Page 001 of 657 to/à Page 006 of 657

Withheld pursuant to/removed as

s.12; s.13; s.14

From: Rowe, Katherine EMPR:EX
To: MacLaren, Les EMPR:EX
Cc: Wieringa, Paul EMPR:EX; McNeil, Kevin EMPR:EX
Subject: For Review: Site C Speaking Points
Date: July 27, 2017 11:53:14 AM
Attachments: s.12;s.13

Hi Les – here you go. They may be a bit on the long side (18 pages in total). Katherine

Page 008 of 657 to/à Page 026 of 657

Withheld pursuant to/removed as

s.12; s.13

Page 027 of 657 to/à Page 033 of 657

Withheld pursuant to/removed as

s.12; s.13; s.14

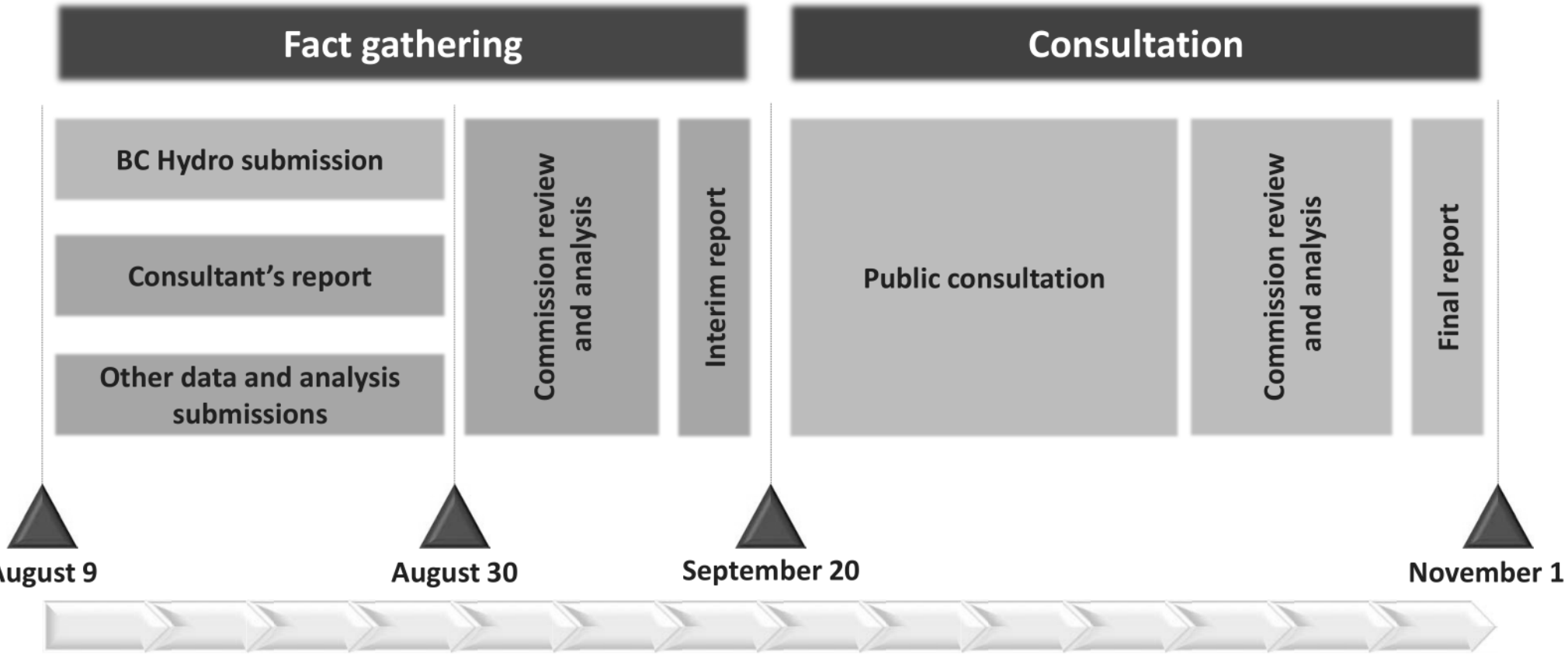
From:	MacLaren, Les EMPR:EX
To:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	FW: Site C inquiry work plan.pptx
Date:	August 3, 2017 1:28:48 PM
Attachments:	Site C inquiry work plan.pptx

Info.

From: Nikolejsin, Dave MNGD:EX
Sent: Thursday, August 3, 2017 1:19 PM
To: MacLaren, Les MEM:EX; Winstanley, Lori PREM:EX
Subject: Site C inquiry work plan.pptx
Confidential for now – but this is their high level plan

bcuc
British Columbia
Utilities Commission

Site C Inquiry –Approach and Schedule



Page 036 of 657 to/à Page 039 of 657

Withheld pursuant to/removed as

s.12; s.13; s.14

From:	Wieringa, Paul EMPR:EX
To:	"Tonja Leach"
Subject:	RE: Presentation request
Date:	October 6, 2017 1:01:00 PM
Attachments:	~WRD000.jpg Energy Policy BC 25 Sept as pw.pptx image001.jpg image002.jpg

---

Sure. I made a minor change in this version under the Bioenergy Strategy. (I mentioned in my talk that the slide might be confusing.)

From: Tonja Leach [mailto:tleach@questcanada.org]
Sent: Friday, October 6, 2017 12:44 PM
To: Wieringa, Paul MEM:EX
Subject: Presentation request

Hi Paul,
Many of the participants at the QUEST BC Caucus meeting are asking for a copy of your presentation. Is it ok to distribute it to the Caucus for their information?
Many thanks and Happy Thanksgiving.
Tonja

Tonja Leach

Senior Lead, National Affairs & Services | QUEST
350 Albert St. Suite 1220 | Ottawa ON | K1R 1A4

T: 866-494-2770 *706 W: questcanada.org

F: 613-627-2938 E: tleach@questcanada.org

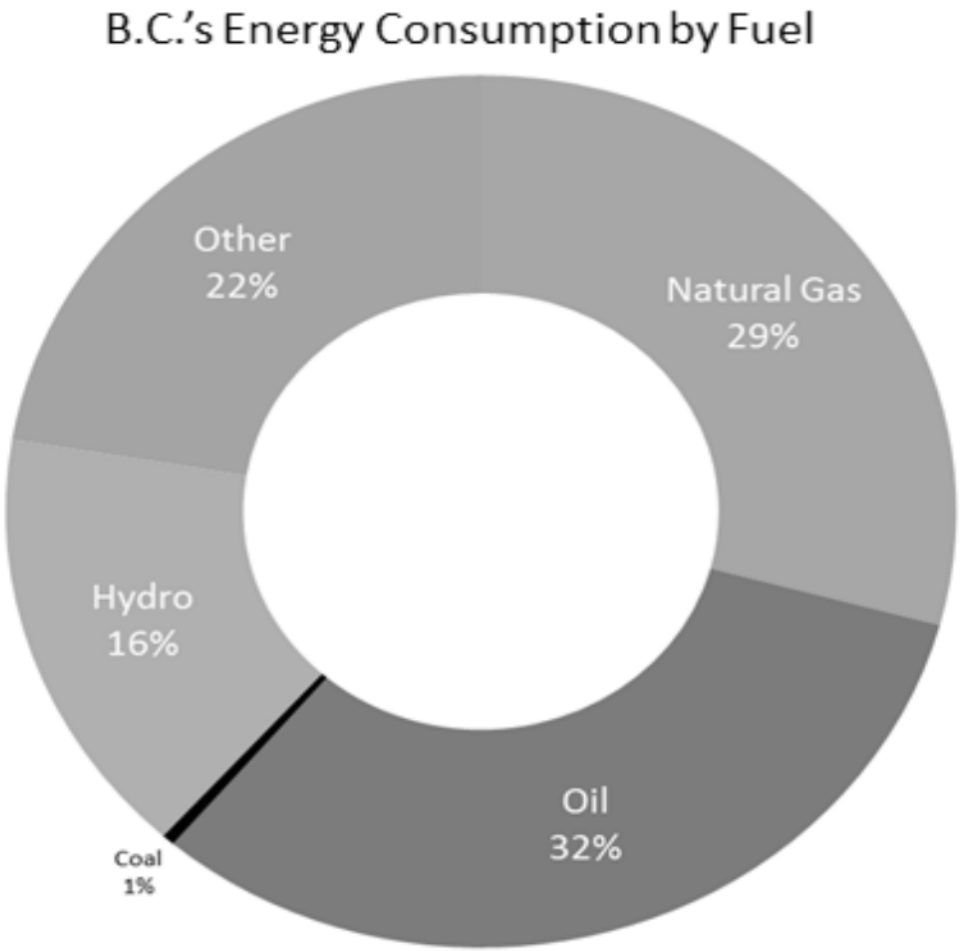
#QUEST2017 - *Smart Energy Communities on the Hill* Nov 6-8 #OTT - Your ultimate 2-day business development and learning opportunity - access the program here for daily updates. Register now using promocode FriendsofQUEST to receive $150 savings from your registration.

Sent with Mailtrack

Energy Policy in British Columbia

Paul Wieringa
Executive Director, Energy Policy Branch
BC Ministry of Energy, Mines and Petroleum Resources

Energy Use in BC



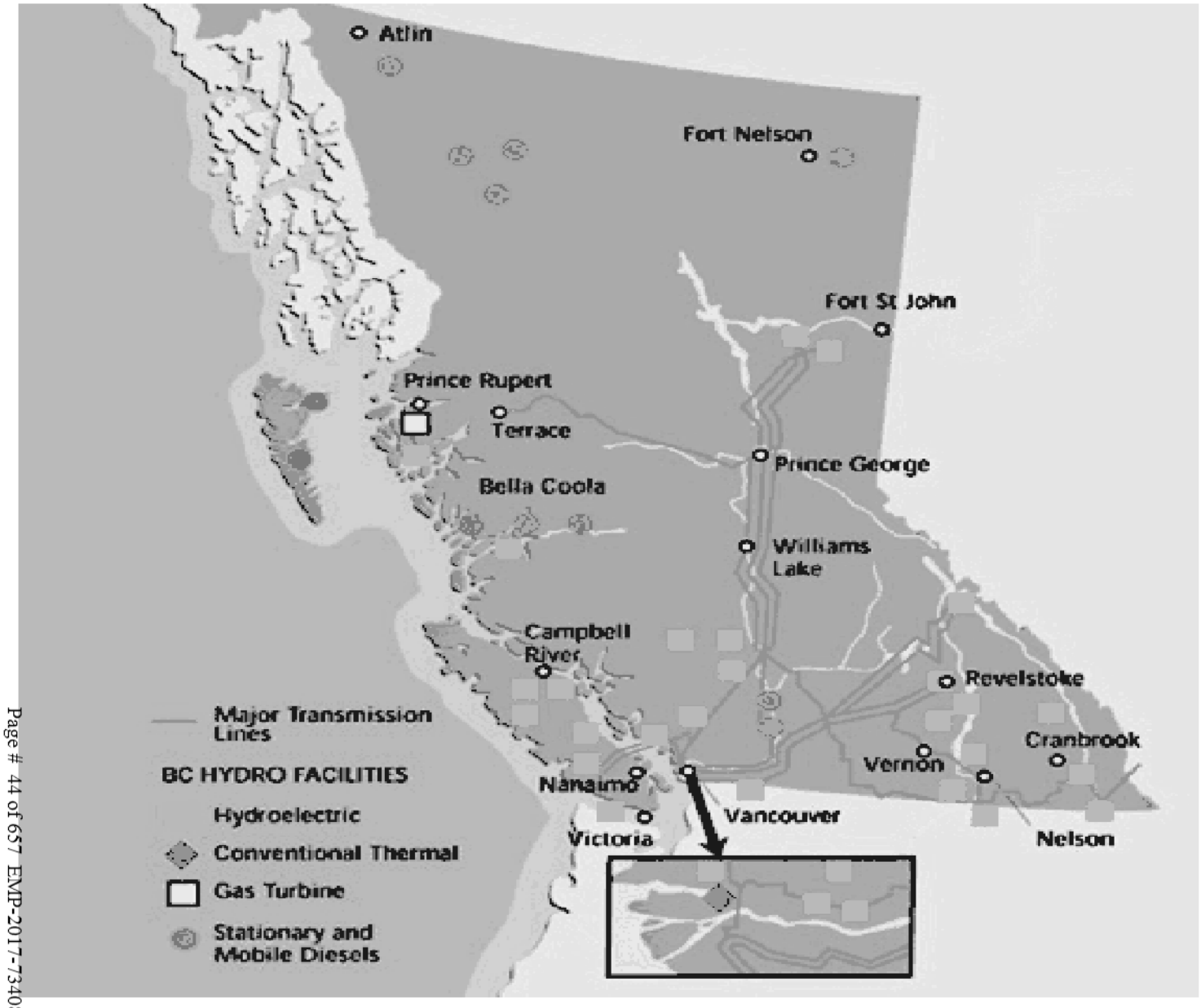
Source: National Energy Board's Energy Futures

British Columbia's Electric System

BC has over 18,000 MW of installed generation capacity:

- BC Hydro (67%) ~ 12,053 MW, 31 facilities
- IPPs (20%) ~ 3,609 MW, 113 facilities
- Alcan (5%) ~ 896 MW, 1 facility
- Teck (3%) ~ 480 MW, 1 facility
- CPC/CBT (2%) ~ 430 MW, 3 facilities
- FortisBC (3%) ~ 560 MW, 5 facilities Including the Waneta Expansion

- In 2016, 97% generated from clean or renewable sources.
- Over 79,000 km of transmission and distribution wires in the province.
- Customers are served by two major electrical utilities: BC Hydro and FortisBC.



British Columbia's Electric System

Site C

- The third dam and hydroelectric generating station on the Peace River in northeastern British Columbia.
- Will provide 5,100 GWh of electricity each year and 1,100 MW of capacity.
- Currently under review by the BC Utilities Commission.
- Cabinet will make the decision to complete, suspend or terminate the project.

British Columbia's Natural Gas Production

- Natural gas production in BC is 4.3 billion cubic feet per day.
- Some natural gas is used domestically, remainder is shipped via:
  - Westcoast Pipeline - BC to Washington State: Capacity 1.6 Bcf/d
  - Alliance Pipeline – Gas from Alberta and BC to Chicago: 1.7 Bcf/d capacity
  - TransCanada Foothills System - Gas from Alberta through corner of BC in the US: 3 Bcf/d capacity

Evolution of BC Energy Policy

- 2007 Energy Plan set out a strategy for increasing investment in alternative technology.
- 2008 Bioenergy Strategy provided new opportunities for agriculture and forestry.
- 2008 Climate Action Plan outlined strategies to help BC meets it GHG reduction targets, including a revenue neutral carbon tax.

Carbon Tax

- Carbon tax rates started at $10 per tonne of carbon dioxide equivalent (CO2e) emissions in 2008, increasing by $5 per tonne each year until reaching the current rate of $30 per tonne of CO2e emissions in 2012.
- The carbon tax was created to be revenue neutral, meaning every dollar generated by the tax is returned to British Columbians through reductions in other taxes.
- In April 2018, the carbon tax will increase by $5 per tonne and not be revenue neutral (i.e., will not be accompanied by an offsetting tax reduction).

BC's Energy Policy Actions

- Incenting clean or renewable electricity generation
- Energy efficiency and Demand Side Management
- Bioenergy Strategy
- Innovate Clean Energy (ICE) Fund and Post-Secondary Clean Energy Partnership programs.
- Low Carbon Fuel Standard
- Upstream natural gas electrification
- LNG for Marine Bunkering and heavy duty vehicles
- RNG Production

BC's Actions: Energy Efficiency and Demand Side Management

- The Province provides the regulatory framework for DSM through legislation and regulation, including the *Clean Energy Act*, the *Utilities Commission Act* and the Demand-Side Measures Regulation.
- *Clean Energy Act* requires that 66% of incremental electricity demand must be met by conservation or demand side measures.
- Low-income DSM has been a priority.

BC's Actions: Bioenergy Strategy

- Goal:
  - BC biofuel production to meet 50% or more of renewable fuel requirements by 2020.
  - Ten community energy projects derived from biomass by 2020.
- Promotes investment and innovation in BC bioenergy projects, technologies and advancements in provincial biodiesel production.

BC's Actions: Focus on Innovation

- The ICE Fund is a Special Account, funded through a levy on certain energy sales, designed to support the Province's energy, economic, environmental and greenhouse gas reduction priorities.
- The ICE Fund supports pre-commercial clean energy technology projects, clean energy vehicles, research and development, and energy efficiency programs.
- Successful ICE Fund partnerships have included universities, First Nations and municipalities.

BC's Actions: Focus on Innovation

- Launched in 2015, the Post-Secondary Clean Energy Partnerships Program supports research in clean energy science and technology projects undertaken by post-secondary institutions in BC, such as next generation high efficiency and smart power converters for electrified transportation battery chargers.
- In 2017, BC announced a $40 million partnership with Sustainable Development Technology Canada to support the development of pre-commercial clean energy projects and technologies.

BC's Action: Low Carbon Fuel Standard

- Reduces British Columbia's reliance on non-renewable fuels.
- Sets renewable fuel content requirements for gasoline (5%) and diesel (4%).
- Sets low carbon fuel requirements for fuels sold in British Columbia (10% reduction in 2020).
- There are over 700 vehicles and vessels that have been converted to natural gas and the Clean Energy Vehicle program has delivered over 2400 new vehicles.

BC's Actions: LNG for Marine Bunkering

- Incentives toward the conversion or purchase of LNG powered trans-pacific marine vessels.
- Investment in related LNG bunkering infrastructure and assets required to enable the development of LNG bunkering capability to fuel LNG ships.
- Converting just one trans pacific vessel will reduce GHG emissions by approximately 93,500 tonnes per year.
- Utilities may recover costs from ratepayers.

BC's Actions: Upstream Natural Gas Electrification

- Utilities provide electricity to natural gas processing facilities and may recover those costs from ratepayers.
- Projects must have an expected in-service date by 2022 and incentive levels decline over time to incent early adoption.
- Significant GHG emissions will be avoided with the use of electric drives.

BC's Actions: RNG Production

- Canada's natural gas utilities have set a target of 5% RNG-blended natural gas in the pipeline distribution system by 2025 and 10% by 2030.
- By 2030, increased RNG content will result in 14 megatonnes of GHG reductions per year.
- BC is the only jurisdiction in North America to have a utility program for RNG.
- BC's achievable potential for RNG is estimated to be up to 4.4 PJ/year.

Page # 57 of 657 EMP-2017-73408

Thank you

Paul Wieringa

Paul.Wieringa@gov.bc.ca

250-952-0651

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s.12; s.13; s.14

BC Hydro
Power smart

Jessica McDonald
President & Chief Executive Officer
BC Hydro
Email: jessica.mcdonald@bchydro.com

May 03, 2017

Dr. Santa Ono
President and Vice-Chancellor
The University of British Columbia
7th Floor, Walter C. Koerner Library
1958 Main Mall
Vancouver, BC V6T 1Z2

Sent via email: presidents.office@ubc.ca

Dear Dr. Ono,

I am writing with regards to a report recently released by the University of British Columbia's Program on Water Governance titled "Reassessing the Need for Site C", which was announced through a UBC press release, promoted on the UBC website and has been referred to by media as "the UBC Report".

BC Hydro has a long history of partnering with UBC in the areas of engineering and geology. We have relied on data from your research teams to assist in our wind forecasts; we leveraged research from UBC to inform our report on the impacts of climate change on our water resources; and in 2010, we worked together to develop a new Master's degree program in Clean Energy.

While we respect and support independent analyses of the Site C Clean Energy Project, I wanted to make you aware that BC Hydro was not afforded the opportunity to provide a review of this report prior to its publication. In our view, peer review is an important best practice and, in this case, a review by other qualified individuals would have been critical to strengthening the integrity of such an analysis – particularly important as UBC timed its release to coincide with a provincial election.

Upon reviewing this report, our analysts have made a number of observations about its data and methodology. The following are a few examples of these observations:

- On Page 32-33, the report states: "As illustrated, the requirement for energy in the 2016 Load Forecast is substantially lower than in the 2012 Load Forecast used to justify proceeding with the Site C Project. Throughout the 20-year forecasting period, the difference is on the order of 5,000 GWh/year of energy."

  In fact, the load forecast used to justify proceeding with the Site C project was the Fiscal 2013 load forecast, not the Fiscal 2012 load forecast. The difference in energy requirements after DSM in Fiscal 2024 (the first year Site C comes into service) between

the Fiscal 2013 and the Fiscal 2016 load forecast is approximately 2500 GWh, declining to less than 1000 GWh by Fiscal 2030, not 5,000 GWh/year for 20 years. This is a substantial error that fundamentally affects the report's conclusions.

As a further note, BC Hydro's Response to Information Request CEC 2.135.1, referenced by the report, contained an error that has subsequently been corrected through an Errata to the BC Utilities Commission. Had BC Hydro been provided with the opportunity to review the report in advance, this error could have been identified prior to the report's publication. Further details on these forecasts can be found in the revision to Attachment 1 to CEC IR 2.135.1 filed by BC Hydro with the BC Utilities Commission on April 28, 2017.

- On Page 55 and 56, the report states "In a backgrounder entitled "Comparing the Options", the Province and BC Hydro indicate that the unit energy cost for Site C would decline by $26/MWh as a result of these changes and by an additional $1/MWh due to a reduction in water rental charges. The result is an updated unit energy cost of $58-$61/MWh as opposed to $85-$88/MWh. However, there is no reason to believe that the 10 Year Rates Plan, which expires in March 2024, would affect the regulatory treatment of the Site C Project, which enters the rate base only after commissioning."

  The financing for Site C is not based on the 10 Year Rates Plan which has a defined start and end period. It reflects Order in Council No. 590 which sets BC Hydro's net income at $712 million for Fiscal 2019 and all subsequent fiscal years.

  Instead of reflecting Order in Council No. 590 in their analysis, the authors assume that the Site C project will be financed differently, artificially inflating its cost by $26/MWh for the purpose of their analysis. What is particularly concerning is that the authors' failure to reflect the current regulation is not accidental, but fully acknowledged. The authors defend their assumption stating "There is no reason to assume that the 10 Year Rates Plan will affect the financing of the Site C Project." This error also fundamentally affects the report's conclusions.

- On Page 80, the report states "Following F2021, no new additional demand-side measures are contemplated to replace and improve upon existing measures. This situation is illustrated in Figure 19 derived from BC Hydro's 2016 RRA where new DSM measures cease after F2021 and the additional energy savings from DSM decline by more than 40% by F2024 and to zero by F2036."

  This is incorrect. The Fiscal 2017 to Fiscal 2019 Revenue Requirements Application indicates that BC Hydro plans to spend approximately $85 million per year after Fiscal 2021 to secure new, incremental demand side management savings. Further details can be found in BC Hydro's BC Hydro Information Request Response to BCOAPO 2.120.1 – Attachment 1 filed with the BC Utilities Commission on January 23, 2017. As with the other points noted above, this oversight fundamentally affects the report's conclusions.

- On Page 119 and 120 in Table 24, the report states that its analysis of an alternative portfolio of resources that does not include Site C relies on 570 MW of capacity focused DSM in F2036 at a cost of $50/kW-year and the commissioning of pumped storage at Mica.

Both of these resources, while possibly promising in the future, are currently unproven and would clearly not be available to be in operation to meet British Columbia's forecast capacity deficit of 8% by 2025/2026. It would be imprudent for BC Hydro to rely on capacity-focused demand side management and pumped storage for the capacity that British Columbia needs on the timeline that it will be required.
In fact, with regards to capacity focused DSM, BC Hydro states in Section 3.7.4 of its 2013 Integrated Resource Plan "At this point in time, there are a number of uncertainties regarding DSM capacity initiatives that are not well understood. Since BC Hydro is just starting to develop long-term DSM capacity savings options, implementation success is an important issue. In particular, precise program initiation dates and customer participation rates are unknown; BC Hydro would want to test both of these drivers through pilot initiatives. Once these approaches are established, operational experience will still be required to understand how participation and savings per participant translate into peak shaving. Similarly, experience will be needed to see how savings for each initiative translates into peak reduction for the entire system – whether these peaks are coincident with peak load and whether peak shaving leads to other system peaks."

With regards to pumped storage at Mica, BC Hydro states in Section 4.4.6.1 of its 2013 Integrated Resource Plan "There are no commercial pumped storage facilities in B.C., and only one pumped storage facility operating in Canada which was permitted in the 1950s. Siting a pumped storage facility in B.C. triggers a number of regulatory/government agency approvals resulting in timing and outcome uncertainty."

- On Page 120, the report states the following with regards to the model it uses to support its analysis: "The model evaluates different resource options over a 20-year planning period, as BC Hydro did in its 2013 IRP."

  In fact, the 2013 Integrated Resource Plan analysis on the Site C project, which has an economic life of 70 years, was based on a 30-year planning horizon, not a 20-year planning horizon. Again, an obvious error.

- Lastly, it is disappointing that in the About the Authors section on Page ii of the report does not disclose that Mr. Raphals has served as a witness for the West Moberly and Prophet First Nations challenging the project's provincial permits and seeking an injunction to halt the project.

  In fact, in his judgment denying the injunction, Judge Sewell stated "I am aware that the petitioners have tendered evidence from Mr. Raphals to the effect that there will be no net loss to the petitioners or the public from a one-year delay in the completion of the project. However, I have decided that I cannot receive that evidence because I am not satisfied that Mr. Raphals has the necessary qualifications to give the opinion relied upon by the petitioners. The opinion given by Mr. Raphals involves sophisticated financial analysis of future costs and the availability of future alternative sources of power as well as future demand. There is nothing in Mr. Raphals resume, his education, or his other qualifications sufficient to persuade me that he is qualified to give that opinion evidence and I, therefore, reject it."

In summary, our observations indicate that the authors made assumptions that deliberately and significantly increased the cost of the Site C Clean Energy Project and compared it to a portfolio of alternative resources that is not feasible or prudent. The authors of the report also did not disclose their past involvement in court cases against the project. Consequently, I am concerned that the debate generated by this report has not been objective or well informed. I note in particular that the report continues to be promoted on UBC's website along with supportive subsequent references to it in the media while failing to mention any critical peer commentary that has also since been published by major media outlets.

Out of respect for the election process, BC Hydro has declined to speak publicly about the fundamental flaws in this report. However, I am writing to you to raise my serious concerns – in particular the lack of peer review, coupled with its substantial errors and oversights – in the hope that UBC would take steps to require best practices in the review of works it wishes to promote, and to consider a more balanced representation of the analyses that have since been undertaken and published in any continued promotion of this report.

British Columbia's energy future is critically important and requires vigorous debate and study. BC Hydro is currently beginning work on our 2018 Integrated Resource Plan and I would welcome the opportunity to discuss with you how the University of British Columbia could be involved in this important process. I can be reached at 604-623-4410.

Sincerely,

Jessica McDonald

CC: Philip Steenkamp, Vice-President, External Relations, University of British Columbia
philip.steenkamp@ubc.ca

From:	MacLaren, Les EMPR:EX
To:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	BCUC Site C Review - Action Required
Date:	Monday, July 24, 2017 10:15:52 AM
Attachments:	Site C Independent Review 17-7-17 LM.docx RE items for this week.msg FW items for this week.msg RE items for this week.msg

s.12;s.13

Attached are the Concept Paper we updated last week on this topic, and some back and forth I had with Dave Nik over the weekend and this morning on some of the new government's early thinking. Let's plan to connect at 3:00 this afternoon on this topic.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy, Mines and Petroleum Resources
Office: 250-952-0204
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

From:	MacLaren, Les EMPR:EX
To:	Nikolejsin, Dave MNGD:EX
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	FW: For July 26 meeting - Site C Executive discussion
Date:	Monday, July 24, 2017 5:12:59 PM
Attachments:	image001.png 20170724_Joint-executive-dashboard-for-July-26-meeting_V1.xlsx

Hi Dave:
Jessica met every 4-6 weeks with Tim for a discussion on permitting. It looks like Chris O-Riley will be continuing that practice. The collaboration between FLNRORD and BCH on permitting is very good. There is a dashboard attached and some further commentary from FLNRORD below.
The dashboard is all green lights except the transmission line where there one yellow related to ongoing issues with a grazing leaseholder. Progress is being made there. The only other issue is the Licence to Commence Construction #8 under the water licence which is not on the dashboard. I sent you a note last week on our feedback to FLNRORD staff. LCC#8 was scheduled to be issued today.
Les

From: Kennah, Morgan FLNR:EX
Sent: Monday, July 24, 2017 11:37 AM
To: Tates, Nancy FLNR:EX
Cc: Craven, Paul EAO:EX; Vince, Karrilyn M FLNR:EX; MacLaren, Les MEM:EX; Larstone, Michelle FLNR:EX; Ethier, Tom FLNR:EX; Kriese, Kevin FLNR:EX; Cuell, James W FLNR:EX
Subject: For July 26 meeting - Site C Executive discussion

Hello Nancy,
For Tim's scheduled conversation regarding Site C on Wednesday , I have the attached dashboard to support their conversation. Kevin Kriese has approved this document.
I have several points that are related to the project but not addressed in the dashboard as it is regulatory in scope:

- BCH regulatory staff meet with Regional Operations staff on July 24 to review three continuing conversations from last month:
  - The revised funding contribution agreement Regional Operations has shared out for comment, pursuant to the discussion last month on this topic;
  - Opportunities to support streamlining *Water Sustainability Regulation* notifications based on existing Approved Work Procedures; and
  - Options for coordinating consultation with First Nations who hold Impact Benefit Agreements with BCH, thus requiring less in-depth consultation for ongoing operational permitting.
- The EAO has progressed their EAC compliance investigation from complaints raised by Nun wa dee Stewardship Society. A series of determinations has been drafted and reviewed by FLNRORD staff. BCH has been shared the record for review as per EAO procedures.
- The construction works tender from MOTI for Highway 29 realignment at Cache Creek, a sensitive site for several First Nations, closes on August 3. Archaeology Branch has been considering what options exist if a chance find is encountered given differing perspectives from Treaty 8 First Nations about arch site management particularly with remains.
- BCH is in the process of forwarding payment for the substation Crown Grant. The dam site Crown Grant was paid for in late Marchs.13

s.13

s.13

- The two outstanding Ministerial Orders and the OiC are in the process of preparation, and the legislative analyst is able to start internal reviews when we are ready. We can anticipate to move the package forward in approximately 60-90 days.

Cheers,
Morgan

Morgan Kennah, RPF
Director, Strategic Initiatives | Northeast
Ministry of Forests, Lands and Natural Resource Operations
780 Blanshard Street, Victoria, BC
Morgan.Kennah@gov.bc.ca
m – 250.896.6268

Site C Clean Energy Project - Executive Dashboard for the July 26, 2017 Meeting

Key Messages:
1. FLNRORD and BCH staff are working together to develop: • a coordinated First Nations Consultation Approach for provincial permit applications issued through the Regional Operations team. The objective of the coordinated consultation approach to support maintenance of the Project's construction schedule as FLNRORD moves the project to a 'business-as-usual' approach in its operational permitting. • a process for implementing BC Hydro/Provincial Approved Work Practices for Section 11 Notifications under the *Water Sustainability Act.* The objective of using the Approved Work Practices is to allow low-impact instream works to have some form of streamlined notification that is legally compliant. • a revised Contribution Agreement which sets out BCH funding for provincial work resulting from Project development, likely including but not limited to monitoring efforts for project impacts (vegetation and wildlife) and crown land transfers under the Tripartite Land Agreements. 2. BCH continues to engage with First Nations on concerns regarding Highway 29 realignment, particularly at Cache Creek. BCH has documented their mitigation plans to date for the known concerns of the potential grave and the sweat lodge. MOTI has issued a construction tender for works on Bear Flat.

Permit Status Summary

Project Component Grouping	Status	Significant points of note for past 30/next 30
Dam Site Area - Main Civil Works	●	LCC8, for earth dam excavation and placement, and approach channel preparation, was granted July 21, 2017. The Deputy Comptroller of Water Rights and BCH continue to engage in discussions with regard to Schedule A (environmental commitments) of the main water licences.
Reservoir Development	●	Permit applications for the remaining Eastern Reservoir Clearing (Cache Creek Drainage) were submitted to FLNRORD on May 15, 2017. Amendments are required for the Eastern Reservoir provincial permit applications to accommodate some changes to the boundaries of the LOO and OLTCs. BCH is working with FLNRORD to clarify the timing of decisions on the amendments, which will require First Nations consultation. This work is to be coordinated as part of submissions for the Indpendent Engineer and Independent Environmental Monitor as changes also fall under their purview. Decisions on the Land Act Licence of Occupation and Forest Act Occupant Licence to Cut for the Cache Creek Drainage are anticipated by October 2017. The next package of clearing permit applications, for Central Reservoir Clearing, is expected to be submitted in early 2018, for clearing to commence in August 2018.
Highway 29 Realignment	●	BCH has submitted an amended application for the Section 11 *Water Sustainability Act* permit for the Cache Creek bridge crossing. This bridge crossing design reflects mitigations developed based on concerns raised by First Nations.
Transmission Line	●	Two *Water Sustainability Act* permit applications for wetland infilling along the transmission line were issued on July 7, 2017. A *Water Sustainability Act* permit for the placement of tower foundations within the transmission line was submitted to FLNRORD on June 14, 2017. A decision on this permit is anticipated in late October 2017. FLNRORD is in the middle of a 60 day "dialogue" period with a grazing leaseholder along the transmission line, in order to resolve this tenure conflict. This period closes at the end of August 2017. FLNRORD has indicated that the leaseholder consents to clearing along the transmission line. FLNRORD has indicated the related related *Land Act* and *Forest Act* permits can be issued given this consent. The leaseholder has not yet consented to construction of the transmission line; one outstanding *Land Act* tenure remains in order to undertake construction. FLNRORD and BCH continue to engage in discussions with the leaseholder to resolve this issue.
Quarry Development	●	A *Mines Act* Permit (Notice of Work) and *Land Act* Licence of Occupation are anticipated for the Peaceview Borrow Area in July 2017 (used for Highway 29 works).
Hudson's Hope Berm	●	Geotechnical investigation works under Leave to Commence Construction 7 and Leave to Construction 7A were completed at Hudson's Hope Berm by May 12, 2017. BC Hydro is in discussions with the District of Hudson's Hope regarding the design of the berm. Applications for construction of Hudson's Hope are anticipated to be made in 2020.
Fish Passage Facility	●	The decision regarding the Water Licences for the Fish Passage Facility is expected in October 2017. Both First Nations consultation timing and information around sampling methylmercury at the facilities are concerns which are being worked thorugh. Construction is scheduled to commence in December 2017.
Inter-organizational coordination	●	Our staff teams meet regularly to review permit applications both before submitting, through screening and consultation phases. Regular permit schedules are produced. Emerging issues are identified as soon as possible and collaborative troubleshooting ensues.

*Overall status definitions: Green – Completed or on course; Yellow – Monitor – moderate risk; Red – Action required and high risk, see comments

Site C Clean Energy Project - Executive Dashboard for July 26, 2017

Pending Permit Applications (Applications submitted; decision not yet issued)

Component	Permit/Approval Statute	BCH Submission Date	BCH/ Contractor Required Date	Expected Decision Date	Overall Status*	Comments
Dam Site Area - Short Term Use of Water for GSS Works	*Water Sustainability Act*	13-Jan-17	01-Aug-17	28-Jul-17	●	Permit applications for short term water use were reviewed at First Nations permitting forum on January 26, 2017.
Dam Site Area - Moberly Clearing	*Land Act*	20-Jun-17	01-Oct-17	TBD	●	Permit application to replace Temporary Use Permit for Dam Site and Moberly Clearing which expires July 7, 2017.
Transmission Line	*Water Sustainability Act (S11)*	14-Jun-17	01-Oct-17	TBD	●	An application for works in/near a stream was submitted for the tower foundations wetland footprint along the transmission line.
Hwy 29 Realignment Peaceview Borrow Source	*Mines Act* *Land Act*	15-Mar-17 15-Mar-17	15-Jul-17	28-Jul-17	●	These applications were reviewed at Permitting Forum #4 on March 29, 2017. An update on the status of the decision is anticipated during the week of July 24. This delay in decision does not affect BCH construction schedule at this time.
Hwy 29 Realignment Cache Creek Construction - unnamed creek crossings	*Water Sustainability Act (S11)*	27-Feb-17	01-Jul-17	13-Jul-17	●	These applications were reviewed at Permitting Forum #4 on March 29, 2017. FLNRO was asked by DRFN for a 1-week extension on this permit; this does not affect BCH construction schedule.
Scientific Fish Collection Permits	*Wildlife Act*	1-Feb-17	01-Jul-17	TBD*	●	*All but one of the scientific fish collection permits were issued on July 4, 2017. BCH is following up with FLNRO regarding the status of the remaining permit.
Eastern Reservoir - Cache Creek Drainage	*Land Act* *Forest Act*	15-May-17	1-Oct-17	09-Aug-17	●	Submitted to FLNRO on May 15, 2017 and was reviewed at Permitting Forum #5 on May 24, 2017. FLNRO is targeting August issuance.
Dam Site Area - Peace River Main Channel Bar Excavation and Fish Habitat Enhancement	*Land Act* *Water Sustainability Act*	06-Jul-17 06-Jul-17	30-Sep-17 30-Sep-17	TBD TBD	● ●	These applications were reviewed at Permitting Forum #5 on May 24, 2017.
Dam Site Area - L3 Ravine	*Water Sustainability Act*	7-Jul-17	7-Aug-17	TBD	●	This application for works in/near a stream was submitted to install mitigation measures to address sediment and erosion control issue in L3 ravine.

Component	Permit/Approval Statute	BCH Submission Date	BCH/ Contractor Required Date	Expected Decision Date	Overall Status*	Comments
Future Permit Applications (2017 look ahead)						
Component	**Permit/Approval Statute**	**BCH Target Submission Date**	**BCH/ Contractor Required Date**	**Expected Decision Date*** **	**Overall Status***	**Comments**
Hwy 29 Realignment Farrell Creek - Investigations	*Land Act* *Water Sustainability Act* *Forest Act*	25-Aug-17	TBD	TBD		
Hwy 29 Realignment Dry Creek - Investigations	*Land Act* *Water Sustainability Act*	25-Aug-17	TBD	TBD		
Hwy 29 Realignment Lynx Creek - Investigations	*Land Act* *Water Sustainability Act* *Forest Act*	25-Aug-17	TBD	TBD		
Quarries/Pits - Portage Mtn Quarry	Water Sustainability Act (S10) Notice of Work	1-Aug-17 TBD	TBD	TBD		

Site C Clean Energy Project - Executive Dashboard for July 26, 2017

Pending Approvals (applications submitted, but not yet received)					
Component	**Name**	**Date Submitted**	**Date Required**	**Status**	**Comments**
Water Licence	Fish Passage Facility	30-Mar-15	1-Dec-17		The decision regarding the Water Licences for the Fish Passage Facility is expected in October 2017. Both First Nations consultation timing and information around sampling methylmercury at the facilities are concerns which are being worked thorugh. Construction is scheduled to commence in December 2017.
LTC1I	Backfill Exploratory Adits	07-May-17	TBD		Issued by the Independent Engineer on July 21, 2017
LCC8	Earthfill Dam Excavation, Placement and Approach Channel	10-May-17	24-Jul-17		Issued by Comptroller of Water Rights on July 21, 2017

Future Approvals - to August 2017. Subject to change based on revised LCC/LTC schedule					
Component	**Name**	**Planned Submission Date**	**Date Required**	**Status**	**Comments**
LCC1 - Initial Works	LTC1J - Moberly River Construction Bridge Debris Boom	TBC	TBC		The installation of the Moberly River Construction Bridge has been deferred for one year.
	LTC1M - Right Bank Drainage Tunnel Completion	25-Sep-17	25-Oct-17		Based on contractor schedule submitted to BCH on July 20, 2017.
LCC4 - Eastern Reservoir Clearing	LTC4C - North Bank Tea Creek to Wilder Creek	TBC	TBC		
	LTC4D - South Bank - Remaining OLTC 6 area	TBC	TBC		
	LTC4E - North Bank - Cache Creek Drainage	1-Sep-17	1-Oct-17		
LCC5 Left Bank Stage 1 Cofferdams and Diversion Works	LTC5D - Left Bank Drainage Adit	31-Aug-17	29-Sep-17		Based on contractor schedule submitted to BCH on July 20, 2017.
	LTC5E - Diversion Tunnels Excavation and Rock Support	7-Sep-17	6-Oct-17		An initial scoping meeting for this LTC was held by the contractor on May 12, 2017.
	LTC5F - Diversion Tunnels Lining and Concrete Structures	7-Sep-17	6-Oct-17		An initial scoping meeting for this LTC was held by the contractor on May 12, 2017.
	LTC5G - Diversion Tunnel Gates & Electro-Mechanics Installation & Testing	9-Sep-17	9-Oct-17		An initial scoping meeting for this LTC was held by the contractor on May 12, 2017.
LCC8 Earthfill Dam Excavation, Placement and Approach Channel	LTC8A - Earthfill Dam Excavation and Foundation including Drilling & Grouting	4-Sep-17	1-Oct-17		LTC application not yet received from PRHP. Subject to LCC-LTC Schedule Change.
LCC9 Halfway River Debris Boom Construction	LCC9 - Halfway River Debris Boom Construction	16-Aug-17	16-Sep-17		The schedule for Halfway River Debris Boom Construction is under review.

TBC - to be confirmed

*Overall status definitions: Green – Completed or on course; Yellow – Monitor – moderate risk; Red – Action required and high risk, see comments

LCCs/LTCs received (for Diversion and Storage)			
Component	**LTCs**	**BCH Submission Date**	**Received Date**
	LCC 1	2-Mar-16	01-Apr-16
	LTC1A - South Bank Back Channel Closure Dikes	11-May-16	18-May-16
	LTC1B - Left Bank Excavation Benches 5&6	17-May-16	08-Jun-16
	LTC1C - Right Bank Drainage Tunnel Portal	19-May-16	23-Jun-16
	LTC1D - Right Bank Shoreline Erosion Protection Works	26-May-16	11-Jul-16
	LTC1D - Amend1 - Additional Right Bank Stage 1 Cofferdam Sho	13-Dec-16	14-Dec-16
	LTC1E - Moberly River Construction Bridge	20-Jun-16	26-Jul-16

LCC1 Initial Works	LTC1F - Backfilling of Historic Drill Holes	03-Aug-16	05-Aug-16
	LTC1G - Left Bank Excavation Phase 2	29-Jul-16	11-Aug-16
	LTC1G - Amend1 - left bank global instability initial remediation	08-Mar-17	09-Mar-17
	LTC1G - Amend2 - Temporary PAG Stockpile on Upper Left Banl	27-Jan-17	29-Jan-17
	LTC2B - Amend3 - left bank global instability remediation measures - side channel infilli		31-Mar-17
	LTC1H - Right Bank Drainage Tunnel Underground Works	11-Aug-16	23-Aug-16
	LTC1K - River Road Blind Corner Remedial Works	05-Jan-17	01-Mar-17
	LTC1L - River Road Water Intake Remedial Works	18-Jan-17	12-Jun-17
LCC2 RSEMs and South Bank Initial Access Road	LCC 2 RSEMs and South Bank Initial Access Road	08-Apr-16	29-Jun-16
	LTC2A - RSEM Area R5b	21-Jul-16	29-Jul-16
	LTC2B - RSEM Area L5	10-Aug-16	18-Aug-16
	LTC2B - Amend1 - left bank global instability initial remediation	08-Mar-17	09-Mar-17
	LTC2B - Amend2 - left bank global instability remediation meas	31-Mar-17	31-Mar-17
	LTC2B - Amend3 - left bank haul road	24-May-17	26-May-17
	LTC2B - Amend4 - Additional Temporary PAG Mgmt	24-May-17	30-Jun-17
	LTC2C - South Bank Initial Access Road	12-Aug-16	14-Oct-16
	LTC2D - RSEM Area R6	16-Aug-16	26-Aug-16
	LTC2E - RSEM R5a	24-Oct-16	08-Nov-16
	LTC2E - Amend1 - starter dyke revised design	14-Mar-17	15-Mar-17
	LTC2E - Amend2 - temporary works for non-contact water mgm	29-Mar-17	30-Mar-17
	LTC2F - RSEM Area L6	17-May-17	30-Jun-17
LCC3 – Right Bank stage 1 Cofferdam and Excavations, and Left Bank Inlet & Outlet Stage 1 Cofferdams	LCC 3	06-Jul-16	20-Jul-16
	LTC3A - Right Bank Stage 1 Cofferdam	17-Jul-16	26-Jul-16
	LTC3A - Amend1 - Additional Right Bank Stage 1 Cofferdam Sho	12-Dec-16	14-Dec-16
	LTC3B - Right Bank Overburden Excavations	22-Jul-16	28-Jul-16
	LTC3C - Inlet Cofferdam	01-Sep-16	27-Sep-16
	LTC3C - Amend1 - left bank global instability initial remediation	08-Mar-17	09-Mar-17
	LTC3C - Amend2 - left bank global instability remediation measures - side channel infilli		31-Mar-17
	LTC3D - Right Bank Bedrock Excavation	20-Sep-16	07-Oct-16
	LTC3D - Amend1 - Temporary PAG Stockpile	17-Nov-16	30-Nov-16
	LTC3E - Stage 1 Diversion Outlet Cofferdam	17-May-17	30-Jun-17
LCC4 Eastern Reservoir Clearing	LCC4 - Eastern Reservoir Clearing, as well as portion of central reservoir by Cache Creek/Hwy 29	20-Oct-16	06-Dec-16
	LTC4A North Bank Dam Site to Tea Creek, Wilder Creek to Cache Creek, South Bank south of Tea Island	1-Dec-16	19-Dec-16
	LTC4A - Amend1 - change of contractor		08-Feb-17
	LTC4B - North Bank Central Reservoir Highway 29 at Cache Cree	4-Jan-17	23-Jan-17
	LTC4B - Amend1 - archaeological stripping	9-Jun-17	14-Jun-17
LCC05 Left Bank Cofferdams and Diversion Works	LCC5 - Left Bank Cofferdams and Diversion Works	08-Jan-17	25-Apr-17
	LTC5C – Pre-approval - Stage 1 Left Bank Cofferdam – Mid-Stream Island Topsoil Stripping.		25-May-17
	LTC5C – Stage 1 Left Bank Cofferdam (Including Slurry Cut-off Wall & Grouting)	23-May-17	16-Jun-17
	LTC5B - Diversion outlet works, including in-river excavations	17-May-17	30-Jun-17
	LTC05A - Inlet Works (Portal and Channel)	02-Mar-17	12-May-17
LCC06 - RCC Buttress Foundation Preparation and RCC Placement	LCC06 - Buttress Foundation Preparation and RCC Placement	30-Jan-17	15-May-17
	LTC6A Powerhouse RCC	06-May-17	02-Jun-17
LCC07 - Geotechnical Investigations	Geotechnical investigations Hudson's Hope Berm and Halfway River Debris Boom	09-Mar-17	20-Apr-17
	LTC7A - Halfway River Debris Boom Geotechnical Investigations	16-Apr-17	28-Apr-17

	LTC7B - Hudson's Hope Berm Geotechnical Investigations	16-Apr-17	28-Apr-17

From:	Nikolejsin, Dave MNGD:EX
To:	MacLaren, Les EMPR:EX
Subject:	FW: items for this week
Date:	Sunday, July 23, 2017 3:22:18 PM
Attachments:	Site C TORs ideass.2 docx

Take a look and give me your thoughts

From: Winstanley, Lori PREM:EX
Sent: Sunday, July 23, 2017 2:52 PM
To: Nikolejsin, Dave MNGD:EX
Subject: items for this week

Hello Dave, to keep you up to date:

You may already know but Don Wright reached out tos.22 this weekend and they talked about possible ways forward on Site C review. Don will be working with the Ministry this week and the goal is to have some decisions made by the end of the week. I have attached some works.22 and myself did on draft Terms of Reference and I believe the Premiers's Office shared them with Don. They are not official in any way, but ideas we passed on. We have come up with other names to add to your list and that iss.22 s.22 I think a lot of people like the idea of an independent thinker likes.22 (my reading of what i have heard.)

As I understand it, Don will have a the responsibility for a Priority Files Committee which will change as needed. As of a Thursday night the committee did not exist but was being set up. Our ministry will be among the first up with Site C review and Kinder Morgan. I will pass you info as i get it but assume Don will be in touch.

Look forward to talking on Monday

From:	MacLaren, Les EMPR:EX
To:	McKnight, Elaine L MEM:EX
Cc:	Wieringa, Paul EMPR:EX; Rowe, Katherine EMPR:EX
Subject:	RE: Additional Transition Materials
Date:	Monday, July 17, 2017 11:33:45 AM
Attachments:	Site C Independent Review 17-7-17 LM.docx

Hi Elaine:

Attached is an updated version of the Site C BCUC Review concept paper, dated today, that includes some edits to Friday's version and a new third para under approach that suggests a consultant's initial report followed by BCUC public consultation and final report write-up.

Let us know if you think changes are required.

Les

From: MacLaren, Les MEM:EX
Sent: Friday, July 14, 2017 5:23 PM
To: McKnight, Elaine L MEM:EX
Cc: Wieringa, Paul MEM:EX; Rowe, Katherine MEM:EX
Subject: Additional Transition Materials

Hi Elaine:

As requested following your meeting this morning, attached are:

s.12; s.13; s.14

- Updated Site C BCUC Review Concept Paper with simplified terms of reference, reference to the large amount of public information over the past year from the revenue requirements process, and a list of potential experts that could support the review (e.g., as temporary commissioner(s))
- An Updated Concept Paper covering the Rates Plan, revenue requirements, and implications of a rate freeze

We have left the latter two documents in an amended Concept Paper format, which I think works, but we can adapt to some other format is required. Happy to make changes as required based on yours or others' feedback. Suggest we wait to share the Waneta document with BCH until next week so we (and the BCH Waneta Team) can have a weekend, hopefully relatively undisturbed.

Paul and Katherine, I have made untracked changes to the documents you sent me, and they are saved in the relevant LAN folders. Paul, I added your suggestions to the Rates Plan/Freeze Paper.

Les MacLaren
Assistant Deputy Minister
Electricity and Alternative Energy Division
BC Ministry of Energy and Mines
Office: 250-952-0204
Cell: 250-889-3479
Energizing BC—clean, sustainable and productive

From: MacLaren, Les EMPR:EX
To: Nikolejsin, Dave MNGD:EX
Subject: RE: items for this week
Date: Monday, July 24, 2017 7:32:00 AM

Some further commentary on ToR section 1. BC Hydro's load forecasting methodology has been reviewed and endorsed by the BCUC, and was reviewed by third party expert Mark Gilbert in the lead up to Site C FID. It includes low, expected and high forecasts over 20 years for both capacity and energy.

s.13

Les

From: MacLaren, Les MEM:EX
Sent: Sunday, July 23, 2017 5:02 PM
To: Nikolejsin, Dave MNGD:EX
Subject: RE: items for this week

Hi Dave:

Here are my comments.

s.13

s.13

Les

From: Nikolejsin, Dave MNGD:EX
Sent: Sunday, July 23, 2017 3:22 PM
To: MacLaren, Les MEM:EX
Subject: FW: items for this week

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From: MacLaren, Les EMPR:EX
To: Nikolejsin, Dave MNGD:EX
Subject: RE: items for this week
Date: Sunday, July 23, 2017 5:01:00 PM
Attachments: 05-03-2017 Letter to Dr. Santa Ono.pdf

Hi Dave:

Here are my comments.

s.13

Les

From: Nikolejsin, Dave MNGD:EX
Sent: Sunday, July 23, 2017 3:22 PM
To: MacLaren, Les MEM:EX
Subject: FW: items for this week

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Sent: Sunday, July 23, 2017 2:52 PM
To: Nikolejsin, Dave MNGD:EX
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Look forward to talking on Monday

BRITISH COLUMBIA | Ministry of Energy and Mines

CONCEPT PAPER

Date: July 17, 2017

Issue: **Independent Review Panel for Site C**

Background:
In November 2013, the Province approved both BC Hydro's 2013 Integrated Resource Plan (IRP) and the 10-Year Rates Plan. The IRP compared resource portfolios with and without Site C using a standardized cost of capital and concluded that the scenarios with Site C were the most attractive from a cost and reliability perspective. The 10-Year Rates Plan established a new regulatory account, and reduced BC Hydro's net income and dividend payments to the Province. Provincial and federal environmental certifications for Site C were granted in October 2014 after a Joint Review Panel noting that Site C was the best project. The Panel also recommended that the BC Utilities Commission (BCUC) should undertake a review of need and costing.

For the Site C Final Investment Decision, the Province reviewed the cost of Site C using the actual cost of capital. KPMG and a Panel of Independent Contractors evaluated the cost of construction, and other third party due diligence was undertaken on load forecasting, cost of alternative resources, and risk. In December 2014, the Province announced the positive final investment decision for Site C with an increased capital budget to $8.335 billion from $7.9 billion (primarily to account for a later project start and reintroduction of PST), plus a $440 million project reserve held by Treasury Board.

Construction began in July 2015, and BC Hydro is on track to deliver the project by November 2024. To date, BC Hydro has made more than $4 billion in financial commitments, including the main civil works contract at $1.75 billion, which comprises the majority of earthworks to construct the project and includes the construction of an earthfill dam, two diversion tunnels, and a concrete foundation for the generating station and spillways. Expenditures are in line with the approved $8.335 billion budget.

In Section 3 of the 2017 Confidence and Supply Agreement between the BC Green Caucus and the BC New Democrat Caucus, one policy initiative identified as a condition of support is to immediately refer the Site C dam construction project to the BCUC on the questions of economic viability and consequences to British Columbians in the context of the current supply and demand conditions prevailing in the BC market. The incoming government has stated it will expect an initial report within six weeks, and a final report within 3 months.

s.13

s.13

Contact: Les MacLaren, ADM, EAED
250-952-0204

Page 090 of 657 to/à Page 092 of 657

Withheld pursuant to/removed as

s.13

Site C

Context

The case to start construction of Site C for a 2024 in-service date was not supported by any independent BCUC or other public review and was specifically questioned by the Joint Environmental Review panel. And the decision to start the project was and remains very controversial because of questions about the need for the electricity it will generate, its very large capital cost, unavoidable environmental impacts and the irreconcilable opposition of some First Nations and residents who will be greatly affected.

While there are strong arguments that the project should not have been started when it was, particularly without independent public review, the issue now is fundamentally different. Many construction activities have been initiated and a large workforce is in place. Almost $2 billion has already been spent on the project and a significant amount more has been committed through contract obligations. The issue now is not whether the project should have been started, it is whether it is in the BC Hydro ratepayer and broader public interest to complete the project.

Given the strongly held views about this project, it is very challenging yet critically important to distinguish the question of whether it should have been started in the manner and timeframe that it was from whether it should be completed. The consequences of suspending or terminating construction at this time are very different from not starting in the first place. This is not to prejudge whether it is or is not the right thing to do. It is simply to say that it requires very careful consideration of what the different options would mean at this time, independent of what one might have concluded before construction had started.

Proposed Terms of Reference

The terms of reference for a review of Site C at this time must be focused on the key economic, environmental and social consequences of the central options available at this time:
-complete the project as planned
-terminate construction and remediate the work done to date
-suspend construction and maintain the option to complete the project at some unspecified later date.

The panel reviewing these options should advise government of the following:

1. BC Hydro and independent forecasts of BC Hydro energy and peak capacity requirements in the short, medium and long term;

2. The resource development plan BC Hydro would propose to undertake or that others propose could be undertaken to meet forecast energy and peak capacity requirements over a minimum 20 year planning period under each option (Completion, Termination, Suspension) – specifically what projects and demand side or other measures would or could be implemented to meet forecast requirements in accordance with prudent reliability criteria and Clean Energy Act obligations;

3. Differences between the options in the net economic costs to BC Hydro – specifically, the estimated present value of capital and operating expenditures BC Hydro would incur under each development plan net of estimated surplus sales revenues.

4. Differences between the options in the BC Hydro annual revenue requirement and rate implications in the short (up to 2024), medium (2024-end of planning period) and longer term

5. Differences among the options in the annual and cumulative amount of GHG emissions in British Columbia and elsewhere in the short medium and longer term

6. Differences among the options in major environmental and social impacts and trade-offs based on the Joint Review panel findings for the completion case.

7. Difference among the options in employment impacts, including both layoffs and new hires.

The panel will provide its best estimate of these consequences but will highlight the uncertainties and their potential significance with respect to BC Hydro energy and peak capacity requirements, costs to complete Site C, alternative resource costs and supply characteristics, carbon taxes, surplus sales prices and any other relevant matters.

The Panel Member(s)

The work and report of this panel must be recognized as impartial, fair to all sides of this very controversial and emotional debate. While the panel member(s) must be generally knowledgeable of the issues involved it is preferable they be able to take a fresh and independent examination of the evidence brought before it. The model we recommend it that of a judge hearing a court case – not an industry expert or participant that may be perceived as or in fact having preconceived views on electricity resource development options.

The process and Timeframe

It is expected that BC Hydro will be able to provide evidence on all aspects of the terms of reference based on previous submissions in related proceedings and more recent analysis it has undertaken. Interested parties will be limited in their ability to provide evidence due to time and budget constraints, but will be able to file and update as appropriate relevant studies that have already been undertaken (eg the "UBC study) as well as submit evidence on different aspects of the terms of reference based on previous work and experience (eg the work of the Joint Review Panel).

The panel members would have the resources to hire independent experts on all aspects of the terms of reference in order to submit evidence on its review of material submitted by BC Hydro and others, and the experts' own analysis of related matters.

The time frame would be challenging but something like the following is proposed.

- Selecting panel members, issuing order and terms of reference under section 5 of BCUC Act.
- Week 1 – procedural hearing to identify interested parties, review terms and reference, process and time frames
- End of week 3 – submission of evidence by BC Hydro
- End of week 5 – submission of evidence by interested parties and panel experts
- End of week 6 – interim report to government
- Week 7 – hearings and cross examination of all submitted evidence
- End of week 11- submission of rebuttal evidence and argument
- End of week 12 – submission of panel report.

bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

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P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

September 20, 2017

BCUC INQUIRY RESPECTING SITE C A-13

Sent via email

The Honourable Michelle Mungall, M.L.A.
Minister of Energy, Mines and Petroleum Resources
Parliament Buildings
PO Box 9060 Stn Prov Gov't
Victoria, British Columbia 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 – Preliminary Report

Dear Minister:

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

In the second phase of the Site C Inquiry, the Commission will continue its public consultation process with a series of Community Input Sessions across the province. As determined in Order G-120-17, members of the public may comment on the Commission's Preliminary Report. These comments will be considered by the Commission in the preparation of its Final Report, to be published on November 1, 2017.

Sincerely,

Patrick Wruck
Commission Secretary

SW/ad
Enclosure

bcuc
British Columbia
Utilities Commission

British Columbia Utilities Commission Inquiry Respecting Site C

Preliminary Report to the Government of British Columbia

PRELIMINARY REPORT

September 20, 2017

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

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

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Email: Commission.Secretary@bcuc.com
Phone: 604-660-4700
Toll Free: 1-800-663-1385

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Executive summary

Introduction

The British Columbia Utilities Commission (Commission) is an independent agency of the Government of British Columbia that is responsible for regulating British Columbia's (BC) energy utilities, the Insurance Corporation of BC's compulsory automobile insurance rates, intra-provincial pipelines and the reliability of the electrical transmission grid. 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 Commission is governed by the *Utilities Commission Act* (UCA) and has specific responsibilities under the *Administrative Tribunals Act* and the *Freedom of Information and Protection of Privacy Act*. We also consider 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 the British Columbia Hydro and Power Authority's (BC Hydro) Site C project (the Project) in accordance with the terms of Order in Council No. 244 (OIC). In the OIC, the BCUC was directed to advise on:

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

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

(iii) terminating construction and remediating the site.

The OIC went on to pose 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?

The Commission engaged Deloitte LLP (Deloitte), an independent consultant, to inform the Panel on the questions posed in the OIC. BC Hydro was directed to make available any and all relevant information to assist Deloitte, including confidential information. In addition, members of the public were invited to provide submissions of data and analysis to assist the Panel in answering the questions posed in the OIC. The Panel considered the 167 submissions received before this Preliminary Report was issued.

The Panel provides preliminary findings on a number of issues related to the OIC questions. However, we have identified a number of areas where additional information is required before any conclusions can be reached on the answers to the questions.

Currently on time

The OIC asks the Commission to review whether the Site C project is currently on time. The Panel has used the date of June 30, 2017, the date of BC Hydro's most recent quarter-end report, as the current date. Further, the Panel has used the date of November, 2024 as the in-service date against which to measure whether the project is on time, this date being specified in the Final Investment Decision (FID) made in December, 2014.

After having reviewed BC Hydro's expenditures and other documentation, the Panel finds that the Site C Project is, as of June 30, 2017, on time for an in-service date of November 2024.

BC Hydro is managing the project to a more aggressive schedule, whereby it would put the dam in service in 2023, one year earlier than the 2024 date in the FID. This provides the project with a year of schedule contingency, allowing the project to be delayed by up to a year and still achieve the FID target date of 2024.

The river diversion is a critical milestone in the construction of the dam. The river diversion must start between September 1 and October 1 of a given year, otherwise it must be rescheduled to the following year to avoid the risk of floods and winter construction constraints. BC Hydro is currently planning to start the river diversion on September 1, 2019. Should the river diversion be delayed one year to September, 2020, the in-service date of November 2023 would be missed. However, the in-service date against which the project is being measured is one year later, November 2024, for which the start of the river diversion need not happen until September 1, 2020.

The Panel considers it more difficult to assess whether the Project is, as of June 30, 2017, on schedule for a river diversion in 2019. While this is not necessary to achieve the November 2024 in-service date, it is important as a one-year delay in the project would have a significant effect on the budget. BC Hydro is facing significant challenges with the main civil works on the left bank as a result of two tension cracks, and currently expects to use three months of float as a result. It is unclear to the Panel how much float remains. Further, BC Hydro and its main civil works contractor, Peace River Hydro Partners (PRHP), are still in discussions regarding the impact of the tension cracks on the schedule, and have not agreed on a schedule which would allow the 2019 river diversion to take place.

While the Panel has already found that the project is currently on schedule to deliver by November 2024, the Panel is not yet in a position to express a view on the probability that the project will remain on schedule. Should there be a one-year delay of the river diversion, the Panel is concerned that the Project will have consumed its one-year "owner's float", although BC Hydro would still have float within specific contractors' schedules and other contingencies available. As a result, should the river diversion be delayed to 2020, any delays to subsequent activities would be more likely to affect the overall project schedule.

The Panel has received submissions, including academic studies, which suggest that many large dam construction projects deliver late and over budget. The Keeyask and Muskrat Falls projects are cited as examples in Canada. The Panel acknowledges that there may be systematic problems estimating the costs and schedules for large dam projects, but gives more weight to the evidence specific to the Site C project. We do not find that generalized studies or other project comparisons are sufficiently relevant to draw specific conclusions about the Site C project.

Currently within the proposed budget

The OIC asks the Commission to review whether the Site C project is currently within the proposed budget of $8.335 billion. As before, the Panel has used the date of June 30, 2017, the date of BC Hydro's most recent quarter-end report, as the current date.

After having reviewed BC Hydro's expenditures and other documentation, the Panel finds that it has insufficient information at this point to determine whether the Project is within its proposed budget, as of June 30, 2017. The Panel requires more information on the current assessment of project spending, the value of outstanding claims and projected use of budget contingency

The Panel is concerned that the amount spent on the project as of June 30, 2017, $1.8 billion, might not accurately represent the spending that should have happened based on the project activities to date. BC Hydro has explained the differences between the planned and actual spending to date against the schedule to complete the dam by November 2024. However, since BC Hydro is managing its activities and incurring expenditures according to a schedule delivering in November 2023, the Panel would find this analysis more useful.

It has been suggested that claims will be forthcoming related to work scheduled to be completed by the current date, which would have increased the spent-to-date figure of $1.8 billion had they been received and accepted. These figures could make a material difference to the costs incurred to date, and the Panel is seeking more information on these amounts.

The Panel is concerned that the $356 million contingency that has been allocated and committed to date represents 45 percent of the planned $794 million contingency, two years into an eight-year project, and seeks further information from BC Hydro as to its expectations for future use of budget contingency.

Looking forward, the Panel finds that if the river diversion is not achieved in September 2019, then the project will not remain within the budget of $8.335 billion. BC Hydro's estimate is that a one-year project delay would cost $630 million, and would "likely trigger a draw on the Treasury Board reserve."

As for a final cost, Deloitte has identified scenarios in which the Project could be up to 50 percent over budget. The Panel is seeking more information from BC Hydro to assess the budget impact of current risks, such as the main civil works delays and claims. In addition, BC Hydro under-estimated the cost of the winning bid for the main civil works contract. Should it have under-estimated the cost of the two other major contracts still to be awarded, for the generator station and spillway and for transmission, there may not be sufficient budget contingency remaining.

The Panel acknowledges that BC Hydro has identified cost savings in the Project that increase the amount of available contingency from the $794 million in the budget to a figure of $1.194 billion now. However, the Panel is concerned that the majority of those savings are relate to lower-than-planned interest costs, and would like to understand the effect of increases in interest rates on the amount of project budget contingency available.

Suspend the project

BC Hydro and Deloitte have provided cost estimates to suspend and restart the Site C project. The Panel finds the estimates provided by BC Hydro and those provided by Deloitte to be similar and appear reasonable with respect to the costs associated with suspension and maintenance of the site through 2024.

However, the Panel finds there to be significant variance between the two with respect to costs related to restarting the project after suspension. As a consequence the Panel finds it premature to reach a conclusion as to the total costs for the project in the event it is suspended and restarted.

Terminate the project

BC Hydro and Deloitte have provided cost estimates to terminate the Site C project. The Panel finds the estimates provided by BC Hydro and those provided by Deloitte to be similar and appear reasonable with respect to the costs associated with terminating the project and remediating the site.

The Panel accepts BC Hydro's figures that, as of December 31, 2017, there will be a balance of $500 million in the Site C regulatory account for expenditures incurred prior to the Final Investment Decision, and $1.6 billion project costs incurred since the FID, for a total sunk cost of $2.1 billion.

In addition, the Panel finds a reasonable estimate of the cost to terminate the project and remediate the site to be $1.1 billion, based on the figures provided by BC Hydro and Deloitte.

However, termination of the project and remediation of the site would trigger incremental costs to replace the energy that would have been provided by Site C with alternative sources of energy. This issue is addressed in the sections below.

Current Load Forecast

As directed by OIC 244, the Panel's analysis utilizes BC Hydro's low, mid-level or expected case and high load forecasts for peak capacity demand and energy demand provided by BC Hydro provided in its Fiscal (F) 2017 to Fiscal 2019 Revenue Requirement Application (F17-F19 RRA) (Current Load Forecast). As a number of submissions point out, sections 3(c)(i) and (ii) of OIC 244 provide flexibility for the Panel to identify factors that may cause the load forecast to deviate from the mid-level load forecast. The Panel also considered the impacts of developments since the load forecast was prepared.

The Panel's analysis highlights a number of issues and potential concerns identified by Deloitte in its independent report and raised in submissions received from other parties.

The Panel acknowledges 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 recognizes 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 and at the same time if it acquires or builds more resources than it needs there is a potential for unnecessarily higher rates for customers. The Panel views an effective forecast model is one that produces results reasonably close to actual with equal instances of over and under forecasts. The Panel recognizes that a utility may view it to be 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 of the other.

In this context, the Panel considers a number of load forecast issues identified to the date of this Preliminary Report and seeks further input and analysis of these issues from BC Hydro and other participants. The Panel has the following preliminary findings related to the Current Load Forecast:

Recent developments in the industrial sectors – the Panel is not yet in a position to make its finding on the reasonableness of the industrial load or the impact of recent developments in the industrial sector due to insufficient information. The Panel has requested that BC Hydro answer a number of questions about BC Hydro's probability assessment for the LNG and non-LNG industrial load.

Accuracy of historical load forecasts – consistent with the issues raised by a number of parties about the historical accuracy of BC Hydro's load forecast model, the Panel finds the historical instances of over-forecasts

are greater than under-forecasts, especially in the industrial load. The Panel also finds that the accuracy of BC Hydro's historical industrial forecasts looking out three and six years have been considerably below industry benchmarks.

GDP and other forecast drivers – the Panel is concerned with the differences in between BC Hydro's forecast drivers for GDP and disposable income compared to those of the Conference Board of Canada. To assist the Panel to make its finding on the reasonableness of BC Hydro's inputs for GDP and disposable income due to the need for further analysis, we request that BC Hydro respond to a number of questions related to its forecast drivers for GDP and disposable income.

Price elasticity and future rate increases – The Panel notes the differences in views related to BC Hydro's elasticity assumptions and GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts", which were developed in 2007, need to be updated. The Panel is particularly concerned about the appropriateness of BC Hydro 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. The Panel requests that BC Hydro respond to a number of questions related to price elasticity and future rate increases.

Potential disrupting trends – The Panel is concerned that, given the long-life of the Site C asset, BC Hydro has only identified a potential upside risks to the load forecast from electrification, and has not identified any potential downside risks. The Panel requests that BC Hydro and other parties specifically address questions related to potential disrupting trends.

Handling of surplus energy and capacity

Once Site C is operational there is the potential for surplus energy and capacity. BC Hydro outlines the potential for capacity and flexibility sales and asserts there is the potential to profit from a short-term energy surplus as compared to the cost of completing the Site C project citing its Mid C energy price forecast through 2040. The Panel has raised concerns with respect to the capacity sales and has asked further clarifying questions. With respect to surplus energy sales, the Panel notes the differences between Mid C forecasts and finds it is premature to reach any specific conclusions on the future demand for surplus energy.

Alternative energy portfolios

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?

BC Hydro presented the result of its screening analysis which in its view demonstrated that biomass, geothermal and battery storage were unsuitable candidates for the alternative portfolio. In addition, a number of alternative sources of generation and capacity have been suggested by Deloitte and other parties, along with different perspectives of the cost and availability of alternative energy sources. The Panel reviews the submissions and makes the following general findings concerning alternative energy sources:

1. Biomass, geothermal, solar and battery storage are potential candidates for alternative generation and should be considered by BC Hydro.
2. Costs modelled by BC Hydro for wind may overstate the amount of decrease in capital costs expected over the next 20 years.

BC Hydro used its "PV Portfolio Analyzer" to develop a series of alternative portfolios. The portfolio analysis tool accepts input assumptions concerning BC Hydro's existing generation assets, the cost of alternate energy projects and the load forecast. Deloitte also provided alternative portfolios from their "MarketBuilder" portfolio analysis tool. BC Hydro's alternative portfolios consisted of wind and pumped storage, while Deloitte produced portfolios with biogas, geothermal and wind. These different choices reflect the difference in the two parties' input assumptions. This is an example of one of BC Hydro's portfolios:

Table 1: Mid Load forecast with IRP DSM plan. Site C terminated.

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

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2028	BCH_LM	2017 Load Curtailment	85	85	0	0	77
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_PR	Wind_PC48	150	39	538	538	95
2029	BCH_NC	Wind_NC09	333	87	1,074	1,074	101
2031	BCH_PR	Wind_PC20	156	41	594	594	92
2032	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2033	BCH_PR	Wind_PC14	144	37	570	570	92
2034	BCH_PR	Wind_PC28	153	40	641	641	94
2035	BCH_PR	Wind_PC10	297	77	1,119	1,119	99
2036	BCH_PR	Wind_PC17	102	27	335	335	106
2037	BCH_KN	Wind_SI15	303	79	898	898	108
2037	BCH_REV	Wind_SI12	186	48	586	586	106
2038	BCH_KN	Wind_SI16	660	172	1,814	1,814	111
2038	BCH_VI	Wind_VI02	147	38	446	446	111
2039	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2041	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_PR	Wind_PC19	117	30	482	482	101

In order to assist with responding to the question posed in section 3(b)(iv) of the OIC, BC Hydro selected a sample portfolio and calculated the "unit energy cost" (UEC) for that portfolio and compared it to the UEC for Site C. The UEC simply expresses the cost for a resource by its levelized annual cost per unit of energy produced BC Hydro's results are summarized below:

Table 2: BC Hydro's Unadjusted and Adjusted UEC

Source	UEC $/MWh	Adjusted UEC $/MWh
Site C	$83	$34
Alternative Block	$85	$153

The adjustments to the Site C UEC to arrive at the "adjusted UEC" include:

- A reduction for sunk and termination cost ($24/MWh)
- A reduction in the cost of capital due to a decision by Government to reduce the dividend received from BC Hydro (approximately $26/MWh)

While the adjustments to the Alternative Block UEC include:

- An increase for line losses, integration, network and transmission upgrade costs (approximately $22/MWh)
- An increase for the cost of additional pumped storage necessitated by the fact the wind energy has less firm capacity than Site C (approximately $48/MWh)

In both cases, the Panel finds the assumptions underlying the calculation of the adjusted UECs to be not well explained and we have requested further clarification from BC Hydro. The Panel also has a number of findings

which are outlined below. In many cases, we have requested further questions from BC Hydro and comments from other parties.

Financing costs: The reduction of financing costs of $26/MWh, which is enabled by transferring some of the financing costs from BC Hydro ratepayers to taxpayers, does not appear to be built into the Alternative Block UEC. If two portfolios are being compared, it is important to ensure that the basis of comparison is the same. If the same debt financing assumption is not being applied to the Alternative Portfolio, and a full weighted-average cost of capital is assumed instead, the Panel also draws a preliminary conclusion that this reflects an implicit assumption that the Alternative Portfolio will not be constructed by BC Hydro. This results in an "apples to oranges" comparison. The Panel finds that the reduction of the UEC to account for reduced financing costs distorts the analysis of unit energy costs comparisons.

70 year modelling period: The Panel has concerns about the 70 year modelling period. In particular, there are possible risks that occur over the longer term. Potential disruptors include: decreasing prices of alternative energy sources such as wind, solar, batteries; improvements in energy efficiency, for example LED lights, net zero energy home), LNG industry development risk, persistent low price of natural gas etc.

The discount rate: Panel notes the approach to establishing a discount rate suggested by the CD Howe Institute – that the discount rate should be based on an analysis of a project's risks. However, BC Hydro used a 6 percent nominal discount rate for all present value calculations. This may result in the risk associated with some generation projects not being correctly accounted for in the financial analysis.

Timing of investments: The Panel also finds that the usefulness of the adjusted UEC, as calculated by BC Hydro, is limited as a comparison methodology because it doesn't appear to take into account when an energy source within a portfolio comes on line. The present cost of a wind farm that comes on line in ten years will be different from the cost today of the identical resource that comes on line today because of the possibly-declining cost of the technology.

Adjustments for sunk costs and termination: A further issue is the use of the term "unit energy cost" in section 3(b)(iv) of the OIC. The question posed in the OIC is "what, if any, other portfolio of commercially feasible generation projects…could provide similar benefits ….. to ratepayers at a similar or lower unit cost as the Site C project?"

The unit energy cost is the cost for a resource by its levelized annual cost per unit of energy produc*ed*. BC Hydro makes a number of adjustments to the UEC, including subtracting the cost of terminating the project. Although the methodology of adding termination and remediation costs to the UEC may have been accepted by the Commission in a previous context, given the wording of Section 3(b)(iv) of the OIC, it isn't clear that it is appropriate in this context. Accordingly the Panel requests that BC Hydro comment on the appropriateness of adjustments for sunk and termination costs to the Site C UEC.

Appropriateness of the selected alternative block: Further, the Panel finds that there are different alternative blocks that arise from the portfolio analysis and that the particular alternative block used in the UEC calculation does not appear to specifically match any of the portfolio results presented.

Rerunning Portfolios: We have also asked BC Hydro to re-run its portfolio model with assumptions of lower costs of alternative energy, additions to the portfolio of geothermal, biomass, solar and battery storage,, and reduced financing costs for alternative portfolios.

The Columbia River Treaty Entitlement: 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 comment on these submissions in Appendix B.

Costs to ratepayers

The OIC requests that the Commission assess the implications of completing, suspending or terminating the Site C project, specifically with respect to the cost to ratepayers. BC Hydro has provided an extensive analysis of the cost impact to ratepayers in each of these three cases, based on a set of financial assumptions.

The Panel finds that it is not yet in a position to assess the cost impact to ratepayers of continuing, suspending or terminating construction. Many questions remain regarding the portfolios of alternative energy that BC Hydro has assumed, and no analysis has been presented to evaluate the costs should the energy and capacity required be closer to the low or high ranges of the load forecast rather than the mid-level forecast.

Closing comments from the Panel

In conclusion, the Panel has identified numerous areas of information gaps which require supplemental evidence and analysis from BC Hydro and/or the public in order to make definitive and conclusive findings. The Panel requests responses to the questions posed in this Preliminary Report by October 4, 2017. In the next stage of the Inquiry, the Panel will host Community Input Sessions throughout the province and will deliver its Final Report to the Minister charged with the administration of the *Hydro and Power Authority Act* by November 1, 2017.

The Panel thanks all participants for their submissions, and for their interest in the Panel's report process. All submissions have been considered, even if there is no specific mention of it in this Preliminary Report.

We invite all participants to provide further comment on this report.

1.0 Introduction to the Preliminary Report

The British Columbia Utilities Commission (BCUC, Commission) is an independent agency of the Government of British Columbia (BC) that is responsible for regulating BC's energy utilities, the Insurance Corporation of BC's compulsory automobile insurance rates, intra-provincial pipelines, and the reliability of the electrical transmission grid. 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 *Administrative Tribunals Act* (ATA) and the *Freedom of Information and Protection of Privacy Act* (FOIPPA). We also consider 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, the authority) Site C project in accordance with the terms of Order in Council 244 (OIC, or OIC 244).

The Commission's Panel for the review of the Site C Inquiry has prepared this Preliminary Report in accordance with the terms of reference set out in OIC 244. The Preliminary Report has been prepared 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. **Based on our review of the information provided, the Panel has identified numerous areas where additional information is required and has therefore requested in this report that BC Hydro provides additional information. We request that BC Hydro respond to the questions in this report, which are summarized in Appendix C, by October 4, 2017.** The Panel acknowledges the relatively short time period with which BC Hydro is requested to respond to these questions. The Panel has set this deadline in order to provide all parties with time to consider BC Hydro's responses and, if applicable, incorporate BC Hydro's responses into parties' written submissions. **We recommend that BC Hydro, instead of submitting all its responses at the deadline, provide its responses to the Commission as they become available so that the Panel and other parties are able to review the information on a timelier basis.**

This additional information requested by the Panel will be critical in preparing our final findings and conclusions related to the OIC requirements in the Final Report. The Panel acknowledges that some of the questions and requests for information will require confidential responses.

The Preliminary Report first addresses the Site C project options as outlined in section 3(a) of OIC 244. This covers issues and questions related to the three cases: (i) completion of the project; (ii) suspension of the project; and (iii) termination of the project. BC Hydro's ability to meet forecasted load using existing and committed resources is then examined with a discussion of BC Hydro's existing and committed resources, BC Hydro's current load forecast 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 accordance with section 3(b)(iv) of the OIC, the Panel then examines resource and generation alternatives and discuss BC Hydro's and Deloitte's portfolio analysis, BC Hydro's Unit Energy Cost (UEC) analysis of Site C and an alternative portfolio, as well as alternative energy and capacity sources.

The Panel considers that the "costs to ratepayers" includes only those costs that directly affect rates. Other economic considerations, such as the loss of income to construction workers or reduced benefit payments from BC Hydro to First Nations, are not considered costs to ratepayers for the purpose of this analysis.

Throughout this Preliminary Report, the Panel has made preliminary findings and seeks additional information. Readers are cautioned that these are preliminary and subject to change as we complete the consultation process and as additional information becomes available.

2.0 Background

2.1 What is Site C?

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, 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 and 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 about 1,145 megawatts (MW)[4] and about 5,286[5] annual GWh of electricity (the amount of energy needed, per BC Hydro) to power the equivalent of 450,000 homes per year[6].

2.1.1 What is being constructed?

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?" https://www.sitecproject.com/faq

[2] BC Hydro Site C Clean Energy Project Website, Information Sheet, November 2016, https://www.sitecproject.com/news-and-information/information-sheets

[3] Ibid.

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

[5] A-12 Submission

[6] Ibid.

[7] BC Hydro Site C Clean Energy Project Website, Information Sheet, November 2016, https://www.sitecproject.com/news-and-information/information-sheets

2.1.2 Site C's construction timeline

The history of the Site C dam spans nearly 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 approved 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 their 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 October 2014, the Joint Review Panel completed their environmental assessment, having held public hearings and received submissions from the public, stakeholders, and other parties. The CEAA Decision was handed down in late October of 2014, but it was revised and reissued on November 25, 2014. In December 2014, the final investment decision from the provincial government (in the affirmative) was received; construction began in the summer of 2015.

