements or restoration of existing facility assets as an alternative.[678]

1.1.4 Panel analysis and findings

The Panel finds that the Kootenay Canal Grohman Narrows project, the Alouette redevelopment project (incremental to decommissioning) and the GMS Units 1-5 capacity increase projects are alternatives to Site C with the potential to provide competitively priced energy and capacity. As such, the Panel finds it appropriate to include these projects in an evaluation of an alternate portfolio. However, whether or not these projects would be actually pursued requires further investigation and evaluation.

1.2 Alternative energy sources

This appendix examines the energy generation and demand-side management components that were considered for inclusion in the alternative generation portfolio.

1.2.1 PPA from existing IPPs

1.2.1.1 Key submissions and issues raised in the Preliminary Report

BC Hydro reports that biomass and run-of-river renewals are maintained at 50 percent and 75 percent, respectively.[679]

Allied Hydro summarizes BC Hydro's current IPP contracts as follows:

> In 2016 BC Hydro reported that it had electricity purchase agreements (EPAs) with 119 independent power producers (IPPs,) many of which are non-storage, run-of-river hydropower generators.
>
> The makeup and some features of these EPAs is as follows:
>
> - Wind - 7 EPAs, 702 MW, 2,060 GWH, 33 percent availability;
> - Gas-powered - 2 EPAs, 380 MW, 3,140 GWH, 94 percent availability, new projects contrary to BC Environmental policy;

678 F36-1, p. 19; F26-7 and F26-8 Submissions; F73-1 Submission; F315-1 Submission, p. 2.
679 F-1 Submission, Appendix K p. 2.

- Hydropower - 80 EPAs, 3,270 MW, 12,000 GWH, 42 percent availability, some dispatchable;
- Bio-energy - 24 EPAs, 850 MW, 3,450 GWH, 46 percent availability, dispatchable.

In 2016 it was also reported by BC Hydro that the lowest EPA contract price was $76.20/MWh, the average price was $100.00/MWh, and the highest price was $133.80/MWh for firm power during the peak winter season. IPPs in 2016 supplied 20,454 GWh of electricity to BC Hydro about one-third of its total supply. BC Hydro will pay $58 billion to IPPs over the life of the EPAs.[680]

1.2.1.2 Panel preliminary findings, analysis and questions in Preliminary Report

The energy prices, as described above, appear to be on the lower side of other alternatives. Further, these resources are already developed and the infrastructure exists to deliver that energy to BC Hydro customers – fewer adders should be required. **Given this, the Panel requested that BC Hydro explain why it is not renewing more IPP contracts.**

1.2.1.3 New submissions and responses

BC Hydro submission

In response to the Panel's question raised in the Preliminary Report, BC Hydro responded that it "renews IPP contracts where it is cost-effective to do so" and explained that the planning assumptions maintained from the 2013 IRP "are not targets but provide a starting point for creating estimates within a financial framework." BC Hydro further explained that this approach allows it to achieve the objective of being able to renew as much volume as possible, on a cost-effective basis, within an overall budget and noted that it expects IPP renewals as a whole will likely have a lower cost relative to other potential clean or renewable greenfield supply options, other than Site C.[681]

With regard to biomass and run-of-river resources, BC Hydro stated that its renewal assumptions are estimates of the likelihood of renewing contracts at "mutually agreeable pricing that is cost-effective for BC Hydro," considering that a number of the projects' generating facilities could be 20 years or older at the expiration of their original EPA. Further, the estimated renewals for biomass was informed by BC Hydro's understanding of the reduced long-term certainty of available fibre supply.[682]

Other submissions

CEC submits that having a segment of IPPs not getting contracts enables BC Hydro to better protect ratepayer interests than signalling that it will acquire all of the energy. Because the prices are negotiated, having degrees of uncertainty are valuable.[683]

1.2.1.4 Panel analysis and findings

The Panel finds that an increase in renewals of biomass and run-of-river projects could reduce the NPV of the strawman alternative portfolio.

[680] Submission F24-1, p. 16.
[681] F1-5, IR 2.60.0.
[682] F1-5, IR 2.60.0.
[683] F82-2, p. 42.

1.2.2 Geothermal

1.2.2.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

Geothermal energy systems draw on natural heat from within the Earth's crust to drive conventional power generation technologies. BC Hydro stated that geothermal resources have the potential to be a cost-effective source of energy and capacity but the resource potential in BC is unproven and that the costs and risks inherent in the development of these resources have thus far deterred any development in BC.

BC Hydro stated that the need to drill wells to identify and confirm the resource potential has made identifying any commercially available resources problematic. BC Hydro and others have investigated the South Meager Creek site since the 1980s, with more than 30 wells drilled on the site (including several multi-million dollar confirmation wells) and no feasible resource has been identified.[684]

BC Hydro stated that it collaborated with Geoscience BC to retain the independent experts to produce an assessment of the economic viability of selected geothermal resources in British Columbia (2015 Geoscience BC Report). Based on the set of assumptions used by the consultant, it was determined there could be two projects (about 1300 GWh and 200 MW total) under $200/MWh but above $100/MWh. A sensitivity analysis examining the economic impacts of a reduced cost of financing and reduced cost of drilling may drive costs to as low as $81/MWh ($2018).[685]

However, BC Hydro states it cannot rely on geothermal resources for planning purposes because there are no proven viable geothermal resources in BC yet, and there is a high cost of confirmation drilling with significant risk of failure. BC Hydro also states it has received two applications for low-medium temperature geothermal projects (for less than 15 MW) in BC Hydro's Standing Offer Program; however, neither site has proven the viability of the underlying resource through confirmation drilling. In addition, BC Hydro has not had any bids from geothermal developers into its other competitive acquisition processes.[686]

Deloitte report

Deloitte considered that there is potential for geothermal energy to be commercially feasible in BC in the next 15 years. Deloitte state that geothermal power is dispatchable and provides baseload power to the grid, and that it can also provide firming and shaping capability.

The Deloitte report stated that it conducted document research and analyzed several studies to determine the potential of geothermal in BC, and that the studies analyzed for this report ranged widely in their assessment of potential geothermal resources in the province, from just 250 MW in specific areas analyzed to more than 6.5 GW of potential capacities across the entire province. However, each of these studies did identify several similar areas in BC as having potential capacity, including the Lower Mainland and North Coast.

Deloitte noted that while geothermal energy is a proven technology across much of the world, no geothermal energy generation currently exists in British Columbia. Deloitte stated that test drilling is required to validate the geothermal resource which can be capital intensive.

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[684] F1-1, pp. 58–69.
[685] F-1 Submission, Appendix L, p. 33
[686] F-1 Submission, Appendix L, p. 35.

For modelling purposes, Deloitte assumed approximately 250 MW of potential capacity was available at the reference capital cost of $7,300/kW and that additional capacity would likely be available, though perhaps at a higher cost (another 750 MW at $8,800/kW).[687]

Other submissions

The Canadian Geothermal Energy Association (CanGEA) disagrees with BC Hydro's assessment of the geothermal resources. CanGEA submits that the model used in the 2015 Geoscience BC Report was inappropriate for estimating costs and that only 2 of the 18 sites chosen to study were Hot Sedimentary Aquifers (which CanGEA submits are the lowest cost and lowest risk form of geothermal electricity generation in BC). CanGEA submits new data, with the assistance from an Oregon-based geothermal development and two additional global geothermal experts, which shows a lower cost of developing geothermal projects.[688]

In its report, CanGEA describes two potential geothermal electricity projects – Canoe Reach near Valemount and Lakelse Lake near Terrace, and provides the following cost comparisons to Site C:[689]

Table 50: Cost Comparison to Site C

Project	Capacity	Capital Cost	Cost .per MW	Energy Cost	Capacity Factor
Canoe Reach	58MW	$300 M	$5.1 M/MW	$20.70/MWhr	95%
Lakelse Lake	23 MW	$120 M	$5.2 M/MW		95%
Site C	1,100 MW	$8.8 B	$8.0 M/MW	$57.4/MWhr	53%

In addition, CanGEA states that BC Hydro has overstated exploration and drilling costs, potentially by a factor of 2 - 4. CanGEA states that recent advances in drilling time have significantly reduced the overall drilling costs and due to current oilfield market conditions, there is currently an opportunity to use some of the best drilling companies and expertise in Canada for the emerging BC geothermal industry. [690]

West Moberly and Prophet River First Nations and Harry Swain state that the Site C Joint Review Panel chastised BC Hydro for not conducting any research into the geothermal potential. Swain states that the Commission advised BC Hydro to seriously examine the possibility of geothermal when it turned down Site C in 1983, but BC Hydro did not do so.

Swain further submits that the attractiveness of Coast Range hot rocks may have declined against the possibility of cooler groundwater (up to 140°C) in the Peace River sedimentary basin, but neither have been fully investigated, the latter in part because BC Hydro seems not to talk to the oil and gas industry. Swain submits that, "after 34 years, all the basic resource characterization and technology development has been left to the private sector. The periodic claim that the technology is unproven is belied by routine operations in Italy, New Zealand, California, Alaska, Iceland, and elsewhere."[691]

[687] A-9 Submission, pp. 23, 101.
[688] F66-1 Submission, p. 5.
[689] F66-1 Submission, p. 9.
[690] F66-1 Submission, pp. 11, 14.
[691] F36-1 Submission, p. 17; F28-2, p. 6.

The Canadian Council of Policy Alternatives states that a 2014 International Renewable Energy Association report noted that geothermal resources can range from $40–100 per MWh.[692] CEC submits that Geothermal energy is considered to be a very low-cost supply option at present and may become a significant IPP supply option for BC Hydro.[693]

1.2.2.2 Panel preliminary findings, analysis and questions in Preliminary Report

The Panel found that geothermal is potentially a viable alternative and did not agree with BC Hydro that geothermal should be excluded from consideration as part of its alternative portfolio. The Panel made the following comments:

- Geothermal is a mature technology as can be seen by looking at the record of countries such as Iceland.
- While it is possible there is no potential in BC, BC Hydro does not provide persuasive evidence this is the case. BC Hydro's experience of drilling for 30 years at Meager Creek, yet being unsuccessful, perhaps demonstrates there is low to no potential at Meager Creek, but BC Hydro provides no evidence that this experience should be extrapolated to the whole province.
- We note Deloitte's assessment that 250 MW of potential capacity are available at the reference capital cost of $7,300/kW, with another 750 MW potentially available at $8,800/kW.
- BC Hydro points out that it has had only two bids on geothermal and they have not proven viable. In contrast, the Canadian Geothermal Association provides evidence of the possibility of two viable projects.

The Panel therefore asked BC Hydro and other parties to respond to the following questions:

- How much has BC Hydro spent in the last 15 years in exploratory drilling for geothermal resources?
    - Please explain whether there has been (or is expected to be) a significant reduction in drilling costs compared to those assumed in the 2015 Geoscience BC Report, and how this could affect both the probability of locating economic reserves by 2025/2035 and/or the cost of those reserves.
    - If BC Hydro were to accelerate the development of the geothermal industry in BC by undertaking additional exploratory drilling, please estimate the size of the budget that would reasonably be required.
- Please provide an update of the $81/MWh ($2018) estimated cost of the two geothermal projects identified by BC Hydro (about 1300 GWh and 200 MW total) delivered to the Lower Mainland, using BC Hydro's cost of financing and current operational costs. Please provide all input assumptions used to calculate the estimated cost, and supporting calculations.
- Do the capital costs as provided by the Canadian Geothermal Association also include exploration costs?
- Please estimate the probability that, by (i) by 2025, and (ii) by 2035, BC Hydro would reasonably be able to locate 200 MW of cost-effective geothermal energy if BC Hydro were to develop the resource in partnership with industry.

[692] 60-1 Submission, p. 13
[693] F82-1 Submission, p. 21.

1.2.2.3 Relevant new submissions

Canadian Geothermal Energy Association submission

In response to the Panel's questions, CanGEA provided additional information on the cost, technology, and availability of the geothermal resource in BC.[694]

CanGEA explained that the industry's exploration and drilling techniques have improved, contributing to reduced drilling costs and improved probability of locating economic reserves. CanGEA submitted that the Geoscience BC Report used outdated and very high drilling numbers, and assumed that large diameter wells would need to be drilled for confirmation; however, modern technology allows slim wells to be drilled to a depth of 2.5 km, which can be done at a very low cost compared to previous drilling technique.[695]

> COMMISSIONER COTE: What is the difference in cost between the two methodologies?
>
> MS. THOMPSON: Millions of dollars. So for example, a 2.5 kilometre well that's a slim well could beanywhere from 2 to 3, 4 million dollars and Geoscience BC was estimating at the high end, $12 million todrill those big wells.[696]

In order to estimate the budget that would reasonably required if BC Hydro were to accelerate the development of the geothermal industry in BC, CanGEA uses the probable sites included in the Geoscience BC Report and provides the full cost breakdown (including exploration costs) using the World Bank Energy Sector Management Assistance Program guidelines.[697] Using the following table, CanGEA submits that the budget required for any combination of projects can be calculated from the pre-survey, exploration and test drilling columns.

Table 51: Full Cost Breakdown (Including Exploration Costs)

Site Name	P90 Site Potential (from Geoscience BC) MWe	High Estimated Site Cost (from ESMAP) USD$MM /MWe	High Estimated Total Site Cost (from ESMAP) USD$MM	Geothermal Development Phases per ESMAP							
				Pre-Survey 0.5% USD$MM	Exploration 1.5% USD$MM	Test Drilling 18% USD$MM	F/S Planning 5% USD$MM	Drilling 45% USD$MM	Construction 20% USD$MM	Start-Up 5% USD$MM	Operation and Maintenance 5% USD$MM
Clarke Lake	20.0	5.50	110.0	0.6	**1.7**	19.8	5.5	49.5	22.0	5.5	5.5
Jedney Area	15.0	5.50	82.5	0.4	**1.2**	14.9	4.1	37.1	16.5	4.1	4.1
Kootenay	20.0	5.50	110.0	0.6	**1.7**	19.8	5.5	49.5	22.0	5.5	5.5
Lower Arrow Lake	20.0	5.50	110.0	0.6	**1.7**	19.8	5.5	49.5	22.0	5.5	5.5
Meager Creek	100.0	5.50	550.0	2.8	**8.3**	99.0	27.5	247.5	110.0	27.5	27.5
Mt. Cayley	40.0	5.50	220.0	1.1	**3.3**	39.6	11.0	99.0	44.0	11.0	11.0
Okanagan	20.0	5.50	110.0	0.6	**1.7**	19.8	5.5	49.5	22.0	5.5	5.5
Lakelse Lake	23.2*	5.50	127.6	0.6	**1.9**	23.0	6.4	57.4	25.5	6.4	6.4
Canoe Reach	58.0*	5.50	319.0	1.6	**4.8**	57.4	16.0	143.6	63.8	16.0	16.0
Lakelse Lake	23.2*	4.15**	96.3	0.5	**1.4**	17.3	4.8	43.3	19.3	4.8	4.8
Canoe Reach	58.0*	4.15**	240.7	1.2	**3.6**	43.3	12.0	108.3	48.1	12.0	12.0

[694] Transcript of the Technical Input Session, October 14, 2017, pp. 1483-1510.
[695] Ibid., p. 1495.
[696] Ibid. p. 1496.
[697] F66-3, p. 16.

CanGEA notes the probability to be very high that BC Hydro would be able to locate 200 MW of cost-effective geothermal energy if BC Hydro were to develop the resource in partnership with industry, in particular the Canoe Reach and Lakelse Lake projects. Independent data reviews from the pre-survey and exploration stages confirmed that these two sites have 58 MW and 23 MW available at the P90 level.

> MS. THOMPSON: So at the P90 level, 58 megawatts have been found at Canoe Reach and at a cost of Canadian $300 million. If you take that on a capital intensity basis, that's 5.1 Canadian million dollars per megawatt, and if you take that through a 30-year life, the capital only contribution to the energy cost would be about $21 a megawatt hour. So to get the true energy cost you need to add the operating cost, and the operating cost should include the financing charges, as well as the profit, but it should also include the ancillary benefits, the geothermal that very high capacity may bring to the grid. And so we look forward to having a credit added to that energy cost, because of course, we'll be stabilizing the grid.
>
> At Terrace, at the P90, if you do the similar math, you're looking at $120 million – again this is total cost, this isn't just exploration cost – for 23 megawatts that's been found and verified by a third party. And that's similar of 5.2 million of megawatts, and the capital cost contribution again is about $21 a megawatt hour. [698]

CanGEA notes that at the P50 level, the Canoe Reach site has 139 MW and Lakelse Lake has 54 MW available, for a total of 193 MW. Therefore, CanGEA believes it would be reasonable to expect that BC Hydro can locate 200 MW of capacity in one year were it to partner with independent developers who have already explored and identified BC's geothermal resources. CanGEA points out that the Geoscience BC Report reported the P90 potential of the probable sites. Even with limited field work, they reported a potential of 270 MW available in BC. Based on the experience at Canoe Reach and Lakelse Lake, where on the ground exploration revealed more capacity is available, CanGEA adjusted the P90 site potential of the other sites and shows in the following table that the portfolio of projects can potentially have 585 MW of capacity. [699]

[698] Transcript of the Technical Input Session, October 14, 2017, p. 1497. CanGEA explains that the P90 level means that there is a 90 percent probability level to find the resource compared to what has been found in other parts of the world with the same results found at these sites.
[699] Ibid, pp. 1499-1500; F66-3, pp. 22-23.

Table 52: Adjusted P90 Site Potential Scenario

Site Name	Original Geoscience BC Estimated P90 Site Potential (MWe)	Dewhurst Group LLC Adjusted P90 Site Potential Scenario (MWe)
Clarke Lake	20.0	**60.0**
Jedney Area	15.0	**41.0**
Kootenay	20.0	**65.3**
Lower Arrow Lake	20.0	**62.0**
Meager Creek	100.0	**87.4**
Mt. Cayley	40.0	**128.4**
Okanagan	20.0	**60.3**
Lakelse Lake	20.0	**23.2**
Canoe Reach	15.0	**58.0**
Total	**270.0**	**585.6**

Furthermore, CanGEA disagrees with BC Hydro's position that "expecting material amounts of geothermal electricity generation in BC by 2026 is unrealistic."[700] First, CanGEA states that the applications from Canoe Reach and Lakelse Lake that went into the Standing Offer Program have online dates of 2020. Second, CanGEA argues that with intentional policy, geothermal capacity can be developed quickly, as demonstrated by Turkey which was able to bring 1,000 MW of geothermal capacity in 10 years despite suffering from adverse geopolitical condition and not being a centre of excellence for drilling like Western Canada.

> MS. THOMPSON: Absolutely it's realistic to expect that by 2025, 2035, or in our case with Lakelse and Canoe Reach, that by 2020 these megawatts are available. Our plan for that is again, addressing your comment of 200 megawatts, is that we believe that from possibly only two or three existing identified locations, it's absolutely reasonable to expect that 40 megawatts per year could come online starting in 2020, and by 2024 you'd have your 200 megawatts online.

With regard to the Geoscience BC Report, CanGEA submits:

> The 2015 Geoscience BC report's primary challenge is that while there were, and remain, active BC geothermal developers and several natural gas developers who have drilled into geothermal resources, all regulated by BC Energy, Mines and Petroleum Resources, they were not provided a meaningful role in the technical advisory committee….. As for peer review before the report was published, evidence based decision making in any other technical field would require subject matter experts to review and be able to offer comment on the results of the report, specifically the levelized cost of electricity (LCOE) and resource availability estimates. In this case, subject matter experts on geothermal development in BC should have included the developers of the BC geothermal sites investigated.[701]

However, BC Hydro responded that

[700] F1-12, p. 43.
[701] T66-1, p. 5.

> [t]his topic was directly addressed at one of the TAC meetings, and the Committee decided that the appropriate role for developers with a clear business interest in developing a resource in BC was as (i) suppliers of publicly available and verifiable data, and (ii) as participants in a stakeholder review after the Report was complete. This decision was made in order to produce an unbiased assessment that would be valuable to government decision-makers. The three developers with permits were to be approached by GeoscienceBC to solicit any relevant data for the Report.

BC Hydro provides the following from the minutes of the Technical Advisory Committee:

> Prior to starting the formal agenda, the issue of outside parties offering to provide input to the study was discussed. It was agreed that the project must not be compromised by the perception that outside groups are manipulating the study, or that non-public information is being disclosed by the project participants, and therefore that all communication around the project should be run through GeoscienceBC. It was noted that this study must be based on unbiased information as the government will make decisions based on it. Geothermal developers may be willing to add data to the study, but will want their resource to look as good as possible. It was clarified that there are only three geothermal developers with leases or permits in the project areas (Ram, Borealis and Tectoenergy). GeoscienceBC will approach these developers to help procure data. It was agreed that final project deliverables will first be reviewed by Geoscience BC's TAC, then by BC Hydro stakeholders and external reviewers.[702]

CanGEA submits that:

> the previous government dragged its feet in permitting geothermal development in British Columbia, significantly setting back the industry development. However, under the new provincial government, encouragingly the regulatory process in BC in 2017 has seen much improvement, moving toward a single-window environmental with the BC Oil and Gas Commission to assist with 'fast tracking' of geothermal land access and drilling permits. On October 13, 2017, the developer of the Canoe Reach site was advised by the Ministry of Energy, Mines and Petroleum Resources that the Order in Council necessary for issuing the permit was not with Cabinet operations, meaning that after much delay, issuing the permit may finally be imminent.[703]

BC Hydro notes that it is "not aware of any policy or permitting barriers to the three geothermal projects referred to by CanGEA, and that these projects received exploration permits in 2010, 2011 and 2014 respectively."[704]

Finally, CanGEA highlights other important key benefits of the geothermal resource:

- Geothermal electricity can support the grid, displacing BC Hydro MW as the baseload generating technology and allowing BC Hydro's own facilities to be used as a complementary battery.[705]
- Geothermal electricity plants routinely achieve over 95 percent in terms of availability. Such capacity factor makes geothermal energy attractive as a baseload resource. Additionally, modern geothermal electricity plants are able to ramp production up and down multiple times per day, making

[702] Submission F1-19, p. 3.
[703] Submission F66-4, p. 8.
[704] Submission F1-19, p. 2.
[705] Ibid, p. 6.

geothermal energy a dispatchable energy source that can be "turned on and off" by a system operator.[706]

- Geothermal energy's baseload and dispatchable qualities strengthen the grid in a complementary way, allowing more intermittent energy sources such as wind, solar and run-of-river hydro to be used.[707]
- In colder climates like Canada, there is the ability to generate more electricity output in the winter months as the change in temperature harnessed by the power cycle increases when the ambient temperature falls and the reservoir temperature remains the same. This "winter sprinting" ability of geothermal electricity can be achieved with no additional capital investment and matches well with the "winter peaking" electrical grid that exists in BC.[708]
- Geothermal can play an important role in decarbonizing the economy, especially for water heating, as geothermal heat is a by-product of geothermal electricity generation. Revenues from the heat can reduce the overall electricity costs.[709]
- The US is the largest producer of geothermal energy in the world, with 3,567 MW of installed capacity, mostly in the Western part of the US and another 1,272 MW in development.[710] The geothermal plants entering service in 2022 have a US weighted average levelized cost of energy of USD 39.5/MWh (2015$), lower than other dispatchable fuels like natural gas or nuclear or non-dispatchable ones like solar PV and wind.[711] Binary hydrothermal geothermal electricity plants have an approximate operating and maintenance cost of USD$19.40/MWh (2015$).[712]
- The BC geology is similar to the US and a mapping exercise with a very limited budget revealed about 5,000 MW are available in BC.

BC Hydro submission

In response to the Panel's questions, BC Hydro confirmed it has not invested in exploratory geothermal drilling in the last 15 years, as it does not have a mandate to conduct exploration for geothermal energy resources.

With respect to the costs of drilling and how this could affect both the probability of locating economic reserves and the cost of those reserves, BC Hydro stated:

> The potential exists at the current time for lower drilling costs as a result of the decline in oil prices over the past year or so. It is however not readily apparent that this trend will carry forward in the long term. Since this assessment has such a long-term perspective, it would not be prudent to base the results on what may be a short-term anomaly in oil prices and resulting drilling costs. […] The relationship between a lower or higher drilling cost and probabilities of locating a viable geothermal resource is difficult to quantify. It stands to reason that at lower drilling costs, one can afford a more conservative development approach whereby there are more exploratory drilling holes to learn more about the

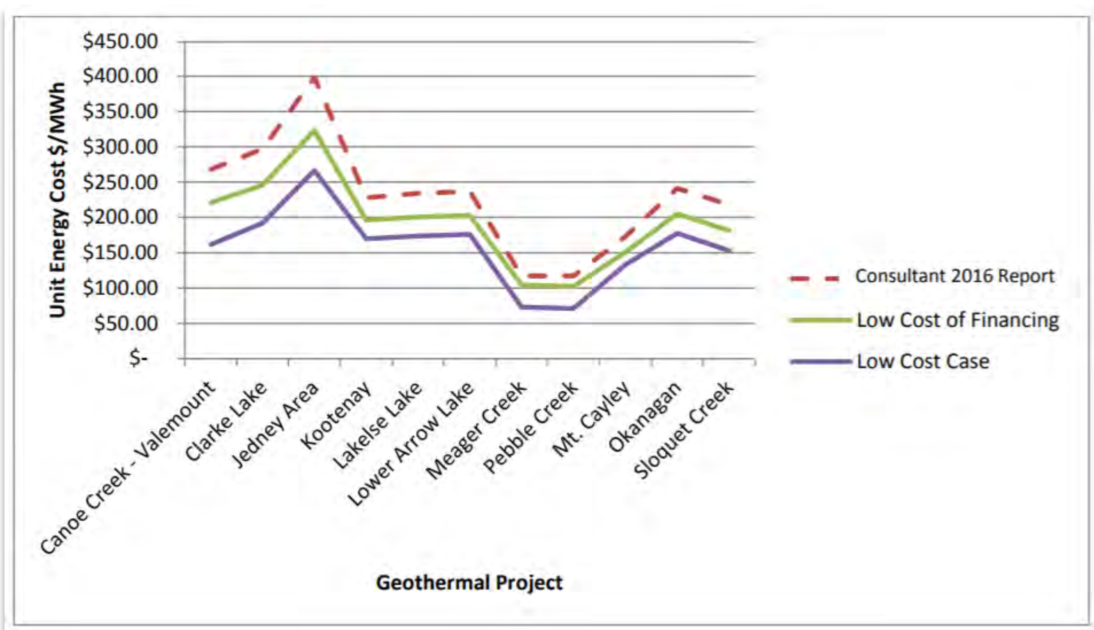
706 Submission F66-4, p. 14.
707 Ibid., p. 15.
708 Ibid., p. 18.
709 Ibid., p. 23.
710 Transcript of the Technical Input Session, October 14, 2017, p. 1484, 1490.
711 Submission F66-3, p. 3.
712 Submission F66-4, p. 12.

reservoir, and more confirmation wells can fail before abandoning a project, although the probability of whether a viable geothermal resource exists remains unchanged.[713]

With respect to the size of the budget required if BC Hydro were to accelerate the development of the geothermal industry in BC, BC Hydro estimated it would undertake the exploratory and confirmation stage drilling to confirm up to 310 MW of dependable capacity at the 11 most economically viable sites in BC identified in the Geoscience BC Report, at a cost of approximately $683 million (ignoring any associated inflation or cost of financing over the decade of exploration and confirmation activities).[714]

Instead of updating the $81/MWh ($2018) estimated cost using BC Hydro's cost of financing and current operational costs as requested by the Panel, BC Hydro provided a link to an October 2016 technical supplement to the Kerr Wood Leidal report, where it had changed three of its primary cost assumption parameters into the most optimistic case, consisting of low cost of drilling, high success of drilling and low cost of financing defined as a flat 5 percent cost of capital applied to all stages of project development. The figure below plots the consultant report's UEC alongside the BC Hydro calculated UEC for two sensitivity cases. The cost of energy for geothermal projects range from $77–$398/MWh. One of the conclusions of this supplement is that assumptions about the cost of drilling have a significant impact on LCOE. The costs for Pebble Creek (with a base cost of 117 CAD$/MWh) are CAD$78 and CAD$152/MWh when drilling costs are tested at 50 percent and 150 percent of base case, respectively.[715]

Figure 33: Geothermal Projects



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713 Submission F1-6, BCUC IR 2.61.0, pp. 4-5.

714 Ibid., p. 5.

715 Submission F1-6, IR 1.61.0, p. 6: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-geothermal-technical-supplement-201610.pdf.