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]

[8] Report of the Joint Review Panel regarding the Site C Clean Energy Project dated May 1, 2014, page 8.
[9] Ibid, page 9.
[10] Ibid.
[11] Report of the Joint Review Panel regarding the Site C Clean Energy Project dated May 1, 2014, page iv.
[12] BC Hydro, Site C Fact Sheet, July 2017.
[13] Decision Statement, issued under Section 54 of the Canadian Environmental Assessment Act, 2012, issued November 25, 2014.,https://www.ceaa-acee.gc.ca/050/documents/p63919/100567E.pdf

3.0 Site C Inquiry process

3.1 Legislative framework

The governing legislation of the Commission is the UCA, which gives the Commission powers to regulate the energy industry in BC. In particular, section 45 of the UCA provides 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 provisions of the *Clean Energy Act* (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 UCA in a way that would directly or indirectly prevent" BC Hydro "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, the LGIC issued OIC 244, invoking section 5 of the UCA, and 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). The OIC further specified the terms of reference for the Inquiry, including the dates for its commencement and completion.[21]

OIC 244 provides that the Inquiry was to start on August 9, 2017, that a Preliminary Report must be submitted by September 20, 2017, and a final report must be submitted by November 1, 2017.[22] 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[23] 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."[24] 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."[25] 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 244), section 2
[21] OIC section 3
[22] OIC 244-17
[23] UCA section 2.1
[24] *Administrative Tribunals Act* (ATA), SBC 2010, Chapter 45, section 11 (ATA) section 11
[25] 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.

Given the limited time available to complete the Inquiry, the Panel has worked strictly within the scope set out below, and has not inquired into other matters which may be related to Site C and be of interest to the public.

It is particularly important to understand that the Panel is not being asked to make recommendations nor to make a decision regarding 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 Panel 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 [26] (Case 3) (collectively the Cases)

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

3.2.2 Specific questions

For further specificity, the OIC directed that the Panel 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?[27]

Question (i) directs the Panel to inquire into the estimated cost of completing the Site C Project "as currently planned".[28] The Panel's interpretation of this question is that, in addition to examining whether the Project is

[26] OIC section 3(a)
[27] OIC section 3(b)
[28] OIC section 3(a)(i)

currently on budget, we are being asked 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.

Questions (ii) and (iii) direct the Panel to inquire into the costs of Cases 2 and 3 respectively, namely the options of suspending or cancelling the Project. The Panel is directed to consider "costs to ratepayers", which we interpret 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.

Question (iv) directs the Panel to inquire into the alternative generation that would be required should the government decide to proceed with either Case 2, suspending Site C, or Case 3, cancelling the Project. In Cases 2 and 3, 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 addressing Case 1 as the Site C project would be completed. The Panel considers the cost of the alternative generation required in Cases 2 and 3 to be a direct economic cost to ratepayers.

Given the specific questions to which the Panel has been directed to respond, the Panel's advice on the implications of the three Cases is restricted to the costs to ratepayers as described above.

3.2.3 Load forecast

The OIC further defined the scope of the Inquiry by directing the Panel 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.[29]

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 parties 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)."[30]

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

[29] OIC section 3(c)
[30] OIC section 3(d)

3.2.4.1 First Nations consultation

The Panel acknowledges that First Nations are interested parties as set out in the terms of reference of the OIC and has therefore 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,[31] the Site C Inquiry is not an application. Further, the OIC does not ask the Panel to make any decisions with respect to Site C. Assessing the adequacy of consultation is therefore beyond the scope of the OIC. Instead, the Panel has sought submissions from any First Nation impacted by Site C and will summarize those submissions received, to date, as they relate to the relevant sections in this Preliminary 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]

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]

3.3 Process

As noted in Section 3.1 above, the Panel has the ability to set out processes and rules of practice and procedure that it considers appropriate to the circumstances of this Inquiry, subject to any specific direction provided in the terms of reference of OIC 244.

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[31] Rio Tinto Alcan v. Carrier Sekani Tribal Council, 2010 SCC 43
[32] OIC section 3 (e)
[33] OIC section 3 (f)
[34] OIC section 3 (g)

The process being undertaken by the Panel is open, transparent and inclusive. It is a requirement of the OIC that the Panel produce a preliminary report in six weeks and a final report in twelve weeks.[35] Given this timeframe, as described in detail in the following sections, this Inquiry differs from typical Commission proceedings.

The essential ingredient of a typical Commission proceeding is that an applicant is seeking some sort of relief or approval. In such cases, a high degree of procedural fairness is owed to all parties involved. This might include, for instance, the testing of evidence through cross-examination before the Commission makes a determination of whether an application is in the public interest. In the case of this Inquiry, no approval has been sought or requested by the government; rather, the OIC asks the Commission to answer certain questions about the costs to ratepayers of the Site C project, and to consult interested parties. The subsequent report from the Commission to the Minister of Energy, Mines and Petroleum (Minister) is but one input to the provincial government's decision-making process.

The Commission's process is split into two phases: initial fact gathering which concludes with the publication of this Preliminary Report, and additional fact gathering, consultation and submissions concluding with the publication of a final report.

3.3.1 Initial fact gathering

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

The OIC specifically directs the Panel to order BC Hydro to report on developments and other factors that may impact its load forecast;[36] however, the Panel determined that BC Hydro shall provide a submission on all aspects of the Inquiry, including on the questions regarding completing, suspending or cancelling the Site C project.

The Panel also engaged Deloitte LLP (Deloitte), a qualified and independent consultant 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 provided two reports which were made public. Deloitte is not a party to the proceeding and does not advocate for or against any issue.

Specifically, Deloitte provided independent estimates of the construction costs to suspend or cancel the Site C project. Deloitte also identified portfolios of alternative generation to replace the energy and capacity of Site C, and additional demand-side management opportunities. Deloitte also provided an assessment of BC Hydro's load forecast.

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. Information in Deloitte's final reports that the Panel determined to be confidential was redacted.

The Panel also sought submissions of relevant data and analysis from any other interested parties. The Panel did not have time to 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.

All submissions received by August 30, 2017 were given consideration in the preparation of the Preliminary Report. To ensure an open and transparent process, the Panel accepted submissions electronically via the

[35] OIC section 3 (g)
[36] OIC section

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.

Using the data and analysis in the submissions received, the Panel provides an initial assessment of the cost to BC Hydro ratepayers of each of the three Cases under consideration: continuation, suspension and cancellation. The financial analysis was performed using the best available data, and in some cases includes ranges of possible costs.[37]

The final step of the initial fact gathering process is the production of this Preliminary Report. This must, according to the OIC, be delivered to the Minister by September 20, 2017, six weeks after the start of the Inquiry.[38] The Preliminary Report is the basis for the subsequent processes, described in Section 3.3.2 below.

To support future processes, the Preliminary Report will be available for review on the Commission's website and is also available in hardcopy at the Commission's office and the executive summary will be available at all Service BC centres around the province.

3.3.2 Consultation

Following the publication of the Preliminary Report, the Panel will conduct an extensive consultation process on the preliminary findings. Input will be sought from BC Hydro, the public and First Nations. Based on further evidence and the submissions received by October 11, 2017, the Panel will further assess the cost impact to BC Hydro ratepayers of continuing, suspending or cancelling the Site C project, and will produce a final report.

BC Hydro is invited to make a further submission on the Panel's preliminary analysis and findings. BC Hydro is not an applicant but it does have a significant interest in the outcome of any decision the government might make using the Panel's preliminary analysis and findings, and also has the deepest knowledge of the details of the Site C project. The Panel wishes to ensure that BC Hydro has every opportunity to identify potential errors or gaps in the preliminary analysis.

The Panel anticipates submissions on the Preliminary Report from interested parties other than BC Hydro. Where relevant to the scope of the Inquiry, they will be considered by the Panel in preparing its Final Report.

In support of public consultation, the Commission is holding Community Input Sessions around the province to solicit oral submissions from the public. Community Input Sessions will be conducted in all major population centres in BC and in areas where the Panel considers the Site C project has a higher impact.

As noted in Section 3.2.4.1, the Panel will seek input from First Nations regarding its Preliminary Report. Treaty 8 First Nations and other First Nations who have made submissions to the Inquiry will be invited to make a submission on the Preliminary Report. The Panel will hold sessions specifically for First Nations in Prince George, Fort St. John, Victoria and Vancouver to present their material and make oral submissions. The public is welcome to attend but only First Nations will be invited to present.

Submissions from the public, BC Hydro, members of the public and First Nations will be received until October 11, 2017. The Panel has also invited specific parties to present material to the Panel. These parties were selected based on the relevance and quality of their submissions, and the degree to which the Panel determines that the party would provide further useful input to its deliberations. These sessions will be held in Vancouver.

The final step will be the production of the Final Report. This must, according to the OIC, be delivered to the Minister by November 1, 2017, six weeks after the delivery of the Preliminary Report[39]. The Panel will consider

[37] OIC section 3(b)(iv)
[38] OIC section 3(g)(i)

the various submissions received on its Preliminary Report, and finalize its position in the Final Report to the Minister. The final report will be available for review on the Commission's website, and in hardcopy at the Commission's office.

3.4 Progress to date

The Panel has completed the work that the OIC directed to be performed by September 20, 2017. Specifically, within the terms of reference set out in the OIC, the Panel has submitted to the Minister this "preliminary report outlining progress to date and preliminary findings."[40]

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.

BC Hydro was directed by Order G-121-17 to submit an evidentiary filing updating its load forecast which was filed in BC Hydro's F2017 – 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 filed its evidentiary filing on August 30, 2017.

The Panel selected and 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 complete, suspend or cancel construction, and what alternative source of generation and demand-side initiatives exist to replace the energy and capacity of Site C. Deloitte submitted their report to the Panel on August 30, 2017. Subsequently, the Panel worked with BC Hydro to identify confidential information in the Deloitte report, and to produce a redacted version for publication.

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, and using Twitter and email notifications. The Panel considered the 167 submissions received before this Preliminary Report was issued.

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

To ensure that the Inquiry was open 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 has been published. Back-office processing has also been set up to handle a significant volume of comments from the public in response to the Preliminary Report.

[39] OIC section 3(g)(ii)
[40] OIC section 3(g)(i)

4.0 Site C project options - OIC 244 section 3a

The government directed the Panel to evaluate three alternative cases:

i. completing the Site C project by 2024, as currently planned;

ii. suspending the Site C project, while maintaining the option to resume construction until 2024; and

iii. terminating construction and remediating the site.[41]

In this section, we consider the costs to ratepayers of these three cases, including the direct and indirect costs to complete, suspend or terminate the project. Consideration of the cost of alternative energy and capacity to Site C is presented in subsequent sections of this Preliminary Report.

BC Hydro, in its submission, considered two versions of suspending construction: restarting construction in 2024; and cancelling construction in 2024.

4.1 Costs to complete the project

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)"[42]. The Panel has established that "currently" shall be interpreted as referring to the date of June 30, 2017, this being the date of BC Hydro's most recent quarter-end report.

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 more clearly explore the budget impacts of any possible delays to the project schedule.

4.1.1 Is the Site C project currently on time?

The OIC asks that, after the Panel 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". As previously noted, the Panel interprets this question as asking whether the project was on time on June 30, 2017.

The Panel notes that there are two schedules for the Site C project that might be relevant to answering this question. The Final Investment Decision (FID) schedule shows an in-service date of the final generation unit in November 2024[43]. BC Hydro also created an internal Performance Measurement Baseline (PMB) schedule, which was last updated in June 2016[44]. 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[45]. Deloitte presents a comparison between the two schedules[46]:

[41] OIC section 3 (a)
[42] OIC section 3 (b) (i)
[43] F1-1 Submission, p. 34.
[44] A-8 Submission, Deloitte report, p. 19.
[45] Ibid., p. 23.
[46] Ibid., p. 20.

Table 3: 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"[47]. 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 has reviewed BC Hydro's submission and the independent report supplied by Deloitte to assess whether the project is currently on schedule.

BC Hydro submission

BC Hydro asserts that the project is currently "on schedule"[48], and that "the November 2024 in-service date is not at risk"[49]. BC Hydro goes on to state that the individual in-service dates of the transmission lines, sub-stations and generating units are all "on track"[50]:

Table 4: 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

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[51]:

[47] OIC section 3 (a) (i)
[48] F1-1 Submission, p. 33.
[49] Ibid., p. 34.
[50] Ibid.
[51] Ibid.

Table 5: 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 provides a more detailed analysis of the state of completion of activities underway[52], e.g. the Main Civil Works activities:

Table 6a: Progress of Work to June 30, 2017, by Location and Type of Work

Main Civil Works		Unit	Contract Quantity	Complete to Date	% Complete
Excavation	Left Bank	m^3	8,858,889	4,754,268	54
	Approach Channel	m^3	8,200,000	2,454,665	30

Table 4b: Progress of Work to June 30, 2017, by Location and Type of Work

Main Civil Works		Unit	Contract Quantity	Complete to Date	% Complete
	Right Bank Powerhouse	m^3	845,000	738,488	87
	Right Bank Stilling Basin	m^3	347,844	347,844	100
	Right Bank Spillway	m^3	1,242,156	265,531	21
	Right Bank Dam	m^3	544,000	381,653	70
Tunnels	Right Bank Drainage Tunnel	m	1,089	26	2
Cofferdams	Stage 1 Right Bank Cofferdam Slurry Wall	m	1,570	1,570	100
	Inlet Cofferdam Slurry Wall	m^2	5,755	470	8
Tension Crack, including mitigation	Left Bank Toe Buttresses	m^3	160,000	160,000	100

[53]

This includes a "% complete" figure for tasks underway, and demonstrates that progress is being made. However, since there is no information provided on what percentage of the work was planned to be completed by the present date, this is not sufficient to determine whether the project is currently on schedule.

BC Hydro states 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[54]. However, its notes that the current challenges with the main civil

[52] F1-1 Submission, Appendix D
[53] F1-1 Submission, Appendix D, page 7-8
[54] F1-1 Submission, p.36,37

works contract on the left bank are "currently forecast to result in the use of 3 months of float for this component of the work"[55]. BC Hydro states that it has identified opportunities to recover this schedule float.

Deloitte report

Deloitte states that "today the Project remains on time"[56], and identifies 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 adds that should BC Hydro not achieve the start of the river diversion by September 2019, and the project is subsequently delayed by one year, the in-service date of November 2024 could still be achieved.[57]

Deloitte further states that, according to the more aggressive PMB schedule, there was 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.[58] Despite challenges owing to the delayed start of work required prior to river diversion[59] and two tension cracks appearing on the left bank slopes, Deloitte assesses that the project is "still on track to meet the September 2019 diversion date, as well as the overall target completion date of 2023."[60]

Notwithstanding the above, Deloitte notes 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"[61]. Deloitte explains 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 states the most recent report from Peace River Hydro Partners (PRHP), the main civil works contractor, shows "completion of work related to diversion tunnels on March 30, 2020"[62]. While they add 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 cautions that it "has not observed a clear method the Project utilizes to measure percent complete"[63]. According to Deloitte, BC Hydro plans to implement earned value methodology (EVM) by December 2017[64] to assess the degree of completion of project activities. Deloitte adds that this is "common practice" for large projects, and "if developed and executed properly"[65] provides an assessment of both current project status and future trends.

Deloitte performed an "integrity check" on BC Hydro's schedules "for compliance with industry standards for scheduling using the critical path method", and concluded that the schedules "appear to have appropriate activity relationships, logic, and WBS (work breakdown structure)"[66].

[55] F1-1 Submission, p.37
[56] A-8 Submission, Deloitte report, p.3
[57] Ibid., p.3
[58] Ibid., p.25 section 5.4.4
[59] Ibid., p.23
[60] Ibid., p.24
[61] Ibid., p.25 section 5.4.4
[62] Ibid., p.25
[63] Ibid., p.28
[64] Ibid., p.28
[65] Ibid., p.22
[66] Ibid., p.23

Panel analysis and preliminary findings

The Panel finds that the project is, as of June 30, 2017, on time for a final in-service date of November 2024. Both BC Hydro and Deloitte agree on this assessment, notwithstanding Deloitte's concern that the project is not using EVM to measure its progress.

BC Hydro's comparison of interim milestones[67] uses the FID schedule, and demonstrates that some dates have been met and others missed. Given that the PMB schedule is more aggressive, it would be instructive to know how the project has performed against this benchmark. As such, **the Panel asks BC Hydro to add a column to Table 6 of its submission (i.e. F1-1, p. 24) showing the PMB plan dates for each interim milestone and to comment on any material variances between the PMB plan dates and the actual completion dates.**

Table D-3 of appendix D of BC Hydro's submission provides an assessment of the percentage completion of Site C project activities as of June 30, 2017. However, it is unclear how much work BC Hydro had originally planned to have completed for each activity by June 30, 2017. As such, **the Panel asks BC Hydro to add two columns to Table D-3, one column for the planned percentage complete by June 30, 2017 according to the PMB schedule and one column for the planned percentage complete by June 30, 2017 according to the FID schedule. BC Hydro is to comment on any material variances between the planned and actual percentages complete.**

The Panel considers it more difficult to assess whether the project is, as of June 30, 2017, on schedule for a river diversion in 2019, which is required to meet the PMB in-service date of 2023. This is important as any delay in the river diversion would have a significant effect on the project budget. The Panel is concerned that BC Hydro is facing challenges with the main civil works contractor on the left bank as a result of two tension cracks, and currently expects to use three months of float as a result. It is unclear to the Panel how much float remains. **The Panel asks BC Hydro to provide its current assessment of the probability that the project will achieve the river diversion in September 2019.**

Further, BC Hydro and PRHP are still in discussions regarding the impact of the tension cracks on the schedule, and have not agreed on a schedule which would allow the 2019 river diversion to take place. **The Panel asks BC Hydro to provide an update on its discussions with PRHP, and to explain in detail how the lost time on the main civil works schedule can be recovered.**

4.1.2 What is the likelihood that the project will remain on schedule?

The Panel has examined not just whether the project is currently on time, but also the likelihood that the project will remain on schedule and be in service by November 2024. This knowledge is important to the Panel's assessment of the likely eventual cost of the Site C project, and hence the cost impact on ratepayers of continuing construction of the dam.

The Panel will 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.

BC Hydro provides a summary of the major project work components and their current status[68]:

[67] F-1 Submission, p.34 table 6
[68] F-1 Submission, p.36

Table 7: 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

For each work component, BC Hydro adds an analysis of the risks currently identified and being managed. The Panel addresses each of these risks in turn, presenting the submissions from BC Hydro and Deloitte on each risk.

Contractor mobilization and 2016 delays

BC Hydro notes that the MCW contractor, PRHP, first faced delays in 2016, due to "late mobilization and submittals, and permit delays"[69], but that these delays were "recovered in February 2017". Deloitte also reports that these activities were "back on schedule in February 2017"[70].

Left bank challenges in 2017

BC Hydro reports that a 400-metre tension crack appeared on the left bank of the dam site in February 2017, which "temporarily stopped some construction activities"[71]. The issues have since been resolved, with "schedule remaining within estimates"[72]. BC Hydro goes on to report that another "much smaller" tension crack was observed on the left bank of the dam site in May 2017, and this has not yet been resolved with the MCW contractor[73]. These two events together are "currently forecast to result in the use of 3 months of float for this component of the work"[74], and "increase the risk related to River Diversion in 2019". BC Hydro states it has identified "opportunities to recover schedule float" and to "recover the schedule and maintain the overall project schedule for diversion in 2019".

Deloitte notes in its risk assessment of the MCW contractor that PRHP has made "slow progress" in its excavation of the left bank, and PRHP has "consistently excavated lower volumes compared to its own prior-month forecasts"[75]. Deloitte also describes the tension cracks on the left bank in February and May 2017, and adds that according to PRHP's latest schedule revisions "the Start of River Diversion milestone would not be achieved in 2019 as planned"[76] in the PMB schedule. According to Deloitte, BC Hydro has "not accepted PRHP's revised schedule" and expects that some months of lost schedule can be regained through "re-sequencing of

[69] F-1 Submission, p.36
[70] A-8 Submission p.24
[71] F1-1 Submission, p.37
[72] Ibid. p.37
[73] Ibid. p.37
[74] Ibid. p.37
[75] A-8 Submission, p.37
[76] A-8 Submission, p.37

work and acceleration measures", but despite this Deloitte concludes that "PRHP's ability to meet the critical milestones poses a major risk to the Project"[77].

Right bank challenges in 2017

BC Hydro notes 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"[78], and this has "the potential to impact the site handover date for the Generating Station & Spillways Contractor". However, the effects on the project schedule are not quantified, nor is there any indication of whether this handover date is on the critical path for the river diversion or the overall project.

Deloitte observes in its risk assessment of the MCW contractor that PRHP has made "slow progress" in its excavation of the right bank, and PRHP has "consistently excavated lower volumes compared to its own prior-month forecasts, except for April 2017 at the Right bank"[79]. Deloitte also does not quantify the effect on the project schedule of these delays.

Petrowest Corporation

According to BC Hydro, on August 11, 2017, "Petrowest Corporation, a 25 percent partner in Peace River Hydro Partners (main civil works contractor), announced that it received a notice of termination"[80] from one of the two other partners, ACCIONA, and Petrowest was subsequently "placed into receivership on August 15, 2017". BC Hydro states that this is "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.

Deloitte is 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"[81]. Deloitte does not quantify the possible impacts to the schedule specifically as a result of this period of instability.

Highway 29 work

BC Hydro describes its work to realign six segments of Highway 29, the "arterial highway that connects Hudson's Hope to Fort St. John, running along the north side of the Peace River"[82], 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, has since advised that they are "willing to discuss the implementation of mitigation measures that would manage the risk of flooding while allowing River Diversion to continue"[83]. BC Hydro states that this development will allow the river diversion to proceed despite the postponement of highway work.

Deloitte does not comment on the highway 29 work in its description of project risks[84].

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[77] Ibid., p.37
[78] F1-1 Submission p.37-38
[79] A-8 Submission, p.37
[80] F1-1 Submission, p.38
[81] A-8 Submission, p.38
[82] F1-1 Submission, p.38
[83] F1-1 Submission, p.39
[84] A-8 Submission, p.36 section 5.7

Prior BC Hydro experience

BC Hydro provides evidence of its recent track record in project management[85], but only provides data on its record in estimating project costs, not on its record of on-time completion. Hover, in BC Hydro's F17-F19 RRA, it noted that

> Generation placed 32 projects into service in fiscal 2015 and fiscal 2016…On average Generation projects were placed into service 8 months after the original approved in-service date. The late average in-service date occurred across the portfolio and was largely due to outage availability and three small projects that experienced significant delays.
>
> …
>
> Transmission and Distribution placed 151 projects into service in fiscal 2015 and fiscal 2016…On average Transmission and Distribution projects were placed into service 9 months after the original approved in-service date. [86]

Other prior experience

Dr. Antif Ansar (Ansar) submitted an academic study published in 2013 addressing the question "Should we build more large dams? The actual costs of hydropower megaproject development"[87]. 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"[88]. Ansar defines a large dam as having a wall height of 15 metres or more; a major dam as having a wall height over 150 metres, volume over 15 million cubic metres, or reservoir storage greater than 25 square kilometres. Their method was to take a "reference class forecasting" approach, or an "outside view", which is "evidence based" and allows the development of predictive models. The Panel notes that the Site C dam wall is 60 metres from the river bed, and is therefore a large dam according to Ansar's classification.

With respect to schedule slippage, Ansar observes: "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)". Ansar adds that "the evidence is overwhelming that implementation schedules are systematically biased towards underestimation", and that "Large dams built everywhere take significantly longer than planners forecast", although "North America with a 27% mean schedule overrun is the best performer". Ansar concludes that "longer time horizons and increasing scale are underlying causes of risk in investments in large hydropower dams".[89]

BC Hydro submits that the Ansar study to is flawed, since many of its data points are outside North America, and the conclusions are "heavily influenced"[90] 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"[91].

[85] F1-1 Submission, Appendix T
[86] BC Hydro F2017-2019 Revenue Requirements Application (F17-F19 RRA) proceeding, Exhibit B-9, BCUC IR 1.119.2
[87] F64-1 Submission
[88] F64-1 Submission, p. 3.
[89] F64-1 Submission
[90] F1-1 Submission, Appendix T, p.6
[91] F1-1 Submission, Appendix T, p.7

A number of other submissions referenced the conclusions of the Ansar report. For the sake of brevity, those references have not been reproduced here. A subsequent section of this report will address the content of the Ansar and Hollmann reports with respect to project costs and estimating accuracy.

BC Hydro quotes Hollman[92] as saying that a statistically controlled study[93] of Canadian hydroelectric projects shows that, under certain circumstances, "the outcomes can be reasonably reliable". The Panel observes that two of the six authors of the statistically controlled study (Hollman) referred to by BC Hydro are employed by BC Hydro[94].

Eliesen[95] states that "the notion that Site C will be completed on time…is illusionary". He cites the examples of the Wuskwatin Dam in Manitoba, which took 6 years to build, 2 more than originally scheduled, and Keeyask Generating Station and Muskrat Falls which are both currently two years behind schedule[96].

Deloitte notes that Keeyask, a dam under construction by Manitoba Hydro, is 21 months behind schedule[97], and Muskrat Falls is at "61% actual completion versus a plan of 63%". The Panel notes 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.

Panel analysis and preliminary findings

The Panel finds that it is not yet in a position to determine whether the project will remain on schedule for completion by November 2024. There remains uncertainty regarding the likelihood of starting the river diversion in September 2019. Furthermore, should there be a one-year delay of the river diversion, the Panel has insufficient information to assess the likelihood that the project can achieve the in-service date of November 2024.

Both BC Hydro[98] and Deloitte[99] agree that the start of the river diversion is critical to the overall schedule. The start of the river diversion must take place between September 1 and October 1 of a given year, otherwise it must be rescheduled to the following year to avoid the risk of floods and winter construction constraints. According to Deloitte, it is "both significantly time sensitive and on the critical path".

BC Hydro is currently planning to start the river diversion on September 1, 2019[100] in order to achieve an in-service date of November 2023. Should the river diversion be delayed one year to September 1, 2020, the in-service date of November 2023 would be missed. However, as noted before, the in-service date against which the project is being measured is one year later, November 2024. To achieve the in-service date of November 2024, the start of the river diversion need not happen until September 1, 2020[101].

The Panel has already found that the project is, as of June 30, 2017, on time for a November 2024 in-service date. However, as both BC Hydro and Deloitte have observed, there are significant risks that the project will not achieve the start of the river diversion on September 1, 2019. In particular, there are multiple issues related to the main civil works contractor on both banks of the river and as a result of the receivership proceedings of one of the contractor's partners.

[92] F1-1 Submission, Appendix T p.7
[93] Ibid., Appendix T p.7
[94] Ibis., Appendix T, pp. 11, 12
[95] F13-1 Submission
[96] Ibid. p.7
[97] A-8 Submisison, p.35
[98] F-1 Submission, p.35
[99] A-8 Submission, p.18
[100] Ibid., p.22
[101] Ibid., p.18

If the start of the river diversion is delayed from 2019 to 2020, the project can still achieve the in-service date of November 2024, and hence be on time. However, such a delay would likely result in significant budget over-runs, which the Panel will address in the next section. Also, the delay would entirely consume the one-year "owner's float", although BC Hydro would still have contractor float and other contingencies available. As a result, should the river diversion be delayed to 2020, any delays to subsequent activities would be more likely to affect the overall project schedule.

In section 4.1.1 of this report, the Panel asked BC Hydro to provide more information on how it will recover its lost time on the main civil works schedule. To provide a more complete picture of the risks, **the Panel asks BC Hydro to provide an analysis of the risks to the project schedule for construction activities subsequent to the river diversion, including but not limited to the generating station and spillway and the transmission work packages**. This risk analysis is to be consistent with the requirements of section 4 (v) of the Commission's 2015 CPCN Guidelines.

The Panel acknowledges the work done by Ansar to identify possible systematic problems with estimating schedules for large dam projects. However, the Panel gives 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 guidance on risks rather than specific evidence. Many submissions quoted the Ansar study; however, the Panel does not ascribe the study more weight merely as a result of the frequency of its references.

The other experience cited by Deloitte and Eliesen is somewhat contradictory. Regardless, the Panel concludes that these data support the findings of Ansar that large dam projects are at risk of budget and schedule overruns, without adding specific information about the Site C project.

Furthermore, the Panel does not consider the recent evidence available on BC Hydro's on-time project performance to be sufficiently relevant to the Site C project to be useful in its analysis, since the size and scale of the Site C project is so much larger than anything BC Hydro has recently undertaken.

4.1.3 Is the Site C project currently on budget?

The OIC asks that, after the Panel 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…within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?"[102]. As previously noted, the Panel interprets this question as asking whether the project was within its budget on June 30, 2017.

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. The Panel has examined the submissions to assess whether the amounts spent to date are aligned with the work that has been completed to date. For example, if a project's work is ahead of schedule, one would expect more to have been spent completing it, but the project would still, other things being equal, be within its budget. This analysis does not consider whether or not the work is on schedule; that was considered in the preceding section.

Likewise, the Panel is not, in this section, considering whether the project will be completed within the budget, merely whether it is currently within the budget. A project may be over budget at a point during its execution, but may have a credible plan to recover and finish within its budget; merely assessing such a project at one point in time would not provide a sufficiently complete analysis of the project's financial health. Subsequent sections will address the Panel's views on whether the project will remain within the proposed budget.

[102] OIC section 3 (b) (i)

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.[103]

It is important to note that analyses of the schedule and budget are closely linked. For instance, should the schedule slip one year from the current PMB schedule, the in-service date might still be on time from the perspective of the FID schedule. In this circumstance, however, the project might not stay within the budget. BC Hydro notes, for example, that if the 2019 river diversion milestone in the PMB schedule is not met, this would "likely trigger a draw on the Treasury Board reserve"[104]; that is, BC Hydro would spend more than the $8.335 billion budget. This is true even though the FID schedule allows for the river diversion to take place as late as 2020.

BC Hydro submission

BC Hydro states that the project is on budget.[105] It goes on to say 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.[106]

BC Hydro states it has spent $1.8 billion to June 30, 2017,[107]representing 22 percent of the budget of $8.335 billion.[108] BC Hydro compares the $1.8 billion spent to date with the FID planned spending to June 30, 2017 of $1.321 billion, and shows that it is $479 million higher than planned.[109] BC Hydro claims 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 notes that there are claims associated with the main civil works activities in 2016, and that they are being managed "within existing contingency funds" [110], although BC Hydro does not quantify these claims. The Panel assumes that these claims are not included in the $1.8 billion spent to date as of June 30, 2017.

Deloitte report

Deloitte summarizes its position by stating: "As the project continues to operate within…the existing budget (and unallocated contingency), today the Project remains…on budget."[111]

Deloitte reports the project has expended $1.8 billion to June 30, 2017[112]. However, they note that this "is based on spent cost only and does not represent actual progress on the site to date." Deloitte goes on to say they have

[103] OIC section 3 (b) (i)
[104] F1-1 Submission, p.35.
[105] Ibid., p.24
[106] Ibid., p.2
[107] Ibid., Appendix D p.3
[108] 1,800 / 8,335 * 100%
[109] Ibid., Appendix D p.3
[110] Ibid., p.37
[111] A-8 Submission, p.3
[112] Ibid., p.28

"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"[113].

Deloitte then compares the $1.8 billion costs incurred to date with the figure of $2.104 billion that the PMB schedule expects to have been spent to date[114], yielding a discrepancy of "$305 million or 14% behind its planned spend as of June 30, 2017"[115]. In Deloitte's view, this underspend can 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 notes that the total contingency of $356 million committed to date represents forty-five percent of the budgeted cost contingency of $794 million, a percentage "significantly higher than the 22% of total budget spent to date"[116].

Deloitte understands that "PRHP plans to submit a claim to BC Hydro"[117] for the delay caused by the first tension crack on the left bank, in February 2017. Also, Deloitte reports that discussions are 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 has "suggested that more claims are to come"[118].

Panel analysis and preliminary findings

The Panel finds that it is unable to determine whether the project is currently on budget. While both BC Hydro and Deloitte agree that the project is "on budget" as of June 30, 2017, the Panel considers that it has insufficient information to warrant this conclusion. In particular, the Panel requires more information on the current assessment of project spending, the value of outstanding claims, and projected use of budget contingency.

Deloitte observes that BC Hydro lacks a "clear method…to measure percent complete". This suggests that the figure of $1.8 billion spent to date might not represent the spending that should have occured to date, even allowing for the factors that Deloitte has presented to explain the underspending to date of $305 million compared to the PMB budget. The Panel understands that BC Hydro is planning to implement regular earned value reporting for the Site C project in December 2017. In advance of this development, **the Panel asks BC Hydro to provide a point-in-time assessment of its progress to June 30, 2017 using the earned value method, including analysis of schedule variance, cost variance, schedule performance and cost performance as compared to both the FID and PMB plans.**

Further, Deloitte has suggested that claims will be forthcoming related to work scheduled to be completed by the current date, which would have increased the spent-to-date figure of $1.8 billion had they been received and accepted. These figures could make a material difference to the costs incurred to date. **The Panel asks BC Hydro to provide a detailed analysis of the claims outstanding for work completed or in progress as of June 30, 2017, including the amount claimed and BC Hydro's assessment of the final settlement amount.**

[113] Ibid., p.23
[114] Ibid. p.27
[115] Ibid. p.28
[116] Ibid. P.32
[117] Ibid. p.25
[118] Ibid. p.34

4.1.4 What is the likelihood that the project will remain on budget?

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. This section will explore what the total cost may be to complete the project, and the likelihood that the project will remain on budget.

The Panel will explore current risks to the project budget and the experience of BC Hydro and others in managing similar projects.

BC Hydro submission

BC Hydro states that it "expects to complete Site C…on budget"[119] and does "not expect to use the additional $440 million project reserve". BC Hydro supports this by adding that it has an "appropriate level of…cost contingency"[120], and that it has "more unused contingency now than at the time of the Final Investment Decision"[121].

BC Hydro states that the Site C budget prepared in 2014 (the FID budget) was "a product of a robust process and appropriate approximations"[122]. It describes 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 describes 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"[123]; a Panel of experienced independent contractors "completed an additional review of the estimate of direct construction costs"[124]; 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".

BC Hydro also notes that its hydro-electric generation facilities are "a mature technology with well-established estimating practices and techniques"[125]. It adds 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 presents 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[126]:

[119] F1-1 Submission, p.2
[120] Ibid., p.2
[121] Ibid., p.24
[122] Ibid., p.25
[123] Ibid., p.25
[124] Ibid., p.26
[125] Ibid., Appendix T p.3
[126] Ibid., p.31

Table 8: 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 2016 2017	 89 76 150
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 adds 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"[127].

BC Hydro goes on to state that it has committed $356 million of contingency to date, and that its unused cost contingency is presently $839 million, over and above $440 million project reserve[128]:

Table 9: 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**

BC Hydro states that it is actively managing current cost pressures, including "construction execution, in particular of the Main Civil Works, geotechnical risks, costs of compliance with environmental requirements and delays in permitting"[129]. It adds that there are also cost risks associated with "several large procurements that are currently in process, with a risk that bids may be higher than budget". BC Hydro in summary states "the remaining $839 million of contingency is sufficient to manage such risks."

However, BC Hydro does 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"[130]. That is, the one-year delay in the project would

[127] Ibid., p.31
[128] Ibid., p.32
[129] Ibid., p.33
[130] Ibid., p.35

cause the project to exceed its budget of $8.335 billion before Treasury Board reserve. BC Hydro adds that "delaying River Diversion for one year would cost approximately $630 million"[131].

BC Hydro also presents a table of "material project risks"[132]. This table contains no quantification of the effect should any of the "risk events" listed come to pass.

BC Hydro claims "a history of delivering projects on budget"[133], with projects coming in at "0.94 per cent less than budget on a total of $6.36 billion of spending". These data were reported in 2016/17[134]. BC Hydro does not provide information about its project cost performance on specific projects in its filing. In its F17-F19 RRA, BC Hydro submitted the following table of projects of $5 million or greater that went over the expected amount over the last 5 years[135]:

[131] Ibid.,.39
[132] Ibid., Appendix D p.9-12
[133] Ibid., p.24
[134] Ibid., Appendix T p. 2
[135] BC Hydro F17-F19 RRA proceeding, Exhibit B-15, response to CEC IR 2.158.1

Table 10: Projects greater than $5 million which exceeded expected amount

Fiscal Year	Project Title	Final / Forecast Costs	First Full Approved Expected Amount	Variance	First Full Approved Authorized Amount	Variance
2011/2012	Spillway Gates Reliability Program - Standby Power Supply	7,907,236	7,471,600	(435,636)	7,471,600	(435,636)
2011/2012	Dam Safety Seismic Hazard Model	9,123,541	5,913,300	(3,210,241)	7,413,300	(1,710,241)
2011/2012	Fort Nelson Resource Smart Upgrade	165,310,716	149,565,500	(15,745,216)	164,620,100	(690,616)
2011/2012	Terzaghi Spillway Gate Reliability Upgrade	38,914,564	21,871,200	(17,043,364)	26,134,700	(12,779,864)
2011/2012	Mica Sewage Treatment Plan	8,422,464	6,082,200	(2,340,264)	6,973,800	(1,448,664)
2011/2012	Cheakamus Spillway Gate Reliability Upgrade	63,594,343	36,432,600	(27,161,743)	49,293,000	(14,301,343)
2011/2012	Seton Spillway Gate Reliability Upgrade	22,283,627	16,837,500	(5,446,127)	20,310,400	(1,973,227)
2011/2012	Lake Buntzen Turbine System Replacement	15,348,684	14,239,600	(1,109,084)	18,162,600	2,813,916
2011/2012	G.M. Shrum Station Service Upgrade	30,780,836	29,804,600	(976,236)	34,508,200	3,727,364
2011/2012	Cheakamus U1 & U2 Turbine Upgrade	15,533,668	8,699,000	(6,834,668)	8,699,000	(6,834,668)
2011/2012	Bridge River 2 Penstock Recoating	9,300,502	7,980,000	(1,320,502)	8,980,000	(320,502)
2011/2012	2L22 Fraser River Crossing - Transmission Line Restoration	12,500,279	9,599,000	(2,901,279)	11,569,000	(931,279)
2011/2012	500 kV Airblast Circuit Breaker Replacement (Ingledow)	10,297,677	5,900,000	(4,397,677)	5,900,000	(4,397,677)
2011/2012	Clowhom Transmission Upgrade 1L44	7,140,901	5,570,600	(1,570,301)	5,570,600	(1,570,301)
2011/2012	Transmission Recurring Capital - Multiple circuits	9,498,619	8,427,000	(1,071,619)	8,427,000	(1,071,619)
2012/2013	G.M. Shrum Units 6 to 8 Capacity Increase	45,188,384	39,113,100	(6,075,284)	44,613,100	(575,284)
2012/2013	Transmission Recurring Capital - Multiple Circuits	8,984,892	8,925,000	(59,892)	8,925,000	(59,892)
2012/2013	Valemount 25kV Outdoor Metalclad Switchgear Replacement	6,001,305	5,572,000	(429,305)	5,572,000	(429,305)
2013/2014	Hugh Keenleyside Navlock Upstream and Downstream Control System Replacement	10,065,862	7,054,999	(3,010,863)	7,885,200	(2,180,662)
2013/2014	Ruskin Dam Safety Improvement Right Abutment Remediation (Stage 1)	16,317,752	14,535,000	(1,782,752)	20,878,000	4,560,248
2013/2014	Smithers Substation - Transformer Addition	6,487,028	5,636,000	(851,028)	5,636,000	(851,028)
2013/2014	5L44 Fraser River Crossing - Transmission Line Restoration	12,012,022	11,920,000	(92,022)	14,294,000	2,281,978
2013/2014	Cape Scott Wind Farm Project - CPC08 IPP	9,063,848	8,834,000	(229,848)	9,421,000	357,152
2013/2014	Vanderhoof Substation T1 Transformer Replacement	12,815,764	11,921,000	(894,764)	13,113,000	297,236
2013/2014	Kelly Lake Synchronous Condenser Unit 2 Refruhishment	6,861,160	6,531,000	(330,160)	7,184,000	322,840
2013/2014	Customer 1	23,963,210	21,686,000	(2,277,210)	28,346,000	4,382,790
2013/2014	Bridge River Generating Station 1 Transformer Addition	12,424,796	9,986,000	(2,438,796)	10,975,000	(1,449,796)
2014/2015	Mica SF6 Gas Insulated Switchgear Replacement	188,636,075	180,624,800	(8,011,275)	200,159,800	11,523,725
2014/2015	G.M. Shrum Fire Alarm Upgrade	11,350,823	11,101,600	(249,223)	12,101,600	750,777
2014/2015	Northwest Transmission Line	704,666,003	560,998,000	(143,668,003)	560,998,000	(143,668,003)
2014/2015	Kidd 1 - Substation Redevelopment	33,897,752	19,410,000	(14,487,752)	19,410,000	(14,487,752)
2014/2015	Forest Kerr Hydro projects (Forest Kerr, McLymont, Volcano)	7,041,003	6,250,000	(791,003)	6,863,000	(178,003)
2014/2015	Customer 2	13,614,832	10,483,000	(3,131,832)	10,483,000	(3,131,832)
2014/2015	Vancouver Island Terminal Synchronous Conderser unit 2 Refurbishment	10,212,124	5,861,000	(4,351,124)	6,751,000	(3,461,124)
2014/2015	Kidd 2 Substation (Richmond Area Reinforcement)	35,125,574	27,326,000	(7,799,574)	29,726,000	(5,399,574)
2014/2015	230 kV Airblast Circuit Replacements	7,611,972	6,718,000	(893,972)	7,108,000	(503,972)
2014/2015	System Spare Transformers Project	16,469,014	16,075,000	(394,014)	16,075,000	(394,014)
2015/2016	Interior to Lower Mainland Transmission Line	740,501,204	657,000,000	(83,501,204)	725,000,000	(15,501,204)
2015/2016	Hugh Keenleyside spillway gate reliability upgrade	112,863,877	90,226,000	(22,637,877)	101,983,500	(10,880,377)
2015/2016	G.M. Shrum Units 1 to 5 Rotor Rehabilitation	33,481,689	26,954,000	(6,527,689)	29,844,000	(3,637,689)
2015/2016	Horsey Substation-Add Feeder	13,769,258	9,951,000	(3,818,258)	11,771,000	(1,998,258)
2015/2016	Dawson Creek/Chetwynd Area Transmission	295,616,514	254,100,000	(41,516,514)	296,400,000	783,486
2015/2016	Merritt Area Transmission	59,823,967	55,834,000	(3,989,967)	64,534,000	4,710,033
2015/2016	Surrey Area Substation Project	79,799,383	76,405,000	(3,394,383)	94,405,000	14,605,617
2015/2016	Forestview 12/25 kV Voltage Conversion	10,531,268	7,974,000	(2,557,268)	8,816,000	(1,715,268)
2015/2016	Customer 3	5,863,882	5,049,000	(814,882)	5,552,000	(311,882)
2015/2016	Customer 4	33,352,862	30,666,000	(2,686,862)	35,933,000	2,580,138
2015/2016	Silverdale Substation	49,300,982	41,482,000	(7,818,982)	45,082,000	(4,218,982)
2015/2016	500 kV Airblast Circuit Breaker Replacement NIC/WSN/ACK	21,515,569	20,204,000	(1,311,569)	21,684,000	168,431
2015/2016	GMS Auxiliary Building Service Upgrade	9,610,135	7,560,200	(2,049,935)	7,560,200	(2,049,935)
2015/2016	60/138 kV Circuit Breakers Replacements	10,676,716	10,664,000	(12,716)	10,664,000	(12,716)
2015/2016	Ashton Creek 500 kV Circuit Breakers and Current Transformer Replacement	9,395,486	8,594,000	(801,486)	9,405,000	9,514
2015/2016	Good Hope Lake / Jade City	9,899,582	6,898,000	(3,001,582)	7,916,000	(1,983,582)

BC Hydro also submitted the following analysis of its project performance in F2015 and F2016:

> Generation placed 32 projects into service in fiscal 2015 and fiscal 2016 with a first full funding expected cost budget of $1.346 billion compared to $1.213 billion forecast at completion costs for a net lower than budget of $133 million. The major drivers for the lower than budget results were the GMS 1-5 Turbine Replacement Project and Mica Unit 5 and 6 Project being delivered under budget. On average Generation projects were placed into service 8 months after the original approved in-service date. The late average in-service date occurred across the portfolio and was largely due to outage availability and three small projects that experienced significant delays.
>
> Transmission and Distribution placed 151 projects into service in fiscal 2015 and fiscal 2016 with a first full funding expected cost budget of $3.189 billion compared to $3.419 billion forecast at

completion costs for a net overrun of $230 million. The major reason for the overrun on the cost was due to cost increases on the Interior to Lower Mainland Project and the Northwest Transmission Line Project offset by a net lower than budget on the Smart Metering and Infrastructure Program. On average Transmission and Distribution projects were placed into service 9 months after the original approved in-service date.[136]

Deloitte report

Deloitte describes how a Class 3 level estimate of $7.96 billion was prepared in 2010, excluding project reserve[137]. They add that, between 2010 and 2014, "as design and project definition progressed, the estimate was further refined but the overall project estimate remained" at $7.96 billion. Finally, in 2014, an external Panel performed "further validation of the cost estimate" and "concluded that the cost estimate was sufficient for the proposed scope and schedule of the project".

According to Deloitte, the FID budget of $8.335 billion announced in December 2014 exceeded the budget of $7.96 billion "to account for HST and PST changes in addition to an adjusted project completion date of 2024"[138].

Deloitte states that the contingency of $794 million was developed by BC Hydro using Monte Carlo statistical models to assess "the potential cost variability associated with each work package due to the following risks: design uncertainty, labour costs, estimating accuracy, and contractor markup expectations"[139]. 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 adds that 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 states that, in their experience reviewing "large complex capital projects", they would "expect that the contingency (including project reserve) would be in the range of 15% - 20% of total project costs"[140], and notes that the Site C project contingency was "just below the low end of that range".

Deloitte notes: "There is a potential that the existing cost contingency is insufficient to cover further increases in the Main Civil Works (MCW) contract, uncertainties in major contracts yet awarded, increases in interest rates, and geotechnical issues"[141]. Deloitte goes on to describe three "impact scenarios" for the outcome of the Site C project with respect to cost: low, medium and high impact, as described in the following table[142]:

[136] Ibid., Exhibit B-9, BCUC IR 1.119.2.
[137] A-8 Submission, p.19
[138] Ibid., p.19 footnote 19
[139] Ibid., p.19
[140] Ibid., p.19,20
[141] Ibid., p.1
[142] Ibid., p.2

Table 11: 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 is 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 is a fifty percent overrun, leading to a project cost of $12.503 billion. These outcomes are presented in the table below:

Table 12: 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 notes that BC Hydro is currently projecting to use $1 billion of cost contingency by the end of the project[143], a twenty-six percent increase over the $794 million planned cost contingency, and eighty-four percent of the total available contingency of $1.195 billion. Deloitte understands that this increase in the forecast cost contingency is explained by additional indirect and management costs, higher contract costs than estimated, and additional unexpected scope[144], and observes 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 expresses 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 states that PRHP "has issued several claims to BC Hydro, the latest of which is dated August 24, 2017"[145].

[143] Ibid., p.30
[144] Ibid., p.31
[145] Ibid., p.38

Deloitte is also concerned about the risks that BC Hydro has under-estimated the cost of its major contracts. BC Hydro under-estimated the cost of the main civil works contract[146], which caused cost contingency to be committed when the contract was awarded. Two other large contracts, generating station and spillways (GSS) and transmission, have 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"[147].

Deloitte states that the geotechnical risks appear to "have been investigated' and the "design has been adapted to the conditions"[148]. They add that issues might arise "if conditions deviated from the assumptions made", but do not quantify the effect if those risks came to pass.

Deloitte estimates 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"[149]. 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[150]. The remaining $130 million would be for "additional indirects".

Ansar study

The study by Ansar referenced in section 4.1.2 above also provides an analysis of the cost accuracy of hydro dams globally.

With respect to cost overruns, Ansar observes: "Three out of every four large dams suffered a cost overrun in constant local currency terms" and that "actual costs were on average 96% higher than estimated costs; the median was 27% [higher]". They conclude: "The evidence is overwhelming that costs are systematically biased towards underestimation".[151]

Adding more detail, the study states that "Large dams build in every region of the world suffer systematic cost overruns", although "Large dams built in North America…have considerably lower cost overrun [11 percent] than large dams built elsewhere [104 percent]"[152]. In terms of trends, the study concludes that "there is no linear trend indicating improvement or deterioration of forecasting errors", and that "forecasts of costs of large dams today are likely to be as wrong as they were between 1934 and 2007"[153]. In terms of other factors which may explain cost overruns, Ansar states: "The larger the dam...the higher the cost overrun"[154].

As previously noted, BC Hydro believes the Ansar study to be flawed, since many of its data points are outside North America, and the conclusions are "heavily influenced"[155] by outliers. BC Hydro highlights the study's observation that the hydroelectric projects in North America had a cost overrun of eleven percent on average, compared to 104 percent elsewhere.

A number of other submissions referenced the conclusions of the Ansar report. For the sake of brevity, those references have not been reproduced here.

[146] Ibid., p.39
[147] Ibid., p.39
[148] Ibid., p.40
[149] Ibid., p.42
[150] Ibid., p.42 footnote 63
[151] F64-1 Submission
[152] Ibid., p.6
[153] Ibid., p.6
[154] Ibid., p.9
[155] F1-1 Submission, Appendix T, p.6

Other submissions

The Panel notes that the Hollman study quoted by BC Hydro as a counterpoint to the Ansar study was based on "24 projects with actual costs ranging from $50 million to $3.6 billion (in 2012 $CAN) completed from 1974 to 2012". Hollman concluded that contingencies including management reserve for class 3 estimates should be 24 percent, although they added that this or other contingency values should not be assigned arbitrarily, rather that "contingency should always be based on risk analyses"[156]. Hollman concluded that a contingency of 24 percent would be appropriate for a class 3 estimate, although "contingency should always be based on risk analyses"[157].The Panel notes that this figure is above the high end of the range provided by Deloitte, and significantly higher than the 14 percent contingency including project reserve used by BC Hydro in the Site C budget.

Eliesen[158] observes that "the most recent major hydro dam constructed in BC was the Revelstoke dam completed in 1984"[159]. 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 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"[160].

AMPC[161] states "documents filed by BC Hydro to the Commission on June 10, 2016 suggested that the project was over budget by $314 million as of that date. Subsequently, BC Hydro filed its most recent public quarterly progress report, which states that as of March 31, 2017, the project is over budget by $482 million." The Panel notes that BC Hydro explains these variances as timing differences in when expenditures were actually incurred compared to the plan[162].

Bakker[163] provides a table of recent hydro and transmission projects:

[156] Hollmann, John et al, "Variability in Accuracy Ranges: A Case Study in the Canadian Hydropower Industry," AACE International Transactions, 2014, p.8
[157] Ibid., p.8
[158] F13-1 submission
[159] Ibid., p.6
[160] Ibid., p.11
[161] F81-1 Submission, p.3
[162] F1-1 Submission, Appendix D, p.3
[163] F106-1 Submission, p.60

Table 13: Recent Large-Scale Hydroelectric and Transmission Project Costs

Hydro Projects	Proponent	Capacity	Total Cost		Overrun		Status
			Initial	Actual	$	%	
Muskrat Falls[173,174]	Nalcor Energy	824 MW	$2.9B	$5.1B	$2.2B	+76%	~60% constructed
Wuskwatim[175,176]	Manitoba Hydro	200 MW	$0.9B	$1.6B	$0.7B	+78%	Operating
Keeyask[177,178,179]	Manitoba Hydro	695 MW	$6.2B	$8.7B	$2.5B	+40%	~40% constructed
Transmission Projects							
Labrador-Island Transmission Link[180]	Nalcor Energy	+/-350kV	$2.6B	$3.4B	$1.2B	+31%	~50% constructed
Bipole III[181,182]	Manitoba Hydro	500 kV	$3.3B	$5.4B	$2.1B	+64%	~50% constructed
Dawson Creek / Chetwynd Area Transmission Project[183,184]	BC Hydro	230 kV	$222M	$296M	$74M	+33%	Operating
Interior to Lower Mainland Transmission Line[185,186]	BC Hydro	500kV	$602M	$743M	$141M	+23%	Operating
Northwest Transmission Line[187,188]	BC Hydro	287kV	$404M	$716M	$312M	+77%	Operating

The Panel notes that the figures provided by Bakker for BC Hydro projects differ from the figures provided by BC Hydro above. The figures provided by BC Hydro have been tested in the F17-F19 RRA proceeding and, in the Panel's view, are therefore more reliable.

Bakker's figures show cost overruns of three hydro projects in Canada ranging from forty percent to seventy-eight percent. She observes that, with respect to Site C, "the extent of eventual cost overruns, if any, cannot be fully determined at this point"[164]. However, she adds that "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 presents the same data that were originally included in Bakker's[165], and were reproduced above, but with updated data[166]:

[164] Ibid., p. 64
[165] F106-1 Submission
[166] A-8 Submission, p.36

Table 14: Cost Performance of Recent Greenfield Canadian Hydroelectric and Transmission Project

Project	Proponent	Capacity	Total Cost [3]		Cost Overrun		Status
			Initial Budget	Actual Cost/ Current Estimate	$	%	
HYDRO ELECTRIC PROJECTS							
Muskrat Falls[2][i]	Nalcor Energy	824 MW	$2.9 B [1]	$5.5 B [1]	$2.6 B	90%	~69% complete
Wuskwatim[ii]	Manitoba Hydro	200 MW	$0.9 B	$1.6 B	$0.7 B	78%	Began operations in 2012
Keeyask[iii]	Manitoba Hydro	695 MW	$5.6 B	$8.7 B	$3.1 B	55%	Under construction
TRANSMISSION PROJECTS							
Labrador-Island Tranmission Link[iv]	Nalcor Energy	350kV, 1050 km	$2.6 B [1]	$3.7 B [1]	$1.1 B	42%	~84% compete
Bipole III[v]	Manitoba Hydro	500 kV, 1384 km	$2.2 B	$4.9 - 5 B	$2.8B	125%	Under construction
Dawson Creek/Chetwynd Area Transmission Project[vi]	BC Hydro	230 kV	$255 M	$296 M	$41 M	16%	Operating
Interior to Lower Mainland Transmission Line[vii]	BC Hydro	500 kV, 247 km	$602 M	$743 M	$141 M	23%	Operating
Northwest Transmission Line[viii]	BC Hydro	287 kV, 344 kM	$404 M	$736 M	$332 M	82%	Operating

Three of the transmission projects identified in the table above were managed by BC Hydro, and had cost overruns varying from sixteen percent to eighty-two percent. There is no data on BC Hydro's performance building recent, large hydropower projects; as Eliesen notes[167], BC Hydro's last project of this nature was in 1984. Deloitte adds that it has 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 that this is an increase of $2.2 billion, or 33.3 percent[168].

Vardy[169] 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[170]. He then proceeds to identify the similarities and differences between Muskrat Falls and Site C, and concludes 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"[171].

A number of other submissions touched on the subject of whether or not the Site C project was likely to be completed on budget. Many submissions quoted from the Ansar study. One submission indicated they believed the project to be on budget[172], whereas others believed that the project was already over budget or would end up being over budget.[173]

Panel analysis and preliminary findings

The Panel finds 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 stated that if the river diversion of September 2019 is not

[167] F13-1 Submission
[168] Ibid., p.6
[169] F52-1 Submisson
[170] Ibid., p.10
[171] Ibid, p.7
[172] F45-1 Submission
[173] F6-1 Submission, F2-1 Submission, F27-1 Submission, F34-1 Submission, F43-1 Submission, F56-1 Submission, F57-1 Submission, F59-1 Submission, F68-1 Submission, F83-1 Submission, F113-1 Submission

achieved, this "would likely trigger a draw on the Treasury Board reserve", and adds that the delay "would cost approximately $630 million". Deloitte estimates this to be $382 million. In order to analyze this cost more fully, **the Panel asks BC Hydro to provide a detailed breakdown and justification of its $630 million estimate.**

Regardless of whether the river diversion takes place in 2019, **the Panel finds that it does not have sufficient information to assess the total possible budget overruns once the Site C project is complete**. To complete this assessment, the Panel wishes to understand more fully the potential costs of a one-year delay in the project, and the likelihood that the budget contingency is sufficient for other eventualities.

The level of contingency that was included in the FID budget in 2014 represented 9.5 percent of the total project cost, or 14 percent if the Treasury Board reserve is added. For such a large and complex project, Deloitte would have expected a contingency of fifteen to twenty percent of the total costs, and Hollman 24 percent. **The Panel asks BC Hydro to explain why it chose a contingency amounting to 9.5 percent of project costs, and what factors suggested this would be sufficient. BC Hydro is also requested to provide backup documentation consistent with the requirements of section 5(vi) of the Commission's 2015 CPCN Guidelines.**

The Panel is concerned that BC Hydro is already forecasting to use $1 billion of contingency, two years into an eight-year project. This is twenty-six percent[174] over the original cost contingency of $794 million, and is eighty-four percent of the revised cost contingency of $1.195 billion. With large outstanding cost pressures still upon the project, such as the two major contracts not yet having been awarded and the challenges with the main civil works contractor, it seems likely that the forecast of using $1 billion in cost contingency will increase. **The Panel asks BC Hydro to estimate the total price of its two major outstanding procurements, generator station and spillway and transmission, in light of its experience with the main civil works procurement, to identify possible cost overruns as a consequence, and to identify whether these possible cost overruns are already accounted for in the $1 billion anticipated contingency usage.**

The Panel is concerned that the $356 million contingency that has been allocated and committed to date represents 45 percent[175] of the planned $794 million contingency, two years into an eight-year project. **The Panel asks BC Hydro to provide a quantitative and qualitative analysis of its contingency allocated and committed to June 30, 2017, and its projections for how it expects contingency to be allocated and committed as the remainder of the project progresses.**

BC Hydro's increase in the amount of contingency available from $794 million to $1.195 billion is based on the current "historically low interest rates"[176]. While BC Hydro has locked in 50 percent of its forecast future debt between F2017 and F2024, it is not clear to the Panel what effect an increase in interest rates would have on the total available contingency for the Site C project. **The Panel asks BC Hydro to provide an analysis of the $315 million that has been identified as savings on forecast interest during construction, indicating what effect a rise of 0.5 percent, 1 percent or 2 percent in interest rates would have on the amount of the savings.**

The Panel observes that the project is facing significant risks to the schedule at present, and that these have the possibility of causing a budget overrun. **The Panel asks BC Hydro provide an updated version of table D-4 in appendix D of their submission, adding a quantification of the budget impact for each risk identified in the table, should the risk come to pass. This analysis should be consistent with section 4(v) of the Commission's 2015 CPCN Guidelines.**

BC Hydro noted that it no longer expects the delay in realigning Highway 29 to affect its schedule; however it does not comment on any cost impacts of its revised approach to the realignment. **The Panel asks BC Hydro to**

[174] (1,000 – 794) / 794 * 100%
[175] 356 / 794 * 100%
[176] F1-1 Submission, p.31

provide the cost of its new approach to the Highway 29 realignment, the degree to which the cost is higher than budgeted, and the degree to which any cost overrun will need to be covered by contingency.

Deloitte identifies that the best-case outcome for the project costs is that it will lie in a range of zero to ten percent over the budget of $8.335 billion. They also identify situations where the project may come in between ten and twenty percent over budget, and between twenty and fifty percent over budget. The Panel notes that these outcomes are not anticipated by BC Hydro, and therefore **the Panel asks BC Hydro to comment on the likelihood of each of the three outcomes listed by Deloitte.**

BC Hydro has presented information on its history of project delivery showing that on average it has completed projects 0.94 percent under budget in the most recent reporting year based on rolling results over the past five years; also, its generation projects delivered in F2015 and F2016 were $133 million lower than budget, and transmission projects were $230 million over budget. **The Panel finds that these results are indicative of BC Hydro's ability to deliver projects on budget on the average, but that they provide little insight into the likelihood that Site C will be delivered on budget, since Site C is so much larger than any other project BC Hydro has managed in its recent history.**

The Panel notes that many submissions quoted the Ansar study and acknowledges the work done by Ansar to identify possible systematic problems with estimating costs for large dam projects. However, **the Panel gives 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 guidance on risks rather than specific evidence.**

The examples of Muskrat Falls, Wuskwatim and Keeyask provided by Bakker and updated by Deloitte show cost overruns varying from 40 percent to 78 percent, supporting the conclusions drawn by Ansar.

Vardy states that the Muskrat Falls project will cost $12.7 billion, compared to the figure of $6.2 billion quoted in 2010. By comparison, Deloitte quotes a current estimate of $5.5 billion (without interest during construction or capitalized financing costs) versus an original estimate of $2.9 billion. As noted previously, the Panel gives more weight to the evidence specific to the Site C project.

4.2 Costs to suspend the project

The terms of reference attached to OIC 244 direct the Commission to inquire into the implications of suspending the Site C project. Specifically, the Commission has been directed to respond to the following question:

> "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 these costs?"

The Panel first addresses the estimates of costs to suspend the project and then reinstate it 7 years hence in late 2024. In doing so we provide an outline of the cost information and analysis that has been completed to date as well as identify information gaps and raise questions we consider important on reaching a conclusion in answer to the question raised. With consideration to the statement "maintaining the option to resume construction until 2024" the Panel is mindful that the terms of reference do not specifically state that the project will be reinstated in 2024 and could be terminated at that time. Therefore, we also discuss the issue of additional costs to terminate the project if it is determined by government that the project should be terminated during or following the seven year period in 2024.[177]

[177] F1-1 Submission, p.80.

BC Hydro submission

BC Hydro states that should a decision be made to resume construction it is working under the assumption it would be possible to restart the project. BC Hydro asserts there are substantial risks with this assumption pointing out that the project is currently underway with key assets built up over a ten-year plus period. While some of these assets could be maintained during the suspension, many would be lost resulting in substantial risk to its ability to restart the project.

BC Hydro has separated its analysis into two sections; (1) the costs to suspend and maintain the site allowing for remobilization in 2024 and (2) the costs of restarting and completing the project after suspension.

Suspension and maintenance during the suspension period

BC Hydro's conceptual estimate of direct costs of suspension and maintenance for a seven year period totals $1.1 billion. This is in accordance Association for the Advancement of Cost Estimating (AACE) for concept screening in the hydropower industry Class 5 estimate standards of +100 percent/-35 percent. BC Hydro states that it first identified categories of costs with the key areas being 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. Contingency factors reflecting the risks associated with the activity were then applied to each activity with a 30 percent contingency factor applied overall. BC Hydro compiled information from key management personnel involved with the project and conducted a Monte Carlo analysis to help understand the risks and uncertainty associated with the estimates. The Company also retained Hemmera Envirochem Inc., for advice on environmental and regulatory requirements for remediation.[178]

As prepared by BC Hydro, a summary of suspension and maintenance costs are outlined in Table X.

Table 15: Breakdown of Suspension and Maintenance Costs[179]

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 cost $0.9 billion and take 2 years. It has broken these down into three categories;

1) Contract termination costs – these are related to terminating all possible project construction contracts and obligations inclusive of demobilization of contractor labour and equipment from the site. Hydro points out that the turbine manufacturing is advanced and it would seek to restructure the agreement but this would be dependent on its ability to negotiate terms with the vendor.
2) Costs related to rendering the site safe and environmentally sound. This would be less intensive than for termination as infrastructure (such as accommodation) would be left in place and environmental work would be of a temporary nature.
3) Cost of maintaining a project team for a two-year period to manage suspension work.[180]

[178] F1-1 Submission, p. 68.
[179] F1-1 Submission, p. 84.
[180] F1-1 Submission, p. 84-85.

BC Hydro prepared an extensive list of anticipated works and activities that will need to be undertaken if a decision is made to suspend the project beginning January 1, 2018. These are outlined in Appendix O of its filing (F1-1 Submission) but have not been costed on an individual basis.

Once the site is suspended and rendered safe there would be ongoing maintenance costs to continue monitor and deal with items like environmental conditions, temporary sediment ponds, the treatment of acid laden rock drainage, remaining site infrastructure and access roads, continuation of environmental studies as required, provide security onsite and maintain a project team to perform this work. BC Hydro estimates these costs to be $0.3 billion.

With reference to a decision to suspend the project, BC Hydro states that if at any time following completion of this it was decided to terminate the project, additional cost and work would be required to remediate the site back to the state outlined in the termination scenario. BC Hydro has estimated these costs at approximately $0.3 billion. Therefore, the total cost of suspending and maintaining project but not reinstating it in 2024 would total $1.4 billion [181]

Restarting and completing the project

Under the current schedule BC Hydro estimates the cost to complete the project to be $6.2 billion as of December, 2017. However, if the project is suspended and reinstated BC Hydro's estimate would increase to $7.9 billion because of the increase in cost related to the effect of cost inflation, remobilization costs and increased risk premiums due to the schedule delay. This $1.7 billion increase in cost is in addition to the $1.1 billion to suspend and maintain the project. Therefore, the cost of suspending, maintaining and restarting the project based on BC Hydro's submissions totals $2.8 billion before any additional interest charges.

BC Hydro states that it expects it would take approximately 2 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. To accomplish this and restart construction by the end of 2024 would therefore require a project restart beginning in the spring of 2023.[182]

BC Hydro estimates that restarting the project after a seven year delay would result in completing the project in 2031 rather than 2024 as currently planned and represent significant risk to the schedule and completion costs. The schedule would be subject to the circumstances existing at the time of recommencement related to items like equipment availability, labour markets and regulatory timelines. Moreover, even if the scope of work remained unchanged, over the delay period there is a risk related to changes in cost drivers such as market conditions, regulatory requirements and increased design standards over time. BC Hydro has included additional costs in its estimates for such items but beyond these brief descriptions of the cause of additional cost related to reinstating the project, it has provided limited detail as to the specific costs and how the quantum of $1.7 billion in additional costs was calculated. This matter will be discussed further in the Panel's analysis.[183]

BC Hydro explains that restarting the project in 2024 and completing it in 2031 would also have a significant impact on interest charges. BC Hydro estimates that interest charges from 2018 through 2031 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. These are summarized as:

[181] F1-1 Submission, pp. 84-85 and p. 90.
[182] F1-1 Submission, p. 86-87; Appendix O, p. 19.
[183] F1-1 Submission, pp. 87-89.

- $2.1 billion in sunk costs through the end of 2017;
- $1.1 billion for suspension and maintenance of the site;
- $7.9 billion to complete the project following suspension (inclusive of the $1.7 billion of additional costs previously discussed); and
- $1.8 billion in additional interest costs from 2018 through 2031.[184]

Deloitte report

Deloitte estimates the suspension scenario, if chosen, will result in an additional cost of approximately $1.4 billion with an accuracy range of -35 percent and +100 percent. Deloitte reports that its estimates do not include incremental interest costs related to the suspension nor does it include any inflation impacts on post suspension costs to complete the project.

Deloitte postulates that a suspension scenario would trigger two sets of activities for BC Hydro's project team; the management of existing contracts and commitments and the creation of a new "suspension project". The project team would need to decide whether to retain the existing contracts and commitments for a future restart or terminate the contracts and protect the site for future use. Deloitte explains that the close out activities would operate in accordance with the provisions of those contracts that are active with main contractors expected to complete continuing elements from their scope of work taken to a practical stage of completion. The creation of a new suspension project would differ significantly from the current Site C project and sufficiently extensive to justify independent project planning for control of budget and would be implemented to meet the objective of the new scope of work. Accordingly, it would involve a set-up phase and be executed with its own scope, budget and execution schedule.[185]

Deloitte estimates the total cost for suspending, maintaining and remobilizing the project to be $1.418 billion. Costs related to the impact of contract cancellations in a suspension scenario total $325 million with the three main contacts being for main civil works (MCW), the turbines and generators and Site C worker accommodation. Demobilization is expected to be $50 million with those not needed to execute the termination scope phased out first and those needed to complete specific construction scopes retained. Site remediation and reclamation costs have been broken down as $25 million for engineering, permitting and procurement activities, $445 million for site preservation activities and $40 million for ongoing care and maintenance. Deloitte in its report has provided its view as to the current status of many of the key areas for site remediation work and has laid out requirements for suspending the project. For site remobilization Deloitte has estimated $195 million for engineering, permitting, procurement and site mobilization activities with a further $5 million for re-validation site materials and equipment. Deloitte's view is that if the decision is made to suspend the project it would change 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 and establish the conceptual design and perform tasks related to an environmental appraisal, permitting, design for construction and contracting. The new project would have its own scope, budget and schedule. In preparing its suspension scenario cost estimates Deloitte has included a contingency of $327 million or 30 percent.[186]

A summary of Deloitte's estimated costs are outlined in Table 16.

[184] F1-1 Submission, pp. 89-90.
[185] A-8 Submission, Deloitte Report, p. 42.
[186] A-8 Submission, Deloitte Report, p.3 and pp. 46-63;

Table 16: Summary of Cost Estimate – Suspension Scenario[187]

#	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 points out that its estimates include the following assumptions:

- It does not include interest costs in the event of a suspension; and
- It does not include inflation impacts of post suspension costs to complete the project.

Panel analysis and preliminary findings

The Panel finds that $1.1 billion is a reasonable estimate of the costs of suspension and maintenance for the project. The estimates provided by BC Hydro and those of Deloitte appear reasonable and are similar with respect to the estimation of costs to suspend and maintain the Site C project for the period encompassing January 1, 2018 through the end of 2024. BC Hydro has estimated the costs at $1.1 billion while Deloitte estimates the cost at $891 million plus a 30 percent contingency ($252 million) resulting in a total estimate of $1.143 billion. This provides the Commission with a degree of comfort with respect to the estimates in that two separate and independent processes have provided a similar result. However, this needs to be tempered by the fact that the work completed by both parties is based on Class 5 estimates which have a broad accuracy range.

The Panel finds there is significant variance between the BC Hydro's 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 and the Panel acknowledges these differences may potentially account for some or all of these differences.

Deloitte has included in its estimate only those costs for engineering (design and site), permitting and procurement and site mobilization. As discussed, Deloitte is of the view that suspending the project for the contemplated time period will result in there being a need to establish a completely new project with its own unique scope budget and schedule. Thus, it follows that it has neither considered nor estimated the impact of inflation on post suspension costs. Further, because it has not considered these cost impacts, Deloitte has not provided its estimate of additional interest costs to the project in the event there is a suspension.

[187] A8 Submission, Deloitte Report, p. 64.

Given the lack of clarity with respect to some of the costs the Panel finds 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.

As discussed, BC Hydro has provided a broader if undetailed estimate encompassing total cost estimates through the completion of the project. In addition to the basic restart costs it has included estimated costs for increased interest costs and some of the additional cost "for escalation and some of the incremental risk to complete the Project due to the period of suspension".[188] **The Panel finds it is these differences that account for much of the variance between the BC Hydro estimate and the Deloitte estimate**.

Of concern to the Panel however, is the lack of information that BC Hydro has provided to support this additional $1.7 billion in restart costs. In its submission, BC Hydro has provided minimal explanation as to what these costs include and has provided no detail as to how these costs are allocated on an item by item basis. The Panel has reviewed Appendix O (F1-1 Submission) but is unable to reconcile the cost estimates provided in the inter-office memo entitled "Site C suspend or Terminate Project, Conceptual Cost Estimate, Comparison Estimate of Incremental Project Costs (Not for Funding)". While this memo seems to address the matter of cost, it does not address the matters raised in BC Hydro's submission in a substantive way and fails to provide clear, concise information that will facilitate Panel analysis and allow us to reach any definitive conclusions.

In order to allow the Panel to reach a conclusion on these additional costs, BC Hydro is requested to readdress the additional $1.7 billion estimate for restarting the project and provide a much more fulsome description of the costs and any assumptions made as to estimated amounts and the likelihood of their being required. In addition the Panel requests BC Hydro to respond to the following questions:

1. BC Hydro has stated that there are substantial risks with the assumption "that it would be possible to restart the project should a decision be made to resume construction in the future." BC Hydro is requested to confirm whether it believes there is any plausible circumstance which would restrict its ability to complete the project and if so provide details.
2. The Panel notes that many of BC Hydro's existing facilities were built with options for expansion. For example, Mica and Revelstoke were initially built with four generators each. Many years later Revelstoke had one generator added and Mica has recently had two generators added. BC Hydro is requested 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.

4.3 Costs to terminate the project

The OIC requests that the Panel answer the question:

> What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?[189]

For the purposes of this analysis, the Panel has assumed that the project would be terminated on December 31, 2017. BC Hydro notes that "Variations in the termination date of a few months earlier or later would not be material to the outcome"[190].

[188] F1-1 Submission, p. 87.
[189] OIC section 3 (b) (iii)
[190] F-1 Submission p.67

BC Hydro submission

BC Hydro explains that its estimate of $7.3 billion to terminate Site C includes $2.1 billion in costs incurred prior to termination and $1 billion to demobilize the project and remediate the site, with the balance being explained by the higher cost of alternative supply[191]. This estimate of $1 billion to demobilize the project and remediate the site 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 their analysis[192].

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[193] are Class 5 estimates, accurate to within a range of +100 percent and -35 percent[194], and include a contingency of 30 percent[195].

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"[196]. The benefit agreements BC Hydro refers to are further explained as being community benefit agreements and First Nation benefit agreements[197].

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"[198], 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[199].

BC Hydro goes on the 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[200]. BC Hydro adds that the balance in the Site C regulatory account includes accrued interest charges.

The Panel notes that the Site C regulatory account was set up in 2006 as part of the Negotiated Settlement Agreement attached as Appendix A to Order G-143-06:

> A regulatory asset shall be established in respect of Site C expenditures. All Site C expenditures during F2007 and F2008 shall be included in the Site C regulatory asset. The creation of this regulatory asset will not preclude the Parties from raising prudency issues under the UCA with respect to Site C expenditures incurred or to be incurred. BC Hydro confirms that there is no impact from these expenditures on the revenue requirements for F2007 and F2008.

BC Hydro summarizes the aforementioned costs as follows[201]:

[191] F-1 Submission p.66
[192] ibid. p.73,68
[193] ibid. p. 73 table 13
[194] Ibid. p.68
[195] Ibid. p.69
[196] ibid. p.70
[197] ibid. appendix O p.29-30
[198] ibid. p.70
[199] ibid. appendix O
[200] ibid.p.67

Table 17: Project-Related Costs by Category and Default Treatment Under Accounting Rules

	Cost Category	Estimated Amount ($Billion)	Description	Default Accounting Treatment Under Accounting Rules
1	Project Capital Costs Between FID and Termination Date	1.6	Forecast Project costs to December 31, 2017,	Write-off at the time of termination.
2	Pre-FID costs already in Site C Regulatory Account	0.5	Forecast balance to December 31, 2017	Write-off at the time of termination.
3	Termination-related Costs	0.3	Forecast costs	Costs BC Hydro would incur as a result of termination (e.g., payments to contractors) would be recognized as an expense at the time of termination.
4	Remediation Costs	0.6*	Present value of forecast costs*	A provision would be recognized at the time of termination, equal to the present value of expected remediation costs to meet BC Hydro's legal or constructive obligations. The amount of the provision would be expensed when the provision is recognized.
	Total Estimated Direct Project-Related Costs	**3.0**		

*Remediation costs are estimated to be $0.7 billion (nominal).

Deloitte report

Deloitte estimates that the incremental cost of terminating the Site C project is "approximately $1.2 billion, excluding inflation impacts and interest costs"[202]. Deloitte has included the activities of "Management of existing contracts and commitments" and "Creation of a new project (the Termination Project)" in their estimates. Deloitte does not comment on the sunk costs of the Site C project.

Deloitte estimates the termination and remediation costs to be $1,203 million, to a class 5 accuracy of +100 percent/-35 percent, including 30 percent contingency[203]. Deloitte includes in its estimates figures of $320 million for cancelling existing contracts and benefit agreements, and $50 million for demobilization. Deloitte identifies the contracts to be cancelled as main civil works, turbines and generators, and worker accommodation[204]. They add that benefit agreements include First Nation and community agreements. In addition to contract termination costs, Deloitte estimates that $50 million will be required to cover demobilization activities by contractors[205].

[201] ibid. p.72,73
[202] A-8 Submission, p.66
[203] Ibid. p.66 and 83
[204] Ibid. p.47-50
[205] Ibid. p.53

Deloitte explains that its costs of remediation include work to "return the site to natural conditions capable of supporting natural vegetation and wildlife"[206]. They add that this work "is extensive enough to require independent project planning for control of budget and schedule" and include "environmental appraisal, permitting, and planning for construction and contracting". Deloitte provides detail on the remediation activities, although detailed costs are not presented[207].

Deloitte summarizes its estimate as follows[208]:

Table 18: Summary of Cost Impact – Termination Scenario

#	Termination Scenario	Cost impact ($ millions)
1	Cost to terminate the Site C Project	
	• Contract cancellations	320
	• FNs, community, and archeological impacts	Included above[69]
	• Demobilization	50
2	Cost impact of site remediation	
	• Engineering (site), permitting, and procurement	40
	• Remediation activities	495
	• Ongoing monitoring for 10 years	20
	Total	**925**
	Contingency (30%)	278
	Grand total	**1,203**

Our estimate includes the following assumptions (further assumptions are included in Appendix E).

- Our estimate does not include incremental interest costs in the event of a termination
- Our estimate does not include inflation impacts
- The costs related to cancelling FN Agreements in a Termination Scenario replace those payments that the FNs would have received if the Project was completed; this distinction is important when comparing with the Suspend Scenario above, where the FN costs are *in addition to* what the FNs are entitled to get from the Project upon completion and during operation

Other submissions

Bakker identifies sunk costs of $1.87 billion expended to June 30, 2017, made up of $1.412 billion in project costs and $458 million in deferred costs[209], based on information received from BC Hydro.

Bakker[210] estimates that the cancellation, demobilization and remediation costs for the Site C project would be $750 million. She calculates this as the mid-point of a range of $600 and $900 million, which in turn was based on an estimate for cancelling Manitoba Hydro's Keeyask dam project. According to Bakker, the costs of cancelling the Keeyask dam project was estimated to be $1.3 billion at the point at which the project had spent $6.5 billion, which was in September 2016. Bakker adds that without access to the Site C construction contracts,

[206] Ibid. p.66
[207] Ibid. p.76-82
[208] Ibid. p.83
[209] F106-1 Submission, p.57
[210] F106-1 Submission p.72-74

"the contract cancellation costs represent a significant unknown cost in evaluating the options to continue, cancel or suspend"[211] the project.

Bakker summarizes her estimates of the cancellation costs as follows[212]:

Table 19: Summary of Cost to Cancel or Suspend the Site C Project

Cost Item	Cancel the Site C Project	Suspend the Site C Project
Sunk costs	$1.87 billion	$1.87 billion
Contractual and demobilization costs	$750 million	n/a
Suspension costs	n/a	$15 million/year
Remobilization costs	n/a	$200 million

Mr. Raphals *et al.* (Raphals)[213] presents updated figures from Bakker, identifying $2.395 billion in sunk costs to December 31, 2017[214], but does not apportion this total between the regulatory account balance and project capital costs. Raphals uses the same figure as Bakker of $750 million for cancellation costs, "including complete demobilization and site regeneration[215]".

Panel analysis and preliminary findings

The analysis in this section considers only the costs to terminate the project and to remediate the site. The costs of alternative energy and capacity will be considered later in this document.

The sunk costs of the project on December 31, 2017 consist of the balance in the Site C regulatory account and the project costs to date. The Site C regulatory account was established in 2006 to capture project costs prior to the end of 2014. The project costs include expenditures incurred since the final investment decision at the end of 2014. The Panel accepts the figures provided by BC Hydro for the balance in the Site C regulatory account ($500 million on December 31, 2017) and the project cost to date ($1.6 billion on December 31, 2017) for the purposes of this analysis. The Panel accepts a figure for sunk costs as of December 31, 2017 of $2.1 billion for the purposes of this analysis.

BC Hydro estimates termination costs to be $300 million, whereas Deloitte provides a figure of $481 million[216]. Both figures are presented as being Class 5 estimates. **The Panel finds that both estimates are reasonable, and that an appropriate estimate for termination costs is $391 million**, being the mid-point between the BC Hydro and Deloitte estimates, and being within the +100 percent and -35 percent range of both those parties' estimates.

BC Hydro estimates remediation costs to be $600 million, whereas Deloitte estimates $722 million[217] for the same activities. On the same basis as above, **the Panel finds that both estimates are reasonable, and that an appropriate estimate for remediation costs is $662 million**, being the mid-point between the BC Hydro and Deloitte estimates.

[211] F106-1 Submission p.74
[212] F106-1 Submission p.76
[213] F106-2 Submission, also submitted by Bakker
[214] Ibid., p. (i)
[215] Ibid., p.8
[216] $320 million for contract cancellation plus $50 million for demobilization plus 30% contingency = $481 million
[217] $40 million for engineering plus $495 million for remediation plus $20 million for monitoring plus 30% contingency = $721.5 million

Bakker provides an estimate of $750 million for the total termination and remediation costs. These costs were based on information from Manitoba Hydro's Keeyask dam project, whereas BC Hydro and Deloitte provided estimates based on information specific to Site C. The Panel assigns no weight to the Bakker estimates as these estimates do not directly relate to the Site C project. Accordingly, **the Panel finds the total cost for termination and remediation to be $1.1 billion.**[218]

The Panel presents its findings in the following table:

Table 20: Preliminary Panel Findings – Termination and Remediation

Findings	Cost
Termination costs	$391 million
Remediation costs	$662 million
Total	$1.1 billion

These figures will be used in the section 7 of the Preliminary Report where the Panel examines the cost impact to ratepayers of continuing, suspending or cancelling Site C.

[218] $390.5 million for termination plus $661.8 for remediation

5.0 BC Hydro's ability to meet forecasted load using existing and committed resources

In this section of the Preliminary Report, the Panel reviews BC Hydro's ability to meet the forecasted load using its existing and committed resources. BC Hydro refers to this as its "load resource balance." The Panel begins by identifying BC Hydro's existing and committed or total electricity supply without Site C. The Panel then considers the load forecast or demand for electricity. As directed by OIC 244, the Panel's analysis uses BC Hydro's low, mid-level or expected case and high load forecasts for peak capacity demand and energy demand that were provided by BC Hydro in its F17-F19 RRA. 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 forecast. The Panel then reviews the handling of surplus energy and capacity.

The Panel's analyses highlight a number of issues and potential concerns identified by Deloitte in its independent report and raised in submissions received from other parties. Based on the information provided by BC Hydro, Deloitte and other parties, the Panel raises a number of questions and points of clarification which need to be addressed in order to inform the Panel's findings in its Final Report.

5.1 BC Hydro's Current Load Forecast

5.1.1 Requirements under OIC 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 F17-F19 RRA. In addition in compliance with these terms of reference, 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.

The Panel notes a number of the participants' submissions express concern that the OIC is 'overly prescriptive' in that it mandates that BC Hydro's Current Load Forecast be utilized for comparing the alternatives. However, as a number of submissions point out, sections 3(c)(i) and (ii) 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 agrees 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.

5.1.2 Overview of BC Hydro's Current Load Forecast

BC Hydro states its Current Load Forecast is "a key input into BC Hydro's short-term operational and financial planning and revenue projections, and its long-term resource planning processes." [219] BC Hydro prepares its load forecast prior to taking demand-side management (DSM) plan savings into account using models that align the relationship between demand and drivers of future demand. BC Hydro explains the drivers its uses include projections of economic variables such as Gross Domestic Product (GDP), efficiency of residential and commercial appliances, temperature, commodity prices and electricity rate increases. BC Hydro notes load

[219] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirement Application (BC Hydro F17-F19 RRA) proceeding, Exhibit B-1, p. 3-1.

forecasting is inherently an uncertain undertaking with volatile drivers of future requirements and as a result its load forecast consists of a high and low band and includes a mid-level projection. [220]

Mid-level forecast

BC Hydro prepares 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, as outlined below:

- **Residential and commercial** - The residential and most of the light industrial/commercial sales are based on statistical adjusted end-use regression methods used through North America (considered to be industry standard) using historical billed sales data up to March 31 of the relevant year combined with a variety of economic forecasts and inputs from third party sources. BC Hydro also uses other forecast drivers including projections of average efficiency of residential and commercial appliances and historical temperature trends;[221]
- **Large industrial** -The large industrial forecast is prepared for each existing large industrial customer connected at the transmission system as well as future customers where the vast majority of these customers have provided electricity service requests to BC Hydro.[222] BC Hydro describes its load projections in the industrial sector generally as being "a probabilistic assessment of their likelihood to materialize and, while the probabilities for individual customers are held confidential, the summation of the loads provides a reasonable system wide estimate"; [223]
- **Other** - BC Hydro combines load projections for the three customer classes identified above with projected load for other utilities supplied by BC Hydro under contract or agreements (City of New Westminster, FortisBC, Seattle City Light and Hyder, Alaska) as well as forecasts for street lights, irrigation and BC Hydro own use.[224]

High/low load forecast

BC Hydro states it uses the mid forecast for resource planning and addresses load uncertainty by developing high and low forecast bands. BC Hydro uses a Monte Carlo analysis to produce "a high and low total system load forecast band before DSM to create high and low forecast bands for the entire system load with approximately 10 percent and 90 percent exceedance probabilities, respectively."[225] BC Hydro explains the high and low forecast bands are used to provide an indication of the magnitude of load uncertainty as well as to develop BC Hydro's contingency resource plans.

BC Hydro describes the Monte Carlo analysis as involving the sampling of probability distributions for key load uncertainty variables such as GDP, electric vehicles, heating degree days and includes four probability distributions for the Large Industrial sub-sectors (mining, oil and gas, forestry and other industrial). BC Hydro states the large industrial sector contributes to a large amount of uncertainty in the total system high and low projections from the Monte Carlo analysis since it is the most volatile sector.[226]

System peak forecast

BC Hydro describes how it arrives at its total system peak requirements as follows:

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[220] Ibid., pp. 3-5 to 3-6.
[221] F1-1 Submission, Appendix H, pp. 2-3.
[222] Ibid, p. 4.
[223] BC Hydro F17-F19 RRA proceeding, Exhibit B-1, pp. 3-5 to 3-6.
[224] F1-1 Submission, Appendix H, pp. 4-5.
[225] Ibid, p. 15.
[226] Ibid.

> The distribution peak forecast is prepared from individual substation forecasts of non-coincident peak demand and then aggregated into regions and adjusted by coincidence factors to develop a total distribution peak forecast. The large industrial peak demand forecast is developed for existing and future new customers, also on a non-coincident basis, and then aggregated into regions and a total system using coincidence factors. The total system peak requirements is then a projection of a total distribution system peak, total system large industrial (i.e., transmission voltage connected) peak, peak demand projections for other utilities supplied by BC Hydro and system losses based on historical real time data of the transmission system losses. The distribution peak is most sensitive to temperature and weather conditions such as snow, wind and cloud cover. As such the distribution peak demand is prepared on a temperature normalized basis which is defined as a rolling 30-year period of the annual coldest daily average temperature. This temperature coincides with cold spells and when the system peaks during the winter months typically in December or January.[227]

Regulatory oversight of BC Hydro's load forecasts

In its final argument in the F17-F19 RRA, BC Hydro submits the Commission and the Provincial Government have previously endorsed the load forecast. BC Hydro argues the Current Load Forecast is the same methodology used in its 2013 Integrated Resource Plan which was approved by the Provincial Government and prior load forecast have been examined in several Commission proceedings including the 2008 Long-term Acquisition Plan Decision.

On August 25, 2017, the Commission issued its key findings on F17-F19 RRA load forecast and stated:

> The Panel concurs with BC Hydro that only the test period load forecast is within scope of the Application and the long-term resource planning is appropriately addressed in BC Hydro's IRP [Integrated Resource Plan] file [filed] with the minister. In the Panel's view, giving direction to BC Hydro on its long term resource planning is outside the scope of this Application and is beyond the Commission's jurisdiction.[228]

5.1.3 Summary of submissions on the Current Load Forecast

BC Hydro submission

BC Hydro states its customer demand for electricity is growing[229] 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.[230] 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 points out 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). [231]

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:

[227] Ibid, p. 5.
[228] BC Hydro F17-F19 RRA proceeding,Exhibit B-1, Key Findings – Load Forecast
[229] F1-1 Submission, p. 3.
[230] F1-1 Submission, p. 46.
[231] Ibid, pp. 12-13.

Figure 1: Current Load Forecast after DSM – Energy[232]

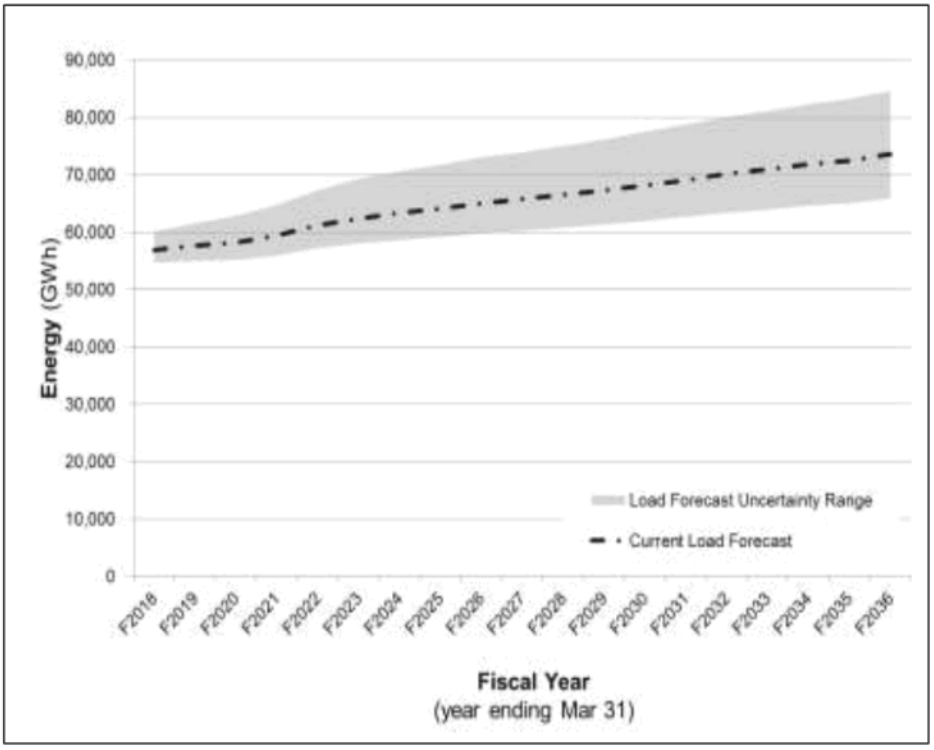
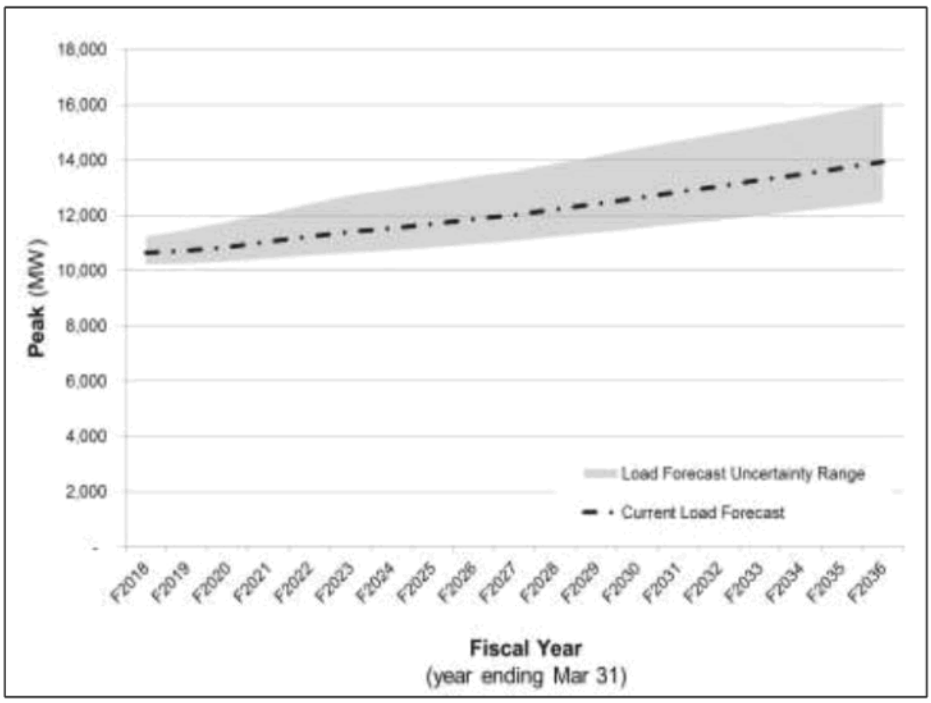


Figure 2: Current Load Forecast after DSM – Capacity[233]



BC Hydro states its current load forecasting methodology has been in place for many years and its Current Load Forecast is developed in a manner consistent with the Commission's resource planning Guidelines. BC Hydro notes the methodology "has been presented in a number of Commission proceedings, accepted by Government

[232] Ibid, p. 46, Figure 9.
[233] Ibid, p. 46, Figure 10.

and endorsed by the Joint Review Panel that considered Site C's Environmental Impact Statement."[234] BC Hydro states the current methodology has been tested by the following:

- The Commission in its 2008 Long-term Acquisition Plan Decision dated July 27, 2009;
- The Government in its 2011 Review of BC Hydro;
- The Joint Review Panel; and
- Recently by a third party expert, GDS Canada Consulting (GDS), as part of BC Hydro's ongoing internal audit process.

BC Hydro notes that while GDS proposed improvements, it did not identify any "critical weaknesses" with load forecasting function at BC Hydro.[235]

BC Hydro describes its methodology at a high level as one that "involves adding the electricity billed sales forecasts from BC Hydro's main customer groups and then accounting for demand-side management savings." BC Hydro states it tailors its forecasting models to each major customer group and links electricity sales to the key drivers impacting demand including population growth, economic growth, temperature and commodity markets and prices.[236]

BC Hydro provides a detailed technical description of its load forecast methodology in Appendix H of its submission.[237]

BC Hydro acknowledges load forecasting involves inherent uncertainty. BC Hydro explains it develops high and low load forecast scenarios to account for uncertainties and risks in its planning. BC Hydro states in its Current Load Forecast, the high growth scenario would advance the need for both energy and capacity. On the other hand, BC Hydro states the low growth scenario would defer the need for energy and capacity and as a result the fiscal 2024 in-service date for Site C would give rise to a short-term surplus.[238] The uncertainty range in Figures 1 and 2 represents the difference between the high load scenario after low demand-side management and the low load scenario also after low demand-side management.[239] The low demand-side management savings estimates are the mean of the lower twentieth percentile tail of the distributions of the demand-side management savings estimates.[240]

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 load compared to the forecast, mostly attributable to projects in the oil and gas sector. [241]

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 assess, 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:

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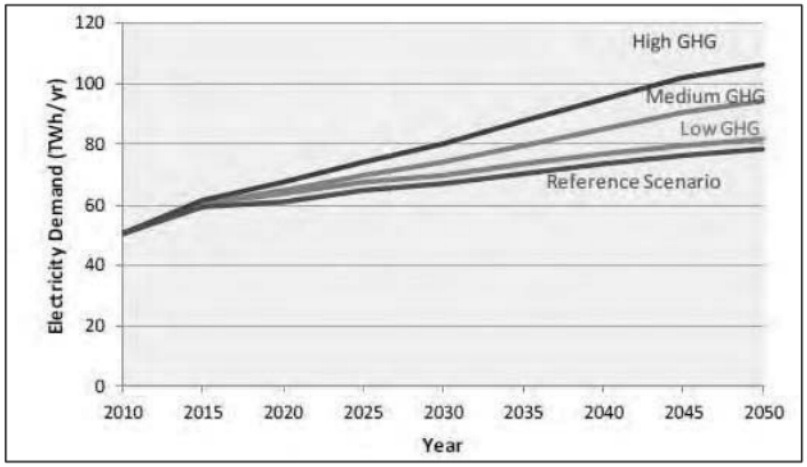
[234] Ibid. , p. 3.
[235] Ibid, pp. 47-48.
[236] Ibid., p. 47.
[237] Ibid., Appendix H.
[238] Ibid, pp. 12-13.
[239] Ibid, p. 45.
[240] BC Hydro F17-F19 RRA, Exhibit B-1-1, p. 3-36.
[241] Ibid, pp. 48-50.

- 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 that 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.[242]

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."[243] 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. [244]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. However, the potential for electrification to have an upward impact is shown in Figure 13 below.[245]

Figure 3: Electrification Potential and the 2013 Integrated Resource Plan Load Forecast[246]



Overall BC Hydro views its load forecasts to be:

> …reasonable, unbiased estimates of future load. Nevertheless, load forecasts are dependent on a range of factors from national economic conditions to the behavior of BC Hydro's customers.

[242] Ibid, pp. 50-52.
[243] Ibid, pp. 2-3.
[244] Ibid, p. 52.
[245] Ibid, p. 54.
[246] Ibid, p. 54.

> There is also considerable potential for electrification, and corresponding load increases, due to initiatives intended to achieve greenhouse gas reductions. This results in inherent and unavoidable uncertainty in BC Hydro's load forecasts, which can change when new resources are expected to be required to serve customer load.[247]

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:

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

Deloitte also notes that BC Hydro's model assumes there will be no future rate increases for the period from 2025 to 2036[248] and states that rate increases introduced between F2025 and F2036 would lower the Current Load Forecast.[249] The Panel reviews these issues in more detail in section 5.2.4.

On the other hand, in Deloitte's assessment, BC Hydro's assumptions regarding electric vehicle use appear conservative compared with public commitments from the federal government. Deloitte uses an alternative assumption that electric vehicles will account for 30 percent of all new cars sold in 2030 (compared to BC Hydro's 22 percent) and calculate increases of load demand from electric vehicles of approximately 115 to 125 GWh in 2026 and 680 to 690 GWh in 2036.[250]

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 Conference Board of Canada;
- 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 illustrates the impact of adopting a more intensive DSM approach, consistent with BC Hydro's own submission in the 2013 IRP. Since BC Hydro analyzes its ability to meet forecasted load using existing and committed resources starting with gross load, the Panel focuses on Deloitte's alternative scenario before accounting for DSM. Figures 4 and 5 compare BC Hydro's load forecast to Deloitte's alternative scenario:

[247] Ibid, p. 98.
[248] A-9 Submission, p. 5.
[249] Ibid, p. 75.
[250] Ibid.

Figure 4: Load Forecasts Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario[251]

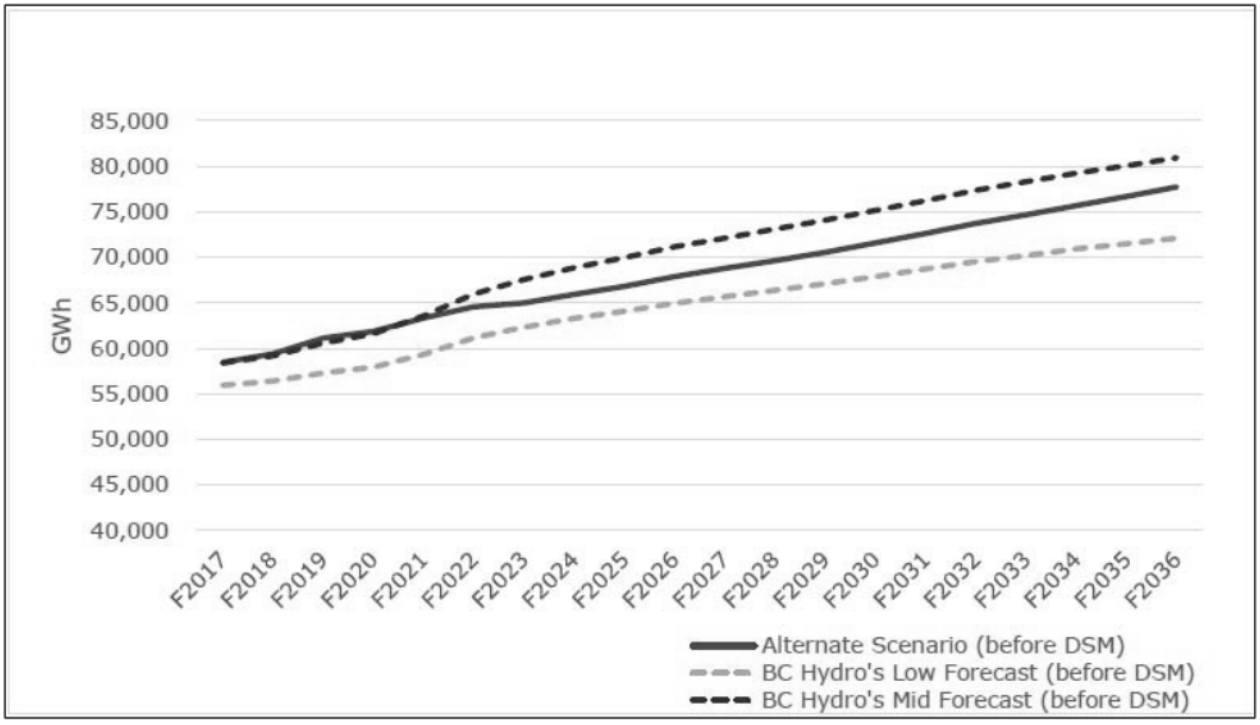
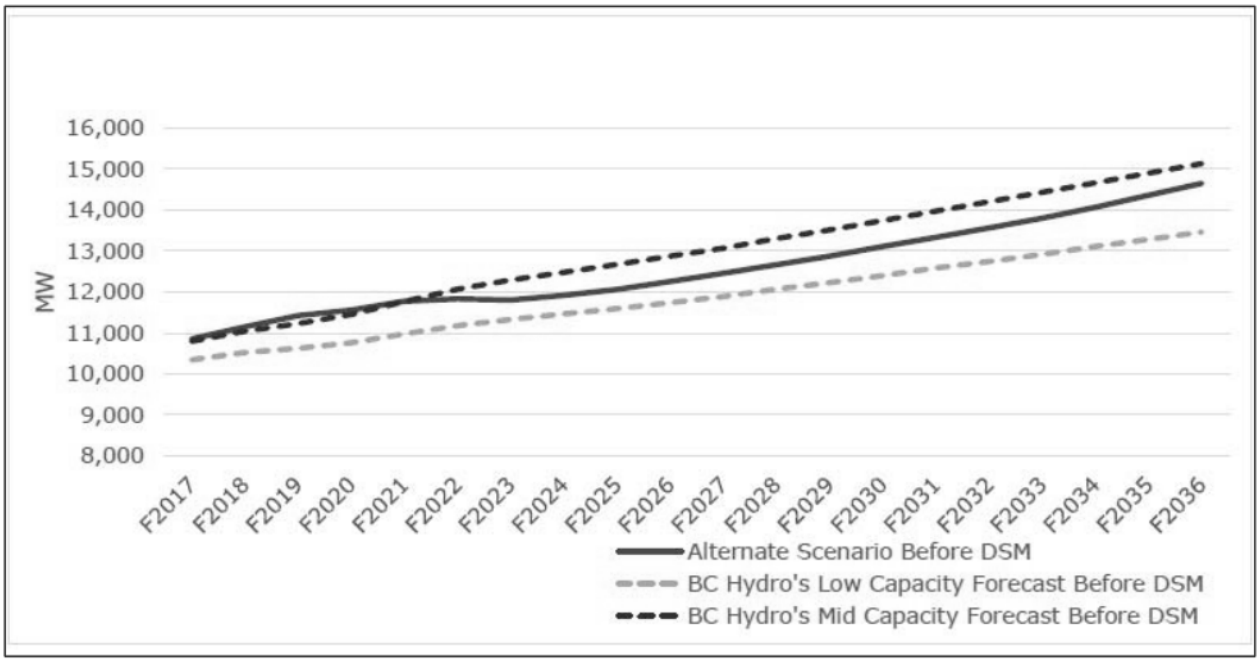


Figure 5: Capacity Forecast Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario[252]



In Deloitte's view, taking into account its DSM adjustment, 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 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 by 2036. Deloitte cautions that these projections should be considered as indicative only, since they have adjusted BC Hydro's mid forecast

[251] Ibid, p. 80, Figure 13.
[252] Ibid, p. 81, Figure 15.

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".[253]

With respect to assessing the model's functional form and statistical features, Deloitte acknowledges while it did not directly test the load forecast model, it did note that with some exceptions, BC Hydro's methodology is consistent with the practices of other North American utilities. Deloitte considers that an opportunity may exist to strengthen the reliability of the forecast by employing an econometric approach that models short-term forecasts on the basis of past actual loads. Deloitte also notes the potential for correlation across the various independent components of the mid-forecast should be tested to minimize risks of suboptimal forecast results.[254]

Other submissions

Many participates raised concerns about the historical accuracy of the load forecasts, commented on the reasonableness of BC Hydro's assumptions in its Current Load Forecast and noted factors that could reasonably be expected to influence demand from the expected case toward the high load or the low load case. A high level, non-exhaustive, summary of submissions in this area is provided below.

Historical forecasting accuracy

BC Hydro's load forecasting has consistently overestimated electricity demand[255] and appears to have inflated demand projections during the time-frame when Site C was being considered for approval.[256]

BC Hydro has failed to adjust for over-estimation bias. [257]

Reasonableness of Current Load Forecast assumptions

The forestry segment will be impacted by trade difficulties, wild fires and BC Hydro rates not just price commodity price changes [258]

With respect to BC Hydro' identification of population growth being a key driver of residential demand, BC population has grown in the last 10 years and expected demand from this growth is offset by falling per capital demand[259]

The need for Site C was based on government policy decisions to stimulate growth in the oil and gas industry, including LNG. [260]

The price elasticity used by BC Hydro appears low.[261]

Factors influencing demand

The impact from any rate increases in planning period.[262]

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[253] A-9 Submission, p. 4.
[254] Ibid., p. 6.
[255] F13-1 Submission, pp. 14-17; F 60-1 Submission, p. 2; F 44-1 Submissio, p. 2-3; F 36-1 Submission, pp. 5-6; F 106-2 Submission, pp. 3-4. F82-1 Submission, p. 26.
[256] F60-1 Submission, p. 2.
[257] F13-1 Submission, p. 16; F82-1, pp. 25-26.
[258] Ibid., p. 16.
[259] Ibid., p. 16.
[260] Ibid., pp. 17-18.
[261] F36-1 Submission, p.12.
[262] F29-3 Submission, pp. 18-20.

Uncertainty attached to the forecast LNG and industrial load.[263]

Possible low-carbon electrification initiatives not already included in the load forecast.[264]

Other potential disrupting trends are set out in section 5.1.4.5.

5.1.4 Load forecast issues

The Panel acknowledges that load or demand forecasting is the foundation of BC Hydro's planning since forecasting electricity demand is crucial for resource planning, determining revenue requirements, designing rate structures and supporting financial and operational decisions. Demand forecasting attempts to predict future electricity needs so that a utility can plan for adequate generation and transmission to meet this future need.

There are many uncertainties that make it difficult to forecast future electricity demand. There is 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 that can significantly affect future electricity demand. A load forecast is probabilistic and does not result in a point estimate that is expected to be accurate especially over a long time horizon. However, an effective forecast model should produce results relatively close to actuals with equal instances of over and under forecasts. The Panel recognizes that a utility may view it to be better to over-estimate rather than to under-estimate demand; however, a load forecast should 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.

The Panel recognizes 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. 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 ultimate cost and economic risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers but nevertheless the decisions must be made today. To assess the cost and economic risk of different resource strategies, it is necessary to identify those future uncertainties that have the potential to significantly affect the cost or economic risk of a resource strategy, such as building Site C, and to bracket the range of those uncertainties so that an optimal decision can be made.

In this context, the Panel considers a number of load forecast issues identified to the date of this Preliminary Report, makes some comments on what it must decide for its Final Report and seeks further input and analysis of these issues from BC Hydro and other participants. The issues discussed in this section include:

1. Recent developments in the industrial sectors;
2. Accuracy of historical load forecasts;
3. Forecast drivers and sources;
4. Price elasticity and future rate increases; and
5. Potential disrupting trends.

[263] F29-3 Submission, pp. 18-20; F 60-1, p. 2; F 36-1, pp. 6-11.
[264] Ibid., pp. 18-20.

5.1.4.1 Recent developments in the industrial sectors

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.[265] BC Hydro provides the following table.

Table 21: Summary of Incremental Load Impacts of Known Developments[266]

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

BC Hydro's analysis of known developments still anticipates that the three announced LNG projects included 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 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.[267]

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."[268]

[265] F1-1 Submission, Appendix J, p. 1.
[266] Ibid., p. 50
[267] Ibid., p. 52
[268] A-9 Submission, p. 5.

Panel analysis and preliminary findings

The data and analysis reviewed by the Panel, as of the issue date of this Preliminary Report, suggests that the most significant developments are forecast to be in the in the industrial sector. **The Panel finds it is not yet in a position to make its finding on impact of recent developments in the industrial sector due to insufficient information.**

BC Hydro's Load Resource Balances included in Appendix K of its submission discloses the Mid Load Forecast before DSM and separately presents the expected LNG load. Further, BC Hydro's analysis of known developments is transparent in its treatment of the impact of developments in the expected LNG load. This enables the Panel to understand the impact of the LNG load on the demand forecast. However, the Panel is concerned with how it can assess the reasonableness of the probabilities assumed in the industrial load given that BC Hydro adjusts only the timing and not the probability attached to the LNG load given recent developments. This raises questions about how the Panel can assess the reasonableness of BC Hydro's probability assessment for the non-LNG industrial load included in the Current Load Forecast and in the information related to incremental known developments.

The Panel requests that BC Hydro respond to the following questions related to its industrial demand forecast:

- **With regard to BC Hydro's forecast for LNG load, please 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.**
- **Please explain how the completion risk and, separately, the timing risk are factored into BC Hydro's current load forecast in relation to each of the following. If there are differences between the factoring of completion and timing risk for the three LNG projects as compared to other industrial projects/customers, please identify, explain and justify the differences:**
    a. **FortisBC Tilbury LNG Phase 2;**
    b. **Woodfibre LNG;**
    c. **LNG Canada; and**
    d. **Other industrial projects and customers.**
- **Based on Table 11 of BC Hydro's submission (and provided in this report above) which shows the incremental industrial load impacts of known developments and the more detailed discussion in Appendix J, for each specific development identified in Appendix J in each of the large industrial (transmission) sectors, please quantitatively and qualitatively provide the probability of each identified increase (or decrease) in load materializing. For the developments which are expected to result in increases to the industrial load, please explain in detail the risks which may prevent the identified loads from materializing and assign a risk level to each identified load.**

The Panel has a number of detailed questions based on the information provided by BC Hydro in Appendices H, J and K of its August 30, 2017 submission (i.e. F1-1). These questions are as follows:

On page 6 of Appendix H to F1-1, BC Hydro explains: "The small number of proponents that are proposing to electrify from the grid (FortisBC Energy Inc., LNG Canada and Woodfibre LNG) precludes confidential aggregation of a probabilistic Load Forecast."

In Tables J-8 and J-9 on page 23 of Appendix J BC Hydro provides revised schedules for the FortisBC Tilbury LNG and LNG Canada facilities.

In Table K-1 of Appendix K, BC Hydro provides expected LNG load schedules.

Based on the above information, please provide the following information:

- **Please confirm, otherwise explain, that the Fortis Tilbury and LNG Canada loads and demands are the total expected electricity loads and demands from these two projects and not probability weighted amounts.**
- **Please provide separate unweighted load and demand schedules to F2036 for each of the FortisBC Tilbury LNG Phase 2 project, the Woodfibre LNG project and the LNG Canada project. Please provide schedules for both what was included in the Current Load Forecast and what is included in the revised outlook. Please use the same format as used in Tables J-8 and J-9.**
- **If there were other LNG projects (weighted or unweighted) included in the Current load and demand forecasts, please identify those projects and provide their respective Current and revised load and demand schedules. Please comment on any differences.**
- **In Tables J-8 and J-9, BC Hydro shows Tilbury and LNG Canada loads. In Table K-2, BC Hydro shows total LNG load. Please explain where the remaining load is coming from. Is it all from the Woodfibre LNG project? Please elaborate.**

The Panel also invites further submissions from other parties on the updates made to the LNG forecasts and others identified changes in industrial load as summarized in Table 21, including any further data that could assist the Panel in concluding on the implications of developments since the Current Load Forecast was prepared that will impact industrial demand in the short, medium and longer terms.

5.1.4.2 Accuracy of historical load forecasts

BC Hydro submission

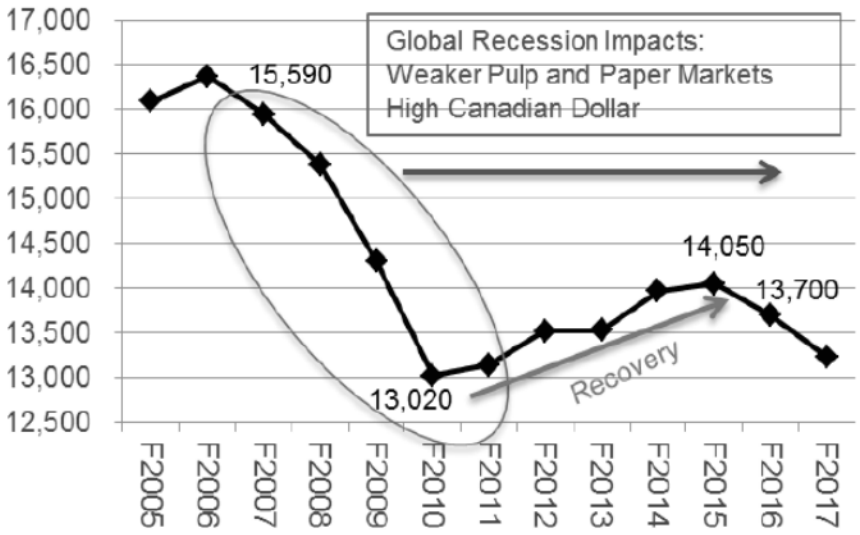
In its analysis of load forecast history, BC Hydro concludes:

- 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.
    - Variances in the Residential, Commercial and Light Industrial sectors have been small.
- That BC Hydro, like most other entities, does not, and is not able to, forecast economic recessions or boom cycles;
- 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.[269]

BC Hydro states the large declines in industrial load between F2006 and 2010 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:

[269] F1-1 Submission, Appendix H, pp. 42-43.

Figure 6: Large Industrial Load F2005 to F2017 – Actual[270]



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.[271]

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 following comparison:

Table 22: Comparison of BC Hydro Forecast Variances to Industry Benchmarks[272]

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

[270] Ibid, p. 46, Figure H-3.
[271] Ibid, p. 46.
[272] Ibid, Appendix I, p. 24.

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.[273]

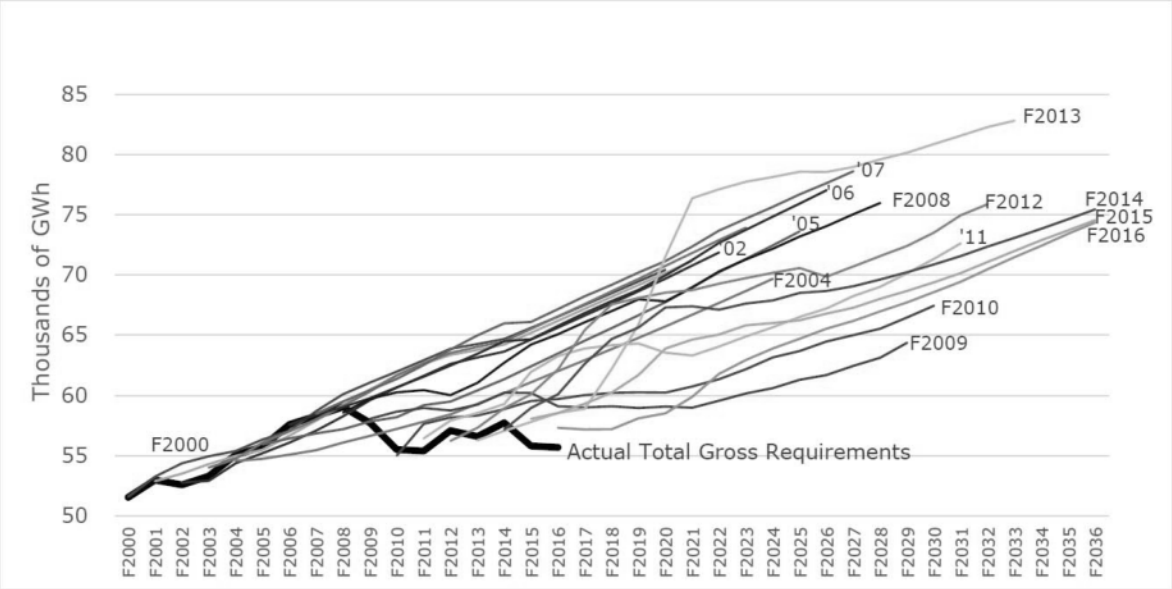
Deloitte report

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.[274]

Deloitte illustrates the performance of the model since the year 2000 in the figure below.

Figure 7: Total Gross Requirement Forecast Models Between 2000 and 2016(with DSM)[275]



Panel preliminary analysis and preliminary findings

The data and analysis reviewed as of the date of this Preliminary Report suggests that the most significant issue with BC Hydro's historical forecasting accuracy relates to the industrial sector forecasts. This issue is of particular

[273] Ibid.
[274] A-9 Submission, p. 5.
[275] Ibid, p. 63.

importance because BC Hydro's Current Load Forecast predicts significant growth in industrial load between now and 2036. The Panel is also concerned that over-estimating industrial load growth could have a compounding impact on the GDP estimates used by BC Hydro, resulting in possible accuracy issues for load growth in other customer classes.

In the Panel's view, to ensure effective resource planning, BC Hydro must be able to make reasonable predictions about the probability and impact of changes in industrial customer load resulting from expected load growth from both future customers, the majority of whom BC Hydro states have provided electricity service requests to BC Hydro, and existing customers. BC Hydro must also be able to effectively assess the risk of loss of load as a result of developments in a segment (e.g. forestry or mining) or customer specific financial difficulty.

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 have been considerably below industry benchmarks. However, the Panel finds that we cannot yet assess the reasonableness of BC Hydro's industrial load forecast due to insufficient information.

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

5.1.4.3 GDP and other forecast drivers

BC Hydro submission

BC Hydro presents the main forecast drivers and sources in Appendix H, Section 10 of its 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."[276]

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 5 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 dropping 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.[277]

[276] Ibid, Appendix J, p. 6.
[277] Deloitte LLP independent report: Site C – Alternative Resource Options and Load Forecast Assessment, A-9, p. 5.

Panel analysis and preliminary findings

The Panel finds that it is not yet in a position to make its finding on the reasonableness of BC Hydro's inputs for GDP and disposable income due to insufficient information. The Panel is concerned with the differences in between BC Hydro's forecast drivers for GDP and disposable income compared to the Conference Board of Canada estimates.

The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income:

- **Please address the differences noted by Deloitte in its Load Forecast Assessment related to GDP and disposable income. Please obtain whatever information from Deloitte that BC Hydro deems necessary in order to respond to this request.**
- **Please provide an analysis of the GDP and disposable income projections developed by RFEC compared to the Conference Board of Canada (CBoC) estimates and explain the reasons for significant differences in projections. In particular, please explain why the RFEC projection for GDP is not consistent with the CBoC's projections after the first five years.**
- **Please quantify the effect on BC Hydro's load forecast of reducing its GDP forecast to align with the CBoC's GDP projections.**
- **Please provide data/information on the historical accuracy of both the CBoC's and RFEC's GDP forecasts and comment on which of these parties' forecasts has historically been more accurate.**
- **Please explain what impact, if any, the recently announced halt to the Aurora LNG Project will have on GDP projections developed by RFEC. For the purposes of this response, please assume that the Aurora LNG Project will not proceed.**

The Panel also invites submissions from other parties on these inputs to could assist the Panel in concluding on the reasonableness of BC Hydro's GDP and other forecast drivers.

5.1.4.4 Price elasticity and future rate increases

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:

- As part of its 2015 Rate Design Application, BC Hydro performed a Residential Inclining Block Rate evaluation 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 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.[278]

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 by 2.6 percent 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.[279]

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.

With respect to BC Hydro's assumption that there will be no real rate increases between fiscal 2025 and fiscal 2036, 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.[280]

Other information on expected rate increases

In the F17-F19 RRRA, 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 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.[281]

[278] F1-1 Submission, Appendix H, p. 3.
[279] Ibid., Appendix R, p. 4
[280] A-9 Submission, pp. 74-75.
[281] BC Hydro F17-F18 RRA proceeding, CEABC IR 1.3.4.

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.[282]

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 states 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 express concern related to BC Hydro's ability to meet the 2013 10 Year Rates Plan. Among other things, intervenors comment on risks related to the industrial load forecast[283] and possible changes in the Provincial Government's approach to the financial management of BC Hydro.[284]

Other submissions

Mr. Swain points to long-run price elasticities from sources such as the JRP 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 (JRP) and -0.29 to -0.97 with a cluster also around -0.4 (Hendriks *et al*). Swain contrasts these with BC Hydro's price elasticity of -0.05 which BC Hydro uses uniformly across all sectors. Mr. Swain 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. Swain 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."[285]

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. BCSEA reproduces a government table that presents how these changes impact the Site C cost to ratepayers:

Table 23: Site C Cost to Ratepayers[286]

Site C Cost to Ratepayers (before changes)	**$83 / MWh**
Under the 10 Year Plan, the amount of net income that BC Hydro is required to earn each year will now be tied to inflation and will no longer increase when new assets like Site C are added to the system.	**- $26 / MWh**
The 10 Year Plan also reduced water rental charges for BC Hydro.	**- $1 / MWh**
The capital cost estimate for Site C has been updated from $7.9 billion to $8.335 billion.	**+ $2.25 / MWh**
Government has established a project reserve of an additional $440 million to account for events outside of BC Hydro's control that could occur over an eight-year construction period, such as higher than forecast inflation or interest rates. The reserve will be managed by the provincial Treasury Board.	**+ $2.50 / MWh** (if fully utilized)
Updated Site C Cost to Ratepayers	**$58 - $61 / MWh**

[282] Ibid., NIARG IR 1.1.1.
[283] Ibid., AMPC Final Argument, para. 2(c).
[284] Ibid., Mr. McCandless Final Argument, pp. 3-4.
[285] F 36-1 Submission, pp. 11-12.
[286] F29-3 Submission, pp. 21-22.

AMPC reiterates its rate concerns raised in the F17-F19 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.[287]

Panel analysis and preliminary findings

The Panel notes the differences in views related to BC Hydro's elasticity assumptions and GDS's recommendation that BC Hydro's price elasticity coefficients used to estimate "rate impacts", which were developed in 2007, need to be updated. [288] **Therefore, the Panel finds it is not yet in a position to make its finding on the reasonableness of BC Hydro's price elasticity or rate increase assumptions due to insufficient information.**

Of particular concern to the Panel is 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. The Panel notes BCSEA and AMPC concerns raised related to negative impact on demand that would result from rising BC Hydro rates over the planning period. Further, the Site C cost to ratepayers presented in Table 23 above depend on a continuation of Provincial Government policy to eliminate the Tier 3 water rates and changes to the calculation of the ROE and reducing the dividend beyond the 10 Year Rates Plan. The Panel also recognizes that achievement of the targets in the 2013 10 Year Rates Plan are subject to risk with respect to the policy changes, weather, industrial load, LNG load, interest rates, energy markets and Site C budget uncertainties, among other things.

Regarding the appropriateness of BC Hydro's assumptions related to price elasticity and future rate increases, the Panel requests BC Hydro to respond to the following questions:

- **Please provide a more detailed explanation as to how elasticity, a measure the Panel understands to be at the margin, is impacted by DSM.**
- **Please confirm, or explain otherwise, that BC Hydro has assumed zero real rate increases as part of its load forecast beyond 2024 (i.e. beyond the 2013 10 Year Rates Plan) and that any rate increases introduced between F2025 and F2036 would lower the Current Load Forecast. If confirmed, please explain the basis for and the reasonableness of this assumption.**
- **Please provide a detailed explanation of the risks which might prevent BC Hydro from achieving its projected zero real rate increases.**

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

5.1.4.5 Potential disrupting trends

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

[287] F81-1 Submission, p. 5.
[288] F1-1 Submission, Appendix I, p. 9.

(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.[289]

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. [290]

Similar to other submissions,[291] 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 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.[292]

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.[293]

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 4kW of installed Panels ($3.60 per Watt), an electricity price of 14.2c/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.[294] 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.[295]

[289] F1-1 Submission p. 52; F 21-1 Submission, p. 1; F 62-1 Submission., p.7; F 82-1 Submission, pp. 31-33.
[290] A-9 Submission, p. 75
[291] F 60-1 Submission, p. 2; F 82-1 Submission pp. 28-31;
[292] A-9 Submission, p. 75-79
[293] Ibid., pp. 77, 78
[294] Ibid., p. 78
[295] F62-1 Submission, p.11

- **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.[296]

Panel analysis and preliminary findings

The Panel is concerned that, given the long-life of the Site C asset, BC Hydro has only identified a potential upside risks to the load forecast from electrification, and has not identified any potential downside risks. **The Panel is not yet in a position to make its finding on the potential impacts of disrupting trends due to insufficient information.**

The Commission's resource planning guidelines state that an analysis of the trade-offs between portfolios incudes assessing how they perform under uncertainty. **The Panel requests 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 (for example, 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.**

5.2 BC Hydro's existing and committed resources and load resource balance

In this section, the Panel considers 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 has summarized its existing and committed (those in development but not in service) resources in Appendix K. Tables K-1 and K-2 within Appendix K summarize (in addition to other items) 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.

A slightly abridged version of these tables covering the years 2018, 2023, 2028, 2033 and 2036 has been presented in Table 24 for energy and Table 25 for capacity.

Table 24: Current Energy Resources (Without Site C (in GWh) [297]

(GWh)		F2018	F2023	F2028	F2033	F2036
Existing and Committed Heritage Resources						
Heritage Resources (excluding Site C)	(a)	46,895	48,491	48,491	48,491	48,491
Existing and Committed IPP Resources	(b)	14,592	13,547	11,983	10,163	8,295
Planned Supply-Side Resources						
		280	1,114	2,223	3,863	5,515
Standing Offer Program		130	801	1,439	2,076	2,448
Sub-total	(c)	410	1,916	3,662	5,940	7,962
Total Supply (Operational View) **	(d) = a + b + c	61,897	63,954	64,137	64,594	64,748

[296] Ibid.
[297] F1-1 Submission, Appendix K, Table K-1 (with updates from Exhibit A-12).

Table 25: Current Capacity Resources (Without Site C (in MW))[298]

(MW)		F2018	F2023	F2028	F2033	F2036
Existing and Committed Heritage Resources						
Heritage Resources (excluding Site C)	(a)	11,410	11,480	11,066	11,480	11,480
Existing and Committed IPP Resources	(b)	1,673	1,167	975	796	683
Planned Supply-Side Resources						
IPP Renewals		23	419	514	680	901
Standing Offer Program		18	53	91	128	150
Sub-total	(c)	41	472	604	808	1,051
Total Supply	(d) = a + b + c	13,124	13,120	12,646	13,084	13,214
14% of Supply Requiring Reserves***	(e)	-1,809	-1,808	-1,749	-1,810	-1,829
Effective Load Carrying Capability	(f) = d + e	11,315	11,311	10,897	11,273	11,385

BC Hydro has broken down its energy and capacity supply into three categories;

- Existing and committed Heritage resources;
  - existing facilities owned and operated by BC Hydro.
- Existing and committed independent power producer (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.

In BC Hydro's report it does not explain how it determines how much 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.[299] Dr. Ruskin questions how BC Hydro determined these amounts.[300]

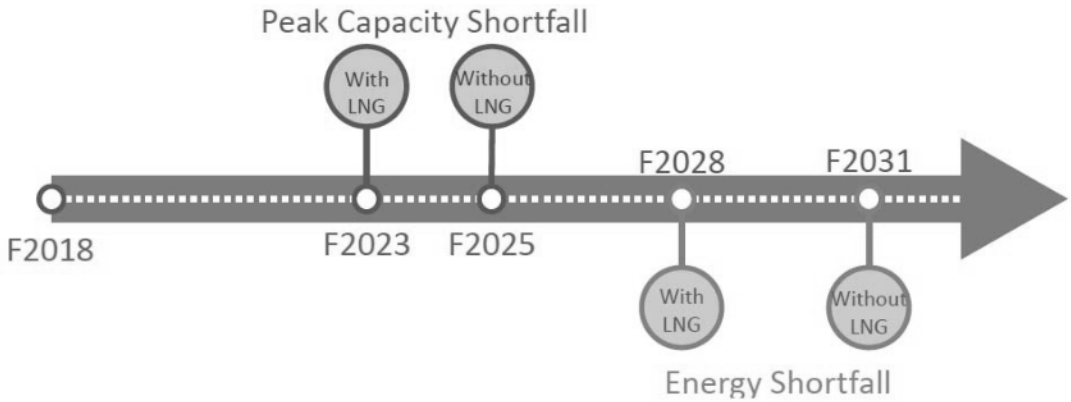
Heritage resources are currently the largest part of BC Hydro's energy supply accounting for approximately 75 percent. IPP resources and anticipated or planned renewals accounting for 24 percent are the next largest group with the standing offer program at approximately one percent providing only a small amount of energy. By 2036 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.

[298] F1-1 Submission, Appendix K, Table K-2 (with updates from Exhibit A-12).
[299] BC Hydro 2013 Integrated Resource Plan, Chapter 2.
[300] F26-1 Submission, F26-2 Submission, F26-3 Submission.

BC Hydro summarizes that without Site C, it would need new energy and capacity resources on the timeline shown in Figure 8. BC Hydro emphasizes that accessing dependable capacity will be one of our most pressing concerns for years to come.[301]

Figure 8: Timing of Energy and Peak Capacity Shortfall (Without Site C and Without Electrification)[302]



Panel analysis and preliminary findings

The Panel notes that Revelstoke 6 was not included in Table K-1 and K-2. **BC Hydro is asked to confirm that there are no other planned resources that have been excluded from these tables. Although energy and capacity from existing and committed Heritage resources are the subject of government approved integrated resource plans, it would be informative if BC Hydro would comment on Dr. Ruskin's submission and further explain how BC Hydro determined how much energy and capacity are available from existing and committed Heritage resources.**

5.3 Handling of surplus energy and capacity

It is acknowledged that once Site C is in operation there is potential for surplus energy and capacity. This section addresses some of the options BC Hydro is exploring with respect to the handling of any unplanned surplus of energy and capacity as well as expectations for the pricing of any such surpluses. 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 gigawatt -hours (GWh). Capacity refers to the highest level of electricity that the utility can supply at one time. Peak demand is measured in megawatts (MW) or millions of watts.

BC Hydro submissions

BC Hydro has projected energy surpluses for each year of the period of 2018 through 2024 without Site C. If Site C is built on schedule the number of surplus years would extend to 2031. From a capacity perspective, BC Hydro projects surplus capacity through 2022 without Site C with a deficit for most years thereafter. With Site C, BC Hydro projects a capacity surplus through 2032.[303]

BC Hydro affirms that its load forecast indicates that capacity and energy will be needed in the period at or close to Site C going into service. However, it 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 BC

[301], F1-1 Submission, p. 3.
[302] Ibid., p. 3, Figure 1.
[303] F1-1 Submission, Appendix K, Tables K1-K4.

Hydro asserts that surplus energy could be sold in the short-term wholesale energy markets outside of BC to mitigate the associated costs. In addition, it points out that the direct sale of surplus energy can be augmented by the emerging opportunity to sell the capacity and flexibility afforded by Site C due to its having made the design decision to include synchronous condense capability in all six Site C generating units (allowing them to be adjusted from high generation levels to no generation without a start/stop). In BC Hydro's view combining sales of surplus energy with sales of capacity and flexibility have the potential to partially or fully offset Site C generation costs until the full capacity is needed to meet BC Hydro's needs.[304]

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. To demonstrate the value of dispatchability it conducted a review of historical Pacific Northwest market prices over the most recent three years. The top 53 percent of hours in each 12-month period was used to serve as a simple measure of the value of Site C's generation dispatchability. The results show that large storage hydro like Site C offers the operator the ability to use the resource in the hours when it is most valuable for ratepayers. When compared with BC wind generation the Company determined the value of Site C to be 28 to 40 percent higher.[305]

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 2020's. 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.

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 also 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. It intends to continue to monitor its domestic needs for the resource and Powerex "would likewise continue to monitor the market opportunities for flexible surplus generation." 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.[306]

BC Hydro asserts that its unit energy cost analysis demonstrates there is potential to profit from a short-term surplus. To support its position it has prepared a graph comparing Site C energy cost to the Mid Columbia (Mid C) market electricity price.

[304] F1-1 Submission, Appendix S, pp. 1-3.
[305] F1-1 Submission, Appendix F, pp.7-8.
[306] F1-1 Submission, Appendix S, pp. 1-3.

Figure 9: Comparison of Site C Energy Cost to Mid C Market Electricity Price (F2018$/MWh)

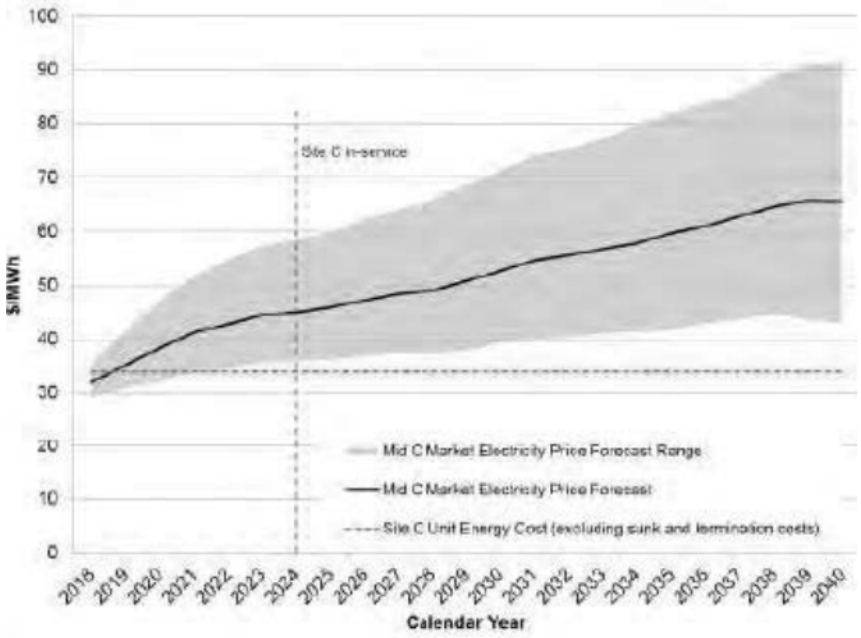


Figure 9 shows BC Hydro's current market electricity price forecast in comparison to its estimate of the incremental cost for completion of Site C "net of sunk costs and the termination and remediation credit at a unit energy cost of $34/MWh." Based on these market price estimates BC Hydro states that if Site C's temporarily had surplus energy it could be sold at a profit enhancing the case for completing Site C. BC Hydro's use of a $34/MWh UEC will be discussed further in section 6 of this Preliminary Report.

BC Hydro states that the expected prices for 2024 to 2030 short term energy sales are estimated in the CAD $48/MWh range. These increased market prices are based on the view that electricity markets are currently over built but are returning to a more balanced position. BC Hydro 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 has been considered and is represented by BC Hydro's use of the lower band of the price curve. BC Hydro reports that a sensitivity run on this lower band shows that 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.[307]

Deloitte report

Deloitte reports a higher wholesale price of energy outlook than BC Hydro. It submits that 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. It encourages comparison with other projections in interpreting a particular result but cautions that "care must be taken to understand that assumptions as well as approaches, methodologies, and other differences can account for a wide variation in forecasts". The information relied upon for this scenario is based upon a set of three cases used by FortisBC Inc. with Mid C market price projections through 2035 as part of their 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 FortisBC in its LTERP.[308] This differs from BC Hydro's reliance on a lower band and reflects estimates to purchase energy in the market and includes adders for transmission costs and delivery losses.[309]

[307] F1-1 Submission, p. 104.
[308] A9 Submission, p.116.
[309] FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan proceeding

Other Submissions

Allied Hydro Council of British Columbia

The Allied Hydro Council of British Columbia (AHCBC) generally agrees with BC Hydro stating that the availability of surplus power could be a benefit rather than a negative factor. It points out 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. AHCBC also raises the possibility of an opportunity for power exports to Alaska. Alaska is a large region with minimal power generation (mainly diesel generation at costs averaging $350 MWh) and transmission structure and the state is not connected to the North American grid. AHCBC notes that BC Hydro has recently completed the Northwest Transmission Line which runs close to the Alaska border and there is a potential for the two systems to be connected.

Bakker

With reference to Mid C price forecast provided by BC Hydro in the 2017-2019 Revenue Requirements proceeding Dr. Bakker 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.

Dr. 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.[310]

CEABC

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

CEABC also notes that there are constraints to capacity sales revenue stating "[T]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". [311]

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.[312]

Panel analysis and preliminary findings

BC Hydro has presented an explanation of how it might handle surplus energy and capacity in the event there is not a requirement for the additional domestic load when Site C comes on line. BC Hydro is very optimistic that in these circumstances it has the ability to optimize the trade benefits through its subsidiary, Powerex.

[310] F106-2 Submission, p. 58-59.
[311] F18-3 Submission.
[312] BC Hydro 2013 IRP Application, p. 5-47.

BC Hydro has demonstrated the potential value of capacity and flexibility as compared to an intermittent wind or solar source. However, BC Hydro has not provided any evidence to support the notion that other Pacific Northwest or Alberta utilities are actively seeking to purchase this capability now or in the future. The Panel notes that BC Hydro currently forecasts a capacity surplus prior to completion of Site C for 2018 through 2022. This gives rise to the following questions: Has BC Hydro pursued the sale of this surplus in other jurisdictions? If so what have been the results? It may be that the concept is so nascent that there are no market examples of where this potential opportunity is currently being exploited. Accordingly, the Panel asks that BC Hydro address this in future submissions and provide any evidence that a market exists or acknowledge that this potential is speculative at this point in time.

BC Hydro has provided forecasts for Mid C market price estimates going forward through 2036. The Panel finds that BC Hydro and Deloitte estimates are decidedly different but both agree there is always a potential for projections to differ from what actually occurs. The Panel agrees and remains concerned as to the reliability of future forecasts. Given the variance in Mid C forecasts the Panel finds it premature to reach any conclusions on the future demand for surplus energy. Accordingly, specific questions have been developed to assist the Panel in understanding the current saleability of surplus energy and any potential impacts on future projections for energy sales in the event an energy surplus exists. These, among others are listed below.

AHCBC raises the issue of transmitting power to Alberta and the potential for a transmission line from Site C to Alberta. The Panel notes that any large surplus of energy resulting from Site C would require transmission in the event it was sold to another utility. CEABC have also raised the issue of available transmission capacity. BC Hydro is requested to address whether this will result in the need for additional transmission capability to move surplus energy from Site C to other utilities.

The Panel notes that BC Hydro made a number of statements with respect to the potential for export sales in the 2012 Draft IRP. Specifically, BC Hydro states that "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. These included the following:

- recent increases in renewable energy resources in the Western Interconnection;
- the persistence of tax incentives available to U.S. producers; and
- the enactment of renewable energy portfolio standards in potential markets (with specific reference to California that excludes many renewable B.C. resources).[313]

BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow.

The Panel requests that BC Hydro respond to the following questions:

- **Please provide a breakdown BC Hydro's market price forecast for F2025 (US $36/MWh) and F2034 (US $46/MWh) showing (in Can $ and US $): Mid C price; wheeling costs; real power losses; other (please describe).**
    - **Please explain whether (i) the market price forecast assumes the Mid C price is set by a CCGT; (ii) whether Mid C prices over the past 5 years support this assumption, and (iii) to what extent lower price renewables may increasingly set the Mid C price at lower levels in the future.**

[313] BC Hydro 2012 IRP Application, p. 7-14.

- **Please provide, in graph and table form, the average annual Mid C price (on-peak, off-peak and all hours) for the last 20 years.**

- **Please provide in graph and table form, for each year from F2013 to F2017, a comparison of (i) the average all hours Mid C price for that year and (ii) the $/MWh price that BC Hydro received (after transaction costs, such as wheeling and power losses) for the sale of its surplus energy.**

- **Please provide, in graph and table form, for each year from F2015 to F2017, the monthly all hours, on-peak and off-peak Mid C price.**

- **Please describe the energy and capacity markets in the US and Alberta that BC Hydro considers it will be able to participate in.**
    - **Please describe any key difficulties BC Hydro might face in participating in the US and Alberta market, such as access to transmission and regulatory approvals required.**
    - **Please explain if any of BC Hydro's key export markets (such as California, Alberta) have, or are currently considering, legislative or regulatory requirements that would restrict BC Hydro from selling into their markets (such as self-sufficiency requirements, renewable compliance market), or the price BC Hydro could offer (such as a requirement to bid in at zero).**
- **Please provide in table form the percentage of total annual generation expected from Site C for each month of the year.**
    - **Using the monthly delivery factor adjustments included in BC Hydro's SOP program, please provide an estimate of the seasonally adjusted value of Site C energy, using a starting (pre-seasonally adjusted) value of $45/MWh. Please show supporting calculations.**
- **Please provide additional details on the transmission line to (a) the US and (b) Alberta, including (i) the maximum rating (for BC exports), (ii) the extent to which it is constrained to a lower level (and if so what is the lower level); (iii) how much firm and non-firm transmission capacity is generally available; and (iii) what percentage of the time the transmission line is on average constrained.**
- **Has BC Hydro considered restoring the capacity of the tie-line to Alberta? Similarly, has BC Hydro considered building additional transmission capacity to the US? Would either of these transmission projects offer additional economic opportunities for the sale of surplus energy/capacity provided by Site C? Please elaborate.**
- **With regards to the flexibility benefits of Site C, please explain whether technological advances could impact the market value of these flexibility benefits (for example, advancements in smart inverter technology).**
- **Please describe rough load zones, no run zones and minimum generation constraints (e.g. transmission reliability, hydraulic balance, fisheries requirements, ice flows etc…). Is Site C or its generators expected to have these restrictions? If so, what are they and how will they effect Site C's operations and flexibility? If not, why not? Please elaborate.**
- **Please describe synchronous condense. Are any features of synchronous condense related to the ability to make adjustments from high generation levels to no generation without a start/stop? If so, what are they? Please elaborate.**
- **Please elaborate on how the design decision to include synchronous condense in all six generating units is related to the opportunity to sell the capacity and flexibility afforded by Site C.**
- **Has BC Hydro analyzed selling Site C's surplus energy and capacity within BC at discounted rates to incent incremental consumption (i.e. similar to the Freshet Rate pilot)? If so, please elaborate. If not, why not?**

- **Please discuss the potential implications and impact of Powerex joining, or potentially not joining, the Energy Imbalance Market and how that relates to the value of Site C energy and capacity. Include an analysis and discussion of the potential impact resulting from an expansion of Energy Imbalance Market.**

6.0 Resource and generation alternatives

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?

In this section we review various energy portfolios that may be a substitute for Site C energy. We consider the portfolios presented by BC Hydro and Deloitte. We also consider the Unit Energy Cost approach put forward by BC Hydro. We then consider the potential resources that make up those portfolios, along with other sources that could potentially be considered.

6.1 Definitions and assumptions

Before beginning the analysis of resource alternatives, the Panel will consider the definitions of terms used in the question posed in section 3(b)(iv) of the OIC.

BC Hydro submits that at a basic level, providing reliable service requires both:

1) having enough electricity resources (e.g., hydro, wind, solar, biomass) to meet the total requirements of its customers (called "energy" and measured in gigawatt hours per year); and
2) ensuring that the electricity system has resources that are available when customers need them.

Meeting the latter requirement means having adequate resources with the following characteristics: dependable capacity, firming capability, shaping capability and storage capability.

BC Hydro notes that three of these characteristics are referenced in the Terms of Reference. BC Hydro also provides the following definitions:

Dependable capacity (measured in megawatts (MW)) is the ability of resources to ensure they are available when customer load is at its greatest, typically cold winter evenings. Large hydro, biomass, pumped storage, demand-side management and gas-fired generation provide dependable capacity. Variable resources like wind, solar and run-of-river hydro, the output of which depends on environmental factors, do not have this capability;

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.[314]

In addition, BC Hydro states that "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced".[315]

Panel analysis and preliminary findings

The Panel adopts the above definitions of firming, shaping, storage and Unit Energy Cost for the purpose of section 3(b)(iv) of the OIC.

We have made the following assumptions with regard to additional terms in the question posed above:

1. *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.
2. *Grid reliability* means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards.
3. *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.

The Panel invites comment on the interpretations above.

6.2 Generation alternatives

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.

In Appendix A, the Panel reviews the submissions and makes the following general findings (please see the appendix for further detail):

3. **Biomass, geothermal, solar and battery storage are potential candidates for alternative generation and should be considered by BC Hydro.**
4. **Costs modelled by BC Hydro for wind may understate the decrease in capital costs expected over the next 20 years.**

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.

6.3 UEC analysis of Site C and an alternative portfolio

The OIC requires the Panel to determine whether an alternative portfolio is available to ratepayers at similar or lower *unit energy costs*.

[314] F1-1 Submission, pp. 41-42.
[315] F1-1 Submission, p. .61.

BC Hydro submission

BC Hydro states that it has prepared a simplified unit energy cost comparison of clean or renewable energy and capacity resources that is similar in its energy and dependable capacity output, that it refers to as a Block UEC Analysis. It then compares the UEC of Site C to the UEC of that block.

It describes the block of alternative energy - the "alternative block", as "generally wind". However, comparing the table showing the cost of the alternative block on page 62 (of F1-1) to the Figure L-5 on pp. 19-21 of Appendix L to F1-1 Submission, it appears that BC Hydro is actually using the cost of wind as a proxy for the cost of the "alternative block" even though it states that "[a]ny alternative to Site C must be comprised of a collection of energy resources and "backstopping" from other dispatchable resources with firming, shaping and storage capability".[316]

BC Hydro provides no other description of the methodology underlying the UEC Analysis".[317]

With regard to the benefits of Site C, BC Hydro submits:

- Our long-term planning considers many factors in determining a preferred portfolio including system reliability requirements, resource viability and delivery risk, resource cost-effectiveness, and greenhouse gas emissions;
- Our Current Load Forecast shows growth, even in the "low load" scenario. Initiatives targeting greenhouse gas emission reductions through electrification could drive a substantial additional need for clean and reliable electricity;
- Without Site C, we forecast needing new capacity and energy resources by F2023 and F2028 respectively. Meeting dependable capacity needs will continue to be one of our most pressing concerns for years to come;
- We are planning for a clean energy future. Integrating variable (or intermittent) resources like wind, run-of-river hydro and solar require dependable and flexible resources like Site C as a "backstop." These are the "firming; shaping; storage; grid reliability" benefits referenced in the Terms of Reference, and Site C is unmatched in this regard by any alternative resource;[318]

BC Hydro appears to add or subtract various amounts from the UEC of both Site C and of the Alternative Block to account for these benefits.

BC Hydro's results are summarized below:

Table 26: BC Hydro's Unadjusted and Adjusted UEC

Source	UEC Before Adjustments ($/MWh)	Adjusted UEC ($/MWh)
Site C	$83	$34
Alternative Block	$85	$153

[316] F1-1 Submission, p. 57.
[317] F-1 Submission, p. 61.
[318] F-1 Submission, pp. 40-41.

CEABC submission

CEABC submits that the UEC is "a proxy number intended to allow widely differing projects to be ranked on the same scale of cost per MWh. It does create that ranking, generally speaking, but it is oversimplified. It can introduce a number of distortions into the comparison of projects, if all the underlying assumptions are not fully recognized when making project comparisons."[319]

CEABC continues, saying that the shorthand way used by BC Hydro to calculate this value is referred to as the 'annualized cost method'. This method simply converts the initial capital cost to a level annuity payment at the real cost of capital. Then annual operating and maintenance costs, taxes, etc. (in real dollar amounts) are divided by the Average Annual Energy (in MWh) and added to the capital annuity value to obtain an overall unit cost for the energy.[320]

Panel analysis and preliminary findings

We will discuss the Site C and Alternative Block UECs in the subsequent sections of this report. **In these sections we find that the assumptions underlying the derivation of both UECs are not well documented enough to be able to make any finding concerning:**

- **The alternative portfolio proposed is indeed the least cost of all possible alternative portfolios; and**
- **The unit energy cost of either Site C or the alternative portfolio.**

Based on the data and analysis available at this time, the Panel finds that the Site C UEC delivered to the Lower Mainland may be understated and the alternative portfolio UEC delivered to the Lower Mainland may be overstated.

[319] F18-3 Submission, p. 17.
[320] F18-3 Submission, p. 18.

6.3.1 Site C UEC

BC Hydro calculates the Site C UEC as follows:

Table 27: Site C UEC [321]

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**

Cost Factor	Unit Energy Cost $/MWh
Delivered to Lower Mainland in F2018$	
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**

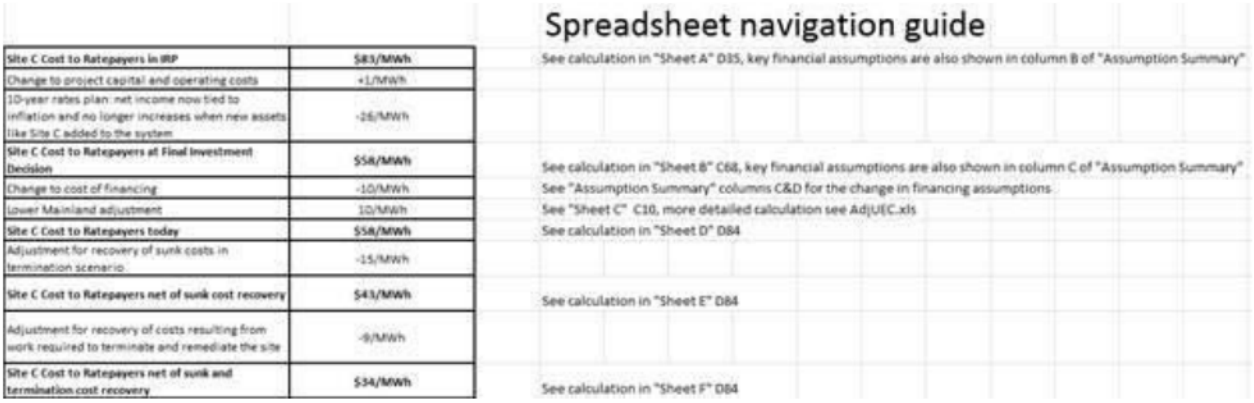
6.3.1.1 BC Hydro response to Panel clarification questions

On September 5, 2017 the Panel requested more information regarding how the Site C unit energy costs in the above table were calculated. In response BC Hydro provided an Excel spreadsheet and noted the "UEC table" tab column E helps the reader navigate the spreadsheets. No more explanation was provided.

The "UEC table" tab provided the following information:

[321] F1-1 Submission, BC Hydro, pp. 62-63

Table 28: "UEC Table"



Site C Cost to Ratepayers in IRP	**$83/MWh**
Change to project capital and operating costs	+1/MWh
10-year rates plan: net income now tied to inflation and no longer increases when new assets like Site C added to the system	-26/MWh
Site C Cost to Ratepayers at Final Investment Decision	**$58/MWh**
Change to cost of financing	-10/MWh
Lower Mainland adjustment	10/MWh
Site C Cost to Ratepayers today	**$58/MWh**
Adjustment for recovery of sunk costs in termination scenario	-15/MWh
Site C Cost to Ratepayers net of sunk cost recovery	**$43/MWh**
Adjustment for recovery of costs resulting from work required to terminate and remediate the site	-9/MWh
Site C Cost to Ratepayers net of sunk and termination cost recovery	**$34/MWh**

The assumption tab included the following information:

Table 29: "UEC Table" Assumption Tab

	2013 IRP/JRP	FID (December 2014)	BCUC Review (Aug 2017)
Site-C Capital	7.9 B	8.35 B	8.35 B
Site-C Economics	70/30	100% Debt Finance	100% Debt Finance
WACC/Discount Rate in Real Dollars	5%	5%	3.90%
Site - C Debt Interest Rate	5.2%	4.7%	3.43%
IPP WACC in real Dollars	7.0%	7.0%	6.40%
$/MWh (F2013$)	**Site C (including sunk cost per 2013 IRP) ($F2013)**	**Site C (including sunk cost & with 100% debt financing) - 4.7% ($F2013)**	**Site C (Excluding sunk and termination cost & with 100% debt financing) - 3.43% - ($F2018)**
UEC at POI	**83**	**58**	**48**
GHG cost Adjustments	0	0	0
Locational Adjustments (CIFT)	6	6	6
Locational Adjustments (Line Losses)	9	6	5
Locational Adjustments (Network Upgrade)	0	0	0
Soft Cost Adder	0	0	0
Firm Energy Adjusters	-2	-2	-1
Wind Integration Cost	0	0	0
Capacity Credits	-11	-9	-11
Adjusted UEC without Capacity Credit	**96**	**68**	**58**
Adjusted UEC with Capacity Credit	**85**	**59**	**48**

Page 1

The "Sheet A UEC at IRP" tab provides the calculations for the $83/MWh "Site C Cost To Ratepayers in 2013 Integrated Resource Plan (November 2013) at Point of Interconnection in F2013$" UEC.

The "Sheet B CoS-FID" tab provides the calculations for the $58/MWh "Site C Cost To Ratepayers at Final Investment Decision (December 2014) at Point of Interconnection in F2013$" UEC. This tab's calculations include the effects of "Change to project capital and operating costs", "Debt Finance as per OIC No.590-2016 Net Income Frozen" and changes due to an increase in energy from Site C from 5,100 GWh to 5,196 GWh.

The "Sheet D UEC Site-C" tab provides the calculations for the $58/MWh "Site C Costs to Ratepayers Today Delivered to the Lower Mainland in $F2018" UEC. This includes the effects of "Updated financing rates and conversion to F2018$". The "Sheet C Lower Mainland adj" tab provides the calculations for the "Adjustment for Delivery to Lower Mainland and annual shape adjustment" which is also included in the "Sheet D UEC Site-C" tab. The "Locational Adjustments (CIFT)" is $6.38/MWh (F2018$), "the Locational Adjustments (Line Losses)" is

$5.32/MWh(F2018$), and the "Firm Energy Adjusters" is -$1.06/MWh (F2013$). This results in a total upward adjustment of $10.64/MWh. However, there were no calculations or explanation as to how these values were determined included in the spreadsheet. The "Sheet C Lower Mainland adj" tab also includes "Capacity Credits" of $10.64/MWh (F2018), again with no calculations or explanation for this value. However, "Capacity Credits" were not used to derive the $58/MWh. Note, in this tab the capacity is increased from 1100MW to 1132.2MW and the energy is increased from 5,196 GWh to 5,286 GWh.

The "Sheet E UEC (Sunk)" tab provides the calculation for the $43/MWh "Site C Cost To Ratepayers Today Less Sunk Costs Delivered to Lower Mainland in F2018$" UEC. Note, the amount shown in this tab is actually $41.52,with no explanation was provided to account for this difference between this number and the $43/MWh in the Site C UEC. This tab includes the effects of "Adjustment For Sunk Costs" and includes approximately $2.6 billion in offsetting sunk costs spread out over the F2020 to F2029 period.

The "Sheet F UEC (Sunk + Term)" tab provides the calculations for the $34/MWh "Site C Cost To Ratepayers Today Less Sunk Costs and Credit for Termination / Remediation Costs Delivered to Lower Mainland in F2018$" UEC. This includes the effects of "Credit for avoiding termination and site remediation costs" and includes approximately $3.75 billion in offsetting sunk and termination costs spread out over the F2020 to F2029 period.

Other parties have identified a number of issues regarding the UEC analysis, and costs associated with Site C energy generally, which we discuss below.

6.3.1.2 Issues with 100 percent debt financing for Site C

Regarding the downward adjustment of $26 per MWh for debt financing, BC Hydro states that with OIC 590, its net income is now a fixed amount. BC Hydro therefore concludes: "the cost to the ratepayer of financing Site C is equal to Hydro's cost of debt."[322]

CEABC raises concerns with debt financing. "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."

CEABC concludes that "[f]or the purposes of doing financial analyses for the Site C project economics there is an assumption of zero return on equity, while for everything else BC Hydro uses the 70/30 WACC methodology (including the 11.84% return on equity), which was used for all the analyses presented during the JRP Review."

CEABC submits that "[n]one of the actual calculations or models used to determine the Site C project's alleged UEC has ever been publicly released, so that all the assumptions and methodology could be reviewed and tested. The BCUC's review of the Site C project must make these assumptions and calculations clear and transparent."

Harry 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.[323]

[322] F1-1 Submission, p. 61.
[323] F36-1 Submission, pp. 18-19.

Prophet River First Nation and West Moberly First Nations (PRWMFN) submits 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. "British Columbia will still pay $83/MWh, but will recover the cost more slowly and from a different set of its inhabitants. For example, the elimination of water rental means less money for British Columbia's general revenues and, eventually, higher taxes for taxpayers". PRWMFN conclude that "[w]ithout a requirement to provide any financial return - because there is no equity with which to provide a return - the unit energy cost can be decreased, but this is the equivalent of a mirage".[324]

6.3.1.3 Impact of the additional project reserve

PRWMFN provide the following table, from the "Site C Final Investment Decision Technical Briefing, December 16, 2014, page 16" that suggests the project reserve adds an additional $2.25/MWhr to the UEC:

Table 30: Impact on Ratepayers – Site C[325]

Impact on Ratepayers – Site C	
Site C Cost to Ratepayers (before changes)	**$83 / MWh**
Under the 10 Year Plan, the amount of net income that BC Hydro is required to earn each year will now be tied to inflation and will no longer increase when new assets like Site C are added to the system.	**- $26 / MWh**
The 10 Year Plan also reduced water rental charges for BC Hydro.	**- $1 / MWh**
The capital cost estimate for Site C has been updated from $7.9 billion to $8.335 billion.	**+ $2.25 / MWh**
Government has established a project reserve of an additional $440 million to account for events outside of BC Hydro's control that could occur over an eight-year construction period, such as higher than forecast inflation or interest rates. The reserve will be managed by the provincial Treasury Board.	**+ $2.50 / MWh (if fully utilized)**
Updated Site C Cost to Ratepayers	**$58 - $61 / MWh**

[324] F107-1 Submision, Appendix Site C Business Case Assumptions Review, p. 5.
[325] Exhibit F107-1, Appendix Site C Business Case Assumptions Review, pp. 4-5.

6.3.1.4 Line losses and capacity credits

CEABC submitted the following table taken from the 2013 Resource Options Update:

Table 31: Resource Options[326]

Resource Option	Project Name	Transmission Region[7]	Average Annual Energy (GWh)	UEC at POI ($/MWh)	Soft Cost Adder ($/MWh)	Firm Energy Adjusters[8] ($/MWh)	CIFT ($/MWh)	Line Losses ($/MWh)	GHG Cost ($/MWh)	Capacity Credit ($/MWh)	Wind Integration Cost ($/MWh)	Adjusted Firm UEC ($/MWh)
				1	2	3	4	5	6	7	8	∑1 to 8
Run-of-River Hydro	ROR_110-120_VI	VI	386	113	6	52	0	-1	0	0	0	169
Run-of-River Hydro	ROR_100-110_KN	KL	217	101	5	64	0	4	0	0	0	174
Run-of-River Hydro	ROR_110-120_NC	NC	135	115	6	54	1	8	0	0	0	183
Run-of-River Hydro	ROR_120-130_VI	VI	116	125	6	54	0	-1	0	0	0	185
Run-of-River Hydro	ROR_120-140_NC	NC	90	125	6	49	1	9	0	0	0	190
Run-of-River Hydro	ROR_120-130_LM	LM	649	125	6	64	0	0	0	0	0	195
Site C	Site C	PR	5,100	83	0	0	6	9	0	-11	0	88
Wind - Offshore	OBC24-1	VI	1892	166	8	-2	0	-1	0	0	10	182
Wind - Offshore	OBC25-1	VI	1347	167	8	-2	0	-1	0	0	10	183
Wind - Offshore	OBC28	VI	1442	181	9	-2	0	-1	0	0	10	196
Wind - Onshore	PC28	PR	591	90	5	-2	2	11	0	0	10	115
Wind - Onshore	PC21	PR	371	92	5	-2	2	11	0	0	10	117
Wind - Onshore	PC13	PR	541	92	5	-2	2	11	0	0	10	117

In this Inquiry, BC Hydro's evidence shows that the Starting UEC for Site C is $83 at the point of interconnection. That is consistent with the chart above. However, in the chart above, adjustments are made for line losses and CIFT. In addition the capacity credit is no longer provided. CEABC asks why BC Hydro does not explain why these adders have been dropped.