Table 53 : Geothermal Project Assumptions

Assumptions	Drilling Cost	Financing Cost	Drilling Success Rate
Consultant 2016 Report	"High" costs of drilling as per GETEM	30% for early stages of development, declining to 7% at plant start up	60% for confirmation stage; 80% for well field development
Low Cost of Financing Case	Same as Consultant 2016 Report	5% flat financing rate	Same as Consultant 2016 Report
Low Cost Case	"Low" costs of drilling as per GETEM	5% flat financing rate	90% for confirmation stage; 90% for well field development

With regard to the probability of locating 200 MW of cost-effective geothermal energy by 2025 and 2035, BC Hydro stated that it has no basis upon which to answer the Commission's request. BC Hydro submitted:

> Given B.C.'s very preliminary state of geothermal resource characterization geothermal should not be included in an alternative resource portfolio in timeframe sufficient to be an alternative to Site C. Undertaking the detailed analysis required (using Iceland's staged resource assessment process as a model) to characterize geothermal would likely take five to ten years to explore all the sites and obtain history of geological data after which some more educated guesses on how to develop sites and approach the drilling could be made. As a result, expecting material amounts of geothermal electricity generation in B.C. by 2025 is unrealistic.[716]

At the October 14, 2017 Technical Input Presentation, BC Hydro agreed with CanGEA in one respect:

> MR. REIMANN: I think it would be a wonderful resource, because if you can find it and prove it, it's firm and it's got capacity.[717]

But disagreed with CanGEA with regards to availability of the resource:

> MR. REIMANN: But our view on this is that it is just highly risky and that there's nothing that we've seen that any of these reservoirs have been tested, drilled and explored in the province, and we've had failed efforts ourselves. Others have worked on the Meeker Creek in the 2000s and never managed to land it. And we've had over 30 wells drilled in that supposedly prime location and it's never gotten to the point of a confirmed geothermal resource.
>
> THE CHAIRPERSON: We heard this morning, though, that I guess there's been a lot of development in drilling technology especially in Western Canada and that perhaps that assessment, you know, could be looked at in light of that evidence. And that there are, in fact, a couple of projects that are approaching some sort of viability. I don't want to restate what the testimony was this morning, but it seemed more optimistic than you are portraying it.
>
> MR. REIMANN: It always does.[718]

[716] Submission F1-6, IR 2.61.0, p. 7.
[717] Transcript, Oct. 14, 2017, p. 1626.

1.2.2.4 Panel analysis and findings

There is evidence in this Inquiry that a commercially viable geothermal resource may exist. Furthermore, the regulatory process in BC in 2017 has seen much improvement, moving toward a single-window environment with the BC Oil and Gas Commission to assist with fast tracking of geothermal land access and drilling permits. For instance, the Ministry of Energy and Mines indicated that a permit expansion is forthcoming for one of the identified projects.

The Panel takes no position on whether any specific geothermal project may be commercially viable, or whether any geothermal project will be commercially viable. However, given the successful commercialization of this technology in other areas of the world, we consider it to be commercially feasible. Further, there are commercially viable projects in the Western United States, which shares similar geologic features with British Columbia. **Therefore, the Panel finds, on the balance of probabilities, there is a likelihood that some commercial viability may be obtained.** Accordingly, it is appropriate to include a relatively small amount of geothermal energy in the Alternative Portfolio.

In consideration of the concerns raised by BC Hydro, rather than including 200 MW of geothermal in 40 MW increments starting in 2020 as recommended by CanGEA, the Panel chooses to only include the Canoe Reach and Lakelse Lake projects, for a total capacity of 81 MW, in the year in F2025, which is when capacity constraints start to occur for the Medium and High load scenarios. No geothermal capacity is added in the Low load case.

1.2.3 Wind

1.2.3.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro considers that onshore wind is one of the lowest cost supply side resources that can replace Site C's energy, however BC Hydro submits that the comparison against Site C must include the cost of capacity required to integrate and firm up wind.

BC Hydro submits that "[f]or the onshore wind assessment, [719] BC Hydro conducted analysis based on potential projects identified in the 2009 BC Hydro Wind Data Study and the 2009 BC Hydro Wind Data Study Update. [720] Installed capacity for each project was left unchanged but average annual energy (and net Capacity Factor) and costs for each site was updated in 2015 by applying updated turbine characteristics, hub heights and cost profiles."[721] Although these documents weren't submitted to this proceeding, they appear to be publically accessible.

BC Hydro conducted analysis based on potential projects identified in the 2009 BC Hydro Wind Data Study and the results are shown below: [722]

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[718] Transcript, Oct. 14, 2017, p. 1626-1627.
[719] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.pdf.
[720] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf.
[721] F1-1 Submission, Appendix L, p. 30.
[722] F1-1 Submission, Appendix L, pp. 29-31.

Figure 34: Onshore Wind Results – Summary by Region

Region	Number of Resource Options	Total Installed Capacity (MW)	Dependable Capacity or ELCC (MW)	Annual Energy (GWh/year)	Annual Firm Energy (GWh/year)	UEC at POI ($/MWh)	Adjusted UEC ($/MWh)
Peace River	47	6057.0	1574.8	20114.1	20114.1	81 - 300	101 – 341
North Coast	24	3867.0	1005.4	11654.2	11654.2	90 - 280	106 - 305
Revelstoke / Ashton Creek	4	567.0	147.4	1613.6	1613.6	95 - 118	113 – 136
Kelly Nicola	22	3264.0	848.6	8969.9	8969.9	97 - 143	111 – 159
Vancouver Island	13	1071.0	278.5	3367.9	3367.9	100 - 140	108 – 146
Central Interior	9	1038.0	269.9	2831.9	2831.9	110 - 163	128 – 184
East Kootenay	2	135.0	35.1	343.8	343.8	129 - 133	149 – 153
Selkirk	2	81.0	21.1	203.5	203.5	140 - 152	162 – 176
Lower Mainland	1	87.0	22.6	263.4	263.4	135	144
Totals	**124**	**16167.0**	**4203.4**	**49362.4**	**49362.4**	**81-280**	**101-305**

Based on BC Hydro's responses to the Panel's follow up questions regarding the UEC or the alternate portfolio, the Panel calculates this to be BC Hydro's assumption about the capital cost of wind energy:[723]

Figure 35: BC Hydro Wind Cost Assumptions[724]

	Size (MW)	Cost at gate ($'000)	Tax ($'000)	Road ($'000)	Total ($'000)	$/MW
Wind_PC20	156	$342,512	$43,892	$1,495	$387,898	$2,487
Wind_PC14	144	$318,160	$52,176	$1,715	$372,051	$2,584
Wind_PC28	153	$404,922	$40,260	$1,256	$446,438	$2,918
Wind_PC10	297	$774,243	$51,596	$548	$826,387	$2,782
Wind_PC17	102	$233,391	$26,497	$352	$260,240	$2,551
Wind_SI15	303	$657,843	$42,518	$0	$700,361	$2,311
Wind_SI12	186	$410,223	$39,818	$8	$450,049	$2,420

BC Hydro states that "[d]ue to the intermittent and variable nature of wind energy output, an adjustment was added to the wind resource UECs to account for the incremental cost of integrating wind projects into the BC Hydro system."[725]

Deloitte report

Deloitte estimated the cost of wind as follows:

- Capital cost: $1,600 to $3,200/kW
- Fixed O&M cost: $70 to $110/kW-yr
- Future costs: capital costs expected to fall by 10 – 12 percent per MW in the next 10 – 20 years.[726]

[723] A-12 Submission, BC Hydro UEC Excel File (BCUC Request), Tab UEC_UCC.
[724] F106-1 Submission, p. 67; BC Hydro 2017-F2019 RRA, Exhibit B-14, BCUC IR 310.1.
[725] F1-1 Submission, Appendix L, Table L-2, p. 20.

Deloitte referenced 31 sources for its wind cost estimates, including a 2015 Hatch Wind Data Study Update Report for BC Hydro and Black & Veatch study used for Pacificorp's 2017 IRP. Cost comparisons for a 100 MW wind project located in Washington (Pacificorp) and Peace River (Hatch study) were:

- Capital costs: Pacificorp – US $1,800/kW; Hatch – Can $$2,390/kW
- Fixed O&M costs: Pacificorp – US $36/kW-year; Hatch – Can $74/kW-year
- Wind integration cost: Pacificorp – US $0.573/MWh
- Capacity factor: Pacificorp - 38 percent. [727]

Deloitte further states: "The economics of onshore-wind generation in British Columbia differ greatly by geography due to various factors, including the quality of the wind resource, proximity to dense populations, proximity to transmission lines, and terrain. Document research was conducted and several studies were analyzed.[728] Three transmission regions with high wind potential were included in the model (Vancouver Island, Kelly Nicola, and Peace River), each with its own wind profile and cost profile. Each of these regions were further refined by capacity constraints. Onshore wind in the Peace River region was determined to have the lowest cost. However, transmission lines between Peace River and the Lower Mainland were expected to become congested if more than about 600 MW of wind capacity was added. Similar analysis was carried out for Kelly Nicola and Vancouver Island. Kelly Nicola benefits from being near the Lower Mainland and sparsely populated. Consequently, more capacity was available at lower prices compared to Vancouver Island. Vancouver Island had the highest capital cost compared to the other two regions. However, capacity was limited to 500 MW in the model at the reference price. Another 600 MW was offered at a higher price, approximately 15 percent more than the reference price.[729]

Canadian Wind Energy Association and Clean Energy Association of British Columbia

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CanWEA) and CEABC to provide an independent assessment of the cost of various renewable generation projects, including onshore wind. The Power Advisory report supports the following assumptions:

- Capital costs: $2,328/kW installed cost for a 100 MW project (10 percent lower for a 200MW project)[730]
- O&M costs: $43/kW-year and $1.4/MWh
- Future costs: 5 percent real cost reduction from 2017 to 2024
- Capacity factor: 40 percent
- Real levelized price: $68/MWh

The Power Advisory report also raised concern regarding BC Hydro's $5/MWh wind integration estimate, including: (i) BC Hydro now has a 15-minute scheduling (compared to 1-hour schedule previously) which could reduce incremental operating reserve requirements for wind by 51 percent; and (ii) BC Hydro has relied on ancillary services prices from California to price wind integration which may not be appropriate for this analysis and whose costs have declined significantly (from 50 percent to 80 percent) since the date of the study.[731]

[726] A-9 Submission, pp. 17, 18.
[727] Ibid., pp. 17; Pacificorp 2017 IRP, pp. 106, 120, 123; 2015 Hatch Wind Project Cost Review, p. 23.
[728] Submission A-9, p.101.
[729] Ibid., pp. 101-102.
[730] F18-3 Submission, Appendix 1, p. 6-8.
[731] F18-3 Submission, Appendix 1, pp. 16, 17.

The report further adds that "[t] The US DOE report indicates that wind integration costs are generally estimated to be below $6/MWh and can be as low as $0.50 to $2/MWh even at wind capacity penetration levels beyond 40%."[732]

CEABC submits that "this is not a definite cash outlay from ratepayers' pockets. Rather it is an allowance to compensate for a possible lost opportunity to sell capacity in the day forward market across the border – an opportunity which may or may not be real, depending on many other variables, including available transmission capacity."[733]

CEABC further submits: "The amount was set in 2008, reaffirmed in 2010, and continued in use for the 2013 IRP. However, BC Hydro indicated in 2015 that a re-evaluation of this charge was being undertaken, with results targeted for July 2016. Those results have never been revealed, but the report by Power Advisory, attached to this submission as Appendix 1, gives some comparative costs from other jurisdictions."[734]

Other submissions

Allied Hydro submits the following:

> [w]ind power is a rapidly growing renewable power sources around the world. In 2016 the world total was 432,883 MW of capacity. China had 145,362 MW and Canada 11,205 MW.
>
> Capital costs for new wind projects in BC vary depending upon several factors. Cape Scott Wind 99 MW, had a capital cost of $3.3 million/MW; Meikle Wind, 185 MW, $2.2 million/MW.
>
> From general industry information it appears that the cost of turbines, construction, overheads and contingencies for a green-field site in BC would be in the range of $3 million per MW of capacity. For a brown-field site the all-in capital costs could be lower. For a small 15MW plant the capital cost would be expected to be in the C $45 million range. 15 MW is used here because that is the maximum size of IPP BCH's Standing Offer program allows, the only operating program currently in place.
>
> The availability to generate wind power is a function of the strength and frequency of the winds. The average availability tends to be in the 25% to 35% range. Thus a 15 MW plant will generate power only for about 90 to 130 days per year. That means about 40,000 MWh/year, which would translate into a unit capital cost of about $100/MWh, over a 30 - year project life, before operating, tax, and maintenance costs.
>
> For larger plants the unit cost may be somewhat lower. The Canadian Wind Association has said that in Quebec in 2016 Hydro-Quebec recorded a new low average price for wind power in Canada of $63/MWh (the basis of this number is not available and thus should only be taken as indicative).
>
> In short, wind power is a good source of green energy, and its costs are falling. The unit cost now is in the $100/MWh range. However, with a low availability wind is not highly dependable. Wind needs a base power supply, gas-fired plants or hydropower reservoirs as back up. Possibly in the future energy storage in batteries will provide a source of backup for

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[732] F104-1 sbmission, Appendix 1, pp. 13- 14.
[733] F18-3 Submission, p. 7.
[734] Ibid.

> wind. At this time wind can only be considered as a source, not a major source of BC power supplies. In addition, wind power has been criticized for its impact on bird populations.[735]

Peace Energy Renewable Energy Cooperative submits that a total of approximately 600 MW of wind are presently operational in the Peace Region, with another 2000 MW waiting to be developed by IPPs. "Estimates suggest the Peace Region has some 10,000 MW of readily developable wind energy. This wind resource is some of the best in the world, featuring a power capacity factor (PCF) of 40 percent + (BC Hydro states that the Site C dam PCF will be approximately 60%, a standard figure for hydro power in the industry.) Distributing and expanding wind facilities across the region will improve this remarkable PCF for wind energy until it approaches the base-load reliability of hydro (some 15 years of wind monitoring across the region confirm this conclusion)."[736]

Prophet River and West Moberly First Nations' expert McCullough, submits the following:

> [m]ajor manufacturers sell thousands of virtually identical wind turbines throughout North America. The [U.S. Energy Information Administration] EIA data indicates that wind turbines will cost $1,850/kW for a 100 MW utility scale project. This is consistent with industry experience. The RODAT's three cheapest wind projects – PC13, PC19, and PC21 – are $2,857/kW (U.S.). Since the underlying equipment is most likely the same, the only explanation would be that wind farms in British Columbia are extremely more remote than those in Washington State and that transportation costs are almost $1,000/kW more. Since these projects are in the Peace River area, this seems unlikely.[737]

Dauncey further presents the following costs for wind:[738]

Table 54: Cumulative New Wind Energy Forecast

1 MW produces 3 GWh a year	2016	2020	2025	2030	2035	2040
Price of best wind, cents/kWh (unadjusted for grid integration costs)	10	9	7.5	6.8	6.0	5.3
New wind capacity in MW	0	0	2,000	5,000	8,300	10,000
Cumulative number of 2.5 MW turbines	0	0	800	2,000	3,300	4,000
New wind energy GWh	0	0	6,000	15,500	25,000	30,000

1.2.3.2 Panel preliminary findings, analysis and questions in Preliminary Report

BC Hydro's capital cost assumptions appear to be in the range of capital cost estimates provided by other parties. Considering BC Hydro does not need this resource unit until approximately 2030, depending on load forecast assumptions, it seems that a lower cost should be modelled. Dauncey estimates a reduction of wind energy costs of a little over $30/MWh between 2016 and 2030. BC Hydro is requested to provide any forecasts or estimates of future wind energy costs.

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[735] F24-1 Submission, p. 17.
[736] F51-1 Submission, p. 21.
[737] F28-2 Submission, Tab 7, Site C Business Case Assumptions Review, p. 13.
[738] F62-1 Submission, p. 11.

The Panel found there has been a decline in the cost of wind in recent years, and parties expect future declines. The Panel shared concerns raised by parties that BC Hydro's $85/MWh wind estimate is not supported.

The Panel therefore sought input from BC Hydro and other parties on the following questions:

1. What is the current BC installed capacity cost of a 100MW onshore wind project ($/kW) and operating cost ($/year and $/MWh)? What would a reasonable forecast of the cost be in F2025 and F2035?
2. Where are the best locations in BC to install wind farms from the perspective of (i) wind levels, and/or (ii) available transmission capacity? What would be a reasonable assumption regarding maximum capacity levels in these locations, and the wind farm capacity factor?
3. Please provide BC Hydro's 2016 Wind Integration Study, or indicate when it will be available. [739]

In addition, BC Hydro was asked to explain in more detail the basis for selecting the amount for the wind integration adder.[740]

Wind capital cost and O&M

In response to the Preliminary Report questions, BC Hydro stated:

> For a 100 MW onshore wind project in B.C., the current capital cost at gate is estimated to be $2,360/kW for an ideal site, and $2,830/kW for a complex site (in the 2015 Wind Resource Options Update, 36 per cent of projects are considered complex). The operating cost is $73/kW-yr (or between $17/MWh and $32/MWh depending on the capacity factor) for onshore wind projects in B.C. …
>
> According to our analysis the best location in B.C. to install wind farms is currently the Peace Region. …
>
> In our portfolio where Site C is terminated, the model picks up rough 1,000 MW and 3,800 GWh of wind resources in Peace Region before needing incremental transmission capacity by additional reactive power support. [741]

Wind Integration

In response to the Preliminary Report questions, BC Hydro stated:

> The 2016 Wind Integration Study is expected to be available for BC Hydro's next Integrated Resource Plan, scheduled for November 2018.[742]
>
> …
>
> In 2010, BC Hydro conducted a Wind Integration Study which looked at the cost of integrating wind power onto the electric system across various study scenarios. Based on this study, a wind integration cost of $10/MWh was used in the 2013 IRP. An update to the 2010 study has not been completed, but BC Hydro recognizes that a number of factors that would impact the integration cost, such as reduced natural gas prices and market

[739] Submission A-13, Appendix A, p. 15, 16.
[740] Submission A-13, p. 92.
[741] F1-8 Submission, IR 63.
[742] F1-8 Submission, IR 63.

> conditions. In advance of completing the updated study, BC Hydro used a wind integration cost of $5/MWh in its August 30, 2017 filing to the Commission. The $5/MWh wind integration cost estimate is in line with a recent survey of wind integration studies by the US Department of Energy (2016 Wind Technologies Market Report).[743]
>
> …
>
> The Wind Integration Study models how BC Hydro, through its power trading subsidiary, Powerex, participates in the day ahead (DA) power trading market. With wind power generation output being uncertain in the DA timeframe, a portion of the BC Hydro system flexibility has to be withheld from the market in order to manage system operating requirements. It is these foregone trade impacts that are also being captured in the DA power trading opportunity cost. In this study, DA wind opportunity costs are not incurred to the extent that the transmission interties are constrained as there would otherwise not have been an opportunity to use the reserved hydro flexibility.[744]

The US Department of Energy 2016 Wind Technologies Market Report referenced by BC Hydro above stated:

> One new integration cost study was completed in 2016 as part of PacifiCorp's 2017 Integrated Resource Plan (PacifiCorp 2017). PacifiCorp's cost estimate of [US] $0.57/MWh is lower than the costs in previous PacifiCorp assessments due to lower electricity prices and more resources being available to provide reserves. PacifiCorp defines integration costs to include both the cost of additional regulating reserves and the cost of managing day-ahead forecast errors.[745]

The Power Advisory provided in a report prepared for CEABC benchmarking information and a graph of wind integration costs as a function of wind penetration levels included in the US Department of Energy 2016 Wind Technologies Market Report.[746]

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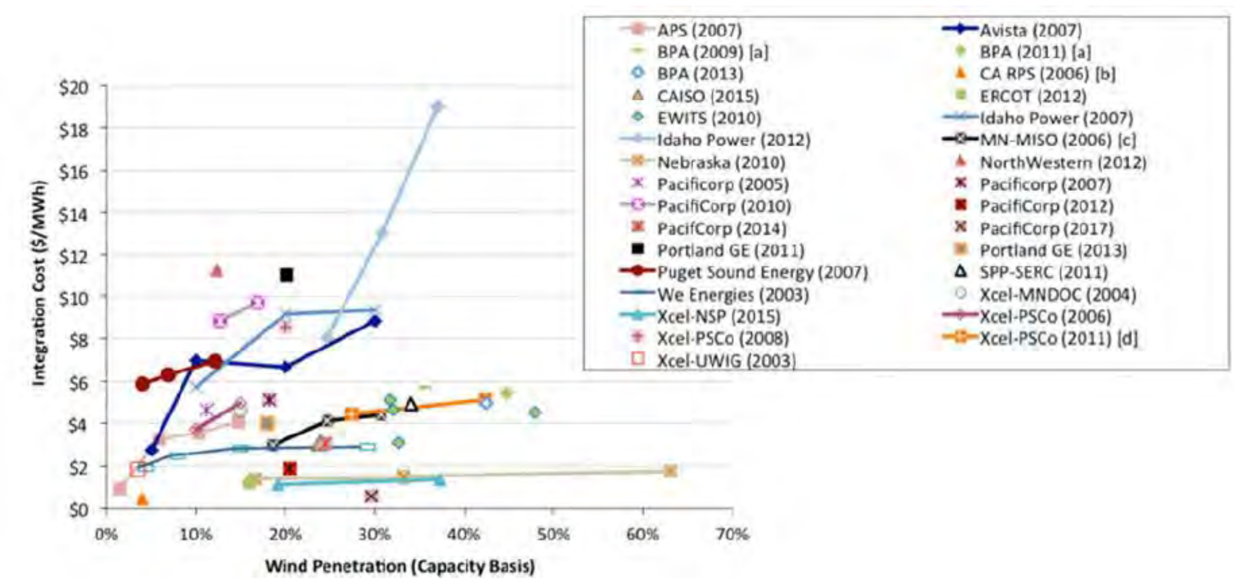
[743] F1-6 Submission, IR 37.
[744] F1-6 Submission, IR 43.
[745] https://energy.gov/sites/prod/files/2017/10/f37/2016_Wind_Technologies_Market_Report_101317.pdf, p.69
[746] F18-3 Submission, Appendix 1, p. 15.

Table 55: US Dept of Energy 2016 Wind Technologies Market Report: Wind I Integration benchmarking

Jurisdiction	Integration Cost ($/MWh)	Year $*	Penetration Level (Capacity Basis)	Notes
Wind				
Arizona Public Service (APS)	3.25 / 4.08	2010	6% (468 MW) / 15% (1,185 MW)	As of the 2017 IRP, APS continues to base integration costs on its 2007 Wind Integration Cost Impact Study. Cost said to be updated "to increased penetration levels of wind in the APS systems and current fuel prices", but the specific value is not provided in the IRP.
PacifiCorp	0.57	2016	30% (3,007 MW)	2017 Flexible Reserve Study (FRS) conducted as part of the 2017 PacifiCorp IRP. Down from $3.06/MWh in the 2014 Wind Integration Study.
Pacific Gas and Electric (PG&E)	4.00	2014	Benchmark Average	Interim variable integration cost for wind approved by the California Public Utilities Commission in the 2014 RPS and IRP off-year proceeding.
Public Service Company of Colorado (PSCo) [Xcel Energy]	2.93	2016	28% (2,000 MW)	2016 ERP. Value based on 2011 Wind Integration Study methodology and updated natural gas prices. PSCo did not allow for gas prices below $3.24/MMBtu, while recognizing current and forecasted gas prices below this value. Average wind integration costs from 2011 were $3.68/MWh for 2 GW of wind.

Figure 36 : US Dept of Energy 2016 Wind Technologies Market Report: Wind Integration Costs & Penetration Levels



BC Hydro stated in the 2013 IRP (Appendix 3E) regarding wind integration:

> <u>BC Hydro currently has 246 MW of wind generation operating on the electric system</u> and an additional 534 MW of wind generation contracted through electric purchase agreements [for a total of 780 MW]. Combined, this wind power generation represents a wind penetration level of approximately 7.8 per cent, as measured by wind power generating capacity divided by peak load. (p. 3) (emphasis added)
>
> This wind integration study is undertaken at a time when there is still a relatively low level of wind power penetration on the BC Hydro electric system. (p. 6)

Three wind penetration levels of 15 per cent, 25 per cent and 35 per cent are included in the study, representing installed wind capacities of approximately 1500 MW, 2500 MW and 3500 MW, respectively. (p. 6)

Prices from the California Independent System Operator (CAISO) ancillary services market are used in this study as proxy values for an ancillary services market. A market for ancillary services exists as well in the Pacific Northwest. However, this market consists of less transparent bi-lateral transactions between buyers and sellers. The CAISO ancillary services market, on the other hand, is an open and transparent market. (p. 12)

[BC Hydro's Generation Optimization Model] explicitly optimizes the operations of the five major BC Hydro hydroelectric plants which include GM Shrum (GMS), Peace Canyon (PCN), Mica (MCA), Revelstoke (REV) and Arrow Lakes Hydro (ARD). Of these facilities, GMS, MCA and REV are modeled to provide any type of reserve, whereas PCN and ARD are restricted to supplying only following and contingency reserves. (p. 18)[747]

The table below shows the average annual CAISO market clearing prices for three ancillary services used in the study for transmission node NP15 [to determine wind integration costs]. (p. 20)

Table 56: BCH 2013 IRP – Ancillary Service Market Price Assumption

Canadian Water Year	Down-Regulating Price ($/MWh)	Up-Regulating Price ($/MWh)	Spinning Price ($/MWh)
2002/03	17.27	16.44	5.94
2003/04	12.74	16.70	6.01
2004/05	13.73	19.40	9.71
2005/06	18.80	21.45	9.31
2006/07	10.51	14.58	4.86
2007/08	16.26	19.81	5.54

BC Hydro's 2016 Wind Integration Study Kick-Off Meeting slides, dated April 1, 2015 stated that the study had an expected completion date of July 2016.[748] The presentation included the following slides:

[747] The capacity of GM Shrum, Mica and Revelstoke is close to 8,000 MW https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-quick-facts-june-2017.pdf/.

[748] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-integration-wind-meeting1-20150401-presentation.pdf, Slide 8/

Figure 37: CAISO Ancillary Service Prices: 2010 Study vs. 2016 Study

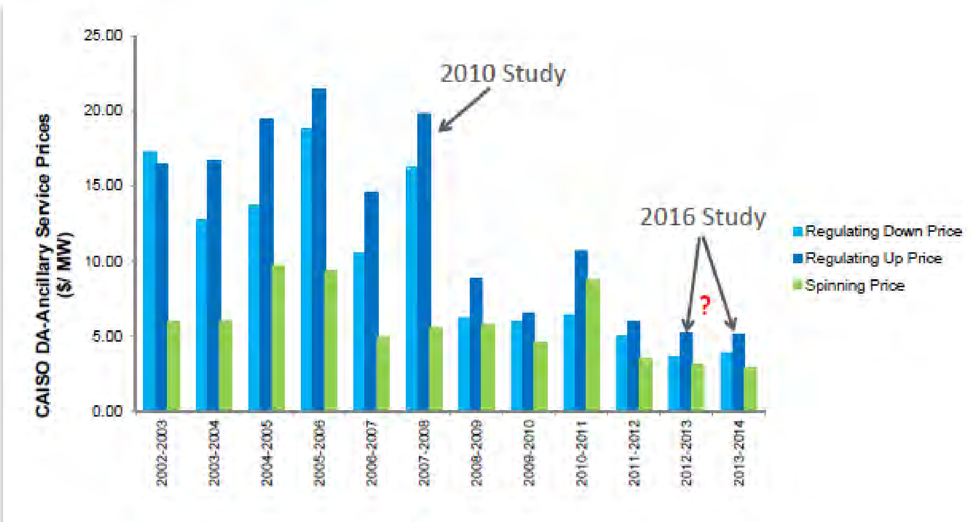


Table 57: 2016 BCH Wind Integration Study – proposed scenarios

Scenario	Type	Description/ Purpose	Parameters
1	Base	To determine wind integration cost for 15% wind penetration level for 3 market price scenarios	Penetration level – 15% Diversification – economic Market Price – low, mid, high Market transactions – status quo
2 (TBD)	Base	To determine wind integration cost for 25% wind penetration level for 3 market price scenarios	Penetration level – 25% Diversification – economic Market Price – low, mid, high Market transactions – status quo
3	Sensitivity	To test how geographic diversification impacts wind integration cost	Penetration level – 15% Diversification – high Market Price – mid Market transactions – status quo
4	Sensitivity	To test how a 15-min market would impact wind integration cost	Penetration level – 15% Diversification – economic Market Price – mid Market transactions – 15-min market

BC Hydro stated with regard to its participation in the Western Energy Imbalance Market (EIM):

> Although Powerex may increase its level of participation as opportunities arise, it is currently expected that Powerex's level of participation in the EIM will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability in the EIM. Therefore, at this time, there is no direct connection between Powerex's participation in the EIM and Site C. … Nonetheless, the EIM is expected to continue to remain just one market amongst several by which Powerex can monetize the residual flexible capability of the BC Hydro system.

The Power Advisory states in a report prepared for CEABC:

> A Power Advisory report for Natural Resources Canada found that hydroelectric systems such as BC Hydro's are well suited to the integration of variable output wind resources and

> that they can allow large amounts of wind generation to be integrated at relatively low costs.
>
> A similar finding was made in the Pan-Canadian Wind Integration Study, which found that: (1) "Hydro generation, particularly hydro with pondage, provides a valuable complement to wind generation."; and (2) "The combination of wind and hydro provides a firm energy resource for use within Canada or as an opportunity to increase exports to U.S. neighbours." The Pan-Canadian Wind Integration Study also found that: (1) "Regulation reserve requirements to mitigate wind variability appear to be a small fraction of the additional installed wind capacity;" and (2) Overall the additional regulation reserve requirements across all of Canada were less than 1.7% of the installed wind." The regulation reserve requirements (i.e., increased regulation requirement relative to wind capacity) for BC under the 35% penetration scenario were just .9%, representing about 50 MW. While curtailment of wind was required in high wind resource scenarios there was little need for such curtailment in BC. …
>
> CanWEA engaged Brendan Kirby, a noted utility industry expert who participated in the referenced Western Wind and Solar Integration Study Phase 2 among other similar studies, to assess BC Hydro's wind integration cost estimates … Kirby noted that BC Hydro relied upon ancillary service prices from the California ISO (CAISO) and that these prices have declined significantly (from 50 to 80%) since the data relied upon in the study.
>
> Furthermore, Power Advisory notes that the CAISO market has a dramatically higher proportion of thermal generation than BC and as such is likely to have significantly higher costs for ancillary services than would be appropriate for BC. … The question regarding the wind integration study should be what is the cost to BC Hydro of providing these services? The difference is between costs and market value. When making resource investment decisions for the benefit of BC consumers and the required services are being provided by BC Hydro, Power Advisory believes that the cost of providing the service should be considered, not its theoretical value in a somewhat distant market. [749]

Swain submits: "… BC Hydro's great storage capacity in its reservoirs, especially outside of the freshet, allows the integration of more intermittent sources than less fortunate systems."[750]

Assumptions in the Illustrative Draft Alternative Portfolio

The Illustrative Draft Alternative Portfolio contained the following assumptions:[751]

> Wind project characteristics (load, annual energy, installed capacity) were taken from BC Hydro's portfolio results.[752] Effective load carrying capacity and plant life for each project was taken from BC Hydro's resource options spreadsheet.[753]
>
> Wind capital and operating costs are taken from the National Renewable Energy Laboratory (NREL) 2017 Annual Technology Baseline.[754] NREL costs were increased by 10% in light of

[749] F18-3, Appendix 1, p. 13-17.
[750] F36-1 submission, p. 17.
[751] Exhibit A-22 p. 7.
[752] F1-1 Submission, Appendix Q, p. 8.
[753] F1-4 Submission, Attachment BCUC_1_001_00_ATT_01.xlsm, UEC_UCC tab (select wind project from cell K9, dependable capacity is shown in cell D23).
[754] F35-5 Submission, p. 15; NREL (National Renewable Energy Laboratory). 2017. 2017 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html, land based wind tab, TRG4 mid

cost differences between BC Hydro's 2015 capital costs in BC Hydro's resource options spreadsheet and NREL 2015 estimates for wind investments of similar capacity factor. Costs were converted to Canadian dollars and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet.[755] Wind farms are assumed to be refurbished at the end of 25 years at a cost 30% less than the cost of a new wind farm.[756]

Wind integration costs were assumed to be $2.5/MWh, taking into account concerns raised with BC Hydro's $5.00/MWh estimate.[757]

BC Hydro submission

In its October 18, 2017 submission, BC Hydro states that the Illustrative Draft Alternative Portfolio assumes wind cost declines below BC Hydro's median estimates.[758]

BC Hydro submits that the network upgrade costs associated with wind resources need to be added to the overall cost. BC Hydro estimates network upgrade costs for low capacity factor generation including wind to be $6/MWh.[759] BC Hydro did not comment on the $2.50 MWh assumed wind integration cost in the October 11 Illustrative Alternative Portfolio.

Others submissions

CEABC submits that the discount for refurbishment costs after 25 years should be at least 50 percent. CEABC also submits that the assumed wind integration costs are still too high, given that capacity is available in BC Hydro's system and has no avoided sales value. [760]

BCSEA supports evidence filed by CEABC and CanWEA estimating a levelized cost for wind power of CAD$68/MWh at the point of interconnection.[761]

CanWEA/CEABC submit that the NREL 2017 Annual Technology Baseline is a highly credible and definitive source. CanWEA/CEABC disagree with BC Hydro's claims that wind cost estimates are too optimistic, and state that the 2016 Wind Technologies Market Report indicates a 5.9 percent decline in installed wind costs compared to the data the 2017 Annual Technology Baseline is derived from. CanWEA/CEABC further submit the wind integration costs assumed in the strawman model are reasonable, noting the relatively limited penetration of wind in BC to date, projected future volumes and the ability of BC Hydro's existing hydroelectric resources to integrate additional volumes of wind cost-effectively.[762]

Bakker submits that BC Hydro's future repowering estimates for wind power are extremely pessimistic, and considers the Commission's repowering assumptions reasonable.[763]

McCullough disagrees with BC Hydro and submits the assumed wind cost declines are supported by precedent and authoritative sources. McCullough also cites studies by Lazard and the International Energy

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(weighted average net capacity factor of 43.5%).

[755] F1-4 Submission, Attachment BCUC_1_001_00_ATT_01.xlsm, resource options tab, cell BD1.

[756] F18-3 Submission, p. 30.

[757] F1-1 Submission, p. 63; F18-3 submission, pp. 14- 17.

[758] F1-17 Submission, pp. 18-19.

[759] F1-17 Submission, p. 29.

[760] F18-6 Submission p. 5.

[761] F29-10 Submission, p. 1 citing F104-1 Submission.

[762] F104-3 Submission, pp. 4-5.

[763] F106-11 Submission, p. 1.

Agency that indicate additional future cost reductions could be possible. McCullough notes the assumptions used by the Commission are within the ranges forecasted by Lazard. [764]

CEC states that capitalized costs for wind are established at between $263/kW and $297/kW, and submits that the overall costs for wind have been underestimated by $600 million.

Hadland submits: "On page 14/15 of BCHs submission Hydro says 'As part of the analysis conducted for the Site C Environmental Impact Statement, BC Hydro forecast that Site C would provide the capability to integrate an additional 900 MW of wind resources when complete.' If that is the case then a simple ratio of existing Hydro plant to integratable wind resources yields about 10,000 MW of wind resources, or about 9 Site C's. That should be enough for a while."[765]

Naikun submits: "Naikun is peased to see that Commission staff is taking account of concerns about BC Hydro's dated wind-integration study. Naikun cannot know until BC Hydro properly updates its work whether or not the rop from $5 per MWh to $2.50 per MWh takes full account of the necessary adjustments, but directionally the change seems appropriate."[766]

CEABC submits that the $2.5/MWh wind integration cost assumed in the October 11 Illustrative Alternative Portfolio is more reasonable that BC Hydro's $5/MWh estimate but is still too high given that capacity is available in BC Hydro's system and has no avoided sales value.[767]

Regarding wind integration, the CEC refers to the survey of recent WECC renewable integration costs included in the US Department of Energy 2016 Wind Technologies Market Report and states:

> The CEC considers that the above information does not support wind integration costs of $2.50/MWh, particularly when BC Hydro has declared the costs in BC to be in the order of $5.00/MWh. The CEC considers that the PacifiCorp figure [US $0.57]is atypical given the costs in other jurisdictions and should not be used to artificially lower the expected integration costs.
>
> The CEC submits that it is not appropriate to disregard the BC Hydro evidence as to the likely costs that will be experienced with integration. The CEC submits that BC Hydro will have BC specific costs actual costs that can be examined to assess future wind integration costs. The CEC recommends that the Commission utilize the BC Hydro costs of $5/MWh unless BC Hydro actuals support a different figure. [768]

McCullough, on behalf of the Peace Valley Landowner Association and Peace Valley Environment Association, states: "We estimate that 1 MF [millon-acre feet] of Mica storage capacity will firm 4,782 MW of wind over one year. This is more than enough to back up the 444-685MW of wind included in the alternative portfolio."[769]

[764] F35-21 Submission pp. 24-29.
[765] F19-3 Submission, p. 8.
[766] F272-2 Submission, p. 7.
[767] F18-6 Submission, p. 5.
[768] F82-4 Submission, pp. 13-15.
[769] F35-21, p. 8.

1.2.3.3 Panel analysis and findings

The Panel finds the capital and operating costs and capacity assumptions used for wind generation in the Illustrative Draft Alternative Portfolio to be reasonable. However, the Panel agrees with BC Hydro that it is appropriate to apply a cost adder to capital and operating costs to account for network upgrades.

The Panel notes that BC Hydro believes the assumed unit energy cost figure for wind to be too low. However, it also considers that other submissions have highlighted further cost reductions that may be possible beyond the levelized costs assumed in the Illustrative Draft Alternative Portfolio (for example, CanWEA, CEABC, McCullough). The Panel agrees with CanWEA and CEABC in finding that the NREL 2017 Annual Technology Baseline represents an appropriate resource for estimating the levelized cost of wind, and believes that this estimate strikes an appropriate balance with regard to future cost forecasts.

BC Hydro submitted that a $6/MWh network upgrade cost should be added to the cost of wind power. The Panel notes that the Cost of Incremental Firm Transmission (CIFT) is not included in BC Hydro's portfolio analysis, but rather BC Hydro models specific transmission upgrade requirements and their associated costs.[770] The Panel therefore finds that it is appropriate to update the Illustrative Draft Alternative Portfolio so that capital costs and operating costs also account for transmission and road costs, with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet.[771] The Panel considers that network upgrades would have a lifetime of 50 years, therefore capital cost adders are not assumed to apply to the first tranche of refurbished wind generation.

The Panel also notes that delays in building wind compared to Site C in the alternative portfolio delay the need for the cost of incremental firm transmission required for Site C (from F2024 to F2039). The Panel has not quantified the effect of this delay, but notes that it would reduce the cost of the Alternative Portfolio.

Regarding the cost of wind integration, the Panel determines that the cost in the Illustrative Draft Alternative Portfolio should be reduced from $2.50/MWh to $1.0/MWh. The Panel also determines that Site C should receive a "wind integration credit" of $1/MWh for each MWh of wind generation it is able to integrate.

The Illustrative Draft Alternative Portfolio includes 444 MW (low load forecast) and 591 MW (high load forecast) of wind generation. 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.

It is therefore reasonable that BC Hydro's approach to estimating wind integration costs is based on the lost opportunity of selling surplus wind integration into the market. BC Hydro stated in the 2013 IRP that the California Independent System Operator (CAISO) ancillary service market prices (F2003 – F2008) are used as a proxy for the lost opportunity of sales into the ancillary market, and estimated the lost opportunity cost of wind integration at $10/MWh. These results were based on a 2010 wind integration study.

For the purpose of the Site C update, BC Hydro noted the reduced natural gas prices and market conditions relative to F2003 – F2008, and updated wind integration estimate to $5/MWh. A BC Hydro provided chart indicates that by 2016, prices for CAISO ancillary services have dropped to about one third of the F2003-

[770] BC Hydro Response to IRs 2.26.0, 2.36.0.
[771] F1-4 Submission, Attachment BCUC_1_001_00_ATT_01.xlsm, UEC_UCC tab, cells K22:L29, uplifted for inflation based on Resource Options tab, cell BD1.

F2008 levels. No adjustment appears to be made for transmission costs/real power losses. In addition, CEABC submits that a move to hourly scheduling since the last wind integration study (2010) reduces wind reserve requirements.

In April 2015, BC Hydro started its 2016 Wind Integration Study, the purpose of which included determining the wind integration cost for 15 percent wind penetration and 25 percent wind penetration. The expected completion date for this study was July 2016, however BC Hydro was unable to provide the Commission with a final or draft copy for this Inquiry.

The Panel shares the concern raised by CEABC concern that wind integration cost estimates provided by BC Hydro are out of date, and that the cost of wind integration is set by BC Hydro based on “a theoretical value in a somewhat distant market.” The Panel also notes BC Hydro’s submission regarding participation in the Western Energy Imbalance Market that it currently expects participation will not frequently be limited by the capacity or flexibility of the BC Hydro system, but rather by the level of market opportunities and the transmission transfer capability.

Regarding the benchmarking information provided in the US Department of Energy 2016 Wind Technologies Market Report on the cost of wind integration, the Panel notes that the more recent cost estimates have lower costs than older estimates, and that that the most recent estimate from PacifiCorp (based on a 2017 Flexible Reserve Study) shows a wind integration cost estimate of US $0.57/MWh, compared to their previous US $3.06 MWh wind estimate. Deloitte used the US $0.57/MWh PacifiCorp wind integration cost in its model.

BC Hydro did not object to the revised $2.50/MWh estimate, while CEABC submits it is still too high given the capacity that is available in BC Hydro’s system and has no avoided sales value. The Panel agrees with CEABC that a further downward adjustment to the wind integration cost would be appropriate, and considers a $1/MWh estimate would be reasonable. This is supported by the Pacificorp benchmarking results of US $0.57/MWh (used by Deloitte), one third decrease in the CAISO ancillary services price since BC Hydro’s last wind integration study, no adjustment made for transaction costs (such as transmission and real power losses), lack of evidence of lost Powerex opportunity sales as a result of increased wind integration, scheduling changes decreasing the need for wind reserves and the Pan-Canadian Wind Integration Study results on BC wind integration potential.

For the reasons above, the Panel disagrees with CEC’s submission that “it is not appropriate to disregard the BC Hydro evidence as to the likely costs that will be experienced with wind integration” and that “BC Hydro will have BC specific costs actual costs that can be examined to assess future wind integration costs.” To the extent BC Hydro does have updated BC specific lost opportunity costs, the Panel has not been provided with them.

The Panel also finds that, as wind projects are charged $1/MWh for the cost of wind integration, Site C should be provided a similar credit to reflect the potential export of this service into neighbouring jurisdictions. Based on BC Hydro’s submission that Site C can integrate 90 0MW of wind, the Panel estimates that this will result in a credit of $3.36 million per year to Site C’s cost in the Commission’s model.[772]

[772] Low load forecast wind projects in the Illustrative Alternative Portfolio having 444 MW of capacity and 1,656 GWh/year of energy. The annual cost of wind integration for this portfolio at $1/MWh would be $1.656 million, and so 900 MW of wind would have a wind integration cost of $3.36 million.

1.2.4 Energy focused DSM

1.2.4.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submissions

BC Hydro states:

> One of the obvious ways for a utility to address load growth is to try to reduce and shift demand for electricity. Utilities all over the world, including BC Hydro, invest in initiatives to achieve this outcome, and that such initiatives are referred to as "demand-side management", or DSM.[773]

In BC Hydro's 2013 IRP, BC Hydro modelled five levels of DSM spending, including:

- Option 1 was the minimum level of DSM required to meet the Clean Energy Act target of reducing BC Hydro's expected increase in demand by the year 2020 by at least 66 percent; and
- Option 2 was to maintain the target in the 2008 Long Term Acquisition Plan of 7,800 GWh/year of energy savings and 1,400 MW of capacity savings by F2021. These targets included energy savings from codes and standards and rate design (55 percent of the total), as well as DSM programs (45 percent).

For the purpose of this Inquiry, BC Hydro modelled increased levels of DSM spending based on moving to Option 2 in the 2013 IRP (IRP DSM Plan) and a higher level of DSM spending (IRP DSM Plan Plus) which was informed by the work performed to date from the Conservation Potential Review (CPR).[774] These options were treated as adjustments to the load forecast rather than supply side alternatives.[775]

Deloitte report

Deloitte considered that BC Hydro could take a more aggressive approach to DSM and noted:

> BC Hydro's overall energy savings from DSM programs as a percentage of retail sales was 0.6 percent for the period 2014-201653. The 2017 American Council for an Energy Efficient Economy (ACEEE) benchmarking report of U.S. utilities estimates an average of 0.9% savings can be achieved, with leaders demonstrating savings of 1.5%to 2.9%. While numerous jurisdictional variances such as climate, political, and socioeconomic factors make direct comparisons difficult, this illustrates that BC -savings performance is below the industry average.[776]

Deloitte also noted that BC Hydro's residential program spending in particular is significantly below other jurisdictions.[777] Deloitte also compared the breadth and type of efficiency programs offered by BC Hydro to those in the 2017 ACEEE report and comments that while some of these are already being pursued by BC Hydro, many are not.[778]

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[773] F-1 Submission, Appendix L, p. 5.
[774] F-1 Submission, Appendix L, pp 7–11.
[775] Ibid., Appendix Q, p. 2.
[776] A-9 Submission, p. 52.
[777] Ibid., p. 53.
[778] Ibid., p. 55.

Deloitte modelled increasing DSM spending levels Option 3 in the IRP through an adjustment to the load forecast rather than as a supply side alternative.[779]

Other submissions

BCSEA submits that the "Without-Site C" portfolio should include all DSM energy savings that are (a) cost-effective in modified total resource cost terms; and (b) less expensive than the least-expensive supply-side resource.[780] Swain submits that BC Hydro can meet any likely shortfall in supply by ramping up DSM again, especially if BC Hydro takes advantage of the encouragement to use rate structures embodied in section 2(b) of the *Clean Energy Act*.[781]

CCPA submits that conservation is clearly the most cost-effective way of meeting new demand.[782] Dauncey submits BC Hydro's investments in DSM have been successful at a cost of 5 cents/kWh, which Dauncey submits is cheaper than any known method of developing new power.[783]

Bakker submits that the cumulative effect of BC Hydro's decisions to moderate DSM during and following the 2013 IRP is more than 3,000 GWh/year and 600 MW by F2024, and that this is more than 50 percent of the Site C project.

Prophet River and West Moberly First Nations submitted a 2014 report by the Helios Centre as an attachment to their submission. This report states that, by the mid-2020s, choosing DSM Option 3 over DSM option 2 would result in additional savings of over 200 MW of capacity and over 1,200 GWh-year of energy.[784]

1.2.4.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel agrees with BC Hydro and other parties that one of the obvious ways for a utility to address load growth is to try to reduce and shift demand for electricity. However, what is important to the Panel is how much additional energy savings are available through DSM, and at what cost.

The Panel asked BC Hydro to identify:

- how much energy and associated capacity was included in the two options modelled (IRP DSM Plan and IRP DSM Plan Plus), with IRP DSM Plan Plus treated as incremental to the IRP DSM Plan. Energy and capacity savings should be grossed up for distribution losses; and
- the associated utility costs rather than the total resource cost as the focus of this review is on costs to ratepayers (rather than broader BC benefits).

Other parties were also invited to provide their own estimates of DSM portfolio options (clearly stating the cost and energy /capacity savings associated with each DSM "cost bucket") in a format that would allow it to be evaluated against supply side options.

[779] A-9 Submission, p. 52.
[780] F29-3 Submission, p. 17.
[781] F36-1 Submission, p. 13.
[782] F60-1 Submission, p. 10.
[783] F62-1 Submission, p. 8.
[784] F28-2 Submission, Tab 5, Helios Centre, p. 7.

1.2.4.3 Relevant new information

In response to the Preliminary Report question, BC Hydro provided estimated annual energy savings associated capacity savings, utility cost and total resource cost from two DSM options: (i) IRP DSM incremental to RRA DSM; and (ii) IRP DSM Plus Incremental to IRP DSM.[785]

This data was used in the Illustrative Alternative Portfolio model. Energy efficiency DSM was treated as a supply side alternative rather than an adjustment to the load forecast, and the following assumptions were used:

> This energy efficiency option represents BC Hydro's Integrated Resource Plan (IRP) DSM Incremental to RRA DSM option.786 Energy volumes have been grossed up by 11% for avoided real power losses to be comparable to wind plant gate supply side options.787
>
> For the purpose of comparison to Site C costs, societal costs/benefits of energy efficiency DSM have not been included. However, it is assumed that energy efficiency DSM programs in this portfolio would pass the total resource cost test (i.e. BC energy savings exceed BC costs). The cost of energy efficiency DSM has therefore been included at the utility cost to BC Hydro (i.e., it includes the cost to BC Hydro of an incentive to encourage customers to install efficient lightbulbs, rather than the cost of the lightbulbs before the incentive). Costs are deferred and amortized over 15 years. [788]

The Alternative Portfolio reflects a "plant gate" cost.

BC Hydro raised the following key issue with the DSM assumptions used in the Illustrative Alternative Portfolio model:

> … BC Hydro expects to pursue additional DSM with or without Site C. … As such, Site C will only change the timing of when DSM activities occur, not their overall level. … replacing Site C with incremental DSM may be representative of the short-term differences between portfolios (e.g., over a five-year timeframe), it is not sufficient for the long-term (e.g., years 6 to 70). … wind and pumped storage are the true alternatives to Site C over the long term. …
>
> Isolating the correct treatment of energy-focused DSM results in portfolio costs approximately $215 million higher on a present value basis than in the [strawman] portfolio. … The impact of changes to the treatment of DSM would increase substantially with more realistic assumptions regarding the costs of alternative [wind and battery] resources …[789]

In addition, BC Hydro raised the following methodological issues with the portfolio assumptions:

- the energy-focused DSM volumes double-count loss savings as they are already grossed up to the system level to reflect losses;
- the total resource cost should be used to compare DSM to other resource options, and not the utility cost or the societal cost (which would include broader BC benefits and costs or externalities).

[785] F1-5 Submission, IR 64, Attachment 1
[786] F1-5 submission, IR 64, Attachment 1.
[787] Wind transmission losses are $9/MWh on a levelized firm energy price of $83/MWh (F1-1 submission, Appendix L, pp. 19, 20).
[788] A22 submission, pp. 5, 6.
[789] F1-17 submission, pp. 4–9.

BC Hydro submits that this underestimates the NPV of the cost to ratepayers of $220 million over the period to 2047;[790]

- For the industrial load curtailment program, BC Hydro estimated the utility cost at $75/kW-year and the total resource cost at $60/kW-year;[791]

- BC Hydro requires a 14 percent reserve requirement from generating resources (such as Site C or wind), which is not required from DSM resources. The strawman portfolio therefore has more DSM capacity resources than would be required; and
- the strawman portfolio has erroneously applied DSM costs one year later than the associated savings. This understates its cost.[792]

BCSEA notes that in the Commission's recent review of BC Hydro's F2017-F2019 RRA, BC Hydro argued against increasing the amount of cost-effective DSM that it would seek to acquire in the test period. [793] In the F2017-F2019 RRA, BC Hydro stated that its determination not to pursue higher levels of program DSM expenditures was driven by changing system needs (BC Hydro's load resource balance showed a reduced need for additional resources than what was forecast in the 2013 Integrated Resource Plan), and the impact to the 2013 10 Year Rates Plan.[794]

BC Hydro also stated in the F2017–F2019 RRA that:

- there was no need for additional cost-effective demand-side management at this time due to the reduced forecast need for additional resources in the short-term.[795]
- BC Hydro added an extra Utility Cost Test screening filer using the B.C.-border sell price forecast as the avoided energy cost steam (approximately $36 per MWh) in order to prioritize DSM investments.[796]
- with Site C, BC Hydro expects to be in an energy surplus situation until F2032 in the medium load forecast scenario, and in F2036 will have a surplus of 3,746 GWh/year in the low load forecast scenario.[797]

Swain proposed an Alternative Portfolio with "Deep DSM," up to 9,600 GWH/year, at under $50/MWh, almost double of Site C.[798]

Bakker put forward an Alternative Portfolio that included the IRP DSM plan, stating "Like the BCUC [Illustrative Alternative Portfolio], we have used the additional costs and savings flowing from using the IRP DSM portfolio instead of that found in the RRA. We have also explored, as an option, the use of the IRP PLUS DSM portfolio, again using its marginal costs and savings in relation to the RRA figures."[799]

[790] F1-5 Submissions, IR 64.
[791] F1-11, IR 73.
[792] F1-17 submission, pp. 26-29.
[793] F29-9, p. 43.
[794] BC Hydro F2017-2019 Revenue Requirement Application, Exhibit B-20, p. 18.
[795] Ibid., BC Hydro Final Argument, p. 108.
[796] BC Hydro F2017-2019 Revenue Requirement Application, Exhibit B-1-1, p. 10-19.
[797] Ibid., Exhibit B-1-1, p. 3-31.
[798] F315-1, p. 2.
[799] F106-11, p. 3.

Naikun cautions the Commission in relying too heavily on BC Hydro's evidence for both the cost and effectiveness of its DSM programs and submits that DSM tends to be a diminishing resource, which becomes exhausted a it penetrates the market.[800]

Bass submits that the DSM performance of BC Hydro has been weak, and that the amount it has invested in DSM has been less than the average utility in the ACEEE and much less than that group's leading utilities.[801]

CEABC and CanWEA consider the strawman energy efficiency DSM assumptions to be reasonable.[802]

1.2.4.4 Panel analysis and findings

The Panel finds that, with the exception of the reserve requirement adjustment, the energy efficiency DSM assumptions included in the Illustrative Alternative Portfolio model are reasonable.

The Panel considers that inclusion of DSM as part of the Alternative Portfolio (as opposed to an adjustment to the load forecast) is consistent with the OIC 3(b)(iv) requirement that the alternative portfolio be comprised of "commercially feasible generating projects and demand-side management initiatives."

The Panel acknowledges BC Hydro's concern that the Alternative Portfolio may be only advancing DSM initiatives that would otherwise have occurred, and that while incremental DSM may be representative of the short-term differences between portfolios (e.g., over a five-year timeframe), it is not sufficient for the long-term (e.g., years 6 to 70).

However, the Panel notes that with Site C, BC Hydro forecasts to be in an energy surplus position until F2032 in the medium load forecast scenario and still have a significant surplus in F2036 (3,746 GWh/year) in the low load forecast scenario. The Alternative Portfolio will therefore not be advancing DSM for a five-year period, but for 14 years (medium load forecast) to over 20 years (low load forecast). The Panel does not consider it reasonable to exclude DSM from consideration in the Alternative Portfolio on the basis that BC Hydro will eventually be undertaking the DSM program more than 20 years down the road.

Regarding the use of the utility cost compared to the total resource cost, the Panel agrees that BC Hydro should not be undertaking DSM programs that do not pass the total resource cost test. For example, a DSM program to encourage customers to use LED lightbulbs would need to demonstrate that the cost of the LED lightbulb is less than the long-run marginal cost of the associated energy savings.

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.

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

[800] F272-2, p. 6.
[801] F267-2, p. 1.
[802] F104-1, p. 1; F18-6, p. 4.

cost to the industrial customer of curtailing supply (total resource cost), instead of the cost to the utility of obtaining the curtailment (utility cost).

The Panel disagrees with BC Hydro that energy-focused DSM volumes have double counted the loss savings. DSM volumes provided by BC Hydro were grossed up for distribution losses, however the Alternative Portfolio location is at the Site C plant gate. A gross up for avoided transmission losses is therefore appropriate.

The Panel agrees with BC Hydro that the Illustrative Alternative Portfolio should be adjusted for the 14 percent reserve requirement that is required by generating resources (such as Site C or wind) but not from DSM resources, **and for the one year delay between DSM costs and associated savings**.

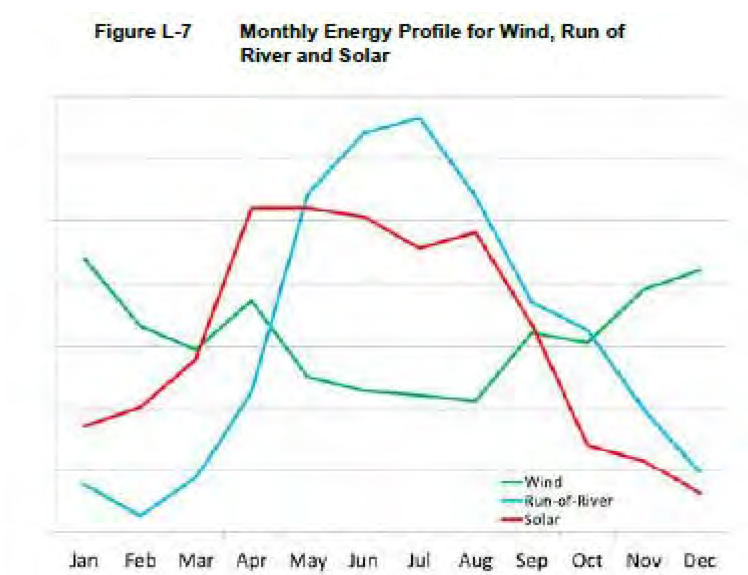
1.2.5 Run-of-river

1.2.5.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro states that run-of-river hydroelectric projects do not have any material amounts of water storage, meaning that their output varies with the natural flow in the river. Although BC Hydro includes run-of-river hydro projects for its alternative portfolio, it reports the "adjusted UEC" as $124- $2,430/MWh. Further, it suggests that a large portion of run-of-river energy is delivered during freshet, which is a period of low energy value. BC Hydro provides the table below to illustrate.[803]

Figure 38: Monthly Energy Profile for Wind, Run-of-River and Solar



As a result, the cheapest alternative portfolio contains no run-of-river projects.