6.3.1.5 Climate change risks

Kleana Power Corporation submits the following:

> There is inherent risk to the Public of British Columbia with respect to the development of Site C. Apart from the failure of BCH to provide a comprehensive risk analysis of climate change impacts on Site C, the risk of price escalations (already in evidence) is borne by the public, rather than the private developers and financiers in the case of Kleana (and other IPP's). There is no effective way of eliminating this risk at the budget estimate stage, particularly having regard to preliminary work already underway which would result in "sunk costs". The sunk costs must not be used by BCH to bootstrap its economic arguments for Site C. This simply results in additional "moral hazard" for this project.
>
> In addition to "sunk costs", BCH has a vested interest in keeping Site C "in-house". This makes the need for independent review of costs, contingencies and risk mitigation strategies absolutely essential, along with independent review of same, all of which must be taken into account in budgeting.[327]

[326] F18-3 Submission, CEABC, Appendix 12, p. 21
[327] F53-1 Submission, p. 5.

6.3.1.6 Natural capital

The David Suzuki Foundation (DSF) encourages this Inquiry to consider the impacts of the project on natural capital in the Peace Valley and associated ecosystem services which it submits sustain the health and wellbeing of local communities, contribute to the cultural and traditional ways of First Nations and are worth hundreds of millions of dollars annually in non-market benefits. The DSF provides a report that it describes as peer-reviewed and published research conducted by the David Suzuki Foundation.[328]

The report concludes the following:

> …the ecosystem benefits of natural capital in the Peace Valley and surrounding region are extremely valuable in monetary terms, and in some cases are truly priceless. We conservatively estimated that the ecological services provided by farmland and nature in the Peace River Watershed are conservatively worth an estimated $7.9 billion to $8.6 billion a year – through the cumulative contribution of services such as water supply, air filtration, flood and erosion control, habitat for wildlife and agricultural pollinators, carbon storage and other benefits.
>
> For example, the total annual value for carbon stored in the forests, wetlands and grasslands of the Peace River Watershed is estimated at $6.7 billion to $7.4 billion per year, and the total value for other ecosystem services is estimated at $1.2 billion per year in economic benefits. Carbon storage, carbon sequestration and the habitat value of wetlands accounted for the greatest ecological value per hectare in the watershed. While there is no truly right way to fully value a forest or river, there is a wrong way, which is to give it no value at all in land use decisions, such as whether construction of the Site C dam should proceed or not. Unfortunately, most ecosystem services are ignored or are treated as externalities in the development decisions we make, with the assumption that their degradation or loss will have little or no consequence to our economy or society.[329]

6.3.1.7 Impact on the Peace Athabasca Delta

Mikisew Cree First Nation submit that the Site C Dam, should it proceed, may limit or impede Canada's ability to protect and restore the Peace Athabasca Delta (PAD) as required by Recommendation 4 of the Reactive Monitoring Mission to the Wood Buffalo National Park World Heritage Site or Paragraph 6 of World Heritage Committee decision (Recommendation 4). To do so "may require changes in the operation of the Site C Dam (for example by requiring alterations in the release of water in order to properly restore the PAD) and so may alter the costs of operation of the Site C Dam and the effectiveness of the Site C Dam from a cost-perspective".

However, it acknowledges that Subsection 3(e) of the Terms of Reference for this Inquiry confirms that this Inquiry is not an environmental review of the Site C Dam, and, as such, is not responsive to Recommendation 4 of the Reactive Monitoring Mission to the Wood Buffalo National Park World Heritage Site or Paragraph 6 of World Heritage Committee decision insofar as it does not include a review of the Project's environmental effects on the Peace Athabasca Delta. It submits however, that this Inquiry may be responsive to these recommendations and requests if the Commission advises that the Site C Dam should be terminated and remediated. Such a recommendation, if implemented, would eliminate the risk of adverse impacts to the Peace Athabasca Delta and the associated environmental and social costs of the Site C Dam.[330]

[328] F87-1 Submission
[329] F87-1, Submission, p. 1.
[330] F84-1 Submission, pp 5-6.

Mikisew Cree First Nation also submits that because downstream effects on the Peace Athabasca Delta were improperly scoped out of the Joint Review Panel process, the following costs that may be incurred directly or indirectly by ratepayers were not considered during that review but should be considered here:

a) costs for undertaking the environmental review of the Site C Dam on the Peace Athabasca Delta requested by the World Heritage Centre, IUCN and the World Heritage Committee;

b) costs associated with BC Hydro causing further environmental impacts to the Peace Athabasca Delta and restricting or depriving Indigenous groups (including those of Mikisew Cree, the Athabasca Chipewyan First Nation, Fort Chipewyan Metis, among others) that depend on the Peace Athabasca Delta for their beneficial use of their Treaty entitlements;

c) costs associated with the increased complexity and cost of restoring the flow rates of the Peace River and flooding cycle required to maintain and protect the OUV of the Wood Buffalo National Park World Heritage Site, should the Site C Dam proceed;

d) costs associated with impairments to good will and other assets should the Site C Dam contribute to Wood Buffalo National Park being inscribed on the List of World Heritage in Danger; and

e) increased operational costs associated with ongoing assessments, additional monitoring and operational modifications required to verify and correct potential impacts to the Peace Athabasca Delta from the Site C Dam.

Mikisew Cree First Nation also notes the following:

> …the issue of whether or not the Site C facility constitutes an unjustified infringement of the Treaty 8 rights of certain First Nations has been left to be determined in future proceedings. This raises the very real potential for a future judicial determination that the Site C dam has to be de-commissioned, its operations significantly altered or damages paid.
>
> These costs may be born directly by ratepayers through costs arising from First Nation compensation and/or settlement costs, increased operational costs or litigation costs. Additional costs may be born indirectly by ratepayers through the need for provincial or federal governments to secure funds to cover such costs or address other costs associated when individuals are deprived of their ability to secure their livelihood. In Mikisew's submission, the Terms of Reference for this Inquiry are broad enough to allow the Commission to consider direct and indirect costs to ratepayers.[331]

Mikisew acknowledges that these costs cannot be readily quantified at present, given the lack of an adequate assessment of the effects of the Site C Dam on Wood Buffalo National Park and the limited timeframes for this Inquiry.[332]

6.3.1.8 Other submissions

The Association of Consulting Engineering Companies state that Site C offers "a unique opportunity with benefits that cannot be matched by any other portfolio of generating projects".[333]

The Independent-Contractors-and-Business-Association submit that the Site C project "provides the most cost-effective and reliable incremental resource available to BC Hydro; it has a very low greenhouse gas emission (GHG) profile; and, it provides the best source of both energy and capacity. In other words, while it may be possible to assemble energy derived from a portfolio of smaller scale wind, solar, and other means, these

[331] F84-1 Submission, pp. 8-9.
[332] F84-1 Submission, pp 8-9.
[333] F49-1 Submission, p. 2.

sources are generally not firm, nor are they 'dispatchable' like Site C. Dispatchability is a critical feature setting the Site C Project apart from a smaller scale, intermittent 'portfolio approach' to energy generation which makes energy difficult to store and to reliably draw upon when required".[334]

Panel analysis and preliminary findings on the Site C UEC

The Panel finds that the reduction of the UEC to account for reduced financing costs distorts the analysis of unit energy costs comparisons.

The decision to reduce the financing costs, by transferring some of the financing costs from BC Hydro ratepayers to taxpayers, does not appear to be built into the Alternative Block UEC described in the following section. If two portfolios are being compared, it is important to ensure that the basis of comparison is the same. **The Panel is concerned that if BC Hydro is not applying the same assumed project financing rate to the Alternative Portfolio, the result will not be comparable and furthermore, it assumes that BC Hydro will not be constructing and owning the Alternative Portfolio. This results in an "apples to oranges" comparison. BC Hydro is requested to clarify its financing assumptions.**

The Panel has reviewed the response made by BC Hydro to its request for more information (see A-12 Submission) regarding how the Site C unit energy costs in the above table were calculated. We have the following additional observations and questions:

1. The adders "Debt Finance as per OIC No.590-2016 Net Income Frozen" and "Change to project capital and operating costs" appear to also include the effects of an assumption of an increase in energy from Site C from 5,100GWh to 5,196GWh between the IRP and the FID. **BC Hydro is requested to provide each of these two adders without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.**
2. Similarly, the adders "Updated financing rates and conversion to F2018$" appears to include the effects of an assumption of an increase in energy from Site C from 5,196GWh to 5,286 between the FID and the "Site C Cost To Ratepayers Today Delivered to Lower Mainland in F2018$". **BC Hydro is also requested to provide this adder without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.**
3. The adder for "Adjustment for Delivery to Lower Mainland and annual shape adjustment" appears to be derived from three input parameters: "Locational Adjustments (CIFT)", "Locational Adjustments (Line Losses)", and "Firm Energy Adjusters". **BC Hydro is requested to explain in more detail the assumptions and calculations used to determine the values of these three input parameters.**
4. "Capacity Credits" are included in the Excel spreadsheet but appear to not be used to derive the $58/MWh "Site C Cost To Ratepayers Today Delivered to Lower Mainland in F2018$" UEC. Between the IRP/FID calculations and the "Site C Cost To Ratepayers Today Delivered to Lower Mainland in F2018$" calculation the Site C capacity increased from 1100MW to 1132.2MW. In other locations in BC Hydro's report, Site C's capacity is shown as 1145MW. **BC Hydro is requested to explain in more detail how the specific amount for "Capacity Credits" was calculated/determined, if they are related to the increase in capacity from 1100MW to 1132.2MW or 1145MW, and why they are included in this spreadsheet.**
5. The offsetting sunk, and offsetting sunk plus termination costs of $2.6 billion and $3.75 billion, respectively, spread over F2020 to F2029 were direct inputs to the "Site C Cost To Ratepayers Today Less Sunk Costs" and "Site C Cost To Ratepayers Today Less Sunk Costs and Credit for Termination / Remediation Costs Delivered to Lower Mainland in F2018$" calculations. **BC Hydro is to explain in detail how these annual amounts for both of these direct inputs were calculated from the sunk and termination costs reported elsewhere in BC Hydro's report. Please also comment on the appropriateness of these adders to the UEC given the definition of UEC that the Panel has adopted.**

[334] F45-1, Submission, p. 2.

BC Hydro is requested to comment on whether it is appropriate to add an adjustment to the UEC to account for sales of surplus energy and capacity. Should the Site C cost be reduced by the value of surplus energy sold on the market, with a corresponding reduction in energy volumes?

There is also no adjustment for the project reserve as pointed out by PRWMFN. **BC Hydro is requested to explain why that adjustment has not been made.**

The Panel notes the submission of the David Suzuki Foundation regarding the economic impact of the Site C project on "natural capital". However, there is no analysis of the impact of the alternative portfolio so there is no way for the Panel to include this in its economic assessment. The DSF is invited to provide further evidence on this issue. The Panel is unclear how, or whether, this is a direct cost to ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. **We invite further comment on this issue.**

The Panel finds that if Mikisew Cree First Nation is correct in its submissions relating to either the potential downstream impacts on the PAD (Peace Athabasca Delta) or litigation relating to potential treaty infringements of Site C then this could impact the costs to Site C and ratepayers, and therefore result in an upward adjustment of the UEC for Site C energy. The Panel is unclear how, or whether, this is a direct cost to ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. **We invite further comment on this issue.**

6.3.2 Alternative Block UEC

BC Hydro states: "[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."

The table below shows the UEC for this alternative block as adjusted by BC Hydro. [335]

[335] F1-1 Submission, p. 63.

Table 32: Alternative Block UEC

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**

The chart shown above, described as the UEC of a levelized block, is the same chart provided Appendix L of BC Hydro's submission, illustrating the cost of wind energy.[336]

BC Hydro explains the adjustments as follows:

- -$2/MWh shape adjustment reflects the value of electricity delivered at different time periods;
- $2/MWh cost of incremental firm transmission (CIFT) is a general indication of the long-term cost of upgrading the bulk transmission system;
- $9/MWh line losses adjustment reflects transmission losses for delivery to the load centre;[337] and
- $5/MWh wind integration cost represents the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security as wind power generation is highly variable. [338]

To arrive at the UEC of $153, BC Hydro starts with a UEC of $83, itself a price that is provided with little to no substantiation. Further, there is little explanation of the adders.

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 the resulting calculations can create an apparent price, as shown to the public, which is double the amount actually received by the project.

[336] Appendix L, pp. 19-21
[337] F-1 Submission, Appendix L, p. 20
[338] F-1 Submission, Appendix F, p. 6

CEABC states 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).[339]

6.3.2.1 BC Hydro response to Panel questions

The Panel asked the following question of BC Hydro, subsequent to the filing of its submission (A-12 Submission):

> Regarding Main Submission, pp. 62, 63. Site C Unit Energy Costs and Alternate Energy Resource Unit Energy Costs: Please provide source data, calculations and any assumptions underlying the numerical values in the UEC column.

BC Hydro provided three spreadsheets in response.

The Resource Alternative UEC of $153 is based on a portfolio of wind for energy resources and pumped storage for capacity. BC Hydro then outlined the steps to take to navigate the spreadsheets to arrive at the UEC for the portfolio. BCUC staff reviewed the spreadsheets submitted.

6.3.2.2 Financing costs

CEABC raises two further issues about BC Hydro's UEC/UCC approach to the analysis of alternatives to Site C in the 2013 IRP:

1. The use of two implicit costs of capital; and
2. The fact that projects have greatly differing project life-spans.

Finally CEABC raises the issue of extending UECs beyond the plant gate Adjustment Adders to the Unit Energy Cost – The basic project UECs (the Plant Gate prices) are then augmented to become Adjusted UECs, by means of adjustment "adders" intended to be proxies for certain other costs or benefits which may be incurred by the BC Hydro system.[340]

CEABC submits that the Block Analysis evaluation methodology assembles portfolios of projects, and attempts to calculate the total combined UEC, for comparison to other portfolios that are selected to exactly match the same energy and capacity production. BC Hydro states that "Unit Energy Cost simply expresses the cost for a resource by its levelized annual cost per unit of energy produced."[341]

CEABC submits that "[b]lock Analysis is intended to give an indicative total portfolio UEC for comparison to other portfolios (or, in this case, to the Site C project). However, it is inherently flawed in that it fails to give any consideration to the need or the timing of the various energy and capacity projects, and any necessary transmission upgrades. It still relies on the "adder" adjustments that have been affixed to the individual projects. i.e. it still incorporates the inaccuracies imbedded in the underlying project Adjusted UECs. It is a simplified proxy, used because it is easy to calculate, but it lacks the sophistication and thoroughness of the 3rd form of evaluation."[342]

[339] F18-3 Submission, p. 63.
[340] F18-3 Submission, p. 21.
[341] F-1 Submission, p. 61.
[342] F18-3 Submission, p. 24.

6.3.2.3 Line Losses

BC Hydro states that transmission losses are based on a general set of coefficients developed for the BC Hydro system that shows the expected losses for various regions of the system[343], but provides no further details.

CEABC submits that "it represents transmitting all the energy from each project to the Lower Mainland." However, CEABC claims that loads in other regions are also growing and argues that this allowance appears to be based on looking backward, at past energy flows, instead of forward, at future flows. "Because it is assuming flows that won't necessarily happen, it is again a hypothetical allowance that may never become an actual cash outlay for ratepayers. These hypothetical costs won't become real costs if the system isn't operated that way".[344]

In addition, CEABC is of the view that BC Hydro probably overestimates the losses under average load conditions because the line losses are based on a study done by the BC Transmission Corporation that primarily dealt with peak load losses. It submits that while losses may be this bad, but on the other hand it may be a lot less. [345]

6.3.2.4 Network Upgrades

BC Hydro states this adder as the costs for upgrades typically required between the Point of Interconnection and the Bulk Transmission system and are estimated from past acquisitions.[346]

CEABC argues that any causality seems to be missing, or at least very difficult to establish. Because there is not necessarily any direct link between these upgrades and any specific generation project, these costs are not true incremental costs that would occur directly as a result of the building and operation of any specific project.[347]

6.3.2.5 Cost of Incremental Firm Transmission (CIFT)

BC Hydro states that "[t]he CIFT provides a general indication of the long-term cost of upgrading the bulk transmission system to accommodate the delivery of the electricity from a resource option to the load centre. The CIFT adder for the resource options are based on a general set of coefficients developed for the BC Hydro system that show the expected CIFT for various regions of the system."[348]

CEABC states that "[a]s with line losses, the implicit assumption is that any new energy will not be used in the region where it's generated." It further submits that "[t]he need for bulk transmission upgrades can only be determined from a complete analysis of where the new loads are going to be located and where will be the dependable generation to serve those loads during peak periods… The need for bulk transmission upgrades is largely determined by the location of the large hydro dams that are designated to serve the big load centres during the peak load periods.[349]

6.3.2.6 Wind Integration Charge

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."[350]

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[343] F1-1 Submission, Appendix L, Table L-2, p. 20.
[344] F18-3 Submission, p. 6.
[345] F18-3 Submission, p. 6.
[346] F1-1 Submission, Appendix L, Table L-2, p. 20.
[347] F18-3 Submission, p. 7.
[348] F1-1 Submission, Appendix L, Table L-2, p. 19.
[349] F18-3 Submission, p. 7.
[350] F1-1 Submission, Appendix L, Table L-2, p. 20.

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.[351]

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".[352]

6.3.2.7 Capacity Credit / Adder

BC Hydro points out that alternatives to Site C must be portfolios of alternative resources and states: "Site C will provide energy and dependable capacity with firming, shaping and storage capability. There is no single resource alternative that would provide the same low-cost energy and dependable capacity with firming, shaping and storage capability. Any alternative to Site C must be comprised of a collection of energy resources and "backstopping" from other dispatchable resources with firming, shaping and storage capability".[353]

BC Hydro states that "[t] This adder is calculated based on the fixed cost of pumped storage and the variable costs for operating the project as a capacity resource (18 percent capacity factor). The variable costs is $2/MWh with the rest being fixed cost."

CEABC submits that another related charge that arises in the Block Analysis is the Cost of Capacity Backup. This is something that has never appeared before, in any Resource Options Report, and appears to be a 3rd way of imposing a charge for the same thing, i.e. for providing capacity. In the Block Analysis, a block of energy projects needs to be "topped up" with some capacity projects in order to match a specific comparator, like Site C. What this means is that 3 differential charges are being imposed for providing capacity:

1. Site C is given an $11/MWh credit for having capacity;

2. Each wind project is charged $10/MWh for not having capacity;

3. And, finally, the entire block of projects is charged an additional amount for acquiring the capacity projects to provide its own backup, such as simple cycle gas turbines that will rarely run except on the coldest days of the year, because all dependable hydro will be dispatched first, to avoid the carbon tax, which could equate to $13/MWh or more. This really amounts to triple-charging for the same thing.

It argues that "[t]here is no good reason why this capacity charge should be imposed on a project by project basis or even for a block of projects. Hydro acquires energy projects when it needs energy and capacity projects when it needs capacity. It does not have to acquire a capacity project to back up every energy project. Its need for new capacity is not determined by the acquisition of the energy project. Its need is determined by the growth of its peak customer load (i.e. the total system load on the 4 coldest days of the year), and there are many other possible, and much cheaper, ways to deal with that peak load requirement. The cheapest obvious remedy would be to pay large industrial users for load curtailment. The curtailment is only ever needed on a few days out of the year, and most years it will never be needed at all".[354]

[351] F18-3 Submission, p. 7.
[352] Ibid.
[353] F1-1 Submission, p. 57.
[354] F18-3 Submission, Appendix 4 pp. 6-8.

Panel preliminary findings and analysis

The Panel finds BC Hydro's analysis of the adjusted UEC of the alternative portfolio to be too opaque to be of value in a comparison of costs of Site C to an alternative portfolio and finds the assumptions underlying the UEC to be not well explained. In addition, the particular portfolio that is used for the Alternative Block UEC does not appear to specifically match any of the portfolios provided in Appendix Q. There is only one Alternative Block UEC, although BC Hydro's portfolio analysis, as presented in the next section, models a number of different portfolios, with resources, coming on stream at different times, depending on assumptions of load forecast, DSM and the presence or absence of Site C energy. We will address this issue further in the following section of this report. **We request that BC Hydro explain all assumptions made in its analysis of the UEC for the alternative portfolio.**

Further, BC Hydro should avoid submitting a spreadsheet containing numbers with undocumented assumptions. The spreadsheets that were submitted in response to the Panel's previous request contained a number of such examples, including:

a) The firm energy, columns F and G, are based on calculations which use these monthly energy profiles along with the project capacities, the source for which is undocumented. **BC Hydro is requested to provide this data.**

b) A "soft cost adjustment" of 1.025 is applied. **BC Hydro is requested to explain how and why it selected this soft cost number?**

c) The levelized Mid C market price of $50.36 per MWh is an input to the downward firm energy price adjustment calculation, as is a table which weighs the value of when the generation is expected (super peak, peak, off-peak). **BC Hydro is requested to explain why it used $50.36 per MWh for a Mid C price and why it used these values for super peak, peak and off-peak.**

d) Cost of incremental firm transmission and line losses are upward adjustments. How these numbers are derived is not understandable and therefore not explainable from the inputs and formulas used in the spreadsheets provided. They are based on the inputs and formulas in the lookup table in the "Table of Constants" tab, for each respective project area. **BC Hydro is requested to explain in more detail the calculations for cost of incremental firm transmission and line losses.**

e) Wind integration and network upgrade are both upward adders. However, in contrast to the unexplained inputs and formulas for CIFT and line losses, the wind integration and network upgrade adders appear simply as numbers in this spreadsheet. **BC Hydro is requested to explain in more detail the basis for selecting the amounts for these adders.**

f) Prices are escalated annually by 4% to account for inflation from 2015 to 2018. **BC Hydro is requested to explain why it selected 4% for an inflation adjustment.**

g) **Please explain why the $105/MWh appears to be based on the weighted average of only the first 8 projects listed in the portfolio.**

The Panel finds that the usefulness of the UEC is limited as a comparison methodology because it doesn't appear to take into account when the energy source comes on line. The present cost of a wind farm that comes on line in ten years will be different from the cost today of the identical resource that comes on line today because of the time value of money. BC Hydro is invited to explain how the UEC accounts for these timing issues.

The Panel notes CEABC's comment regarding the assumptions regarding the amount of capital required to "keep the project going for another 20 years". **BC Hydro is requested to explain its assumptions regarding refurbishment of projects in its alternative portfolio and how those assumptions affect the calculation of the UEC.**

A further timing issue is that the costs of many clean energy technologies are decreasing over time – some significantly. If a resource is expected to come on stream in 2030, it may have a lower real cost than a resource being built today. This appears to be a limitation to the UEC analysis provided by BC Hydro. **BC Hydro is requested to address how this assumption is handled in its UEC analysis.**

In contrast to the low financing costs for Site C, it appears that full rate base financing applies to the Alternative Block. If so, this assumption results in an apples-to-oranges comparison. If any capital project undertaken by BC Hydro is also financed by interest, this differential in financing assumptions of Site C vs the alternative portfolio implies that BC Hydro would not build any of the projects in the alternative portfolio. It is not clear why there is this implicit assumption. Further, if this is the case, outsourcing generation projects may result in differences in assumptions about project risk, and may affect the assessment of UEC. **BC Hydro is requested to clarify its assumptions underlying financing costs.**

BC Hydro is requested to comment on CEABC's submission that the wind integration charge "is an allowance to compensate for a possible lost opportunity to sell capacity in the day forward market".

6.4 Portfolio analysis

In this section we review the portfolio analysis that was presented in BC Hydro's submission. The Panel has concerns that, as in the case with the UEC analysis, many assumptions were undocumented. In addition, it is unclear how the portfolio analysis and the UEC analysis described in the previous section are related. We provide more detailed preliminary findings at the end of this section.

6.4.1 BC Hydro's portfolio analysis

BC Hydro states that "Portfolio present value cost analysis (Portfolio PV Analysis) is BC Hydro's main tool to compare resource options, and is standard utility practice for resource planning. It is the proper method for comparing the costs associated with a portfolio that includes completing the Project 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."

BC Hydro states that it has applied its standard portfolio approach to identify alternative resource portfolios that could be pursued without Site C and states that"[n]o alternative portfolio provides similar benefits to customers at a similar or lower cost than a portfolio including Site C".[355]

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. This is important in the context of our comparison for this Inquiry because alternative resources (which provide smaller increments than Site C) would not all be brought in at once. Rather, we have modelled portfolios assuming resources would be acquired in small volumes in response to growth in customer demand. The portfolio 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. This allows BC Hydro to include the value of surplus energy in the markets as an offset to costs;

[355] F-1 Submission, p. 41.

- 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[356] cost of capital of 6 percent (in nominal dollars). Using our weighted average cost of capital as the discount rate is standard practice, and reflects what we use in all of our project applications to the Commission. It ensures that the results are specific to BC Hydro's circumstances, such as the interest rates at which we are able to obtain debt financing for our projects;
- 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;
- 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 inherent in our Portfolio PV Analysis.[357]

CEABC submits that "[a]t least this optimization methodology avoids some of the dangerous oversimplifications of the other two methods. For instance, it selects transmission upgrades and capacity additions as needed by the system, rather than attempting to assign them to specific generation projects. However, even this most costly and sophisticated method still relies on a lot of the same root information taken from the individual project estimates in the Resource Options Database. It will, therefore, carry forward any of the same fundamental flaws that are imbedded in that data. In this method, a complex (and proprietary) optimization *"black box"* is given the inventory of all project options, with all of their underlying energy, capacity, capital and operating cost estimates. It is also given the constraints of the energy and capacity demand forecasts. Then, in order to meet the forecast energy and capacity needs, the model systematically chooses which projects will be added in which years, with the objective of minimizing the 30-year present value of the total portfolio costs.

Also, rather than attempting to add transmission upgrade costs and capacity addition costs onto individual projects, the model simply schedules capacity and transmission projects as they are needed. It can also use the forecast spot market to fill any minor gaps or dispose of any surplus energy. In short, it creates an optimal balanced plan going forward, with generation, capacity, and transmission projects bound together with market sales and purchases so as to minimize the overall present value of all the costs, both capital and operating.[358]

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 have 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 pricing of alternative energy sources
- The pricing of "Natural Capital"
- The economic impact of the dam's effect on the Athabasca delta

The following sections detail these concerns as they have been raised in this proceeding.

6.4.1.1 BC Hydro Portfolio Results

BC Hydro provides results for three portfolios shown below:[359]

[356] F-1 Submission, p. 60.
[357] F-1 Submission, pp. 60-61.
[358] F18-3 Submission, pp. 24-25.
[359] F-1 Submission, Appendix Q, pp. 4 – 14.

Table 33: BC Mid load forecast with current DSM plan transitioning to IRP DSM. Site C completed on current schedule

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

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/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

Table 34: Mid Load forecast with IRP DSM plan. Site C construction suspended until 2024.

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

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_LM	2017 Load Curtailment	85	85			77
2031	BCH_PR	Site C	1145	1,145	5,286	5,286	34+Suspension Costs
2036	BCH_LM	Pumped_Storage_LM	1000	1,000			124
2037	BCH_PR	Wind_PC14	144	37	570	570	92
2038	BCH_PR	Wind_PC20	156	41	594	594	92
2039	BCH_PR	Wind_PC28	153	40	641	641	94
2039	BCH_PR	Wind_PC48	150	39	538	538	95
2040	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_NC	Wind_NC09	333	87	1,074	1,074	101

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2027	Nicola-Vaseux Lake Compensation (NVLC)	SEL to KN	147
2031	Increase series compensation of 5L1, 5L2, 5L7 from GMS to WS	PR to CI	360
2031	Increase series compensation of 5L11, 5L12, 5L13 from WSN to	CI to KN	390
2031	Static VAr compensation at WSN	PR to KN	650
2034	Shunt compensation at NIC and MDN	KN to LM	570

Table 35: Mid Load forecast with IRP DSM plan. Site C terminated

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

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2028	BCH_LM	2017 Load Curtailment	85	85	0	0	77
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_PR	Wind_PC48	150	39	538	538	95
2029	BCH_NC	Wind_NC09	333	87	1,074	1,074	101
2031	BCH_PR	Wind_PC20	156	41	594	594	92
2032	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2033	BCH_PR	Wind_PC14	144	37	570	570	92
2034	BCH_PR	Wind_PC28	153	40	641	641	94
2035	BCH_PR	Wind_PC10	297	77	1,119	1,119	99
2036	BCH_PR	Wind_PC17	102	27	335	335	106
2037	BCH_KN	Wind_SI15	303	79	898	898	108
2037	BCH_REV	Wind_SI12	186	48	586	586	106
2038	BCH_KN	Wind_SI16	660	172	1,814	1,814	111
2038	BCH_VI	Wind_VI02	147	38	446	446	111
2039	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2041	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_PR	Wind_PC19	117	30	482	482	101

6.4.1.2 BC Hydro responses to Panel clarification questions

The Panel requested the following from BC Hydro regarding Appendix Q page 8, Mid Load forecast with IRP DSM plan. Site C terminated (the scenario immediately above):

> *Please provide descriptions of the identified resources (other than Revelstoke and load curtailment). Please include the location of the facility, along with data sources, calculations and assumptions underlying the UEC/UCC values for those facilities.*

BC Hydro responded with a spreadsheet: UEC (BCUC Request).xls, stating that "Resource Options" tab shows:

- the location of the facility (in terms of transmission region – see column B), and
- calculations (see "UEC_UCC tab")

Key assumptions and data sources used to develop this information include:

- Pumped storage assumptions:
  - The pumped storage resource potential was identified by Knight Piesold Consulting in 2010.
  - For modelling simplicity, the least cost pumped storage site (named by the consultant as 'Upper Deserted – Un-named') was used to represent multiple sites in the Lower Mainland region.
  - Cost shown has not reflected energy losses, however this is reflected in the UEC blocks (see below) and BC Hydro's portfolio analysis.
  - Pumped storage is assumed to run at an 18% capacity factor based on assumption of running during heavy load hours during high-use months (November through February).

- Wind Resource Assumptions:
    - Wind speeds based on 10 years of modelled 10-minute wind speed time series (BC Hydro Wind Data Study, 2009)
    - Project location and installed capacity based on GIS analysis (BC Hydro Wind Data Study, 2009; BC Hydro Wind Data Study Update, 2009)
    - Assumed a 3 MW turbine nameplate capacity with a 100 m hub height
    - Applied updated power curves, based on information provided by turbine manufacturers in 2015. Power curves were developed for each IEC turbine class
    - Assumed a 20.4% loss factor (includes losses due to availability, wake effect, electrical, environmental, turbine performance and curtailment)
    - Capital costs are based on line item analysis conducted by Hatch in 2015, and considers impact of project size on capital costs. Based on stakeholder input, BC-wide costs instead of region specific costs are used.
    - Costs based on generic 'best case scenario' site conditions. A 20% increase in CAPEX is applied to sites with challenging topography (identified using Google Earth) to better reflect higher costs associated with building in difficult terrain (vetted by stakeholders).

6.4.1.3 Issues with portfolio analysis

6.4.1.3.1 Issues with the 70 year forecast

CEABC states that "[t]he term used for the Site C Model and Comparative Analysis is from 2024 to 2094 or from 2017 to 2094 as the amounts are being expressed in 2017 dollars. The logic is that the Site C project will be depreciated over a 70 year period which is an accounting concept and the Site C debt will be repaid over the same period. Taxpayer equity is never forecast to be repaid.

This results in the need to make forecasts over the same period the results of which are imputed, where applicable, into the Site C Model and the Comparative Analysis. Some of these required 77-year forecasts are:

1. Government's cost of debt as it borrows on behalf of BC Hydro. This includes forecasting this government's credit rating.
2. The operating and maintenance costs for Site C including major maintenance.
3. BC Hydro's revenue which at a minimum is going to be dependent on forecasts for BC Hydro's electricity prices and load forecast. There are multiple other forecasts that are inherent in the load forecast including the expected provincial economic growth.
4. Inflation.
5. Wind and solar equipment prices which are currently declining and are projected to continue to decline.
6. Currency.
7. Export electricity prices.
8. The Government's return on its investment in BC Hydro.

9. The outcome of BC Hydro's application for a new water licence for the Site C project. A forty year forecast"

In the view of CEABC, forecasts of this type and for 77 years are wild speculation and have no practical value. It points out that the terms of the fully executed Government of Canada arm's length guarantee of some of the debt for the Muskrat Falls, a hydro-electric project in Newfoundland include an amortization period of 35 years.

CEABC submits that instead of the 70 year term assumed in the portfolio analysis, the "[t] erm should be 40 years which is the maximum term of any Government bond issue. The bond market is placing an upper bound on the accuracy of some of the same forecasts that are inherent in the Term of the Model and the Comparative Analysis".

CEABC continues that "[a] Term of 40 years is also the maximum allowable term for the existing water licence for the Site C project, not including the development term, under the Water Sustainability Act 12 (B.C.). It is presumptuous to assume that a new licence will contain the same terms and conditions as the existing licence. There could be major modification or the decision could be made to require the decommissioning of the project because of adverse impacts especially those relating to First Nations Treaty rights or resulting from climate change. There is nothing sacrosanct about a crown corporation owned large run of river hydro project".

CEABC further submits that one of the factors that the BCUC must consider when reviewing the Site C project is technological change and the very high potential that the Site C project will become a stranded asset. This stranding will not be because the demand for renewable electricity will disappear but because there will be cheaper customer self-generation options than the Site C project. It is BC Hydro's customers that will disappear. The technological risk is not exclusive to this project and is applicable to wind and solar projects. However the corresponding term of contract available from BC Hydro which to date has not exceeded 40 years, with large wind installations about 25 years, ameliorates this risk. Lower priced generation can replace higher priced generation at the end of the term of contract. There is no such flexibility with respect to the Site C project until 2094.[360]

Clean Battery Power states that "[t]he cost of renewables, primarily wind and solar energy, have been declining exponentially in recent years. The US Department of Energy reports that since 2008, the (unsubsidized) cost of wind installations per MW has declined by 50%, and since 2010 (unsubsidized) solar costs have fallen 60%. In addition, technological improvement has increased capacity utilization from these technologies meaningfully. A study by McKinsey and Company this year reported that lithium ion battery storage costs declined by close to 80% between 2010 and 2016. Batteries are already an economic means of addressing peaking requirements of less than one hour in duration and providing ancillary services to transmission grids. Most importantly, the time period required to permit and build out a battery farm would be in the order of 12 to 18 months, not 10 years. In contrast, Site C represents a technological "line in the sand" whereby ratepayers would make a significant 100-year bet on a proven but dated technology and forego exploitation of declining costs on new technologies. Clean Balance Power contends that measured increases in capacity and energy over time would preserve the opportunity for ratepayers to exploit technological innovation. This would ultimately result in lower cost and risk to BC Hydro ratepayers".[361]

6.4.1.3.2 The Life of the W.A.C. Bennett Dam

The Peace-Valley-Environment Association questions whether the costs of maintaining and extending the life of W.A.C. Bennett Dam have been adequately considered in the Site C business case. The continued operation of W.A.C. Bennett Dam is integrally linked to the operation of Site C Dam. It points out that "the life expectancy of W.A.C. Bennett Dam is 100 years. Thus it is presently just over half way through its life expectancy and Site C, if

[360] F18-3 Submission, pp. 13-14
[361] F33-1 Submission, pp. 3-4.

built to completion, would only just become operational once W.A.C. Bennett Dam was 58 years old. Site C also has a life expectancy of 100 years, thus my concern that the costs of maintaining W.A.C. Bennett Dam should be included in the overall cost estimates associated with the creation of Site C."[362]

6.4.1.3.3 Issues with the discount rate

CEABC also provide a commentary from the CD Howe Institute regarding "[f]our mistakes [that] are commonly made when evaluating public and private investments." CEABC further states:

> One of these four mistakes is calculating the net present value (NPV) of a given project by using different discount rates, depending on whether the project is carried out by the public sector (lower rate) or by the private sector (higher rate).[363]

A 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.[364]

CEABC submits that "[t]his policy is intended to make life easier for electricity consumers at a time when BC Hydro needs to spend $2 billion a year for a period of approximately 20 years simply to refurbish its capital infrastructure. This was certainly a noble goal (at least from the point of view of BC Hydro ratepayers); however, the consequence is that every dollar saved by the ratepayers is a dollar foregone by the taxpayers. Every dollar of debt not incurred by the electric utility will be incurred instead by the Government."[365]

6.4.1.3.4 Issues with prices for alternative portfolios

Parties also raised concerns about the price of alternative energy sources used in BC Hydro`s previous portfolio analyses.

The Canadian Centre for Policy Alternatives (CCPA) submits that:

> "[t]he ongoing drop in costs for renewables has consistently exceeded the expectations of power utilities. Consider the trends as presented by the International Renewable Energy Association (IRENA):[366]
>
> - The cost of utility scale solar PV fell by 58 percent between 2010 and 2015 to $130 per MWh, but another 59 percent drop to $60 per MWh is 2025 is anticipated due to continued technological improvements, economies of scale and greater competition.
> - Concentrated solar power costs are anticipated to follow a similar trend, falling from $150 per MWh in 2015 to $90 per MWh in 2025.
> - Onshore wind in 2015 was already $70 per MWh and is projected to drop to $50 by 2025, an offshore wind from $180 to $120 over the same period."[367]

[362] F54-1 Submission, p. 1.
[363] F18-3 Submission, pp. 9-10
[364] F18-3 Submission, pp. 9-10.
[365] F18-3 Submission, p. 4.
[366] As cited by the CCPA: Data in US dollars and based on the Levelized Cost of Energy. IRENA, The Power to Change: Solar and Wind Cost Reduction Potential to 2025: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf

CCPA goes on to say that in an earlier (2014) report, IRENA notes that geothermal resources can range from $40– 100 per MWh, and biomass between $50 and $150 per MWh.28 In either case, BC is likely to be on the low end of the cost curve due to abundant geothermal potential and wood waste.[368]

CCPA submits: "A proper apples-to-apples comparison of a wide range of renewable power options— situated in the BC context, addressing idiosyncratic factors like distance to the transmission network, and based on the most recent data—is needed to properly assess any cost differences with Site C."[369]

This should form part of the 2018 Integrated Resource Plan exercise. The upshot is that much rigorous analysis supports the proposition that cost-effective alternatives to Site C exist, and could be more gradually implemented as demand grows. In addition, the economics of those alternatives are likely to become even more favourable if the costs associated with GHG emissions and other environmental factors (land disturbance and impact on agriculture) are included in the analysis".[370]

The CCPA also states that First Nations in BC are taking a leadership role in installing solar and other renewables that displace the need for BC Hydro electricity or diesel power. It cites a recent survey from the University of Victoria[371] that notes that almost half (47 percent) of 105 BC First Nations who responded were involved in clean energy generation to some degree, and that if financing barriers were reduced, this penetration could be even higher. The report specifically flagged BC Hydro for not being more supportive in fostering more such opportunities.[372]

Prophet River West Moberly's expert concludes that "adopting realistic changes from standard and well respected sources makes an enormous difference. Using BC Hydro's assumptions, the difference in cost between the least expensive option and Site C is minimized. Using industry standard assumptions, Site C is more than three times as costly as the least expensive option. In fact, Site C fares poorly when compared to cogeneration, wind, landfill, and coal gasification"[373].

6.4.2 Deloitte's portfolio analysis

Deloitte's findings are provided for the single scenario modeled as part of this assessment. Model outputs are presented below and include the following information:

- Year: The year in which the alternative resource is selected by the MarketBuilder model.
- Alternative resources selected: The alternative resources (supply-side sources of energy and capacity) selected by the MarketBuilder model.
- Generation: Total energy generated by alternative resource (MWh).
- Capacity: Total installed capacity by alternative resource (MW).
- Costs: Capital and O&M costs by alternative resource (mn $CAD).
- Price of energy: Average price of energy provided by the portfolio ($CAD/MWh).
- GHG emissions: Total annual GHG emissions generated by the portfolio (tCO2e).

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[367] F60-1 Submission, p. 13.
[368] Ibid.
[369] Ibid.
[370] Ibid.
[371] Cited by CCPA: 9 D Cook, E Fitzgerald, J Sayers and K Shaw, First Nations and Renewable Energy Development in British Columbia, April 2017: https://dspace.library.uvic.ca/handle/1828/7919
[372] F-60-1 Submission, p. 13.
[373] F107-1 Submission, Appendix Site C Business Case Assumptions Review, p. 17.

The portfolio run results for the base scenario are described in the following categories below:

- Generation (shown below)
- Capacity
- Costs
- GHG emissions

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)
- BC Hydro hydroelectric facilities (new endogenous)
- Biogas (new)
- Geothermal (new)
- Onshore wind – Vancouver Island (new)

Total energy generation is forecast to rise from 67 million MWh in 2018 to 79 million MWh in 2036, as the province remains a net exporter while meeting internal demand that rises from 57 million MWh to nearly 74 million MWh over the same period. The majority of this energy will continue to be generated by existing and committed BC Hydro assets. However, the total share of electricity being generated by these existing and committed BC Hydro assets will fall from about 70% in 2018 to approximately 62% in 2036 as new generation comes online to meet increasing demand. Most EPAs are assumed to renew. Consequently, generation from EPAs fall only slightly through the forecast. New generation is expected to account for about 13% of generation by 2036, from a combination of new geothermal, biogas, onshore wind, and hydro expansions.

The generation mix in British Columbia is expected to change over the forecast horizon, as new sources of generation are added. Total hydro generation in the province (from existing units, committed units, new units, and EPAs) is forecast to grow ~6% in absolute terms over the forecast horizon. Hydroelectric market share is forecast to drop slightly form 91% to 81% by 2036, but it is expected to remain the dominant source of power in the province. Generation from biogas and onshore wind increase as incremental capacity is added. Geothermal is the largest source of new generation, accounting for about 10% of total generation by 2036.

Figure 10: Cumulative Energy Generation by Existing, Committed, and New Sources by Year (2018-2036)

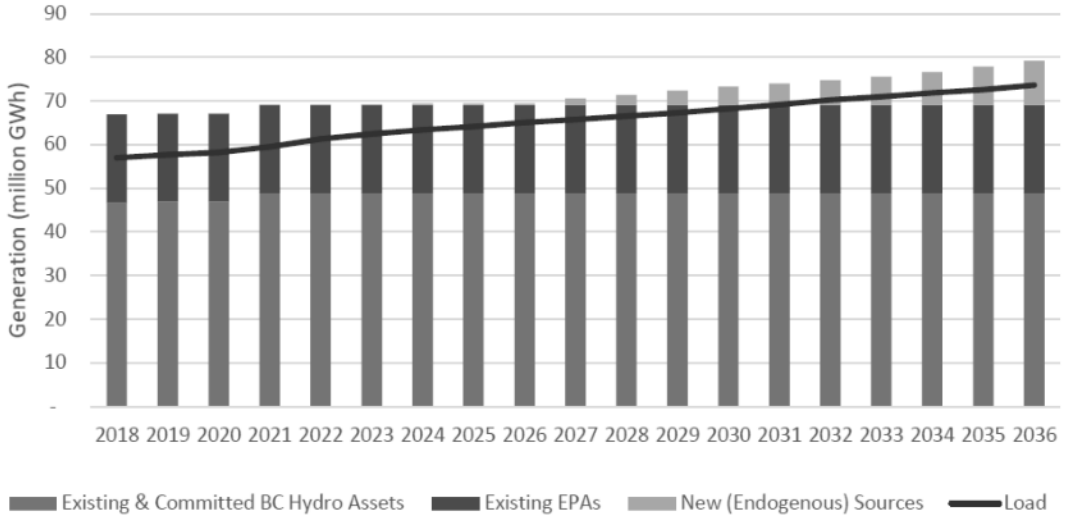
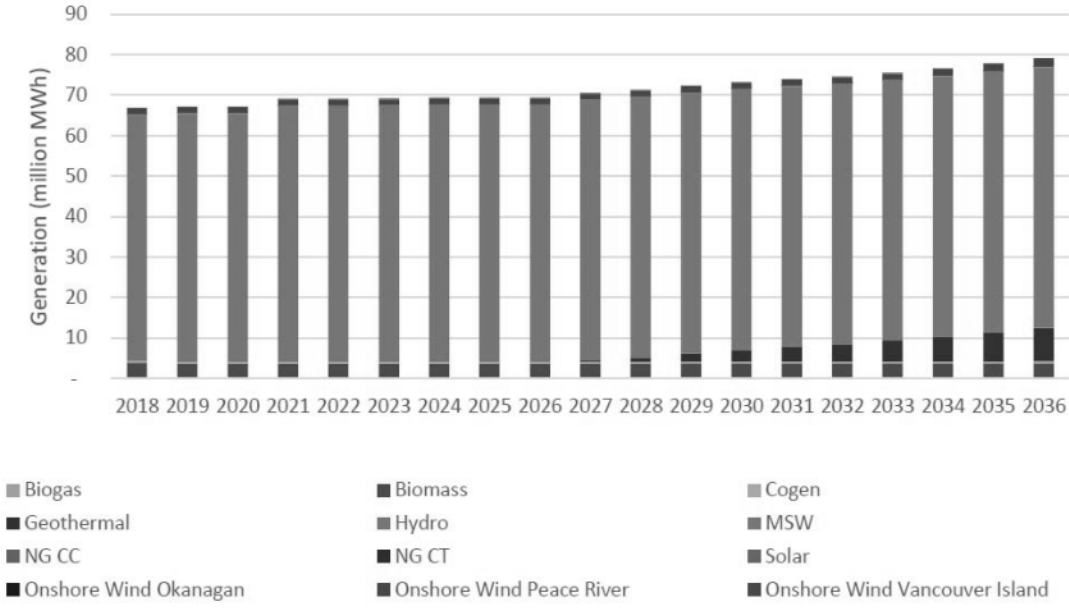


Figure 11: Cumulative Energy Generation by Resource Type by Type (2018-2036) for all resources (existing, committed and new endogenous)



Total energy generation from the portfolio reaches 79 million MWh by 2036.[374]

Panel analysis and preliminary findings

The Panel finds the assumptions used by BC Hydro are not as well documented as they need to be to allow us to make any findings regarding the appropriateness and cost of alternative portfolios, in particular in the development of the assumptions of energy sources. This is a similar concern as we expressed in regard to the derivation of the UEC. There are no capital, O&M, taxes, etc. cost assumptions provided for these sources. Further, the only costs identified in the portfolio analysis results are UECs. Each result of the portfolio model

[374] A-9 Submission, pp. 103 – 104.

shows the UEC of each individual project – it isn't clear whether the UEC is an input or an output to the portfolio run. It also isn't clear whether the same assumptions apply to the derivation of the UEC and to development of the portfolio.

The additional information provided clarifies some of these questions, although some questions remain. In particular, the cost assumptions, as shown in the table above, are fixed – that is they are the same whether the resource they are associated with comes on line in 2024 or in 2041. We will be discussing wind energy pricing further in Appendix A of this Preliminary Report. One of our comments on the derivation of the UEC in the previous section is that in all likelihood, the capital costs of wind energy are likely to decrease over time. This assumption does not appear to be built into this analysis either. **BC Hydro is requested to clarify the portfolio assumptions.**

BC Hydro provided 11 different portfolios, corresponding to the following scenarios:

- Mid load forecast with current DSM plan transitioning to IRP DSM. Site C completed on current schedule;
- Mid Load forecast with IRP DSM plan. Site C construction suspended until 2024;
- Mid Load forecast with IRP DSM plan. Site C terminated;
- Low load forecast with current DSM plan transitioning to IRP DSM. Site C completed on current schedule;
- Low Load forecast with IRP DSM plan. Site C construction suspended until 2024;
- Low Load forecast with IRP DSM plan. Site C terminated;
- High load forecast with current DSM plan. Site C completed on current schedule;
- High Load forecast with current DSM plan. Site C construction suspended until 2024;
- High Load forecast with current DSM plan. Site C terminated;
- Electrification scenario. Site C completed on current schedule; and
- Electrification scenario. Site C terminated.

None of the resulting portfolios appear to be the portfolio analyzed by BC Hydro to determine the alternative portfolio UEC. It is the Panel`s understanding that the portfolio analysis determines the lowest cost portfolio (subject to constraints such as GHG emissions) and from that a UEC can be derived, taking into account the projects that make up the portfolio and the dates in which they come into service. **BC Hydro is requested to clarify which portfolio(s) were used in its alternate portfolio UEC calculation.**

Deloitte's portfolio analysis results included a significant amount of geothermal energy. Understandably, BC Hydro's portfolio results didn't include geothermal because this resource was screened out of BC Hydro's analysis. As noted elsewhere in this report, **the Panel finds that geothermal, biomass, solar and battery storage may be viable alternatives and requests that BC Hydro rerun its portfolio analysis with these alternatives included.**

The Panel has commented previously on the fact that BC Hydro hasn't incorporated a reduction in the real capital cost of wind energy facilities over time. **BC Hydro is requested to model a reduction in the capital cost of wind energy as follows:**

Table 36: Percent Reductions in Capital Cost of Wind Energy

2020	2025	2030	2035	2040
10%	25%	30%	40%	45%

The Panel has commented on BC Hydro's assumptions regarding the costs of solar energy. **BC Hydro is requested to model a capital cost of solar energy of $1.64/W in 2017, and a reduction of 60% in the capital cost by 2040.**

The Panel has also commented on BC Hydro's assumptions regarding the costs of battery storage. **BC Hydro is requested to update the current battery cost and to incorporate the assumption that the cost of battery storage falls by 50% by 2040.**

For these analyses, BC Hydro may focus on the following scenarios:

- **Low Load forecast with IRP DSM plan. Site C terminated**
- **Mid Load forecast with IRP DSM plan. Site C terminated**
- **High Load forecast with IRP DSM plan. Site C terminated**

Deloitte's portfolio analysis outputs include a schedule of the capital and O&M costs by alternative resource and the price of energy produced by the portfolio. However that information does not appear to have been provided with the results of BC Hydro's portfolio analysis. **BC Hydro is requested to provide this information for its portfolio analyses.**

The Panel notes CEABC's concerns about the 70 year modelling period that it is difficult to forecast costs over a period this long. In addition, there are possible risks that occur over the longer term. Potential disruptors include: decreasing prices of alternative energy sources such as wind, solar, batteries; improvements in energy efficiency, (for example LED lights, net zero energy home), LNG industry development risk, persistent low price of natural gas etc.

The Panel notes the approach to establishing a discount rate suggested by the CD Howe Institute – that the discount rate should be based on an analysis of a project's risks. However BC Hydro has presented no such analysis here. Instead it states that it used a 6 percent nominal discount rate for present value calculations in this filing. The 6 percent nominal discount rate was derived using the weighted average cost of capital (WACC) methodology that BC Hydro has employed since 2008. **BC Hydro is requested to explain whether it has considered the relative risk of the projects in the alternative portfolio. Parties are also requested to provide comment on the approach to the discount rate recommended by the CD Howe Institute.**

There appears to be an implicit assumption that of the projects considered in the portfolio analysis, only Site C would be constructed by Hydro and the alternatives would be built and operated by IPPs. If that is the case, IPP projects should be less risky to BC Hydro ratepayers and therefore should have a lower discount rate. However, at the same time, the cost of capital to an IPP may be greater than to BC Hydro.

Given the future incremental portfolio after the successful completion of Site C, how valid is the assumption of no real rate increases given the cost of the incremental additions? BC Hydro is requested to respond to this question.

BC Hydro's portfolio results show new resources are added up until, at the latest, 2041.However, BC Hydro's modelling period is 70 years. It is unclear how BC Hydro is modelling the life of the alternate projects, and what assumptions are made as the projects reach the end of their book life. In this regard we note the concern of

CEABC that "for a wind project, probably close to 50% of the of the total initial capital will not need to be re-spent to keep the project going for another 20 years (only the mechanical and electrical elements will wear out)." [375] **BC Hydro is requested to provide clarification of the assumptions it applied regarding the life of alternative projects and if it has considered whether the useful life, with refurbishment, of certain components of the alternative projects may extend beyond the assumed depreciation period.**

[375] Exhibit F18-3, p. 20

7.0 Cost to ratepayers of completion, suspension and termination and mechanisms for recovery

The OIC asks the Panel to evaluate the costs to ratepayers of suspending or cancelling the Site C project and to address the potential mechanisms to recover these costs. The Panel notes that any budget overrun in the project would also potentially be borne by ratepayers, and consequently we seek to evaluate this impact. The Panel also addresses the cost to ratepayers of completing the project under different cost scenarios.

BC Hydro uses its Regulatory Rate Impact Model (RRIM) as its baseline to estimate the "total revenue requirement over the fiscal 2018 to fiscal 2094 period", since F2094 represents the end of the 70-year economic planning life of Site C"[376]. It then goes on to estimate the incremental impact to ratepayers of suspension and cancellation of the Site C project under different financial assumptions. BC Hydro's base case assumes that Site C will go into service in 2024[377] at a cost of $8.335 billion, the approved budget for the project without Treasury Board reserve.

7.1 Cost to ratepayers of completion

The Panel notes that BC Hydro has stated that a delay of the river diversion from 2019 to 2020, which would delay the in-service date of Site C until 2024, would cause the budget to be exceeded. It appears that this contradicts the assumption made in the base case of the RRIM analysis. **The Panel asks BC Hydro to confirm that the assumption made in its RRIM analysis that Site C is delivered in 2024 and within the budget of $8.335 billion is both reasonable and internally consistent.**

The total revenue requirement from F2018 to F2094 is estimated as follows:

> In the Base Case, rate increases are assumed to increase by 3.5 per cent in fiscal 2018, 3.0 per cent in fiscal 2019, and by 2.6 per cent each year from fiscal 2020 to fiscal 2024, consistent with the 10 Year Rates Plan. For years after fiscal 2024, BC Hydro has assumed for the purposes of this analysis annual rate increases equal to inflation of 2.0 per cent.[378]

The Panel assumes this to mean that BC Hydro is expecting the cost of Site C, implemented in 2024 at a cost of $8.335 billion, to be reflected in the total revenue requirement calculated on the basis above. Thus, it follows that if Site C were to be delivered in a year other than 2024, or for a cost other than $8.335 billion, there would be cost impacts to ratepayers.

In its description of the RRIM[379], BC Hydro does not refer to which load forecast it assumes. This is a critical assumption, since the load forecast determines the amount of energy that is needed and the time at which it is needed should Site C not be built. **The Panel asks BC Hydro to confirm that it has used its mid forecast from the F17-F19 RRA in this RRIM analysis.**

The Panel asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using each of the mid load forecast, the low load case and the high load case from the F17-F19 RRA for the following scenarios:

[376] F1-1 Submission, Appendix R page 1
[377] Ibid., Appendix R p. 4
[378] Ibid, Appendix R p.4
[379] Ibid., Appendix R

- **Site C goes into service in 2023, the current PMB schedule, at a cost of $8.335 billion;**
- **Site C goes into service in 2024, the current FID schedule and one year later than the current PMB schedule, at a cost of $9.169 billion, being 10 percent over budget[380];**
- **Site C goes into service in 2024 at a cost of $10.002 billion, being 20 percent over budget[381]; and**
- **Site C goes into service in 2023 at a cost of $8.335 billion, and the capital costs are amortized over 40 years rather than 70.**

For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM scenario assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.

7.2 Cost impact on ratepayers of suspension

BC Hydro has considered two scenarios when calculating the cost impact of a suspension on ratepayers. One scenario option would be to restart the project in late 2024 as has been explored while the other would be to terminate the project at the end of 2024 or sooner. Each of these has significantly different financial implications and the impact of these costs correspondingly also differs.

Because the OIC Terms of Reference make reference to the suspension scenario as maintaining the "option" to resume, it contemplates a number of years passing before a decision is made to resume the project or take other action. BC Hydro states that the accounting rules under which it operates stipulates that a suspension would result in it being required to write-off or expense approximately $3 billion immediately.[382]

BC Hydro's analysis assumes a decision to suspend would be made by the end of 2017 and provides Table 37 outlining the project related costs by category and the default accounting treatment under its accounting rules.

[380] $8,335 million * 110%
[381] $8,335 million * 120%
[382] BC Hydro states it is required to follow Prescribed Standards pursuant to Government regulation. It notes that further information on such requirements is available in Section 8.12 of BC Hydro's Fiscal 2017-2019 Revenue Requirements Application.

Table 37: Project Related Costs by Category and Default Treatment Under Accounting Rules[383]

	Cost Category	Estimated Amount ($ Billion)	Description	Default Accounting Treatment Under Accounting Rules
1	Project Capital Costs Between FID and Suspension Date	1.6	Forecast project costs to December 31, 2017	Write-off at the time of suspension.
2	Pre-FID costs already in Site C Regulatory Account	0.5	Forecast balance to December 31, 2017	Write-off at the time of suspension.
3	Suspension-related Costs	0.9	Forecast costs	Costs to meet BC Hydro's legal or constructive obligations incurred as a result of suspension (e.g., payments to contractors) would be recognized as an expense at the time of suspension.
4	Maintenance Costs	0.3	Forecast costs	Costs to meet BC Hydro's legal or constructive obligations (e.g., to keep the site safe, to meet environmental requirements) as well as other costs not categorized as Suspension-related Costs (i.e. item 3 above). These costs would be expensed as incurred.
	Total Estimated Direct Project-Related Costs	3.2		

*Numbers above do not add due to rounding

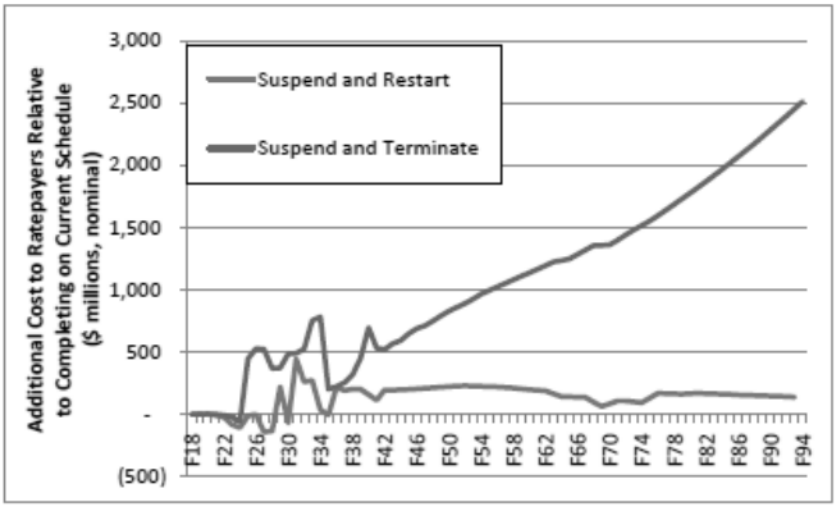
In order to recover these costs approval to use the Site C regulatory account for recovering these costs would be obtained. Estimated project capital costs up to the suspension date ($1.6 billion) and forecast suspension related costs ($0.9 billion) would be deferred to the Site C regulatory account and added to the $0.5 billion in pre-FID costs already there bringing the balance to $3 billion. Maintenance costs would be expensed as incurred and added to the account over the suspension period. BC Hydro points out that the Site C Regulatory account would continue to attract interest reflective of carrying costs. By the end of 2024, assuming the project did not proceed the account balance would total $3.9 billion while if the project did proceed with the projected delayed in service date of 2031, the amount would climb to $5 billion.[384]

If construction were to resume at the end of F2024 BC Hydro states that the balance of $3.9 billion would stay in the regulatory account and attract interest until Site C came into service. At that time BC Hydro would propose to recover the estimated $5 billion account balance over the 70 year economic planning life of Site C. Consistent with regulatory principles this will allow the costs to be matched with the period of benefits that ratepayers obtain. As outlined in section 4.2 of this report, 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.

Figure 12 graphically shows the additional cost impact to ratepayers as compared to completing the project on the current schedule for both the suspend and restart and suspend and terminate scenarios. In its calculations

[383] F1-1 Submission, p. 88.
[384] F1-1 Submission, pp. 88-89.

Figure 12: Annual Ratepayer Impact of Site C Suspension[385]



BC Hydro has included the impact of all costs to complete construction of Site C under this scenario plus the following:

- Site C operating costs beginning in F2032.
- Future sustaining capital expenditures through 2094.
- Estimated incremental costs of procuring alternative higher cost energy and capacity that would be required to meet customer requirements until the later in service date (inclusive of increased DSM efforts). The additional costs total $1.4 billion[386]

Under the suspend and restart scenario BC Hydro states there is a relatively steady cost increase to ratepayers due to the additional cost. Table 38 below shows BC Hydro's estimated incremental impact on cumulative rate increases under this scenario and the incremental impact on revenue requirements from customers. The rate impact analysis conducted indicates that the most significant incremental impact to ratepayers will be in 2032 which is the first year the suspend and restart scenario will impact customer rates. This scenario results in incremental cumulative increases in F2024 of 1 percent and 2 percent in F2094 over and above any general rate increases.

Table 38: Incremental Rate Increases and Ratepayer Costs - Suspension[387]

	Estimated Incremental Costs F2018-F2094 ($ billion)		Est. Incremental Cumulative Rate Increases (%)		
	Nominal	Present Value	in F2024	in F2032	in F2094
Suspend Site C, maintain site, resume construction and complete Site C	9.6	1.1	1	12	2
Suspend Site C, maintain site, terminate Site C, remediate, acquire alternative resources	82.6	7.3	1	13	40

[385] F1-1 Submission, p. 92.
[386] F1-1 Submission, Appendix R, PP. 8-9.
[387] F1-1 Submission, p. 93.

BC Hydro estimates that ratepayers would pay an estimated additional $9.6 billion (nominal) over the 70-year Site C economic life period. In developing its estimate, BC Hydro affirms it considered only those incremental costs to ratepayers associated with this suspension scenario including:

- Project related costs as well as amortization, operating costs, finance charges and other costs that would occur later if construction were to resume at a later date.
- Any incremental costs of acquiring alternative resources, including generation and demand side management.

Panel analysis and preliminary findings

The Panel accepts that the rate impacts estimates by BC Hydro in the suspend and restart scenario are reflective of its estimates of incremental costs related to this scenario. However the key issue remains the lack of information BC Hydro has provided in support of its inputs. Questions have already been raised with respect to supportive data regarding the additional $1.7 billion in projected restart costs. BC Hydro's analysis of the cost impact for ratepayers creates additional informational gaps.

Of specific concern are the following additional cost inputs BC Hydro has added to its model outlined in Appendix R reflecting differences between suspending the project in comparison to the base case completion of the model:

1. There is no explanation of why future sustaining capital expenditures have increased from $2.1 billion in the base case to $2.4 billion in the suspension/restart scenario.
2. There is no explanation of the incremental energy costs of $0.5 billion and the incremental demand side expenditures of $0.9 billion and how they were arrived at.[388]

BC Hydro is requested to address and provide an explanation for these cost differentials.

The Panel also asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using the mid load forecast, the low load forecast and the high load forecast from the F17-F19 RRA for the following scenario, using the lowest-cost portfolio of alternative energy that BC Hydro has created in response to the questions asked in section 6 above:

- **Site C is suspended December 31, 2017 and restarted in 2024, with suspension, maintenance and remobilization costs as per BC Hydro's estimates presented in their submission[389].**

For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM scenario assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.

7.3 Cost to ratepayers of termination

In the event that the Site C project is cancelled, to the extent that the energy and capacity it would have provided is required, that energy and capacity would have to be procured from elsewhere. The Panel is accounting for the difference between Site C's energy and capacity and alternative sources of supply in this analysis of the ratepayer impact of terminating the Site C project.

[388] F1-1 Submission, Appendix R, pp. 7-9.
[389] F1-1 Submission, section 7

BC Hydro submission

BC Hydro provides an estimate of $81.4 billion (nominal) and $7.3 billion (present value) for the incremental cost terminating Site C, including incremental DSM costs and the cost of acquiring alternative sources of energy and capacity[390]. The net figure of $81.4 billion includes $105.5 billion in incremental energy costs[391], and is offset by costs that would be avoided if the Site C project were to be cancelled.

In the event that the Site C project is terminated, BC Hydro has planned for "approximately 1,300 GWh/yr of incremental energy savings and an additional 175 MW of dependable capacity"[392] through incremental DSM, at a cost of $700 million by F2024. In addition, BC Hydro would "advance a load curtailment program to the late 2020's to obtain 85 MW of capacity savings".

In addition, BC Hydro has estimated that it would procure "approximately 1,000 MW of additional capacity resources starting in 2024"[393] and "approximately 5,300 GWh of additional energy from F2029 to F2036 after accounting for the energy from incremental demand side management"[394].

In appendix R, BC Hydro provides an analysis of the rate impact of terminating the Site C project[395]. Compared to their base case, described above, BC Hydro removes the impact of the Site C capital, operating and sustaining capital costs, then added back the project termination and remediation costs, and the incremental cost of DSM and alternative energy and capacity. BC Hydro presents a summary of their estimated costs to terminate the Site C project based on 10, 5 and 1-year assumptions of the recovery period for the Site C regulatory account[396]:

Table 39: Site C Termination Scenarios

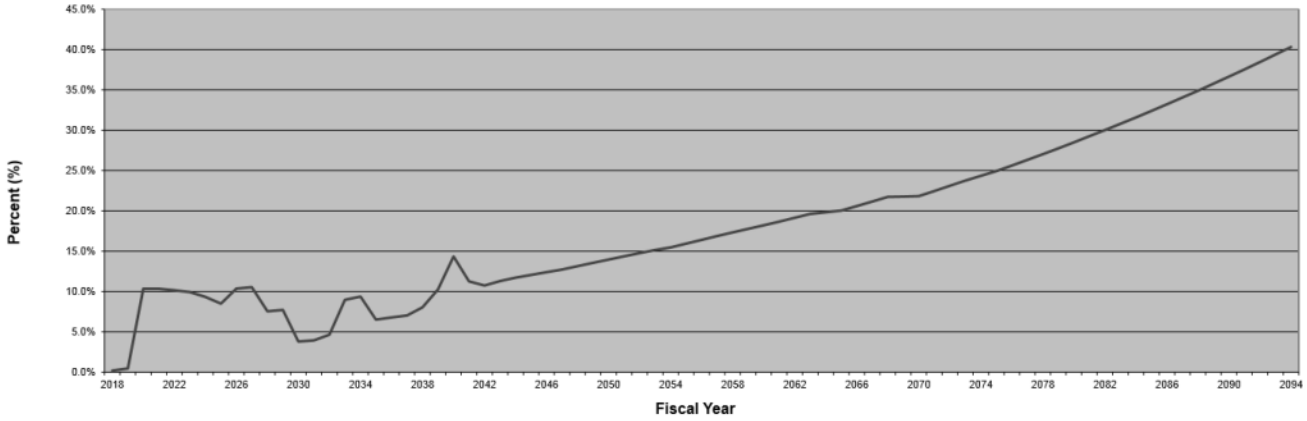
	Estimated Incremental Cumulative Rate Increases (%)			Total Estimated Incremental Costs to F2094 ($ Billions)
	in F2020	in F2024	in F2094	Nominal
Terminate Site C – 10 Year Recovery of Site C Regulatory Account	10	9	40	81.4
Terminate Site C – 5 Year Recovery of Site C Regulatory Account	17	15	40	81.2
Terminate Site C – 1 Year Recovery of Site C Regulatory Account	72	1	40	80.9

BC Hydro also includes the results of its model to create these estimates. For instance, in justification of the estimate of $81.4 billion for termination costs using a 10-year recovery of the Site C regulatory account, BC Hydro provides tabular analysis in Appendix R, Attachment 1.[397]

[390] Ibid., p.66
[391] Ibid.,Appendix R p.6
[392] Ibid., p.75
[393] Ibid., p.75
[394] Ibid., p.75
[395] Ibid., Appendix R p.5-7
[396] Ibid., Appendix R p.7
[397] Ibid., Appendix R attachment 1 pages 2-4

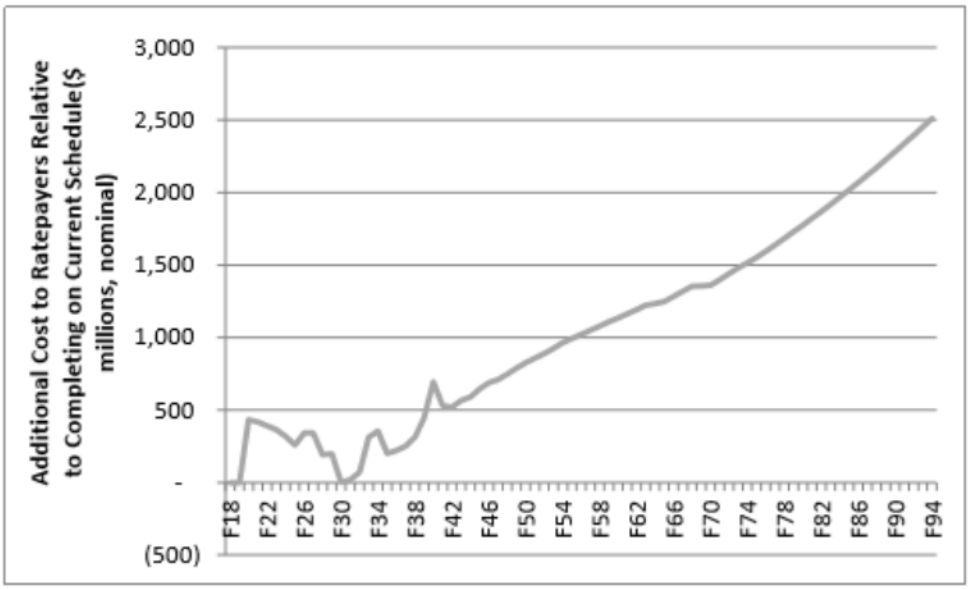
BC Hydro has also presented some of this information in graphical form, specifically the "Estimated Incremental Cumulative Rate Impact" from row 18 of the spreadsheets above[398]:

Figure 13: Incremental Cumulative Rate Impact Terminate & 10 Yr Recovery



As well as, the incremental ratepayer impact in nominal terms by year from row 8 of the spreadsheets above[399]:

Figure 14: Annual Ratepayer Impact of Site C Termination



BC Hydro presents no graphs that illustrate the figures of $81.4 billion (nominal) or $7.3 billion (present value) for the incremental cost terminating Site C.

BC Hydro also provides information to explain the cost of alternative energy used in the calculations above in Appendix R, Attachment 1.[400]

[398] Ibid., Appendix R attachment 1 p.1
[399] Ibid., p.76
[400] Ibid., Appendix R attachment 1 pages 5-6

Appendix Q includes a portfolio called "Mid load forecast with IRP DSM plan. Site C terminated"[401], with the following information:

Table 40: Mid Load Forecast with IRP DSM Plan. Site C Terminated

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

			Capacity - MW		Energy - GWh		UEC / UCC
Year	Zone	Resource	Installed	Dependable	Firm	Total	$/MWh or $/kW-year
2024	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2027	BCH_REV	Revelstoke Unit 6	500	488	26	26	46
2028	BCH_LM	2017 Load Curtailment	85	85	0	0	77
2029	BCH_PR	Wind_PC18	138	36	524	524	92
2029	BCH_PR	Wind_PC48	150	39	538	538	95
2029	BCH_NC	Wind_NC09	333	87	1,074	1,074	101
2031	BCH_PR	Wind_PC20	156	41	594	594	92
2032	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2033	BCH_PR	Wind_PC14	144	37	570	570	92
2034	BCH_PR	Wind_PC28	153	40	641	641	94
2035	BCH_PR	Wind_PC10	297	77	1,119	1,119	99
2036	BCH_PR	Wind_PC17	102	27	335	335	106
2037	BCH_KN	Wind_SI15	303	79	898	898	108
2037	BCH_REV	Wind_SI12	186	48	586	586	106
2038	BCH_KN	Wind_SI16	660	172	1,814	1,814	111
2038	BCH_VI	Wind_VI02	147	38	446	446	111
2039	BCH_LM	Pumped_Storage_LM	1000	1,000	0	0	124
2041	BCH_PR	Wind_PC13	135	35	577	577	98
2041	BCH_PR	Wind_PC19	117	30	482	482	101

Transmission Expansion

Year	Project Description	Between	Capacity - MW
2027	Nicola-Vaseux Lake Compensation (NVLC)	SEL to KN	147
2035	Increase series compensation of 5L11, 5L12, 5L13 from WSN to	CI to KN	390

Bakker report

Bakker presents an analysis of the ratepayer impact of cancelling Site C given a series of different assumptions[402]. She presents her analysis as follows[403]:

Table 41: Cost Implications – Cancelling the Site C Project (Model Results)

Load Forecast	Market Price Forecast	PV of Scenario D (without Site C) (M$)	PV of Scenario B (with Site C) (M$)	PV benefit (cost) of completing the Site C Project (M$)
Mid	Medium	1,637	2,259	-622
Low	Medium	-2,311	-1,517	-794
High	Medium	5,979	6,498	-518

In the above table, Bakker estimates that "under the 2016 mid-load forecast, it would be $622 million to proceed down an alternative path by cancelling the Site C Project"[404]. She adds that the low and high load

[401] Ibid., Appendix Q p.8-9
[402] F106-1 Submission, p.135 - 144
[403] Ibid., p.136
[404] Ibid., p.136

forecasts show a benefit of $794 million and $518 million respectively to cancelling Site C rather than continuing with the project. No year-by-year analysis of costs is presented, nor is it clear how

Bakker's estimates are generated from an Excel-based model which includes both DSM and supply-side resources to provide alternative energy and capacity to that provided by Site C[405]. The model makes a number of financial assumptions, including an exchange rate of 0.82 USD/CAD, a table of market prices for sales of surplus energy, and different portfolios of alternative energy and capacity supply sources. The model uses real 2016 Canadian dollars for the period F2017 to F2036.

For the alternative supply sources, the Bakker model uses levelized unit energy costs provided by BC Hydro, with the exception of wind resources, which are "presumed to be available at an adjusted UEC of $80/MWh beginning in the late 2020's"[406]. Energy costs for gas-fired generating alternatives are calculated based on the forecasts in BC Hydro's 2013 IRP. Levelized unit capacity costs are provided by BC Hydro, including $84/kW-year for SCGTs plus energy costs, $199/kW-year for pumped storage, and $100/kW-year for market purchases.

Bakker notes a number of limitations in the model, such as the use of a 20-year planning period. She notes that since Site C has a 70-year economic life, the model has the possibility of "computational bias, resulting from the exclusion of 'end effects'"[407].

Bakker goes on to provide alternative analyses showing the benefit of cancelling the Site C project in the circumstances of a 25 percent cost overrun on the Site C construction costs:

Table 42: Cost Implications – Site C Project + 25 Percent Cost Overrun (Model Results)

Load Forecast	Market Price Forecast	PV of Scenario D (without Site C) (M$)	PV of Scenario E (with Site C) +25% Overrun (M$)	PV benefit (cost) of completing the Site C Project (M$)
Mid	Medium	1,637	2,922	-1,285
Low	Medium	-2,311	-854	-1,457
High	Medium	5,979	7,160	-1,181

Low export market prices:

Table 43: Cost Implications – Low Market Prices (Model Results)

Load Forecast	Market Price Forecast	PV of Scenario G (without Site C) Low Market Prices (M$)	PV of Scenario F (with Site C) Low Market Prices (M$)	PV benefit (cost) of completing the Site C Project (M$)
Mid	Low	1,911	2,600	-689
Low	Low	-901	84	-985
High	Low	6,030	6,566	-536

High export market prices:

[405] Ibid., p.124
[406] Ibid., p.125
[407] Ibid., p..127

Table 44: Cost Implications – High Market Prices (Model Results)

Load Forecast	Market Price Forecast	PV of Scenario I (without Site C) Low Market Prices (M$)	PV of Scenario F (with Site C) Low Market Prices (M$)	PV benefit (cost) of completing the Site C Project (M$)
Mid	High	1,301	1,856	-555
Low	High	-3,925	-3,333	-593
High	High	5,911	6,414	-503

And finally, low export market prices and a 25 percent Site C construction project cost overrun:

Table 45: Cost Implications – Site C Project + 25 percent cost overrun + low market prices (model results)

Load Forecast	Market Price Forecast	PV of Scenario G without Site C + Low Market Prices (M$)	PV of Scenario H with Site C + 25% Overrun + Low Market Prices (M$)	PV benefit (cost) of completing the Site C Project (M$)
Mid	Medium	1,911	3,263	-1,352
Low	Medium	-901	747	-1,648
High	Medium	6,030	7,229	-1,199

In all the above analyses, Bakker estimates that cancelling the Site C project would be beneficial to completing construction.

Raphals report

Raphals submits an analysis that builds on the Bakker report, using a refined version of the same forecasting model[408]. In addition to the aspects of the Bakker model described above, Raphals adds that the model is "unable to duplicate (the) degree of sophistication"[409] of the System Optimizer model used by BC Hydro. Rather, he adds that all portfolio supply options are assumed to be "modular, and hence available in the required amounts", and that "A combination of algorithms and manual fine-tuning is used to ensure that resources are selected for each scenario that meet energy and capacity needs for each year, and at least cost".

The Raphals model makes the simplifying assumption that all incremental clean resources will be wind projects, that they can be sized to meet requirements, with a utilization factor of 32.75 per cent, with load carrying capability of 26 per cent, at a levelized unit cost of $80/MWh.

To estimate the cost impact of cancelling the Site C project, Raphals replaces the energy and capacity of Site C with a "modified DSM plan whereby 50% of load growth beyond 2017 is met by DSM", "Capacity-focussed DSM, adding 30 MW per year beginning in F20-18", and "energy storage when required to meet capacity needs"[410]. The specific alternatives for Raphals' "scenario B1", referring to cancelling site C under the mid-load forecast, are presented in a table[411]:

[408] F106-2 Submission, p.10
[409] Ibid., p.13
[410] Ibid., p.36
[411] Ibid., p.37

Table 46: Additional Resources – Mid-Load Scenarios

Scenario	Load Forecast	Capacity resources	Energy resources
A1	Mid	• Site C in F2024 • Capacity DSM starting in F2024 • Mica off-line F2026 through F2030 • Revelstoke 6 in-service in F2027 • 90 MW of SCGTs in F2026 • Market purchases of up to 400 MW of capacity	• Site C in F2024 • 1500 GWh of wind energy (523 MW installed) added in F2036
B1	Mid	• Capacity DSM starting in F2018 • Mica off-line F2023 through F2027 • Revelstoke 6 in-service in F2030 • 110 MW of storage in F2027 • Market purchases of up to 400 MW of capacity •	• Addl DSM F2026-F2036 • 1000 GWh of wind energy (349 MW installed) added in F2030, increasing to: o 2000 GWh (697 MW installed) in F2032; and o 3000 GWh (1046 MW installed) in 2034. • Energy market purchases of up to 350 GWh/yr in F2029, F2030 and F2036
C1	Mid	• Capacity DSM starting in F2018 • Revelstoke 6 in F2028; • Mica offline starting in F2031 (if technically feasible); • Market purchases of up to 150 MW of capacity	• Addl DSM F2026-F2036 • Energy market purchases of up to 500 GWh/yr in F2029 and F2030; •

The outcome of Raphals model in the mid-load forecast is presented below[412]:

[412] Ibid.,p.41

Table 47: Present Value Costs – Low Load Forecast

	PV ($ millions)		
SCENARIO	**A1**	**B1**	**C1**
Load forecast	medium	medium	medium
Site C Strategy	Complete	Cancel	Suspend
Canadian Entitlement			
ADDL CAPACITY COSTS			
Site C Capital Cost	2,293	557	1,328
Site C GHG cost	153	0	89
Revelstoke Unit 6	134	87	118
Canadian Entitlement	0	0	0
Market reliance	53	216	24
Clean Resources	0	0	0
SCGT	3	0	0
Storage	0	60	0
CCGT	0	0	0
Subtotal	**2,483**	**920**	**1,470**
ADDL ENERGY COSTS			
Addl Gas costs	4	0	0
Addl Wind costs	45	507	0
Canadian Entitlement	0	0	0
Storage losses	0	2	0
Market Purchases	52	25	21
Subtotal	**101**	**534**	**21**
ADDL TRADE REVENUE			
Surplus sales revenues ($M)	-1,412	-757	-1,069
Surplus capacity revenues	-23	-15	-17
Subtotal	**-1,434**	**-771**	**-1,086**
ADDL DSM COSTS			
Addl DSM	0	268	268
Capacity-focussed DSM	63	148	148
Subtotal	**63**	**416**	**416**
TOTAL INCREMENTAL COSTS	**1,367**	**1,098**	**910**

Note that the table is incorrectly labelled “low load forecast”; the text identifies the information as using the mid-load forecast.

In the table above, Raphals concludes that it would be cheaper to cancel the Site C project, as the present value cost of cancellation is $1,098 million versus a present value cost of $1,367 million to continue to complete Site C.

Raphals goes on to examine the situation should the government adopt regulation to allow reliance on the Canadian Entitlement to energy under the Columbia River Treaty:

Table 48: Present Value Costs – Mid-Load Forecast (with Canadian Entitlement)

	PV ($ millions)		
SCENARIO	**A1-CE**	**B1-CE**	**C1-CE**
Load forecast	medium	medium	medium
Site C Strategy	Complete	Cancel	Suspend
Canadian Entitlement	included	included	included
ADDL CAPACITY COSTS			
Site C Capital Cost	2,293	557	1,328
Site C GHG cost	153	0	89
Revelstoke Unit 6	134	87	118
Canadian Entitlement	81	81	81
Market reliance	2	4	0
Clean Resources	0	0	0
SCGT	0	0	0
Storage	0	0	0
CCGT	0	0	0
Subtotal	**2,511**	**728**	**1,527**
ADDL ENERGY COSTS			
Addl Gas costs	0	0	0
Addl Wind costs	0	95	0
Canadian Entitlement	873	873	873
Storage losses	0	0	0
Market Purchases	9	10	0
Subtotal	**882**	**979**	**873**
ADDL TRADE REVENUE			
Surplus sales revenues ($M)	-2,219	-1,376	-1,927
Surplus capacity revenues	-83	-48	-79
Subtotal	**-2,298**	**-1,422**	**-2,002**
ADDL DSM COSTS			
Addl DSM	0	268	268
Capacity-focussed DSM	63	148	148
Subtotal	**63**	**416**	**416**
TOTAL INCREMENTAL COSTS	**1,311**	**701**	**903**

Raphals concludes that, in the medium-load forecast, "allowing reliance on 50percent of the energy and capacity of the Canadian Entitlement reduces present value costs by a substantial margin"[413].

Finally, Raphals presents a comparison of his findings with those of Bakker[414]:

[413] Ibid., p.47
[414] Ibid., p.50

Table 49: Comparison of findings to Reassessing the Need ($million)

	Reassessing the Need		Current Report	
Load Forecast	Cancel Site C	Suspend Site C	Cancel Site C	Suspend Site C
Low	-794	-794	-366	-146
Mid	-622	-867	-269	-457
High	-518	-865	-447	-498

Both reports conclude that cancelling Site C would be cheaper than continuing, although the Raphals "current report" shows smaller benefits.

Other submissions

The Allied Hydro Council of B.C. lists[415] a number of "lost development benefits" in the event that the Site C project is cancelled, but does not provide a comprehensive analysis of the overall costs to ratepayers in the event of termination.

Panel analysis and preliminary findings

The Panel asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using the mid load forecast, low load forecast and high load forecast from the 2016 Revenue Requirements Application for the following scenarios, and all using the lowest-cost portfolio of alternative energy that BC Hydro has created in response to the questions asked in section 6 above:

- **Site C is terminated December 31, 2017, with sunk costs at that date of $2.1 billion, and termination and remediation costs of $1.1 billion. Site C regulatory account costs are amortized over 10 years.**
- **Site C is terminated December 31, 2017, with sunk costs at that date of $2.1 billion, and termination and remediation costs of $1.1 billion. Site C regulatory account costs are amortized over 20 years.**

For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.

7.4 Mechanisms for cost recovery

BC Hydro states that if the project were terminated, commonly applied regulatory principles would account for the following factors in determining an appropriate recovery period:

- The amount of time ratepayers receive benefit from the cost; and
- Avoidance of rate shock

That there is no long-term benefit to ratepayers due to the asset never going into service might suggest the balance be recovered over a short period in this case. However, consideration of avoidance of rate shock suggests the period should be more spread out. BC Hydro states that in the event of project termination and

[415] F24-1 Submission, p.12-13

final remediation it has reviewed scenarios of one year five years and ten years. BC Hydro notes that the 10 year scenario will mitigate some of the rate volatility associated with the one year scenario and therefore believes it is preferable in this instance. BC Hydro has prepared its calculations based on a 10-year recovery period.[416]

Panel analysis and preliminary findings

The Panel finds that recovery of expenditures over a longer period rather than a shorter period in the event of termination as proposed by BC Hydro is reasonable. If a shorter time period were considered the impact on ratepayers would be significant with potentially extreme consequences. Spreading the costs over a longer period would allow ratepayers a better opportunity to absorb the impact and plan accordingly. Any determination of the appropriate recovery mechanism, including the period of recovery, would need to be made in the context of a future proceeding.

[416] Exhibit F1-1, p. 74 and p. 90.

8.0 Closing comments from the Panel

In conclusion, the Panel has identified numerous areas of information gaps which require supplemental evidence and analysis from BC Hydro and/or the public in order to make definitive and conclusive findings. The Panel requests responses to the questions posed in this Preliminary Report by October 4, 2017. In the next stage of the Inquiry, the Panel will host Community Input Sessions throughout the province and will deliver its Final Report to the Minister charged with the administration of the *Hydro and Power Authority Act* by November 1, 2017.

The Panel thanks all participants for their submissions and for their interest in the Commission's report process. All submissions have been considered, even if there is no specific mention of it in this Preliminary Report.

We invite all participants to provide further comment on this report.

1.0 Appendix A – Alternative energy and capacity sources

1.1 Alternative energy sources

This appendix examines the energy generation components that make up an alternative generation portfolio. BC Hydro's portfolio is based on its inventory of resources. This inventory "derives in large part from a 2015 update of the Resource Options Inventory, for which we reviewed input and feedback from industry experts, consultants, and others with technical expertise to update the cost and technical information of most generation resources identified in the previous Integrated Resource Plan."[417]

BC Hydro presented the results of its screening analysis in its August 30, 2017 submission. This analysis resulted in the following resources being excluded from consideration in its portfolio. [418]

[417] F1-1 Submission, Appendix L, p. 1.
[418] F1-1 Submission, Appendix L, pp. 3-4.

Table 50: Resources Excluded from Portfolios

Resources Excluded from Portfolios			
Resource	**Adjusted UEC ($/MWh)**	**UCC at POI ($/kW-year, $F2018)**	**Comments**
Natural Gas – CCGT	81-97	-	Fossil fuel producing relatively high GHG emissions. Inconsistent with reference in the Terms of Reference to maintaining 2016/17 levels of GHG emissions and "British Columbia's energy objectives" in the *Clean Energy Act* Limited by 93% clean objective in *Clean Energy Act* Not consistent with climate change goal (including the 100% clean policy in the provincial Climate Leadership Plan) SCGTs are reviewed in sensitivity analysis.
Natural Gas – SCGT	-	77-156	

Resources Excluded from Portfolios			
IRP DSM PLUS	See figures 3 and 4	-	Uncertain market potential of cost effective measures IRP DSM Plus is reviewed in sensitivity analysis.
Geothermal	78-461	-	No proven viable geothermal resources in BC yet, with high cost of confirmation drilling with significant risk of failure.
Solar	133-182	-	Costs currently uneconomic. Long-term uncertainty of technology cost declines
Biogas	61-165	-	Small resource potential
Demand Response & Time of Use Rates	-	-	Uncertain savings and uncertain ability to meet system capacity need
Resource Smart – GMS Capacity Increase Units 1-5	-	66	Increased reliability risk associated with implementation logistics
Other resource smart projects	See table 16	-	Limited potential with uncertain feasibility and cost
Wave	533-676	-	Technology Immaturity and High Cost
Tidal	420-899	-	Technology Immaturity and High Cost
Distributed Generation	-	-	Not considered as a separate resource option on its own. Customer based solar is a customer decision, long pay back in B.C. and therefore limited growth expected in near future.
Nuclear	-	-	Policy barred through "British Columbia's energy objectives" in the *Clean Energy Act*.
Large Hydro other than Site C	-	-	Legislatively barred projects as listed in Schedule 2 of the *Clean Energy Act*
External market reliance (including Canadian Entitlement)**	-	-	Reliability concerns and uncertain long term availability. Also legislatively barred through section 6(2) of the *Clean Energy Act* – the legal requirement to be self-sufficient requires "solely from electricity generating facilities within the province"
Hydrokinetic	-	-	Technology Immaturity

Allied Hydro states that:

> There are a number of energy supply alternatives to Site C, the lowest cost would be a CCGT plant, but that is probably not acceptable for environmental reasons. DSBs could be a relatively low-cost source but may not be dependable;
>
> If Site C was not available to fill part of this energy gap it could be filled by IPP hydropower or wind projects. There are now 80 hydropower IPP EPAs and 7 wind EPAs. At the current average scale of plant, the gap would require another 70 to 100 hydropower plants or 35 to 50 wind power plants. They would not be less costly than Site C power, would not have storage capacity, and would have less availability, 42% and 33% versus 53%;
>
> The expected unit cost of Site C power is difficult to predict due to rising capital cost estimates over time, the question of sunk costs and the appropriate discount rate. The best estimate that can be provided in this Review is that it is likely in the $110/MWh to $120/MWh range;[419]

CEABC submits the following:

> The old adage that large hydro projects are a wise investment despite their high upfront costs because it is less expensive to build them today than tomorrow because of inflation is only true if there are no other similarly priced renewable generation alternatives or if there are, they are more expensive to replace at the end of their life. This is not today's paradigm. There are alternatives such as wind and solar and even with inflation they are decreasing in price and are expected to continue to decrease in price for some time to come. In the case of wind they are already lower priced than the Site C project, including capacity backup. Battery storage is also expected to decline in price.[420]

Panel preliminary findings

The Panel will discuss specific alternative portfolio sources further below. However, in summary, the Panel finds that Geothermal, Solar, Biomass and Battery Storage should be included in the portfolios.

1.1.1 Upgrade of existing BC Hydro assets

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.[421]

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.[422]

[419] F24-1 Submission, p. 22.
[420] F18-3 Submission, p. 13.
[421] F1-1 Submission, Appendix L, p. 43.
[422] F1-1 Submission, Appendix L, p. 43.

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 51: Comments Regarding Opportunities for Upgrading BC Hydro's Existing Assets

Project name	BC Hydro	Deloitte	Comments
Revelstoke Unit 6	488MW, 26GWh/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.[423]	500MW. $591M-$398M. All committed BC Hydro expansion is included in the Deloitte model as firm supply, that is, it is included regardless of economic performance.[424]	Similar project, but different capacities and potentially different costs. Swain provides comment.[425]
John Hart replacement, Ruskin upgrade, Clowhom 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	Not identified.	All committed BC Hydro expansion is included in the Deloitte model as firm supply, that is, it is included regardless of economic performance.[426]	Sekw'el'was Cayoose Creek Band (CCB) provide comment on the Bridge River system.[427] Swain provides comment on John Hart and Ruskin.[428]
GMS units 1-5 capacity increase	100MW, $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	220MW, $71 million. Additional potential is included in the model as a supply option.[430]	Similar project, but different capacities and potentially different costs and energy.

[423] F1-1 Submission, Appendix L, p. 44.
[424] A-9 Submission, pp. 40, 96.
[425] F36-1 Submission, p. 19.
[426] A-9 Submission, p. 40.
[427] F73-1 Submission
[428] F36-1 Submission, p. 19.
[430] A-9 Submission, pp. 43, 45.

	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. [429]		
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 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."[431]	The additional potential from this project does not appear to be included as a supply option in either party's models.
Falls River redevelopment	24MW, 170GWh/yr, $550/kW-yr.[432]	Incremental 9MW (25MW – 7MW) for $165 million, or incremental 18MW (25MW – 7MW) for $260 million.[433]	Similar project, but different capacities and potentially different costs and energy.

[429] F1-1 Submission, Appendix L, pp. 44-45.
[431] A-9 Submission, pp. 45-46.
[432] F1-1 Submission, p. 45.
[433] A-9 Submission, p. 44.

Alouette redevelopment	21MW, 61GWh/yr, $51/MWh, $121 million.[434]	9.7MW and $100 million, or 21MW and $160 million.[435]	Similar project, but different costs and potentially different energy.
Elko redevelopment	20.8MW, 118.5 GWh/yr to 124.9 GWh/yr, $180.1 million, $105/MWh ($95/MWh net of a $29 million decommissioning credit).[436]	20MW, $225 million.[437]	Similar project, but slightly different capacities, different costs and potentially different energy.
Kootenay Canal Grohman Narrows	0MW, 89 GWh/yr, $68 million[438]	Not identified.	
Seven Mile turbines upgrade	48MW, 89GWh/yr, $137 million.[439]	32MW, $100 million.[440]	Similar project, but different capacities, different costs and potentially different energy.
Strathcona additional unit	31MW, 0GWh/yr, $98/kW-yr $F2018.[441]	31.3MW, $37 million.[442]	Similar project, very similar capacities. Unclear if there are cost or energy differences.
Duncan Dam new generation	30MW, 103GWh/yr, $98/MWh ($F2018), $336/kW-yr ($F2018).[443]	22MW, $250 million, $114/MWh.[444]	Similar project, but with different capacities and potentially different costs and energy. Swain provides comment.[445]
Lajoie additional unit	30MW, 80GWh/yr, $108/MWh ($F2018), $288/kW-yr ($F2018).[446]	30MW, $340 million.[447]	Potentially same project, same costs and same energy, but could not be confirmed. CCB comments on Lajoie.[448]

[434] F1-1 Submission, p. 45.
[435] A-9 Submission, p. 43.
[436] F1-1 Submission, pp. 45-46.
[437] A-9 Submission, p. 44.
[438] A-9 Submission, p. 46.
[439] F1-1 Submission, p. 47.
[440] A-9 Submission, p. 43.
[441] F1-1 Submission, p. 48.
[442] A-9 Submission, p. 46.
[443] F1-1 Submission, p. 48.
[444] A-9 Submission, p. 43.
[445] F36-1 Submission, p. 19.
[446] F1-1 Submission, p. 48.
[447] A-9 Submission, p. 47.

Ladore additional unit	9MW, 8GWh/yr, $272/MWh ($F2018), $242/kW-yr.[449]	9MW, $11 million.[450]	Potentially same project, same costs and same energy, but could not be confirmed.
Ash River additional unit	9MW, 30GWh/yr, $84/MWh ($F2018), $279/kW-yr.[451]	9MW, 36GWh/yr, $101 million.[452]	Similar project, but with different energy and potentially different costs.
Ash River refurbishment of the powerhouse	Not identified.	8MW, $57 million.[453]	
Puntledge additional unit	10MW, 18GWh/yr, $69/MWh ($F2018), $126/kW-yr.[454]	10MW, $115 million.[455]	Potentially same project, same costs and same energy, but could not be confirmed.
Seton unit upgrade	Not identified.	2MW, $20 million.[456]	CCB comments on Seton.[457]
Shuswap refurbishment of generating unit	Not identified.	3MW, $6 million.[458]	
Wahleach turbine replacement	Not identified.	14MW, $5.8 million.[459]	
Whatshan transformer replacement	Not identified.	4.7MW, $3.6 million.[460]	

Panel analysis and preliminary findings

BC Hydro is requested to provide further comment on the table above. In particular, the Panel would like to know its assessment of the cost of any potential refurbishments and upgrades that are 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.

[448] F73-1 Submission.
[449] F1-1 Submission, p. 48.
[450] A-9 Submission, p. 47.
[451] F1-1 Submission, p. 48.
[452] A-9 Submission, p. 45.
[453] A-9 Submission, pp. 44-45.
[454] F1-1 Submission, p. 48.
[455] A-9 Submission, p. 47.
[456] A-9 Submission, p. 46.
[457] F73-1 Submission.
[458] A-9 Submission, p. 46.
[459] A-9 Submission, p. 47.
[460] A-9 Submission, p. 47.

1.1.2 PPA from existing IPPs

BC Hydro reports that biomass and Run of River renewals are maintained at 50 percent and 75 percent respectively.[461]

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;
> - 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.[462]

Panel analysis and preliminary findings

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 requests that BC Hydro explain why it is not renewing more IPP contracts.**

1.1.3 Geothermal

BC Hydro submission

Geothermal energy systems draw on natural heat from within the Earth's crust to drive conventional power generation technologies. BC Hydro states that geothermal resources have the potential to be a cost-effective source of energy and capacity but the resource potential in B.C. is unproven and that the costs and risks inherent in the development of these resources have thus far deterred any development in B.C.

BC Hydro states 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

[461] F-1 Submission, Appendix K p. 2.
[462] Submission F24-1, p. 16.

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.[463]

BC Hydro states 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 that 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).[464]

However, BC Hydro states that it cannot rely on geothermal resources for planning purposes because there are no proven viable geothermal resources in B.C. 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.[465]

Deloitte report

Deloitte consider 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 states 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 looking at potential 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 note that, while geothermal energy is a proven technology across much of the world, no geothermal energy generation currently exists in British Columbia. Deloitte state that test drilling is required to validate the geothermal resource which can be capital intensive.

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). [466]

Other submissions

The Canadian Geothermal Energy Association (CGEA) disagrees with BC Hydro's assessment of the geothermal resources. CGEA 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 CGEA submit are the lowest cost and lowest risk form of geothermal electricity generation in BC). CGEA assembled new data, with the assistance from an Oregon-based geothermal development and two additional global geothermal experts, that they submit shows a lower cost of developing geothermal projects.[467]

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[464] F-1 Submission, Appendix L, p. 33
[465] F-1 Submission, Appendix L, p. 35.
[466] A-9 Submission, pp. 23, 101
[467] F66-1 Submission, p. 5

In its report, CGEA it describes two potential geothermal electricity projects – Canoe Reach near Valemount, and Lakelse Lake near Terrace and provides the following cost comparisons to Site C:[468]

Table 52: 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	

In addition, CGEA state that BC Hydro has overstated exploration and drilling costs, potentially by a factor of 2 - 4. CGEA state 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. [469]

West Moberly Profit River and Harry Swain state that the 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 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, and that the periodic claim that the technology is unproven is belied by routine operations in Italy, New Zealand, California, Alaska, Iceland, and elsewhere".[470]

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.[471] 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.[472]

Panel analysis and preliminary findings

The Panel finds that geothermal is potentially a viable alternative and we do not agree with BC Hydro that geothermal should be excluded from consideration as part of its alternative portfolio. 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.

[468] F66-1 Submission, p. 9.
[469] F66-1 Submission, pp. 11, 14
[470] F36-1 Submission, p. 17; F28-2, p. 6.
[471] 60-1 Submission, p. 13
[472] F82-1 Submission, p. 21

However BC Hydro does point 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 asks 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.**

1.1.4 Wind

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, 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. 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."[473] Although these documents weren't submitted to this proceeding, they appear to be publically accessible.[474][475]

BC Hydro conducted analysis based on potential projects identified in the 2009 BC Hydro Wind Data Study, and the results are shown below: [476]

[473] F-1-1 Submission, Appendix L, p. 30
[474] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.pdf
[475] https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf
[476] F-1 Submission, Appendix L, pp. 29-31

Figure 15: 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 the 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:[477]

Figure 16: BC Hydro Wind Cost Assumptions (BC Hydro 'UEC (BCUC Request)' Excel file)

	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

Deloitte report

Deloitte estimates regarding the cost of wind were 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.[478]

Deloitte referenced 31 sources for their 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 100MW wind project located in Washington (Pacificorp) and Peace River (Hatch study) were:

[477] A-12 Submission, BC Hydro UEC Excel File (BCUC Request), Tab UEC_UCC
[478] A-9 Submission, pp. 17, 18

- 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 [479]

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 analyzed176, 177. 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 was 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 to 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.[480]

Canadian Wind Association and CEABC

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CWEA) 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)[481]
- 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.[482]

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%."[483]

[479] Ibid., pp. 17; Pacificorp 2017 IRP, pp. 106, 120, 123; 2015 Hatch Wind Project Cost Review, p. 23
[480] Ibid., pp. 101-102.
[481] F18-3 Submission, Appendix 1, p. 6-8,
[482] F18-3 Submission, Appendix 1, pp. 16, 17
[483] F104-1 sbmission, Appendix 1, pp. 13- 14.

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 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.[484]

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 Independent Power Producers (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)".[485]

Prophet River West Moberly's expert Robert McCullough, submits the following:

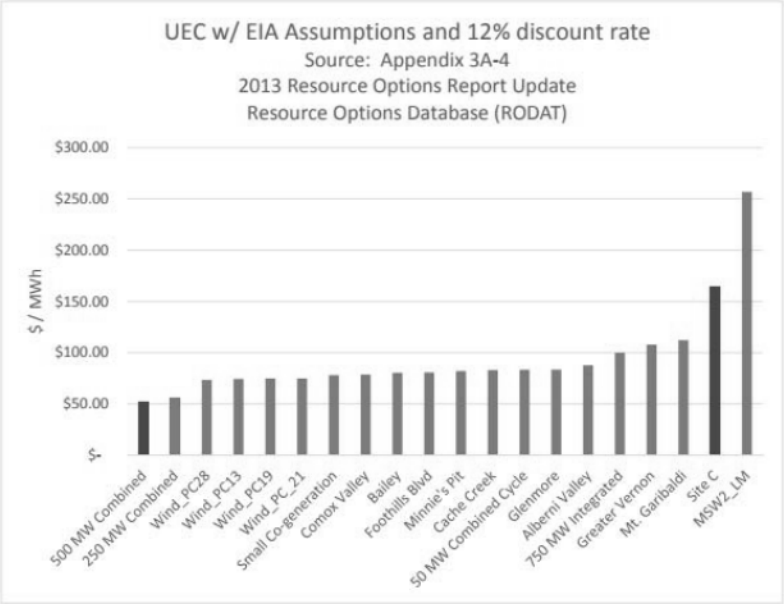
> [m]ajor manufacturers sell thousands of virtually identical wind turbines throughout North America. The [U.S. Energy Information Administration] EIA data indicates that wind turbines will cost $1,850/kW for a 100 MW utility scale project. This is consistent with industry experience.

[484] F24-1 Submission, p. 17.
[485] F51-1 Submission, p. 21

> 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.[486]

Prophet River West Moberly's expert provide a correction to the RODAT data using EIA plant assumptions, and revised discount rate assumption, showing the following rankings for the twenty cheapest Site C alternatives:

Figure 17: UEC w/ EIA Assumptions and 12 Percent Discount Rate



Dauncey further presents the following costs for wind[487]:

Table 53: Dauncey 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

Panel analysis and preliminary findings

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.**

[486] F107-1 Submission, Appendix Site C Business Case Assumptions Review, p. 14.
[487] F62-1 Submission, p. 11.

The Panel finds there has been a decline in the cost of wind in recent years, and parties expect future declines. The Panel shares concerns raised by parties that BC Hydro's $85/MWh wind estimate is not supported.

The Panel therefore seeks 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.**

1.1.5 Energy focused DSM

BC Hydro states the following:

> 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.[488]

In BC Hydro's 2013 IRP, BC Hydro modelled five levels of DSM spending (Option 1 to 5):

- 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;
- 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).
- Option 3 increased funding for DSM programs, and resulted in targets of 8,300 GWh/year of energy savings and 1,500 MW of associated capacity by F2021.
- Options 4 and 5 relied on significant government regulation in the form of codes and standards.[489]

Option 1 and 2 had a utility cost (including energy savings from codes and standards and rates) of $18/MWh ($140 million/year), while Option 3 (with the additional portfolio spending) had a utility cost of $22/MWh ($180 million/year). The incremental difference between Option 2 and 3 were therefore 500GWh/year at an additional cost of $40 million.[490]

In the 2013 IRP BC Hydro, selected a moderated Option 2:

- Short term - energy savings of 6,300 GWh/year with an annual cost of around $150 million/year
- Longer term - increase in DSM spending to achieve 7,800 GWh/year in energy savings and 1,400 MW in capacity savings by F2021. Of these energy savings, 45 percent was expected to come from BC Hydro's DSM programs, and 55 percent from BC codes and standards and rate design. [491]

In the F2017 – 2019 Revenue Requirements Application, BC Hydro incorporated the use of screening tool which evaluated the utility cost of DSM programs against the BC border sell price forecast (approximately $36 per

[488] F-1 Submission, Appendix L, p. 5
[489] BC Hydro 2013 IRP proceeding, Exhibit B-1-, pp. 3-16 – 3-22, 9-10
[490] BC Hydro 2013 IRP proceeding, Exhibit B-1-,, pp. 3-18, 3-21, 3-27
[491] BC Hydro 2013 IRP proceeding, Exhibit B-1-,, pp. 9-8 – 9-10

MWh) in order to prioritize DSM investments.[492] BC Hydro moderated its DSM spending for the F2017-F2019 year to around $110 million/year (excluding capacity focused DSM), with an average utility cost of the DSM programs (excluding BC codes and standards and rates) of around $32/MWh (compared to $37/MWh for F2014-F2016).[493]

BC Hydro submission

BC Hydro modelled the following options for increasing DSM spending levels:

- IRP DSM Plan: this was based on Option 2 in the 2013 IRP, with sub-options regarding timing (one option had the increase in DSM now, the other delayed until there was a need for new resources and DSM was the lowest cost option). The utility incremental cost of this option was assumed to be $41/MWh.
- IRP DSM Plan Plus: this was informed by the work performed to date from the Conservation Potential Review (CPR) and targeted a higher level of DSM spending. BC Hydro cautions that the cost information is uncertain, but estimated it could result additional in energy savings by F2035 of up to 1,000 GWh compared to the IRP DSM Plan, with an assumed cost of $64/MWh. BC Hydro also undertook sensitivity testing by assuming double the amount of energy could be obtained at this cost.[494]

BC Hydro states that the DSM options are assumed to continue out for the full analytical period, but caution that there is uncertainty with this assumption as BC Hydro's ability to continue to achieve energy savings, particularly out past 20-years, is dependent on what conservation potential exists at that time. The following chart shows the DSM energy and associated capacity savings from these options: [495]

[492] BC Hydro F17-F19 RRA proceeding, Exhibit B-1-1, pp. 10-18, 10-19
[493] BC Hydro F17-F19 RRA proceeding, Exhibit B-1-1, p. 10-33, Exhibit B-9, BCUC IR 172.1
[494] F-1 Submission, Appendix L, pp. 7 - 11
[495] F-1 Submission, Appendix L, p. 11

Figure 18: DSM Energy Savings (including loss savings, mid estimate)

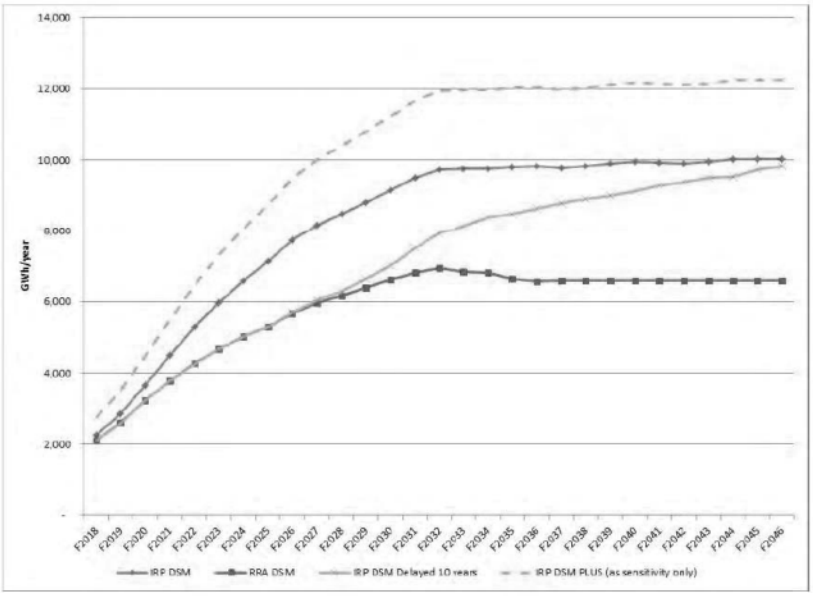
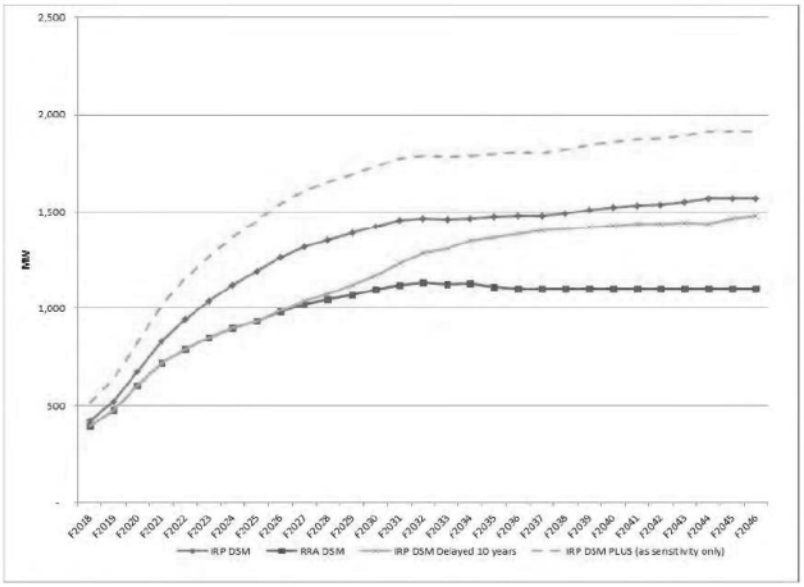


Figure 19: DSM Capacity Savings (including loss savings, mid estimate)



Deloitte report

Deloitte considers that BC Hydro could take a more aggressive approach to DSM, noting:

> 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.[496]

[496] A-9 Submission, p. 52

Deloitte also noted that BC Hydro's residential program spending in particular is significantly below other jurisdictions:[497]

Figure 20: Comparison of expenditures by BC Hydro vs. other jurisdictions

	DSM Expenditures		
	Other jurisdictions	**BC Hydro F2014-16**	**BC Hydro F2017-19**
Residential	29%	11%	9%
Low Income	6%	2%	3%
Commercial and Industrial	61%	71%	75%
Cross sectorial	4%	16%	13%

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, may are not.[498]

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.[499] 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 s. 2(b) of the Clean Energy Act.[500]

CCPA submits that conservation is clearly the most cost-effective way of meeting new demand.[501]

Dauncey submits the 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.[502] Dauncey further states:

- In California, all new residential construction is required to be net-zero energy by 2020, and all new commercial construction by 2030. In BC, the equivalent goal for residential construction has been pushed back to 2032 because of foot-dragging by the housing industry.
- The US Department of Energy has projected that LED lighting, as one of many energy-saving technologies, will achieve a market share of 84 percent of the general illumination market by 2030, reducing lighting energy by 40 percent for a savings of 261,000 GWh, equivalent to the energy consumed by nearly 24 million homes. The equivalent projection for BC's smaller population would see an energy saving of 3,740 GWh a year, equivalent to 73 percent of the energy from Site C. Switching all of BC's 360,000 streetlights to LEDs, for instance, would save 105 GWh a year, with financial payback in eight years.
- If the 300,000 homes in BC that still use baseboard electrical heating all switched to air-source heat-pumps their owners or tenants would save 2,500 kWh a year, reducing demand by 750 GWh a year.

[497] Ibid., p. 53
[498] Ibid., p. 55
[499] F29-3 Submission, p. 17
[500] F36-1 Submission, p. 13
[501] F60-1 Submission, p. 10
[502] F62-1 Submission, p. 8

- North American energy efficiency portfolio administrators in Vermont, California and Connecticut have been able to and plan to continue saving 2 percent of total retail electric sales annually for half the long-run marginal cost of new supply. Data provided by John Plunkett in 2012 and 2013 Commission hearings showed that if BC Hydro adopted the best practices used by the leading US states, saving 2 percent or 1,000 GWh a year, between 2013 and 2024 it could reduce its anticipated demand by 11,000 GWh.[503]

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. Bakker submits that overall, the cost difference between DSM Option 3 and the DSM Plan contemplated in the 2016 RRA appears to be on the order of $150 million/year, and that BC Hydro is continuing to cancel or scale back many DSM programs that have utility costs well below the unit energy costs of the Site C Project, at $85 to $88/MWh. [504]

Bakker states she has assumed for modelling purposes additional energy savings through 2036 under the mid load scenario of 4,083 GWh/year, at a cost of $33/MWh, with associated capacity savings of 656 MW.[505] Bakker and CEC also raise a concern that data presented in BC Hydro's Revenue Requirement Application shows a significant drop off in DSM savings over 20 years. [506]

Prophet River and West Moberly First Nation (PRWMFN) 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 200MW of capacity and over 1,200 GWh-year of energy.[507]

Scott provides several examples of energy efficiency initiatives which he submits could save some 5,550 GWh of electricity, including oil furnace replacement and replacing electric baseboard heaters/furnaces with heat pumps.[508]

Panel analysis and preliminary findings

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 considers that, as deeper DSM savings can be more expensive, it is also reasonable to develop two or more incremental DSM portfolios with differing levels of energy (and associated capacity) savings and costs.

The Panel therefore seeks input from BC Hydro and other participants on the following questions:

- **Clearly identify how much energy and associated capacity is 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.**
    - **The annual energy/capacity savings and associated utility costs over the analysis period should be clearly stated.**
    - **As the focus of this review is on costs to ratepayers (rather than broader BC benefits) please (i) estimate the utility (rather than total resource) cost, and (ii) assume that the incremental DSM options are delayed until is a need for new resources.**

[503] F62-1 Submission, pp. 8, 9
[504] F106-1 Submission, p. 79, 81, 82
[505] F106-2 Submission, p. 28
[506] F82-1 Submission, p. 28; F-106-2 Submission, p. 26
[507] F28-2 Submission, Appendix Helios Centre, p. 7
[508] F77-2 Submission, pp. 6, 22

- **The energy/capacity savings of DSM should be adjusted to reflect delivery (i.e., energy grossed up for distribution losses), and the cost should be adjusted for the DSM energy/capacity shape.**
- **Please do not include codes and standards/rate design in the incremental DSM portfolios.**

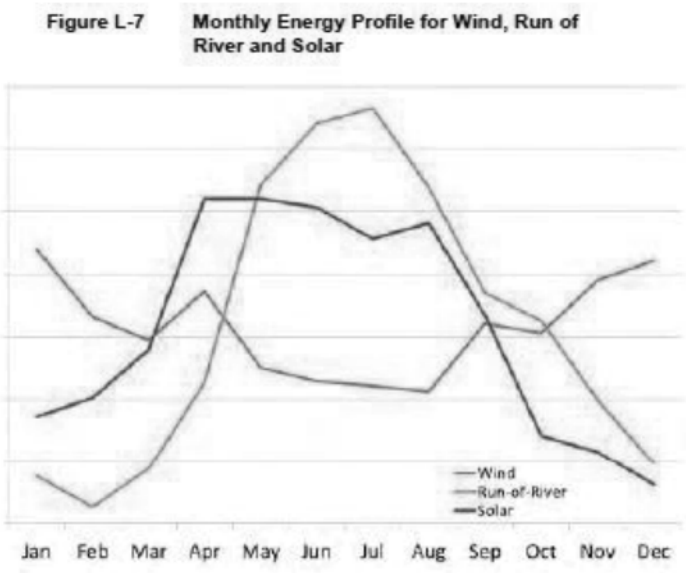
Other parties are invited to provide their own estimates of DSM portfolio options (clearly stating the cost and energy /capacity savings associated with each DSM 'cost bucket') in a format that will allow it to be evaluated against supply side options.

1.1.6 Run-of-River

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.[509]

Figure 21: Monthly Energy Profile for Wind, Run of River and Solar



As a result the cheapest alternative portfolio contains no run of river projects.

Deloitte report

Deloitte submits 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.[510]

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

[509] F-1 Submission, Appendix L, p. 28.
[510] A-9 Submission, p. 25

connection to the BC Hydro transmission grid is located at Campbell River. Kleana submits that it has the water rights to and that, if developed, would be one of the largest run-of-river independent power projects ("IPP") in North America. Kleana compares its project's footprint to that of Site C in the following table:[511]

Figure 22: 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 the 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".[512]

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
- It has the support of the affected indigenous peoples.[513]

Kleana also submits that the Project 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 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".[514]

Kleana 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 Page 3-4 of 2013 Integrated Resource Plan, 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.

[511] F53-1 Submission, p. 2,6.
[512] F53-1 Submission, p. 25
[513] F53-1 Submission, p. 3.
[514] F53-1 Submission, p. 4.

Kleana submits that Table 3-13 of the 2013 Integrated Resource Plan 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).[515]

Panel analysis and preliminary findings

The Panel invites BC Hydro to respond to the submission of Kleana Power.

The Panel invites parties to provide submissions on specific project data (including capital and operating costs, capacity factor and economic life) on potential Run-of-river projects.

1.1.7 Biomass

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".[516]

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:[517]

Table 54: 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**

[515] F53-1 Submission, p. 25 of 134.
[516] F1-1 Submission, Appendix L, pp. 23, 24
[517] F1-1 Submission, Appendix L, pp. 23-24.

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.[518]

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.[519]

Table 55: 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.[520]

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. Allied Hydro estimated that the cost for 2017 would be about $70/MWh.[521]

[518] A-9 Submission, p. 29
[519] F78-1 Submission, p. 1.
[520] F78-1 Submission, p. 1.
[521] F24-1 Submission, p. 20.

Panel analysis and preliminary findings

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.

1.1.8 Solar

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. [522]

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.
- Future cost declines: F2025 cost of $97/MWh (for Cranbrook), with a range of $82 - $114. [523]

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. [524]

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

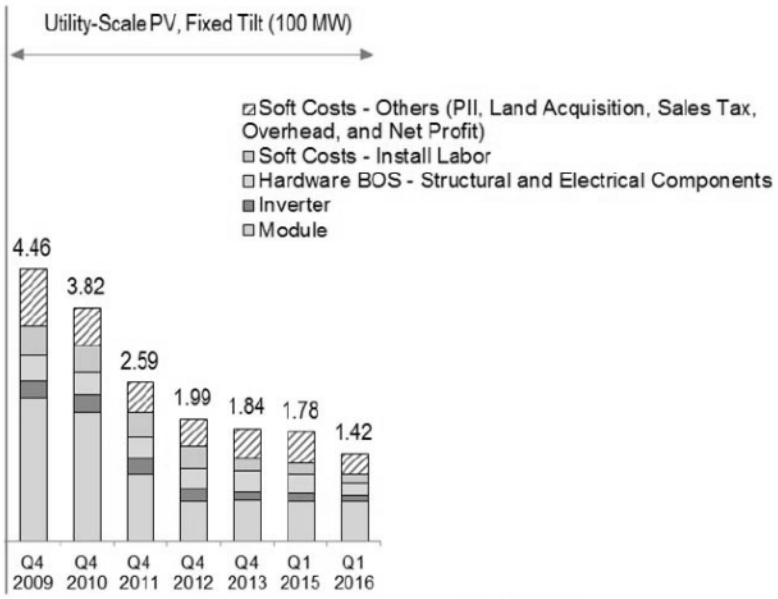
Deloitte also note that solar PV has been shown in a recent California study to provide frequency response and voltage support with appropriate controls.[525]

[522] F-1 Submission, p. 42, Appendix L, p. 38
[523] F-1 Submission, Appendix L, pp. 4, 39, 50
[524] F-1 Submission, Appendix L, pp. 4
[525] A-9 Submission

Other submissions

Many participants noted in their submissions the recent significant decreases in the cost of utility scale energy and projected future cost declines. CWEA/CEBC provided the following charts showing past capital cost declines: [526]

Figure 23: PV System Cost Summary (2016 USD/Watt DC)



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. [527] 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. [528]

Participants also put forward a variety of estimates of future cost declines, including:

- CWEA/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). [529]
- 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. [530]
- 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. [531]

[526] F18-3 Submission, p. 9
[527] F35-2 Submission, p. 8
[528] F41-2 Submission, p. 2
[529] F18-3 Submission, p. 14
[530] F106-1 Submission, p. 95
[531] F60-1 Submission, p. 13

- 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. [532]
- 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. [533]

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. [534]

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.

Panel analysis and preliminary findings

The Panel finds 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 seeks input from BC Hydro and other participants on the following questions:

- **What is the current BC installed capacity cost of a 5MW utility solar PV instillation ($/Watt) and operating cost ($/year and $/MWh)?**
    - **What would a reasonable forecast of the cost be in F2025 and F2035?**
- **What are the regional solar radiation levels in BC, and how do they compare to other jurisdictions with higher levels of solar PV penetration (Arizona, California, Germany)?**
    - **Where are the best locations in BC to install utility scale solar from the perspective of (i) regional solar radiation levels, and/or (ii) available transmission capacity?**
- **What would be a reasonable assumption regarding utility scale solar PV capacity factor and life?**
- **Assuming the solar investment was financed by BC Hydro, and using a 6 percent discount rate, what is the estimated levelized cost in today's dollars of a 5MW utility solar PV investment made in in (a) F2025 and (b) F2035, assuming delivery at (i) the plant gate and (ii) delivered to the Lower Mainland. Please show supporting assumptions (including capital cost assumptions, real power losses etc.) and calculations.**
- **Please describe any recent developments in utility solar PV that have the potential to significantly decrease costs, increase efficiency and/or increase flexibility (for example, through the use of smart inverters).**

[532] F62-1 Submission, p. 12
[533] F82-1 Submission, p. 34
[534] F62-1 Submission, p. 12

1.1.9 Other hydroelectric with storage

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." (F-1 Submission, Appendix L, p. 51)

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 B C. 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, the expansion.

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.[535]

Panel analysis and preliminary findings

The Panel finds that while this project may show promise, it is at an early stage of pre-development. Accordingly we are reluctant to draw any conclusions from the material presented by Alaska Hydro.

[535] F11-1 Submission, p. 1.

1.2 Alternative Capacity Sources

CEABC submits that "both Firm Energy and Dependable Capacity are important definitions affecting the determined cost of IPP projects, and should therefore be important topics to explore further. Firm Energy refers to the amount of annual energy that BC Hydro can count on to meet its load during critical low water years. For wind projects, 100 percent of their average annual generation is considered firm. For run-of-river projects, only 78 percent.

The reduced Firm Energy value for run-of-river projects assumes that 22 percent of the average annual energy either will not be available during critical low water, or it will not arrive at a time when BC Hydro can use it to serve its load. (e.g. Excess energy arriving during the freshet may have to be sold to the US or Alberta because BC Hydro doesn't have the loads available to utilize that energy. It should be noted that the Site C project will suffer from this same problem during the freshet season, due to the inflows from the West Moberly and Halfway Rivers. This, however, is a condition due to a lot of other variables outside the purview of the project, and many of which could change dramatically over the life of a project.)

Dependable Capacity refers to the amount of its capacity that a project can deliver during the critical high-load winter months. It is generally more dependent on the reliability of the fuel source than the technology, and it can be impacted by operating requirements such as minimum flow or ramping rate restrictions. It can be attributed to individual projects, and it is the essential attribute for calculating a capacity project's UCC.

It can also allow an energy project to receive a capacity credit in its overall Adjusted UEC. One interesting quirk of the capacity credit calculation is that a project with a lower capacity factor will earn a greater $/MWh credit than an equal sized project with a higher capacity factor. Thus, the Site C project, with a 50 percent capacity factor, receives a capacity credit of $11/MWh, whereas a geothermal project, with a 95 percent capacity factor, receives only $6/MWh. (This occurs because the capacity credit allows for a fixed annual amount of $50,000 per MW of dependable capacity, but that number has to be divided by the total MWh, and the number of annual MWh per MW of capacity is greater for the geothermal project.)"

CEABC further argues that "the whole issue of the value of capacity is highly questionable in the first place, since new capacity added to a system that is already in surplus (which BC Hydro's system is), is worth nothing unless it can be sold, and that is constrained by the market and by the transmission connections. Other than that, new capacity may postpone a later capacity addition for a few years, but only for a few years. Site C has been granted a capacity credit worth $56,000,000 per year for 70 years.

Another measure of capacity contribution is the ELCC (Effective Load Carrying Capability). Although it is not assigned to individual projects, it is used in portfolio analysis to determine when additional capacity resources are required. ELCCs for intermittent resources are determined through statistical analysis. Wind resources are assigned 26 percent of their installed capacity, and run-of-river resources ("ROR") are attributed 60 percent of their average megawatts during December and January".[536]

Site C is a dispatchable resource with a capacity factor of about 53 per cent, meaning there is enough water to run the plant at full output about 53 per cent of the time. The plant benefits from all of the upstream storage already in the Williston Reservoir. Because of this storage, Site C can be operated at full or partial output whenever it is needed to serve domestic load or to take advantage of a high priced market opportunity. Also, because of the upstream storage, when power from the plant is not needed it can be turned off and water flowing into the upstream reservoir can be stored for later use. BC Hydro and Powerex undertake.[537]

[536] F18-3 Submission, Appendix 4, pp. 2-3.
[537] F1-1 Submission, Appendix F, p. 6.

1.2.1 Purchases and existing resources

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, reportedly at a take or pay amount of $55 million.

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*; (emphasis added)[538]

With regard to natural gas fired generation, BC Hydro states that "[a]ny portfolio including natural gas-fired generation would challenge the consideration in the Terms of Reference to maintain greenhouse gas emissions at 2016/17 levels. It is inconsistent with the 100 per cent clean policy in the Climate Leadership Plan. In addition, the 93 per cent clean objective in the *Clean Energy Act* limits its role in resource planning."[539]

The Clean Energy Act 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
>
> 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

[538] F1-1 Submission, Appendix L, p. 49.
[539] F1-1 Submission, Appendix L, p. 37.

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.

Panel analysis and preliminary findings

BC Hydro states 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. BCF 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 acknowledges BC Hydro's comments on the unsuitability of natural gas fired generation, given the policy framework it describes. However, we note that the Climate Leadership 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". In addition the Climate Leadership Plan 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".

The Panel requests 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 is 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?

1.2.2 Pumped storage

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." [540]

[540] F-1 Submission, Appendix L, pp. 41-42

BC Hydro assesses the PS potential in the following table:[541]

Figure 24: Summary of Pumped Storage Potential

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. [542]BC Hydro believes pumped storage hydro is the least expensive capacity resource that meets B.C.'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.[543]

BC Hydro estimates the cost of providing wind resources with pumped storage capacity as:[544]

Figure 25: 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 pumped storage 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. [545]

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: [546]

[541] F-1 Submission, Appendix L, pp. 41-42
[542] F-1 Submission, Appendix Q, p. 4
[543] F-1 Submission, p. 75
[544] F-1 Submission, p. 63
[545] A2-9 Submission, pp. 37, 38
[546] A2-9 Submission, p. 35

Figure 26: 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.[547]

Three parties identified specific projects that they were considering or planning:

- Hydro Battery Inc.
- Clean Balance Power
- Van-Port Sterilizers

These projects are described below.

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 Pumped Storage Hydro 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 Clean Energy Project that is currently under construction on the Peace River in British Columbia, Canada. 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 the Site C Clean Energy Project. [548]

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.[549]

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

[547] F18-3 Submission, Appendix 4, p.6
[548] F67-1 Submission, Appendix: Concept Validation Assessment p. 1 of 22.
[549] F67-1 Submission, Appendix: Concept Validation Assessment p. 1 of 22.

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.[550]

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 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 Knight Piesold report is located just 60 km from downtown Vancouver and only 15 km from two 500 kV transmission lines (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".[551]

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".[552]

[550] F67-1 Submission, Appendix: Concept Validation Assessment p. 19 of 22.
[551] F33-1 Submission, p. 1.
[552] F99-1 Submission, p. 1.

Panel analysis and preliminary findings

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 requests that BC Hydro comment on the viability of pumped storage. BC Hydro is 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 is 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.).

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.

1.2.3 Battery storage

BC Hydro submission

The battery storage option focuses on solid state battery technologies that are available, and include Sodium Sulphur (NaS), Lithium ion (Li-ion), Advanced Lead Acid and Metal Air.[553] In BC Hydro's view, lithium-ion batteries are mature technologies in electronics and transportation applications, though still an emerging technology in large-scale grid applications. BC Hydro states:

> An analysis of current costs of capacity from lithium ion batteries in the U.S. context has been done by Lazard and Enovation Partners [2016]. Their estimate suggests that a 10 MW Li-Ion system offering four hours of energy storage will have UCCs in the range of $399 – 813 / kW-year (U.S.). Expanding Li-Ion energy storage beyond four hours offers minimal economies of scale. To have longer duration storage, the cost of Li-Ion based energy storage is likely to be over $1000 / kW-year under current prices.

BC Hydro concludes that, by virtue of the high costs of Li-Ion battery storage and the uncertain future cost reductions, Li-Ion battery storage is not included in resource portfolio analysis.[554]

Deloitte report

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.

[553] A-9 Submission, p. 15
[554] F-1 Submission, Appendix L, p. 52

Deloitte's research suggests that capital costs for utility-scale batteries are highly variable (particularly by technology and size), ranging from $2,000 to $6,000/kW, with O&M costs of 1-2 percent of capital costs. Deloitte further states that capital costs associated with battery storage are conservatively estimated to fall 50 percent by 2040.[555]

Deloitte references 18 recent reports on battery costs and trends in their report, including a recent Pacificorp 2017 study titled "Battery Energy Storage Study for the 2017 IRP", which estimates on page 20 the installed cost of a 10 MW, 20 MWh NCM Li-Ion energy storage system as ranging from a low side estimate of US $1,400/kW and a high side estimate of US $1,980/kW for the system. The Pacificorp report also forecasts a declining cost trend over the next ten years.[556]

Other submissions

Power Advisory LLC (Power Advisory) was engaged by the Canadian Wind Energy Association (CWEA) and CEABC to provide an independent assessment of the cost of various renewable generation projects, including battery storage. The Power Advisory report states:

> Battery storage is particularly well-suited for wind and solar integration given that it can also serve as an incremental load and therefore assist with managing surpluses more effectively than storage hydro. In addition, as a modular technology they can be located to address specific transmission and distribution constraints and potentially avoid costly upgrades to resolve these constraints. …
>
> Storage prices are falling faster than solar PV or wind technologies. Bloomberg New Energy Finance reports that as of year-end 2016 lithium-ion battery prices had fallen by almost 50% since 2014. Further cost declines are being realized and forecast. A recent study by a research team from the University of California and Technical University of Munich in Germany forecast the cost per MWh of a lithium-ion battery to decline at an average annual rate of 11.4% through 2020.[557]

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 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:[558]

Figure 27: 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 notes that in Denmark, EV owners are already earning money by plugging their cars into two-way charge stations.[559]

[555] A2-9 Submission, pp. 37, 38
[556] A2-9 Submission, p. 37
[557] F18-3 Submission, Appendix 1, p. 12
[558] F106-2 Submission, p. 33
[559] F62-1 Submission, pp. 14, 15

Panel analysis and preliminary findings

The Panel finds the results of the studies cited by the Wind Energy Association, Baker and Deloitte to be reasonable. Given the example of significant declines in costs of computer and telecommunications technology, it is believable that new technology may also drive battery storage costs down.

It is not clear what the impact, if any, on BC Hydro's alternative portfolio would be if instead of pumped storage, battery storage was assumed. In order to evaluate battery storage as part of the portfolio evaluation, **the Panel asks that BC Hydro provide:**

- **A description of the type of battery(s) the BC Hydro considered is required to firm up intermittent generation (such as wind/solar), including the battery type, power capacity, duration, technical life, ramp rate, provision of regulation and frequency response etc.**
    - **A description of the cost difference (if any) for batteries that (i) do not need to provide ancillary services such as regulation and frequency response and/or (ii) have shorter vs. longer number of hours of storage capability.**
    - **An estimate of the installed $/kW capital cost and annual O&M cost ($-year) for the battery(s) above: now, in 2023 and in 2027.**
- **Based on the assumption above, BC Hydro must estimate the $/kW-year cost of battery storage for battery(s) installed in (i) 2025 and (ii) 2035 (using BC Hydro cost of capital and a 6 percent discount rate).**
- **Comment on any other key differences between battery storage and pumped storage that may result in a preference for one over the other if costs were the same.**

1.2.4 Capacity focused DSM

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.[560]

In the F17-F19 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

[560] F-1 Submission, Appendix L, p. 5

- Electrification related initiates[561]

BC Hydro Submission

BC Hydro states 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.[562]

BC Hydro states 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.[563] BC Hydro further states 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.[564]

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).
>
> While BC Hydro's capacity-focused projects are still in the pilot stage, there are numerous examples of utilities already successfully implementing and realizing savings from capacity-focused DSM programs, including …

[561] F-1 Submission, Appendix L, p. 15; BC Hydro F17-F19 RRA, Exhibit B-1-1, p. 10-33, Exhibit B-14, BCUC IR 319.1
[562] F-1 Submission, Appendix L, p. 15 - 18
[563] F-1 Submission, Appendix L, p. 16
[564] F-1 Submission, Appendix L, p. 16

> The Arizona Corporation Commission has ordered [Arizona Public Service Company] to spend up to US$4 million to develop a residential, battery-storage program to facilitate energy-storage technologies through demand response or load management, allowing customers to lower energy use during times of peak demand. While this is only a pilot program, it reflects the dramatic advancements in battery storage and surge in current utility-scale, battery project.[565]

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 Revenue Requirements Application 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. [566]

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."[567]

Bakker submits, in its 2013 IRP, BC Hydro identified two types of capacity-focused DSM with substantial potential:

- Industrial load curtailment: 382 MW of expected capacity savings from large customers who agree to curtail load on short notice to provide BC Hydro with capacity relief during peak periods; and
- Capacity-focused programs: 193 MW in expected capacity savings from programs that leverage equipment (e.g. water heaters, heating, lighting and air conditioning) and load management systems to enable peak load reductions to occur automatically or with intervention through direct load control.[568]

Bakker submits that as a result, the potential for capacity-focused DSM savings identified in the IRP totalled 575 MW, but that for planning purposes in its 2013 IRP BC Hydro entirely disallowed capacity-focused DSM as an available resource, assuming it would deliver zero MW over the next 20 years.[569]

Bakker submits that BC Hydro has acknowledged the benefit of load curtailment to avoid costly generation capacity resource additions in the 2015 Rate Design Application, and has further advanced its investigation of capacity focused DSM in the form of load curtailment (including the industrial load curtailment pilot) and demand response (including a demonstration pilot using wireless load control relays on residential water heaters). Bakker submits that the contribution of capacity-focused DSM now appears to be much larger than the 0 MW presumed in the 2013 IRP.[570]

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.[571]

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[565] A-9 Submission, pp. 57-59
[566] F-29-3 Submission, p. 17
[567] F62-1 Submission, p. 15
[568] F-106-1 Submission, p. 87
[569] F-106-1 Submission, p. 87
[570] F-106-1 Submission, pp. 88, 89
[571] F-106-1 Submission, pp. 89, 90

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.[572]

Prophet River and West Moberly First Nation (PRWMFN) submitted a 2014 report by the Helios Centre as an attachment to their submission. This report states that capacity-focused DSM is an extremely important and cost-effective component for alternative portfolios to be compared to those built around Site C. [573]

Panel analysis and preliminary findings

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 requests BC Hydro to explain why it has only identified capacity DSM savings for the industrial sector.

The Panel therefore seeks 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..). Please include consideration of time of use and interruptible rate structures.

[572] F-106-1 Submission, p. 90
[573] F28-2 Submission, Appendix (Helios Centre), p. 10

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 U.S. as a result of the Columbia River Treaty ratified in 1964. The Province 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 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 an the 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.[574]

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”.[575]

Allied Hydro 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 .The recommendation is to " modernize" the CRT.

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.

[574] F-1 Submission, Appendix L, p. 48.
[575] F36-1 Submission, p. 15.

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 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." (Exhibit F-24-1, pp. 15-16)

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".[576]

Allied Hydro further 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.

[576] F60-1 Submission, p. 14.

- 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.
- 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.

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 .The recommendation is to "modernize" the CRT. 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 W to 500 kV). Such a 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 $750 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/MWhr, assuming a 30 year arrangement.[577]

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".[578]

Panel analysis and preliminary findings

The Columbia River Entitlement is not available to BC Hydro because of the restrictions in the Clean Energy Act. 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.

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 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.

[577] F24-1 Submission, pp. 14-16.
[578] F106-2 Submission, Executive Summary, pp. i-ii.

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 that because the treaty could be terminated on notice, in ten 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 notes 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 Clean Energy Act required.

The Panel also notes Allied Hydro'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 s further 12 years.

3.0 Appendix C – List of questions for BC Hydro

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry Respecting Site C

PANEL QUESTIONS FOR BC HYDRO

	Question	Page No.
1.	the Panel asks BC Hydro to add a column to Table 6 of its submission (i.e. F1-1, p. 24) showing the PMB plan dates for each interim milestone and to comment on any material variances between the PMB plan dates and the actual completion dates.	15
2.	the Panel asks BC Hydro to add two columns to Table D-3, one column for the planned percentage complete by June 30, 2017 according to the PMB schedule and one column for the planned percentage complete by June 30, 2017 according to the FID schedule. BC Hydro is to comment on any material variances between the planned and actual percentages complete.	15
3.	The Panel asks BC Hydro to provide its current assessment of the probability that the project will achieve the river diversion in September 2019.	15
4.	The Panel asks BC Hydro to provide an update on its discussions with PRHP, and to explain in detail how the lost time on the main civil works schedule can be recovered.	15
5.	the Panel asks BC Hydro to provide an analysis of the risks to the project schedule for construction activities subsequent to the river diversion, including but not limited to the generating station and spillway and the transmission work packages.	20
6.	the Panel asks BC Hydro to provide a point-in-time assessment of its progress to June 30, 2017 using the earned value method, including analysis of schedule variance, cost variance, schedule performance and cost performance as compared to both the FID and PMB plans.	22
7.	The Panel asks BC Hydro to provide a detailed analysis of the claims outstanding for work completed or in progress as of June 30, 2017, including the amount claimed and BC Hydro's assessment of the final settlement amount.	22
8.	the Panel asks BC Hydro to provide a detailed breakdown and justification of its $630 million estimate.	33
9.	The Panel asks BC Hydro to explain why it chose a contingency amounting to 9.5 percent of project costs, and what factors suggested this would be sufficient. BC Hydro is also requested to provide backup documentation consistent with the	33

	requirements of section 5(vi) of the Commission's 2015 CPCN Guidelines.	
10.	The Panel asks BC Hydro to estimate the total price of its two major outstanding procurements, generator station and spillway and transmission, in light of its experience with the main civil works procurement, to identify possible cost overruns as a consequence, and to identify whether these possible cost overruns are already accounted for in the $1 billion anticipated contingency usage.	33
11.	The Panel asks BC Hydro to provide a quantitative and qualitative analysis of its contingency allocated and committed to June 30, 2017, and its projections for how it expects contingency to be allocated and committed as the remainder of the project progresses.	33
12.	The Panel asks BC Hydro to provide an analysis of the $315 million that has been identified as savings on forecast interest during construction, indicating what effect a rise of 0.5 percent, 1 percent or 2 percent in interest rates would have on the amount of the savings.	33
13.	The Panel asks BC Hydro provide an updated version of table D-4 in appendix D of their submission, adding a quantification of the budget impact for each risk identified in the table, should the risk come to pass. This analysis should be consistent with section 4(v) of the Commission's 2015 CPCN Guidelines.	33
14.	The Panel asks BC Hydro to provide the cost of its new approach to the Highway 29 realignment, the degree to which the cost is higher than budgeted, and the degree to which any cost overrun will need to be covered by contingency.	33
15.	the Panel asks BC Hydro to comment on the likelihood of each of the three outcomes listed by Deloitte.	34
16.	The Panel requests that BC Hydro respond to the following questions related to its industrial demand forecast: • With regard to BC Hydro's forecast for LNG load, please 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. • Please explain how the completion risk and, separately, the timing risk are factored into BC Hydro's current load forecast in relation to each of the following. If there are differences between the factoring of completion and timing risk for the three LNG projects as compared to other industrial projects/customers, please identify, explain and justify the differences: **a.** FortisBC Tilbury LNG Phase 2; **b.** Woodfibre LNG; **c.** LNG Canada; and **d.** Other industrial projects and customers.	55–56

- Based on Table 11 of BC Hydro's submission (and provided in this report above) which shows the incremental industrial load impacts of known developments and the more detailed discussion in Appendix J, for each specific development identified in Appendix J in each of the large industrial (transmission) sectors, please quantitatively and qualitatively provide the probability of each identified increase (or decrease) in load materializing. For the developments which are expected to result in increases to the industrial load, please explain in detail the risks which may prevent the identified loads from materializing and assign a risk level to each identified load.

The Panel has a number of detailed questions based on the information provided by BC Hydro in Appendices H, J and K of its August 30, 2017 submission (i.e. F1-1). These questions are as follows:

On page 6 of Appendix H to F1-1, BC Hydro explains: "The small number of proponents that are proposing to electrify from the grid (FortisBC Energy Inc., LNG Canada and Woodfibre LNG) precludes confidential aggregation of a probabilistic Load Forecast."

In Tables J-8 and J-9 on page 23 of Appendix J BC Hydro provides revised schedules for the FortisBC Tilbury LNG and LNG Canada facilities.

In Table K-1 of Appendix K, BC Hydro provides expected LNG load schedules.

Based on the above information, please provide the following information:

- Please confirm, otherwise explain, that the Fortis Tilbury and LNG Canada loads and demands are the total expected electricity loads and demands from these two projects and not probability weighted amounts.
- Please provide separate unweighted load and demand schedules to F2036 for each of the FortisBC Tilbury LNG Phase 2 project, the Woodfibre LNG project and the LNG Canada project. Please provide schedules for both what was included in the Current Load Forecast and what is included in the revised outlook. Please use the same format as used in Tables J-8 and J-9.
- If there were other LNG projects (weighted or unweighted) included in the Current load and demand forecasts, please identify those projects and provide their respective Current and revised load and demand schedules. Please comment on any differences.
- In Tables J-8 and J-9, BC Hydro shows Tilbury and LNG Canada loads. In Table K-2, BC Hydro shows total LNG load. Please explain where the remaining load is coming from. Is it all from the Woodfibre LNG project? Please elaborate.

The Panel also invites further submissions from other parties on the updates made to the LNG forecasts and others identified changes in industrial load as summarized in Table 21, including any further data that could assist the Panel in concluding on the implications of developments since the Current Load Forecast was prepared that will impact industrial demand in the short, medium and longer

	terms.	
17.	The Panel invites submissions from BC Hydro and other parties on the implications of the historical overestimates on the Panel's assessment of the accuracy of the industrial load included in the Current Load Forecast.	59
18.	The Panel requests that BC Hydro respond to the following questions related to its forecast drivers for GDP and disposable income: • Please address the differences noted by Deloitte in its Load Forecast Assessment related to GDP and disposable income. Please obtain whatever information from Deloitte that BC Hydro deems necessary in order to respond to this request. • Please provide an analysis of the GDP and disposable income projections developed by RFEC compared to the Conference Board of Canada (CBoC) estimates and explain the reasons for significant differences in projections. In particular, please explain why the RFEC projection for GDP is not consistent with the CBoC's projections after the first five years. • Please quantify the effect on BC Hydro's load forecast of reducing its GDP forecast to align with the CBoC's GDP projections. • Please provide data/information on the historical accuracy of both the CBoC's and RFEC's GDP forecasts and comment on which of these parties' forecasts has historically been more accurate. • Please explain what impact, if any, the recently announced halt to the Aurora LNG Project will have on GDP projections developed by RFEC. For the purposes of this response, please assume that the Aurora LNG Project will not proceed. The Panel also invites submissions from other parties on these inputs to could assist the Panel in concluding on the reasonableness of BC Hydro's GDP and other forecast drivers.	61
19.	Regarding the appropriateness of BC Hydro's assumptions related to price elasticity and future rate increases, the Panel requests BC Hydro to respond to the following questions: • Please provide a more detailed explanation as to how elasticity, a measure the Panel understands to be at the margin, is impacted by DSM. • Please confirm, or explain otherwise, that BC Hydro has assumed zero real rate increases as part of its load forecast beyond 2024 (i.e. beyond the 2013 10 Year Rates Plan) and that any rate increases introduced between F2025 and F2036 would lower the Current Load Forecast. If confirmed, please explain the basis for and the reasonableness of this assumption. • Please provide a detailed explanation of the risks which might prevent BC Hydro from achieving its projected zero real rate increases.	64

	The Panel also **invites submissions from other parties to assist the Panel in assessing the appropriateness of the assumptions related to price elasticity and future rate increases.**	
20.	The Panel requests 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 (for example, 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.	66
21.	BC Hydro is asked to confirm that there are no other planned resources that have been excluded from these tables. Although energy and capacity from existing and committed Heritage resources are the subject of government approved integrated resource plans, it would be informative if BC Hydro would comment on Dr. Ruskin's submission and further explain how BC Hydro determined how much energy and capacity are available from existing and committed Heritage resources.	68
22.	BC Hydro is requested to update this information and provide an explanation as to the impact these issues could have on export sales. This issue has been included in the questions that follow. The Panel requests that BC Hydro respond to the following questions: ▪ Please provide a breakdown BC Hydro's market price forecast for F2025 (US $36/MWh) and F2034 (US $46/MWh) showing (in Can $ and US $): Mid C price; wheeling costs; real power losses; other (please describe). o Please explain whether (i) the market price forecast assumes the Mid C price is set by a CCGT; (ii) whether Mid C prices over the past 5 years support this assumption, and (iii) to what extent lower price renewables may increasingly set the Mid C price at lower levels in the future. ▪ Please provide, in graph and table form, the average annual Mid C price (on-peak, off-peak and all hours) for the last 20 years. ▪ Please provide in graph and table form, for each year from F2013 to F2017, a comparison of (i) the average all hours Mid C price for that year and (ii) the $/MWh price that BC Hydro received (after transaction costs, such as wheeling and power losses) for the sale of its surplus energy. ▪ Please provide, in graph and table form, for each year from F2015 to F2017, the monthly all hours, on-peak and off-peak Mid C price. ▪ Please describe the energy and capacity markets in the US and Alberta that BC Hydro considers it will be able to participate in. o Please describe any key difficulties BC Hydro might face in participating in the US and Alberta market, such as access to	72–74

transmission and regulatory approvals required.

- Please explain if any of BC Hydro's key export markets (such as California, Alberta) have, or are currently considering, legislative or regulatory requirements that would restrict BC Hydro from selling into their markets (such as self-sufficiency requirements, renewable compliance market), or the price BC Hydro could offer (such as a requirement to bid in at zero).

- Please provide in table form the percentage of total annual generation expected from Site C for each month of the year.
  - Using the monthly delivery factor adjustments included in BC Hydro's SOP program, please provide an estimate of the seasonally adjusted value of Site C energy, using a starting (pre-seasonally adjusted) value of $45/MWh. Please show supporting calculations.
- Please provide additional details on the transmission line to (a) the US and (b) Alberta, including (i) the maximum rating (for BC exports), (ii) the extent to which it is constrained to a lower level (and if so what is the lower level); (iii) how much firm and non-firm transmission capacity is generally available; and (iii) what percentage of the time the transmission line is on average constrained.
- Has BC Hydro considered restoring the capacity of the tie-line to Alberta? Similarly, has BC Hydro considered building additional transmission capacity to the US? Would either of these transmission projects offer additional economic opportunities for the sale of surplus energy/capacity provided by Site C? Please elaborate.
- With regards to the flexibility benefits of Site C, please explain whether technological advances could impact the market value of these flexibility benefits (for example, advancements in smart inverter technology).
- Please describe rough load zones, no run zones and minimum generation constraints (e.g. transmission reliability, hydraulic balance, fisheries requirements, ice flows etc…). Is Site C or its generators expected to have these restrictions? If so, what are they and how will they effect Site C's operations and flexibility? If not, why not? Please elaborate.
- Please describe synchronous condense. Are any features of synchronous condense related to the ability to make adjustments from high generation levels to no generation without a start/stop? If so, what are they? Please elaborate.
- Please elaborate on how the design decision to include synchronous condense in all six generating units is related to the opportunity to sell the capacity and flexibility afforded by Site C.
- Has BC Hydro analyzed selling Site C's surplus energy and capacity within BC at discounted rates to incent incremental consumption (i.e. similar to the Freshet Rate pilot)? If so, please elaborate. If not, why not?

Please discuss the potential implications and impact of Powerex joining, or potentially not joining, the Energy Imbalance Market and how that relates to the

	value of Site C energy and capacity. Include an analysis and discussion of the potential impact resulting from an expansion of Energy Imbalance Market.	
23.	We have made the following assumptions with regard to additional terms in the question posed above: 1. *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. 2. *Grid reliability* means that Site C and alternative portfolios should include any network costs required to maintain BC Hydro's grid reliability standards. 3. *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. The Panel invites comment on the interpretations above.	76
24.	BC Hydro is requested to provide each of these two adders without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.	86
25.	BC Hydro is also requested to provide this adder without the effect of the energy increase, and to provide a separate adder for the effect of this energy increase.	86
26.	BC Hydro is requested to explain in more detail the assumptions and calculations used to determine the values of these three input parameters.	86
27.	BC Hydro is requested to explain in more detail how the specific amount for "Capacity Credits" was calculated/determined, if they are related to the increase in capacity from 1100MW to 1132.2MW or 1145MW, and why they are included in this spreadsheet.	86
28.	BC Hydro is to explain in detail how these annual amounts for both of these direct inputs were calculated from the sunk and termination costs reported elsewhere in BC Hydro's report. Please also comment on the appropriateness of these adders to the UEC given the definition of UEC that the Panel has adopted.	86
29.	BC Hydro is requested to explain why that adjustment has not been made.	87
30.	The Panel notes the submission of the David Suzuki Foundation regarding the economic impact of the Site C project on "natural capital". However, there is no analysis of the impact of the alternative portfolio so there is no way for the Panel to include this in its economic assessment. The DSF is invited to provide further evidence on this issue. The Panel is unclear how, or whether, this is a direct cost to	87

	ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. We invite further comment on this issue.	
31.	The Panel finds that if Mikisew Cree First Nation is correct in its submissions relating to either the potential downstream impacts on the PAD (Peace Athabasca Delta) or litigation relating to potential treaty infringements of Site C then this could impact the costs to Site C and ratepayers, and therefore result in an upward adjustment of the UEC for Site C energy. The Panel is unclear how, or whether, this is a direct cost to ratepayers. It appears to the Panel that this is a cost that would be borne by taxpayers. We invite further comment on this issue.	87
32.	We request that BC Hydro explain all assumptions made in its analysis of the UEC for the alternative portfolio.	92
33.	The firm energy, columns F and G, are based on calculations which use these monthly energy profiles along with the project capacities, the source for which is undocumented. BC Hydro is requested to provide this data.	92
34.	A “soft cost adjustment” of 1.025 is applied. BC Hydro is requested to explain how and why it selected this soft cost number? BC Hydro is requested to provide this data.BC Hydro is requested to explain how and why it selected this soft cost number.	92
35.	BC Hydro is requested to explain why it used $50.36 per MWh for a Mid C price and why it used these values for super peak, peak and off-peak.	92
36.	BC Hydro is requested to explain in more detail the calculations for cost of incremental firm transmission and line losses.	92
37.	Wind integration and network upgrade are both upward adders. However, in contrast to the unexplained inputs and formulas for CIFT and line losses, the wind integration and network upgrade adders appear simply as numbers in this spreadsheet. BC Hydro is requested to explain in more detail the basis for selecting the amounts for these adders.	92
38.	BC Hydro is requested to explain why it selected 4% for an inflation adjustment.	92
39.	Please explain why the $105/MWh appears to be based on the weighted average of only the first 8 projects listed in the portfolio.	92
40.	BC Hydro is requested to explain its assumptions regarding refurbishment of projects in its alternative portfolio and how those assumptions affect the calculation of the UEC.	93
41.	A further timing issue is that the costs of many clean energy technologies are decreasing over time – some significantly. If a resource is expected to come on stream in 2030, it may have a lower real cost than a resource being built today.	93

<table>
<tr><td></td><td>This appears to be a limitation to the UEC analysis provided by BC Hydro. BC Hydro is requested to address how this assumption is handled in its UEC analysis.</td><td></td></tr>
<tr><td>42.</td><td>BC Hydro is requested to clarify its assumptions underlying financing costs.</td><td>93</td></tr>
<tr><td>43.</td><td>BC Hydro is requested to comment on CEABC's submission that the wind integration charge "is an allowance to compensate for a possible lost opportunity to sell capacity in the day forward market".</td><td>93</td></tr>
<tr><td>44.</td><td>BC Hydro is requested to clarify the portfolio assumptions.</td><td>103</td></tr>
<tr><td>45.</td><td>BC Hydro is requested to clarify which portfolio(s) were used in its alternate portfolio UEC calculation.</td><td>103</td></tr>
<tr><td>46.</td><td>BC Hydro is requested to model a reduction in the capital cost of wind energy as follows:
Table 56: Percent Reductions in Capital Cost of Wind Energy
<table>
<tr><th>2020</th><th>2025</th><th>2030</th><th>2035</th><th>2040</th></tr>
<tr><td>10%</td><td>25%</td><td>30%</td><td>40%</td><td>45%</td></tr>
</table></td><td>103</td></tr>
<tr><td>47.</td><td>BC Hydro is requested to model a capital cost of solar energy of $1.64/W in 2017, and a reduction of 60% in the capital cost by 2040.</td><td>104</td></tr>
<tr><td>48.</td><td>BC Hydro is requested to update the current battery cost and to incorporate the assumption that the cost of battery storage falls by 50% by 2040.
For these analyses, BC Hydro may focus on the following scenarios:
Low Load forecast with IRP DSM plan. Site C terminated
Mid Load forecast with IRP DSM plan. Site C terminated
High Load forecast with IRP DSM plan. Site C terminated</td><td>104</td></tr>
<tr><td>49.</td><td>Deloitte's portfolio analysis outputs include a schedule of the capital and O&M costs by alternative resource and the price of energy produced by the portfolio. However that information does not appear to have been provided with the results of BC Hydro's portfolio analysis. BC Hydro is requested to provide this information for its portfolio analyses.</td><td>104</td></tr>
<tr><td>50.</td><td>BC Hydro is requested to explain whether it has considered the relative risk of the projects in the alternative portfolio. Parties are also requested to provide comment on the approach to the discount rate recommended by the CD Howe Institute.</td><td>104</td></tr>
</table>

51.	Given the future incremental portfolio after the successful completion of Site C, how valid is the assumption of no real rate increases given the cost of the incremental additions? BC Hydro is requested to respond to this question.	104
52.	BC Hydro is requested to provide clarification of the assumptions it applied regarding the life of alternative projects and if it has considered whether the useful life, with refurbishment, of certain components of the alternative projects may extend beyond the assumed depreciation period.	104–105
53.	The Panel asks BC Hydro to confirm that the assumption made in its RRIM analysis that Site C is delivered in 2024 and within the budget of $8.335 billion is both reasonable and internally consistent.	106
54.	The Panel asks BC Hydro to confirm that it has used its mid forecast from the F17-F19 RRA in this RRIM analysis.	106
55.	The Panel asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using each of the mid load forecast, the low load case and the high load case from the F17-F19 RRA for the following scenarios: • Site C goes into service in 2023, the current PMB schedule, at a cost of $8.335 billion; • Site C goes into service in 2024, the current FID schedule and one year later than the current PMB schedule, at a cost of $9.169 billion, being 10 percent over budget[579]; • Site C goes into service in 2024 at a cost of $10.002 billion, being 20 percent over budget[580]; and • Site C goes into service in 2023 at a cost of $8.335 billion, and the capital costs are amortized over 40 years rather than 70. For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM scenario assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.	106–107
56.	Of specific concern are the following additional cost inputs BC Hydro has added to its model outlined in Appendix R reflecting differences between suspending the project in comparison to the base case completion of the model: 1. There is no explanation of why future sustaining capital expenditures have increased from $2.1 billion in the base case to $2.4 billion in the suspension/restart scenario.	110

[579] $8,335 million * 110%
[580] $8,335 million * 120%

	2. There is no explanation of the incremental energy costs of $0.5 billion and the incremental demand side expenditures of $0.9 billion and how they were arrived at.[581] BC Hydro is requested to address and provide an explanation for these cost differentials.	
57.	The Panel also asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using the mid load forecast, the low load forecast and the high load forecast from the F17-F19 RRA for the following scenario, using the lowest-cost portfolio of alternative energy that BC Hydro has created in response to the questions asked in section 6 above: • Site C is suspended December 31, 2017 and restarted in 2024, with suspension, maintenance and remobilization costs as per BC Hydro's estimates presented in their submission[582]. For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM scenario assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.	110-111
58.	The Panel asks BC Hydro to use its RRIM model to calculate the cost impact to ratepayers relative to BC Hydro's current baseline using the mid load forecast, low load forecast and high load forecast from the 2016 Revenue Requirements Application for the following scenarios, and all using the lowest-cost portfolio of alternative energy that BC Hydro has created in response to the questions asked in section 6 above: • Site C is terminated December 31, 2017, with sunk costs at that date of $2.1 billion, and termination and remediation costs of $1.1 billion. Site C regulatory account costs are amortized over 10 years. • Site C is terminated December 31, 2017, with sunk costs at that date of $2.1 billion, and termination and remediation costs of $1.1 billion. Site C regulatory account costs are amortized over 20 years. For all of the cost impact scenarios above, the Panel asks BC Hydro to present details of any DSM assumptions, portfolios of alternative energy that it assumes, and their associated unit energy costs.	120
59.	BC Hydro is requested to provide further comment on the table above. In particular, the Panel would like to know its assessment of the cost of any potential refurbishments and upgrades that are 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.	Appendix A (A)-7
60.	Given this, the Panel requests that BC Hydro explain why it is not renewing more	A-8

[581] F1-1 Submission, Appendix R, pp. 7-9.
[582] BC Hydro section 7

	IPP contracts.	

61.	The Panel therefore asks 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.
		A-11

62.	BC Hydro is requested to provide any forecasts or estimates of future wind energy costs.	A-16
63.	The Panel therefore seeks input from BC Hydro and other parties on the following questions: 4. 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? 5. 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? Please provide BC Hydro's 2016 Wind Integration Study, or indicate when it will be available.	A-16

64.	The Panel therefore seeks input from BC Hydro and other participants on the following questions: • Clearly identify how much energy and associated capacity is 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. o The annual energy/capacity savings and associated utility costs over the analysis period should be clearly stated. o As the focus of this review is on costs to ratepayers (rather than broader BC benefits) please (i) estimate the utility (rather than total resource) cost, and (ii) assume that the incremental DSM options are delayed until is a need for new resources. o The energy/capacity savings of DSM should be adjusted to reflect delivery (i.e., energy grossed up for distribution losses), and the cost should be adjusted for the DSM energy/capacity shape. o Please do not include codes and standards/rate design in the incremental DSM portfolios.	A-20
65.	The Panel invites BC Hydro to respond to the submission of Kleana Power. The Panel invites parties to provide submissions on specific project data (including capital and operating costs, capacity factor and economic life) on potential Run-of-river projects.	A-23
66.	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.	A-25
67.	Parties are invited to provide updated costing data (capital, O&M, capacity factor) and long term availability estimates for biomass.	A-25
68.	The Panel therefore seeks input from BC Hydro and other participants on the following questions: • What is the current BC installed capacity cost of a 5MW utility solar PV instillation ($/Watt) and operating cost ($/year and $/MWh)? o What would a reasonable forecast of the cost be in F2025 and F2035? • What are the regional solar radiation levels in BC, and how do they compare to other jurisdictions with higher levels of solar PV penetration (Arizona, California, Germany)? o Where are the best locations in BC to install utility scale solar from	A-27–A-28

	the perspective of (i) regional solar radiation levels, and/or (ii) available transmission capacity? • What would be a reasonable assumption regarding utility scale solar PV capacity factor and life? • Assuming the solar investment was financed by BC Hydro, and using a 6 percent discount rate, what is the estimated levelized cost in today's dollars of a 5MW utility solar PV investment made in in (a) F2025 and (b) F2035, assuming delivery at (i) the plant gate and (ii) delivered to the Lower Mainland. Please show supporting assumptions (including capital cost assumptions, real power losses etc.) and calculations. • Please describe any recent developments in utility solar PV that have the potential to significantly decrease costs, increase efficiency and/or increase flexibility (for example, through the use of smart inverters).	
69.	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. BCF 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.	A-31
70.	The Panel requests that BC Hydro provide an analysis of how much, if any, natural gas fired generation can be relied upon for backup capacity given: c) Section 6 and the 93 percent clean objective in the CEA d) the Terms of Reference for this report, under there should be no increase in GHG intensity. BC Hydro is 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?	A-31
71.	The Panel requests that BC Hydro comment on the viability of pumped storage. BC Hydro is 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 is 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.). 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	A-35

	reduce the cost of the pumped storage project.	
72.	the Panel asks that BC Hydro provide: • A description of the type of battery(s) the BC Hydro considered is required to firm up intermittent generation (such as wind/solar), including the battery type, power capacity, duration, technical life, ramp rate, provision of regulation and frequency response etc. o A description of the cost difference (if any) for batteries that (i) do not need to provide ancillary services such as regulation and frequency response and/or (ii) have shorter vs. longer number of hours of storage capability. o An estimate of the installed $/kW capital cost and annual O&M cost ($-year) for the battery(s) above: now, in 2023 and in 2027. • Based on the assumption above, BC Hydro must estimate the $/kW-year cost of battery storage for battery(s) installed in (i) 2025 and (ii) 2035 (using BC Hydro cost of capital and a 6 percent discount rate). Comment on any other key differences between battery storage and pumped storage that may result in a preference for one over the other if costs were the same.	A-37
73.	Given this, the Panel requests BC Hydro to explain why it has only identified capacity DSM savings for the industrial sector. The Panel therefore seeks 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..). Please include consideration of time of use and interruptible rate structures.	A-40–A-41

4.0 Appendix D – Process for Site C public notice of inquiry and invitation for public comments

Phase I

August 3, 2017: News release announced Site C inquiry initiated August 2, 2017 by Order in Council 244

August 4 – 17, 2017: Digital banner ad (right) displayed on Post Media Network (estimated impressions: 2.75M)

August 8 – 21, 2017: Quarter-page, black and white advertisements ran in print newspapers as listed below. A PDF of the ad's contents is available.