[803] F-1 Submission, Appendix L, p. 28.

Deloitte report

Deloitte submitted that estimates of run-of-river hydro costs vary greatly, between $2,700/kW to more than $8,000/kW depending on the remoteness of the area, with estimated fixed O&M costs of $40/kW-yr.[804]

Other submissions

Kleana Power Corporation describes its proposed run-of-river hydroelectric facility located on Klinaklini River. This project has a nameplate capacity of 565 MW delivering 2,450 GWh of annual energy. The point of connection to the BC Hydro transmission grid is located at Campbell River. Kleana submits it has the water rights to and that, if developed, would be one of the largest run-of-river independent power projects in North America. Kleana compares its project's footprint to that of Site C in the following table:[805]

Figure 39: Footprint of Kleana vs Site C

	Site C	Kleana
Energy:	5100 GWh	2450 GWh
Land Footprint:	9100 -10000Hectare	1100 Hectare
Energy Intensity (GWH per Hectare):	0.56-0.51 GWH per Hectare	2.22 GWh per Hectare

Kleana states that the project will benefit from superior catchment characteristics by virtue of glacial summer runoff and non-glacial winter precipitation (as compared to typical run-of-river projects). In addition, the project's hydrology "is expected to benefit from climate change which is opposite of the expected impacts of the interior of BC."[806]

Kleana submits that its project is a preferred alternative to Site C because:

- It is a more cost effective alternative to Site C;
- It is smaller than Site C, and therefore has a lower risk of creating excess supply;
- There is no cost overrun risk to rate payers and cost to build and operate is the responsibility of the Owners;
- It has lower actual costs (see "Factors Influencing Costs"…below), lower impacts (which must be included in cost analysis), and lower future risk associated with Climate Change;
- It has a more effective delivery point and massive savings in system losses due to backfeed to Vancouver Island; and
- It has the support of the affected indigenous peoples.[807]

Kleana Power Corporation also submits that Kleana can be a compliment or partial alternative to Site C, stating that:

> [c]onsidering the history and facts around the Kleana Project, good engineering practice would have integrated the Kleana Project into an optimization study to determine the optimal size for Site C. This would have potentially reduced the size of the flooded area by the Site C project. Not only can the Kleana Project deliver 48%of the energy of Site C (2450

[804] A-9 Submission, p. 25.
[805] F53-1 Submission, p. 2, 6.
[806] F53-1 Submission, p. 25
[807] F53-1 Submission, p. 3.

GWh vs 5100 GWh), it delivers this energy to the City of Campbell River on Vancouver Island. This is very important strategically for dependable energy delivery, reduced transmission cost and impact.[808]

Kleana Power Corporation states that while BC Hydro's frequently refers to "Dependable Capacity," their equivalent concept for wind and run-of-river projects is "Effective Load Carrying Capacity" (ELCC). Citing pages 3 to 4 of BC Hydro's 2013 IRP, it submits that BC Hydro uses ELCC to represent the capacity contribution from intermittent clean or renewable IPP resources such as wind and run-of-river hydro.

Kleana submits that Table 3-13 of BC Hydro's 2013 IRP illustrates that 24 percent is the ratio of ELCC to Installed Capacity for potential run-of-river projects in the Vancouver Island Transmission Region (420 MW of ELCC / 1754 MW of Installed Capacity). Based on this data from BC Hydro, the equivalent dependable capacity of Kleana is 135 MW (24 percent of 565 MW).[809]

1.2.5.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel invited BC Hydro to respond to the submission of Kleana Power Corporation and invited parties to provide submissions on specific project data (including capital and operating costs, capacity factor and economic life) on potential Run-of-river projects.

1.2.5.3 Relevant new submissions

In response to the question raised in the Preliminary Report, BC Hydro provided background information on its experience with Kleana and a UEC analysis which it stated "reaffirms our conclusions that due to development risks and cost uncertainties the Kleana project is not economic when compared to other lower cost clean alternatives with or without Site C."[810]

BC Hydro explains that on May 6, 2010, it advised Kleana that it had completed an evaluation of Kleana's proposal submitted under the 2008 Clean Power Call Request for Proposals, and that the proposal had not been successful and was no longer under consideration for an award of an EPA, primarily because the project presented an "unacceptably high level of development risk." BC Hydro further explains that Kleana subsequently brought forward a number of judicial reviews and appeals, which were dismissed. BC Hydro states that in dismissing Kleana's appeal, the BC Court of Appeal also rejected the premise that BC Hydro should be required to enter into agreements to purchase energy based on set prices free of Commission approval. Kleana's application for leave to appeal to the Supreme Court of Canada was dismissed in 2016.[811]

Regarding the UEC of Kleana's run-of-river project, BC Hydro states that using information in Kleana's submission (F53-1) and in its submission in the 2008 Clean Power Call would produce an adjusted UEC of approximately $112/MWh ($2018). If BC Hydro included Kleana in the Block UEC analysis, it would result in a levelized UEC of approximately $154/MWh, which is not materially different from the $153/MWh alternative block cost using pumped storage and wind put forth by BC Hydro in its August 30, 2017 submission. Therefore, BC Hydro states that including the Kleana project would not alter its conclusions reached in its August 30, 2017 filing.[812]

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[808] F53-1 Submission, p. 4.
[809] F53-1 Submission, p. 25 of 134.
[810] F1-5, IR 2.65.0.
[811] F1-5, IR 2.65.0.
[812] F1-5, IR 2.65.0.

Kleana disputes BC Hydro's submissions and submits that it remains a strong competing alternative to Site C.[813]

1.2.5.4 Panel analysis and findings

The Panel considers there to be a large amount of uncertainty regarding the Kleana Power project, including the legal issues described by BC Hydro in IR 2.65.0. Accordingly, the Panel makes no findings on the viability of the Kleana Power project as an alternative to Site C.

1.2.6 Biomass

1.2.6.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro submits that "[w]ood based biomass generally provides firm energy and dependable capacity. However, cost effective fiber (therefore energy potential) is limited and its long term availability is uncertain due to the many competing uses of fiber – both existing and emerging uses.

BC Hydro submits that it:

> …updated an assessment in 2015 of wood-based biomass. The assessment included a review of the wood-based biomass (fiber) potential, the performance of technologies for biomass electricity generation, and updated cost information and associated unit energy costs. The assessment showed a marked decline in the forecast availability of fiber for new potential bioenergy projects and an increase in cost for pulp logs. The primary drivers of a decreased forecast of fiber available are the closure of many sawmills, construction of new pellet plants, and reductions in annual allowable cut (AAC) sooner than anticipated.[814]

BC Hydro submits that its estimated unit energy cost is $122 / MWh (at the POI in 2018 dollars) and up. In comparison, the average levelized plant gate price for firm energy in the last BioEnergy Call (i.e. Bioenergy Phase 2 Call in 2010/2011) was $132/MWh (in 2018 dollars, escalated from $123/MWh in F2013 dollars).

BC Hydro provides the following table showing biomass potential by region:[815]

[813] F53-2, p. 1.
[814] F1-1 Submission, Appendix L, pp. 23, 24.
[815] F1-1 Submission, Appendix L, pp. 23-24.

Table 58: Wood-based Biomass Results Summary by Region

Region	Number of Resource Options	Total Installed Capacity (MW)	Dependable Capacity or ELCC (MW)	Annual Energy (GWh/yr)	Annual Firm Energy (GWh/year)	UEC at POI ($/MWh)	Adjusted UEC ($/MWh)
Selkirk	2	49.0	49.0	395.0	395.0	122 - 157	131 – 168
North Coast	10	271.8	271.8	2164.7	2164.7	125 - 311	133 – 331
Peace River	5	149.6	149.6	1192.2	1192.2	148 - 239	165 – 266
Lower Mainland	1	63.0	63.0	503.0	503.0	150	147
East Kootenay	1	12.0	12.0	97.0	97.0	154	165
Central Interior	2	6.0	6.0	46.0	46.0	165 - 166	177 – 177
Totals	**21**	**551.3**	**551.3**	**4397.9**	**4397.9**	**122 - 311**	**131 – 331**

Deloitte report

Deloitte submitted that estimated capital costs for biomass generation range from $4,400 to $7,700/kW in BC, depending on the type of generation technology used; fixed operating costs may range from $40 to $160/kW-year; variable O&M costs range from $5 to $20/MWh; and fuel costs (including the costs to source and transport wood-based biomass) would vary depending on the distance from the source.[816]

Other submissions

The Pulp and Paper Coalition (PPC) states that:

> According to BC Hydro's wood based biomass report (July 2015) for the 2015 Integrated Resource Plan Update, there is almost 200 MW of additional biomass power potential in BC (not including standing timber) over and above the existing EPAs under contract. This does not include additional biomass potential from higher forest utilization rates and use of biomass pellets that are currently exported from BC to produce green power in other countries.

PPC provides the table below to demonstrate that Biomass power has many key attributes that distinguishes its value from other sources of electricity.[817]

[816] A-9 Submission, p. 29.
[817] F78-1 Submission, p. 1.

Table 59: Generation-type characteristics

Type of Power Producer	# of EPAs	Firm	Freshet Dispatchable	Supports Cogeneration	Renewable	Near Major Users
Run of River Hydro	70	☒	☒	☒	☑	☒
Storage Hydro	14	☑	☒	☒	☑	☒
Wind	8	☒	☒	☒	☑	☒
Biogas	7	☑	☒	☑	☑	☑
Energy Recovery Generation	4	☒	☒	☑	?	☑
Gas Fired Thermal	4	☑	☑	☑	☒	☑
Municipal Solid Waste	1	☑	☒	☑	☒	☑
Solar	1	☒	☒	☒	☑	☒
Biomass	19	☑	☑	☑	☑	☑

PPC states in summary:

- BC Hydro's current position on biomass EPA renewals will place at risk:
  - the volume of dispatchable renewable power;
  - employment, especially in rural communities; and
  - competitiveness of the BC Forest Products sector.
- Given the overarching benefits of biomass EPAs, there is a need to coordinate BC Hydro EPA prices for biomass power and BC Government policies to reflect the full value of biomass electricity generation to the province and its rural communities while protecting rate payers from unsustainable inflation.[818]

Allied Hydro states that a 2005 study of feedstock availability and power costs associated with using BC's beetle-infested pine estimated the bioenergy cost at $70/MWh. AHC estimated that the cost for 2017 would be about $70/MWh.[819]

1.2.6.2 Panel analysis, preliminary findings and questions in the Preliminary Report

Based on BC Hydro's submission, the Panel finds that biomass is eligible for inclusion in an alternate portfolio. It is firm, dispatchable and has a relatively low UEC. However, BC Hydro also states that the availability of source fibre is limited and its long term availability is uncertain. **BC Hydro is requested to confirm this conclusion is current and up to date.**

Parties are invited to provide updated costing data (capital, O&M, capacity factor) and long term availability estimates for biomass.

1.2.6.3 Relevant new submissions

BC Hydro submissions

BC Hydro confirms that its conclusions are current and notes that it is in the process of commissioning an updated analysis of biomass fuel availability. BC Hydro further states that its assessment of the availability of cost-effective biomass fuel sources, which was provided in Appendix L of its August 30, 2017 filing, is based

[818] F78-1 Submission, p. 1.
[819] F24-1 Submission, p. 20.

on the most current information available at the time, which is a July 2015 report by Industrial Forestry Services titled, "Wood Based Biomass in British Columbia and its Potential for New Electricity Generation."[820]

BC Hydro provides the following table which summarizes the fibre availability and delivered cost for 2026-2040 by region. BC Hydro submits that the below table demonstrates that there is a large range in pricing and availability across the regions depending on the fibre source. BC Hydro also points out that key insights from the consultant reports and industry experts reinforce that there is considerable uncertainty in forecast values.[821]

Table 60: Potential Biomass Energy and Delivered Fibre Cost by Fuel Category, Region in 2026-2040[822]

Period	2026 - 2040							
Biomass Type	Sawmill Waste		Roadside Residues		Pulplogs		Standing Timber	
Region	GWh/ Year	Delivered Fiber Cost ($/MWh)	GWh/ Year	Delivered Fiber Cost ($/MWh)	GWh/ Year	Delivered Fiber Cost ($/MWh)	GWh/ Year	Delivered Fiber Cost ($/MWh)
Coast - Mainland	37	$25	523	$55				
East Kootenay			97	$58				
West Kootenay	220	$25	187	$58				
Kamloops/Okanagan								
Cariboo			17	$52				
Prince George								
Mackenzie			29	$63				
South Peace	9	$32	163	$54	99	$84		
North-east							921	$134
East Prince Rupert	9	$20	1	$55	199	$84	49	$108
West Prince Rupert	21	$18	17	$54	65	$97	1718	$125
North-west							86	$134

With regard to plant costs, BC Hydro submits that the costs vary significantly depending on the type of generation technology and whether the project is cogeneration. BC Hydro states that its estimates are based on greenfield standalone projects due to expectations that there would be a limited number of available steam hosts:

- Capital Cost – BC Hydro modeled a capital cost of $5,400/kW based upon net plant output MWs.
- Operating, Maintenance and Adminstration (OMA) Costs – BC Hydro modeled $130/kW-year ($120/kW-year gross) for the fixed annual OMA cost and $7/MWh for variable OMA.
- Capacity Factor – BC Hydro modeled a net 91 percent capacity factor.[823]

[820] F1-11, IR 2.66.0.
[821] F1-11, IR 2.67.0.
[822] F1-11, IR 2.67.0.
[823] F1-11, IR 2.67.0.

Other submissions

PPC submits that biomass cogeneration, as opposed to standalone greenfield biomass generation, is the only resource option available to BC Hydro that provides reliability with the following attributes:

- Dependable generation with the capacity for firming, shaping and storage;
- Cost effective and connected to the grid near major users; and
- Renewable as defined by being GHG neutral.[824]

PPC asserts that biomass energy sales:

> is an outcome of the government strategy of increasing forest utilization and is critically integrated into the forecast sector supply chain"; thus, "as a minimum, 100% of the existing biomass cogeneration Electricity Purchase Agreements (EPAs) need to be renewed to preserve the value of the integration of the forest industry and mitigate the load attrition risk of major forest products customers whose EPAs may not be renewed.[825]

PPC further submits that fuel risk associated with biomass energy sales by forest companies is manageable and is already being taken on by the proponents, and there is likely opportunity for some growth. PPC notes that BC Hydro has 730 MW and 2,600 GWh of generation of biomass cogeneration under EPAs.[826]

In response to the questions and preliminary findings in the Preliminary Report, PPC submits that it believes that biomass fuel supply dynamics, which are a key component of the forest industry integrated supply chain, are not well understood outside of the sector and that the issue of fuel availability can be readily managed by the forest companies. PPC makes the following points:

- Fuel risk is to the proponent's account – EPAs have been structured so the proponent takes the fuel risk in the form of Liquidated Damages for delivery shortfall – not BC Hydro. PPC asserts that BC Hydro should plan to renew 100% of the existing biomass generator fleet capacity while allowing for an opportunity to reshape generation profiles based on biomass supply situation and flexibility for each generator.
- Increased Forest Utilization will increase Fuel Supply – The recent government policy announcement to apply a carbon tax to slash pile burning effective April 1, 2018 appears to be a clear signal that the government wants more biomass to come out of the forest and it is reasonable to assume that the impact of this change will increase the available fuel for bioenergy.
- Efficiency Improvements Reduce Biomass Requirements – Equating fuel supply to generating capacity is an oversimplification of future bioenergy potential. Conversion efficiency, the amount of electricity output per mass of biomass fuel input, of mills across the province varies widely and all mills have varying opportunities to improve their conversion efficiency.
- Regional Fuel Availability is Variable – The BC Forest Industry is diverse with supply and demand balances that vary across its unique regions and commercial environments. Excess fuel supply is a greater issue in the foreseeable future with many suppliers being forced to stockpile or landfill biomass due to an imbalance in demand from biomass boilers.
- Fibre Availability is not the Same as Fuel Availability.[827]

[824] F78-2, p. 1.
[825] F78-2, p. 1.
[826] F78-2, p. 1.
[827] F78-2, pp. 2-3.

PPC submits that it appears that BC Hydro's portfolio analysis was based on the Phase 2 Bioenergy Call, which only considered greenfield biomass IPPs. PPC submits that these plants are inherently more expensive than cogeneration facilities due to the economy of scale and the higher thermal efficiency of an integrated facility with an on-site steam host for the steam and heat extracted from the turbine. The Phase 1 Bioenergy Call was a competitive process that was open to all potential proponents, and this call provides a good benchmark for the price of bioenergy in the province at that point in time and would be an indicator of the high end of the potential price range presently. PPC submits that a breakdown of the detailed costing data for an integrated facility is not practicable since each facility is unique in terms of the characteristics of its steam demand, boiler design, fuel quality and turbine design. The estimate of capacity factor is similarly complicated since the capacity of an integrated site is a function of the generator capacity, boiler capacity and steam load at the site – all of which can have seasonal factors of various magnitudes. PPC concludes that the cost of an integrated facility is a function of many site-specific factors and therefore an open call process provides the best reference point; however, it is fair to assume that the UEC of biomass cogeneration would be significantly lower than a standalone plant as contemplated in the Phase 2 Bioenergy Call.[828]

1.2.6.4 Panel analysis and findings

The Panel finds that biomass projects could reduce the NPV of the strawman alternative portfolio.

1.2.7 Solar

1.2.7.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

Solar power is generated from sunlight using photovoltaic cells (PV) – either crystalline silicon or thin film. BC Hydro states that the cost of solar photovoltaic (PV) generation has been declining significantly in recent years and is expected to continue to decrease in the near to mid-term future as the global installed capacity continues to increase. BC Hydro states that, unlikely large hydro, solar does not have the ability to quickly change output in response to changes in customer demand and output from variable generation resources. [829]

Regarding current and future costs, BC Hydro provides the following estimates for utility scale PV solar:

- Capital cost: $1.64/W for utility scale solar (lower than $3.5/W estimated for rooftop solar);
- Unit energy cost: $133/MWh to $182/MWh; and
- Future cost declines: F2025 cost of $97/MWh (for Cranbrook), with a range of $82 - $114. [830]

BC Hydro states that it excluded solar from its portfolio of alternative options to Site C as costs are currently uneconomic and there is long-term uncertainty of technology cost declines. [831]

[828] F78-2, pp. 3-4.
[829] F-1 Submission, p. 42, Appendix L, p. 38.
[830] F-1 Submission, Appendix L, pp. 4, 39, 50.
[831] F-1 Submission, Appendix L, pp. 4.

Deloitte report

Deloitte also notes that solar PV prices have fallen significantly over the past several years, and are expected to continue to decline for the next few years. Deloitte makes the following assumptions for a 5MW utility solar PV installation:

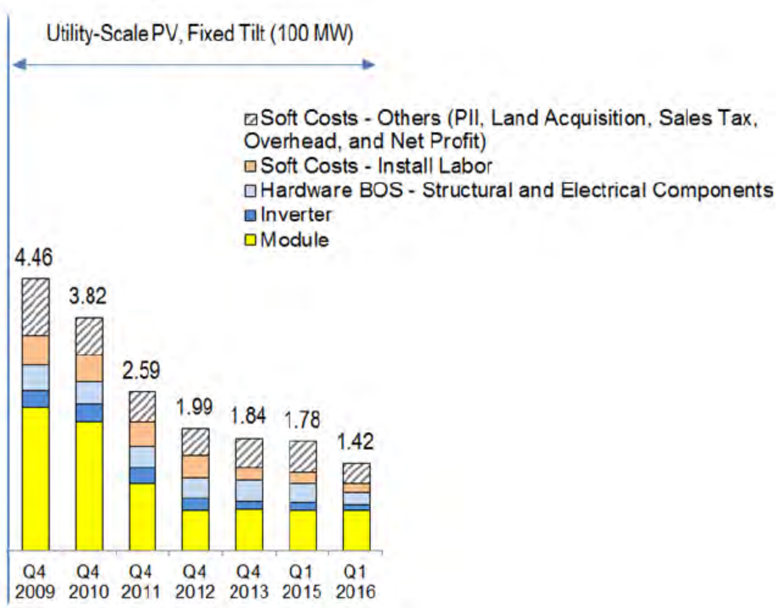
- Capital cost: $2.9/W
- Operating and maintenance cost: $18/MWh
- Capacity factor: 20 percent
- Future cost declines: 35 percent decrease in cost over the next 10 years

Deloitte also note that solar PV has been shown in a recent California study to provide frequency response and voltage support with appropriate controls.[832]

Other submissions

Many participants noted in their submissions the recent significant decreases in the cost of utility scale energy and projected future cost declines. CanWEA and CEABC provided the following charts showing past capital cost declines:

Figure 40: PV System Cost Summary (2016 USD/Watt DC) [833]



Source: NREL, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016

Participants put forward estimates of current solar costs. Peace Valley Landowner Association referenced a Lazard December 2016 report (Levelized Cost of Energy Analysis) which estimated costs for solar PV at Can $57.50 - $76.25/MWh. [834] The District of Hudson's Hope states that the end of the year it will have installed what will be the largest municipal solar project in British Columbia, with total peak output of approximately 500 kW and submits that solar has enormous potential for expansion throughout the province. [835]

[832] A-9 Submission, p. 21 (California ISO).
[833] F18-3 Submission, Appendix I, p. 9.
[834] F35-2 Submission, p. 8.
[835] F41-2 Submission, p. 2.

Participants also put forward a variety of estimates of future cost declines, including:

- CanWEA and CEABC referenced a 2016 GMT research report that expects a 27 percent drop in average global project prices by 2022(about 4.4 percent each year); [836]
- Bakker referenced a Bloomberg New Energy Finance 2016 forecast of a 60 percent decline in utility-scale solar PV prices by 2040, and submitted that a 60 percent decline would see unit energy costs drop to $60/MWh in the most cost effective locations in BC in the next 10 to 20 years; [837]
- CCPA and Dauncey referenced an International Renewable Energy Association report that predicts the cost of utility scale solar to be [US] $60/MWh in 2025 as a result of continued technological improvements, economies of scale and greater competition; [838]
- Dauncey referenced a Greentech report 2016 which forecast that the installed cost of utility-scale solar will fall to [US] $1.00/watt by 2020; and a 2017 Deutsche Bank report estimate of [US] 70c/watt by 2022;[839] and
- CEC referenced an EPIA estimate of a 2020 capital cost of utility solar of US $1.8/watt by 2020 and $1.06 –$1.38/watt by 2030, and a IEA estimate for the same dates of $1.8/watt and $1.2/watt. [840]

Dauncey submits that in Germany, with similar solar radiation to BC, solar PV supplied 7 percent of the electricity in 2016. Duncey submits that if solar PV was to provide 7 percent of BC's energy in 2030 (forecast by BC Hydro to be 75,000 GWh), it would produce 5,250 GWh a year. Dauncey also notes continued solar PV technological improvements that could future improve efficiency, such as the use of smart inverters to allow the utility to control energy entering the grid, and 'floating solar' (for example, floating on an existing hydro reservoir) which can act to cool the solar electronics making it more efficient. [841]

Island Transformations also notes the solar PV cost decline, and submits that overall solar radiation in Victoria is 4.0 kWh/m^2, compared to Phoenix of 6.5 kWh/m^2.

1.2.7.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel found there have been significant declines in the cost of utility scale solar over recent years, and that further declines are expected. The Panel is concerned, however, that BC Hydro's utility solar cost estimate of $133/MWh to $182/MWh may not have been updated to reflect BC Hydro's estimate of the current capital cost of utility solar at $1.64/W and so may have prematurely excluded utility solar PV from further consideration.

The Panel therefore sought input from BC Hydro and other participants on PV costs and asset life.

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836 F18-3 Submission, Appendix I, p. 10.
837 F106-1 Submission, pp. 95, 96.
838 F60-1 Submission, p. 13.
839 F62-1 Submission, p. 12.
840 F82-1 Submission, p. 34.
841 F62-1 Submission, p. 12.

1.2.7.3 Relevant new information

In response to the Panel's questions, BC Hydro states:

> There are currently no utility scale solar projects in B.C. with a capacity of at least 5 MW, therefore all estimates for utility scale solar are based on currently reported costs for utility-scale solar in the U.S. adjusted to the B.C. context. Our current estimates for utility-scale solar in B.C. are reported below, along with projected costs in F2025 and F2035. … The estimates of realized and projected future cost reductions in both installed costs and OMA are based on the projections of the National Renewable Energy Labs' (NREL) 2016 Annual Technology Baseline Report.[842]

	Current Costs ($2018)	In F2025 ($2018)	In F2035 ($2018)
Installed Cost ($/W)	1.69	1.13	1.02
Annual OMA ($/MWh)	20.60	12.12	12.12

> Solar insolation – a measure of the solar energy available per square meter over a given period – varies around the world. …
>
> - in parts of Africa and Australia, ~2,550 kWh/m2 per year are available;
> - In the sunniest parts of Germany generation is ~1300 kWh/m2 per year;
> - Pheonix, Arizona averages 1963 kWh/m2 per year;
> - Los Angeles, California averages 1971 kWh/m2 per year; and
> - in most parts of B.C. less than 1,100 kWh/m2 per year.[843]
>
> Capacity factor of solar projects is dependent on the quality of the solar resource (sunnier regions produce more kWh per kW per year) and the configuration of the facility (fixed angle vs single-axis tracker vs dual axis tracker). Below is a chart showing the range of annual energy production for different B.C. locations with different configurations.[844]

Analysis Site	Solar Potential with Fixed System (kWh/kW/a)	Solar Potential with Single-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Single-Axis Tracker	Solar Potential with Dual-Axis Tracker (kWh/kW/a)	Percent Increase from Fixed System with Double-Axis Tracker
Vancouver	1010	1224	21.2%	1386	37.2%
Victoria	1092	1364	24.9%	1570	43.8%
Kamloops	1157	1429	23.5%	1640	41.7%
Fort St. John	1157	1421	22.8%	1658	43.3%

> BC Hydro assumed Single-Axis Tracker systems for all utility-scale solar installations.[845]

[842] F1-8 Submission, IR 68.1.
[843] F1-8 Submission, IR 68.2.
[844] F1-8 Submission, IR 68.3.
[845] Ibid.

… Cranbrook presents the lowest unit energy cost of all potential solar sites by virtue of a strong solar resource relative to the rest of the province and a minimal cost of incremental transmission and road construction to the point of interconnection. … The resulting UEC in $2018 at gate and adjusted to delivery to the lower mainland is as follows:

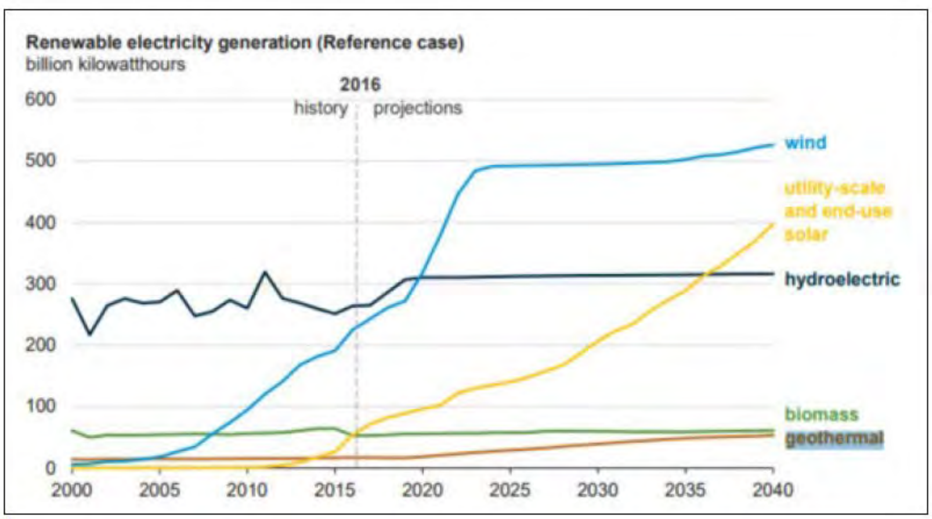
	UEC at gate ($/MWh)	UEC delivered to lower mainland ($/MWh)
5 MW Cranbrook solar in 2025	48.04	59.04
5 MW Cranbrook solar in 2035	44.31	54.72

Note that the above UECs do not include the cost of additional capacity that would be required by ratepayers, and are thus not a direct comparator to the Site C UEC.[846]

BC Hydro expects that Solar technologies still have potential for further advancement as solar manufacturing and installations continue to grow, which may translate to lower capital costs, lower costs of installation or reduced maintenance.[847]

The Peace Valley Landowner Association and the Peace Valley Environment Association quotes a Lazard, Levelized Cost of Energy Analysis (December 2016) solar cost of C$ 57.50-76.25/MWh and provides US Energy Information Agency (EIA) chart showing significant expected growth in solar investment.[848]

Table 61: Renewable Electricity Generation (Reference case)



[846] F1-8 Submission, BCUC IR 68.4.
[847] Ibid., IR 68.8.
[848] F35-2 Submission, p. 2; F35-14 Submission, p. 3.

Galiano Solar Coop referenced a NREL 2017 cost of around US 1.00/W and submits:

> … since solar panels perform better at lower temperatures, the sunshine-hour advantage for California and Arizona is decreased substantially by the decreased efficiencies in these areas where panels are working beyond their thermal optimum. In fact, a direct comparison between Abu Dhabi (3374 h/y) and Dawson Creek BC (2213 h/y), results in almost identical output by solar panels (within 10%) in these two places, once temperature compensation and non-production due to sandstorms (and subsequent clean-up) have been taken into consideration. Besides, in Dawson Creek, the albedo effect from reflection off snow cover should not be dismissed. In conclusion, large parts of BC are ideal for solar PV and it is difficult to identify true solar 'hotspots'. …
>
> Warranties on solar panels have now reached 25 to 30 years, while installations with the types of panels in current use have reached the 45 to 50 y mark and, although showing the expected light-induced decreases in efficiency (0.1% loss per y), they still produce power in the 80% range of nominal production.

Utility scale solar was not included as a generation option in the Commission's Illustrative Alternative Portfolio, however the model assumptions state: "It is acknowledged that there may be additional options that could reduce the cost of the Alternative Portfolio, such as … solar …"

In response to the Commission's Alternative Portfolio, Bakker submitted that:

- BC Hydro uses a 5 MW utility-scale solar project to represent all utility-scale solar. However, over the last four years a substantial gap has opened up, such that a 100 MW facility is now 25% less expensive on a per watt basis than a 5 MW facility;
- The current estimated cost of developing a 100-MW solar facility in Cranbrook, BC is $79/MWh based on the most recent information provided by NREL for installations in the first quarter of 2017; and
- residential solar PV (5.7 kW) and medium general service solar PV (200 kW) is projected to decline below the Tier 2 rates by 2025 in the regions of the Province having greater solar potential, including the East Kootenay (i.e. Cranbrook), the Peace Region and Selkirk (Kelowna).[849]

1.2.7.4 Panel analysis and findings

The Panel finds that utility scale solar projects have the potential to reduce the NPV of the Illustrative Alternative Portfolio, and notes that 'behind-the-meter' residential and commercial solar also have the potential to place downward pressure on BC Hydro's load forecast over time.

[849] F106-10 submission.

1.2.8 Other hydroelectric with storage

1.2.8.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro states that:

> Sections 10 and 11, and Schedule 2, of the CEA prohibit the development of the following large hydroelectric projects: Murphy Creek, Border, High Site E, Low Site E, Elaho, McGregor Lower Canyon, Homathko River, Liard River, Iskut River, Cutoff Mountain, and McGregor River Diversion. Cutoff Mountain on the Skeena River and McGregor River Diversion are also legislatively barred by, respectively:
>
> 1. the B.C. Fish Protection Act, which designates the Skeena River as a "protected river" and prohibits the construction of bank to bank dams, and
> 2. the B.C. Water Protection Act, which prohibits the construction of "large scale projects" such as McGregor River Diversion capable of transferring a peak instantaneous flow of 10 or more cubic metres per second of water between major watersheds.[850]

Other Submissions

Alaska Hydro Corporation (a company incorporated in British Columbia) is currently in the permitting stage for the construction of a hydroelectric storage dam and generating facility on More Creek in Northwest BC. The project has a design capacity of 75 MW and could be expanded to 170 MW. The current plant is projected to generate up to 348 GWh annually with a potential to increase this to approximately 446 GWh with the Forrest Kerr Creek diversion.

Alaska Hydro further submits:

- A preliminary feasibility for the More Creek project has been completed with a revision to the original dam concept. The revised cost estimate is approximately $250,000,000 or $3.4 million per MW installed. Additional turbines could be added bringing down the cost per unit installed and increasing the capacity.
- The More Creek Project, due to its significant water storage capability, provides firm capacity and energy. Accordingly, the More Creek Project closely matches the stated advantages of Site C as compared to wind, solar and run-of- river alternatives. Further the project is located is approximately 11 km from the terminus of BC Hydro's Northern Transmission line and substation at Bob Quinn Lake, closer to the electrical demand for capacity than the Site C location.
- This project has the potential to provide up 6.82 percent of the capacity of site C as currently configured or 15.45 percent if expanded. It is estimated to generate 3.16 percent of Site C energy generation as planned or 4.05 percent if the Forrest Kerr Diversion is included. The More Creek Project has completed the first phase of the CEAA process with the receipt of the EA guidelines for an Environmental Assessment Certificate and has the final draft of the EAO Sec 11 Order for the preparation of the Application Information Requirements.[851]

[850] F-1 Submission, Appendix L, p. 51.
[851] F11-1 Submission, p. 1.

- Alaska Hydro's More Creek Project was not included in the Commission's October 11, 2017 strawman Alternative Portfolio.[852] Alaska Hydro submitted that the Moore Creek Project should be included.[853]
- The Tahltan Central Government submits that the More Creek project is located wholly in Tahltan territory, that it would flood a 20 km long stretch of More Creek resulting in a destruction of riverine fish habitat and fisheries and loss of culture sites, and does not have the support of the Tahltan Nation.[854]

1.2.8.2 Panel analysis, preliminary findings and questions in the Preliminary Report

The Panel is reluctant to draw any conclusions from the material presented by Alaska Hydro.

1.3 Alternative capacity sources

This section examines the capacity generation and DSM components that were considered for inclusion in the alternative generation portfolio.

1.3.1 Market capacity purchases and thermal generators

1.3.1.1 Key submissions and issues raised in the Preliminary Report

Island Generation IPP is, according to its website, a natural-gas-fired combined-cycle 275 MW facility. It is fully contracted by BC Hydro until 2022. BC Hydro pays a fixed demand charge to ensure it is available.

BC Hydro states the following:

> BC Hydro is already reliant upon the electricity markets. BC Hydro plans to average water levels, which means that in a low water year we will be reliant upon external electricity markets. Further, BC Hydro rarely dispatches its Island Generation IPP favouring electricity imports instead due to their low costs. As a result, most of the 2,300 GWh of planned supply from Island Generation is not produced. As a result, we rely upon in excess of 6,000 GWh/year in low water years. On a capacity side, with many less known resources supplying some capacity contributions to the system like Demand Side Management and variable clean resources, *BC Hydro relies upon external markets for backup capacity supply*.[855]

The *Clean Energy Act* (CEA) section 2 states that one of BC's Energy Objectives is to generate at least 93 percent of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity. Section 6 states:

> (2) The authority must achieve electricity self-sufficiency by holding, by the year 2016 and each year after that, the rights to an amount of electricity that meets the electricity supply obligations solely from electricity generating facilities within the Province,
>
> a) assuming no more in each year than the heritage energy capability, and

[852] Submission A-22, p. 2.
[853] F11-4 Submission, p. 1.
[854] F314-14, p. 2.
[855] F1-1 Submission, Appendix L, p. 49. Emphasis added.

b) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

(3) The authority must remain capable of meeting its electricity supply obligations from the electricity referred to in subsection (2), except to the extent the authority may be permitted, by regulation, to enter into contracts in the prescribed circumstances and on the prescribed terms and conditions.

The British Columbia Climate Leadership Plan states:

> B.C.'s clean electricity supply is activating numerous opportunities to reduce GHG emissions across our industrial sectors. When an industry switches to electricity instead of fossil fuels, their emissions go down. The CLT recommended that we increase the target to 100 per cent clean energy on the integrated grid by 2025, while allowing for the use of fossil fuels for reliability. BC Hydro will focus on acquiring firm electricity from clean sources.
>
> Going forward, 100 per cent of the supply of electricity acquired by BC Hydro in British Columbia for the integrated grid must be from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. Acquisition of electricity from any source in British Columbia that is not clean or renewable must be approved by government through an Integrated Resource Plan, where it will be aligned with the specific reliability or cost concerns.

1.3.1.2 Panel analysis, preliminary findings and questions in the Preliminary Report

BC Hydro stated that it rarely dispatches supply from Island Generation because of the low cost of imports. It further states that it relies upon external markets for backup capacity supply. It is difficult to understand how purchasing backup capacity can be cheaper than dispatching from a facility with which it has a take or pay contract. BC Hydro is requested to please explain under what circumstances Island Cogeneration has been dispatched in the past three years and how much energy has been purchased from the facility.

The Panel requested that BC Hydro provide an analysis of how much, if any, natural gas fired generation can be relied upon for backup capacity given:

a) Section 6 and the 93 percent clean objective in the CEA
b) the Terms of Reference for this report, under there should be no increase in GHG intensity.

BC Hydro was requested to provide the process it applies to evaluate whether electricity imports are clean. What proportion of purchases in the past three years have been clean?

1.3.1.3 Relevant new information

BC Hydro response to Preliminary Report questions:

Island Cogeneration Use for Capacity and Export

BC Hydro stated that it has a planned reliance upon Island Generation (IG) for 2,170 GWh of firm energy and 275 MW of dependable capacity. BC Hydro states that the IG contract is a "tolling" contract and not a take or pay contract, as it pays a fixed demand charge to ensure that IG is available when required to support BC Hydro load. BC Hydro further explains that in dispatching IG, BC Hydro will purchase natural gas from the market and deliver it to the project to generate electricity; thus, unlike other take or pay contracts like wind, solar or run-of-river, BC Hydro is not required to acquire the energy that this plant can generate but rather will only acquire it when it is needed.

BC Hydro does, however, make use of IG's ability to provide dependable capacity, and does so on an as-needed basis. BC Hydro will dispatch IG under the following circumstances:

- To support Vancouver Island reliability during periods of VI transmission line outages; and
- To serve high domestic loads during cold snaps.

BC Hydro notes that IG is operated to support Powerex trade exports (gas purchased by Powerex) under opportune market conditions. It is also operated as part of routine testing.[856] BC Hydro provides the following table summarizing how IG has been dispatched and the generation that has been purchased:

Table 62: IG Generation (January 2014 through September 2017)[857]

Reason for Operating	Energy (MWh)
Vancouver Island Reliability	70,444
Overall system need	84,198
Testing	12,104
Trade	92,710
	259,456

Market Reliance for Capacity

BC Hydro states that Market capacity backup is important as BC Hydro strives to gain a better understanding of the behaviour of such resources during the winter peak.[858] BC Hydro states that it is during instances such as outages and cold snaps that BC Hydro relies upon external markets for backup capacity supply to supplement the capacity provided by IG and BC Hydro's large hydro facilities.[859]

Single Cycle Gas Turbine (SCGT)

BC Hydro includes the following cost estimate in the 2013 IRP:

Table 63: Summary of the SCGT Potential

Transmission Region	Number of Potential Sites	Installed Capacity (MW)	DGC (MW)	UCC at POI ($2013/kW·year)
100 MW SCGT in Kelly Lake/Nicola	1	103	98	84
100 MW SCGT on Vancouver Island	1	103	101	180

Note: UCCs for SCGTs include fixed costs only.

[856] F1-6, IR 69.
[857] Ibid.
[858] Ibid.
[859] F1-6, IR 69.

Available GHG Room for Natural Gas Generation

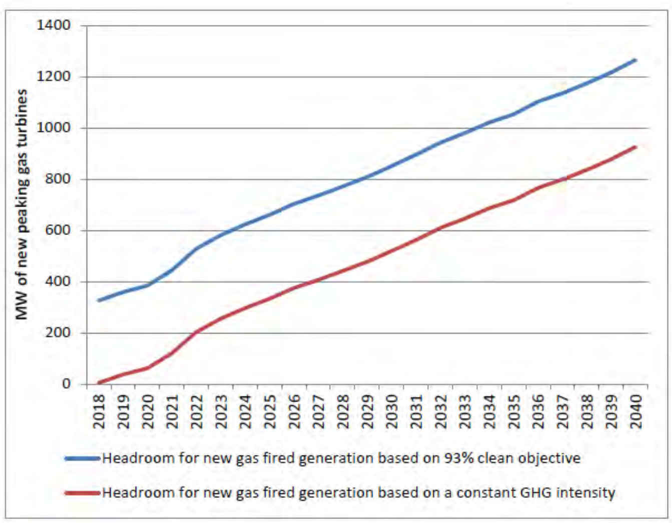
BC Hydro stated that it:

> …owns or has electricity purchase agreements with a few non-clean generating resources" including Prince Rupert generating station, Island Generation facility, McMahon co-generation facility, and Fort Nelson generating station. The total firm energy contribution from these facilities is approximately 3,500 GWh. New gas generation relied upon for dependable capacity is expected to operate around 18 percent of the time, which means that a 100 MW gas turbine would generate 150 GWh/year.[860]

BC Hydro stated that SCGTs are typically built for dependable capacity (i.e. for use as peakers) and that the emission intensity of generation from a SCGT varies with the make and model and is assumed to be 500 tonnes/GWh for the purpose of this calculation. Given BC Hydro's assumption that gas generation relied upon for dependable capacity is expected to operate around 18 percent of the time, a 100 MW gas turbine would generate 150 GWh/year, which translates to 75,000 tonnes of GHG emissions per year.[861]

BC Hydro provides the following chart that shows the capacity of SCGT that could be relied on for dependable capacity (assuming operated for around 18 per cent of the time) while maintain the same GHG intensity under and expected mid load forecast with planned DSM.

Figure 41: Headroom for new SSGT based on maintaining GHG intensity and 93% clean objecitve



BC Hydro explains that electricity imports are reported pursuant to the BC Greenhouse Gas Emission Reporting Regulation (Regulation). Powerex, as an "electricity import operation" as defined under the Regulation, reports on an annual basis the emissions that are associated with the production of electricity that is imported in BC and delivered to BC Hydro load using the standards defined in the Regulation. Imported electricity is divided into three categories: electricity from i) specified sources; ii) unspecified sources; and iii) Canadian Entitlement Power. Emissions from specified sources are assigned the emission intensity of that specific facility. Emissions from unspecified sources are assigned the emission intensity from the jurisdiction or State that is listed as the source in the NERC e-Tag. The Canadian Entitlement is not assigned emissions.

[860] F1-5, IR 2.70.0.
[861] F1-5, IR 2.70.0.

BC Hydro states that when defining *clean* as "Imported Electricity for which zero or *de minimus* tonnes of CO2 (less than 40 tonnes/GWh) are associated," imports from clean resources (including the Canadian Entitlement Power) for the three most recent reporting years (2014 to 2016 inclusive), was 65.9 percent.[862]

Other submissions

CEABC states:

> One of the options for backing the intermittency of renewable generation is single cycle natural gas fired turbines. In terms of capital cost per megawatt they are relatively inexpensive (BC Hydro's 2012 Resource Options Database lists a 100 MW Simple Cycle Gas Turbine plant at between $80 and $95 million, i.e. less than $1 million per MW) and can be installed relatively quickly as demand requires. Their drawback is their greenhouse gas emissions in the context of the Clean Energy Act (B.C.) …
>
> The CEABC agrees with BCH that OIC 244 is predicated on emission and not intensity levels. It is not correct to impute intensity as the BCUC has in its assumption. CEABC does not agree with BCH's conclusion: "… that we have no room for the addition of any new gas fired generation…" ..
>
> OIC 244 is not specific about: "maintenance or reduction of 2016/17 greenhouse gas emission levels" and the CEABC interprets this to mean Provincial greenhouse gas emission levels and not
>
> BCH's 2016/17 levels which are totally dependent on how BCH decides to manage its system including its own and third party natural gas fired thermal generation. …
>
> Any single cycle natural gas fired turbines used to backup renewable generation would also hardly ever be used. … Looked at from another perspective a peaking facility is required for very few hours in a year and some years not at all. BCH's peak demand in winter is for only a few hours on the 4 coldest days. The hours required for monthly testing could exceed the hours when it is used for capacity.
>
> BCH maintains that: "New gas generation relied upon for dependable capacity is expected to operate around 18 per cent of the time. This means that a 100 MW gas turbine would operate 160 GWh/year."
>
> The IG reality test does not support this conclusion. The 18 per cent figure should be in the order of 2-3%.. …
>
> … there remains the option of acquiring offsets or carbon credits to reduce the emission from single cycle peakers to zero. The Clean Energy Act or OIC 244 does not preclude the use of offsets, or carbon credits to reduce greenhouse gas emissions. There are two examples where the B.C. Government has looked to use carbon offsets to help reduce greenhouse gas emissions. [Greenhouse Gas Reduction Targets Act and Carbon Neutral Government Regulation.] …
>
> Given the very low amount of time single cycle peakers would be in operation and corresponding minimal greenhouse gas emissions, purchasing offsets would not be a

[862] F1-5, IR 2.70.0.

material expense. It is a proven viable option to reduce greenhouse gas emissions to zero. [863]

Bakker states:

> The 2016 RRA upated the unit capacity cost of an SCGT at the point of interconnection at Kelly-Nicola to $79/kW-year and stated:
>
> > BC Hydro notes that the Climate Leadership Plan requires 100 per cent clean resources for new greenfield sites in the integrated system unless there is reliability or cost concern. Exceptions on the basis of reliability or cost concerns could be granted through an Integrated Resource Plan. If we encounter a large shortfall of capacity and do not have enough lead time to build new clean generation resources, temporary market reliance and the use of gas resources may need to be considered. …
>
> In the 2013 IRP, BC Hydro presumed that these facilities would operate with an 18% capacity factor, or 1577 hours per year. The effect of this assumption is not inconsequential, as the GHG emissions of SCGTs depend upon both their hours of service and on the frequency of start-ups and shutdowns.
>
> In response to information requests during the 2016 RRA concerning its load curtailment pilot programs, BC Hydro provides insight into how it determines this 18% capacity factor for SCGTs:
>
> > We periodically assess system need and have determined that, with the current system and load characteristics, the ability for a load curtailment program to curtail 16-hour peak/day for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months (October through March) would give BC Hydro sufficient capacity and reliability to defer generation capacity and would be assigned a value at 85 per cent of generation capacity annual fixed cost. An additional ability to curtail four peak hours /day over the remaining months would be assigned the remaining 15 per cent of generation value. [864]

Eliesen states:

> The Burrard Station had a capacity and energy generation very similar to Site C, but was not operated by BC Hydro as a base load facility. The plant was a very costefficient back-up, on call for BC Hydro's system, as well as available to meet any peaking capacity requirements. …
>
> While Burrard Station is currently retired and is being utilized by BC Hydro for transmission support, it could be refurbished to operate again as an important strategic asset for BC Hydro. An evaluation similar to that undertaken for BC's Treaty Entitlement should be pursued and the quantitative implications of the Burrard Station on the need for Site C should beincluded as a viable scenario in the Commission's Final Report. [865]

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[863] F18-5 Submission, p. 14-17.
[864] F106-1 Submission, pp. 99, 100.
[865] F13-2 Submission, pp.10, 11.

1.3.1.4 Panel analysis and findings

The Panel acknowledges BC Hydro's comments on the unsuitability of natural gas fired generation, given the policy framework it describes. In addition, we note that the Climate Leadership plan:

- recommends that we increase the target to 100 per cent clean energy on the integrated grid by 2025, while allowing for the use of fossil fuels for reliability. BC Hydro will focus on acquiring firm electricity from clean sources"; and
- states that "Acquisition of electricity from any source in British Columbia that is not clean or renewable must be approved by government through an Integrated Resource Plan, where it will be aligned with the specific reliability or cost concerns."

However, the Panel also notes that:

- BC Hydro relies on external markets for backup capacity, and market prices are low enough that BC Hydro rarely dispatches its Island Generation IPP even though it would only have to pay for the cost of gas.
    - During 2014 to 2016 inclusive, 66% of BC Hydro's imports were from clean resources (including the Canadian Entitlement Power).
- BC Hydro dispatches the Island Generation IPP to support Powerex trade exports under opportune market conditions. This increases BC GHG emissions.
- Single cycle gas turbines fueled by natural gas are a low cost source of capacity, but increase BC GHG emissions.
    - If the fuel used was renewable natural gas GHG emissions may not be an issues, however there may be limits on available volumes.
- In evaluating the use of SCGT's for the purpose of providing capacity in BC, BCH assumes that it will be operated for 18% of the hours in the year. However, when designing its load curtailment pilot program, BC Hydro stated that up to 576 hours (6.6%) of curtailment would be sufficient to defer generation capacity.
- Submitters have commented that an increase in BC GHG emissions from a SSGT operated to only a few hours in the year could be offset by reductions in emissions elsewhere. This could include, for example, reducing the use of IG for export or acquiring offset or carbon credits.

The Panel finds that capacity options available to BC Hydro could include increased reliance on the market, and that purchases could be from clean sources. Regarding potential transmission constraints, the Panel has previously found that there is insufficient evidence to conclude there is inadequate transmission capacity for future exports, and expects that this would be the same for market imports.

Regarding the use of single cycle gas turbines, the Panel finds that they could be a cost effective source of new capacity, however they have a GHG impact if fueled by natural gas. The Panel notes, however, that the GHG impact could be small if they are only operated as peaking plants for a few hours each year, and BC Hydro could potentially offset any GHG emissions by reducing its operation of IG in order to support Powerex trade exports.

1.3.2 Pumped storage

1.3.2.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submission

BC Hydro describes pumped storage (PS) as units that use electricity from the grid, typically during light load hours, to pump water from a lower elevation reservoir to an upper elevation reservoir. The water is then released during peak demand hours to generate electricity. Reversible turbine/generator assemblies or separate pumps and turbines are used in PS facilities.

BC Hydro notes that PS units are a net consumer of electricity due to inherent inefficiencies in the pumping-generating cycle which result in recovery of about only 70 per cent of the energy used. It is thus not an energy option. However, the ability to store water and release it during times of system need makes PS a potentially useful capacity resource. PS units can respond quickly to variations in system demand and can provide ancillary services such as voltage regulation.

BC Hydro states that it:

> engaged Knight Piésold Ltd. to identify greenfield PS potential in the Lower Mainland, Vancouver Island and North Coast regions, and engaged Hatch Ltd. to assess the cost of installing a pump-turbine or a pump at Mica Generating Station. The technical feasibility of the Mica pumped storage option is subject to additional studies and is unknown at this time. It also has a higher unit capacity cost than the pumped storage options in Lower Mainland, which BC Hydro states is the predomin[ant] capacity option in the portfolios.” [866]

BC Hydro assesses the PS potential in the following table:

Table 64: Summary of Pumped Storage Potential[867]

Region	Number of Resource Options	Total Installed Capacity (MW)	Dependable Capacity or ELCC (MW)	UCC at POI ($/kW-yr)
Kelly Nicola	4	4,000	4,000	127 – 171
Vancouver Island	84	79,000	79,000	135 – 350
Lower Mainland	105	105,000	105,000	125 – 335
North Coast	50	37,000	37,000	124 – 658
Mica	1	500	465	140
Totals	**244**	**225,500**	**225,465**	**124-658**

Notes:
UCCs for pumped storage include fixed costs only.
North Coast UCCs are at plant gate; transmission and road access cost components have not been studied.

BC Hydro includes in its model two 1,000 MW blocks of pumped storage at a cost of $124/kW-year.[868] It believes pumped storage hydro is the least expensive capacity resource that meets BC’s greenhouse gas reduction objectives. However, BC Hydro states that there is significant risk that pumped storage resources will have a lead time that extends beyond when we expect to require new capacity resources. In such a case, BC Hydro would expect to use natural gas generation for dependable capacity.[869]

[866] F-1 Submission, Appendix L, pp. 41-42.
[867] F-1 Submission, Appendix L, pp. 41-42.
[868] F-1 Submission, Appendix Q, p. 4.
[869] F-1 Submission, p. 75.

BC Hydro estimates the cost of providing wind resources with pumped storage capacity in the figure below as:[870]

Figure 42: Pumped storage cost $/MWh adder for wind generation

Cost Factor	Unit Energy Cost $/MWh
Capacity Resources (Pumped Storage)	
Fixed Costs	+31
Costs of Energy Loss (30% Pump/ Generation Cycle)	+17

Deloitte report

Deloitte states that their research suggests PS are highly variable, ranging from $1,600 to $7,300/kW, with O&M costs of 1-2 percent of capital costs. Deloitte consider that capital costs for pumped-storage projects are not expected to change significantly in the next 20 years. [871]

Deloitte references 18 recent reports on pumped storage costs in their report, including a recent Pacificorp 2017 study titled "Battery Energy Storage Study for the 2017 IRP." This study reviewed three potential pumped storage projects and provided the following cost estimates on page 21 of the report: [872]

Figure 43: Pacificorp Pumped Storage Summary (US $)

ITEM	SWAN LAKE NORTH	JD POOL	SEMINOE (EAST AND WEST)
General Criteria			
Location	OR	WA	WY
Installed Capacity (MW)	400	1,200	700
Expected Life of Generating Equipment (yrs)	20+		
Expected Life of Project (yrs)	50+		
Basis of Cost Opinions (Costs are expressed in 2016 dollars.)			
Range of Capital Costs ($/kW)	$1,800 - $2,700		
Range of O&M Costs ($/kW-yr)	$4.45 - $6.99		
Bi-annual Outage Costs ($)	$280,000		
Range of Major Maintenance Costs/Unit ($)	$3,700,000 - $8,000,000		
Replacement Frequency (yrs)	20		

Other submissions

CEABC questions whether pumped storage would be able to provide additional flexibility to BC Hydro (such as purchasing cheap freshet energy for resale during the high load season), which could reduce its cost.[873]

[870] F-1 Submission, p. 63.
[871] A2-9 Submission, pp. 37, 38.
[872] A2-9 Submission, p. 35.
[873] F18-3 Submission, Appendix 4, pp. 5–6.

Three parties identified specific projects that they were considering or planning. These projects are described below.

- Hydro Battery Inc.
- Clean Balance Power
- Van-Port Sterilizers

Hydro Battery Inc.

Hydro Battery Inc. (HBI) commissioned Knight Piésold Ltd. (KP) to complete a concept validation assessment of a proposed 1,100 MW Hydro Battery Pumped Storage Hydro (PSH) Project, near Revelstoke, BC. HBI's states that the proposed project will provide a combined 1,100 MW PSH Project and 1,500 -1,800 MW of variable wind power that will provide equivalent or better power and energy characteristics than the 1,100 MW Site C. HBC states that he 1,100 MW PSH Project will provide the dispatchable power, and the 1,500 -1,800 MW of wind will provide the 5,100 GWh of annual energy, providing a combined product that delivers equivalent power and energy numbers to that of Site C. [874]

HBI also proposes that the fast acting Hydro Battery units could also be used to mitigate the flow ramping concerns of the new BC Hydro Revelstoke Dam units 5 and 6.[875]

HBI states that the estimated capital cost for the 1,100MW Hydro Battery PSH Project, near Revelstoke, BC is approximately $2,420 million. It further submits that based on recent and relevant experience with the development and permitting of other similar sized projects in Canada it could take approximately 10 years to develop the project. This would include:

- 3–5 years for environmental studies, bankable feasibility studies and project permitting, and
- 5–8 years for detailed design, procurement, construction and commissioning.

HBI notes that these two phases might overlap to some extent, thereby shortening the overall development timeline.[876]

Clean Balance Power

Clean Balance Power (CBP) submits that for roughly ten years it has been assessing the potential for low-impact pumped hydro storage located in the Lower Mainland. It further states that:

> Kwantlen First Nation has worked closely with Clean Balance Power over this period, and has expressed an interest in moving forward with a low-impact pumped hydro project in their traditional territory that would not only respect their cultural and environmental values but also provide long term economic and employment opportunity.

CBP submits that it:

> Hired Knight Piesold Consultants to undertake cost assessments on a number of potential sites in the Lower Mainland varying in size from 100 MW to 1000 MW. Results of that study showed that the capital cost of a facility with 1000 MW of dependable capacity (available 10 hours per day, 6 days per week) was estimated at $1.06 billion (+/- 40 percent), including 38 percent in contingency allowances. Based on an 80 year economic life, and a 5 percent

[874] F67-1 Submission, Appendix: Concept Validation Assessment p. 1 of 22.
[875] F67-1 Submission, Appendix: Concept Validation Assessment p. 1 of 22.
[876] F67-1 Submission, Appendix: Concept Validation Assessment p. 19 of 22.

> discount rate, and a 5-year construction period, this results in a Levelized Unit Cost of Capacity of $61 per kw-yr (fixed investment only), significantly less than any of the pumped storage costs reported in the 2013 Resource Options Report.