August 9, 2017: News release invites public "to submit data and analysis within the scope of the inquiry to the BCUC by August 30, 2017," and publishes the inquiry process on www.sitecinquiry.com.

August 21, 2017: Information release announces launch of a notification feature for Site C inquiry news and updates; subscribers "receive periodic notifications of news and updates related to the Site C Inquiry via email."

Phase II

August 31, 2017: News release announces schedule for Site C Inquiry Community Input Sessions

Sept 5 – 15, 2017: Print ads

Sept 6 – 22, 2017: Digital advertising

Sept 14 – Oct 10, 2017: Radio spots will announce the Community Input Sessions in various locations.

Location	Date (2017)	Time	Venue
Vancouver	Saturday, September, 23	1:00–5:00 p.m.	1125 Howe Street , 12th floor
Kamloops	Sunday, September 24	6:00–10:00 p.m.	Kamloops Coast Hotel
Kelowna	Monday, September 25	6:00–10:00 p.m.	Kelowna Coast Capri
Nelson	Tuesday, September 26	6:00–10:00 p.m.	Nelson Best Western Hotel
Prince George	Friday, September 29	6:00–10:00 p.m.	Prince George Ramada Hotel
Hudson's Hope	Saturday, September 30	6:00–10:00 p.m.	Pearkes Centre
Fort St. John	Sunday, October 1	6:00–10:00 p.m.	Fort St. John Pomeroy Hotel
Fort St. John	Monday, October 2	6:00–10:00 p.m.	Fort St. John Pomeroy Hotel
Vancouver	Thursday, October 5	6:00–10:00 p.m.	1125 Howe Street , 12th floor
Nanaimo	Tuesday, October 10	6:00–10:00 p.m.	Nanaimo Coast Bastion Hotel
Victoria	Wednesday, October 11	6:00–10:00 p.m.	Delta Ocean Pointe Hotel

4.1.1 List of market/publications where advertisements (seeking public input) were published

Lower Mainland - Vancouver
Abbotsford News (includes Mission)
Abbotsford News
Agassiz-Harrison Observer
Aldergrove Star
Chilliwack Progress
Cloverdale Reporter
Hope Standard
Langley Advance
Langley Times
Maple Ridge/Pitt Meadows News
Mission City Record
North Delta Reporter
Peace Arch News (White Rock)
Surrey Now Leader
Surrey Now Leader (includes Cloverdale)
Vancouver Province
Vancouver Province - Fr/Su
Vancouver Sun
Vancouver Sun - Fr-Sa
Bowen Island Undercurrent
Burnaby Now
Delta Optimist
Richmond News
The New West Record
Tri City News
Vancouver Courier
Westender
Westside Weekly

BC Interior - North
100 Mile House Free Press
Bella Coola Coast Mountain News
Burns Lake District News
Fort St. James Caledonia Courier
Haida Gwaii Observer
Houston Today
Kitimat Northern Sentinel
Prince Rupert Northern View
Quesnel Cariboo Observer
Smithers Interior News
Terrace Standard
Vanderhoof Omineca Express
Stuart/Nechako Advertiser
Williams Lake Tribune
Dawson Creek Mirror
Fort Nelson News
Fort St. John Alaska Highway News
Prince George Citizen
Prince George Extra

BC Interior - South
Ashcroft Cache Creek Journal
Barriere N. Thompson Star Journal
Castlegar News
Clearwater N. Thompson Times
Cranbrook Townsman
Creston Valley Advance
Fernie Free Press
Golden Star
Grand Forks Gazette
Greenwood Boundary Creek Times*
Kelowna Capital News
Keremeos Review
Kimberley Bulletin
Lakeshore Shuswap Market News
Nakusp Arrow Lakes News
Nelson Star
Penticton Western News
Princeton Similkameen Spotlight
Revelstoke Times Review
Rossland News
Salmon Arm Observer
Sicamous Eagle Valley News
Summerland Review
Trail Times
Vernon Morning Star
Winfield Lake Country Calendar
Bridge River Lillooet News
Columbia Valley Pioneer
Courier Extra (Kelowna)
Kamloops This Week
Kelowna Daily Courier
Lumby Valley Times
Okanagan Advertiser
Peachland View
Penticton Herald
Penticton Herald Extra
Pique Newsmagazine
Squamish Chief
Whistler Question
Okanagan Saturday

Vancouver Island
Alberni Valley News
Campbell River Mirror
Chemainus Valley Courier
Comox Valley Record
Duncan Cowichan Valley Citizen
Ladysmith Chronicle
Lake Cowichan Gazette
North Island Gazette
Nanaimo News Bulletin
Parksville Qualicum News
Tofino/Ucluelet Westerly News
Peninsula News Review
Saanich News
Oak Bay News
Victoria News
Goldstream News Gazette
Sooke News Mirror
Gabriola Sounder
Victoria Times Colonist
Victoria Times Colonist (non subscribers)

Independents
Gulf Islands Driftwood
Merritt Herald
Oliver Chronicle
Osoyoos Times
Sunshine Coast - The Local
Valemount Valley Sentinel
Coast Reporter
Powell River Peak (and Shopper

5.0 Appendix E – First Nations consultation

The British Columbia Utilities Commission has invited the following First Nations to the First Nations Input Sessions:

1. West Moberly and Prophet River First Nation
2. Saulteau First Nation
3. Blueberry River First Nation
4. Doig River First Nation
5. Halfway River First Nation
6. McLeod Lake First Nation
7. Fort Nelson First Nation
8. Dene Tha' First Nation
9. Horse Lake First Nation
10. Duncan's First Nation
11. Mikisew Cree First Nation
12. Tsilhqot'in National Government and Homalco First Nation
13. Sekw'el'was Cayoose and N'Quatqua First Nations

First Nation Input Session locations confirmed, as of September 14:

1. Fort St. John - West Moberly and Prophet River First Nation
2. Prince George - McLeod Lake First Nation
3. Victoria - Mikisew Cree First Nation
4. Vancouver - Sekw'el'was Cayoose and N'Quatqua First Nations
5. Vancouver - Tsilhqot'in National Government and Homalco First Nation

6.0 Appendix F – Summary of preliminary findings

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry Respecting Site C

SUMMARY OF PRELIMINARY PANEL FINDINGS

	Findings	Page No.
1.	Based on our review of the information provided, the Panel has identified numerous areas where additional information is required and has therefore requested in this report that BC Hydro provides additional information. We request that BC Hydro respond to the questions in this report, which are summarized in Appendix C, by October 4, 2017.	1
2.	We recommend that BC Hydro, instead of submitting all its responses at the deadline, provide its responses to the Commission as they become available so that the Panel and other parties are able to review the information on a timelier basis.	1
3.	Throughout this Preliminary Report, the Panel has made preliminary findings and seeks additional information. Readers are cautioned that these are preliminary and subject to change as we complete the consultation process and as additional information becomes available	1
4.	The Panel finds that the project is, as of June 30, 2017, on time for a final in-service date of November 2024.	14
5.	The Panel finds that it is not yet in a position to determine whether the project will remain on schedule for completion by November 2024.	19
6.	The Panel finds that it is unable to determine whether the project is currently on budget.	22
7.	The Panel finds that if the river diversion is not achieved in September 2019, the project will not remain within its budget of $8.335 billion.	32
8.	the Panel finds that it does not have sufficient information to assess the total possible budget overruns once the Site C project is complete.	33
9.	The Panel finds that these results are indicative of BC Hydro's ability to deliver projects on budget on the average, but that they provide little insight into the likelihood that Site C will be delivered on budget, since Site C is so much larger than any other project BC Hydro has managed in its recent history.	34
10.	the Panel gives 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 guidance on risks rather than specific evidence.	34
11.	The Panel finds that $1.1 billion is a reasonable estimate of the costs of suspension	38

	and maintenance for the project.	
12.	The Panel finds there is significant variance between the BC Hydro's and Deloitte's estimates with respect to costs related to restarting the project.	38
13.	Given the lack of clarity with respect to some of the costs the Panel finds 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.	39
14.	The Panel finds it is these differences that account for much of the variance between the BC Hydro estimate and the Deloitte estimate.	*39*
15.	The Panel finds that both estimates are reasonable, and that an appropriate estimate for termination costs is $391 million	43
16.	the Panel finds that both estimates are reasonable, and that an appropriate estimate for remediation costs is $662 million	43
17.	the Panel finds the total cost for termination and remediation to be $1.1 billion.	43
18.	The Panel finds it is not yet in a position to make its finding on impact of recent developments in the industrial sector due to insufficient information.	56
19.	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 have been considerably below industry benchmarks. However, the Panel finds that we cannot yet assess the reasonableness of BC Hydro's industrial load forecast due to insufficient information	59
20.	The Panel finds that it is not yet in a position to make its finding on the reasonableness of BC Hydro's inputs for GDP and disposable income due to insufficient information.	61
21.	Therefore, the Panel finds it is not yet in a position to make its finding on the reasonableness of BC Hydro's price elasticity or rate increase assumptions due to insufficient information.	64
22.	The Panel is not yet in a position to make its finding on the potential impacts of disrupting trends due to insufficient information.	66
23.	The Panel adopts the above definitions of firming, shaping, storage and Unit Energy Cost for the purpose of section 3(b)(iv) of the OIC.	76
24.	In Appendix A, the Panel reviews the submissions and makes the following general findings (please see the appendix for further detail): 5. Biomass, geothermal, solar and battery storage are potential candidates for alternative generation and should be considered by BC Hydro. Costs modelled by BC Hydro for wind may understate the decrease in capital costs expected over the next 20 years.	76

25.	In these sections we find that the assumptions underlying the derivation of both UECs are not well documented enough to be able to make any finding concerning: • The alternative portfolio proposed is indeed the least cost of all possible alternative portfolios; and • The unit energy cost of either Site C or the alternative portfolio. Based on the data and analysis available at this time, the Panel finds that the Site C UEC delivered to the Lower Mainland may be understated and the alternative portfolio UEC delivered to the Lower Mainland may be overstated.	78
26.	The Panel finds that the reduction of the UEC to account for reduced financing costs distorts the analysis of unit energy costs comparisons.	86
27.	The Panel is concerned that if BC Hydro is not applying the same assumed project financing rate to the Alternative Portfolio, the result will not be comparable and furthermore, it assumes that BC Hydro will not be constructing and owning the Alternative Portfolio. This results in an "apples to oranges" comparison. BC Hydro is requested to clarify its financing assumptions.	86
28.	The Panel finds BC Hydro's analysis of the adjusted UEC of the alternative portfolio to be too opaque to be of value in a comparison of costs of Site C to an alternative portfolio and finds the assumptions underlying the UEC to be not well explained.	92
29.	The Panel finds that the usefulness of the UEC is limited as a comparison methodology because it doesn't appear to take into account when the energy source comes on line.	92
30.	The Panel finds the assumptions used by BC Hydro are not as well documented as they need to be to allow us to make any findings regarding the appropriateness and cost of alternative portfolios,	102
31.	the Panel finds that geothermal, biomass, solar and battery storage may be viable alternatives and requests that BC Hydro rerun its portfolio analysis with these alternatives included.	103
32.	The Panel finds that recovery of expenditures over a longer period rather than a shorter period in the event of termination as proposed by BC Hydro is reasonable.	121
33.	The Panel finds that geothermal is potentially a viable alternative and we do not agree with BC Hydro that geothermal should be excluded from consideration as part of its alternative portfolio.	A-10
34.	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.	A-25
35.	The Panel finds there have been significant declines in the cost of utility scale solar over recent years, and that further declines are expected.	A-27
36.	The Panel finds that while this project may show promise, it is at an early stage of pre-development. Accordingly we are reluctant to draw any conclusions from the material	A-29

	presented by Alaska Hydro.	
37.	The Panel finds the results of the studies cited by the Wind Energy Association, Baker and Deloitte to be reasonable.	A-37

7.0 Appendix G – List of Acronyms

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry Respecting Site C

LIST OF ACRONYMS

AAC	Annual allowable cut
AACE	Association for the Advancement of Cost Estimating
ACEEE	American Council for an Energy-Efficient Economy
AMPC	Association of Major Power Customers
ATA	*Administrative Tribunals Act*
BC Hydro	British Columbia Hydro and Power Authority
BCSEA	British Columbia Sustainable Energy Association
CBoC	Conference Board of Canada
CCGT	Combined cycle gas turbine
CCPA	The Canadian Centre for Policy Alternatives
CEA	*Clean Energy Act*
CEAA	The Canadian Environmental Assessment Agency
CEABC	Clean Energy British Columbia
CGEA	The Canadian Geothermal Energy Association
CIFT	Cost of Incremental Firm Transmission
CEBC	Clean Energy Association of British Columbia
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalent
Commission	British Columbia Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
CPR	Conservation Potential Review

Deloitte	Deloitte LLP
DSB	Downstream Benefits
DSF	David Suzuki Foundation
DSM	Demand-Side Management
ELCC	Effective Load Carrying Capacity
EPAs	Electricity Purchase Agreements
EVM	Earned value methodology
F17-F19 RRA	BC Hydro's Fiscal 2017 to 2019 Revenue Requirements Application
FID	Final Investment Decision
GDP	Gross Domestic Product
GDS	GDS Associates Inc.
GHG	Greenhouse gas emissions
GSS	Generating station and spillways
GWh	Gigawatt hours
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
LGIC	Lieutenant Governor in Council
LNG	Liquified Natural Gas
MarketBuilder	An energy and economic modeling and forecasting platform used by Deloitte MarketPoint
MCW	Main Civil Works

MC	Mid Columbia
MW	Megawatts
MWh	Megawatt hour
O&M	Operations and maintenance
OIC	Order-in-Council
PAD	Peace Athabasca Delta
PMB	Performance Measurement Baseline
Power Advisory	Power Advisory LLP
PPC	Pulp and Paper Coalition
PRHP	Peace River Hydro Partners
PS	Pumped Storage
PV	Photovoltaic
R&D	Research and Development
RFEC	Robert Fairholm Economic Consulting
ROE	Return on Equity
RRIM	Regulatory Rate Impact Model
SCGT	Single cycle gas turbine
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
UCA	*Utilities Commission Act*
UEC	Unit Energy Cost
WACC	Weighted average cost of capital

Briefing: Site C Labour

SITE C LABOUR MODEL

- BC Hydro's managed open site labour model for the project allows for access to the largest pool of skilled and experienced labour. All qualified contractors, regardless of union affiliation or status, can participate in the construction of the project while maintaining their existing bargaining relationships.
- The model supports BC Hydro's procurement strategy with respect to providing First Nations with economic opportunities to accommodate their interests. First Nations companies that are working on site are able to choose their own labour affiliation, if any.
- BC Hydro values labour stability during the construction of Site C. With this in mind, BC Hydro entered into a memorandum of understanding with certain B.C. Building Trades unions to achieve labour stability and a mix of labour representation on site, including building trades unions. This MOU is specific to unions who have negotiated labour agreements for project work.
    - The five Poly-Party Building Trades Unions include the Construction and Specialized Workers Union (Local 1611), the Operative Plasterers' Cement Masons' Union (Local 919), the International Association of Bridge, Structural, Ornamental and Reinforcing Ironworkers (Local 97), the International Union of Operating Engineers – Local 115 and the Teamsters Union (Local 213).
- BC Hydro has also included labour stability terms such as no strike, no lockout and no raiding provisions in contracts on the site.

SITE C LABOUR UNIONS

- To date, unions that have participated in the construction of Site C include: Construction Maintenance and Allied Workers (CMAW); Christian Labour Association of Canada (CLAC Local 68); Canada West Construction Union (CWU); Pile Drivers 2402; the Construction and Specialized Workers Union (CSWU, Local 1611); the International Union of Operating Engineers (IUOE) Local 115, Ironworkers (Local 97); the International Brotherhood of Electrical Workers (IBEW); MoveUp; and the Teamsters Local 213. In addition, 10 unions affiliated with the BC Building Trades will be working on the installation of the turbines and generators.
- BC Hydro's main civil works contractor for the Site C project is Peace River Hydro Partners (PRHP), whose workforce is currently represented by the CLAC Local 68, and CMAW.
- Voith Hydro has negotiated a labour agreement with the Bargaining Council of BC Building Trades Unions for the supply and installation of the turbines and generators for the Site C project. This labour agreement includes participation from 10 BC Building Trades Unions.
- In spring 2017, IUOE, as a member of the poly party group, filed an application at the BC Labour Relations Board to displace the CLAC as the legal bargaining agent for PRHP's workforce (a union raid). This application was dismissed by the BC Labour Relations Board.
    - The BC Labour Relations Board determined that the IUOE did not meet threshold for a union vote on site.
    - As a result of this dismissed application, there is currently a statutory time bar of 22 months for other raid applications. The IUOE cannot raid the PRHP's workforce during its 2018 open period.

Briefing: Site C Labour

- To date there have been two successful union organizing drives on the project by the Teamsters Local 31, with no site disruption:
    - ATCO Two Rivers Lodge operations workers were certified by the Teamsters 213, and they have successfully negotiated a first collective agreement; and
    - Saulteau Securiguard voluntarily recognized the Teamsters as their union, and have successfully negotiated and ratified a collective agreement.

UPCOMING PROCUREMENT

- The Generating Station and Spillways (GSS) procurement process is well advanced with technical and financial submissions expected to be completed in October, 2017.
- Each of the proponents has invested significant effort over the past year to develop their submissions, including developing agreements with their labour groups. BC Hydro expects that the bids will have a mix of Building Trades and CLAC.
- These labour agreements are an essential feature of their cost estimates and project budgets.
- A change to the labour model at this time would have potential cost and schedule implications.

SITE C EMPLOYMENT

- BC Hydro's latest employment statistics from the latest quarter show that in June 2017 there were:
    - 2,633 total workers on the Site C project. Of the total workers, 2,125 were from British Columbia (81 per cent).
    - 771 workers on site from the Peace River Regional District (35 per cent of the construction and non-construction workforce).
    - 58 apprentices employed during the month. As with any construction project, the number of apprentices will vary depending on the type work being performed.
    - Since the project started the types of apprentices working project have included carpenters, scaffolder construction managers/supervisors, crane operators, electricians, heavy equipment operators, ironworkers, labourers, mechanics, millwrights, pipefitters, plumbers and welders

Issue:	SITE C REVIEW: DELOITTE REPORT TO THE BCUC

ISSUE SUMMARY AND APPROACH

Deloitte was hired by the BCUC to conduct a review of Site C consistent with the Terms of Reference provided by the Government. On September 8, 2017 the BCUC publicly released two reports from Deloitte: the first focuses on the Site C project status, termination and suspension; the second focuses on load forecasting and alternative resources.

Depending on media coverage and interest, BC Hydro could respond publicly to certain key points of the Deloitte report through a statement on the BC Hydro website. If coverage is limited to certain key media, BC Hydro could reach out directly to provide further clarification.

BC Hydro also anticipates having an opportunity to respond through the BCUC inquiry process following the BCUC's release of its draft report on September 20.

Until approved, BC Hydro will not communicate proactively about the report and will use the following holding lines in response to media requests:

- BC Hydro is aware of Deloitte's submission and we are reviewing their report.
- Our submission was filed last week, and can be found on our website or the BCUC website.

INITIAL FINDINGS FROM BC HYDRO'S REVIEW OF THE REPORT

- The Deloitte report confirms Site C is on time and on budget. Deloitte identifies some risk to schedule and budget should the 2019 diversion window not be met. While we have not verified Deloitte's estimate of cost impacts, we agree that the diversion window is an important milestone.

- BC Hydro's estimates for suspension and termination costs are consistent with Deloitte's at over $1 billion. Deloitte appears to be in agreement with BC Hydro that termination of Site C would require recovery of over $3 billion (including sunk costs).

- **Load Forecasting:** Deloitte reaches the same conclusion as the Site C Joint Review Panel and an external audit: BC Hydro's load forecasting methodology is consistent with other North American utilities and no other load forecasting methodology would be better in all respects.

  While Deloitte identifies and we recognize that our load forecasts have been high in the past, we note that an external audit of BC Hydro's load forecast found that our residential and commercial variances are lower than the industry benchmarks and that our higher industrial variance is expected given the volatility of the industries involved.

- There are some areas of the Deloitte report that we disagree with. We plan to file a detailed response to the issues in the Deloitte report and other submissions as part of the BCUC inquiry, but identify here some of the issues we have identified in our initial review.

- **River Diversion Window:** BC Hydro recognizes there are schedule pressures but in order to mitigate the risk of missing the 2019 River Diversion Window, we have conducted reviews

with the contractor and other construction experts that have identified opportunities to keep this milestone on schedule.

- **Contingency:** BC Hydro's budget contingency position is stronger today than it was at Final Investment Decision. BC Hydro has more unused contingency now than at December 2014 when the project was approved ($839 million remains available). In fact, BC Hydro has added $401 million to available contingency since the project started, primarily from savings in financing charges.

- **Main Civil Works:** The statement that the Main Civil Works contract was awarded over budget is incorrect. BC Hydro transferred substantial cost risks to the Main Civil Works contractor compared to the original estimating basis, and would expect to pay for this risk transfer but hold less for contingency. An assessment at the time of award concluded that the contract was on budget.

- **"Alternative" load scenario:** Deloitte suggests an "alternative load scenario" that is 6,000 GWh lower than BC Hydro's load forecast. We included a similar sensitivity scenario in our filing. Completing Site C remains cost-effective even in this low load case. Moreover, we disagree with Deloitte's methodology. About half of their load reduction comes from assuming higher levels of demand-side management without assessing whether this is the best option for ratepayers. Deloitte also applies an oversimplified methodology to their proposed GDP change which results in an overestimation of the load change by a factor of six.

- **Response to price changes (elasticity):** The Deloitte report mischaracterizes how BC Hydro's customers change their electricity consumption in response to changes in rates. Deloitte relied on a number of academic papers describing research from regions other than British Columbia. The response to rate changes in Vancouver will not be the same as the response to rate changes in other jurisdictions.

  Our research and customer data provides a more reliable estimate for BC Hydro customer response to rate changes than studies from other regions.

- **Analysis Term:** Deloitte has considered only 12 years of benefits of Site C in its comparison, which treats the remaining decades of low cost electricity as if it does not exist. One of the key benefits of Site C is that the electricity gets less expensive over time and provides increasing savings to ratepayers. Alternative resources, with a much shorter life than Site C, would need to be replaced once or twice within the period that Site C would be operating, at substantial cost.

- **Capital projects:** Deloitte provides an overview of recent capital overruns at BC Hydro and other utilities, but the report selectively includes only BC Hydro projects that have had challenges and ignores our record of delivering projects on time and on budget. Over the last five years, BC Hydro has completed 540 capital projects at a total cost of $6.4 billion and 0.94% under budget overall.

- **Demand-side management:** The Deloitte report suggests that higher levels of demand-side management should be analyzed, which is something that BC Hydro addressed in its submission to the BCUC. BC Hydro agrees that we can achieve higher levels of demand-side management but we ensure our spending is timed appropriately in order to keep customer rates low. Our sensitivity analysis shows that Site C is more cost-effective than a

portfolio that includes even higher levels of demand-side management than those suggested by Deloitte.

The report also incorrectly assumes that BC Hydro investment declines over time, when in fact, BC Hydro has assumed a relatively constant level of investment over the longer term.

- **GHG emissions:** The Terms of Reference require the BCUC to consider alternative resources with regard to "maintenance or reduction of 2016/17 greenhouse gas emission levels." The Deloitte report interprets this requirement as meaning maintaining the same carbon intensity (tonnes of GHGs per MWh) as opposed to maintaining or reducing total GHG emissions. This means that Deloitte's analysis allows for GHG emissions to increase as load increases. We do not agree with this approach and believe it is inconsistent with the Province's GHG reduction targets.

- **Alternative resources:** The report also proposes geothermal as the largest source of new generation, with geothermal providing 10% of BC Hydro's generation capability in 2036. Geothermal resources have the potential to be a cost-effective source of energy and capacity, but the resource potential in B.C. is unproven and we believe the potential to reach 10% of our supply in 20 years to be highly unlikely.

- **Financing:** Deloitte assumes that BC Hydro rather than IPPs would finance any new resources (geothermal or otherwise). Since BC Hydro can obtain debt on more favourable terms than Independent Power Producers, Deloitte's assumption has the effect of understating the costs of renewable energy included in the alternative portfolio. For example a 2% increase in financing costs above what Deloitte has used (which would be typical for an IPP) would translate into a 15% increase in a wind project's unit energy cost.

bcuc
British Columbia
Utilities Commission

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Commission Secretary

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September 8, 2017

BCUC INQUIRY RESPECTING SITE C A-9

Sent via eFile

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

In accordance with Order G-120-17, in which the British Columbia Utilities Commission (Commission) stated that it has engaged the consulting firm Deloitte LLP to produce independent reports on the questions posed in section 3(b) of the terms of reference in Order in Council (OIC) No. 244, please find attached the following Deloitte LLP independent report: Site C – Alternative Resource Options and Load Forecast Assessment.

The Commission will consider the information contained in the Deloitte LLP independent report, as well as the information provided by BC Hydro in its August 30, 2017 submission, and the submissions of data and analysis from members of the public, when preparing its preliminary report due September 20, 2017.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

Deloitte.

British Columbia Utilities Commission

Site C - Alternative Resource Options and Load Forecast Assessment

British Columbia Utilities Commission

September 8, 2017

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September 8, 2017

David Morton
Chair and Chief Executive Officer
British Columbia Utilities Commission
900 Howe Street, Suite 410
Vancouver, BC
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Site C – Alternative Resource Options and Load Forecast Assessment

Dear Mr. Morton,

Deloitte LLP (Deloitte) is pleased to submit this report as part of the British Columbia Utilities Commission (BCUC or the Commission) inquiry respecting the Site C Clean Energy Project (Site C project or the Project). This engagement has been performed in accordance with the consulting services agreement between Deloitte and BCUC, dated August 30, 2017.

The objective of the engagement is to provide an independent review of the Project to assist BCUC answer four questions of the inquiry:

1. Is 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)?
2. What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024?
3. What are the costs to ratepayers of terminating the Site C project?
4. What, if any, other portfolio of commercially feasible generating projects and demand-side, management initiatives could provide similar benefits to ratepayers at a similar or lower, unit energy cost as the Site C Project?

The scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report entitled Site C Construction Review covers the response to the first three questions.

We would like to express our appreciation for the cooperation and assistance provided by BCUC, and BC Hydro during this review.

Yours sincerely,

Deloitte LLP

Deloitte LLP

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1. Executive summary

In December 2014, the BC Hydro and Power Authority (BC Hydro or the Authority) Site C Clean Energy Project (the Site C Project or the Project) received approval from the Government of the Province of British Columbia (the Province) to proceed with construction. Construction of the Project began in July 2015 and was expected to be in service in November 2024. At the time of the Project's approval, BC Hydro estimated its cost at $8.775 billion, which included a capital-cost estimate of $8.335 billion, plus a $440 million project reserve held by the Treasury Board.

The British Columbia Utilities Commission (BCUC or the Commission) has engaged Deloitte LLP (Deloitte) to provide an independent review of the Site C Project as part of its inquiry into the Project. Deloitte has conducted site visits, interviewed senior management and the Project team, and reviewed project documentation and data provided by BC Hydro and BCUC.

The objective of the engagement is to provide an independent review of the Project to assist BCUC answer four questions of the inquiry:

1. Is 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)?
2. What are the costs to ratepayers of suspending the Site C Project, while maintaining the option to resume construction until 2024?
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4. What, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits to ratepayers at similar or lower unit energy cost as the Site C Project?

The scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report covers the response to the first three questions.

1.1. Alternative supply-side sources of energy and capacity to replace that due to be provided by Site C

The assessment of alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C is based on a review and analysis of public and confidential data provided by BC Hydro; independent, external research; interviews with BC Hydro's Integrated Resource Planning (IRP) and Demand Side Management (DSM) teams, and interviews with several independent subject-matter professionals.

On the basis of this information, BCUC has requested an assessment of the following alternative sources of energy and capacity:

- Alternative sources of energy and capacity, including storage options;
- Expansion potential of current BC Hydro facilities; and
- Opportunities to increase demand-side management (DSM). Note that DSM is considered an alternative resource option in that it serves to meet future demand through energy conservation and efficiency.

The results of this high level assessment are used as inputs into the modelling of an alternative portfolio of sources of energy and capacity to meet demand (load) without generation provided by Site C. The modeling is completed using MarketBuilder, an energy-modeling and economic-forecast-modeling platform by Deloitte MarketPoint (herein referred to as the MarketBuilder model). The results of this alternative portfolio are summarized in Appendix E.

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1.1.1. Approach

Our approach to the assessment of alternative sources of energy and capacity, including storage options, followed BCUC guidance to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[1];
- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted in the existing regulatory environment in BC;
- Benefits: Our assessment reviewed the firming, shaping, and grid-reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity: Our assessment reviewed the current range of capital costs, and the operations and maintenance (O&M) costs associated with the technology, as well as a cost outlook for the future.

Our approach to the assessment of the expansion potential of current BC Hydro facilities was based on the review of the 2013 Integrated Resource Plan (IRP), Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA), and the individual Facility Asset Plans for each facility. The purpose of our review was to identify additional capacity and associated capital costs. In identifying additional capacity, we have used current capacity as the basis for calculating additional capacity. As such, for facilities that have been derated, the derated capacity value is used as the basis and for facilities that are out of service current production is assumed to be zero. In identifying values for additional capacity and associated capital costs, we have relied on values identified by BC Hydro in the Facility Asset Plans and the RRA. Our analysis identified assets which have potential for expansion; however, we have not conducted a cost benefit analysis on each of these expansion options.

As we noted above, our purpose in assessing BC Hydro's DSM initiatives was to identify opportunities to increase energy and capacity savings. DSM is considered an alternative resource option in that it serves to meet future demand through energy conservation and efficiency. BC Hydro considers two types of DSM measures, energy focused and capacity focused. Energy-focused DSM includes measures to conserve energy, and promote energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to delivery capacity savings during peak load periods. Both are included in the scope of this assessment.

1.1.2. Findings

Based on the results of our high-level assessment, the following sources of generation and storage were included in the model to assess alternative sources of energy and capacity to replace that due to be provided by Site C: Onshore Wind, Offshore Wind, Utility-Scale Solar PV, Geothermal, Natural gas (SCGT and CCGTs), Run-of-river hydroelectricity, Biomass (wood-based), Biogas, Biomass (municipal solid waste), Cogeneration, Pumped storage and Battery storage. Nuclear was not included in the alternative-generation portfolio modeling, given that it is not aligned with the energy objectives of the Clean Energy Act. Tidal and Wave were not included in the alternative-generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[1] It is unrealistic to assume that any technology could provide an infinite amount of capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.

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The assessment of current BC Hydro facilities identified several assets with expansion potential. The total additional capacity identified ranges from 600MW to 1000 MW. The types of expansion opportunities are as follows:

- Where there is an empty bay at an generating station which can be utilized to add a generating unit;
- Where the generating station can be replaced/refurbished to add capacity through enhanced efficiency and/or reinstate nameplate capacity;
- Where a generating facility can be added to an asset where there is no current power generation;
- Where individual components of the generating station can be refurbished/replaced to add capacity through enhanced efficiency; or
- Where additional untapped flow is available.

The assessment of DSM initiatives identified additional opportunities to increase energy and capacity savings. BC Hydro's current DSM option, referred to as the moderated DSM Option 2 from the F17-F19 RRA DSM Plan, was selected for the alternative portfolio. An additional DSM option with the potential for higher energy and capacity savings is also described in this report.

1.1.3. Modeling alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C (Appendix E)

The provincial government's Order-in-Council (OIC) asks the question: "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 results contained in Appendix E offer findings to help inform BCUC's assessment of this question.

The MarketBuilder model was used to generated a portfolio of alternative-generation projects that:

- Meet the energy objectives set out in the Clean Energy Act
- Contain commercially feasible generating projects
- Contain achievable DSM initiatives
- Consider firming/shaping and reliability of the grid
- Maintain the 2016/17 GHG emission levels

The costs and value of the generated portfolio are detailed in the findings section of Appendix E.

Deloitte considers this scenario to be a base case for informing BCUC's assessment of this case vis-à-vis the Site C scenario. Running additional scenarios would offer more insights. For example, it could be of interest to BCUC to consider the following:

- Applying the alternative load forecast developed by Deloitte to replace that provided by BC Hydro;
- Applying an increased level of DSM above what BC Hydro is currently doing (e.g., using BC Hydro's Option 3 DSM);
- Running a 'suspension scenario' to assess the need for alternative supply if Site C is suspended until a specified timeframe;
- Examining the impact of certain decisions or variable combinations (e.g., incorporating the Columbia River Treaty Entitlement if the requirements for 'self-sufficiency' are relaxed, or running various price forecasts, assuming that Burrard Thermal is restarted).

Given the inherent uncertainty of any projection, additional scenarios and analysis could be used to better quantify the sensitivity of the base scenario findings to changes in the assumptions. Additionally, while project

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cost and performance (e.g., capacity factor) inputs are reasonable for the various technologies in the alternative-supply portfolio, any particular project will have different costs and performance driven by specific needs, even if such values fall within the expected range. Scenarios probing different cost or performance assumptions for technologies can also evaluate how alternate portfolios may perform under different circumstances.

1.2 BC Hydro's load forecast model

1.2.1 Approach

BC Hydro's load forecast model ("the Forecast Model") published in July 2016, provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. Our approach to the assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other, major utilities in Canada; and interviews with several subject-matter professionals. Importantly, Deloitte has not accessed BC Hydro's Forecast Model directly. As such, this assessment cannot independently validate the information received regarding it, nor project the exact impacts on projected load requirements from changing model inputs. On the basis of information provided, this assessment provides estimates of the direction and order-of-magnitude impacts resulting from changes to several key model inputs.

1.2.2 Findings

BC Hydro uses two distinct models to forecast future demand for load and capacity. To produce its baseline mid forecast, BC Hydro uses an additive, statistically adjusted end use (SAE) approach. It consists of 12 sub models broken down by region and customer segment, as well as separate models for the light-manufacturing sector, FortisBC's expected load, a projection of heavy-industrial load for major customers, and a projection of 'all other' load requirements (e.g., streetlights and irrigation). Separate from the mid forecast, BC Hydro produces high and low-load requirement forecasts. These are the outcome of Monte Carlo simulations that model uncertainty with respect to consumers' responsiveness to future rate increases, the magnitude of these increases, and future provincial economic growth, among other variables. The inputs driving the Monte Carlo simulation are fewer and, in some cases, different from the inputs driving the mid forecast. Due to assumptions relating to demand-side management (DSM), the mid-point of the high and low-load requirements is different from (higher than) BC Hydro's mid forecast.

The assessment of the Forecast Model focused on three aspects: historical performance of model outputs vis-à-vis actuals, inputs to the model, and the model's functional form and statistical features.

In terms of historical performance, the analysis finds that, across model vintages going back to 1964, the model has more frequently overestimated load than underestimated it; of the 647 forecasted points, 500 (77%) were overestimates. Forecasts have 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 of the model, which is responsible for 29% of total sales on average between fiscal 2000 and 2017, has been the largest contributor to overestimation. In forecast models from fiscal 2008 to 2016, large industrial sales are overestimated by an average of 7% of actuals in the first fully forecasted year, and by an average of 21% of actuals in the eighth forecasted year. Interviews with two other Canadian utilities reveal that one of them has tended to overestimate load over time, and that the heavy industrial sector has been the most challenging to estimate accurately.

The residential and light industrial components have performed closer to actuals over both the short and long term. Using forecast models from F2008 to F2016, residential sales are overestimated by an average of 0.2% of actuals in the first fully forecasted year, and underestimated by 4% of actuals in the eighth forecasted year.

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Commercial and light industrial sales are overestimated by an average of 1% of actuals in the first fully forecasted year, and by 4% of actuals in the eighth forecasted year.

In terms of inputs, the assessment finds that the types of variables included in the Forecast model appear reasonable, based on consultations with the two other Canadian utilities and several subject-matter professionals. The forecasts for employment, population, and housing starts that BC Hydro uses as inputs, which come from Robert Fairholm Economic Consulting, appear in line with projections published by independent third parties.

With respect to GDP and disposable income growth, the input forecasts appear higher than alternative forecasts after the first 5 years. For instance, in the 2016 load forecast, real GDP growth is assumed to average 2.3% in the first five years (i.e., based on the BC Ministry of Finance's forecast), before increasing to 3.5% over the next five years (based on Robert Fairholm Economic Consulting projections). By comparison, the 2016 Conference Board of Canada forecast projects that real GDP will grow by 2.6% on average between 2016 and 2020, before slowing to an average of 2.3% between 2021 and 2025. Beyond 2025, the two forecasts exhibit similar trends. The 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.

Two assumptions regarding specific LNG projects, Pacific NorthWest LNG (now cancelled) and LNG Canada (final investment decision deferred), appear optimistic assumes that the Forecast model that both will be built. It should be pointed out that the project cancellation and deferral decisions were made after the 2016 Load Forecast was released. The impact of those 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.

The assumption of a constant price elasticity of demand across time horizons and customer segments appears to be an oversimplification; as well, the exact elasticity value (-0.05) is lower than several alternative estimates. This leads to a lower impact on load from projected, future rate increases. The impact of using different price elasticities of demand cannot be reliably established without direct testing of the model. Also of note is that the model assumes there will be no future rate increases for the period F2025 to F2036.

A number of potential disrupting trends exist with respect to electricity demand, including 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, among others. Of those, BC Hydro explicitly models future use of electric vehicles. The assessment included an analysis of BC Hydro's assumptions regarding electric vehicle use, the potential impact from solar photovoltaic technology in a residential context, and fuel-switching (i.e., from gas to electric and vice versa). BC Hydro's assumptions regarding electric vehicle use appear conservative compared with public commitments from the federal government. Using an alternative assumption that electric vehicles will account for 30% of all new cars sold in 2030 (compared to BC Hydro's 22%), we can see that load demand from electric vehicles increases by approximately 115 to 125 GWh in 2026 and 680 to 690 GWh in 2036.

The current state of residential solar PV and residential heat and hot water switching were also reviewed as part of this report. These potential disruptors are not currently incorporated in BC Hydro's forecast. This assessment finds that the use of solar PV is currently limited, accounting for approximately 0.002% of residential load demand in F2016. The current payback period for solar PVs in BC is estimated to be 23 years. While costs could decrease going forward and induce further uptake, this assessment has not attempted to model such a scenario.

In terms of fuel switching, the current annual cost of an electric furnace to heat an average detached home is estimated to be over $800 higher than using natural gas, even when comparing the most efficient electricity option to the least efficient gas option. While there are indications that potential future policies will incentivize

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a shift from natural gas to electricity, this assessment has not attempted to model the potential for fuel switching to alter future electricity needs.

As part of this assessment, we illustrate the impact on the 2016 load forecast by making several plausible changes to the input assumptions. These include adopting an alternative GDP forecast sourced from the Conference Board of Canada, removing the assumptions that Pacific NorthWest LNG (now cancelled) and LNG Canada (final investment decision deferred) will proceed, increasing the adoption of electric vehicles in line with federal commitments, and assuming a more intensive DSM approach (Option 3 as reported by BC Hydro in the 2013 Integrated Resource Plan).

By F2026, the 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. By 2036, 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. These projections should be considered as indicative only, as BC Hydro's mid forecast has been adjusted after the fact rather than conducting a complete rerun of the models that produced the original forecast.

While this assessment has not included direct testing of the model, it does find that with some exceptions, BC Hydro's methodology is consistent with the practices of other North American utilities. An opportunity may exist to strengthen the reliability of the forecast by employing an econometric approach that models short-term forecasts on the basis of past actual loads. The potential for correlation across the various independent components of the mid-forecast should be tested to minimize risks of suboptimal forecast results.

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2. Glossary

Acronym/Abbreviation	Terminology
ACEEE	American Council for an Energy-Efficient Economy
Advisor	Deloitte LLP and affiliated entities
BC Hydro	BC Hydro and Power Authority
BCUC	British Columbia Utilities Commission
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalent
CVR	Conservation voltage reduction
Deloitte	Deloitte LLP and affiliated entities
DSM	Demand Side Management
g	Grams
GHG	Greenhouse gas
IRP	Integrated Resource Plan
kW	Kilowatt
kW-yr	Kilowatt year
LNG	Liquefied natural gas
Forecast Model	BC Hydro's load and capacity forecasting models
MarketBuilder	An energy and economic modeling and forecasting platform used by Deloitte MarketPoint
MW	Megawatt
MWh	Megawatt hour
PV	Photovoltaic
SAE	Statistically adjusted enduse
SCGT	Single cycle gas turbine
The Authority	BC Hydro and Power Authority
The Commission	British Columbia Utilities Commission
The Project	Site C Clean Energy Project
Var	Volt-ampere reactive
VVO	Voltage and Var optimization

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3. Introduction

3.1. Scope of the Review

On August 2, 2017, the Province of British Columbia directed the British Columbia Utilities Commission (BCUC, or the Commission) to conduct a review of certain aspects of the Site C Clean Energy Project (the Site C project, or the Project), under section 5 of the Utilities Commission Act (UCA). Specifically, the Commission has been asked the following:

1. After the Commission has made an assessment of BC Hydro's (the Authority) 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)?
2. 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?
3. What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?
4. 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 scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report entitled Site C Construction Review covers the response to the first three questions.

3.2. Approach

Deloitte's review comprises a high-level assessment of:

1. Alternative supply-side sources of energy and capacity to replace those due to be provided by Site C.
2. BC Hydro's load-forecasting model, with a focus on the version of the forecast published in July 2016 and provided by BC Hydro.

Each assessment required a distinct approach, summarized below.

3.2.1. Assessment of alternative supply-side sources of energy and capacity to replace those to be provided by Site C

Our approach to the assessment of alternative sources of energy and capacity, including storage options, followed BCUC guidance to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[2];

[2] It is unrealistic to assume that any technology could provide an infinite amount of capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.

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- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted by the existing regulatory environment in BC:
- Benefits: Our assessment reviewed the firming, shaping, and grid reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity: Our assessment reviewed the current range of capital costs and the operations and maintenance (O&M) costs associated with the technology, as well as a cost outlook for the future.

Our approach to the assessment of the expansion potential of current BC Hydro facilities was based on the review of the 2013 Integrated Resource Plan (IRP), Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA) and the individual Facility Asset Plans for each facility. The focus of our review was to identify additional capacity and associated capital costs. In identifying additional capacity, we have used current capacity as the basis for calculating additional capacity. As such, for facilities that have been derated, the derated capacity value is used as the basis; for facilities that are no longer in service, current production is assumed to be zero. In identifying values for additional capacity and associated capital costs, we have relied on values identified by BC Hydro in the Facility Asset Plans and the F17-F19 RRA. Our analysis identified assets where there is potential for expansion; however, we have not conducted a cost benefit analysis on each of these expansion options.

Our approach to the assessment of BC Hydro's demand-side management (DSM) initiatives focused on identifying opportunities to increase energy and capacity savings. DSM is considered an alternative resource option, in that it serves to meet future demand through energy conservation and efficiency. BC Hydro considers two types of DSM measures: energy focused and capacity focused. Energy-focused DSM includes measures to conserve energy and promote energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to deliver capacity savings during peak load periods. Both are included in the scope of this assessment.

The results of this high-level assessment were used as inputs for modelling an alternative portfolio of sources of energy and capacity to meet demand (load), without generation provided by Site C (herein referred to as MarketBuilder model). The results of this alternative portfolio are summarized in Appendix E. The general approach to building the MarketBuilder model was to apply BC Hydro's load forecast, and consider what additional generation (not relying on Site C) is required to meet the forecast at the lowest potential cost, within a specific greenhouse gas emissions cap, and specific assumptions and constraints, which are detailed in Appendix E.

3.2.2. Assessment of BC Hydro's load forecast model

BC Hydro's load-forecast model ("the Forecast Model") published in July 2016, provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. Our approach to the assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other major utilities in Canada; and interviews with several subject matter professionals. Based on information obtained from these sources, we assessed the impact of changing several assumptions on load and capacity. Importantly, Deloitte has not accessed BC Hydro's Forecast Model directly. As such, this assessment cannot independently validate the information received regarding it, nor project the exact impacts on projected load requirements from changing model inputs. This assessment should be considered as indicative of the direction and approximate magnitude of the impacts only.

3.3. About Deloitte

Deloitte LLP is Canada's leading professional services firm, providing a full range of consulting, assurance and advisory, financial advisory, enterprise risk, and tax services to clients in all sectors of the Canadian economy through more than 8,800 people in more than 55 locations across the country. Deloitte has been in business in Canada for over 150 years. During this tenure, our clients have relied on Deloitte and its predecessor

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organizations for solutions to their ever-changing needs. We are a national and global leader today because we have earned our clients' trust and exceeded their expectations throughout our history. As one of the world's leading professional services firm, Deloitte LLP Canada can, when needed, call on our over 57,000 professionals serving 100 countries. This report was created primarily by a team of professionals from three different practice area: Deloitte's Sustainability and Climate Change practice; Deloitte Economics; and Deloitte MarketPoint.

3.3.1. Deloittes' Sustainability and Climate Change

Deloitte has Canada's largest Sustainability and Climate Change (S&CC) practice among the "Big 4" professional services firms. For more than 20 years, our team has been supporting organizations in every aspect of sustainability.

In Canada, our S&CC team has advised governments, global and national companies, and development agencies on climate change issues and strategies to meet regional, national, and international needs and to deploy innovative de-carbonization strategies that respond to the future low-carbon reality. We have also concluded a series of studies designed to define and characterize the Clean Technology Sector across jurisdictions in Canada and globally. Through these experiences, we have developed a broad understanding of the key challenges and opportunities in the Clean Technology Sector, as well as insights into what other jurisdictions around the world are doing to address them.

Our S&CC practice has deep experience serving the power and utilities industry with 15+ clients across British Columbia, Alberta, Saskatchewan and Ontario.

3.3.2. Deloitte Economics

Deloitte Economics is a team of economists and public policy specialists, who use economic, econometric, statistical and financial expertise to help address the business and policy challenges facing our clients. We advise both public sector and private sector organizations in Canada on a range of areas including: economic development strategy; socio-economic impact analysis; and competition and market analysis. Drawing on the depth of industry knowledge from across Deloitte's global network, we develop rigorous solutions based on the practical application of economic and policy analysis.

3.3.3. Deloitte MarketPoint

Deloitte MarketPoint is a leading provider of economic modeling solutions that are used to analyze energy resource economics, assess market fundamentals, and provide strategic insight for the global power, oil, and gas markets for clients ranging from public and private utilities to project developers to end-users to financial and government institutions.

Our subject matter specialists, many of whom have in excess of twenty years of energy experience, develop Reference Case outlooks and provide custom analysis to support advisory clients and help them better understand changing energy market fundamentals, asset valuation and asset development, risks to strategic plans, disruption in the marketplace, and the impact of new and potential regulations.

Leveraging MarketBuilder, a proprietary economic modeling platform with over 30 years of continuous development and application, Deloitte MarketPoint has developed energy market models and approaches to quantify energy market reactions under various scenarios. The cross-commodity capability of MarketBuilder allows for the seamless integration of energy commodities as well as other related attributes such as emissions limits and renewable energy credits or requirements. As a result, clients benefit from analysis that is comprehensive and consistent. The US Department of Energy utilized MarketBuilder and the MarketPoint team to evaluate the impact of a carbon policy on shifts in generation mix and required power plant and gas pipeline infrastructure development as part of the Quadrennial Energy Review.

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3.4. Assumptions and Limitations

This report has been prepared pursuant to the following general assumptions and general limiting conditions:

1. The analyses, advice, recommendations, opinions, or conclusions contained herein are valid only as of the indicated date and only for the indicated purpose.
2. The analyses, advice, recommendations, opinions, or conclusions contained herein are for the exclusive use of BCUC for the sole and specific purposes noted herein and may not be used for any other purpose by BCUC or any other party. Furthermore, the analyses, advice, recommendations, opinions, or conclusions are not intended by the author and should not be construed by the reader to be investment advice in any manner whatsoever. The analyses, advice, recommendations, opinions, or conclusions represent the considered opinion of Deloitte LLP ("Advisor"), and are based on information furnished to it by the client, its representatives, and other sources.
3. Possession of this report, or a copy thereof, does not carry with it the right of publication or distribution to, or use by, any third party. Any third party that uses the information contained herein does so at its sole risk and agrees to hold Advisor, its subcontractors, and their respective personnel harmless from any claims resulting from use by any other third party. Access by any third party does not create privity between Advisor and any third party.
4. No item in this report shall be changed by anyone other than Advisor, and Advisor shall have no responsibility for unauthorized changes.
5. Neither Advisor nor its personnel, by reason of this engagement, is required to give testimony, or to be in attendance in court unless arrangements have been previously made in writing.
6. The Advisor conducted interviews with BC Hydro and have assumed that the information gathered in such interviews is accurate and complete.
7. Financial information provided to us in the course of this engagement by BC Hydro has been accepted without any verification as fully and correctly reflecting the business conditions and operating results of the relevant assets, properties, or businesses for the respective periods, except as specifically noted herein. We have not audited, reviewed, or compiled any financial information provided to us and, accordingly, we express no audit opinion or any other form of assurance regarding such information.
8. If prospective financial information provided by the client or its representatives has been used in this analysis, we have not examined or compiled the prospective financial information and, therefore do not express an audit opinion or any other form of assurance on the prospective financial information or the related assumptions. Events and circumstances frequently do not occur as expected, and there will usually be differences between prospective financial information and actual results, and those differences may be material.
9. The Advisor do not provide assurance on the achievability of any forecasted results contained herein because events and circumstances frequently do not occur as expected, differences between actual and expected results may be material, and achievement of the forecasted results is dependent on actions, plans, and assumptions of management.
10. The Advisor believes the information obtained from public sources or furnished to us by other sources is reliable. However, we issue no warranty or other form of assurance regarding the accuracy of such information.
11. The Advisor is not an environmental consultant or auditor, and it takes no responsibility for any actual or potential environmental liabilities. Any person entitled to rely on this report wishing to know whether such liabilities exist, or the scope and their effect on the value of any subject asset, property, or business interest, is encouraged to obtain a professional environmental assessment. Advisor does not conduct or provide environmental assessments and has not performed one in the course of this engagement.

Note: Additional limitations are provided in section 4.3 specifically related to the assessment of opportunities to increase DSM.

3.5. Project Description

The Site C project is the third dam and hydroelectric generating station on the Peace River in northeast BC. It is part of BC Hydro's overall program to invest in and renew the Province's electricity system. The Project

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would provide approximately 1,100 megawatts of capacity, and produce about 5,100 gigawatt-hours of energy per year.

In December 2014, the Project received approval from the Government of the Province of British Columbia to proceed to construction. Construction of the project began in July 2015 and is expected to be completed in 2024.

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4. Assessment of alternative sources of energy and capacity

This section provides an assessment of alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C. This assessment has been utilized to determine which sources of alternative generation to include in the modeling of a single, alternative-generation portfolio that could replace the energy and capacity of Site C.

4.1. Introduction

We have been asked by BCUC to assess the following supply-side sources of alternative energy and capacity:

Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
1. Onshore wind	Wind power refers to the conversion of kinetic energy from moving air into electricity. Modern utility-scale wind turbines are horizontal axis machines with three rotor blades. The blades convert the linear motion of the wind into rotational energy that then is used to drive a generator. Onshore wind generation facilities are placed on land.
2. Offshore wind	Wind power refers to the conversion of kinetic energy from moving air into electricity. Offshore wind- generation facilities can be placed on the substrate in water, either in the ocean or possibly in lakes. This source of alternative energy considers the potential to generate electricity with offshore wind turbines located in ocean substrate depths of up to 40 m.
3. Utility-scale solar photovoltaic (PV)	Solar power is obtained by converting energy from sunlight into electricity; it can be manufactured directly using photovoltaic cells (crystalline silicon or thin film). which have the ability to modularly increase the size of the solar-power installation over time, thereby managing capital investment risk. This alternative considers commercial installations on the utility side of the meter, with commercial-scale solar installations sized at 5 MW.
4. Geothermal	Geothermal energy systems draw on natural heat from within the Earth's crust to drive conventional power- generation technologies. The primary source of geothermal energy is radioactive decay occurring deep within the Earth, supplemented by residual heat from the Earth's formation, and heat generated by its gravitational forces pulling dense materials into its core. This source of alternative energy focuses on geothermal electricity generated from conventional resources, in the form of steam or, hot water using flash or binary technologies.
5. Natural gas – simple-cycle gas turbine (SCGT) and combined-cycle gas turbine (CCGT)	Natural gas-fired units generate electricity using the heat released by the combustion of natural gas.

[3] All definitions, with the exception of nuclear, are from the BC Hydro 2013 Integrated Resource Plan; Chapter 3 – Resource Options. The definition for Nuclear is from the U.S. Energy Information Administration www.eia.gov/tools/glossary

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Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
	Combined cycle gas turbines or CCGTs are an energy and capacity resource. CCGTs use the combination of combustion and steam turbines to generate electricity. Exhaust gases from a combustion turbine flow to a heat-recovery, steam generator that produces steam to power a steam turbine, resulting in higher efficiencies than those achievable by operating the combustion or steam turbines individually. CCGTs have a relatively high efficiency in converting fuel to electricity in comparison to other thermal generation. Simple-cycle gas turbines or SCGTs are a capacity resource. SCGTs are stand-alone generating plants that use combustion gases to propel a turbine, similar to a jet engine connected to an electrical generator. SCGTs are less efficient than CCGTs in converting fuel to electricity.
6. Run-of-river hydroelectricity	A run-of-river hydro-generation facility diverts a portion of natural stream flows and uses the natural drop in elevation of a river to generate electricity. A weir (i.e., a structure smaller than a dam used for storage hydro) is required to divert flows into the penstocks that lead to the power-generation facilities. A run-of-river project either has no storage, or a limited amount of storage, in which case the storage reservoir is referred to as pondage.
7. Tidal	Tidal energy refers to the kinetic energy available in the flow of water driven by the rotation of the Earth in the gravitational fields of the sun and the moon. Tidal energy can be captured in two different ways – tidal barrages and tidal current systems. Tidal barrage is not considered a viable prospect in BC. Review for this source of alternative energy in BC focuses exclusively on tidal current systems.
8. Wave	Wave energy is generated by winds blowing over the surface of the ocean. Because ocean waves are a product of the interactions among variable local winds, occasional storms and the effects of distant sea conditions, wave energy is a complex and variable phenomenon.
9. Nuclear	Electricity generated by the use of the thermal energy released from the fission of nuclear fuel in a reactor.
10. Biomass (wood-based)	Wood-based biomass electricity is generated from the combustion or gasification of organic materials as fuels. The potential of wood-based biomass considers the following categories of fuels: Standing timber (including pine beetle-killed wood) Roadside wood waste (wood already harvested, but left in the forest or road side, some are pine beetle-killed wood) Sawmill wood waste
11. Biogas	Landfill gas (primarily methane) is created when organic waste in a municipal solid waste landfill decomposes under anaerobic conditions. Landfill gas can be captured, converted, and used as an energy source to help prevent methane from migrating into the atmosphere and contributing to global climate change. Technologies for producing electricity from landfill gas include internal combustion engines, gas turbines and microturbines.
12. Biomass (municipal solid waste)	Municipal solid waste (MSW) biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used MSW technologies.
13. Cogeneration	Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a low-pressure steam/thermal 'host' to use the excess

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Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
	heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat such as pulp mills, greenhouses, or hospitals. This alternative energy considers generation of electricity using the heat released by the combustion of natural gas.

BCUC also asked us to assess the following storage options to assist with grid balancing, reliability and supporting renewables integration.

Storage options	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options
14. Pumped storage	Pumped storage (PS) units 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.
15. Battery storage	Batteries come in different chemistries that generally fall into two distinct categories: solid state and flow. Solid state batteries are contained, do not require pumps or other moving parts, and rely on the closure of a conducting loop to allow a flow of electrons that either charge or discharge the battery. Flow batteries rely on chemicals that are pumped through a membrane and require periodic refreshing. This storage option focuses on solid state battery technologies that are available, and include Sodium Sulphur (NaS), Lithium ion (Li-ion), Advanced Lead Acid and Metal Air.

BCUC has asked us to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[4];
- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted in the existing regulatory environment in BC:
- Benefits: Our assessment reviewed the firming, shaping, and grid reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity5: Our assessment reviewed the current Capital Costs and the Operations & Maintenance (O&M) Costs associated with the technology, as well as a cost outlook for the future. All costs are expressed in Canadian dollars.

[4] It is unrealistic to assume that any technology could provide an infinite amount of energy or capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.
[5] Exchange rate of $1USD=$0.75 has been used to convert costs from USD to CAD where relevant. Reference for exchange rate: BCUC IR 1.154.8. Exhibit B-9.

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4.1.1. Summary of our assessment

The following sections summarize the results of our research and assessment for the energy sources and storage options.

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4.1.1.1. Onshore Wind[6]

Assessment characteristic	Summary of assessment
Commercial feasibility	Onshore wind is deemed commercially feasible in BC, as demonstrated by the existing onshore wind farms.
Regulatory limitations	The development of onshore wind resources is not barred.
Firming/shaping/storage	Wind provides no traditional firming or shaping capability. It is a non-dispatchable, intermittent resource.

[6] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 4, Table 4-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf;
Zero Emission Energy Developments Inc. website. http://zeroemissiondevelopments.com/zed-projects/;
EnergyBC Electricity Generating Stations in British Columbia Map. http://www.energybc.ca/electricitymap.html;
Boralex Moose Lake Wind Project website. http://www.boralex.com/projects/mooselake;
Meikle Wind project website. http://meiklewind.com/;
Canadian Wind Energy Association website. http://canwea.ca/wind-energy/installed-capacity/;
Canadian Wind Energy Association (CanWEA) Pan-Canadian Wind Integration Study (PCWIS). http://canwea.ca/wind-integration-study/wind-data/;
GE Renewable Energy website. https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines;
MIT Technology Review Wind Turbines, Battery Included, Can Keep Power Supplies Stable. https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/;
EPRI Wind Power Integration: Energy Storage for Firming and Shaping. https://www.epri.com/#/pages/product/000000000001008388/;
Hydro-Québec website - Combining Wind and Water. http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook;
NEB Canada's Renewable Power Landscape - Energy Market Analysis 2016. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2016cndrnwblpwr/index-eng.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Hydro-Québec website - Combining Wind and Water. http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html;
IESO 2015 Year-End Data: Electricity Production, Consumption, Price and Dispatch Data. http://www.ieso.ca/corporate-ieso/media/year-end-data/2015;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Hatch Wind Data Study Update Report for BC Hydro. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf;
Alberta Electric System Operator (AESO) 2017 Long-term Outlook and data file. https://www.aeso.ca/grid/forecasting/;
IEA Wind Annual Report for 2015. https://www.ieawind.org/annual_reports_PDF/2015/2015%20IEA%20Wind%20AR_small.pdf;
REN 21 Renewable 2017 Global Status Report. http://www.ren21.net/gsr-2017/chapters/chapter_02/chapter_02/#wind-power-markets;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
Wind Power Monthly website - Turbine advances cut O&M costs. http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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Grid reliability (e.g., dispatchability)	Wind is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, there is an opportunity to leverage hydroelectric resource as a storage medium to balance intermittency in wind power.
Direct GHG emissions	Direct GHG emissions from onshore wind generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for onshore wind range from $1,600 to $3,200/kW, and fixed O&M costs range from $70 to $110/kW-yr.
Future costs	Capital costs for wind are expected to fall by 10-12% per MW in the next 10-20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.1.2. Offshore Wind[8]

Assessment characteristic	Summary of assessment
Commercial feasibility	Offshore wind is used commercially in other jurisdictions, but has not yet been proven to be commercially feasible in BC.
Regulatory limitations	The development of offshore wind is not barred.
Firming/shaping/storage	Wind provides no traditional firming or shaping capability. It is a non-dispatchable, intermittent resource.
Grid reliability (e.g., dispatchability)	Wind is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, there is opportunity to leverage hydroelectric resources as a storage medium to balance the intermittency of wind power.

[8] NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
IEA Wind Annual Report for 2015. https://www.ieawind.org/annual_reports_PDF/2015/2015%20IEA%20Wind%20AR_small.pdf;
NaiKun Wind Energy Group Inc. – Benefits of the project. http://naikun.ca/the-project/project-benefits/;
NY Times – America's First Offshore Wind Farm Spins to Life. https://www.nytimes.com/2016/12/14/science/wind-power-block-island.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Nova Scotia Power - Capacity Value of Wind Assumptions and Planning Reserve Margin;
http://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf;
GE Renewable Energy website. https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines;
MIT Technology Review Wind Turbines, Battery Included, Can Keep Power Supplies Stable.
https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
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NREL Energy Analysis of Offshore Systems. https://www.nrel.gov/wind/offshore-energy-analysis.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
REN 21 Renewable 2017 Global Status Report. http://www.ren21.net/gsr-2017/chapters/chapter_02/chapter_02/#wind-power-markets;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants.
https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf;
IRENA The Power to Change: Solar and Wind Cost Reduction Potential to 2025.
http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf;
NREL Distributed Generation Renewable Energy Estimate of Costs. https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
IRENA Innovation Outlook: Offshore Wind.
http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=2742;
Wind Power Monthly website - Turbine advances cut O&M costs. http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives.
https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP.
https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017.
https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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Direct GHG emissions	Direct GHG emissions from onshore wind generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for offshore wind resources in BC range from $2,700 to $8,700/kW, with fixed O&M costs of $240/kW-yr.
Future costs	Capital costs and O&M costs for offshore wind are both expected to fall by about 20-25% in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.1.3. Utility-Scale Solar PV[9]

Assessment characteristic	Summary of assessment
Commercial feasibility	Solar PV is commercially feasible in Canada. While the vast majority of installations are located in Ontario, there is a demonstrated example in BC.
Regulatory limitations	The development of Utility-Scale Solar PV is not barred.
Firming/shaping/storage	Solar power provides no firming or shaping capability. It is a non- dispatchable, intermittent resource.
Grid reliability (e.g., dispatchability)	Solar is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, it has

[9] Sunmine website. http://www.sunmine.ca/;
Compass Renewable Energy Consulting Inc. British Columbia Solar Market Update 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf;
CanSIA Solar PV Overview of Solar Electricity Supply Chain in Canada. http://www.cansia.ca/solar-pv.html;
Compass Renewable Energy Consulting Inc. British Columbia Solar Market Update 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf;
Prepared for Natural Resources Canada by Power Advisory LLC. Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Services. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf;
California ISO, First Solar, and NREL Using Renewables to Operate a Low Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant. https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
IESO Large Renewable Procurement (Independent Electricity System Operator). http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx;
US Department of Energy website, Energy Department Announces More than 90% Achievement of 2020 SunShot Goal, Sets Sights on 2030 Affordability Targets. https://energy.gov/eere/articles/energy-department-announces-more-90-achievement-2020-sunshot-goal-sets-sights-2030;
Navigant Marginal cost of wind and solar PV electricity generation. http://www.ieso.ca/-/media/files/ieso/document-library/engage/fpr/fpr-20150625-navigant.pdf?la=en;
NREL Distributed Generation Renewable Energy Estimate of Costs. https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf;
IRENA The Power to Change: Solar and Wind Cost Reduction Potential to 2025. http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf;
NREL Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. http://www.nrel.gov/docs/fy15osti/64898.pdf;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016. https://www.nrel.gov/docs/fy16osti/67142.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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	been shown to provide frequency response and voltage support with appropriate controls.
Direct GHG emissions	Direct GHG emissions from utility-scale solar PV generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for utility-scale solar PV range from $2,300 to $3,500/kW, and fixed O&M costs range from $30 to $35/kW-yr.
Future costs	Solar PV capital costs have been dropping in recent years and are expected to continue to drop by 35- 60% in the next 10 years. For the purposes of modeling, a conservative estimate of a 35% drop is assumed.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative-generation portfolio modeling.

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4.1.1.4. Geothermal[10]

Assessment characteristic	Summary of assessment
Commercial feasibility	Geothermal is used commercially in other jurisdictions but not in BC. There is potential for it to be commercially feasible in BC in the next 15 years.
Regulatory limitations	The development of geothermal resources is not barred.
Firming/shaping/storage	Geothermal power can provide firming and shaping capability due its ability to be dispatched.
Grid reliability (e.g., dispatchability)	Geothermal energy is dispatchable and provides baseload power to the grid.
Direct GHG emissions	Direct GHG emissions from geothermal generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated geothermal capital costs range from $6,000 to $8,700/kW (dependent partially on size), and O&M costs range from $20 to $30/MWh.
Future costs	Capital costs associated with geothermal are expected to fall slowly, at about 0.5% per year through the forecast period as the technology matures.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative-generation portfolio modeling.

[10] Geoscience BC Section B Roadmap for Development of Geothermal Direct-use Projects in British Columbia, Canada. http://www.geosciencebc.com/i/project_data/GBCReport2016-07/GBC%20Report%202016-07_Section%20B_Roadmap.pdf;
Natural Resources Canada Geothermal Energy Resource Potential of Canada. http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf;
Clean Energy BC - Geothermal Power. https://www.cleanenergybc.org/about/clean-energy-sectors/geothermal;
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Geothermal Energy. http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch04.pdf.
FortisBC - Supply side resource options. https://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecResourcePlanning/Documents/2_Supply-Side_Resource_Options.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
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EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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4.1.1.5. Natural gas (SCGT and CCGT)[11]

Assessment characteristic	Summary of assessment
Commercial feasibility	Natural gas (SCGT and CCGT) generation is commercially feasible in BC and Canada, as demonstrated by existing plants.
Regulatory limitations	The development of natural gas generation is not barred; however, there are regulatory limitations to the development of natural gas generation resources due to the percentage of clean electricity generation required in BC, as per the Clean Energy Act.
Firming/shaping/storage	Natural gas generation provides traditional firming and shaping capability. SCGTs are generally better suited for firming/shaping than CCGTs, given typically better ramping responsiveness.
Grid reliability (e.g., dispatchability)	Natural gas generation is dispatchable.
Direct GHG emissions	Direct GHG emissions from natural gas generation are assumed to be approximately 520 to 632 g CO2e/kWh for existing SCGTs in BC and 364 to 375 g CO2e/kWh for CCGTs.
Current costs	Estimated costs related to natural gas generating technologies are: CCGT: capital costs of $1,200 to $2,500/kW, annual fixed O&M costs of $15 to $25/kW-year, and variable O&M costs of $5 to $10/MWh. SCGT: capital costs of $1,000 to $2,000/kW, annual fixed O&M costs of $10 to $25/kW-year, and variable O&M costs of $5 to $15/MWh.
Future costs	Capital costs associated with natural gas generation are not expected to decline significantly in the future. Applying a carbon price would increase operating costs.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

[11] FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook.
Alberta Electric System Operator (AESO) 2017 Long-term Outlook and data file. https://www.aeso.ca/grid/forecasting/;
Government of British Columbia Consolidated B.C. Emissions Report Summaries for 2015. http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg;
FortisBC heat content values. https://www.fortisbc.com/NaturalGas/Business/PriceAndMarketInformation/Pages/Heat-content-values.aspx;
Environment and Climate Change Canada National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
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Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
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EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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4.1.1.6. Run-of-river hydroelectricity[12]

Assessment characteristic	Summary of assessment
Commercial feasibility	Run-of-river hydroelectricity is commercially feasible in BC (subject to seasonal river flows), as demonstrated by existing projects.
Regulatory limitations	The development of Run-of-river hydroelectricity is not barred.
Firming/shaping/storage	Run-of-river hydro power is a non-dispatchable, intermittent resource and therefore does not normally provide firming or shaping capabilities. However, run-of-river hydro with pondage can provide dispatchable baseload with firming and shaping capabilities.
Grid reliability (e.g., dispatchability)	Run-of-river hydro power with pondage can provide dispatchable baseload.
Direct GHG emissions	Direct GHG emissions from run-of-river hydroelectricity generation is assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated 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.
Future costs	Capital costs associated with run-of river projects are not expected to change significantly in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

[12] Kerr Wood Leidal Run of River report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-run-of-river-report-20150710-kwl.pdf;
Clean Energy BC - Run of River Hydro in BC. https://www.cleanenergybc.org/about/clean-energy-sectors/run-of-river.
Devlin Gailus Barristers and Solicitors A Review of Environmental Regulation of Run of River Power Projects in British Columbia. http://www.dgwlaw.ca/wp-content/uploads/2014/12/Testing_the_Waters_April_2010.pdf;
Pacific Salmon Foundation Potential impacts of run of the river power hydro projects on salmonids. https://www.psf.ca/sites/default/files/ROR_Report.pdf.
IRENA Renewable energy technologies: Cost Analysis Series. https://hub.globalccsinstitute.com/sites/default/files/publications/138178/hydropower.pdf.
BC Hydro Electricity Supply Options- Chapter 3. https://www.bchydro.com/energy-in-bc/planning-for-our-future/electricity-supply-options.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Energy BC - Run of River Power. http://www.energybc.ca/runofriver.html#section16;
Natural Resources Canada Emerging Hydropower Technologies R&D in Canada - A Strategy for 2007-2011. http://www.nrcan.gc.ca/energy/publications/sciences-technology/renewable/small-hydropower/6489;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
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Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
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PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
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4.1.1.7. Tidal[13]

Assessment characteristic	Summary of assessment
Commercial feasibility	While tidal-power technology is currently being tested in BC, there is currently not enough information to determine if this technology is commercially feasible in BC.
Regulatory limitations	The development of tidal-power generation is not barred.
Firming/shaping/storage	Tidal power is not dispatchable and does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Tidal energy is not dispatchable, but can be highly predictable and reliable.
Direct GHG emissions	Direct GHG emissions from tidal electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for tidal energy vary significantly from $8,000 to $21,000/kW. However, due to the high costs associated with the engineering of these projects, as well as the costs of transmission to bring this power to market, this technology is likely cost prohibitive at this time.
Future costs	There are no projected future costs for tidal power in BC readily available; however, it is estimated in other jurisdictions that the cost of this technology could fall by approximately 25% by 2040.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[13] Energy BC website - Tidal Power. http://www.energybc.ca/tidal.html;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Government of BC Clean Energy Production in B.C., an Inter-Agency Guidebook for Project Development. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf.
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Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
World Energy Council 2013 - Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf.
Government of Nova Scotia - Nova Scotia Electricity System Review. Summary Report- Emerging Technology and Market Trend Studies. https://energy.novascotia.ca/sites/default/files/files/NS%20Electricity%20System%20Review%20Summary%20Report%20June%202014.pdf
Carbon Trust - Future Marine Energy. Results of the Marine Energy Challenge: Cost competitiveness and growth of wave and tidal stream energy. http://ec.europa.eu/ourcoast/download.cfm?fileID=967.

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4.1.1.8. Wave[14]

Assessment characteristic	Summary of assessment
Commercial feasibility	Based on the current available information, there is insufficient research and data available to support wave energy as a commercially feasible source of alternative energy for BC.
Regulatory limitations	The development of wave generation is not barred.
Firming/shaping/storage	Wave power is not dispatchable, and does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Wave energy is not dispatchable, but it is highly predictable and reliable.
Direct GHG emissions	Direct GHG emissions from wave electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	The range of capital costs varies significantly ($7,300 to $21,000/kW) due to the early stage of its development, and the varying size and development of commercial-scale installations. Due to the lack of sufficient data on the successful implementation and resourcing in BC, it is unlikely that this option is feasible at this time.
Future costs	The cost per kWh in other jurisdictions is predicted to fall by approximately 50-70% by 2040, as the technology is further developed.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[14] Natural Resources Canada. The Atlas of Canada - Clean Energy Resources and Projects (CERP). http://atlas.gc.ca/cerp-rpep/en/;
Natural Resources Canada - West Coast Wave Initiative. http://www.nrcan.gc.ca/energy/funding/current-funding-programs/eii/16092;
Government of BC Clean Energy Production in B.C., an Inter-Agency Guidebook for Project Development. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf.
Kim et al. Catching the Right Wave: Evaluating Wave Energy Resources and Potential Compatibility with Existing Marine and Coastal Uses. http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0047598.
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Ocean Energy. http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch06.pdf.
World Energy Council 2013 - Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Government of Nova Scotia - Nova Scotia Renewable Energy Strategy. https://energy.novascotia.ca/sites/default/files/Nova-Scotia-Marine-Renewable-Energy-Strategy-May-2012.pdf.
Ernst & Young Cost of and financial support for wave, tidal stream, and tidal range generation in the UK. A report for the Department of Energy and Climate Change and the Scottish Government. http://webarchive.nationalarchives.gov.uk/20121205081857/http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20mix/renewable%20energy/explained/wave_tidal/798-cost-of-and-finacial-support-for-wave-tidal-strea.pdf;
Government of Nova Scotia Nova Scotia Electricity System Review. Summary Report- Emerging Technology and Market Trend Studies. https://energy.novascotia.ca/sites/default/files/files/NS%20Electricity%20System%20Review%20Summary%20Report%20June%202014.pdf

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4.1.1.9. Nuclear[15]

Assessment characteristic	Summary of assessment
Commercial feasibility	Nuclear power is commercially feasible in Canada, as demonstrated by existing plants.
Regulatory limitations	Nuclear power is not aligned with the energy objectives of the Clean Energy Act, such that the BC government will not accept nuclear power as an option for meeting BC's energy needs. Unless there are changes to these regulatory limitations, this is not deemed to be a viable option.
Firming/shaping/storage	Nuclear power provides baseload power to the grid. It is neither dispatchable nor non-dispatchable. It does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Nuclear power provides baseload power to the grid. It is neither dispatchable or non-dispatchable.
Direct GHG emissions	Direct GHG emissions from nuclear electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for nuclear range from about $8,000 to $10,700/kW, with fixed O&M costs around $120/kW-yr.
Future costs	The capital costs associated with nuclear power generation are not expected to change considerably over the next 20 years.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, given that it is not aligned with the energy objectives of the Clean Energy Act.

[15] Nuclear Energy Institute - World Nuclear Generation and Capacity. http://www.world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx;
World Energy Council Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Nuclear Energy Institute - World Statistics: Nuclear Energy Around the World (Nuclear Energy Institute). https://www.nei.org/Knowledge-Center/Nuclear-Statistics/World-Statistics.
Government of BC - The BC Energy Plan. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf.
Natural Resources Canada Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Service. Energy and Mines Ministers' Conference. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Chu and Majumdar. Opportunities and challenges for a sustainable energy future. http://www.indiaenvironmentportal.org.in/files/file/sustainable%20energy.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
Ontario Energy Board - Ontario Energy Board Regulated Price Plan. https://www.oeb.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_May2016.pdf;
NEB Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf.

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4.1.1.10. Biomass (wood-based)[16]

Assessment characteristic	Summary of assessment
Commercial feasibility	Wood-based biomass power generation is commercially proven in BC and Canada, although its financial viability depends on the source of biomass fuel.
Regulatory limitations	The development of biomass is not barred.
Firming/shaping/storage	Wood-based biomass can provide baseload power to the grid with firming and shaping capability. The biomass feedstock can also be stored to optimize power output
Grid reliability (e.g., dispatchability)	Wood-based biomass can provide baseload power to the grid. Steam-based plants using solid biomass can be ramped-up, but without the flexible peaking capability of other resources such as natural gas.
Direct GHG emissions	Direct GHG emissions from wood-based biomass generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	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. Fuel costs (including the costs to source and transport wood-based biomass) would vary depending on the distance from the source.
Future costs	Capital costs for biomass are not expected to fall significantly (less than 10%) in the next 10- 20 years.

[16] NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 4, Table 4-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Lessons Learned from Existing Biomass Power Plants. https://books.google.ca/books?id=55IGWS1C0Q4C&pg=PA105&lpg=PA105&dq=peaking+biomass+plant&source=bl&ots=YBOPQ-wfZG&sig=MmV1zRzB7i23oFs2pwjhUgZI48g&hl=zh-TW&sa=X&ved=0ahUKEwjW7via--HVAhUi5YMKHaFdCRIQ6AEIYDAK#v=onepage&q=peaking%20biomass%20plant&f=false;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook.
Energy Storage Association website - Flexible Peaking Resource. http://energystorage.org/energy-storage/technology-applications/flexible-peaking-resource;
AMEC Bioenergy Projects Technology Review for BC Hydro. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-20150722-amec-foster-wheeler.pdf.
Government of BC - B.C. Rural Development Progress Report. http://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/doing-business/rural-development/rural_dividend_progress_report_oct_2016.pdf;
Alaska Highway News website Kwadacha First Nation seeks to build biomass plant. http://www.alaskahighwaynews.ca/regional-news/kwadacha-first-nation-seeks-to-build-biomass-plant-1.2185149;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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Assessment characteristic	Summary of assessment
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.11. Biogas[17]

Assessment characteristic	Summary of assessment
Commercial feasibility	Biogas is commercially proven in BC and Canada.
Regulatory limitations	The development of biogas is not barred.
Firming/shaping/storage	Biogas can provide baseload power to the grid. It is neither dispatchable or non-dispatchable (i.e., it can be ramped-up over time, but not quickly enough to smooth out intra-day changes). It does not provide a shaping capability; however, the energy can be stored to enable smoothing of output.
Grid reliability (e.g., dispatchability)	Biogas power can provide baseload power to the grid. It can ramp-up slowly if LFG is stored; however, the ramp-up is slow (similar to coal and nuclear) so it cannot be dispatched to smooth intra-day changes.