CBP further submits that in that report, the lowest cost option was $100/kw-yr (fixed investment only), which was a 500 MW pumped hydro project proposed for the BC Hydro Mica Dam. The 1000 MW facility assessed in the KP report is located just 60 km from downtown Vancouver and only 15 km from two 500 kV transmission lines (i.e. 5L82 and 5L83).

CBP states that "[m]oreover, because virtually all of the plant is located in an excavated underground cavern, the environmental footprint of the 1000 MW project would be less than 50 hectares, or roughly 1 percent of the land area proposed to be flooded by Site C."[877]

Van-Port Sterilizers Ltd.

Van-Port Sterilizers Ltd. (VPS) states that it

> …has long-proposed building a merchant pumped storage hydroelectric plant in combination with a commercial wastewater reclaim-treatment pipeline at Jordan River, a project that we believe could have significant impact on demand for electricity as it would catalyze identified major industrial, agricultural, commercial and residential development initiatives along the pipeline corridor.

VPS believes its project power would produce and deliver at a lower cost per kW/h than from Site C. It states that the project is referenced in Appendix F4 attached to the BC Hydro 2008 LTAP and ROU. It does not believe that a suspension of Site C is needed to justify the cost-effectiveness of our project and seek only to clarify its competitive status against conventional waste management and pumped hydro schemes.[878]

1.3.2.2 Panel analysis, preliminary findings and questions in the Preliminary Report

There is currently no pumped storage facility in BC either operational or in the construction process. These projects are large capital projects. The approximately 10 year development schedule for the HBI project demonstrates that these projects have similar planning and environmental permitting issues as does a dam. Further, costs are not likely to decrease over time, as may be the case with battery storage.

The Panel requested that BC Hydro comment on the viability of pumped storage. BC Hydro was also requested to provide particulars, including but not limited to location, capital and operating costs and general project description of the pumped storage facilities identified as Pumped_Storage_LM in the results of its portfolio analysis.

BC Hydro was requested to respond to the submissions made by Hydro Battery, Clean Balance Power and Van-Port Sterilizers. Specifically, could these projects be lower cost to ratepayers than the pumped storage facilities assumed by BC Hydro, and if yes, what would the cost be (capital cost, O&M etc.) as well as levelized $/kW-year cost (assuming BC Hydro financing costs and a 6 percent discount rate).

Please describe any potential non-price related concerns with pumped storage facilities compared to capacity focused DSM/batteries (for example, development time, environmental concerns etc.).

[877] F33-1 Submission, p. 1–4.
[878] F99-1 Submission, p. 1.

Please describe any additional benefits that pumped storage can provide in addition to be used to firm intermittent resources (for example, as a result of the flexibility of pumped storage), and comment on whether these benefits could reduce the cost of the pumped storage project.

1.3.2.3 Relevant new submissions

CBP makes the following comments on certain assumptions and calculations relating to pumped storage projects and the impacts these assumptions and calculations would have on the Alternative Portfolio analysis described in the Preliminary Report:

- With regard to BC Hydro's Alternative Block UEC analysis which, was provided as Table 32 on page 88 of the Preliminary Report, CBP "questions the usefulness" of adding certain Levelized Unit Capacity Cost (UCC) operating components to Levelized UECs to derive a higher UEC to compare with Site C's UEC. CBP submits that UCCs and UECs are sufficiently different to be considered separately. CBP further submits that if Site C were considered separately as a capacity resource, it would be considered quite expensive and not optimally located. CBP suggests that a more useful comparison might be the differences in UCC value to the BC Hydro system of having 1,100 MW of capacity located in the Lower Mainland as opposed to northeastern BC. CPB submits that while pumped storage hydro does consume off-peak energy, the relative incremental UCC value of having 1,100 MW located in the Lower Mainland could be significant.[879]
- CBP raises issue with BC Hydro's determination of the UCC for Pumped Storage of $124/kW-year, which was provided in Tables 33 to 35 on pages 95 and 96 of the Preliminary Report. CPB states that BC Hydro's cost estimate was based on the 2010 Knight Piesold Consulting Screening Assessment Report; whereas, in November 2016, CBP hired the same consultants to do a "far more comprehensive" cost estimate for eight pumped storage hydro sites. CBP submits that Knight Piesold looked at CBP capacity projects varying in size from 102 MW to 1000 MW and included estimates for site access, transmission and interconnection, with a 30 percent contingency on all estimated construction costs being applied. Additionally, the operating constraint was to provide a minimum of 10 hours of generation per day. CBP submits that the resulting construction costs were significantly below the estimates derived in 2010, with two projects coming in at just over $1 million per MW. Based on a real rate of return of 5 percent, CBP estimates the UCC of the lowest cost 1,000 MW site is approximately $60/kW-year (compared to BC Hydro's estimate of $124/kW-year).[880]

CBP concludes that if energy and capacity had been assessed separately, and if a UCC of $60/kW-year had been used in the alternative portfolio as the pumped storage hydro UCC instead of $124/kW-year, it is conceivable that the optimal Alternative Portfolio would have been presented as a lower cost alternative to ratepayers than Site C.[881]

BC Hydro responses to Preliminary Report questions

BC Hydro considers the following characteristics as key in evaluating pumped storage as a resource to meet future system needs:

- It is a clean source of dependable capacity and a mature technology. Over 140 GW of pumped storage facilities have been installed globally, with one facility in Canada – the Sir Adam Beck Pump Generating Station facility in Ontario commissioned in the late 1950s.

[879] F33-2, p. 1.
[880] F33-2, pp. 2-3.
[881] F33-2, p. 3.

- Pumped storage hydro facilities have the ability to respond quickly to changes in system conditions. Their output can be altered as desired with the proper equipment and controls. It is also possible to switch between generation and pumping modes within a few minutes.
- The flexibility of the facilities is influenced greatly by the size, characteristics, and constraints of the two reservoirs.
- The facilities are a net consumer of energy. Only around 70 percent of the energy consumed during the pumping cycle can be recovered during the generation cycle. This means that a portion of system energy needs to be dedicated to facilitate the operation of a pumped storage facility, which is a significant requirement.[882]

BC Hydro provides the following information on the pumped storage facilities identified as "Pumped_Storage_LM" in its portfolio analysis:

- The site used in the analysis is identified as Upper Deserted – Un-named in the KP report.
- It has an installed capacity of 1,000 MW, a capital cost of $1.32 billion ($1,320/kW) and fixed annual operating costs of $12.6 million.
- The project is located in the Lower Mainland region and provides transmission benefits to the portfolios by deferring or avoiding transmission upgrades from the interior to the lower mainland.
- The project would have storage sufficient for only 6 hours of continuous generation, which is insufficient to meet BC Hydro's peak winter demands that require 16 hours of continuous generation. A facility capable of providing 16 hours of generation would require a larger upper reservoir and have higher capital cost.
- For the portfolio modelling, BC Hydro has assumed that the pumped storage cost estimate was sufficient to provide a ten-hour pumping cycle such that each facility would pump for 14 hours and generate for 10 hours.[883]

BC Hydro also notes that the cost of the modelled facility (i.e. $1,320/kW) is significantly lower than the range identified by Deloitte of $1,600 to $7,300 per kW.[884]

BC Hydro provides the following comments on the submissions made by Hydro Battery, Clean Balance Power and Van-Port Sterilizers which were included in the Preliminary Report:

- The cost of the Hydro Battery project is $2,180/kW, which is significantly higher than the value used by BC Hydro in its modelling.
- The Clean Balance Power project does not seem to include permitting costs nor the cost of transmission to interconnect to the 500 kV transmission system and any access roads that may be required; whereas the value used in BC Hydro's modelling includes all of these costs which are a necessary part of project development. Once these costs are incorporated into the Clean Balance Power proposal (BC Hydro used approximately 6 percent of the project capital cost to estimate permitting costs and approximately 7 percent of project capital costs to estimate transmission costs), BC Hydro submits that the proposal cost would be extremely close to the value used in its modelling.

[882] F1-6, IR 2.71.0.
[883] F1-6, IR 2.71.0.
[884] F1-6, IR2.71.0.

- The Van Port Sterilizers submission does not provide any cost information. The proposal referenced in the submission was deemed to be non-viable due to factors such as provincial legislation requiring coal fired facilities to fully sequester their emissions.[885]

Regarding non-price related concerns with pumped storage, BC Hydro submits that the permitting process for this type of generating facility which has not been built since the 1950s is uncertain, which could impact facility development time which BC Hydro expects to be around 8 to 10 years. There are also environmental considerations specific to pumped storage including issues related to mixing of water between two reservoirs. BC Hydro submits that this could be mitigated by the use of an artificial reservoir and through closed loop systems where the water used by the facility is in a hydraulically closed loop. [886]

The other major area that BC Hydro continues to investigate is how to integrate a 10-hour resource into the system when 16 hours is needed in the winter peak period and how to accommodate the pumping requirement that is needed to refill the reservoir in the off-peak periods.[887]

Regarding additional benefits, BC Hydro submits that the dependable capacity contribution and transmission deferral benefits of pumped storage are explicitly captured in the portfolio modelling. Further, pumped storage can provide many of the dispatchable capacity benefits identified as being applicable to Site C.[888] BC Hydro expects the benefits to be smaller for pumped storage than Site C given the limited storage capability of typical pumped storage facilities.[889]

1.3.2.4 Panel findings

The Panel finds that it is reasonable to exclude pumped storage from the Illustrative Alternative Portfolio. While pumped storage is a commercially feasible means of providing capacity, the Panel is concerned with the large size of the project (1,000 MW with a capital cost of $1.32 billion), facility development time of around 8 to 10 years, and environmental considerations specific to pumped storage.

1.3.3 Battery storage

1.3.3.1 Key submissions and issues raised in the Preliminary Report

BC Hydro submits that, by virtue of the high costs of Lithium-Ion battery storage and the uncertain future cost reductions, Lithium-Ion battery storage is not included in resource portfolio analysis.[890]

Deloitte submits that battery storage is not a commercially feasible technology at the present time. However, Deloitte considers that there is increasing evidence that energy storage will eventually mature into a commercially viable, grid-scale resource over the time of the forecast to 2040.

A Power Advisory Report for CanWEA and CEABC and Bakker submits that the costs of lithium-ion battery storage have declined substantially in recent years, and while the rate of change is expected to decrease, an overall decline in cost is anticipated to continue into the foreseeable future. Bakker provides the following

[885] F1-6, IR 2.71.0.
[886] F1-6, IR 2.71.0.
[887] F1-6, IR 2.71.0.
[888] Appendix F the August 30th filing.
[889] F1-6, IR 2.71.0.
[890] F-1 Submission, Appendix L, p. 52.

Energy Storage Association November 2016 forecast of an installed cost (inclusive of batteries, balance of system costs, financing and O&M) of a 100 MW/4-hour lithium-ion storage battery:[891]

Figure 44: Forecast US$/kW installed cost of a 100MW/4-hour lithium-ion battery

	2016	2017	2018	2019	2020
Upper	$ 1,814	$ 1,549	$ 1,337	$ 1,209	$ 1,083
Lower	$ 1,660	$ 1,315	$ 1,056	$ 911	$ 774

Dauncey submits that BC's future electric vehicle owners could also have the ability to sell their battery power back to the grid in what's known as Vehicle to Grid (V2G), helping BC Hydro provide power to its customers at critical times of peak demand. Dauncey refers to a trial involving electric cans in Denmark, where owners are earning up to US $1,530 a year.[892]

1.3.3.2 Panel analysis, preliminary findings and questions in the Preliminary Report

In the Preliminary Report, the **Panel found the results of the studies cited by the CanWEA, Baker and Deloitte to be reasonable.** Given the example of significant declines in costs of computer and telecommunications technology, the Panel considered it believable that new technology may drive battery storage costs down.

However, the Panel stated in the Preliminary Report that it was not clear what the impact, if any, on BC Hydro's alternative portfolio would be if instead of pumped storage, battery storage was assumed, and requested that BC Hydro provide additional information.

1.3.3.3 Relevant new submissions

The Illustrative Alternative Portfolio model prepared by Commission staff included 400 MW of batteries starting between F2025 and F2026 for the medium load forecast scenario, at a cost based on an August 2016 NREL report, titled Exploring the Potential Competitiveness of Utility-Scale Photovoltaics plus Batteries with Concentrating Solar Power 2015-2030.[893]

Several submitters stated that the strawman model assumption for batteries included the 'balance of system' costs related to the batteries, but not the batteries themselves. In addition, it did not reflect energy losses associated with the battery recharge cycle or operation and maintenance costs.[894]

Submissions on recent investments by utilities in batteries included the following:

> Ontario recently procured 33.5 MW of energy storage and is proceeding with additional procurement to a total of 50 MW. Of particular interest in the current context, San Diego Gas & Electric recently contracted for both a 20 MW lithium ion battery energy storage facility and 18.5 MW of DSM capacity savings. Considering that the need for [capacity] in the

891 F106-2 Submission, p. 33; F18-3 Submission, Appendix 1, p. 12.
892 F62-1 Submission, pp. 14, 15; https://www.bloomberg.com/news/articles/2017-08-11/parked-electric-cars-earn-1-530-feeding-power-grids-in-europe.
893 Exhibit A-22, pp. 2, 8.
894 F1-17 submission, pp. 10 – 13; F81-3, p.3; F33-3, p. 3; F82-4, pp. 2-5.

> Alternative Portfolio does not arise until F2027, BC Hydro has ten years to benefit from additional declines in the costs of battery and other energy storage …[895]
>
> … California relied on batteries to provide 70 MW of required peaking capacity to replace a portion of the natural gas-fired generation that was unavailable when the Aliso Canyon gas storage facility was shut down last year. These batteries were deployed within 9 months, demonstrating their value as a contingency resource to address unanticipated risks.[896]

Bakker provides the following estimate of future battery and advanced compressed air storage costs:

> Based on a 10-year equipment life (also conservative, because while the batteries need to be replaced after 10 years, the balance of plant does not), we obtained a unit cost of CA$109/kW-yr in 2020.
>
> In BCUC 2.48.0, BC Hydro estimated the capital cost of a 100 MW 10-hour Li-ion storage system at US$743 million, or US$7430/kW, with a unit cost of $651/kW-yr (2018$). While mention is made of an analysis by Lazard and Enovation Partners (2016), no precise reference was provided, nor were the calculations explained.
>
> Based on our confidential discussions with commercial providers of Li-ion storage systems, it appears that a 1000 MWh system could be acquired today in Canada for CA$500 to $600 million, together with an asset management (fixed OMA) contract of $5 million/year. In other words, systems are available today at prices lower than those estimated by BC Hydro for twenty years from now, in the late 2030s.
>
> Furthermore, in a document addressed to Energy Storage Canada, Hydrostor Inc. has provided an indicative cost estimate for an Advanced Compressed Air Storage (A-CAES) system of this same size (100 MW / 1000 MWh), with a capital cost of just US$175 million, plus fixed operating costs of US$2 million/year. The round-trip efficiency is estimated at 60-65%.[897]

Dauncey submits that "In 2016, Greentech Media research found that in 2025, in America, 11.4 million EVs could be adding 5 GW of storage capacity to the grid. BC's equivalent would be 72 MW."

1.3.3.4 Panel analysis and findings

The Panel finds that utility scale battery storage has reached the early stages of commercial feasibility. However, the Panel agrees with BC Hydro and submitters that the cost estimates for batteries included in the October 11 Illustrative Alternative Portfolio model were understated and batteries should therefore be screened out of the Alternative Portfolio as a means of meeting short term capacity gaps.

However, over the longer term the Panel considers that batteries could become a cost competitive supply of capacity for BC Hydro as increased volumes drive down costs. For example, a report prepared for the US Department of Energy categorized 2015 as the start of a new period for utility scale battery deployment, with 145 MW lithium ion projects coming online, more than the previous five years combined.[898]

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[895] F28-2, tab 9 (Program on Water Governance, Competitive analysis of GHG emission of Site C vs. Alternatives, July 2016) p. 19.
[896] F104-3 submission, p. 4.
[897] F106-4 submission, p. 22.
[898] https://energy.gov/sites/prod/files/2017/01/f34/Deployment%20of%20Grid-Scale%20Batteries%20in%20the%20United%20States.pdf.

Regarding vehicle-to-grid applications, the Panel considers that they are currently at an early stage of development with small-scale utility and micro-grid pilot projects underway to establish proof-of-concept. The Panel therefore finds that they should not be included in the Alternative Portfolio.[899] However, the Panel considers that the vehicle-to-grid innovations could become a low cost source of capacity over the long term as BC Hydro would not have to own the batteries.

For example, the Panel notes that production at Tesla's Gigafactory began in January 2017, and will scale up towards full production in 2020. Numerous other firms are planning battery production factories including BMZ, Samsung SDI, LG Chem and InnoEnnergy, which could result in a competitive and scaled manufacturing base.[900] The Panel considers that innovations in the vehicle-to-grid area have the potential to provide low cost capacity to BC Hydro while providing significant additional income to BC Hydro's customers.

1.3.4 Capacity focused DSM

1.3.4.1 Key submissions and issues raised in the Preliminary Report

One of the obvious ways for a utility to address load growth is to try to reduce and shift demand for electricity. Utilities all over the world, including BC Hydro, invest in initiatives to achieve this outcome, and that such initiatives are referred to as DSM.[901]

In the F2017-F2019 RRA, BC Hydro asked for acceptance of $38 million in funding to understand the dependability/reliability of capacity focused programs and technologies applicable to the BC market. This included funding for:

- Localized DSM pilots to test the ability of DSM to defer network investments;
- Residential demand response trials of new technologies (e.g., heat pump water heaters, electric thermal storage, smart electric vehicle charging, and battery storage) and approaches (e.g., behavioural peak savings);
- Commercial and Industrial demand response investigations of new technologies (e.g., smart charging for fleets, commercial battery storage, and building automation);
- Connected home trials with large service and technology providers and retailers/manufacturers;
- Industrial load curtailment pilot program;
- Distributed energy resource management software system/service; and
- Electrification related initiates.[902]

BC Hydro Submission

In its initial submission on August 31, 2017, BC Hydro stated that "[i]ndustrial load curtailment is being pursued but there are limited volumes of load that can provide the dependable capacity over the hours when we most need it."[903]

[899] http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf; https://www.bloomberg.com/news/articles/2017-08-11/parked-electric-cars-earn-1-530-feeding-power-grids-in-europe.
[900] http://www.powermag.com/battery-storage-goes-mainstream-2/.
[901] F-1 Submission, Appendix L, p. 5
[902] F-1 Submission, Appendix L, p. 15; BC Hydro F17-F19 RRA, Exhibit B-1-1, p. 10-33, Exhibit B-14, IR 319.1
[903] Submission F1-1, p. 59.

BC Hydro stated that it included industrial load curtailment is an available capacity resource in its portfolio analysis, but considered capacity focused DSM beyond this to be too uncertain to be counted on for planning decision at this time.[904]

BC Hydro further stated that a capacity-focused DSM resource would need to curtail for 16-hours for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months (October through March) to give BC Hydro sufficient capacity reliability to defer generation capacity.[905]It stated that the industrial load curtailment pilot has demonstrated that, while some uncertainties remain, about 85 MW of curtailment at the price point of $75/kW-yr could be available as generation capacity alternative.[906]

Deloitte report

Deloitte states with regard to capacity focused DSM:

> In the 2013 IRP, BC Hydro states that "since then, in accordance with government policy, BC Hydro has no plans to implement Time-Based Rates to address capacity requirements for residential and commercial customers." Nonetheless, 76% of the utilities surveyed in the ACEEE 2017 benchmarking report use Time- Based Rates.
>
> Although BC Hydro has yet to quantify the potential savings from capacity-focused pilot programs, limited results to date demonstrate that these programs may provide a cost-effective source of new capacity. BC Hydro provided the following examples of incentives paid to customers through capacity-focused DSM pilots:
>
> - Residential hot water trial: The residential demand response pilot project focused on managing electric water-heating loads using wireless load control relays, and an alternative three-element water heater that typically operates at a lower demand than standard water heaters. BC Hydro offered customers $40/year (the $/kW-year will be determined after evaluating results for the three-year period ending March 2017).
>
> - Commercial and industrial demand response trials: The commercial and industrial demand response pilot initiatives offer customers $0.25/kW-year through a manual-call, demand-response program where participants select their own actions for implementation (e.g., refrigeration, lighting, heating, ventilation).
>
> - Industrial load curtailment pilot: The load curtailment program targets large industrial customers, offering them $75/kW-yr for up to 28 days of 16 hour per day curtailment (448 hours).

Other submissions

BCSEA submit that the 'Without-Site C' portfolio should include capacity-focused DSM in amounts and at costs that BC Hydro said in the F2017-F2019 RRA would likely be available. BCSEA submit that this is important for a valid comparison with the Site C portfolio because BC Hydro's next supply-side capacity resource beyond Revelstoke Unit 6 will come in increments of hundreds of MW, cost hundreds of millions of dollars and take eight to 10 years to build. [907]

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[904] F1-1 Submission, Appendix L, p. 15 - 18
[905] F1-1 Submission, Appendix L, p. 16
[906] F1-1 Submission, Appendix L, p. 16
[907] F-29-3 Submission, p. 17, 18.

Dauncey submits that dispatchability can also come through 'demand response' whereby industrial and commercial customers are given advance notice and paid to reduce their demand at certain times. Dauncey notes that in Texas, with six times BC's population, half of their dispatchable power is already being obtained in this way, and that in January 2014, when a polar vortex knocked out several Texas power plants, "demand response provided 496 MW of capacity to the grid within 46 minutes of being called."[908]

AMPC submits that the 400 MW of potential capacity savings identified by BC Hydro from industrial load curtailment was too small, and that the program should be broadened to include a larger set of industrial customers. AMPC also notes the success of the industrial load curtailment pilot.[909]

Bakker notes that the actual costs in the first year of the industrial load curtailment the average weighted unit capacity contracted payment to participants in BC Hydro's load curtailment program is $75/kW-year. Baker states that BC Hydro's initial estimate was $57/kW-year (based on the 126 MW contracted in year one of the pilot), however actual costs in the first year of the pilot program were $49/kW-year because customers curtailed more than the amount contracted.[910]

Bakker further submits that, based on the identified capacity-focused DSM potential and the results of pilot programs to date, it is anticipated that at least 500 MW of capacity-focused DSM is available to BC Hydro. Bakker submits that she has conservatively assumed that these savings would take longer to develop than the five-year period identified in the 2013 IRP, and that the savings could grow from 30 MW in F2018 to 570 MW by F2036.[911]

Bryenton references a 2010 SmartGrid (U.S. Department of Energy) report in submitting that the implementation of smart meters has the potential to facilitate capacity savings of up to 20% in the peak period.[912]

1.3.4.2 Panel analysis, preliminary findings and questions in the Preliminary Report

BC Hydro identified in the 2013 IRP that there was 382 MW of expected capacity savings from industrial load curtailment, and 193 MW of expected capacity from capacity focused programs. BC Hydro is now half way through the F2017 – F2019 funding request of $38 million to understand the dependability/reliability of capacity focused programs.

Given this, the Panel requested BC Hydro to explain why it has only identified capacity DSM savings for the industrial sector.

The Panel sought input from BC Hydro and other parties regarding what level of incremental capacity curtailment would be reasonable to expect from industrial, residential and commercial customers through capacity focused DSM programs at: (i) F2019, (ii) F2023 and (iii) F2027 at different cost levels (for example, $10/kW-year; $30/kW-year, etc..).

[908] F62-1 Submission, p. 15
[909] F81-2 Submission, pp. 8-10
[910] F106-1 Submission, pp. 89, 90.
[911] F106-1 Submission, p. 90.
[912] F6-8 Submission, p. 4.

1.3.4.3 Relevant new information

Assumption in the model

The Commission Illustrative Alternative Portfolio model contained the following assumptions on capacity-focused DSM:

> DSM Costs and cumulative capacity savings for optional TOU rates and capacity focused DSM programs were estimated from the graphs on page 3-21 of BC Hydro's 2012 draft IRP. For the Industrial Load Curtailment volumes/costs were assumed to be 100 MW at $75/kW-year based on BC Hydro's industrial load curtailment pilot, available at 1MW increments. Costs are deferred and amortized over 15 years.[913]

The assumptions for total capacity savings available from capacity focused DSM and levelized costs are summarized in the table below.

Table 65: Capacity Focused DSM Assumptions used in BCUC Illustrative Alternative Portfolio

Capacity Focused DSM Option	Modelled MW Savings (Medium Load Forecast Scenario) F2023	Modelled MW Savings (Medium Load Forecast Scenario) F2027	Maximum MW Savings	Year Maximum Savings Reached	Levelized Cost ($/kW-year)[914]
Optional Time-Based Rates	50	150	430	F2038	30
Capacity DSM Programs	210	220	500	F2037	68
Industrial Load Curtailment	32 MW in F2025; 57 MW in F2026		100	n/a	75

BC Hydro submission

BC Hydro submitted that the October 11 Illustrative Alternative Portfolio assumes roughly twice the level of capacity DSM programs and Time-Based Rate capacity savings that BC Hydro believes is available (930 MW compared to 450 MW). BC Hydro states that capacity DSM programs have been estimated at a significantly lower Total Utility Cost than its own assumptions ($15/kW-year compared to the $50/kW-year estimate used in the Illustrative Alternative Portfolio). It stated that the capacity focused DSM options considered contain substantial deliverability and cost risks due to future uncertainty over customer response.[915]

BC Hydro submitted that a key finding since the draft 2012 IRP has been the requirement for a minimum 10-hour capacity product and not the four-hour product contemplated in the draft 2012 IRP.

BC Hydro stated that research since the draft 2012 IRP suggests that TOU response from General Service customers may not reach the participation rates that were previously assumed. BC Hydro states that the rate designs for optional time-based rates identified in the draft 2012 IRP would not meet its current understanding of peak capacity requirements, citing the short duration and limited number of Critical Peak Pricing events in other jurisdiction, restricting the availability of capacity savings.

[913] Submission A-22, p 7.
[914] Based on a Net Present Value at 4%, over a 20 year period, of costs divided by capacity.
[915] F1-17 Submission, pp. 14-18.

BC Hydro submits that the Illustrative Alternative Portfolio model assumes more savings from capacity DSM programs than estimated in the draft 2012 IRP.

BC Hydro's response to IR 2.73.0 provides updated estimated capacity savings from capacity focused DSM options, based on information provided by Navigant and BC Hydro analysis. It noted that these results are subject to a high degree of uncertainty:

	MW savings		Levelized Costs ($/kw-year)	
	F2023	F2027	Utility	TRC
Direct Load Curtailment Programs (Res, SGS, MGS)	170	210	55	70
LGS Load Curtailment	100	120	75	60
Voluntary Time of Use Rates (all classes, including electric vehicles)	80	120	10	10
TOTAL	**350**	**450**	**50**	**55**

In its initial submission, BC Hydro stated that: "[i]ndustrial load curtailment is being pursued but there are limited volumes of load that can provide the dependable capacity over the hours when we most need it."[916] BC Hydro was asked in a meeting with AMPC on the design of a load curtailment rate whether it would permit aggregation to get the 8 hours of curtailment. BC Hydro responded "Potentially yes, but this is getting into structuring. Aggregation could impact pricing"[917]

Other submissions

AMPC disputes BC Hydro's assertion. It cites the view of BC Hydro laid out in its submission that "a capacity focused DSM resource would need to curtail for 16-hours for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months (October through March) to give BC Hydro sufficient capacity reliability to defer generation capacity." In AMPC's view, BC Hydro has defined the required product far too narrowly, ignoring the ability of other jurisdictions to aggregate and make effective use of blocks of energy that both last for fewer hours and fewer consecutive days. Curtailable load can be a flexible tool to both manage forecast risk as well as system contingencies, e.g., such as a contingency response program with direct load control. BC Hydro has done little to explore it.[918]

AMPC asserts that "In late 2008, AMPC argued (under the name of the Joint Industry Electricity Steering Committee, or 'JIESC') that a *400 MW* load curtailment program was *too small*, and represented a capacity resource that BC Hydro should take greater advantage of, in the manner of other jurisdictions."[919]

AMPC notes the inclusion on the Preliminary Report[920] of BC Hydro's identification of a potential 382 MW of capacity as recently as the 2013 IRP. [921]

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[916] Submission F1-1, p. 59.
[917] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/capacity-discussion-with-ampc-june-2014.pdf.
[918] Submission F81-2, paras, 42-43, citing Exhibit F1-1, Appendix L, pdf p. 486.
[919] The Annual Energy Outlook 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf, p. 1.
[920] At Appendix A, p. 39, citing Submission F106-1.
[921] Submission F81-2, pp. 8-9.