[17] IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook;
Natural Resources Canada - Map of Clean Energy Resources and Projects (CERP) in Canada. http://atlas.gc.ca/cerp-rpep/en/;
Metro Vancouver website - Annacis Island (Delta). http://www.metrovancouver.org/services/liquid-waste/treatment/treatment-plants/annacis-island/Pages/default.aspx;
Village Farms International, Inc. Management's Discussion and Analysis Year Ended December 31, 2016. http://villagefarms.com/wp-content/uploads/2017/04/4Q-2016-VFF-MDA-final.pdf;
Government of BC Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization. http://www.cscd.gov.bc.ca/lgd/infra/library/IRR_Landfill_Gas_Capture_Case_Study.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Suncurrent website - Biogas Utilization Electrical Generation website. http://suncurrent.co/biogas-utilization/electrical-generation/;
Suncurrent website - Suncurrent Biogas Utilization Storage website. http://suncurrent.co/biogas-utilization/storage/.
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2014. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2014hartland-gasmonitoring.pdf?sfvrsn=1f1d5dca_8;
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2015. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2015-hartlandlandfillgasmonitoringannualreport.pdf?sfvrsn=76572bca_12;
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2013. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2013-hartland-landfill---landfill-gas-monitoring-annual-report-(appendix-b).pdf?sfvrsn=c6bc71ca_6;
Government of British Columbia Consolidated B.C. Emissions Report Summaries for 2015. http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg;
Metro Vancouver, Greater Vancouver Regional District Utilities Committee Meeting Agenda. http://www.metrovancouver.org/boards/Utilities/UC-Jun_15_2017-Agenda_Revised.pdf;
Metro Vancouver's Climate Actions 2016. http://www.metrovancouver.org/boards/ClimateAction/CAC-Jul_5_2017-Agenda_Revised.pdf;
City of Vancouver Administrative Report - Vancouver Landfill: Landfill Gas Projects. http://council.vancouver.ca/020205/a6.htm;
City of Vancouver Administrative Report - Vancouver Landfill: Selection of a Design-Build Contractor for Expanded Landfill Gas Control System Project. http://council.vancouver.ca/000328/a12.htm;
City Farmer website- Vancouver Landfill: Landfill Gas Collection and Utilization Project. http://cityfarmer.org/LandfillGas.html;
Village Farms International, Inc. Management's Discussion and Analysis Year Ended December 31, 2016. http://villagefarms.com/wp-content/uploads/2017/04/4Q-2016-VFF-MDA-final.pdf;
Government of BC Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization. http://www.cscd.gov.bc.ca/lgd/infra/library/IRR_Landfill_Gas_Capture_Case_Study.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

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Assessment characteristic	Summary of assessment
Direct GHG emissions	Direct GHG emissions from wood-based biomass generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for biogas generation range from $2,400/kW to $4,400/kW in BC. O&M costs range from $140/kW-yr to $280/kW-yr. However, some of these O&M costs could offset landfill operating costs.
Future costs	Capital costs for biogas are not expected to fall significantly (less than 10%) in the next 10- 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.12. Biomass (municipal solid waste)[18]

Assessment characteristic	Summary of assessment
Commercial feasibility	Biomass - Municipal Solid Waste (MSW) is a commercially proven resource option, with one Waste to Energy (WTE) facility located in Metro Vancouver.
Regulatory limitations	The development of biomass is not barred.
Firming/shaping/storage	Waste to energy is dispatchable and can be used for firming and shaping.
Grid reliability (e.g., dispatchability)	Waste to energy can provide base load generation and is dispatchable.
Direct GHG emissions	Direct GHG emissions from MSW generation are assumed to be negligible (0 g CO2e/kWh).

[18] BioCAP Canada An Inventory of the Bioenergy Potential of British Columbia. http://cesarnet.ca/biocap-archive/images/pdfs/BC_Inventory_Final-06Nov15.pdf;
Government of BC, An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in British Columbia for First Nations, Small Communities, Municipalities and Industry. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc_bioenergy_primer.pdf;
Clean Energy BC website – Biomass. https://www.cleanenergybc.org/about/clean-energy-sectors/biomass;
Metro Vancouver, Generating Energy from Waste - Metro Vancouver's Waste-to-Energy Facility. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/WTEFactSheet.pdf;
Metro Vancouver, Management of MSW in Metro Vancouver. A comparative analysis of options of management of waste after recycling. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/SDD_3_AECOM_FULL_REPORT.pdf.
Natural Resources Canada website - Map of Clean Energy Resources and Projects (CERP) in Canada. http://atlas.gc.ca/cerp-rpep/en/;
Metro Vancouver, Management of MSW in Metro Vancouver. A comparative analysis of options of management of waste after recycling. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/SDD_3_AECOM_FULL_REPORT.pdf;
BC Hydro Generating Renewable Electricity with Distributed Generation; A Self-assessment Toolkit for BC Local Governments. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2012q4/self-assessment_toolkit_form_oct2012_ar.pdf.
FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf;
Industrial Forestry Service Ltd. Wood Based Biomass in British Columbia and its Potential for New Electricity Generation. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-201507-industrial-forestry-service.pdf;
World Energy Council: Waste to Energy 2016. https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_Waste_to_Energy_2016.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/.

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Assessment characteristic	Summary of assessment
Current costs	Estimated capital costs for energy from MSW range from $6,700 to $8,000/kW, with O&M costs of $130/kW-yr. In addition, since generation of electricity from MSW achieves two purposes (waste disposal and electricity generation), the allocation of costs between the dual purposes can affect the economics of generation.
Future costs	Capital costs for MSW/WTE are not expected to fall significantly in the next 10- 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.1.13. Cogeneration[19]

Assessment characteristic	Summary of assessment
Commercial feasibility	Cogeneration is commercially feasibile, and has been proven globally and in Canada.
Regulatory limitations	The development of cogeneration facilities is not barred.
Firming/shaping/storage	Cogen may be dispatchable, though its host use may prevent or limit the flexibility. In general, cogeneration is not used for firming, shaping, or storing electricity.
Grid reliability (e.g., dispatchability)	Cogen, like other types of distributed energy, produces and consumes power onsite, however, excess can be sold on to the grid. Electricity from cogeneration may be dispatchable, but host use may prevent or limit flexibility.
Direct GHG emissions	Direct GHG emissions from cogeneration are assumed to be approximately 300 g CO2e/kWh, depending on the technology.
Current costs	Estimated capital costs for cogeneration are approximately $1,300 to $5,000/kW, with O&M costs of $15 to $20/kW-yr. In addition, since cogeneration achieves two purposes (heat and electricity production), the allocation of costs between the dual purposes can affect the economics of electricity generation.

[19] Canadian Consulting Engineer Nanaimo sewage plant generates 2000 MW annually. http://www.canadianconsultingengineer.com/water-wastewater/nanaimo-sewage-plant-generates-2000-mw-annually/1001923726/;
British Columbia: Ministry of Agriculture, Regulating combined heat and power generation at greenhouses in the ALR. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/agriculture-and-seafood/agricultural-land-and-environment/strengthening-farming/local-government-bylaw-standards/combined-heat-and-power-generation/chp_discussion_paper_-_may_2013.pdf.
Doluweera et al. Evaluating the role of cogeneration for carbon management in Alberta. https://scholar.harvard.edu/files/davidkeith/files/149.doluweera.etal_.evalrolecongeneration.e.pdf;
World Energy Outlook Projected Costs of Generating Electricity (2010). http://www.worldenergyoutlook.org/media/weowebsite/energymodel/ProjectedCostsofGeneratingElectricity2010.pdf;
Science Integrity Network Greenhouse gas emissions associated with various methods of power generation in Ontario. http://www.opg.com/darlington-refurbishment/Documents/IntrinsikReport_GHG_OntarioPower.pdf;
IEA Executive Summary. http://www.iea.org/textbase/npsum/ElecCostSUM.pdf;
NSW Government Office of Environment & Heritage: Energy Saver Cogeneration feasibility guide. http://www.environment.nsw.gov.au/resources/business/140685-cogeneration-feasibility-guide.pdf;
Center for Climate and Energy Solutions Cogeneration/Combined heat and Power. https://www.c2es.org/technology/factsheet/CogenerationCHP;
IEA Energy Technology Network: Energy Technology Systems Analysis Programme; https://iea-etsap.org/E-TechDS/HIGHLIGHTS%20PDF/E04-CHP-GS-gct_ADfinal%201.pdf;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
BVG Associates and KIC InnoEnergy, Future Energy Costs: Coal and Gas Technologies. http://www.innoenergy.com/wp-content/uploads/2016/09/CleanCoal_BF.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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Future costs	Costs, particularly O&M costs, for cogeneration are expected to fall by approximately 10% in the next 10 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.1.14. Pumped storage[20]

Assessment characteristic	Summary of assessment
Commercial feasibility	Pumped storage is a commercially proven capacity resource option; however, it has not been implemented in BC.
Regulatory limitations	The development of pumped storage is not barred.
Firming/shaping/storage	Pumped storage provides a number of benefits, including storage, shaping, and firming.
Grid reliability (e.g., dispatchability)	Pumped storage is not an energy resource, but is a good capacity resource. It is a non-intermittent, dispatchable resource. Pumped storage can complement the intermittent nature of some renewables, firming these resources to ensure stable grid operation and reliable supply.
Direct GHG emissions	Direct GHG emissions from pumped-storage operations are assumed to be negligible (0 g CO2e/kWh).

[20] BC Hydro 2013 Resource Options Report Update - Lower Mainland/Vancouver Island Pumped Storage Report and North Coast Pumped Storage Report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a30-nov-2013-irp-appx-3a-30.pdf;
FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf.
IRENA Renewable Energy Integration in Power Grids Technology Brief. https://www.researchgate.net/profile/GL_Kulcinski/publication/223663980_Life_cycle_energy_requirements_and_greenhouse_gas_emissions_from_large_scale_energy_storage_systems/links/0c960526ec0ab00722000000.pdf;
IRENA Renewable Energy Technologies: Cost Analysis Series. https://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf;
Energy Storage Association website Pumped Hydroelectric Storage. http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
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Northwest Hydroelectric Association Valuing Pumped Storage: Debunking Myths, Creating Tools. http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/2%20-%20Rick%20Miller.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf;
World Energy Council Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Black & Veatch for PacifiCorp Bulk Storage Study for the 2017 Integrated Resource Plan. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

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Current costs	Research suggests that capital costs for pumped storage are highly variable, ranging from $1,600 to $7,300/kW, with O&M costs of 1-2% of capital costs.
Future costs	Capital costs for pumped-storage projects are not expected to change significantly in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.1.15. Battery storage[21]

Assessment characteristic	Summary of assessment
Commercial feasibility	Battery storage as not a commercially feasible technology at the present time. However, 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.
Regulatory limitations	The development of battery storage is not barred.
Firming/shaping/storage	Battery storage provides a number of benefits, including storage, shaping, and firming.
Grid reliability (e.g., dispatchability)	Battery storage is not an energy resource but rather a mechanism for storage, and a good capacity resource. It is a non-intermittent, dispatchable resource. Battery storage can complement the intermittent nature of some renewables, firming these resources to ensure stable grid operation and a reliable supply.
Direct GHG emissions	Direct GHG emissions from battery storage are assumed to be negligible (0 g CO2e/kWh). Relevant GHG emissions should reflect the electricity-generation sources.

[21] FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf;
Avista 2015 Electric Integrated Resource Plan Technical Advisory Committee Meeting No. 1 Presentation. https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/appendix-a-final.pdf?la=en;
The Climate Examiner Energy storage expanding and going mainstream. http://theclimateexaminer.ca/2015/03/12/energy-storage-expanding-going-mainstream/
Utility Dive 10 trends shaping the electric utility industry in 2017. http://www.utilitydive.com/news/10-trends-shaping-the-electric-utility-industry-in-2017/434541/;
Puget Sound Energy Puget Sound Energy 2015 IRP, Appendix L: Electric Energy Storage. https://pse.com/aboutpse/EnergySupply/Documents/DRAFT_IRP_2015_AppL.pdf;
California Energy Storage Alliance California Adopts Historic Energy Storage Targets. http://www.prnewswire.com/news-releases/california-adopts-historic-energy-storage-targets-228251181.html.
Deloitte Energy storage: Tracking the technologies that will transform the power sector. https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-energy-storage-tracking-technologies-transform-power-sector.pdf.
Scientific American, Study Indicates Bulk Energy Storage Would Increase Total U.S. Electricity System Emissions. https://blogs.scientificamerican.com/plugged-in/study-indicates-bulk-energy-storage-would-increase-total-u-s-electricity-system-emissions/.
Lazard's levelised cost of storage - version 2.0. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
Utility Dive McKinsey: Cheaper batteries present imminent threat of load defection for utilities. http://www.utilitydive.com/news/mckinsey-cheaper-batteries-present-imminent-threat-of-load-defection-for-u/446193/;
World Energy Resources E-storage: Shifting from cost to value 2016. https://www.worldenergy.org/publications/2016/e-storage-shifting-from-cost-to-value-2016/;
PacifiCorp Battery Energy Storage Study for the 2017 IRP. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf;
E3 Review of Capital Costs for Generation Technologies. https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf;
ESMAP and IFC Energy Storage Trends and Opportunities in Emerging Markets. https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStorage-report.pdf?MOD=AJPERES;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf.

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Current costs	Research suggests that capital costs for utility-scale batteries are highly variable (particularly by technology and size), ranging from $2,000 to $6,000/kW, with O&M costs of 1-2% of capital costs.
Future costs	Capital costs associated with battery storage are conservatively estimated to fall 50% by 2040.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

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4.1.2. Implications for MarketBuilder portfolio modelling

Based on the assessment detailed above, as well as Deloitte's experience and professional judgment, the following alternative resource options and associated inputs will be included in the MarketBuilder model. The reason for their inclusion is to assess alternative sources of energy and capacity to replace those expected to be provided by Site C:

Table 1: Alternative resource options – MarketBuilder model inputs[22]

Alternative resources	Reference Capital cost ($CAD/kW)	O&M cost ($CAD/MWh)[23]	Direct GHG emissions (g CO2e/kWh)[24]	Capacity factor (%)
Onshore wind	2,400	33	0	30
Offshore wind	5,700	78	0	35
Utility-scale solar PV	2,900	18	0	20
Geothermal	7,300	25	0	92
Natural gas (SCGT)	1,300	12	580	92
Natural gas (CCGT)	1,700	9	370	92
Run-of-river hydroelectricity	5,300	49	0	36
Biomass (wood-based)	5,300	32	0	85
Biogas	3,600	32	0	66
Biomass (MSW)	7,300	27	0[25]	76
Cogeneration	3,000	10	300[26]	68
Pumped storage	3,300	13	0	n/a
Battery storage	2,500	24	0	n/a

[22] Detailed assumptions related to MarketBuilder portfolio modeling are included in Appendix F.
[23] O&M costs (fixed and variable depending on the resource) have been converted to a common unit of $CAD/MWh for input into the MarketBuilder model.
[24] The Clean Energy Act defines a "clean or renewable resource" as biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. These alternative resource options are assumed to have zero direct GHG emissions.
[25] Estimated emissions from biomass – MSW (see section 4.1.1.12) are assumed to be zero based on the Clean Energy Act definition of biomass as "clean or renewable resource". While the non-biogenic component of MSW is not considered a "clean or renewable resource", this component can vary significantly. The overall impact on the modeling is not considered to be significant.
[26] Cogeneration is assumed to be natural gas fired (see section 4.1.1.13).

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4.2. Assessment of the expansion potential of current BC Hydro facilities

4.2.1. Introduction

As one of the options for identifying alternative sources of electrical capacity we reviewed current BC Hydro hydroelectric facilities to determine if there are opportunities to expand current capacity.

To determine this expansion potential we reviewed the IRP, RRA and the individual Facility Asset Plans for each facility. The focus or our review was to identify additional capacity and associated capital costs. In identifying additional capacity we have used current capacity as the basis on which the additional capacity is calculated. As such, for facilities that have been derated, the derated capacity value is used as the basis and for facilities that are out of service, current production is assumed to be zero. In identifying values for additional capacity and associated capital costs we have relied on values identified in BC Hydro's Facility Asset Plans and the RRA. Our analysis identified assets where there is potential for expansion. We have not conducted a cost benefit analysis on each of these expansion options.

4.2.2. Summary of our assessment

We noted that there are several assets with expansion potential. The expansion potential relates to one of the following types of opportunities:

- Where there is an empty bay at an existing generating station which can be utilized to add a generating unit;
- Where the generating station can be replaced/refurbished to add capacity through enhanced efficiency and/or reinstate nameplate capacity;
- Where a generating facility can be added to an asset where there is no current power generation;
- Where individual components of the generating station can be refurbished/replaced to add capacity through enhanced efficiency; or
- Where additional untapped flow is available to add generating capacity.

4.2.3. Implications for MarketBuilder portfolio modelling

The additional capacities identified for each expansion project range from 2MW to 500MW in size. The total additional capacity identified ranges from 600MW to 1000 MW.The tables below list the specific facilities which, as we noted, have expansion potential.

Additional capacity identified by BC Hydro as planned/committed[27]:

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
1	Revelstoke	Revelstoke Install Unit 6	The scope of the Revelstoke Unit 6 project is to install a 500 MW unit in the existing empty Unit 6 bay. In addition, there is a transmission requirement for an additional series capacitor station on the transmission line	500	591-328	RRA Appendix J

[27] All committed BC Hydro expansion is included in the model as firm supply (exogenous variable).

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			from Vaseux to Nicola and some enhancements within existing substations.			
2	John Hart	John Hart Generating Station Replacement	The purpose of the project is to replace the existing John Hart Generating Station. The existing six unit, 121 MW generating station, located on Vancouver Island near the community of Campbell River, has been in operation since 1947. The age and condition of the John Hart facility indicate the need for significant capital investment in the powerhouse and penstocks to ensure reliable generation from the facility in the long term and to mitigate seismic and environmental risks. The John Hart Replacement Project includes: replacement of the existing powerhouse with a new three-unit 132.2 MW powerhouse with integrated flow bypass capability. The new facility will provide an additional 11.2 MW dependable capacity (from 121 MW to 132.2 MW) and approximately 10 per cent additional Resource Smart energy from the same amount of water.	11.2	1092.9	RRA Appendix J
3	Ruskin	Ruskin Dam Safety and Powerhouse Upgrade	The Project includes the replacement of parts of the seismically deficient Ruskin Dam and the rehabilitation/replacement of the 105 MW Ruskin Powerhouse, including generating equipment brought into service between 1930 and 1950, and associated substation.	9	718.1	RRA Appendix J Ruskin Public Report #10
4	Clowhom	Clowhom Rehabilitate Generating Station	The purpose of this project is to rehabilitate the Clowhom Generating Station to enable it to provide reliable, dependable energy and capacity.	0	90.9	RRA Appendix I Cost from FAP
5	Cheakamus	Cheakamus Units 1 and 2 Generator Replacement	The purpose of this project is to replace the Cheakamus generators which are in Poor condition. There is also an	40	73.4	Cost from RRA Appendix J,

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			opportunity to uprate the generators to achieve increased dependable capacity and energy.			capacity from FAP
6	Bridge river	Bridge River 2 Upgrade Units 5 and 6	The purpose of this project is to restore the reliability of the Unit 5 and 6 generators and their ancillary systems, as well as the reliability of other major components (governors, exciters and circuit breakers). The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.	54	83.3-52.5	Cost from RRA, capacity from RRA final arguments
7	Bridge river[28]	Bridge River 1 Upgrade Unit 4 Generator and Governor	This project will restore the capacity and reliability of the Unit 4 generator and governor. The project also presents an opportunity to increase the capacity of the generators to achieve incremental dependable capacity and energy.	18	35.6	Cost and capacity from FAP
8	Bridge river[29]	Bridge River 2 Upgrade Units 7 and 8	The purpose of this project is to restore the reliability of the Unit 7 and 8 generators and their ancillary systems, as well as the reliability of other major components such as the circuit breakers. The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.	37	53.7	Cost and capacity from FAP

[28] It is assumed that the project will restore nameplate capacity and increase capacity by 15.38% in line with Bridge River 2 Unit 5 and 6 (Unit 4 capacity 50MW derated to 40MW. Refurbished back to capacity of 10MW).
[29] It is assumed that the project will restore nameplate capacity and increase capacity by 15.38% in line with Bridge River 2 Unit 5 and 6 (Unit 7 and 8 capacity 65MW. Unit 8 derated to 48MW).

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Additional capacity identified by Deloitte to further expand existing BC Hydro facilities[30]:

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
9	Seven mile	Seven Mile Overhaul Units 1 to 3 Turbines	The purpose of this project is to overhaul Units 1 to 3 turbines in order to provide continued reliable service. The overhaul would address known issues such as cavitation repair to the runner and erosion repairs on the runner band seal. There is also an opportunity for a 2-3% efficiency gain by replacement of the runners with a new modern design.	32	100	RRA Appendix I & J; Additional Capacity from IRP table 3-25 page 3-70.
10	Alouette[31]	Redevelopment of the Alouette powerhouse	The purpose of the project is to redevelop the powerhouse. Efficiencies associated with new generating equipment would marginally improve the installed capacity of a like-for-like redeveloped 9 MW facility to approximately 9.7 MW based on the same unit parameters. If the powerhouse were to be redeveloped to utilize the Power Tunnel capacity of 57 cms, Alouette could attain an installed capacity of 21 MW. This would be approximately 8 MW - 18 MW of Winter Dependable Capacity.	9.7 21	100 160	BCUC IR 1.74.1 Attachment 1 Facility Asset Plan July 2013
11	Duncan[32]	Installation of generating facilities at Duncan Dam.	The purpose of the project is to install a generating facility. There are no power generation facilities at Duncan Dam currently. A two unit Vertical Axial type Kaplan option was found to be the most economical. The approach included a 22 MW small hydro generating plant, installation of a new sub-station at the dam site. Would not generate from mid-January to June due to operating limits of the units (based on reservoir head and	22	250	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan 2016

[30] The additional potential is included in the model as a supply option (endogenous variable).
[31] It is assumed that all capacity generated from the project will be in addition to current capacity. Alouette Generating Station has been out of service since February 2010.
[32] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			flow discharges). The levelized cost of energy was estimated to be $114/MWh.			
12	Elko[33]	Installation of an additional powerhouse	The purpose of the project is to install an additional generating facility. Previous Resource Smart studies identified the potential for adding additional capacity at Elko. This would be achieved by means of an additional powerhouse. A 20 MW additional unit in a standalone powerhouse was considered the most attractive alternative. It is recommended that a study be conducted as prior to the next major capital investment to evaluate this opportunity.	20	225	BCUC IR 1.74.1 Attachment 2 - Facility Asset Plan September 2013
13	Falls river[34]	Redevelopment of the Falls river powerhouse	The purpose of the project is to redevelop the powerhouse. Prior studies have assessed the likely re-development potential of Falls River to lie somewhere between 16 MW (9 incremental) and 25 MW (18 incremental). Based on historical inflows it is expected that the full MW rating would contribute to winter generating capacity for the region. Regional load forecasts developed by BC Hydro Energy Planning support the long-term strategy to increase generating capacity for the region.	9 18	165 260	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan April 2015
14	Ash River[35]	Refurbish of the Ash river powerhouse	The purpose of the project is to refurbish the powerhouse. Generating capability could be increased by replacing existing components in order to increase unit efficiency and make use of the additional	8	57	100 Site C Review - Deloitte Questions - August 2017 - Attachment

[33] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).
[34] Redeveloped capacities are assumed to be net of current capacity (i.e., 16MW and 25 MW minus 7MW) as the facility is currently generating power. The cost of redeveloping a powerhouse is assumed to be similar on a KW basis to that identified in the Alouette FAP of $10.3M/MW ($100M/9.7 MW).
[35] A project increase in capacity from derated value is assumed (from 25MW to 33MW). The cost of refurbishment is assumed to be the sum of 3 projects in the FAP Capital Plan (Generator $40M, Governor $6M, Turbine $11M). Unit Capacity of 28MW derated to 25MW.

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			available water. The new exciter and transformer have been sized to accommodate uprating of the unit to 33MW.			- Facility Asset Plan January 2016
15	Ash River[36]	Additional Generating Unit	The purpose of the project is to install an additional generating facility. There is an opportunity to increase the generating capacity at Ash River by tapping off the existing steel penstock and adding a new generating unit beside the existing facility. This is expected to provide an additional 9MW of capacity and 36GWh per year of energy. Any future upgrades to the water passage (such as replacement of the wood stave penstock) should consider sizing/selection to allow for future increased generation capacity. This may require a modification to BC Hydro's Water License.	9	101	
16	GM Shrum	U1-U5 Capacity Increase[37]	The purpose of the project is to enhance the capacity of the powerhouse. Units 1-5 capacity would increase to a dependable capacity of up to 220 MW.	220	71	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan November 2015
		Install 2 New Generating Units[38]	The purpose of the project is to install 2 new generating units. A resource opportunity had 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	TBD	TBD	

[36] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).
[37] Capacity increase identified in IRP section 3 (pg. 69). Cost identified in FAP capital plan.
[38] Potential opportunity identified in FAP; no additional information provided.

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			units would require a separate, new water passage.			
17	Ladore[39]	Additional Generating Unit	The purpose of the project is to install an additional generating unit. Ladore was designed for the potential installation of three generating units. Two units have been installed but there is an unused penstock available for a third unit.	9	11	BCUC IR 1.86.6 Attachment 1 - Facility Asset Plan October 2015
18	Seton[40]	Unit upgrade	The purpose of the project is to upgrade the existing unit. The current maximum generating capacity is 48MW with upgrade this will be 50MW.	2	20	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan September 2013
19	Shuswap[41]	Refurbishment of generating unit	The purpose of the project is to refurbish unit 1. Unit 1 is currently out of service due to the poor condition of multiple components and triggered by the generator phase-to-phase fault. Linked to the unit condition is the poor condition of the woodstave penstock.	3	6	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan August 2014
20	Strathcona[42]	Additional Generating Unit	The purpose of the project is to install an additional generating unit. The Strathcona Facility was designed for the potential installation of three generating units. Two units have been installed but there is an empty bay available for the installation of a third unit.	31.3	37	BCUC IR 1.87.6 Attachment 1 - Facility Asset Plan February 2014

[39] The cost of adding a unit is assumed to be similar on a kW basis to that identified in the RRA for the Revelstoke addition of $1.18M/MW ($591M/500 MW).
[40] Assumed project increase in capacity from current capacity value (from 48MW to 50MW).
[41] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Ash River FAP of $1.84M/MW ($61M/33 MW).
[42] The cost of adding a unit is assumed to be similar on a kW basis to that identified in the RRA for the Revelstoke addition of $1.18M/MW ($591M/500 MW).

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#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
21	Wahleach[43]	Turbine Replacement	The purpose of the project is to install a new turbine. Given the very high pressure head at Wahleach (620 m at full reservoir), the water energy at the plant is very efficient and highly valuable. Thus, there is an opportunity to replace the turbine and increase the unit flexibility to produce up to 75 MW.	14	5.8	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan March 2016
22	Whatshan	Transformer replacement	The purpose of the project is to replace a transformer. Whatshan's maximum rated capacity of 55 MW is currently limited by the old transformer which was recently replaced with a new 65 MVA unit. The unit generator has an overload rating of 64 MVA and the turbine has a maximum nameplate capacity of 59.7 MW. Therefore, there is potential to increase the maximum rated capacity of the unit.	4.7	3.6	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan January 2017
23	Puntledge[44]	Additional Generating Unit	Puntledge additional unit (Puntledge River, Vancouver Island)	10	115	IRP Chapter 3 table 3-25
24	Lajoie[45]	Additional Generating Unit	Lajoie additional unit (Bridge River/Fraser River area)	30	340	IRP Chapter 3 table 3-25

The potential of expansion of BC Hydro current BC Hydro facilities is included in the MarketBuilder model as follows:

- All existing BC Hydro generation capacity is included in the model as firm supply (exogenous variable).
- All planned/committed BC Hydro expansion is included in the model as firm supply (exogenous variable).
- Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

[43] Assumed project increase in capacity from current (from 61MW to 75MW).
[44] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW). This expansion potential is identified in the IRP but not in the FAP.
[45] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW). This expansion potential is identified in the IRP but not in the FAP.

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The potential for expanding BC Hydro's existing facilities is included in MarketBuilder as follows:

- All existing BC Hydro generation capacity is included in the model as firm supply (exogenous variable).
- All committed BC Hydro expansion is included in the model as firm supply (exogenous variable).
- Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

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4.3. Assessment of the opportunities to increase demand-side management

4.3.1. Introduction

As part of the assessment of alternative sources of energy and capacity to replace those due to be provided by Site C, Deloitte was asked by BCUC to assess BC Hydro's demand-side management (DSM) initiatives. The purpose is to identify opportunities to increase energy and capacity savings. DSM is considered an alternative-resource option in that it serves to meet future demand through energy conservation and efficiency.

BC Hydro considers two types of DSM measures: energy focused and capacity focused. Energy-focused DSM includes measures aimed at conserving energy and promoting energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to deliver capacity savings during peak load periods. Both are included in the scope of this assessment and described in more detail below.

4.3.2. Additional limitations

This section of the report has been prepared pursuant to the following additional assumptions and limiting conditions:

1. The Advisor does not assess the cost-effectiveness of BC Hydro's DSM scenarios (as defined in the 2013 IRP, F17-F19 RRA, or otherwise) or the specific measures included therein beyond the publically available analysis previously conducted by BC Hydro. It reflects assumptions at that time.
2. The Advisor does not assess the performance, cost effectiveness, or other characteristics of DSM programs or initiatives offered by other utilities and used as examples.
3. Information related to BC Hydro's DSM initiatives provided to The Advisor have been accepted without any verification as fully and correctly reflecting the business conditions and results for the respective periods. The Advisor has not audited, reviewed, or compiled any information provided and, accordingly, expresses no audit opinion or any other form of assurance regarding such information.
4. The Advisor does not provide assurance on the achievability of any forecasted DSM results contained herein. This is for several reasons: events and circumstances frequently do not occur as expected; differences between actual and expected results may be material, and achievement of the forecasted results is dependent on actions, plans, and assumptions of management.

4.3.3. Summary of assessment

4.3.3.1. Current DSM Plan – base case used in MarketBuilder modeling

In the 2013 Integrated Resource Plan (IRP), BC Hydro describes five options for energy-focused DSM that also provide capacity savings (summarized in Table 2). While all of the options were determined to be cost effective according to the Total Resource Cost (TRC) and Utility Cost (UC) tests[46], BC Hydro determined DSM Option 2 to be the most cost-effective target at the time.

[46] The TRC test measures the overall economic efficiency of a DSM initiative from a resource options perspective based on its total cost including both customer participant and the public utility's costs. The UC measures the costs of the DSM initiative from the utility's perspective, excluding any costs of the participant. The benefits are similar to the TRC utility benefits (avoided supply costs and capacity). The UC test result indicates the change in total utility bills (revenue requirements) due to DSM). For the TRC and UC tests, the long-run marginal cost of electricity from the 2013 IRP ($85/MWh) was used to compare DSM investments against other options. In addition, BC Hydro added an extra UC test screening filter using the B.C.-border sell price forecast (approximately $36/MWh) to prioritize DSM investments. Any DSM initiative that did not pass the TRC test (at long-run marginal cost) and did not pass the UC test at the value of $36/MWh was investigated for

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Table 2: Summary of DSM Options in 2013 IRP

DSM Option	Description	Energy savings by F2021 (GWh/yr)	Capacity savings by F2021 (MW)	Total Resource Cost ($/MWh)	Utility Cost ($/MWh)
Option 1	A scaling back of the current DSM activities to generally meet 66% of the load growth.	6,100	1,200	32	18
Option 2	An update of BC Hydro's current DSM Plan with a balanced offering of codes and standards, conservation rate structures, and programs.	7,800	1,400	32	18
Option 3	Expands programs to the limit of cost-effectiveness. Keeps codes and standards and conservation rate structures the same as in Option 2.	8,300	1,500	35	22
Option 4	Builds upon Option 3 and expands the codes and standards and conservation rate structure tools.	9,500	1,500	47	30
Option 5	Reflects an aggressive effort to change market parameters and societal norms and patterns in order to save electricity.	9,600	1,600	49	29

Subsequent to the 2013 IRP, the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA) proposed an update to Option 2. This was done to further moderate the strategy for DSM investments, given the reduction in the rate of growth of demand for electricity and reduced need for additional resources[47]. Table 3 below compares BC Hydro's F17-F19 DSM expenditure schedule to that in the 2013 IRP. The "moderated" Option 2 described in the current F17-F19 DSM Plan is projected to achieve 5,300 GWh/yr in energy savings by 2021[48].

modifications to pass these tests, with the exception of the DSM initiatives required by the Demand-Side Measures Regulation.

[47] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

[48] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1. 168.1. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf. Savings are cumulative (risk adjusted with losses) with Fiscal 2013 start year for comparability with 2013 IRP data.

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Table 3: Comparison of expenditures in BC Hydro 2013 IRP Option 2 and F17-F19 RRA DSM Plan49

	BC Hydro 2013 IRP F17-F19 ($m)	DSM expenditure schedule F17-F19 ($m)	Variance ($ m)	Variance %
Codes and Standards	18.5	14.5	(4)	(22%)
Rate Structures	6.6	3.5	(3.1)	(47%)
Programs:				
Residential	55.6	37.9	(17.7)	(32%)
Commercial	132.5	99.4	(33.1)	(25%)
Industrial	139.3	82.9	(56.4)	(40%)
Thermo-Mechanical Pulp	0	55.8	55.8	n/a
Total	**327.3**	**276**	**(51.3)**	**(16%)**
Supporting Initiatives	61.2	42.4	(18.8)	(31%)
Total before capacity DSM	413.6	336.4	(77.2)	(19%)
Capacity focused DSM	0	38.6	38.6	n/a
Total	**413.6**	**375**	**(38.6)**	**(9%)**

The moderated selected the moderated DSM Option 2 from the F17-F19 RRA was selected as the base case for portfolio modelling because it represents BC Hydro's current proposed DSM portfolio.

While the decision to moderate DSM spending in the F17-F19 RRA was supported by the Minister of Energy and Mines[50], it was also criticized by a number of third parties for curtailing cost-effective DSM[51,52]. Given these assertions, and the fact that BC Hydro has significantly curtailed its DSM initiatives over the past several years, an additional assessment was conducted to identify a DSM option with the potential for higher energy and capacity savings.

4.3.3.2. Assessment of alternate DSM scenarios with higher energy and capacity savings

In order to select an alternate DSM scenario with higher energy and capacity savings than the base case, Deloitte reviewed the options proposed by BC Hydro in its 2013 IRP to determine which could represent a realistic estimate of the DSM energy and capacity savings achievable by BC Hydro.

It is important to recognize that each of the DSM options outlined in the 2013 IRP was created as a specific portfolio with a suite of measures (e.g., programs, codes and standards, conservation rate structures) to achieve a particular path of energy savings over time. As a result, the suite of measures included in each option may no longer reflect the current market situation and specific DSM opportunities. For the purpose of

[49] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1.168.3. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[50] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix BB. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[51] BCSEA Final Argument. http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf
[52] CEC Final Argument. http://www.bcuc.com/Documents/Arguments/2017/DOC_49470_06-13-2017-CEC-Final-Argument.pdf

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this assessment, we considered the options as energy savings targets, and did not assess the feasibility or cost-effectiveness of each measure within the portfolio of options.

Based on a review of the five DSM options against the criteria below, Option 3 was selected as the alternate scenario. While DSM Options 1 to 5 were all considered to be cost effective at the time of the 2013 IRP, and to contribute towards energy and capacity savings beyond the current state, Options 1 to 3 were the only options considered to be technically feasible. DSM Options 4 and 5 were determined to require significant government intervention, including changes to policies, codes and standards that are outside of the control of the utility.

The criteria used to select the alternate DSM option included the following:

- DSM performance of BC Hydro against peer utilities in North America
- Technical feasibility of BC Hydro achieving the target defined in the option
- Cost-effectiveness of achieving the option (at time of 2013 IRP)

The results from the assessment are summarized below:

DSM performance – BC Hydro's current performance on energy savings as a percentage of revenue is below industry average as compared to U.S. utilities. BC Hydro's overall energy savings from DSM programs as a percentage of retail sales was 0.6% for the period 2014-2016[53]. 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[54]. While numerous jurisdictional variances such as climate, political, and socioeconomic factors make direct comparisons difficult, this illustrates that BC Hydro's energy-savings performance is below the industry average. This trend suggests that BC Hydro could take a more aggressive approach to DSM by implementing any of the five options to close the gap in energy-savings performance with other comparable utilities.

Technical feasibility of achieving efforts by BC Hydro – A review of considerations under Options 1 to 3 suggest the implementation of options is technically feasible. However, BC Hydro describes Options 4 and 5 as "not technically viable options for prudent utility planning." These options include significant government intervention in policies, codes and standards, and in some cases, considerable technological innovation and adoption. For example, DSM Option 5 considers changes to building codes, which would require residential and commercial buildings to reach net-zero electricity by FY2032. These substantial shifts in technology adoption are not considered achievable within the proposed timeframes. Therefore, it is assumed that only Options 1-3 are technically achievable for the purpose of utility planning. Option 3 was described by BC Hydro in the 2013 IRP as the "greatest level of DSM program savings currently considered deliverable"[55].

Cost effectiveness – While all options considered by BC Hydro in the 2013 IRP were considered cost-effective, DSM Options 1 to 3 were estimated to come in at a lower TRC and UC than DSM Options 4 and 5. While further analysis needs to be done to evaluate the current costs of each option, Options 4 and 5 had an estimated utility cost of $30/MWh and $29/MWh respectively, as compared to Option 3 with a cost of $22/MWh. A study of the total cost savings for utility energy efficiency programs in the U.S. concluded that the weighted average cost of electricity saved from utility energy efficiency programs from 2009 to 2013 was

[53] BC Hydro Final Argument. 415. http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
[54] 2017 ACEEE scorecard.
[55] BC Hydro 2013 Integrated Resource Plan. Chapter 4 – Resource Planning Analysis. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

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$US23/MWh[56]. Therefore, it is assumed that DSM Option 3 is consistent with DSM opportunities implemented across utilities in the US, and is more cost effective than Options 4 and 5.

4.3.3.3. Opportunities to achieve or exceed Option 3

Quantifying and modeling the potential energy and capacity savings associated with new DSM portfolios or specific measures were beyond the scope of the assessment. However, a number of observations were identified that support the assessment that there is significant potential for BC Hydro to increase its DSM savings beyond its current portfolio to at least those represented by DSM Option 3. These observations are summarized in the following section.

a) Energy-Focused Demand Side Management

Expenditure on energy-focused DSM

BC Hydro's total DSM spending as a percentage of revenue was 2.3% for the period 2014-2016[57]. The 2017 ACEEE benchmarking report of U.S. utilities estimates an average of 2.7%, with leaders (the top five by ranking) demonstrating expenditures of 4.8-11.7% of revenue[58]. This illustrates that BC Hydro's DSM expenditures are somewhat below the industry average.

A comparison conducted by BC Hydro between its sectoral DSM program spend/results and the results of a 2014 Lawrence Berkeley study[59] demonstrate that BC Hydro's residential program spending in particular is significantly below other jurisdictions (see Table 4).

Table 4: Comparison of expenditures by BC Hydro vs. other jurisdictions[60]

	DSM Expenditures		
	Other jurisdictions	**BC Hydro F2014-16**	**BC Hydro F2017-19**
Residential	29%	11%	9%
Low Income	6%	2%	3%
Commercial and Industrial	61%	71%	75%
Cross sectorial	4%	16%	13%

While BC Hydro's FY17-19 DSM Plan did increase spending in some areas (e.g., the industrial thermo-mechanical pulp program, which was not included in the 2013 IRP), there are several notable areas where expenditures on energy-focused DSM decreased:

[56] Berkeley Lab – The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf
[57] Calculated based on actual DSM results included in Exhibit B-9 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf and revenues from BC Hydro annual reports.
[58] 2017 ACEEE scorecard. It is important to note that some states have implemented energy efficiency spending caps for utilities that limit cost-effective energy savings opportunities.
[59] The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs. Ernest Orlando Lawrence Berkeley National Laboratory, 2014. http://utilityscalesolar.lbl.gov/sites/all/files/lbnl-6595e.pdf
[60] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1.168.3. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

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- Residential programs – decrease in spending of $17.7 million (-33%)
- Commercial programs – decrease in spending of $33.1 million (-25%)
- Supporting initiatives – decrease in spending of $18.8 million (-31%)

Overall, BC Hydro's energy-focused DSM expenditures proposed in the FY17-19 DSM Plan have decreased by 32% relative to the 2013 IRP (not including capacity-focused pilot spending and the Thermo-Mechanical Pulp program[61], which were not included in the 2013 IRP). Including the Thermo-Mechanical Pulp program, expenditures have decreased by 19% (see Table 3).

Evaluation of energy-focused DSM

Over the long-term, BC Hydro's forecasted, incremental DSM energy savings from the F17-F19 RRA DSM Plan level off (post-2021) and begin to decline, dropping below zero by 2036[62]. In discussion with BC Hydro, management noted that their projections simplify over the long-term due to the uncertainty involved. However, there are examples of other utilities taking a different approach to forecasting long-term energy savings.

For example, in its Long-Term Energy Plan, Ontario's Independent Electricity System Operator (IESO) includes estimates for the energy savings from future programs, codes and standards, in addition to currently planned measures. According to IESO, "To achieve the longer-term target, it is assumed that conservation programs will continue to be made available to customers after the Conservation First Framework ends. The focus and design of future programs will be determined based on future sector and market conditions and on the experience gained in the current framework"[63].

An additional opportunity for BC Hydro to increase forecasted energy savings from DSM could exist through changes in the approach used to estimate energy savings from codes and standards. Subsection 4(1.4) of the Demand-Side Measures Regulation permits the BCUC to attribute a portion of the avoided energy and capacity costs that will result from a code or standard to a demand-side measure that will increase the use of a "regulated item"[64]. However, as outlined in Chapter 10 of the RRA, BC Hydro has not included the attribution of savings from codes and standards in calculating the cost tests to assess the feasibility of DSM programs[65].

BC Hydro acknowledges that the attribution of codes and standards savings would result in improved cost effectiveness test results for some DSM programs. However, it argues that it would present practical challenges and, given that the programs included in the DSM Plan did not require the attribution of savings from codes and standards to pass the cost tests, it is not worth the time, effort, and cost[66].

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[61] Expenditures for the Thermo-Mechanical Pulp program are shown separately from other industrial program spending, because the costs of this program are covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015).
[62] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 3, Table 3-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[63] Ontario Planning Outlook, IESO, 2016. http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/ontario-planning-outlook-september2016.pdf?la=en
[64] Demand-Side Measures Regulation. 2008. http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section4
[65] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[66] Letter dated November 21, 2016 – BC Hydro Submitting Responses to Interveners Information Request No. 1 (Exhibit B-10). http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf

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Despite this, it is possible that this lack of attribution could result in BC Hydro scaling back or eliminating a DSM program that might otherwise have been maintained. For example, in the F17-F19 DSM Plan BC Hydro eliminated the residential New Home Program on the basis of cost-effectiveness, shifting its focus instead to codes and standards.

Specific opportunities to increase energy-focused DMS

The 2017 ACEEE report identifies the breadth and types of efficiency programs (e.g., small business, low income, multifamily) as "essential determinants of utility energy efficiency capability and performance." It notes a number of emerging program areas that reflect new trends and opportunities in the industry[67]. While some of these are already being pursued by BC Hydro, many are not.

Table 5: BC Hydro's pursuance of emerging programs (as defined by ACEEE)

Emerging area	Description	Status at BC Hydro
Advanced space-heating heat pumps	Programs that encourage the adoption of cold- or warm-climate heat pumps with a Heating Seasonal Performance Factor (HSPF) above 10. To receive credit, utilities must provide extra incentives for advanced heat pumps relative to those provided for moderate-efficiency heat pumps.	• BC Hydro does offer incentives for heat pumps through its Home Energy Retrofit Offer program[68], but it does not appear to be pursuing programs that specifically encourage the adoption of heat pumps with HSPF above 10 at this time[69].
Commercial and industrial geo-targeting	Energy efficiency programs that target businesses in specific geographic locations that will yield high savings. Does not include geo-targeted marketing efforts or comparative business energy report programs.	• BC Hydro does not appear to be pursuing this at this time.
Conservation voltage reduction (CVR), or volt/ volt-ampere reactive (Var) optimization (VVO)	Voltage-reduction systems to improve the efficiency of a utility's transmission and distribution system, whether explicitly included in the utility's energy efficiency portfolio or not.	• BC Hydro is pursuing Var and Voltage Optimization energy reductions; however, this is not currently classified as a DSM measure[70].
Energy use feedback to consumers in real time	Programs that allow consumers to better understand their behavior and react to their energy usage to increase savings. Includes programs that provide feedback in near real time.	• BC Hydro does not appear to be pursuing this at this time. An Energy Insights program aimed at providing proactive information to customers about energy consumption has been deferred[71].
Heat pump water heaters	Programs to improve the efficiency of water heating systems, either stand-	• BC Hydro does not offer a heat –pump, water heater program at this time;

[67] ACEEE 2017 scorecard
[68] BC Hydro – Home renovation rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
[69] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 186.2 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[70] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 3. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[71] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 114.9. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

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Emerging area	Description	Status at BC Hydro
	alone or included as part of another program.	however, it does have a technical trial in the marketplace and will be investigating the potential for a program offer[72].
High-efficiency ceiling fans	Efforts to promote the installation of high-efficiency ceiling fans, either stand-alone or included as a part of another program.	• BC Hydro does not appear to be pursuing this at this time. However, it does offer incentives for bathroom ventilation fans through its Home Energy Retrofit Offer program[73],
High-efficiency consumer electronics (residential)	Efforts to promote the purchase and use of high-efficiency consumer electronics, including through rebates, midstream and upstream programs, and the use of smart strips with consumer electronics.	• BC Hydro supports product and equipment standards (including residential electronics) and offers rebates on consumer electronics through the Retail program[74]. However, funding for this program was reduced by 35% in the F17-F19 DSM Plan.
High-efficiency residential clothes dryers	Programs offering rebates for high-efficiency clothes dryers, or participation in the Super-Efficient Dryers Initiative. Does not include advocacy for dryer efficiency standards.	• BC Hydro does provide appliance rebates through its Retail program (seasonal only)[75]. However, funding for this program was reduced by 35% in the F17-F19 DSM Plan[76].
Midstream and upstream programs	Programs to transform the market for energy-efficient products by targeting midstream and/or upstream retailers and partners to improve choices and reduce costs for consumers. Includes midstream and upstream lighting and appliance programs. Midstream and upstream programs are scored separately.	• BC Hydro does support market transformation through its Commercial and Residential Sector Enabling Initiatives[77].
Quality HVAC installation	Programs to improve and ensure the quality installation of HVAC equipment.	• BC Hydro does not appear to be pursuing this at this time[78].
Reduction of plug and other miscellaneous load in commercial buildings	Programs that aim to reduce plug or other loads in commercial buildings, including midstream and upstream programs.	• BC Hydro does provide support for strategic energy management in commercial buildings through its Leaders in Energy Management – Commercial program (though not targeted to the

[72] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 186.2 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[73] BC Hydro – Home renovation rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
[74] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[75] BC Hydro – Appliance Rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/appliance-rebates.html?WT.mc_id=F18_spring_appliances_bchpromos
[76] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 184.6. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[77] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[78] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 184.2. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

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Emerging area	Description	Status at BC Hydro
		reduction of plug and other, miscellaneous load)[79].
Residential geo-targeting	Energy efficiency programs that target residents in specific geographic locations that will yield high or particularly valuable savings. Does not include geo-targeted marketing efforts or comparative home energy reports.	• BC Hydro does not appear to be pursuing this at this time. BC Hydro's DSM programs are province-wide offerings[80].
Residential learning thermostats	Programs to boost savings for consumers by increasing energy-efficient behaviors through smart thermostats. Includes learning thermostats, Wi-Fi enabled thermostats, and other smart-thermostat programs.	• BC Hydro does not offer programs to increase energy-efficient behaviors through smart thermostats at this time. It is in the early stages of researching demand-response programs, including programmable, communicating thermostats and other connected home technologies[81].
Zero net energy buildings	Developing zero net energy buildings through codes and standards or other methods. Does not include programs or participation in zero net energy forums or coalitions.	• BC Hydro is actively focused on building codes. However, it has cancelled the New Home Program encouraging builders and developers to build energy-efficient homes[82].

b) Capacity-Focused Demand Side Management

Capacity savings from capacity-focused DSM are currently not quantified in BC Hydro's DSM plan projections. BC Hydro proposes to spend $38.6 M on capacity-focused DSM pilots over F2017-F2019 which, according to the F17-F19 RRA, are aimed at determining the dependability of targeted capacity savings for inclusion in BC Hydro's future integrated resource planning[83].

BC Hydro's 2010 Resource Options Report describes three options for capacity focused DSM[84]:

[79] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[80] Letter dated January 23, 2017 - BC Hydro Submitting Responses to Intervener Information Request No. 2. 37.2. http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf
[81] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[82] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[83] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[84] BC Hydro 2010 Resource Options Report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a01-nov-2013-irp-appx-3a-1.pdf

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- Time-based rates that encourage and reward customers for shifting their electricity consumption to off-peak periods. Both Time-of-Use (TOU) rates and Dynamic Pricing (DP), such as critical peak pricing (CPP) and peak time rebate (PTR), are rate structures that could accomplish this objective.
- Capacity-focused programs that consist of a suite of programs that target capacity savings in all three customer sectors. They are designed to provide capacity savings that can be dispatched under utility control.
- Industrial load curtailment that targets large customers who agree to curtail load on short notice in return for a financial payment.

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[85].

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[86]:

- 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).

BC Hydro estimates the long run marginal cost for capacity to be $50/kW-yr to $55kW-yr (fiscal 2013 $) based on Revelstoke 6; however, it notes that this is a unique low-cost capacity option and is only available for approximately 500 MW. The next clean- generation capacity option is estimated to be pumped storage facilities (estimated at $200/kW-yr including the impact of energy losses in the pump generation cycle)[87].

While BC Hydro's capacity-focused projects are still in the pilot stage, there are numerous examples of utilities already successfully implementing and realizing savings from capacity-focused DSM programs, including:

Hydro Quebec

- Interruptible electricity options for large-power customers – Hydro-Québec Distribution can ask large-power customers that have signed up for the interruptible electricity option to reduce their power demand in return for financial compensation. Since 2006, the division has been offering a similar option to medium-power customers. The Electricity Supply Plan 2008–2017 provides for the renewal of these options, yielding an expected contribution of 1,000 MW[88].

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[85] ACEEE 2017 scorecard
[86] Letter dated May 11, 2017 –BC Hydro Submitting Responses to Commission IRs on Rebuttal Evidence (Exhibit B-21). http://www.bcuc.com/Documents/Proceedings/2017/DOC_49232_B-21_BCH-Responses-BCUC-IR-No1.pdf
[87] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1. 168.1. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[88] Hydro Quebec Strategic Plan 2009-2013. http://www.hydroquebec.com/publications/en/docs/strategic-plan/plan-strategique-2009-2013.pdf

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- Residential dual energy – A dual-energy heating system lowers the demand for power in peak periods, which are generally winter cold spells. This gives Hydro-Québec some leeway concerning the amount of electricity it has available to meet Québec customers' greatest demand for power at those times, and makes it easier to balance high electricity demand with availability[89]. This rate option provides for a 640-MW decrease in peak power requirements[90].

Manitoba Hydro[91]

- Bioenergy optimization programs – Launched in 2008, this program encourages customers to install, operate, and maintain customer-sited, load-displacement generation systems that employ heat and CHP applications fueled by renewable energy. The program is expected to achieve 12.2 MW of capacity savings and 32.5 GWh of energy savings in 2016/2017.
- Load-displacement program – Launched in 2014, this program encourages industrial and municipal customers to install, operate, and maintain customer-sited, load- displacement generation systems that employ combined heat and power (CHP) technologies relying on waste and by-product streams or locally available, low-cost sources of renewable energy. The program is expected to achieve 12.4 MW of capacity savings and 91.9 GWh of energy savings in 2016/2017.
- Curtailable rate program – This program allows qualifying customers to receive a monthly credit on load, which can be curtailed on notice from Manitoba Hydro. With 55 customers, this program is expected to achieve 159.5 MW of capacity savings in 2016/2017.
- Arizona Public Service Company (APS)[92]
- APS peak solutions program – A commercial and industrial demand response program utilizing direct load control and manual load reduction. This program is available for the summer months between 12pm and 7pm, and anticipated a 2016 weekday load reduction of approximately 25 MW.
- Residential battery storage program – The Arizona Corporation Commission has ordered APS to spend up to US$4 million to develop a residential, battery-storage program to facilitate energy-storage technologies through demand response or load management, allowing customers to lower energy use during times of peak demand[93]. While this is only a pilot program, it reflects the dramatic advancements in battery storage and surge in current utility-scale, battery project.

4.3.4. Implications for the MarketBuilder portfolio modeling

BC Hydro's current DSM Plan (i.e., "moderated Option 2/"mid DSM") was included in the MarketBuilder modeling.

It should be noted that running additional scenarios would offer more insights, for example, by applying Option 3 from the 2013 IRP, in order to consider a higher level of DSM energy and capacity savings.

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[89] Hydro Quebec – Residential Dual Energy. http://www.hydroquebec.com/residential/customer-space/account-and-billing/understanding-bill/residential-rates/rate-dt.html
[90] Hydro Quebec 2014-2023 Supply Plan Integrated System.
[91] Manitoba Hydro 2016/2017 Demand Side Management Plan. https://www.hydro.mb.ca/corporate/pdfs/demand_side_management_plan.pdf
[92] APS 2016 Demand Side Management Implementation Plan. http://images.edocket.azcc.gov/docketpdf/0000162231.pdf
[93] Arizona Corporation Commission – Commission Approves Energy Efficiency Programs that Save APS Customers Money. http://azcc.gov/Divisions/Administration/news/2016Releases/7-13-2016%20Commission%20Approves%20Energy%20Efficiency%20Programs.pdf

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5. Assessment of Load Forecast Model

This section provides an assessment of BC Hydro's load-forecast model published in July 2016 ("the Forecast Model"), which provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. The assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other major utilities in Canada; and interviews with several subject matter professionals. Importantly, Deloitte has not accessed BC Hydro's model directly. As such, this assessment cannot independently validate the information received regarding the model, nor the exact impacts on the forecast from changing model inputs. On the basis of information provided, this assessment provides estimates of the direction and an order-of- magnitude calculation of impacts resulting from changes to several model inputs.

5.1. Description of the Load Forecast Model

BC Hydro forecasts future load and capacity requirements using two distinct methodologies. First, to produce its mid forecast, BC Hydro uses an additive, statistically adjusted end use (SAE) model, which technically consists of 12 sub models broken down by region and customer segment. In addition to the 12 SAE models, BC Hydro produces a linear regression for the light manufacturing sector, a model of FortisBC's expected load based on its cost of purchasing energy from markets, and two projections. The first projection, of heavy industrial load, consists of an assessment of load requirements for roughly 180 major clients, plus 20 to 30 prospective ones. It includes assumptions regarding the prospects of major capital projects, such as liquefied natural gas (LNG) plants, advancing to the construction phase. The second, which consists of 'all other' load requirements (e.g., streetlights and irrigation), is both small and more straightforward to estimate, as it has historically remained relatively stable compared with other market segments.

In addition to the mid forecast, BC Hydro produces high and low load requirement forecasts. These are the outcome of Monte Carlo simulations that model uncertainty with respect to consumers' responsiveness to future rate increases, the magnitude of future rate increases, and future provincial economic growth, among other variables. The inputs driving the Monte Carlo simulation are fewer and in some cases. different from the inputs driving the mid forecast. We understand that BC Hydro ensures that data that is common to the two models is consistent.

While these modeling approaches involve a high degree of complexity, they appear generally in line with the practices of other utilities, with some exceptions (see section 5.6). Potential risks and alternatives to these approaches are explored.

The mid, high and low forecasts are produced both before and after accounting for demand-side management (DSM) initiatives. These initiatives, which are designed to improve efficiency, and thus mitigate the need for major capital projects to increase electricity supply, are assumed to provide increased load and capacity savings over time. The gross forecasts prepared for each of the customer segments (e.g., residential) are then lowered by either a mid or low DSM factor, producing forecasts of net (or actual) future electricity requirements.[94]

[94] High DSM does not feature in either the Monte Carlo simulations or the mid forecast.

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Interpreting the SAE and Monte Carlo models together can be conceptually challenging, as assumptions relating to DSM differ; as a result, the mid forecast of actual requirements is closer to the low projection than the high projection. In fact, while the Monte Carlo simulations are used to produce high and low pre-DSM forecasts that have equal probabilities of occurring (Figure 1), the DSM adjustment that is made to these forecasts is smaller than in the mid SAE forecast. As a result, the average of the high and low forecasts tends to be greater than the mid forecast produced by the SAE model (Figure 2). BC Hydro's rationale for applying low DSM to the low forecast is that it is unrealistic to assume that if electricity requirements were growing slowly, a mid- or high-DSM policy would be pursued. Presumably, however, this same reasoning would see high DSM applied to the high forecast, since mitigating demand growth would be comparatively more important—and cost effective—in an environment where load requirements are growing rapidly.

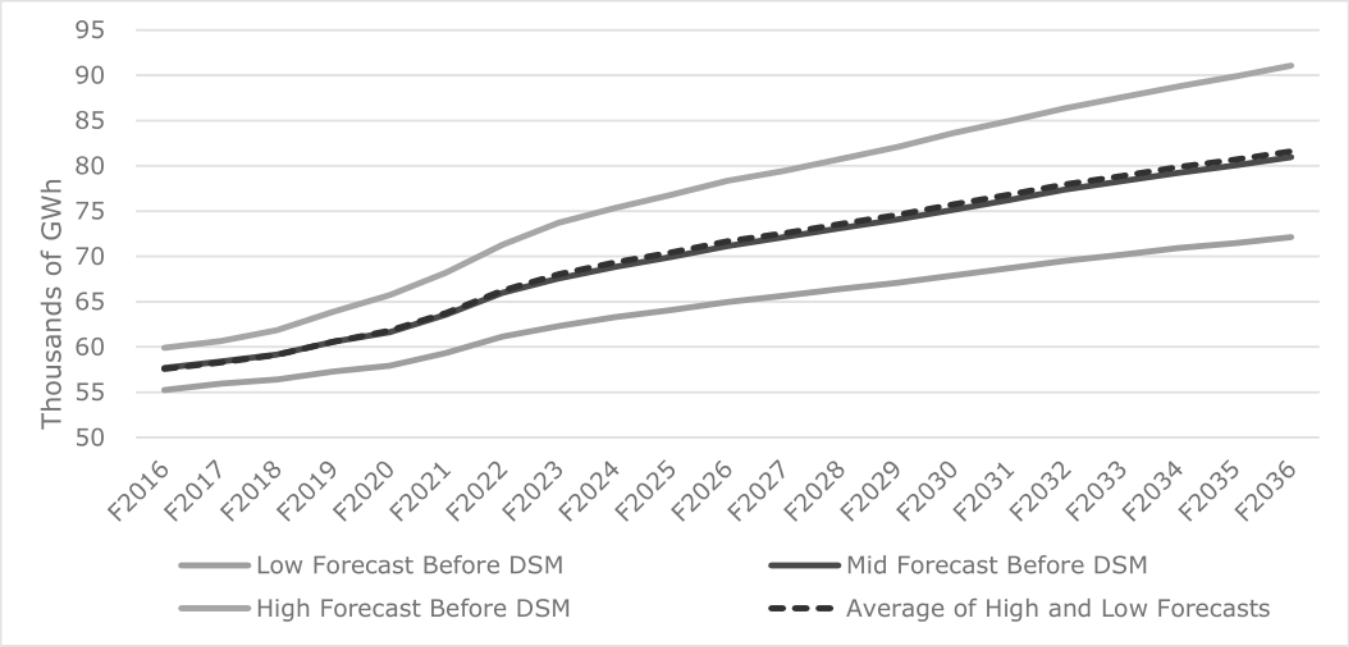

Figure 1: Total Integrated Gross Requirement Forecasts before DSM

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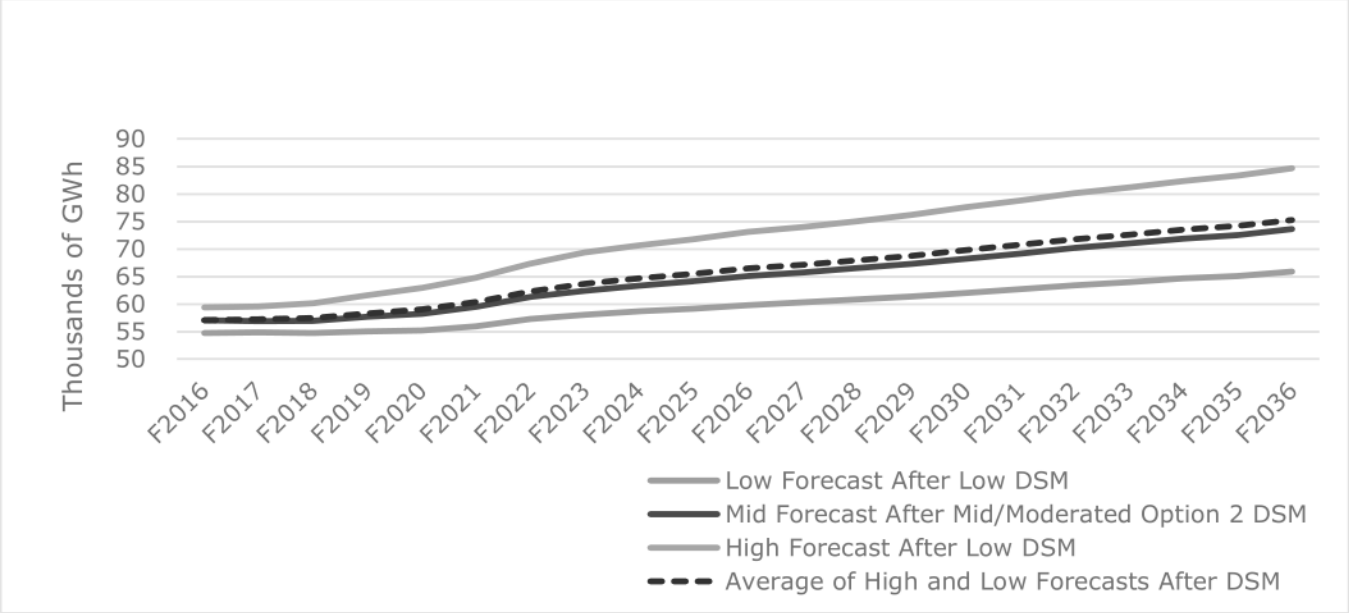

Figure 2: Total Integrated Gross Requirement Forecasts after DSM

5.2. Historical Model Performance

Forecasting several years or decades into the future is a difficult task that is prone to error regardless of the scenario being examined. This challenge is particularly hard in an electricity-demand context, where actual demand is driven by a large number of variables, some of which can change rapidly, such as advancement in energy efficiency, fluctuations in commodity prices, weather variability, and others. Nevertheless, forecast models should be routinely compared to actuals, and recalibrated to ensure that they do not result in systematic overestimation or underestimation. A high-performing forecast model is one that produces estimates relatively close to actuals, and results in relatively equal instances of overestimation and underestimation.

The analysis in this section uses BC Hydro's forecasts of total, gross load requirements after DSM. DSM cannot be measured with a high degree of accuracy as it is difficult to determine whether electricity consumers changed their level of demand as a result of DSM or for other reasons. Actual electricity demand measured by BC Hydro is by definition demand after DSM. When comparing actual demand to forecasted demand after DSM, some of the deviance from forecasted demand could be the result of a larger/smaller size of DSM compared with BC Hydro's expectations.

BC Hydro has run a load forecast model every year from fiscal 1964 onwards. Each model forecasts loads between five and twenty years into the future, as well as current fiscal year requirements. For all models between fiscal 1964 and 2016, there were 647 point estimates that can be compared to actual load demand. Of the 647 forecasted points, 500 (77%) were overestimates, with this being especially common since the global financial crisis (Figure 3). We explore the model's performance overtime and across customer segments below.

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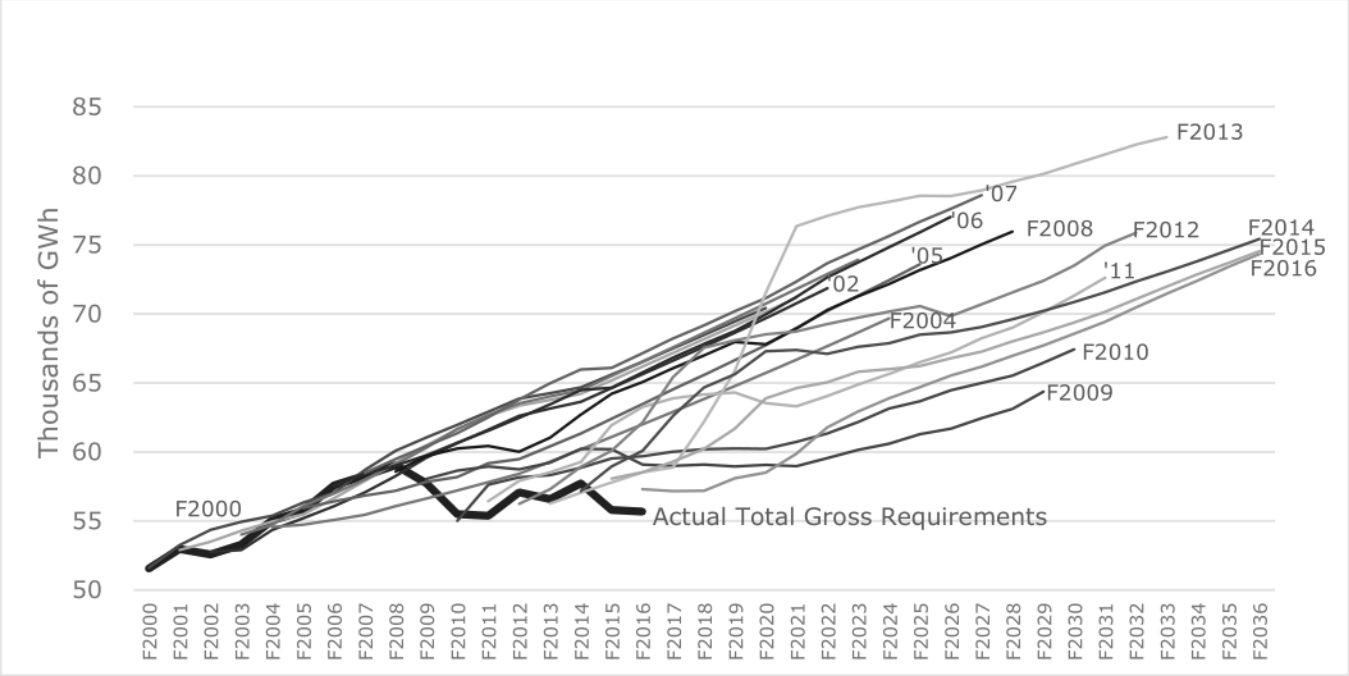

Figure 3: Total Gross Requirement Forecast Models Between 2000 and 2016 (with DSM

BC Hydro's load forecasts have performed better in the short-run compared with the long-run. Averaging over all point estimates from models starting in fiscal 1964 shows that forecasts in the first full year were overestimated on average by 1.7% of actual loads. Five-year forecasts were overestimated on average by 4.5% of actual loads, 10-year forecasts were overestimated on average by 12.2% of actual loads, 15-year forecasts were overestimated on average by 18.0% of actual loads, and 20-year forecasts were overestimated on average by 30.8% of actual loads.

BC Hydro's load forecast methodology has changed several times since its first forecast in fiscal 1964. However, the magnitude of overestimation has not decreased over the 10-year and 15-year horizons, but has increased somewhat for the first fully forecasted year and over a 5-year horizon.[95]

- The average forecast in the first fully forecasted year[96] was overestimated by 0.9% of actual load for models run between fiscal 1986 and 1995, 0.7% for models between fiscal 1996 and 2005, and 2.7% for models between fiscal 2006 and 2015 (Figure 4).[97]

[95] Data provided in document B-15, BC Hydro Submitting Responses to Intervener Information Request No. 2.
[96] We have used the second forecasted data point (first fully forecasted year) as BC Hydro forecasts the fiscal year during which the model is produced. That is, the first forecasted data point is load in fiscal 1980 for the model vintage completed in fiscal 1980.
[97] Three 10-year periods were analyzed going back from 2015, the last date a comparison can be made between the first fully forecasted year and actuals.

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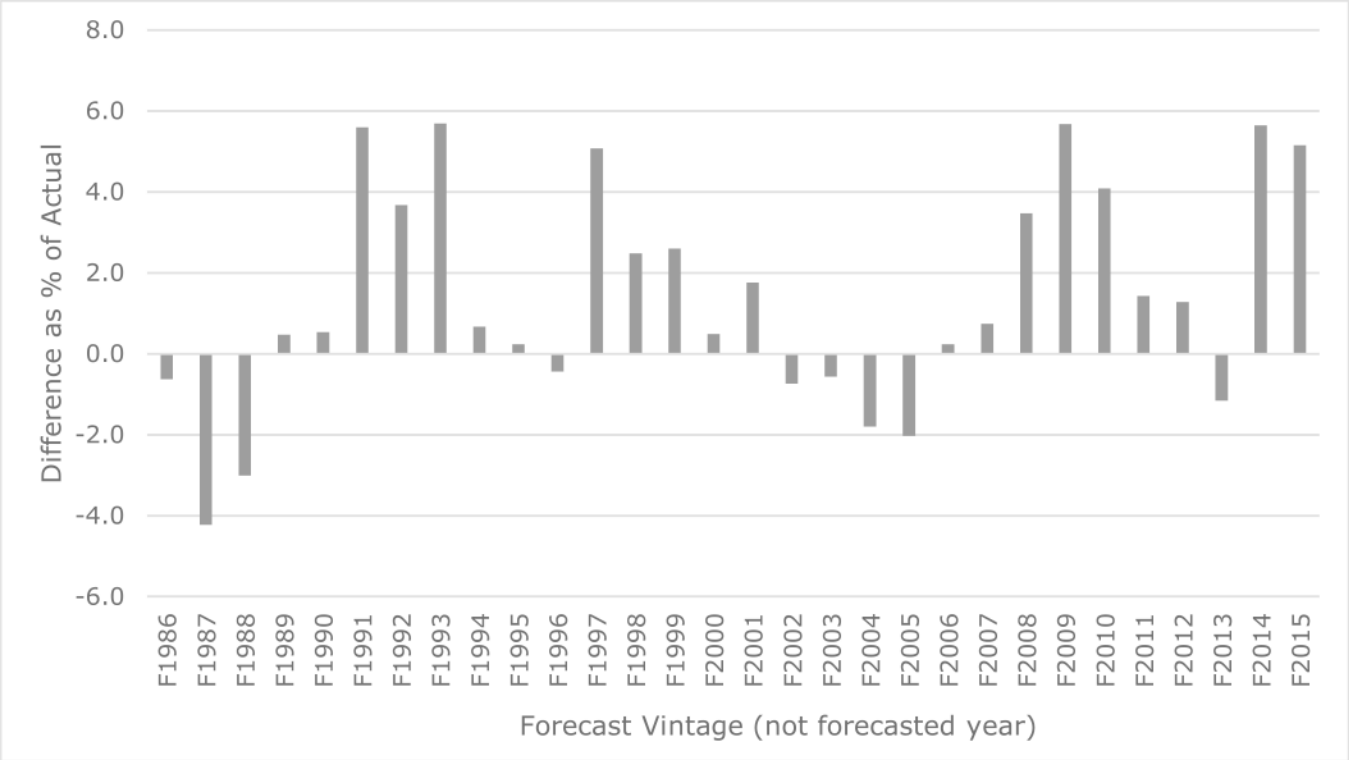

Figure 4: Difference Between First Fully Forecasted Year and Actual Total Gross Requirements (with DSM)

- The average 5-year-out forecast overestimation was 0.1% of actual load for models ran between 1983 and 1992, 3.2% for models between 1993 and 2002, and 5.1% for models between 2003 and 2012 (Figure 5).[98]

[98] Three 10-year periods were analyzed going back from 2012, the last date for which a five-year comparison can be made.

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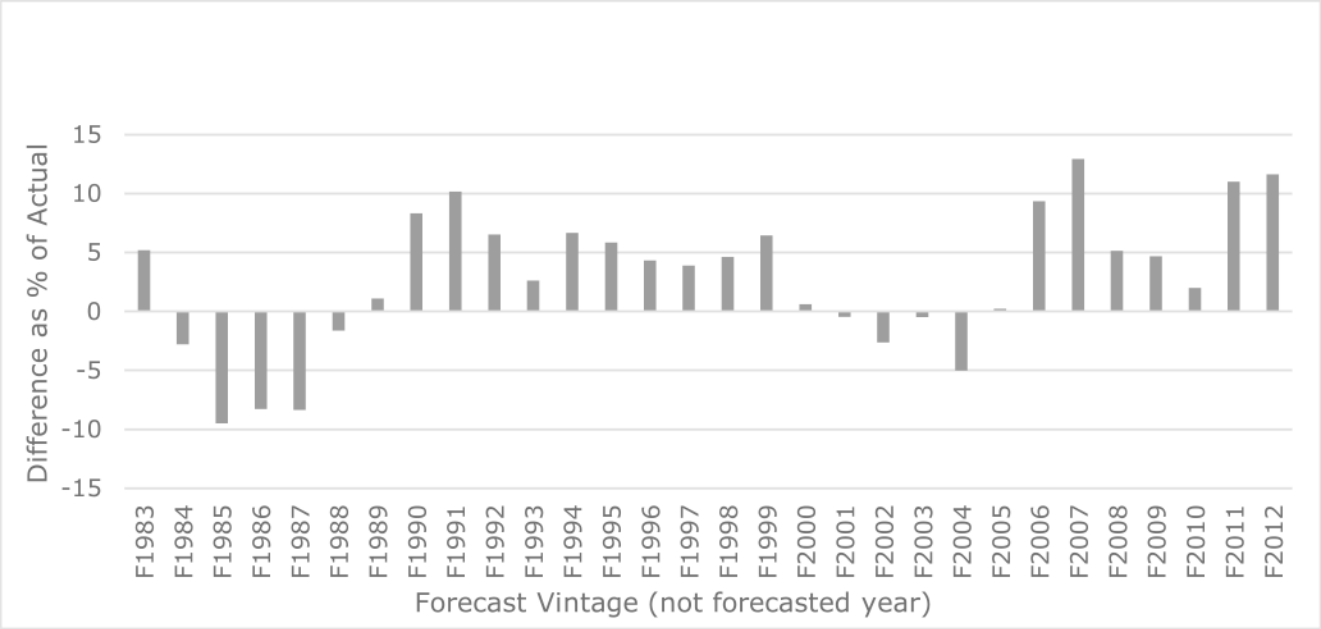

Figure 5: Difference Between 5-Year Forecast and Actual Total Gross Requirement (with DSM)

- The average 10-year-out forecast overestimation was 11.9% of actual load for models ran between 1978 and 1987, 8.2% for models between 1988 and 1997, and 9.5% for models between 1998 and 2007 (Figure 6).[99]

[99] Three 10-year periods were analyzed going back from 2007, the last date a 10-year comparison can be made.

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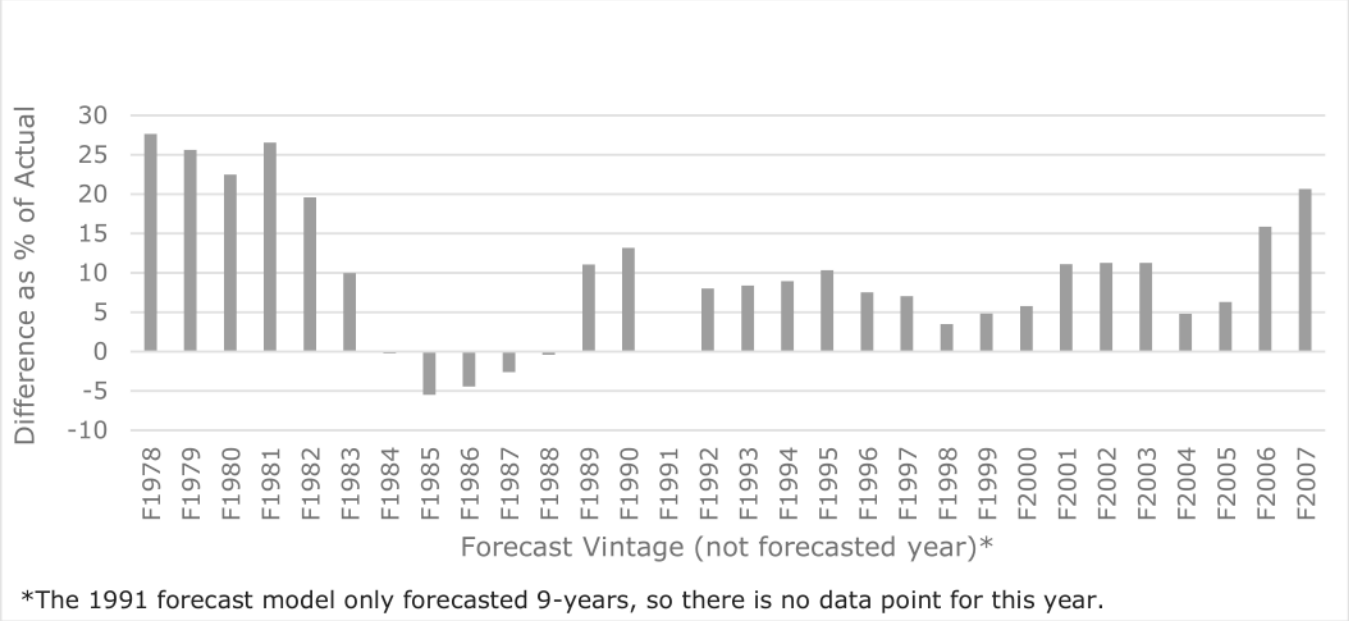

*The 1991 forecast model only forecasted 9-years, so there is no data point for this year.

Figure 6: Difference Between 10-Year Forecast and Actual Total Gross Requirement (with DSM)

- The average 15-year-out forecast overestimation was 14.5% of actual load for models ran between 1993 and 1997, and was 15.7% for models between 1998 and 2002 (Figure 7).[100]

[100] Two 5-year periods were analyzed going back from 2002, the last date a 15-year comparison can be made.

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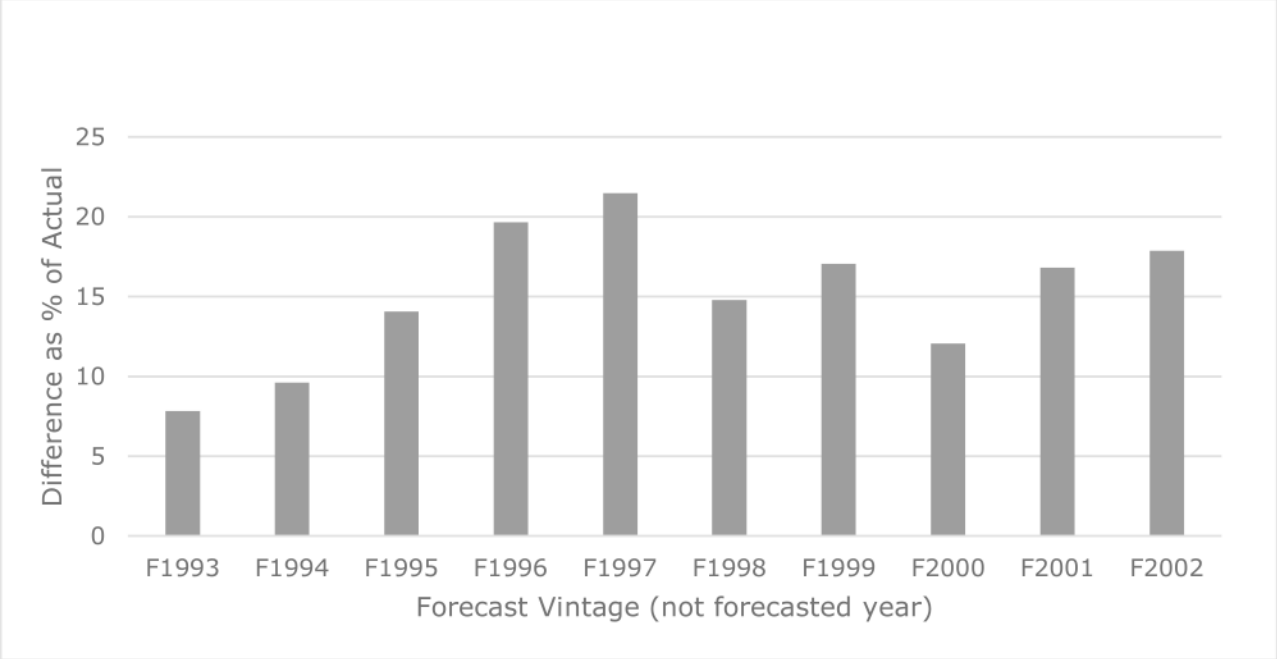

Figure 7: Difference Between 15-Year Forecast and Actual Total Gross Requirement (with DSM)

The large, industrial component of the model is the largest contributor to the deviation from actuals in both the short and long term. This component is responsible for 29% of total sales[101] on average between fiscal 2000 and 2017.

- Using forecast models from fiscal 2008 to 2016, large, industrial sales are overestimated by an average of 954 GWh (or 9% of actuals) in the first fully forecasted year.[102]
- Large industrial sales were overestimated by an average of 2,664 GWh (or 19% of actuals) in the fifth forecasted year.[103]
- Large industrial sales are overestimated by an average of 2,796 GWh (or 21% of actuals) in the eighth forecasted year (Figure 8).[104]

[101] Share of total sales, not total gross requirement. Total sales do not included system losses.
[102] The first forecasted year is completed the same year that the forecast is completed. For example, the first forecasted year in the fiscal 2008 forecast is also fiscal 2008. Forecasts for models before fiscal 2014 were completed in December of the fiscal year, meaning that much of the year had already happened. The first fully forecasted year is technically the second year of the forecast.
[103] Fifth forecasted year was used as a reference between the short (first fully forecasted year) and longer term (eighth year) estimations.
[104] The eighth forecasted year was chosen as actual data ends in fiscal 2017 and we are using model vintages that start forecasting in fiscal 2008. As such, we take the average of 8-year forecasts for three model vintages (model fiscal 2008, 2009, and 2010). Using longer time horizons would decrease the number of model vintages used to compare the deviance from actuals.