In commenting on the Illustrative Alternative Portfolio, AMPC submits:

> 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.[922]

CanWEA submits:

> Interestingly, BC Hydro noted in its initial filing with the Panel that with respect to demand response, "We are testing technologies that then can be used on a larger or aggregated scale to meet the system peak needs or to contribute to a non-wires alternative on the distribution system. This work is still ongoing so data for consideration as an alternative is not available at this time." This is surprising. Demand response is used across North America to provide large volumes of "capacity."
>
> There are large, experienced companies that offer demand response solutions, with whom BC Hydro could contract to realize these peak load reductions quickly. In New England demand response resources provide over 8% of the capacity resources that are relied upon to meet peak demand. Demand response resources provide equivalent amounts of peak load reductions in the PJM (Pennsylvania-New Jersey-Maryland) capacity market. Experience in these markets as evidenced by the results of capacity auctions indicates that these are among the least costly capacity resources since they invariably bid lower prices than generation resources.[923]

CanWEA and CEABC submit:

> Consistent with our comments regarding the magnitude of the DSM energy savings presented above, CanWEA believes that more ambitious cost-effective peak load reductions can be realized by BC Hydro than assumed in the Commission's Medium and High Load Forecast Portfolios.
>
> CanWEA and CEABC are concerned that BC Hydro is effectively calling into question the effectiveness of demand reduction programs by indicating that it requires "capacity resources that are available in aggregate to generate or curtail load for 16-hours per day for up to 36 days." We believe that a sixteen-hour duration for load curtailment is

[922] Submission F81-3, pp. 2-3.
[923] Submission F104-2, p. 3.

> unreasonable. We reviewed for other industrial demand response programs in the Pacific Northwest and were unable to find any similar requirements. Puget Sound Energy's Voluntary Load Curtailment Rider requires a minimum of a one-hour reduction.4 Portland General Electric Company's Firm Load Reduction Program requires a minimum 4-hour duration for large customers. Idaho Power's Flex Peak program for large industrial and commercial customers limits its event durations to two – four hours.
>
> A primary driver for the duration of peak load reductions is the typical peak day load shape. A review of a typical peak day load shape for BC Hydro indicates that 16 hours is well beyond what would be required to reduce the peak by amounts that BC Hydro is likely to able to realize. More importantly, it is well beyond what the vast majority of customers are likely to be able to offer or end-uses are able to provide.
>
> If longer duration customer load reductions are required (e.g., 8 to 10 hours) these can be realized by BC Hydro by calling upon successive groups of customers to realize these load reductions. This is common practice elsewhere. In essence, BC Hydro would have a portfolio of demand reduction resources that it can call upon to manage its peak. This may affect the value offered to customers to participate, but if this value considers the cost of resources that BC Hydro has identified as required to provide capacity (e.g., pumped storage hydro), it is likely to be more than enough to induce high levels of customer participation.[924]

Evidence was also presented by CanWEA about programs in other jurisdictions, notably Ontario, that automatically shut off domestic hot water heaters during periods of peak capacity. This included programs to more effectively integrate wind generation.[925]

Dauncey states:

> Faced with the rapid increase in intermittent wind and solar energy, however, thinking about
>
> dispatchability is changing. In August 2017, US Energy Secretary Rick Perry's commissioned Report on Electricity Markets and Reliability emphasized the importance of smart control systems and electric cars:
>
>> "An aggregated fleet of vehicles or chargers can act as a [demand response] resource, shifting load in response to price signals or operational needs; for example, vehicle charging could be shifted to the middle of the day to absorb high levels of solar generation and shifted away from evening hours when solar generation disappears and system net load peaks."
>
> In BC, most EV drivers will charge their batteries at night, so their power draw won't impact the periods of peak demand when dispatchability is needed. BC's future EV owners could also have the ability to sell their battery power back to the grid in what's known as Vehicle to Grid (V2G), helping BC Hydro provide power to its customers at critical times of peak demand. In Denmark, EV owners are already earning money by plugging their cars into two-way charge stations.
>
> In 2016, Greentech Media research found that in 2025, in America, 11.4 million EVs could be adding 5 GW of storage capacity to the grid. BC's equivalent would be 72 MW.69 By 2040, if

[924] Submission F104-3, pp. 3-4.
[925] Transcript, pp. 1267-1273.

all of America 265 million vehicles were electric, they would add 116 GW of storage capacity to the grid. BC's equivalent with our smaller population would be 1,656 MW. This is significant, since it is more than would be provided by Site C.

Dispatchability can also come through 'demand response' whereby industrial and commercial customers are given advance notice and paid to reduce their demand at certain times. In Texas, with six times BC's population, half of their dispatchable power is already being obtained in this way. In January 2014, when a polar vortex knocked out several Texas power plants, "demand response provided 496 MW of capacity to the grid within 46 minutes of being called."

Cold ice storage is another form of demand response: large cold ice storage managers are paid a small incentive to add extra cold to their storage in the hours before peak demand, enabling them to switch off during peak demand. Home-owners can participate through the use of grid-interactive water heaters that are set to heat the water at night and avoid periods of peak demand. … As the savings from demand-side management and the energy from wind, solar and geothermal add up, especially in light of falling prices, it is clear that we are capable of meeting our future power needs without Site C. [926]

1.3.4.4 Panel analysis and findings

The Panel has reviewed the comments on the Illustrative Draft Alternative Portfolio and has addressed the three main options for capacity-focused DSM.

Optional time-based rates

Under this option, optional time-based structures are used to incentivize customers to shift electricity consumption away from peak demand periods. There are a number of mechanisms that can achieve this, including optional time-of-use rate structures, dynamic pricing such as optional Critical Peak Pricing (CPP) and optional Critical Peak Rebates (CPR).

The Deloitte report refers to the ACEEE 2017 benchmarking report which states that 76 percent of the utilities surveyed use time-based rates. Commission staff analysis of programs undertaken in other jurisdictions[927] indicates a considerable range of program designs utilizing time-based rates that have demonstrated a shift in demand from peak periods. For example, a report prepared for the Ontario Energy Board summarizes the results of programs undertaken in North America, including: [928]

- Ontario Smart Price Pilot – achieved load shift during critical periods of 5.7%-25.4% from CPP and 2.4% to 11.9% from CPR;
- Illinois Energy Smart Pricing Plan – using hourly market based rates, consumers made energy savings averaging 10% over a four year period;
- Washington D.C. PowerCentsDC Program – implemented time-of-use, CPP and CPR; residential CPP customers achieved reductions of 11-13%; and
- California Statewide Pricing Pilot[929] – peak energy reductions of 13% for fixed CPP and 16-27%.

[926] Submission F62-1, pp. 14, 15.
[927] For example, California Statewide Pricing Pilot, Florida Energy Select Program, Georgia PoweRewards, Illinois Energy Smart Pricing Plan, Ontario Smart Price Pilot, Washington D.C. PowerCentsDC Program, California Statewide Critical Peak Pricing, New Zealand Electricity Authority Customer Compensation Scheme.
[928] Power Advisory "Jurisdictional Review of Dynamic Pricing of Electricity," 2014.
[929] The California Public Utilities Commission has since implemented a Statewide CPP program that utilizes both mandatory and

The Panel notes that there are a considerable range of program designs that have been implemented in other jurisdictions that provide a wider scope for capacity reductions than currently under consideration by BC Hydro. Particularly, the Panel considers that additional utilization of optional CPP for commercial customers provides an opportunity to achieve capacity reductions additional to the BC Hydro estimates. The Panel also notes the potential for engaging residential customers with the implementation of smart metering.

The Panel acknowledges the issues of scalability and replicability of successful programs undertaken in other jurisdictions. However, the Panel considers that effective design of programs to meet the requirements of the BC Hydro peak periods, utilizing a range of potential optional time-based rate designs, can deliver highly cost-effective capacity reductions.

The Illustrative Draft Alternative Portfolio model assumptions were for optional time-based rates costs and capacity savings of 150 MW by F2027 and 430 MW total potential. The Panel notes BC Hydro's submission that commercial customer participation and utility costs would be lower than that expected in the 2012 IRP, but consider that they are reasonable overall. For this reason and the reasons outlined above, the Panel finds these assumptions to continue to be appropriate.

Capacity DSM Programs

The Panel finds that the assumed capacity savings and costs from Capacity DSM Programs in the Illustrative Alternative Portfolio model should be modified to mirror the estimates outlined in BC Hydro's response to BCUC IR 2.73.0 (referred to as Direct Load Control Programs), to 170 MW in F2023 and 210 MW in F2027, at a total utility cost of $55/kW-year.

Capacity DSM programs utilize equipment and load management systems to enable automatic or intervention-led peak load reductions. Examples of capacity-focused programs include load control of water heaters, heating, lighting and air conditioning. Customers may be offered financial incentive to participate or payment for equipment.

The Panel acknowledges the scale of capacity DSM programs will depend in part upon the success of pilots and technological advancement. The Panel notes that BC Hydro is undertaking trials including Residential Hot Water and Commercial and Industrial Demand Response as part of $38 million requested as part of its F2017–F2019 RRA, to gain a better understanding of the potential for wider implementation of capacity DSM programs. The Panel also notes the BC Hydro pilot study conducted in Kamloops on automated demand response and direct load control which identified 53 MW of potential capacity savings, which extrapolates to 500 MW potential province-wide.[930] Elsewhere, the Northwest Power Council has estimated that up to 48% winter savings could be possible from demand response programs in the residential sector by 2021.[931] Research by Brattle indicates that electric water heating demand response programs could generate customer benefits of $200/year under certain market options, presenting a short payback period for participation.[932] CanWEA notes programs in other jurisdictions, such as Ontario, that automatically shut off domestic hot water heaters during periods of peak capacity.[933]

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voluntary enrollment of commercial customers.

[930] F106-1 Submission, Appendix B, p. 16, citing Enbala Power Networks (Undated), Capacity Focused Demand Side Management at BC Hydro: Industrial and Commercial Potential in the Kamloops Region.

[931] Seventh Northwest Conservation and Electric Power Plan, p. 14-5.

[932] http://www.brattle.com/system/news/pdfs/000/001/007/original/The_Hidden_Battery_-_Opportunities_in_Electric_Water_Heating.pdf?1455129462.

[933] Transcript, pp. 1267–1273.

The Panel also considers that in future, further capacity DSM programs may be available to BC Hydro due to technological advancement. One such example is electric vehicle-to-grid applications, which are currently at an early stage of development with small-scale utility and micro-grid pilot projects underway to establish proof-of-concept. In a Pacific Gas and Electric Company (PG&E) pilot involving 100 BMW electric vehicles, PG&E successfully dispatched 209 demand response events to electric vehicle owners for vehicle-to-grid charging, totaling 19,500 kilowatt-hours with an average contribution of 4.4 kW per vehicle participating.[934]

The Panel considers the Illustrative Draft Alternative Portfolio estimates of program capacity were higher than BC Hydro estimates in the 2012 IRP, and therefore finds that volumes and cost should be adjusted to reflect BC Hydro's updated data as provided in response to BCUC IR 2.73.0 for the Illustrative Alternative Portfolio.

Industrial load curtailment

The Panel agrees with AMPC's submission in finding that 400 MW of capacity savings from industrial load curtailment could be available at $75/kW-year, with more reasonably available, and that the Illustrative Alternative Portfolio should reflect this.

Industrial Load Curtailment involves capacity payments to large industrial customers for reducing load at short notice during peak periods.

The Panel notes that BC Hydro submits that it would require a minimum 10 hour product to meet peak loads,[935] and that the Industrial Load Curtailment pilot required curtailment for periods up to 16 hours. The Panel agree with the CanWEA and CEABC submission which proposes that BC Hydro could call upon successive groups of customers to realize its required load reduction. Multiple industrial customers or time products could be called upon to layer additional curtailment resources. The Panel also notes that in the first year, the pilot resulted in higher than expected load curtailment, which also resulted in costs lower than estimated.

The Panel therefore finds that the capacity savings of Industrial Load Curtailment can be increased to meet up to 400 MW of capacity in the Illustrative Alternative Portfolio under the existing cost assumptions

Summary of Panel analysis and findings

The Panel has concluded the following with regard to assumptions for capacity focused DSM in the Illustrative Alternative Portfolio:

- **The Panel finds the assumptions for capacity reductions from optional time-based rates to be reasonable;**
- **The Panel has considered it appropriate to reduce the estimated capacity savings from Capacity DSM Programs and update the cost assumptions; and**
- **The Panel finds that greater capacity savings can be achieved from Industrial Load Curtailment than assumed in the Illustrative Alternative Portfolio**.

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[934] http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf.
[935] F1-17 Submission, p. 15.

2.0 Appendix B – Columbia River Treaty Entitlement

The Columbia River Entitlement is the Canadian portion of the potential for additional electricity produced in the Columbia River in the western US as a result of the Columbia River Treaty (CRT) ratified in 1964. The Provincial Government owns the Canadian Entitlement and Powerex markets the energy, under an agreement with the Province. While the Province receives the financial benefits of the Canadian Entitlement, BC Hydro has access to the physical product (energy and capacity) and can use it as a source of limited supply.

BC Hydro states that it doesn't rely on the Columbia River Treaty Entitlement for the following reasons:

1. The *Clean Energy Act* (CEA)requires that BC Hydro be self-sufficient for energy and capacity by being able to supply mid-level load forecasts planning to average water from heritage hydro and only with resources in B.C. that we have contracted with or own;
2. Access to the electricity markets and delivery of the CE all rely upon the same I-5 transmission corridor through the Seattle region that is frequently constrained. BC Hydro has previously limited the reliance on US for no more than 300-500 MW due to transmission restrictions;
3. The CRT can now be terminated with 10-years notice. While notice was not given for the earliest potential termination date fiscal 2024, there is a high likelihood that negotiations between US and Canada may begin this year and that Canadian Entitlement would be within the scope of negotiations. The U.S. has been seeking a reduction of power benefits to Canada. The timing for any revisions is uncertain but could occur as early as 2024.[936]

With respect to the issue of 10 years notice, Harry Swain submits that "[e]ither side can denounce the treaty with ten years' notice, but that is hardly likely; and even were it to occur, ten years is plenty of time to arrange alternative supply."[937]

Allied Hydro Council of BC (AHC) submits that "[t]he 1964 Columbia River Treaty (CRT) principal features are:

- Three storage facilities were to be developed and operated on the Columbia and Kootenay rivers.
- Most of the obligations and benefits under the CRT were transferred by Canada to BC.
- The principal purpose of the CRT was to provide flood control and power generation improvements for the US, with financial and power supply benefits returning to BC/Canada.
- BC Hydro built facilities at Mica, Keenleyside and Duncan, a total of 15.5 million acre-feet of storage, most of it at Keenleyside and Mica.
- The CRT allowed the US to build Libby dam in Montana in 1973 without any compensation to Canada although BC power plants did benefit from regulated flows at Libby. There are flood control benefits as well. The US obligation to coordinate flows with Canada at Libby continues whether or not there is a CRT.
- Water levels in Kootenay Lake are regulated by the International Joint Commission (IJC) under the Kootenay Lake Order. The Order is administered by FortisBC.
- The CRT requires operation of Libby to be consistent with the Order.

[936] F-1 Submission, Appendix L, p. 48.
[937] F36-1 Submission, p. 15.

- BC receives 50 percent of the additional power generation made possible in the US, the “Downstream Benefits” or DSBs.
- The DSBs are 1,250 MW of capacity, 4,000 GWh/year, valued at roughly $150 million/year priced at $38/MWh, roughly equal to the average market price at Mid C in Washington State; also valued at $515 million/year priced at $129/MWh, what BC Hydro has said in the past is the cost of firm replacement clean energy.
- The first value equates to $1 .688 billion and the second $5.798 billion, in present value terms over 30 years at 8 percent discount.
- Under the CRT BC and the US develop Assured Operating Plans (AOP) every five years focusing on flood control and power generation. The AOP is used to calculate the DSBs.
- There are also annual Detailed Operating Plans (DOPs).
- BC Hydro, Army Corps of Engineers and Bonneville Power Administration develop and implement the AOPs and DOPs.
- The priority of water use under the CRT is: 1) consumptive uses; 2) flood control; 3) firm energy; 4) reservoir refill; and 5) secondary energy.
- Water Use Plans in BC and Variable Flow operations (VARQ) in the US have superseded CRT operating plans in a number of instances, sometimes with compensation to the other side.
- The CRT can be terminated by either Canada or the US unilaterally at any time after September 16, 2024, if notice is given by September 16, 2014.
- However Canada cannot give notice of termination without consent from BC.[938]

AHC further submits that “the US Bonneville Power Administration and US Army Corps of Engineers made their final recommendations on the CRT to the US federal government in December, 2013 and the recommendation is to ‘ modernize’ the CRT. Allied Hydro further states:

> The US Entity says the Canadian DSBs are significantly larger than the value of coordinated power operations (the US implies the power benefit from the CRT is equal to just 10 percent of the DSBs).
>
> BC, it is understood, does not accept the US position and on March 13, 2013 announced " the decision to continue the Columbia River Treaty and seek improvements within its existing framework."
>
> British Columbia says the only benefit to Canada of continued coordination under the Treaty beyond 2024 is the return of the Canadian Entitlement, which is one-half the incremental downstream power potential resulting from the Treaty operations.
>
> According to the Province, beyond the DSBs, it receives no benefits from coordination of flows for power generation or flood control. The DSBs, BC says, in fact are less than 50 percent of the benefits the US receives from CRT coordination for flood and power purposes.
>
> Thus the DSBs are roughly equivalent to Site C in terms of capacity and energy. The DSBs could be taken back to BC from the USA, so they may appear to be "free." But that would require the construction of a new, high voltage power line (230 kV to 500 kV). Such a

[938] F24-1 Submission, p. 12.

> transmission line could cost about $2million/km, based on BC Hydro's Northwest Transmission Line (NTL) cost, so in the range of $500 million to $ 7 50 million.
>
> Currently BC Hydro sells the DSBs in the Washington/Oregon market at relatively low prices, low because of heavily subsidized green wind energy supplies in those states. The price has been in the US$35/MWh to US$50/MWh for some time. If BC Hydro was to take back the DSBs this price would be the " opportunity cost" of the supply, the lost revenues - it is not really free.
>
> In addition to the transmission line investment and opportunity cost considerations are others. BC Hydro has consistently said that it would not want to rely on more than 500 MW of DSBs because they essentially are imports and security of supply is an issue (perhaps more so given current US trade policies). The long-term future of the DSBs is not certain. As noted, the US could terminate the CRT at some point, although no notice has yet been given.
>
> It is worth, however, considering what the cost of supply would be should BC repatriate 500 MW of DSBs and the associated energy, about 1 ,600 GWh/year. The opportunity cost, as indicated would be about $60 million/year. The capital cost for the $500 million. transmission line plus the opportunity cost would be $107 million/year, which would indicate a unit cost of roughly $105/MWh, assuming a 30- year arrangement.” [939]

The CCPA argues that “[i]n addition to the development of an expanded portfolio of renewable alternatives, another option to meet future needs is to make full use of the Canadian Entitlement or the “downstream benefits” as a result of the Columbia River Treaty with the United States. This is a significant block of electricity, amounting to about 4,300 GWh of firm energy, roughly eight per cent of what BC uses each year. BC is entitled to this energy in compensation for the construction of three large reservoirs on the Columbia River on the Canadian side of the border, built to store water from the spring run-off and release it later in the year, enabling both flood control and generation of additional electricity in the US, half of which is owned by the BC government but immediately sold back to the US.”[940]

The Program on Water Governance, University of British Columbia recommends that “the Commission recommend that the Government enact a regulation allowing BC Hydro to take its entitlement under the Columbia River Treaty into account in its energy and capacity planning. Doing so will result in much lower resource costs to ratepayers, in both a mid-load and high-load scenario.” It calculates that reliance on 50 percent of the annual energy and capacity from the Canadian Entitlement when Site C is cancelled would increase savings to $610 million in the mid load scenario and $790 million in the high load scenario. Similarly, if Site C is suspended, reliance on 50 percent of the Canadian Entitlement would reduces (sic) costs by $400 million in the mid load scenario and $880 million in the high load scenario.”[941]

2.1.1.1 Panel analysis and preliminary findings and questions in the Preliminary Report

The Columbia River Entitlement is not available to BC Hydro because of the restrictions in the CEA. However a number of parties, including BC Hydro have commented on the Columbia River Entitlement. Accordingly the Panel will provide its preliminary analysis of this issue.

[939] F24-1 Submission, pp. 15, 16.
[940] F60-1 Submission, p. 14.
[941] F106-2 Submission, Executive Summary, pp. i–ii.

The prohibition outlined in the CEA requires that energy be generated in Canada and this is clearly not the case with the treaty energy. However, the production of hydroelectricity benefits when there is storage, and control of that storage so that the reliance on the run-of-river. As BC Hydro has argued, it becomes more valuable because of its dispatchability and other attributes that the reservoir brings. Further, as BC Hydro has argued in the case of Site C, having a large reservoir upstream allows for the production of energy downstream with a much smaller reservoir than would be required without the upstream reservoir. However, it requires BC Hydro to manage flows from Williston reservoir with flows through Site C in a holistic way.

In an analogous manner, the ability of generators along the Columbia River in the US to generate the treaty entitlement energy relies upon reservoirs in British Columbia and the management of water flowing into and out of those reservoirs and it is managed in British Columbia in such a manner that it increases the amount of water.

It is the Panel's view that the original intent of the treaty Entitlement was to compensate Canada, and by extension British Columbia, for the any costs incurred by this arrangement.

There are parties, including BC Hydro, that argue because the treaty could be terminated on notice, in 10 years, and because the situation with respect to the Columbia River Treaty is politically volatile, this option should not be considered as an alternative to Site C.

The Panel noted that the amount of energy and capacity available to the province in the treaty is approximately equal to the amount of energy and capacity that Site C will provide. In addition it is as clean as the energy that will be produced by Site C. Because of the possible temporary availability of this energy it may not be appropriate as a long term supply. If it was appropriate to use as a short to medium term supply, there would be changes to the CEA required.

The Panel also noted AHC's estimate of the amount of revenues that Powerex would forgo over the next thirty years if BC Hydro were to utilize the Columbia River Treaty entitlement. They calculate the opportunity cost for 1,250 MW of capacity and 4,000 GWh/year as $1.688 billion, in net present value terms over 30 years at 8 percent discount. Further BC Hydro considers this to be "firm replacement clean energy." In addition, a transmission line upgrade estimated at $750 million may be required. This represents a total net present value of approximately $2.438 billion, although this NPV should be calculated at the time the energy is needed, say 2030, so should be discounted further 12 years.

2.1.1.2 Relevant new submissions

McCullough, on behalf of the Peace Valley Landowner Association and Peace Valley Environmental Association submits:

> There have been many mentions of the Canadian Entitlement under the Columbia River Treaty in this proceeding. British Columbia Hydro rejects the Canadian Entitlement for a variety of reasons as a source for energy and capacity other than "for a short-term bridging or contingency resource."
>
> Perhaps because the subjects of the Columbia River Treaty and the Canadian Entitlement are so challenging, British Columbia Hydro's discussion neglected to address the surplus resources on their own system – specifically those currently addressed by the Columbia River Non-Treaty Storage Agreement.

This agreement covers considerably more firming, shaping, and storage than Site C and has been valued at US$8 million per year.

The context for the Non-Treaty Storage is, of course, the Columbia River Treaty. The Treaty is currently in the early stages of renegotiation. Outside of the negotiators at British Columbia Hydro, the Bonneville Power Administration, and the U.S. Army Corps of Engineers, few understand its complex mechanics and financial implications. Below, the history and the operations of the treaty will be briefly addressed.

The geography of the Northwest Power Pool includes massive hydroelectric potential provided by the U.S. and Canadian Rocky Mountains. The headwaters of the Columbia River extend into British Columbia and then cross Washington State until emptying into the Pacific near Astoria, Oregon. The Columbia Gorge provides many excellent locations for hydroelectric dams since the river passes through a relatively narrow canyon. Although this is excellent for dams and generators, it is not ideal for storage. The storage opportunities are on the Canadian side of the border.

British Columbia's negotiators have provided an excellent discussion of the system:

> The Columbia River in Canada has three dams in series – Mica, Revelstoke, and Hugh Keenleyside. The upstream most project – Mica – is the largest storage on the whole Columbia system with 12 MAF of active storage. It for aily/weekly shaping.
>
> Mica and Revelstoke will have a combined generating capacity of approximately 5,700 megawatts (MW) by 2024, or 50% of BC Hydro's generating capacity, and are critical in reliably meeting British Columbia domestic load. Hugh Keenleyside Dam is the third project in the series. It is a low head dam and despite being the third largest reservoir in British Columbia with 7 MAF of active storage, it has relatively little power generation. The primary purpose of this dam was to provide flood control and power benefits to the U.S. under the Treaty. In 2002, the 185 MW Arrow Lakes Generating Station was installed adjacent to the dam.
>
> Duncan Dam (1.4 MAF) on the Kootenay River is the third Canadian Treaty dam and does not currently have any power generating capability.

The basic logic of the treaty was to tie the operations of storage in British Columbia to the generation in Idaho, Montana, Oregon and Washington.

This was a very prudent solution to the extreme variability of flows along the Columbia River. Unlike many other hydroelectric systems, the Columbia River's annual flows can vary dramatically. Without extensive storage, the firm generation along the Columbia would be significantly diminished. The total generation might be roughly the same, but the amount of dependable generation would be considerably less.

The treaty also created the "Canadian Entitlement," which compensates British Columbia for the use of their reservoirs:

> This delivery [of the Canadian Entitlement] ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.

The U.S. Entity has a variety of materials available on the treaty and its benefits:

> Before the Columbia River Treaty, high springtime flows on the Columbia River frequently overwhelmed the ability of the United States' downstream infrastructure to generate power and manage flood risk. The four dams built under the terms of the 1964 Columbia River Treaty (three in Canada and a fourth in Montana) approximately doubled the water storage capacity on the Columbia River system. The Treaty and Treaty dams enhanced the cooperation between the U.S. and Canada, helping to ensure mutually advantageous operation of the dams by improving the ability to regulate the timing of streamflows by capturing high spring flows and releasing this water more gradually over the summer, fall and winter months. Overall, the coordinated storage and regulation of flows between the United States and Canada vastly improved both hydropower production and flood mitigation in the Columbia Basin.
>
> The increased power generation in the United States resulting from the operation of additional storage capacity created by the three Treaty dams built in Canada is referred to as the downstream power benefits. The Treaty negotiators in the early 1960s agreed that the United States and Canada would equally share these benefits, which are calculated annually according to a complex method negotiated among the Treaty's authors. It is essentially a theoretical value placed on the additional generation. Canada's half of these calculated downstream power benefits is called the Canadian Entitlement.

McCullough raises the issue of non-treaty storage at the Mica dam:[942]

British Columbia's three dams provide more storage than is covered by the treaty:

> Coordination of the Pacific Northwest and BC Hydro systems began in 1964 with ratification of the Columbia River Treaty (Treaty). Under the Treaty, Canada was required to construct and operate 15.5 million acre-feet (MAF) of storage in Canada at Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAF of storage at Libby Dam. BC Hydro designed and built Mica dam to store more water than the 7 MAF required under the Treaty. As a result, an additional 5 MAF of usable storage is available at Mica.
>
> This extra storage is referred to as non-Treaty storage and is not operated under the terms of the Treaty. The Treaty limits use of non-Treaty storage to actions that do not reduce Treaty flood control and power benefits. Within that constraint, BC Hydro has used the storage space for its benefit by redistributing water among its reservoirs. BPA access to this storage is obtained only through negotiation of operational agreements that provide mutual benefits to the BPA and BC Hydro. Absent an agreement, the benefits of releasing water from Arrow across the Canada-U.S. border cannot be achieved. [943]

To describe the Non-Treaty Storage Agreement very concisely, British Columbia built more storage at Mica than is required by the treaty and has rented this storage to the Bonneville

[942] Ibid., p. 8.
[943] F35-21 Submission pp. 3-8.

> Power Administration (BPA) for the past fifty years under a series of agreements that are due to expire in 2024.
>
> BC Hydro has rented 1.5 MAF (million-acre feet) of storage capacity with an option for another 1 MAF to the Bonneville Power Authority (BPA). This agreement is due to expire in 2024. Instead of renewing this agreement, BC Hydro could choose to use this Mica storage capacity in addition to or as a replacement for battery storage in the alternative portfolio.

Ruskin submits that the treaty is likely to continue until at least 2040 given the growth in surplus power that is projected in the US over this period, and the flood control benefits to the US and associated Canadian liability for this risk.[944]

2.1.1.3 Panel analysis and findings

While Columbia River Entitlement is not available to BC Hydro because of the restrictions in the CEA, the Panel confirms its view expressed in the Preliminary Report that the amount of energy and capacity available to the province in the treaty is approximately equal to the amount of energy and capacity that Site C will provide.

The Panel is also persuaded by McCullough's arguments describing the significant benefits of the Columbia River Treaty (CRT) to the US by regulating the timing of stream flows. The Panel therefore discounts BC Hydro's arguments that the ability to terminate the treaty on 10-years notice supports excluding the downstream benefits of the CRT from consideration of potential energy and capacity options to supply future load growth.

The Panel also notes McCullough's evidence regarding the additional storage at the Mica dam that has been sold to Bonneville Power Authority under a contract expiring in 2024, and that it could subsequently be used by BC Hydro to meet domestic needs (provided its use does not reduce CRT flood control and power benefits).

While insufficient evidence was provided in this Inquiry to conclude that the additional Mica storage should be included in the Illustrative Alternative Portfolio, the Panel considers that the additional Mica storage may have the potential to reduce the PV cost of the Illustrative Alternative Portfolio.

[944] F26-5 Submission, pp. 2-3.

3.0 Appendix C – Commission Illustrative Alternative Portfolio

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry Respecting Site C

Section 3(b)(iv) of the OIC asks:

> Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?

At the request of the Panel, Commission staff prepared an illustrative Alternative Portfolio (one for each of BC Hydro's July 2016 load forecasts) based on information submitted in the Site C Inquiry. An excel based model was developed to assist in this process, using as a starting point a spreadsheet provided by BC Hydro in response to Panel Question No. 2 of submission F1-4 (Attachment 3 to Question No. 2). The model calculates the the Net Present Value (NPV) of the revenue requirements associated with the Alternative Portfolio.

The Panel invited comments from BC Hydro and other parties on the Alternative Portfolio of generating projects and demand-side management (DSM) initiatives; in particular:

- The underlying assumptions regarding the Alternative Portfolio (see the Key Assumptions table for descriptions of all key assumptions); and
- The calculations, inputs and assumptions used in the Alternative Portfolio Spreadsheet

As a result of comments received, changes were made to the key input assumptions included in the Commission model. The Commission model was also revised to make it easier for users to determine the effect on the results of changing key input assumptions and is published as an attachment to this report.

The Panel is mindful of the comments by BC Hydro and other parties that resource planning is a complex exercise. This exercise is not a substitute for BC Hydro's planning process. We consider that the Commission's Illustrative Alternative Portfolio presented in this report is illustrative only, and was developed as a way to answer the questions posed in the OIC. It was informed by the evidence available, including portfolios presented by BC Hydro that were produced by its PV Portfolio Analyzer.

This Appendix describes the revised key input assumptions that are now used in the updated model, and provides a description of the model itself and its functionality. The purpose is to increase the transparency of the approach used by the Commission to answer the OIC question, and to assist users in understanding the sensitivity of the model output to key input assumptions.

3.1 Key Assumptions

The following table shows the key assumptions made in developing the Alternative Portfolio.

	Portfolio Assumption
1. Discount rate	The discount rate proposed by BC Hydro for Site C (6% nominal, 3.9% real) has been assumed.[945]
2. Financing costs, taxes	The financing costs of the Alternative Portfolio are assumed to be the same as BC Hydro's financing cost for Site C (100% debt financing at a cost of 3.43%).[946] Grants in lieu of taxes and school taxes (GIL/ST) were assumed to be the same as that used by BC Hydro for Site C.[947] 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.[948] 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
3. Alternative Portfolio options	Three portfolios were developed in total, one for each BC Hydro 2016 load forecast.
4. Size of the Alternative Portfolio	The Alternative Portfolio has been sized to replace Site C energy and capacity used for domestic consumption. Specifically, the Alternative Portfolio does not include generation built for the purpose of export. The starting point is the "energy and capacity load resource balance after planned resources" from BC Hydro's Table K-3a and Table K-4a in supplemental response to BCUC IR 2.21.0. The Site C energy and capacity is then subtracted from the surplus/deficit. When subtracting the Site C capacity, a downward adjustment was made to take into account the 14% of supply requiring reserves. Where there is no resulting deficit, there is no gap to fill. Where there is a deficit, the size of the gap to fill is the lower of Site C energy/capacity[949] or the load forecast gap. The F2017–F2019 RRA low load forecast ends in F2036. For the purpose of the low load forecast, a ramp up of 800 GWh/year for energy and 200MW/year for capacity has been assumed.

[945] F1-1 submission, Appendix K, p. 3.
[946] F1-1, Appendix K, p. 4.
[947] F1-4 submission, Question 2, Attachment 3. It is noted that taxes for an IPP may be different.
[948] F1-4 submission, IR 1.2, Attachment 3, Tab 'Assumption Summary; Submission A-13, p. 86.
[949] Ibid.

	Portfolio Assumption
5. Location of the Alternative Portfolio	The Alternative Portfolio reflects a "plant gate" cost, and the location for wind build has been set to be similar to Site C (Peace region) to minimize the risk of additional network reinforcements relative to Site C.
6. Energy surplus to BC Hydro need	In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the energy is assumed to be exported at a plant gate export price ranging from real F2018 CAD $22.3/MWh in 2018 to real F2018 CAD $42.4/MWh in 2040. This is based on: • a Mid-C market price forecast between the BC Hydro proposed Mid-C market price and ABB's bottom forecast range.[950] Approximately, the Mid-C market price rises each year by CAD $1/MWh in real terms starting with a Mid-C market price at real F2018 CAD $32/MWh in 2018 with real escalations to real F2018 CAD $55/MWh in 2040, • less losses (1.9%) and wheeling costs ($6.3/MWh) to the US/Canada border;[951] and • less 11% incremental transmission losses to Site C plant gate location.[952] The underlying data is included in the 'Sensitivity Data' tab. The updated spreadsheet now also allows for the application of different market price assumptions, as adjusted to a plant gate location: (i) market prices forecast in BC's F2017-F2019 Revenue Requirement Application[953], and (ii) the ABB low end of the forecast of BC Hydro's market price forecast.[954]
7. Capacity surplus to BC Hydro need	In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill, and to the extent that it is surplus to BC Hydro's requirements, the surplus capacity is assumed to have no additional value to BC Hydro (i.e., an export price of CAD $0/kW-year).[955]
8. Energy exceeding Site C	In any year, if the energy of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the cost of the Alternative Portfolio will be reduced proportionally. For example, if the Alternative Portfolio generates 5,564 GWh compared to a gap to fill of 5,286 GWh, only 95% of the cost of the Alternative Portfolio for that year will be included in NPV of the Alternative Portfolio.

[950] See BC Hydro F1-1 p. 64, Figure 15 "Comparison of Site C Unit Energy Cost to Mid Columbia ("Mid C") Market Electricity Price (F2018$/MWh)"
[951] Submission F1-8, IR 2.22.1.
[952] BC Hydro submits that wind transmission losses are $9/MWh on a levelized firm energy price of $83/MWh (F1-1 submission, Appendix L, pp. 19, 20).
[953] Submission F106-1, p. 68.
[954] Submission F1-1, Figure 15, p. 64.
[955] Submission F18-3, p. 22, Submission F35-2, p. 9.

	Portfolio Assumption
9. Capacity exceeding Site C	In any year, if the capacity of the Alternative Portfolio exceeds that of the gap to fill and is used to meet BC Hydro's domestic load requirements, the Alternative Portfolio will be credited with the assumed value of this additional capacity at $50/kW-year. The surplus capacity was further adjusted to take into account the 'energy adjustment' described under Assumption 8 above to remove any double-counting effect. This is referred to as capacity credit in the analysis.[956]
10. Energy and capacity Options	The energy and capacity options included in the illustrative Portfolio Alternatives are: wind, energy efficiency DSM programs, capacity focused DSM programs, optional TOU rate, industrial curtailment rate, and geothermal plants. It is acknowledged that there may be additional options that could reduce the cost of the Illustrative Alternative Portfolio, such as codes and standards, Independent Power Producer (IPP) contract renewals, upgrade of existing BC Hydro assets, solar, biomass, etc.[957]
11. Energy efficiency DSM	This energy efficiency option represents BC Hydro's Integrated Resource Plan (IRP) DSM Incremental to RRA DSM option.[958] Energy volumes have been grossed up by 11% for avoided transmission real power losses to be comparable to wind plant gate supply side options.[959] Associated capacity is adjusted to reflect the 14% reserve requirement that is required from generating resources by not demand side resources. For the purpose of comparison to Site C costs, societal costs/benefits of energy efficiency DSM have not been included. However, it is assumed that energy efficiency DSM programs in this portfolio would pass the total resource cost test (i.e. BC energy savings exceed BC costs). The cost of energy efficiency DSM has therefore been included at the utility cost to BC Hydro (i.e., it includes the cost to BC Hydro of an incentive to encourage customers to install efficient lightbulbs, rather than the cost of the lightbulbs before the incentive). Costs are deferred and amortized over 15 years.

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[956] Submission F35-5, p. 15; Estimated based on post F2030 $/kW cost of batteries from NERL. 2016. *Exploring the Potential Competitiveness of Utility-Scale Photovoltaics plus Batteries with Concentrating Solar Power 2015-2030*'. https://www.nrel.gov/docs/fy16osti/66592.pdf, (p. 18, figure 18, median line), assuming a 10 year battery life.
[957] For example, BC Hydro estimates the plant gate cost of utility solar to be $48/MWh in 2025 and $44/MWh in 2035 (F1-8 submission, BCUC 68.4), and that 200 GWh/year of sawmill waste biomass energy could be available in West Kootenay at a cost of $25/MWh (Submission F1-11, IR 2.67.0).
[958] Submission F1-5, IR 2.64.0, Attachment 1.
[959] Wind transmission losses are $9/MWh on a levelized firm energy price of $83/MWh (F1-1 submission, Appendix L, pp. 19, 20).

	Portfolio Assumption
12. Wind – project characteristics	Wind project characteristics (load, annual energy, installed capacity) were taken from BC Hydro's portfolio results.[960] Effective load carrying capacity and plant life for each project was taken from BC Hydro's resource options spreadsheet. [961]
13. Wind – capital and O&M cost	Wind capital and operating costs are taken from the National Renewable Energy Laboratory (NERL) 2017 Annual Technology Baseline.[962] NREL costs were increased by 10% in light of cost differences between BC Hydro's 2015 capital costs in BC Hydro's resource options spreadsheet and NREL 2015 estimates for wind investments of similar capacity factor. Costs were converted to Canadian dollars and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet.[963] Wind capital costs and operating costs were increased to account for transmission and road costs, with values derived from the project specific cost estimates from BC Hydro's resource options spreadsheet. [964] Wind farms are assumed to be refurbished at the end of 25 years at a cost 30% less than the cost of a new wind farm.[965] The user can perform a sensitivity analysis around the wind energy costs. The medium value reflects the above description whereas the high value assumes an additional 20% cost adder. The low value assumes a 5.9% cost reduction.[966] The underlying data is included in the 'Sensitivity Data' tab.
14. Wind – wind integration	It is assumed that BC Hydro has sufficient wind integration ability as a result of its existing hydro assets to integrate the wind included in the Alternative Portfolio. The cost of wind integration is therefore assumed to reflect an incremental reduction in the potential of BC Hydro to export its wind integration services into neighbouring markets. Assumed wind integration costs resulting from the Alternative Portfolio have been reduced to \$1/MWh, taking into account concerns raised with BC Hydro's \$5/MWh estimate.[967]

[960] Submission F1-1, Appendix Q, page 8.
[961] Submission F1-4, Attachment BCUC_1_001_00_ATT_01.xlsm, UEC_UCC tab (select wind project from cell K9, dependable capacity is shown in cell D23.
[962] Submission F35-5, p. 15; NREL (National Renewable Energy Laboratory). 2017. *2017 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html , land based wind tab, TRG4 mid (weighted average net capacity factor of 43.5%).
[963] Submission F1-4, Attachment BCUC_1_001_00_ATT_01.xlsm, resource options tab, cell BD1.
[964] Submission F1-4, Attachment BCUC_1_001_00_ATT_01.xlsm, UEC_UCC tab, cells K22:L29, uplifted for inflation based on Resource Options tab, cell BD1.
[965] Submission F18-3, p. 30.
[966] Submission F104-3, p. 4.
[967] Submission F1-1, p. 63; Submission F18-3, pp. 14–17; Submission F18-6, p. 5; Submission F272-2, p. 7.

	Portfolio Assumption
15. Capacity DSM	Utility costs and cumulative capacity savings for optional time based rates were estimated from the graphs on page 3-21 of BC Hydro's 2012 draft IRP. Utility costs and Costs. Costs are deferred and amortized over 15 years. Utility costs and cumulative capacity savings for capacity focused DSM programs are based on BC Hydro's response to a Commission question in the Preliminary Report.[968] Costs are deferred and amortized over 15 years. Industrial curtailment costs were assumed at $75/kW-year based on BC Hydro's industrial load curtailment pilot, available at 1 MW increments. Maximum volumes are set at 400MW based on a submission by AMPC. [969] Costs are expensed in the year incurred.
16. Geothermal – capital and O&M costs	Geothermal capital and operating costs are taken from the National Renewable Energy Laboratory (NERL) 2017 Annual Technology Baseline.[970] Costs were converted to Canadian dollars, and historical inflation estimates for F2015 to F2018 were taken from BC Hydro's resource options spreadsheet. [971] Geothermal plants are assumed to be refurbished at the end of 25 years at a cost 30% less than the cost of a new plant.[972] The user can perform a sensitivity analysis around the geothermal energy costs. The medium value reflects the NREL capital and O&M costs for hydrothermal flash technology, whereas the high value reflects the NREL capital and O&M costs for hydrothermal binary technology. The low value reflects the project-specific costs that CanGEA submitted in F66-4. The underlying data is included in the 'Sensitivity Data' tab.
17. Exchange rate	Exchange rate of $1 CAD = 0.7979 USD.[973]
18. Firming	Firming capability is the ability of resources to quickly change output in response to changes in customer demand and output from variable generation resources that fluctuate within the hour (e.g., wind or solar). It is assumed that BC Hydro has sufficient firming capability as a result of its exiting hydro assets to meet domestic needs. The Alternative Portfolio does not build for export of firming services into neighbouring markets.

[968] Submission F1-11, IR 2.73.0.
[969] Submission F81-2, p. 8.
[970] Submission F35-5, p. 15; NREL (National Renewable Energy Laboratory). 2017. *2017 Annual Technology Baseline*. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html , geothermal tab, GEO-Hydro Flash (net capacity factor of 90%).
[971] Submission F1-4, Attachment BCUC_1_001_00_ATT_01.xlsm, resource options tab, cell BD1.
[972] Submission F106-11-1, PoWG, 'energy and capacity balance' tab, lines 7, 8.
[973] Submission F1-1, Appendix K, p. 3.

	Portfolio Assumption
19. Shaping, storage	Shaping capability is the ability of resources to reduce their generation supply within the day to allow the electricity system to absorb variable resource electricity (e.g., wind, run-of-river, solar) when its customers do not need it and then to release that energy later in the day when it is required. It is assumed that BC Hydro has sufficient shaping capability as a result of its exiting hydro assets to meet domestic needs. The Alternative Portfolio does not build for export of shaping services into neighbouring markets. Storage capability is the ability of resources to adjust their generation supply at certain periods within the year to respond to seasonal changes in variable generation resources (e.g., run-of river hydro output is highest during the spring freshet and lower in the late summer). It is assumed that the shape of energy generated from Site C and an Alternative Portfolio comprised of energy efficiency DSM, capacity focused DSM and wind energy to be of similar quality.
20. Grid reliability	Grid reliability means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards. It is assumed that the Alternative Portfolio results in similar levels of grid reliability compared to Site C as a result of (i) the inclusion of wind integration costs, (ii) by siting Alternative Portfolio resources at the end-user location (for DSM) or at the Site C location (for wind); and (iii) by addition of a cost adder to the wind farm costs to account for network upgrades. The Alternative Portfolio does not include an adjustment for potential benefits (in the low load forecast case) related to deferral of the cost of incremental firm transmission required for Site C from F2024 to F2039.
21. Greenhouse gas emissions	It is assumed that the Alternative Portfolio has similar levels of greenhouse gas emissions compared to Site C.
21. Flexibility credit	This adjustment applies to Site C only and not the Alternative Portfolio. Site C is assumed to provide 900MW of wind integration that will be surplus to BC's own requirements. It is assumed that BC Hydro will be able to export the incremental wind integration ability arising from Site C into neighbouring markets at the previously estimated wind integration cost of $1/MWh. This results in a Site C 'wind integration credit' of $3.36 million a year.

3.2 Description of the Model

The following table provides a general description of each of the tabs in the Alternative Portfolio Excel spreadsheet. These descriptions are linked to the Key Assumptions table regarding key data sources and inputs.

<table>
<tr><th colspan="2">Summary of Alternative Portfolio Spreadsheet</th></tr>
<tr><th>Tab Name</th><th>Tab Overview</th></tr>
<tr><td>Input and Output</td><td>The purpose of this tab is to create a user-friendly interface that identifies the key inputs to the model on the left-hand side, which the user can change either by inputting a different value into a cell or by using the drop-down menu of options. The model outputs are presented on the right-hand side, for the three load scenarios, and adjust automatically when key inputs are changed. The key outputs are the Alternative Portfolio’s Total Rate Impact, for each load scenario, in F$2018 and the Unit Energy Cost of the Alternative Portfolio, in $/MWh.</td></tr>
<tr><td>Tornado</td><td>The purpose of this tab is to show the sensitivity of the Alternative Portfolio results to variations of key input assumptions. The sensitivity analysis is then presented as a Tornado graph. The Base Case defines the values taken by each of the key variables. Then, each variable is changed to a low/high value while holding all the other variables constant, and the effect on the Total Rate Impact is reported in the table.

A sensitivity analysis has been performed on the following input/assumptions:
Load scenario
Value of termination costs
Amortization period of termination costs
Financing costs for wind and geothermal energy projects
Market price of energy surplus
Wind costs (capital and O&M)
Geothermal costs (capital and O&M)</td></tr>
</table>

Summary of Alternative Portfolio Spreadsheet	
Tab Name	**Tab Overview**
Energy & capacity gap	The purpose of this tab is to identify the size of BC Hydro's energy and capacity load resource balance after planned resources without Site C, under BC Hydro's three 2016 load forecast scenarios. The starting point is the "energy and capacity load resource balance after planned resources" from BC Hydro's Table K-3a and Table K-4a in supplemental response to BCUC IR 2.21.0. The Site C energy and capacity is then subtracted from the surplus/deficit. When subtracting the Site C capacity, a downward adjustment was made to take into account the 14% of supply requiring reserves. Where there is no resulting deficit, there is no gap to fill. Where there is a deficit, the size of the gap to fill is the lower of Site C energy/capacity or the load forecast gap. This approach is also described in the Key Assumptions table (nos. 4 and 5). The F2017–F2019 RRA low load forecast ends in F2036. For the purpose of the low load forecast, a ramp up of 800 GWh/year for energy and 200 MW/year for capacity has been assumed.

Summary of Alternative Portfolio Spreadsheet	
Tab Name	**Tab Overview**
Low, Medium and High Load Forecast (LF) - portfolio	The purpose of the Low LF – portfolio, Medium LF – portfolio and High LF – portfolio tabs is to layer in supply and demand-side resource volumes to fill the energy and capacity gaps. The gap is shown in red and new resources shown in blue. <u>Energy gap after planned resources</u> As DSM resources ramp up over time and geothermal plants and wind farms are layered-in in blocks, there is the potential for energy from the Illustrative Alternative Portfolio to exceed the energy gap. If this occurs during a time that BC Hydro is in an energy surplus position, it is assumed that energy is exported and the surplus energy is shown in green. If this occurs during a time that BC Hydro is in an energy shortage position, it is assumed that energy is used to offset other BC Hydro energy purchases and the surplus energy is shown in black. Energy DSM, and wind and geothermal energy input assumptions are documented in the Key Assumptions table (nos. 11 to 14). <u>Capacity gap after planned resources</u> The capacity gap relates to BC Hydro's ability to meet peak demand. Energy focused DSM has associated capacity savings, and BC Hydro assumes an effective load carrying capacity of wind projects of 26% of the nameplate capacity. An additional 81 MW of geothermal energy capacity was determined to be appropriate to be included in the portfolio. These capacity resources are therefore layered in first to fill the gap. For wind farms and geothermal plants, an adjustment was made to take into account the 14% of supply requiring reserves. Energy DSM and wind energy capacity assumptions are documented in the Key Assumptions table (nos. 11 to 14). Capacity focused DSM options (capacity DSM programs, optional TOU rate, industrial curtailment) are then used to fill in remaining gaps. Input assumptions are documented in the Key Assumptions table (nos. 15 and 16).

Summary of Alternative Portfolio Spreadsheet	
Tab Name	**Tab Overview**
Low, Medium and High LF – portfolio costs	The purpose of these tabs is to translate the GWh/MW volumes from the portfolio worksheets into costs (from a cash flow perspective). The left-hand side of the worksheet (supporting data) summarises the key cost information, noting the type of investment (DSM, wind, geothermal, etc.), investment year and cost. Cost input data for these resources are documented in the assumptions table (nos. 11 to 16). The user can perform a sensitivity analysis of the Total Rate Impact of the Alternative Portfolio to different assumptions regarding wind and geothermal costs. The user can select different assumptions (Low, Medium, High' by using the drop-down menu of these inputs in the 'Input and Output' tab, and the cost information on the left-hand side of the 'portfolio costs' tab gets updated automatically. <u>Revenues from export sales</u> The 'Surplus energy revenue' line in the O&M section of the right-hand side calculate revenue from export sales by applying the forecast value of export revenues in $/MW to the energy volumes identified in green in the previous worksheet. This is treated as a credit to the cost of the Alternative Portfolio and is shown separately in the Output section of the 'Input and Output' tab. Assumptions regarding the value of export energy are documented in the Key Assumptions table (no. 6). The user can perform a sensitivity analysis of the Total Rate Impact of the portfolio to different assumptions regarding the export price of the energy surplus. The user can select different assumptions by changing the input value of 'Market Price of Surplus' between 'ABBLow', 'Panel' and 'BCH RRA' in the 'Input and Output' tab, which automatically updates the market price of the energy surplus on the left-hand side of the 'portfolio costs' tab. No value is assumed for additional capacity surplus to BC Hydro's needs (no. 7), so no equivalent capacity adjustment is made. <u>Energy adjustment</u> This adjustment recognises that, in years where BC Hydro is in an energy shortage situation, if the Alternative Portfolio generates more energy than Site C, the excess energy will be used to meet BC Hydro's load (i.e. it will not be exported). An adjustment is made to the cost of the alternative portfolio in those years to recognise the value of this benefit. The worksheet calculates Site C energy as a percentage of portfolio energy (less exports), and applies this percentage to the cost of the alternative portfolio. For example, if the Alternative Portfolio generates 5,564 GWh compared to a "gap to fill" of 5,286 GWh during a year where BC Hydro is in an energy shortage position, only 95% of the cost of the Alternative Portfolio for that year will be included in NPV of the Alternative Portfolio. This adjustment is shown in purple in the worksheet, and is discussed in the Key Assumptions table (no. 8). <u>Capacity credit</u> While no value is assumed for portfolio capacity that is surplus to BC Hydro's

Summary of Alternative Portfolio Spreadsheet	
Tab Name	**Tab Overview**
	requirements, it is assumed that if BC Hydro is in a capacity shortage position, a benefit will be derived from an alternative portfolio with a higher level of capacity than Site C. This adjustment identifies any capacity provided in addition to Site C during years when BC Hydro is in a capacity shortage situation, and assumes a value of $50/kW-year for this benefit (no. 9). The surplus capacity was further adjusted to take into account the 'energy adjustment' described above to remove any double-counting effect. This is applied as a credit to the portfolio cost.
Low, Medium and High LF – NPV DSM **and** **Low LF – NPV Wind, Medium and High LF – NPV Wind-Geo**	The purpose of these tabs is to translate the cash flow estimates from the previous worksheet into a revenue requirement view. For example, while the Low LF – portfolio costs worksheet shows wind capital costs in the year they occur, this worksheet calculates the associated depreciation and financing costs. For each load scenario, the NPV tab was split into two to enable different financing assumptions to the DSM versus IPP aspects of the portfolio. The user can use the drop-down menu of the input 'Financing Option' in the 'Input and Output' tab to change the financing assumption. Together, the two worksheets calculate a NPV of the alternative portfolio, with key financial assumptions shown in the top left-hand corner. The value for each of these key financial assumptions can be changed from the 'Input and Output' tab. The NPV of the Site C Termination Costs is also shown. This NPV is affected by both the value of the termination costs and the amortization period chosen. These values can be changed in the 'Input and Output' tab. Input assumptions for this worksheet are described in the Key Assumptions table (nos. 1 and 2).
Sensitivity Data	The purpose of this tab is to present the underlying data series for the 'Market Price of Surplus', 'Geothermal costs' and 'Wind costs', as well as the options for the various drop-down menu available in the 'Input and Output' tab.

4.0 Appendix D – List of Acronyms

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry Respecting Site C

LIST OF ACRONYMS

CEC	Commercial Energy Consumers Association
CanGEA	Canadian Geothermal Energy Association
CBP	Clean Balance Power
CanWEA	Canadian Wind Energy Association
AAC	Annual allowable cut
AACE	Association for the Advancement of Cost Estimating
ACEC-BC	The Association of Consulting Engineering Companies of BC
ACEEE	American Council for an Energy-Efficient Economy
AHC	Allied Hydro Council BC
AMPC	Association of Major Power Customers
APSE	Atlantic Pacific Spaceline Enterprise Inc.
ATA	*Administrative Tribunals Act*
BC	British Columbia
BC Hydro, the authority	British Columbia Hydro and Power Authority
BCSEA	British Columbia Sustainable Energy Association
BTUs	British thermal units
CAISO	California Independent System operator
CBoC	Conference Board of Canada
CCGT	Combined cycle gas turbine
CCPA	The Canadian Centre for Policy Alternatives
CCPA	The Canadian Center for Policy Alternatives
CEA	*Clean Energy Act*
CEAA	The Canadian Environmental Assessment Agency
CEABC	Clean Energy Association of British Columbia
CEABC	Clean Energy Association of British Columbia
CIFT	Cost of Incremental Firm Transmission
CEABC	Clean Energy Association of British Columbia
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalent

Commission, BCUC	British Columbia Utilities Commission
CPCN	Certirficate of Public Convenience and Necessity
CPR	Conservation Potential Review
Deloitte	Deloitte LLP
DSB	Downstream Benefits
DSF	David Suzuki Foundation
DSM	Demand-Side Management
EIA	Energy Information Administration
EIM	Energy Imbalance Market
ELCC	Effective Load Carrying Capacity
EPAs	Electricity Purchase Agreements
EVM	Earned value methodology
F2017-F2019 RRA	BC Hydro's Fiscal 2017 to 2019 Revenue Requirements Application
FBC	FortisBC Inc.
FID	Final Investment Decision
GDP	Gross Domestic Product
GDS	GDS Associates Inc.
GHG	Greenhouse gas emissions
GSS	Generating station and spillways
GWh	Gigawatt hours
IBA	Impact Benefit Agreement
ICBA	Independent Contractors and Businesses Association
IPP	Independent Power Producer
IRENA	International Renewable Energy Association
IRP	Integrated Resource Plan
IUCN	International Union for Conservation of Nature
km	Kilometer
kW	Kilowatt
kW-yr	Kilowatt year
LCOE	Levelized cost of energy
LGIC	Lieutenant Governor in Council
LNG	Liquified Natural Gas
LTERP	Long Term Electric Resource Plan
MarketBuilder	An energy and economic modeling and forecasting platform used by Deloitte MarketPoint
MCW	Main Civil Works
MW	Megawatts

MWh	Megawatt hour
O&M	Operations and maintenance
OIC	Order in Council
PAD, the	the Peace River and Athabasca River Delta
PMB	Performance Measurement Baseline
Power Advisory	Power Advisory LLP
PPC	Pulp and Paper Coalition
PRHP	Peace River Hydro Partners
PoWG	Program on Water Governance, the University of British Columbia
PV	Photovoltaic
PVEA	Peace Valley Environment Association
PVLA	Peace Valley Landowner Association
R&D	Research and Development
RFEC	Robert Fairholm Economic Consulting
ROE	Return on Equity
RRIM	Regulatory Rate Impact Model
SCGT	Single cycle gas turbine
Sierra Club	Sierra Club BC
Site C Inquiry, or Inquiry	The British Columbia Utilities Commission inquiry respecting BC Hydro's Site C project, as established by the Lieutenant Governor in Council's Order in Council No. 244
TCI	Transcript for Community Input Session
TFN	Transcript for First Nation Input Session
TLA	Tripartite Land Agreement
TTP	Transcript for Technical Presentations
UCA	*Utilities Commission Act*
UEC	Unit Energy Cost
UNESCO	United Nations Educational, Scientific and Cultural Organization
WACC	Weighted average cost of capital
MCW	Major Civil Works
HST	Harmonized sales tax
PST	Provincial sales tax
IDC	Interest during construction
NREL	National Renewable Energy Laboratory


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