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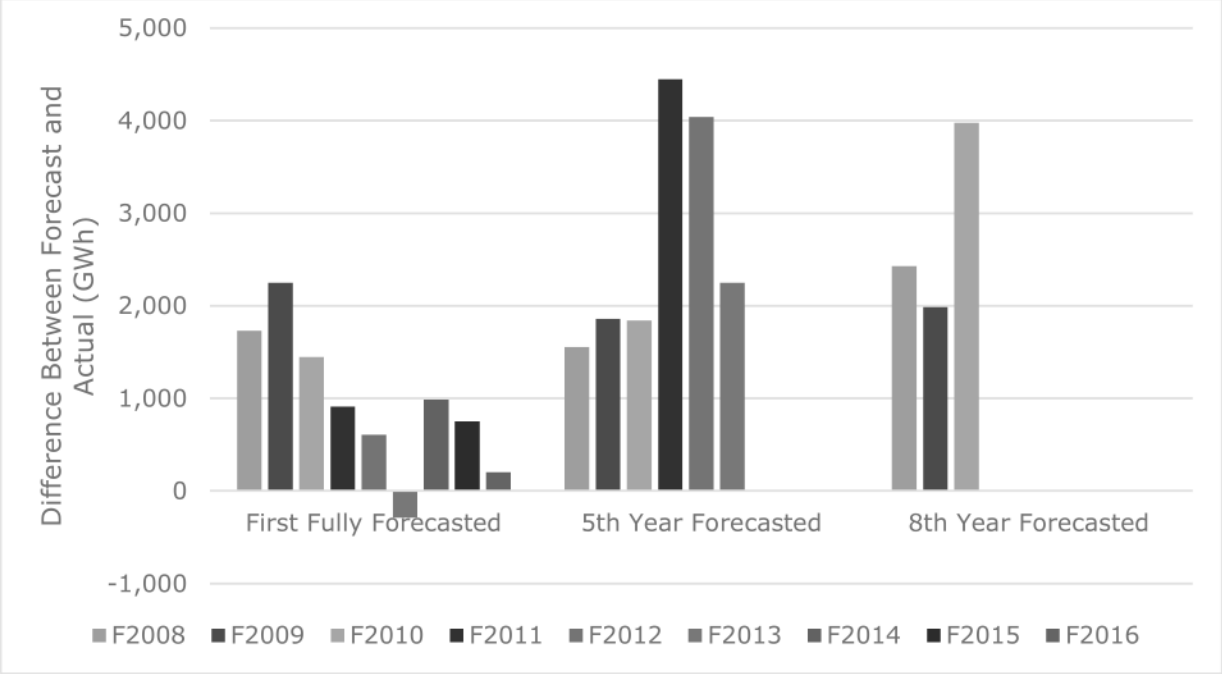

Figure 8: Large Industrial Sector - Difference Between Forecasted and Actual Sales

On average, residential sales account for 33% of total sales between fiscal 2000 and 2017. Forecasts of residential sales are close to actuals in both the short and long run.

- Using forecast models from fiscal 2008 to 2016, residential sales are overestimated by an average 28 GWh (or 0% of actuals) in the first fully forecasted year.
- In the fifth forecasted year, residential sales were underestimated by an average of 347 GWh (or 2% of actuals).
- Residential sales are underestimated by an average of 667 GWh (or 4% of actuals) in the eighth forecasted year.

Commercial and light, industrial sales account for 35% of total sales on average between fiscal 2000 and 2017. Forecasts of this component of the model are close to actuals in both the short and long run.

- Using forecast models from fiscal 2008 to 2016, commercial and light industrial sales are overestimated by an average of 149 GWh (or 1% of actuals) in the first fully forecasted year.
- In the fifth forecasted year, commercial and light industrial sales were overestimated by 191 GWh (or 1% of actuals).
- Commercial and light industrial sales are underestimated by an average of 751 GWh (or 4% of actuals) in the eighth forecasted year.

It should be noted that the challenge in estimating electricity demand accurately is not unique to BC Hydro. Deloitte interviews with two other Canadian utilities revealed that at least one has tended to overestimate load over time. Moreover, as with BC Hydro, this utility reported that the heavy industrial sector was most likely to be overestimated.

5.3. Model Inputs

Appendix A reports the key variables for all SAE models and the Monte Carlo simulations. These include macro-economic indicators, demographic variables, weather-related variables, as well as variables specific to individual customer segments, such as the number of accounts. Based on consultations with two other

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Canadian utilities and several, independent industry subject-matter experts, the key variables included in the models appear reasonable.

The inputs to the 2016 forecast come from five main sources: the BC Ministry of Finance, the U.S. Energy Information Administration, Environment Canada, Robert Fairholm Economic Consulting (RFEC), and BC Hydro itself, which produces calculations based on past load requirements and develops assumptions around future capital projects. To inform its model assumptions, particularly with respect to heavy industrial projects, BC Hydro reports that it reviews a wide array of market data, from sources such as IHS Global Insight, Bloomberg, Wood Mackenzie and PIRA Energy, and engages outside consultants, such as PwC.

5.3.1. Macro-economic inputs

BC Hydro uses a number of macro-economic variables as inputs to their model, such as growth in GDP, employment, population, retail sales, disposable income, and housing starts.

The forecasts for employment, population, and housing starts that BC Hydro uses as inputs in the forecast model appear in line with projections published by Statistics Canada[105] and the Conference Board of Canada.[106]

With respect to GDP, while BC Hydro uses the BC Ministry of Finance's real GDP forecast as an input for the first five years of its load forecast, the values incorporated in the model appear higher than the Conference Board of Canada's in the years that follow. For instance, in calculating its 2016 load forecast, real GDP growth is assumed to average 2.3% in the first five years (i.e., based on the BC Ministry of Finance's forecast), before increasing to 3.5% over the next five years (based on the RFEC projections).[107] By comparison, the 2016 Conference Board of Canada forecast projects that real GDP will grow by 2.6% on average between 2016 and 2020, before slowing to an average of 2.3% between 2021 and 2025. By 2025, the RFEC forecast projects that BC's economy will be 6% larger in real terms (Figure 9). After 2025, the two forecasts exhibit similar trends.

[105] Statistics Canada (2015). *Population Projections for Canada (2013 to 2063), Provinces and Territories (2013 to 2038).* Accessed on August 29, 2017 at: http://www.statcan.gc.ca/pub/91-520-x/91-520-x2014001-eng.pdf
[106] Conference Board of Canada (2016). *Provincial Outlook 2016: Long-Term Economic Forecast.* Accessed on August 29, 2017 at: http://www.conferenceboard.ca/temp/09ed73c5-c0a5-4714-82ae-80d72b70d0fd/8004_po_longterm_2016_rpt_bc.pdf
[107] Refers to the arithmetic average of annual growth rates provided by BC Hydro.

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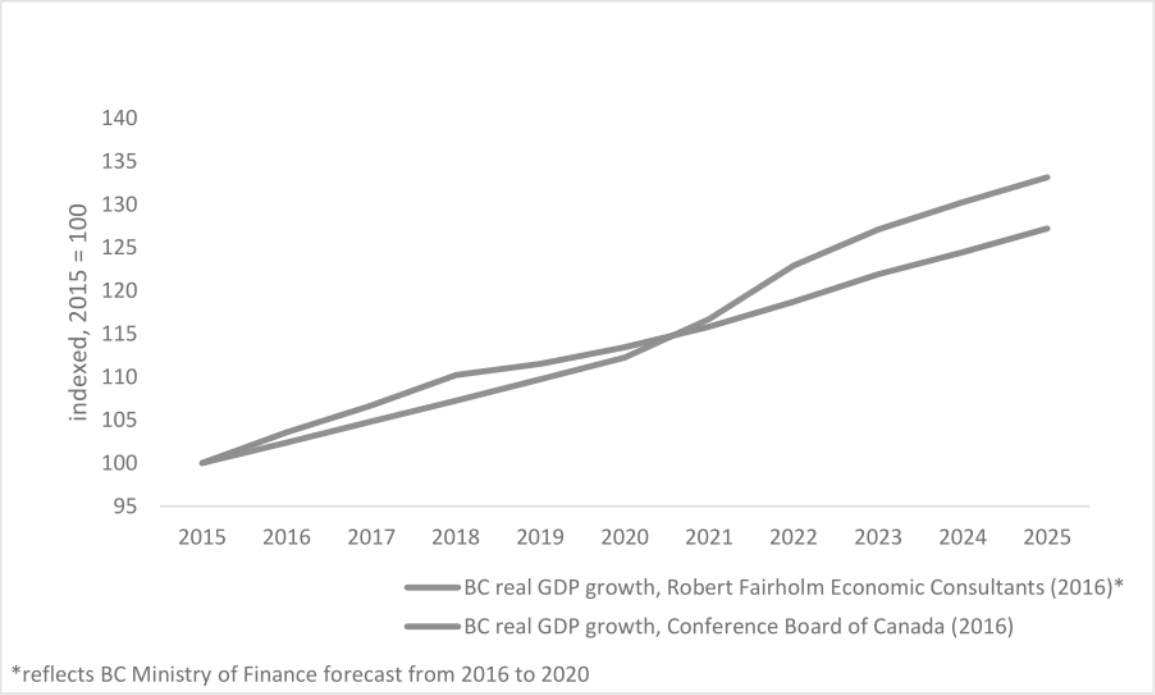

Figure 9: BC's projected economic growth based on RFEC and Conference Board of Canada 2016 forecasts

This assessment does not examine which of the two GDP forecasts is more likely to be accurate, as analyzing the RFEC and Conference Board of Canada's forecast models is beyond its scope. However, we note that the RFEC GDP forecast which BC Hydro uses is itself based on assumptions BC Hydro provides to RFEC regarding future, heavy industrial developments. On one hand, this ensures that the GDP projections RFEC provides are consistent with the assumptions of the load forecast (e.g., in terms of the number of LNG projects that are likely to be developed). On the other hand, it also means that if BC Hydro's assumptions of the likelihood of large projects going forward prove to be incorrect, the impact on the load forecast is magnified via the effect on GDP growth, which affects multiple components of the forecast model.

The Conference Board of Canada does not publish specific assumptions around the timing and prospects of LNG projects. However, RFEC provided BC Hydro with a set of alternate GDP assumptions under the assumption that no LNG projects in BC are built over the forecast horizon. We note that this forecast resembles the Conference Board of Canada's 2016 forecast much more closely: by 2025 (i.e., F2026), it projects BC's economy as being just 1% larger (Figure 10).

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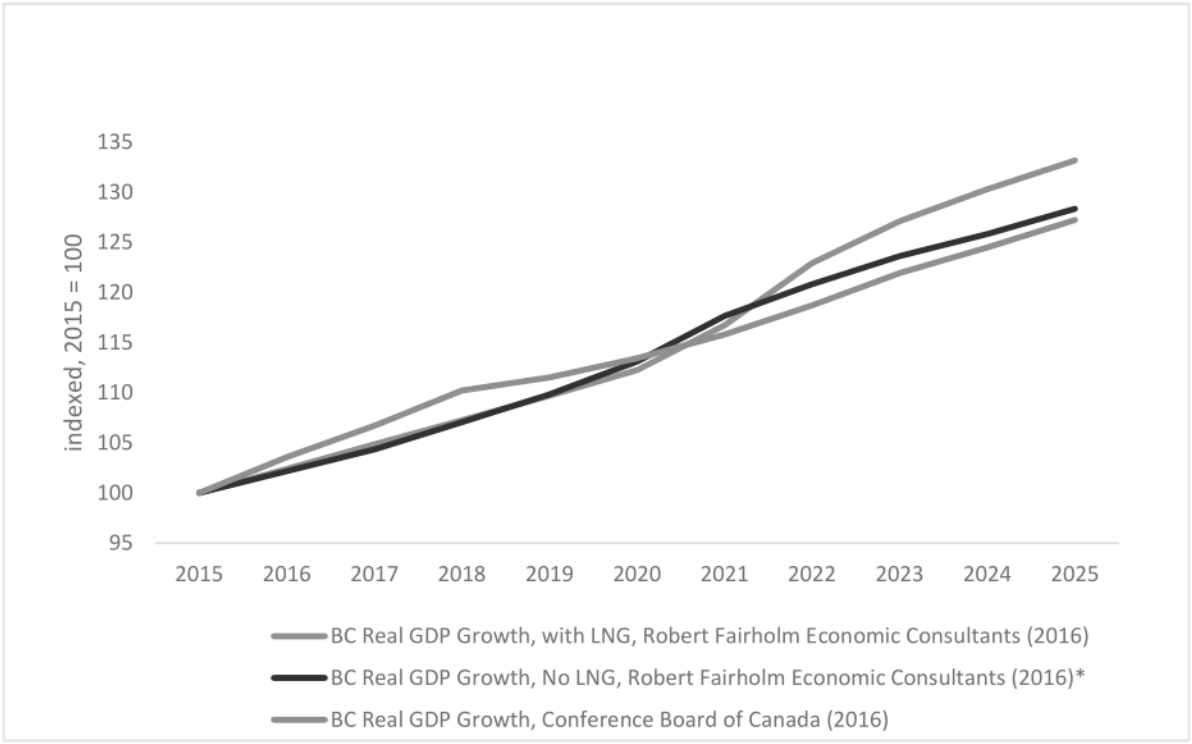

Figure 10: BC's Projected Real GDP Growth, with and without LNG

To assess the sensitivity of the model to a different GDP forecast, rough projections can be done on the basis of the GDP elasticities published by BC Hydro from the Monte Carlo simulation.[108] While these elasticities are not derived from the mid-forecast model itself, it should be noted that the pre-DSM Monte Carlo simulations produce comparable mid-points to the mid-forecast. Nonetheless, the projections derived with regards to load and capacity should be considered approximate, and indicative of magnitude and direction only. BC Hydro publishes elasticities for the residential, commercial and light industrial sectors, but not for the heavy industrial segment, as its load requirements are forecast via a separate process. Based on the published BC Hydro elasticities, and using the Conference Board of Canada's 2016 forecast instead of the RFEC figures, we find that residential load requirements would be 3.8% lower by F2026, while those for the commercial and light industrial sector would fall by 3.6%. These reductions do not include the heavy industrial sector, which accounts for a quarter to a third of overall load.

[108] See BC Hydro's 2012 report titled "Electric Load Forecast: Fiscal 2013 to 2033".

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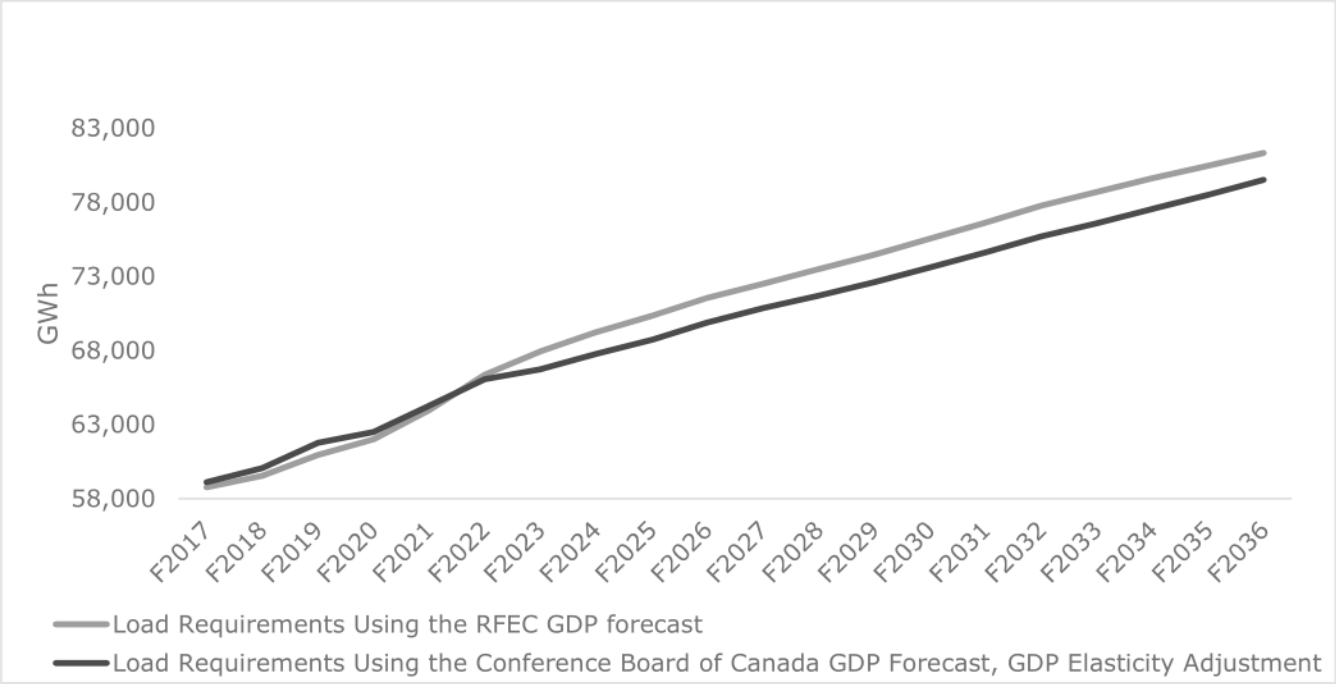

Figure 11: Mid forecast using the RFEC and Conference Board of Canada GDP projections

Using the same approach and GDP elasticities, this exercise was extended to the capacity forecasts. Using the published BC Hydro GDP elasticities and the Conference Board of Canada's 2016 forecast instead of the RFEC figures, by F2026 total peak demand is lower by 3.3% to 3.4% (Figure 12).

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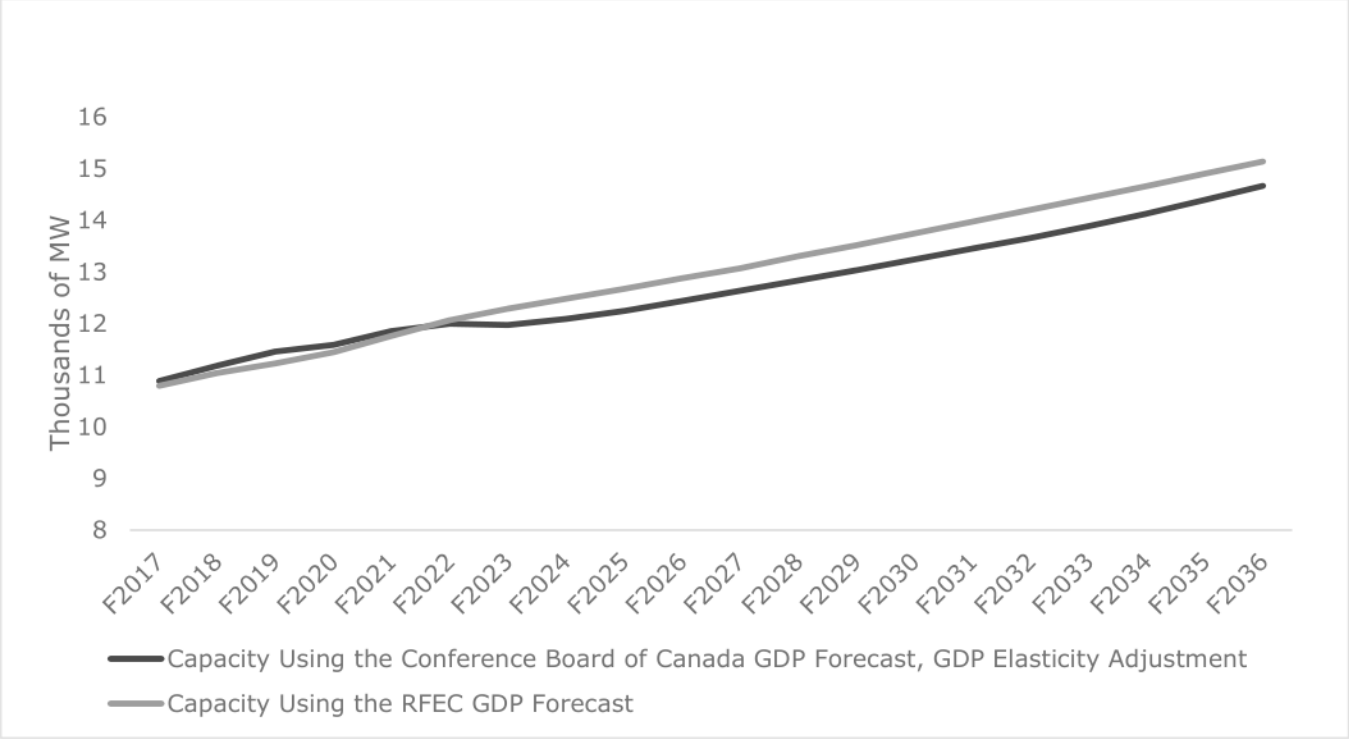

Figure 12: Capacity Forecast Before DSM using the Conference Board of Canada GDP Projection

It should be noted that BC Hydro's mid forecast does not explicitly account for recessionary periods, which may have a larger impact on load requirements than on long-run GDP growth, based on the experience of the 2008 financial crisis.[109,110] While it is not possible to confidently predict when recessions will occur, nor their magnitude, historical analysis shows that over the past 35 years (since provincial GDP records began), BC has seen two recessions, defined as two consecutive quarters of negative growth, and four periods in which annual growth was below 1%.[111] Thus we find it reasonable to assume that there will be at least one recession over the horizon of the 2016 load forecast. However, this assessment does not attempt to model such an adjustment.

Similar to GDP, the RFEC forecast for disposable income growth—which is a driver of residential load in the SAE model—appears higher than the Conference Board of Canada's, particularly in years six to 10 of the forecast. It should be noted that precise comparisons are difficult, however, as the Conference Board of Canada publishes a nominal disposable income growth forecast, while RFEC publishes these figures in inflation-adjusted terms.

[109] Recessionary periods are nonetheless accounted for in the form of lower GDP growth—without accounting for any disproportionate impacts on load—in the Monte Carlo simulations.
[110] In past periods of economic contraction, such as the early 1980s and 1990s, the relationship between recessions and slower load growth is less pronounced; nonetheless, following the economic downturn in the early 1990s, average load expansion slowed by roughly half compared with the 1980s.
[111] Some of the latter could have been recessionary periods as well, but we cannot ascertain whether this is the case as quarterly GDP data is not reported.

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5.3.2. Bottom-up Inputs

In addition to the SAE model, which is used for the residential, commercial and light industrial sectors, BC Hydro projects load for the heavy industrial sector by assessing roughly 180 accounts in mining, forestry, and oil and gas, as well as 20 to 30 prospective large accounts relating to proposed projects in these sectors. In some cases, BC Hydro's assumptions regarding the prospects of proposed major industrial developments appear above consensus. For instance, a May 2017 presentation prepared by BC Hydro indicates that the forecast for BC LNG over the 2024 to 2035 period is more optimistic than reference forecasts prepared by Bloomberg, Wood Mackenzie, ABB Power and PIRA Energy.

The 2016 forecast assumes that four LNG projects will go ahead with certainty: FortisBC Tilbury LNG (currently under construction), Woodfibre LNG (expected to begin construction in 2018), LNG Canada (final investment decision deferred), and Pacific NorthWest LNG (cancelled in July 2017). In the high and low forecasts, BC Hydro applies a probability assessment on when, but not if, these projects will come online. Of the four proposals, the latter two account for over 90% of total combined capital spending.

BC Hydro reports that the direct impact of the cancellation of the $36 billion Pacific NorthWest LNG plant (including related upstream O&G activity) on the load and capacity forecasts is limited. The indirect impacts associated with the project's cancellation, for which roughly $11 billion of the total of $36 billion was already spent, are likely to be more significant with respect to GDP as it relates to the 2016 load forecast. In particular, the project was expected to generate up to 4,500 construction jobs (0.2% of BC's total current employment) and more than $1 billion annually in federal, provincial and municipal government revenues (0.4% of BC's GDP).[112] Thus, the project's cancellation likely represents a material downwards shift in the GDP outlook relative to the 2016 baseline forecast.

We find the assumption that LNG Canada will proceed with certainty to be overly optimistic. LNG Canada has officially deferred their final investment decision, and its prospects of being built are unclear.

Section 5.5 of this report provides alternative load and capacity projections, which exclude the direct and indirect load and capacity requirements of LNG Canada and Pacific NorthWest LNG.

5.3.3. Price Elasticity

BC Hydro reports that it accounts for price elasticity of demand (i.e., the reduction in load requirements that results from higher electricity prices) in two ways. First, it applies a constant, own-price demand elasticity of -0.05 to the residential, commercial, light industrial and transmission segments (i.e., BC Hydro assumes that every 1% increase in price reduces load in these categories by 0.05%). Second, the load forecast includes assumptions related to demand-side management (DSM) pricing initiatives. While not normally considered as a price elasticity, these initiatives are conceptually similar, in that they project a reduction in load or capacity requirements from different price structures.

It appears that BC Hydro's assumed price elasticity may be an oversimplification in three respects. First, ignoring any DSM impacts, its magnitude 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).[113] While location is relevant, these studies suggest that price elasticities for electricity can be at least -0.08 in the short run, and

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[112] http://www.pacificnorthwestlng.com/media/PNW%20Backgrounder_V%2030%200.pdf

[113] See Alberini and Filippini (2011). "Response of Residential Electricity Demand to Price: The Effect of Measurement Error". *Journal of Energy Economics.* 33: 889-895 and Espey and Espey (2004). "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities". *Journal of Agricultural and Applied Economics.* 36,1(April 2004):65-81 .

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at least -0.45 in the long run. Second, BC Hydro assumes that short-run and long-run elasticities are identical; the same empirical research shows that 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). Third, BC Hydro assumes that price elasticity of demand is constant across sectors. Some independent studies have found that commercial and industrial consumers exhibit more price elastic demand than residential consumers (e.g., Griffin and Arent 2006).

Based on interviews with two other major utilities in Canada, we understand that one uses price elasticities for different customer segments, as well as short- and long-term horizons. 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.

BC Hydro assumes rate increases will not occur between F2025 and F2036. Thus, 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. Rate increases introduced between F2025 and F2036 would lower the 2016 load forecast. This assessment does not attempt to model this impact.

5.3.4. Policy Variables

BC Hydro reports that their model does not incorporate any future policy-related assumptions or projections with regards to climate change action or electrification. We find this to be a conservative approach in the current environment. A potential future regulatory or policy push towards electrification and green-house gas emission reduction constitutes an upside risk to the forecast (i.e., the current forecast would be an underestimate, all else being equal). For an assessment of BC Hydro's approach to electric vehicle adoption, please refer to section 5.4.1 below.

5.4. Potential Future Disruptors

A number of trends could potentially disrupt electricity demand in the future. 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. Of these potential disruptions, BC Hydro explicitly models electric vehicles use in its forecasts. Within the context of this study, we examined three specific potential disruptors: electric vehicles, solar photovoltaic technology in a residential context, and fuel switching (i.e., from gas to electric and vice versa).

5.4.1. Electric Vehicles Use

In 2016, there were roughly 5,400 electric vehicles (EVs) on the road in BC; new EV sales accounted for approximately 1% of all new vehicle sales in the province.[114] In absolute terms, BC lags Quebec and Ontario in EV use, as the 2016 stock of EVs was 13,500 and 9,200 in these provinces, respectively.[115] On a per capita basis, BC is the second-largest provincial user of EVs.[116] The potential increase in EV use could impact electricity demand in BC.

BC Hydro currently incorporates potential EV growth in its load demand forecast using a vehicle stock turnover model. Load demand growth from EVs depends on the increase in BC's driving population, capital and

[114] http://www.fleetcarma.com/ev-sales-canada-2016-final/
[115] Ibid.
[116] Using fleetcarma data on EVs in each province and provincial population from Statistics Canada.

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operating costs of EVs versus internal combustion engines, and variables impacting the uptake of EVs (e.g., policy support and customer awareness).

Within its model, BC Hydro makes some key assumptions about the use of EVs that impact load demand. BC Hydro assumes the energy efficiency of EVs is 0.20 KWh/km.[117] Of EV models offered in Canada in 2017, energy efficiencies of battery-electric vehicles (BEVs) range from 0.168 KWh/km to 0.244 KWh/km[118], meaning that BC Hydro's efficiency assumption is consistent with current EV models available to consumers. BC Hydro uses a distribution of annual kilometers driven per vehicle, the mean of which is 13,318 kms. This is consistent with other estimates in the literature.[119] As well, EV market share is constrained in the short run by model availability, relative costs, and limited awareness of consumers. BC Hydro relaxes these restraints over the model time horizon.

In its reference case[120], BC Hydro's estimated EV market share is relatively conservative (lower) compared with policy goals set by the federal government and other estimates of EV growth. Specifically, BC Hydro estimates that roughly 22% of all new vehicles sold will be electric in 2030 while the federal government has recently pledged support to reach an EV share of 30% of all new vehicles sold by the same year.[121] With increased supply and demand side incentives, Wolinetz & Axsen (2017) estimates that EVs could account for between 38% and 49% of new vehicle sales in BC by 2030. BC Hydro's assumptions are also conservative compared to Quebec's goal of having EVs account for 20% of all vehicles (not just new sales) by 2030.[122]

To understand the sensitivity of the forecasts with regards to a change in electric vehicle assumptions, we modelled a scenario where electric vehicles account for 30% of new sales in BC by 2030, consistent with recent federal government's commitments.[123] None of BC Hydro's assumptions beyond the assumption of EV share of new vehicles were changed in the new scenario. Using the assumption that EVs will account for 30% of new vehicle sales in 2030, the estimated load demand in 2026 increases from 323 GWh in BC Hydro's scenario to 440 to 450 GWh. This 115 to 125 GWh increase is equivalent to less than 1% of actual residential sales in fiscal 2016.[124] By 2036[125], the difference in load demand expands to 680 to 690 GWh or just under 4% of actual residential sales in fiscal 2016. Using BC Hydro's fiscal 2016 residential demand forecast, the increase in GWh from our scenario is equivalent to roughly 0.6% of residential demand in 2026, and roughly 2.9% of residential demand in 2036. On the capacity side, this new assumption amounts to roughly an additional 30 to 40 MW in 2026 and 245 to 255 MW by 2036.

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[117] Electric Load Forecast. 2012. BC Hydro. pg. 95.
[118] http://oee.nrcan.gc.ca/transportation/tools/fuelratings/atv-2017.cfm
[119] Wolinetz & Axsen (2017) use an average of 16,000 kms. driven annually in modeling fuel costs by class of vehicle (electric versus internal combustion engine), but they note that drivers have heterogeneous driving patterns highlighting the importance of using a range of driving distances. BC Hydro's EV model uses a distribution of annual kms driven as part of their model to estimate EV market share, where the mean is 13,318 kms.
[120] BC Hydro also estimates a high case for EVs. The reference case is incorporated in its mid forecast, which is used for planning purposes.
[121] This includes battery-electric, plug-in hybrid electric and fuel-cell electric vehicles. https://www.iea.org/media/topics/transport/CampaignDocumentFinal_rev_SENER.pdf
[122] https://politiqueenergetique.gouv.qc.ca/wp-content/uploads/Energy-Policy-2030.pdf
[123] Focusing on the share of new vehicles sold ignores the possibility that consumers import used vehicles, which would also increase the stock of EVs in BC. While this might occur because of cost advantages, it is not possible to accurately capture in this analysis as data on this is not tracked consistently.
[124] BC Hydro adds 75% of the load demand from EVs to their residential load forecast and 25% to their commercial and light industrial forecast. We compare our results to the residential load for simplicity.
[125] 2036 is the end of BC Hydro's forecast.

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5.4.2. Solar Photovoltaic Panels

The use of solar photovoltaic (PV) by residential customers is another potential electricity demand disruptor. Residential use of solar PV for electricity could reduce the demand for hydroelectricity. Growth projections for residential solar PV are not explicitly included in BC Hydro's 2016 load forecast.

As with EVs, projections regarding solar PVs are sensitive to electricity rates, policy, and the costs of solar PV equipment. A benchmarking study by the Berkeley Lab finds that, in the absence of incentive programs to drive adoption, the use of solar PV is highly sensitive to the relative costs of solar versus hydroelectricity.[126] A report by Sunmetrix shows that there are only three main incentive programs for solar PVs in BC: a one-time cash incentive of $250 in Nanaimo, a provincial sales tax exemption for solar PV panels and related equipment, and BC Hydro's own net metering program.[127]

BC Hydro's net metering program allows consumers to sell surplus energy generated from solar PVs back to BC Hydro. Furthermore, it allows customers to lease solar PV equipment. However, only one customer has used this leasing option since the program started and only five customers contacted BC Hydro to inquire about leasing equipment between fiscal 2014 and 2016.[128] As such, it seems the current policy incentives in BC are not driving mass consumer uptake and that the economics of solar PV compared to hydro are what would drive uptake going forward in the absence of further policy incentives.

The cost of solar PV includes the costs of solar panels, installing equipment, installation labor, and balance-of-system equipment[129]. BC Hydro's online solar PV calculator estimates the current cost of residential solar PV to be $3.6/Watt.[130] Similarly, the U.S. National Renewable Energy Laboratory estimates the cost of residential solar PV to be roughly $3.9/Watt on average in the U.S.

Under current prices of solar PVs, BC Hydro estimates the payback period for residential solar PV to be 23 years.[131] This is based on an assumed $14,500 for 4KW of installed panels, and the assumption that the retail rate of electricity is 14.2c/KWh, which is the tier two BC Hydro rate (12.87c/KWh), plus 5% from the rate rider program,[132] and 5% GST.[133] According to EnergySage (supported by the U.S. Department of Energy), the payback period in California and Arizona is approximately 6.4 and 7.6 years, respectively.[134] Solar penetration in these states was roughly 7.2% and 5.8% in 2016, much higher than the use of solar in BC that year.[135] The payback period is a function of both unit costs, retail electricity rates, and solar potential, so comparisons are only used as an estimate to show the payback period in states where residential solar use is much higher.

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[126] https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf

[127] http://sunmetrix.com/solar-tax-credits-incentives-and-solar-rebates-canada/british-columbia/

[128] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/20170426-BCH-Rate-Schedule-1289-Net-Metering-Eval-RPT-4.pdf

[129] Includes equipment required to run panels, such as inverters and wiring.

[130] Based on the assumption that a 4KW system (reasonable size for residential generation) costs roughly $14,500. https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html?WT.mc_id=rd_netmetering

[131] This does not include forecasted retail rate increases. If retail rates increase, the payback period for solar PV would decrease. https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html?WT.mc_id=rd_netmetering

[132] The Rate Rider covers additional and unpredictable energy costs resulting from, for example, low water inflows or higher-than-forecast market prices.

[133] If tier one rates were used instead of tier two rates, the payback period would increase. https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/residential-rates.html

[134] https://www.energysage.com/data/#intel-4

[135] https://www.ohmhomenow.com/2016-solar-penetration-state/

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In addition to solar's long payback period, the use of solar PV by BC Hydro's customers is currently limited. In fiscal 2016, customers under BC Hydro's net metering system installed approximately 3,250 kW of solar PV capacity, generated from just over 600 projects.[136] BC Hydro assumes that a 4KW solar panel generates 0.0044GWh/year. Therefore the estimated load generation from solar PV was approximately 3.6 GWh in fiscal 2016. This is equivalent to roughly 0.02% of residential load for that year. Even if residential load did not grow at all between now and 2030, solar PV gigawatt-hour production would have to increase at an average annual rate of 32% to reach 1% of residential sales by 2030. This is equivalent to a 50-times increase in current load generated by solar PVs. In its seventh power plan, the Northwest Power and Conservation Council estimated that solar PV uptake will increase 15 times at most between 2013 and 2035.[137] The Berkeley Lab estimated that solar PV use would increase 6 times between 2015 and 2040.[138]

Despite long payback periods and low levels of current use, the cost of solar PVs is likely to come down further, and potentially increase uptake going forward. However, it is not clear when this will materialize. Solar PV installation costs have already decreased over time; the Berkley Lab estimates that median installed prices of U.S. solar PVs decreased at an average annual rate of 13% to 18% between 2009 and 2014, and that these decreases continued into 2015.[139] Going forward, the Northwest Conservation and Electric Power Plan (NCEPP) estimates solar PV costs will decrease by 53% between 2012 and 2030.[140]

In summary, the payback period for residential solar PV is still high, and current use is low. While costs could decrease going forward and induce further uptake, this assessment has not attempted to model such a scenario.

5.4.3. Heat and Hot Water Fuel Switching

Fuel switching occurs when energy consumers switch from electricity to gas or oil fuel sources and vice versa. Consumer behaviour may change because of government policy objectives to shift energy use to renewable sources, cost considerations of gas compared to electricity, or personal preferences for greener energy use.

Many factors determine the cost of using a heat pump compared to a gas furnace, including the size of a house, and how well it is insulated. For smaller, well-insulated houses or apartments, using a heat pump could indeed be more cost effective.[141] However, analysis conducted by Fortis BC found that the annual costs of heating a typical, detached home using natural gas are over $800 lower than using electricity, even when the least efficient natural gas furnaces are compared to the most efficient electric heating options.[142] Given this cost differential, the higher fixed cost of installing electric heating is likely to prevent consumers from switching from natural gas to electric heating for some time, assuming that natural gas prices remain low, and absent strong incentives introduced by policy.

There is some evidence that future policy could try to incentivize a shift from natural gas to electricity. For example:

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[136] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/20170426-BCH-Rate-Schedule-1289-Net-Metering-Eval-RPT-4.pdf
[137] https://www.nwcouncil.org/media/7149913/7thplanfinal_appdixe_dforecast.pdf
[138] https://emp.lbl.gov/sites/all/files/lbnl-1006983.pdf
[139] https://energy.gov/sites/prod/files/2015/08/f25/LBNL%20Tracking%20the%20Sun%20August%202015.pdf
[140] https://www.nwcouncil.org/media/7149931/7thplanfinal_chap07_demandforecast.pdf
[141] http://www.pembina.org/pub/bc-heating-costs
[142] As noted in response to BCUC IR 1.4.1.

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- BC's Climate Leadership Plan states[143]: "To advance efficient electrification we are taking action by working with BC Hydro to expand the mandate of its DSM programs to include investments that increase efficiency and reduce GHG emissions."

  – The March 2017 Order in Council 101 enables BC Hydro to pursue cost-effective electrification; Order in Council 100 allows these costs to be charged to the DSM Regulatory Account.[144]

- The City of Vancouver's Green Building Rezoning Policy (in-force May 2017), requires new building developers who are seeking rezoning to meet emissions targets of a 50% decrease in greenhouse gas emissions. Developers can meet these targets in a number of ways, one of which might be to use electric water and space heating instead of natural gas.[145]

A study by Simon Fraser University found that, with strong policy support, residential and commercial buildings may rely almost exclusively on electricity by 2050.[146]

In summary, given current policies and cost differential between gas and electricity, a mass shift from gas to electric heating is unlikely. While there are indications a policy shift may be forthcoming in the future, this assessment has not attempted to model such a scenario.

5.5. An Alternative Scenario

In this section, we illustrate the combined impact of several, alternative input assumptions on the fiscal 2016 load-and-capacity forecast. The results should be considered as indicative only, as BC Hydro's mid forecast has been adjusted after the fact, as opposed to conducting a complete re-run of the models that have produced the forecast. For illustrative purposes, the following changes in assumptions are made:

GDP – the alternative scenario replaces BC Hydro's 2016 GDP forecast with the 2016 Conference Board of Canada long-term BC forecast.[147] To simulate the effect on load and capacity of this change, the alternative projection uses GDP elasticities published by BC Hydro from the Monte Carlo simulation. While these elasticities are not derived from the mid-forecast model itself, it should be noted that the pre-DSM Monte Carlo simulations produce comparable mid-points to the mid-forecast. Nonetheless, the projections derived with regards to load and capacity should be considered approximate and indicative of magnitude and direction only.

LNG – the alternative forecast excludes the impacts on load and capacities from the Pacific NorthWest LNG project (now cancelled) and LNG Canada (final investment decision deferred). The forecast excludes both the direct impact as well as the indirect impact from the oil and gas-extraction activity associated with the projects. However, the forecast does not include impacts on GDP. This is done to avoid double counting the reduction of GDP from adopting the Conference Board of Canada's GDP numbers, as assumptions around LNG projects are unclear. This represents a conservative approach to the LNG adjustment.

Electric Vehicles Use – the alternative forecast assumes a higher adoption curve of electric vehicles in BC than BC Hydro's forecast, consistent with federal public commitments that 30% of new vehicles sold by 2030 will be electric. All other BC Hydro assumptions regarding electric vehicle use are preserved.

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[143] https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf, p. 28.
[144] BCH RRA, Exhibit B-18, p. 1.
[145] http://vancouver.ca/news-calendar/city-response-to-bc-liberal-statement-on-natural-gas.aspx
[146] http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017
[147] Conference Board of Canada (2016). *Provincial Outlook 2016: Long-Term Economic Forecast.* Accessed August 29, 2017 at: http://www.conferenceboard.ca/temp/09ed73c5-c0a5-4714-82ae-80d72b70d0fd/8004_po_longterm_2016_rpt_bc.pdf

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Demand Side Management (DSM) – to illustrate the impact of a more intensive DSM program, the alternative forecast assumes Option 3 DSM savings as projected by BC Hydro in the 2013 Integrated Resource Plan, as opposed to the Moderated Option 2 DSM savings incorporated in the 2016 load forecast. In the 2013 Integrated Resource Plan, BC Hydro notes that DSM Option 3 "features increased program activities and expenditures to target the greatest level of DSM program savings currently considered deliverable".[148] It should also be noted that the 2013 Integrated Resource Plan featured 2 higher DSM Options (4 and 5), which BC Hydro deemed unfeasible at the time.

5.5.1. Summary of Impacts on Load and Capacity

The analysis finds that by F2026, the 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 MW. By F2036, the corresponding impacts are a reduction in load forecast in the range of 5,950 to 6,100 GWh, and a reduction in peak capacity forecast in the range of 1,110 to 1,130 MW. Figures 13 to 16 summarize the impact on load and capacity before and after applying the DSM adjustment.

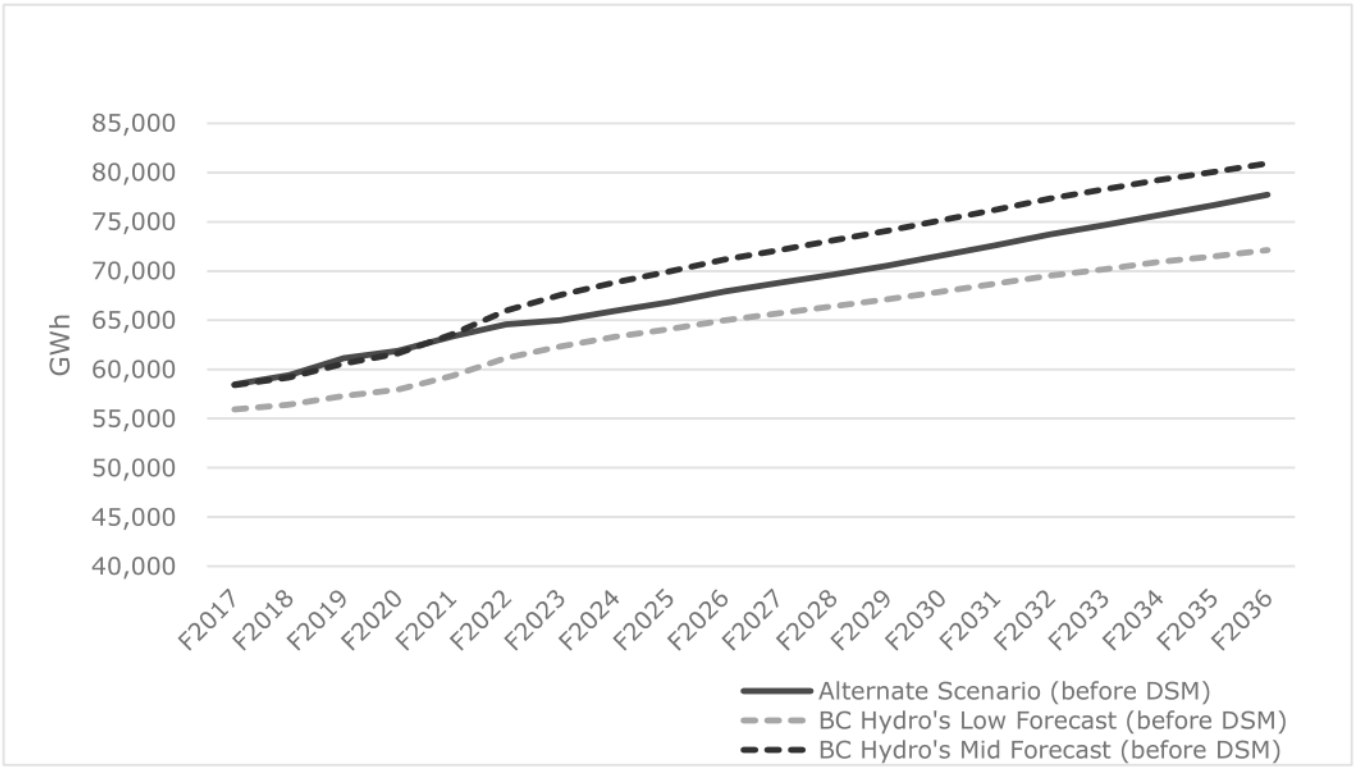

Figure 13: Load Forecasts Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario

[148] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0004-nov-2013-irp-chap-4.pdf

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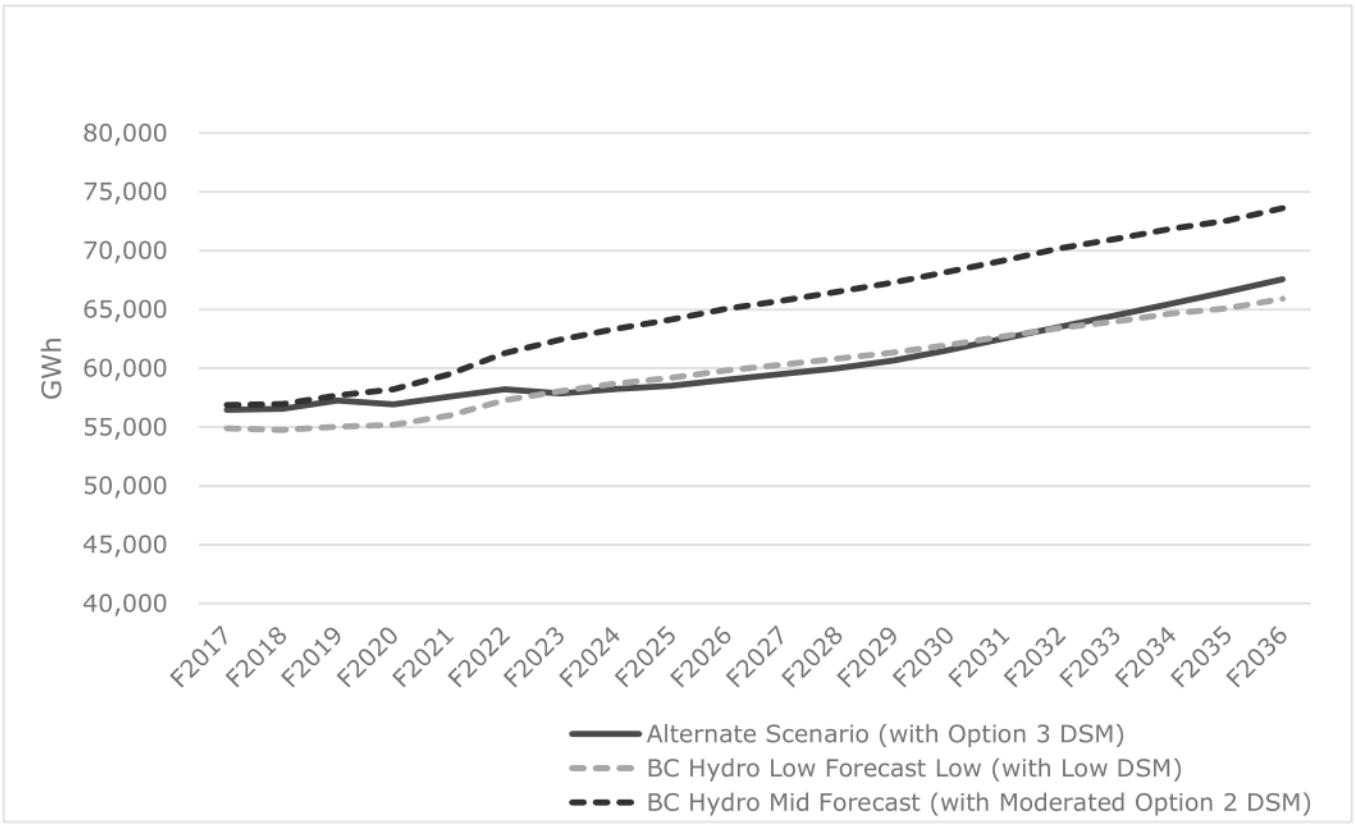

Figure 14: Load Forecasts After DSM - BC Hydro Mid and Low Compared with Alternate Scenario

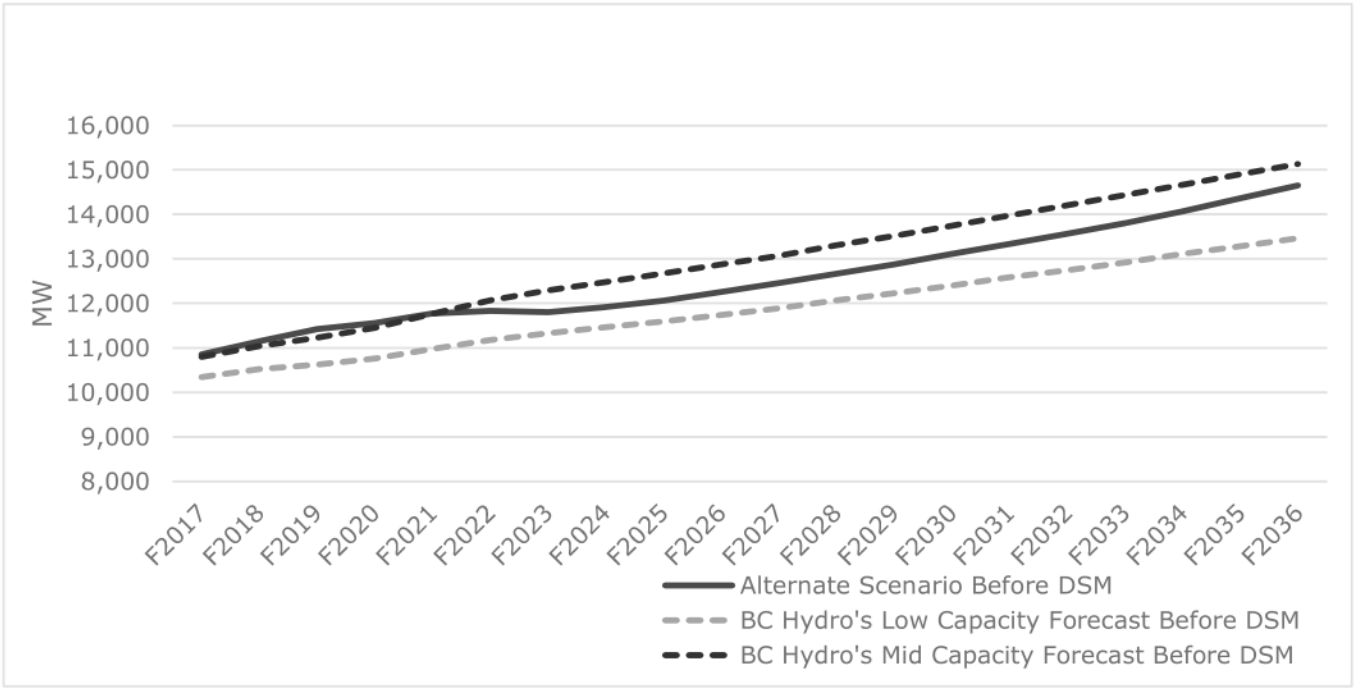

Figure 15: Capacity Forecast Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario

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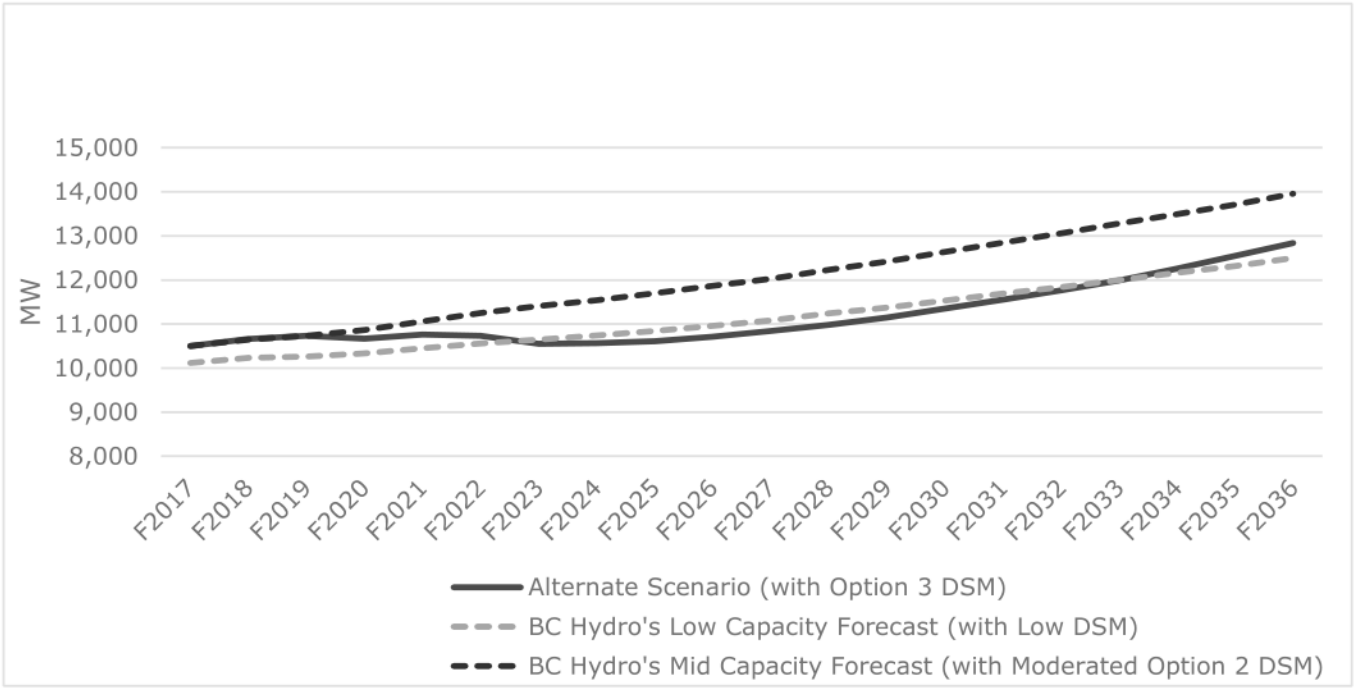

Figure 16: Capacity Forecast After DSM - BC Hydro Mid and Low Compared with Alternate Scenario

5.6. Statistical Considerations

With some exceptions, BC Hydro's approach to forecasting future load requirements appears broadly in line with the practices of utilities elsewhere in North America. For instance, both of the Canadian utilities interviewed reported using an SAE approach, as well as Monte Carlo simulations to model uncertainty. These utilities assessed heavy industrial requirements on a project-by-project basis and noted that this market segment is particularly difficult to forecast as it is more volatile than the residential and commercial sectors. One of the two utilities noted that heavy industrial was particularly sensitive to economic conditions: in the midst of the 2008 financial crisis, it saw heavy industrial requirements collapse, while residential (and, to a lesser extent, commercial) requirements remained comparatively steady.

In contrast to BC Hydro's current approach, the two other Canadian utilities interviewed reported that they had historically used a "top-down" time-series analysis in addition to a "bottom-up" SAE approach. One of the utilities continues to use time series analysis to produce a short-run forecast, and reports that it performs better than the bottom-up SAE approach over a 2-year horizon. From the perspective of mid forecast reliability, this utility also found it could be helpful to analyze time series and SAE regressions simultaneously, as it allowed differences between the two forecasts, if they emerged, to be more thoroughly examined. The other utility interviewed reported that it no longer conducts time-series analysis, as it believed that the speed of technological change meant that the past was no longer a good predictor of the future. While SAE modelling is used by many U.S. utilities, a U.S.-based energy forecasting professional interviewed by Deloitte reported that a top-down approach to load estimation is also common.

While this assessment did not include direct testing of the forecast model, the potential for correlation across the various independent components of the mid-forecast should be examined to make sure risks of suboptimal results are minimized.

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Appendix A – Load Forecast Model Inputs

Model/Customer Segment	Key Input Variables	Source
Residential Model (4 models by region)	Historical # of accounts	BCH's data
	Historical use per account	BCH's data
	Housing starts	Robert Fairholm Consulting
	Personal income	Robert Fairholm Consulting
	Heating degree day	Environment Canada
	Cooling degree day	Environment Canada
	End-use saturation rates	BCH's residential end-use survey for historical, U.S. Energy Information Agency for forecasts
	End-use efficiency data	U.S. Energy Information Agency
	Dummy control variables (for certain months/ years)	N/A
Commercial/Light Industrial Model (8 models by region and demand size)	Billing data	BCH's data
	Industrial manufacturing part of total light industrial	B.C. Ministry of Finance (first five years), Robert Fairholm Consulting (beyond five years)
	Industrial production forecast	Consultant wood production for wood part of light industrial distribution
	Commercial GDP output-SAE	Robert Fairholm Consulting
	Employment-SAE	Robert Fairholm Consulting
	Retail sales-SAE	Robert Fairholm Consulting
	Heating degree day	Environment Canada
	Cooling degree day	Environment Canada
	End-use saturation rates for commercial	End-use efficiency data U.S. Energy Information Agency
	End-use efficiency data for commercial	U.S. Energy Information Agency
	Dummy control variables (for certain months/ years)	N/A

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Model/Customer Segment	Key Input Variables	Source
Large Industrial (180 accounts)	Billing data	BCH's data
	GDP	B.C. Ministry of Finance and Robert Fairholm Consulting
	Forecasts from consultants	Has been provided in a data appendix
	Information from various reports and Key Account Managers	BCH, compared to other major sources (i.e., Bloomberg)
Other (i.e., street lighting)	Billing data	BCH's data
	Historical # of accounts	BCH's data
	Street lights, bc hydro own use, irrigation	BC Hydro data
	Local conditions in the short-term for NIA	BC Hydro data
	Population forecasts for NIA	BC stats
Other Large Utilites	Sales to Fortis BC	BCH model cost of purchased under tariff rates and costs of electricity purchases to the market
Monte Carlo (for high and low forecast)	GDP (regional)	Robert Fairholm Consulting
	Price of electricity (electricity rates)	BCH
	Weather (heating degree days)	Environment Canada
	GDP elasticity of demand	BCH's assumptions/ research (triangular distribution)
	Rate elasticity of demand	BCH's assumptions/ research (triangular distribution)
	Residual load impacts	BCH's own model
	Electric Vehicles	BCH's own model
	Load forecast DSM/integration overlap with codes and standards	BCH's own model

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Appendix B – List of BC Hydro documents reviewed

5.1. Load forecasting:

- PPT titled "BC Hydro Energy Planning 101"
- December 2012 pdf "Electric Load Forecast: Fiscal 2013 to Fiscal 2033"
- PPT titled "A Path to the Long Term Forecast"
- PPT titled "EV Load Forecast Methodology"
- Responses to Deloitte questions #51, #86, #88, #89, #90 (all parts), #91, #92, #140, #141
- Exhibits B-9, B-9-2 and B-10 from BC Hydro's F2017 to F2019 Revenue Requirements Application
- Excel spreadsheet titled "83 to 87Release MID HIGH AND LOW BEFORE AND AFTER DSM"
- Excel spreadsheet titled "CEC_2_135_01_ATT_01" from Exhibit B-15, BC Hydro's response to intervener questions
- Excel spreadsheet titled "126 Site C Review – Deloitte Questions – August 2017 – Load Forecast history since 2007_Attachment" as provided in response to Deloitte's questions #126
- Excel spreadsheet titled "BCH EV Forecast Summary" provided by BC Hydro via email on Thursday August 24, 2017
- All data provided in response to Deloitte's questions #126
- BC Hydro's April 2017 Net Metering Report
- May 2017 BC Hydro PPT titled "Montney Load Forecast Model, Part 2 of 3: Top-down & Alignment Process"
- PDF titled "Site C Historical Savings" sent by BC Hydro on August 25, 2017

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5.2. Assessment of alternative sources of energy and capacity

5.2.1. Publically available documentation

Document name	Author	Date	Source
BC Hydro F2017-F2019 Revenue Requirements Application (RRA)	BC Hydro	July 29, 2016	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
Arguments and exhibits pertaining to BC Hydro's F2017-F2019 RRA	BCUC	Various	http://www.bcuc.com/ApplicationView.aspx?ApplicationId=533
BC Hydro 2013 Integrated Resource Plan	BC Hydro	November 2013	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/november-2013-irp.html#chapters
BC Hydro 2013 Resource Options Update Report	BC Hydro	November 2013	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/2013-ror-update.html
BC Hydro 2010 Resource Options Report	BC Hydro	February 10, 2012	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/final-ror.html
BC Hydro Resource Options Update Results Summary	BC Hydro	October 2016	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-summary-results-201610.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-9	BC Hydro	November 21, 2016	http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-10	BC Hydro	November 21, 2016	http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf
F2017 – F2019 Revenue Requirements Rate Technical Briefing Deck	BC Hydro	Jul. 28, 2016	www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/FY17-FY19-rra-application-technical-briefing-deck-20160728.pdf
BC Hydro and Power Authority F2017 to F2019 Revenue Requirements Application and Demand-Side Management Expenditure Schedule Final Submission of B.C. Sustainable Energy Association and Sierra Club B.C.	BCSEA and SCBC	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf

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Document name	Author	Date	Source
FISCAL 2017 – FISCAL 2019 REVENUE REQUIREMENTS APPLICATION; Final Submissions of BC Hydro	BC Hydro	May 23, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-21	BC Hydro	May 11, 2017	http://www.bcuc.com/Documents/Proceedings/2017/DOC_49232_B-21_BCH-Responses-BCUC-IR-No1.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-14	BC Hydro	January 23, 2017	http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf
Demand Side Measures Regulation (B.C. Reg. 326/2008)	Government of BC	November 7, 2008	http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section4
CEC Final Argument	CEC	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49470_06-13-2017-CEC-Final-Argument.pdf
BCSEA Final Argument	BCSEA	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf
Manitoba Hydro 2016/2017 Demand Side Management Plan	Manitoba Hydro	March 2016	https://www.hydro.mb.ca/corporate/pdfs/demand_side_management_plan.pdf
Commission Approves Energy Efficiency Programs that Save APS Customers Money	Arizona Corporation Commission	June 15, 2016	http://azcc.gov/Divisions/Administration/news/2016Releases/7-13-2016%20Commission%20Approves%20Energy%20Efficiency%20Programs.pdf
APS 2016 Demand Side Management Plan	APS	June 1, 2015	http://images.edocket.azcc.gov/docketpdf/0000162231.pdf
The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: Estimates at the National, State, Sector and Program Level	Berkeley Lab	April 2015	https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf
Ontario Planning Outlook	IESO	September 1, 2016	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/ontario-planning-outlook-september2016.pdf
National Grid – Participate in Demand Response, save energy, and receive incentives!	National Grid	Accessed August 27, 2017	https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolution-ma-ci-dr-info-flier.pdf
Hydro Quebec Strategic Plan 2009-2013	Hydro Quebec	2009	http://www.hydroquebec.com/publications/en/docs/strategic-plan/plan-strategique-2009-2013.pdf

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Document name	Author	Date	Source
Hydro Quebec – Residential Dual Energy	Hydro Quebec	Accessed August 27, 2017	http://www.hydroquebec.com/residential/customer-space/account-and-billing/understanding-bill/residential-rates/rate-dt.html
Hydro Quebec 2014-2023 Supply Plan Integrated System	Hydro Quebec	Accessed August 27, 2017	
BC Hydro – Home renovation rebates	BC Hydro	Accessed August 27, 2017	https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
BC Hydro Final Argument	BC Hydro	May 23, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs	Ernest Orlando Lawrence Berkeley National Laboratory	2014	http://utilityscalesolar.lbl.gov/sites/all/files/lbnl-6595e.pdf

5.2.2. Confidential documentation

Document name	Author	Date	Source
08-18-2017_DSM consolidated issues brief	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
Draft Issues Brief – Chapter 10 – Capacity DSM and Codes and Standards – CPG – R3	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary (no. 2) (final)	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary – (final) V2	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary (no. 1) final	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
Imports and Exports by Powerex: B.C. to/from U.S.	NEB	Received August 25, 2017	https://apps.nebone.gc.ca/CommodityStatistics/Statistics.aspx?language=english Provided by Powerex; email on August 25, 2017
Annual volumes of inter-provincial deliveries and receipts of electricity;	Statistics Canada	Received August 25, 2017	http://www5.statcan.gc.ca/cansim/a47 Provided by Powerex; email on August 25, 2017
BC Hydro (Integrated) Hourly Gen Aggregated (MWh) (206-2016)	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017

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Document name	Author	Date	Source
IPP Forecast – Installed MW by day	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017
Wind Hourly Generation with Breakout	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017
Historical hourly generation for onshore wind; Response to Deloitte Question #134	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly generation for solar; Response to Deloitte Question #133	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly generation for solar; Response to Deloitte Question #133	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly hydro generation; Response to Deloitte Question #132	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical heat rate and hourly generation for natural gas units; Response to Deloitte Question #135	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
79 Site C Review – Deloitte Questions – August 2017 – Attachment; Market Electricity and Gas Price Forecast Data	BC Hydro		Provided by BC Hydro
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-14-1	BC Hydro	Received August 14, 2017	Provided by BCUC; email on August 14, 2017
RE: Solar price in BC	BCUC	Received August 14, 2017	Provided by BCUC; email on August 14, 2017
ACEEE 2017 scorecard	American Council for an Energy-Efficient Economy	Received August 22, 2017	Provided by BCUC; email on August 22, 2017
ACEEE 2016 scorecard	American Council for an Energy-Efficient Economy	Received August 22, 2017	Provided by BCUC; email on August 22, 2017
DSM background information Aug 22	BCUC	Received August 22, 2017	Provided by BCUC; email on August 22, 2017

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Document name	Author	Date	Source
Site C BCUC #175 part 1; Response to Deloitte Question #175	BC Hydro	Received August 28 2017	Provided by, BC Hydro; email on August 28, 2017
Site C BCUC #175 part 2; Response to Deloitte Question #155	BC Hydro	Received August 28 2017	Provided by BC Hydro; email on August 28, 2017
Site C BCUC #175 part 3; Response to Deloitte Question #155	BC Hydro	Received August 28 2017	Provided by BC Hydro; email on August 28, 2017

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Appendix C – Interviewees

- Director, Resource Planning, BC Hydro
- Commercial Manager, Site C Project, BC Hydro
- Sr. Manager, Strategic Planning, BC Hydro
- Senior Business Strategic Advisor, Conservation & Energy Management, BC Hydro
- Director, Conservation & Energy Management, BC Hydro
- DSM Planning Manager, BC Hydro

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Appendix D – Confidentiality agreement

AGREEMENT ON CONFIDENTIALITY PROTOCOL FOR THE SITE C REVIEW
between
BC HYDRO AND DELOITTE LLP

WHEREAS:

A. The British Columbia Utilities Commission (Commission) has initiated the Site C Inquiry (Inquiry) pursuant to Terms of Reference issued on August 2, 2017 by the Province of British Columbia.

B. The Commission retained Deloitte LLP ("Deloitte") to assist in conducting its Inquiry and provide a report to the Commission. Deloitte has, in turn, subcontracted with consultants to assist in its work.

C. The Parties recognize that the disclosure of BC Hydro's commercially sensitive information could cause harm to BC Hydro, and thus potentially adversely impact BC Hydro's ratepayers.

D. On August 4, 2017 Deloitte and BC Hydro agreed to the attached interim terms (Interim Terms) regarding protection of commercially sensitive documents and information that BC Hydro provides to Deloitte during the course of the review. The Interim Terms contemplated that the Parties would develop and agree on a more formal protocol for the protection and treatment of commercially sensitive information.

E. Also on August 4, 2017, BC Hydro provided Deloitte and the Commission with access to a SharePoint site, on which BC Hydro had posted commercially sensitive documents requested by the Commission and Deloitte. BC Hydro has continued to post documents containing commercially sensitive information on the SharePoint site since that time.

F. The commercially sensitive information includes, but is not limited to, the following categories:

(a) Documents and information related to ongoing or potential claims with contractors working on the Project, for which disclosure to the contractor(s) could compromise BC Hydro's position *vis-a-vis* the contractor(s) and thus harm the interests of BC Hydro and ratepayers;
(b) Information that, if disclosed, would compromise BC Hydro's ability to procure materials and services cost-effectively; and
(c) Customer information.

G. The Parties have developed this Agreement Regarding Confidentiality Protocol (Protocol) to ensure that Deloitte can fulfil its mandate from the Commission, while protecting BC Hydro's commercially sensitive information and documents.

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THE PARTIES AGREE AS FOLLOWS:

Confidential Documents and Confidential Information

1. In this Protocol, Confidential Information means:

   (a) documents posted on the confidential SharePoint site; and
   (b) any other information, whether disclosed in writing, orally, or visually, that has been identified by BC Hydro employees, or other representatives, as being commercially sensitive.

Deloitte's Obligation to Maintain Confidentiality Over Confidential Information

2. Deloitte shall hold in confidence, and shall not disclose to any person, any Confidential Information except to the extent that

   (a) the Confidential Information is generally known to the public at the time of disclosure or becomes generally known through no wrongful act on the part of Deloitte;
   (b) the Confidential Information is in Deloitte's possession at the time of disclosure other than as a result of prior disclosure by BC Hydro or a breach of any legal obligation by Deloitte or a third party;
   (c) the Confidential Information becomes known to Deloitte through disclosure by sources other than BC Hydro or those having a duty of confidentiality to BC Hydro; or
   (d) the Commission has determined the Confidential Information should be disclosed publically.

   Deloitte will not make any use of the Confidential Information beyond what is required to fulfil its retainer in this Inquiry.

3. Notwithstanding section 2, Deloitte may provide Confidential Information to:
   (a) the Commission; and
   (b) third parties with whom Deloitte has contracted to perform work on the Inquiry, and who have agreed with BC Hydro to abide by terms equivalent to the Interim Agreement, this Protocol or otherwise acceptable to BC Hydro.

   In the case of both (a) and (b), Deloitte must advise the recipient that the information is Confidential Information.

4. Notwithstanding Section 2 and 3, Deloitte may disclose Confidential Information if Deloitte is compelled to disclose such Confidential Information by an order of a court of competent jurisdiction or a regulatory body, provided that Deloitte provides prompt notice (to the extent permitted by law) to BC Hydro of any proceedings seeking such an

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order, so that BC Hydro has the opportunity to make representations to such court or regulatory body regarding the proposed disclosure. If Deloitte is precluded by law from providing the above notice to BC Hydro, and an order is made without notice to BC Hydro, then Deloitte must provide prompt notice of such order to BC Hydro prior to making any disclosure.

5. Deloitte will destroy or return to BC Hydro any written Confidential Information in its possession by December 1, 2017, and provide confirmation of the same to BC Hydro. This Protocol shall apply to all Confidential Information for as long as Deloitte is in possession of Confidential Information. Notwithstanding the foregoing however, Deloitte shall have access to, or maintain copies of, any such Confidential Information as is needed to support its work papers in accordance with applicable professional standards. Such copies will be destroyed promptly following the retention date specified by applicable professional standards.

Inclusion of Confidential Information in Deloitte Report

6. Deloitte may, in its own discretion, refer to or include Confidential Information in its report to the Commission. In that event, Deloitte will submit that Confidential Information to the Commission in a confidential appendix to the report or otherwise identify for the Commission where the Confidential Information appears.

Acknowledgement of Commission's Jurisdiction

7. The Parties anticipate that BC Hydro will, upon request by the Commission, provide an explanation to the Commission as to why BC Hydro considers that the commercially sensitive information referenced in the Deloitte Report should remain confidential. Nothing in this Protocol is intended to fetter the Commission's jurisdiction to determine the treatment of Confidential Information for the purposes of the Inquiry.

The Parties agree the above terms, effective August 27, 2017.

BC Hydro
Per _____
Fred James
Chief Regulatory Officer

Deloitte LLP
Per DLLP

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Appendix E – Modeling alternative supply-side sources of energy and capacity (MarketBuilder model)

5.1. About MarketBuilder and Disclaimer

MarketBuilder, developed by Deloitte MarketPoint, is a fundamentals-based generalized equilibrium model of commodity supply chains. Deloitte MarketPoint has a 30-year history of continuous development and extensive, documented, and broadly applied use of MarketBuilder by industry and government entities. MarketBuilder allows for a combination of variable measurements, such as fuels and electricity along with emissions allowances/credits and variables such as renewable energy credits, if applicable. It has provided the foundational modeling platform for regulatory impact models, fuel procurement planning, market strategy development, and capital investment decisions for utilities, project developers, investors, regulators, and government agencies. Additionally, U.S.-based investor owned utilities have utilized MarketBuilder to support resource plans and similar regulatory filings. MarketBuilder provides flexibility and rigor in endogenous capacity expansion computations as well as natural multi-commodity (e.g., fuels, electricity, emissions) integration in ways and to a degree not generally available in the other platforms.

The results from the MarketBuilder model are solely directional and for informational purposes only. In our assessment, we did not have the benefit of utilizing BC Hydro's IRP model with each existing generation and transmission asset modeled. Where the results of analysis are discussed in this publication, the results are based on the application of economic logic and specific assumptions. These results are not intended to be predictions of events or future outcomes.

Deloitte MarketPoint is not, by means of this publication, rendering accounting, business, financial, investment, legal, tax, or other professional advice or services to any person. This publication is not a substitute for such professional advice or services, nor should it be used as a basis for any decision or action that may affect your business. Before making any decision or taking any action that may affect your business, you should consult a qualified professional advisor. Deloitte MarketPoint shall not be responsible for any loss sustained by any person who uses or relies on this publication.

5.2. Introduction and approach to MarketBuilder modeling

This appendix presents results from the modeling of alternative supply-side sources of energy and capacity to replace that expected to be provided by Site C. The modeling of an alternative supply-side portfolio is completed using MarketBuilder. It is herein referred to as the MarketBuilder model.

The general approach to constructing the MarketBuilder model was to apply BC Hydro's load forecast and consider what additional generation (not relying on Site C) is required to meet the forecast at the lowest potential cost, within a specific greenhouse gas emissions cap, and specific assumptions and constraints, which are detailed below.

In modeling B.C.'s electricity system, Deloitte utilized MarketBuilder to analyze fuel supply (including thermal and renewable sources) which flows into generation units that convert the fuel into electricity that then flows

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to demand (electrical load). For example, each generation unit is a node that receives the fuel supply and price (inputs to the node), contains parameters such as heat rate (a measure of conversion efficiency) and capacity, and produces electricity at a price (outputs from the node).

In this modeling exercise, the Deloitte team started with a portfolio that includes:

- BC Hydro's existing generation capacity;
- Committed projects expected to come online in the future:
- Current Energy Purchase Agreements (EPA):
- Expected EPA renewals and expirations[165].

These capacities provided a starting point for the model. Deloitte then considered different potential generation types that are commercially feasible in B.C., including geothermal, wind, solar, and wood-based biomass facilities, in addition to new hydroelectric capacity; it also included the available characteristics of each fuel type. The modeling can be done where capacity is exogenous (i.e. specified externally regardless of economic performance), or endogenous (i.e. determined as a function of the economics and added only when economically supported). Deloitte recommends modeling exogenous capacity additions when utilities can confirm new units with a high degree of certainty, and modeling endogenous capacity additions when they seek to incorporate economic assumptions into modeling the performance of the overall system. Therefore, existing resources including contracted supplies as well as BC Hydro projects underway or otherwise very likely to move forward were modeled as exogenous capacity; potential new sources and alternatives were modeled as endogenous options with their related economic and operating parameters. BC Hydro provided additional and updated cost and performance information based on recent and pending capacity additions to the system[166].

Under this approach, the MarketBuilder model for BC was used to evaluate the economic portfolio of supply-side options to meet forecasted electricity demand in BC without Site C. Existing and expected resources were optimized along with the economic alternative sources required to satisfy the expected growth in demand. The assumptions regarding salient inputs such as the demand forecast, operational and economic parameters, and available alternative sources are described in greater detail in the following sections.

5.3. Scenario parameters

To properly define any modeling study, a large number of parameters must be specified. Long-term studies that involve asset development must particularly contend with the potential for changes and uncertainties in the macro-level environment, as well as shorter-term operational issues. This section describes a number of important scenario parameters used in the analysis. Many can debate alternatives to the assumptions, but for any given scenario, one set must be selected and the others can be reserved for further study. The following parameters were applied in the construction of this portfolio.

10.3.1 Time horizon

The study period is for 18 years, and is based on BC Hydro's fiscal year ending March 31 from 2018 to 2036.

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[165] This model does not include BC Hydro's expected capacity reduction of Mica dam's units 1 to 4. This reduction is expected to reduce dependable capacity by 410 MW between F2025 and F2030. This information was not available to Deloitte at the time of the portfolio run.

[166] Data provided by BC Hydro included operating and maintenance costs for their hydroelectric facilities, as well as historical hourly generation data for their hydroelectricity facilities, their hydroelectric EPAs, their solar EPAs, and their wind EPAs. A list of BC Hydro documents reviewed is summarized in Appendix C.

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10.3.2 Regulatory Landscape

The scenario assumes the current regulatory landscape, including the requirements of the Clean Energy Act (e.g. need to generate at least 93% of the electricity in BC from clean or renewable resources; the requirement of self-sufficiency applies; Burrard Thermal is barred; nuclear power is not included in modeling as it is not aligned with BC energy objectives). The assumptions below provide additional details.

10.3.3 Load forecast

The portfolio modeling relies on BC Hydro's load forecast published in July 2016. We used the mid-level projections for electricity load and capacity requirements in BC until F2036, after Option 2 Modified DSM has been applied.

10.3.4 Scope of portfolio

An assessment of the following alternative sources of energy and capacity was included in the model:

1. The list of generation alternatives/storage modelled includes:

    - Onshore Wind
    - Offshore Wind
    - Utility-Scale Solar PV
    - Geothermal
    - Natural gas (SCGT and CCGT)
    - Run-of-river hydroelectricity
    - Biomass (wood-based)
    - Biogas (landfill gas)
    - Biomass (municipal solid waste - MSW)
    - Cogeneration
    - Pumped storage
    - Battery storage

2. Expansion potential of current BC Hydro facilities:

    - All existing BC Hydro assets are included in the model as firm supply (exogenous variable).
    - All committed BC Hydro expansion is included in the model as firm supply (exogenous variable)167.
    - All EPAs are included in the model as firm supply (exogenous variable). However, some EPAs are assumed to expire. Details of these expirations are detailed below in the Assumptions (section 3).
    - Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

[167] Committed projects included in the model as firm capacity (exogenous) include Revelstoke Unit 6, John Hart, Ruskin, Cheakamus, and Bridge River projects (see Section 4.2.3 in the report for more details on these projects).

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- Throughout this report, existing and committed BC Hydro projects will refer to the exogenous variables explained above. New endogenous capacity includes the potential expansion of existing BC Hydro facilities as described above and in section 4.2 of the main report.

3. Demand-side management to account for energy and capacity savings:

- In this portfolio, we apply BC Hydro's mid-load after Option 2 Modified DSM to account for the current energy and capacity savings. Refer to section 4.3 of the main report for an explanation of this DSM option.

5.4. Assumptions

5.4.1. Economic assumptions

5.4.1.1. Cost estimates

The scenario uses constant, current 2017 Canadian dollars over the entire forecast period. Inflation was not included in the analysis.

5.4.1.2. Capital cost estimates

Overnight capital cost is the cost of construction for a power plant, assuming an overnight build period. While plant construction takes time, the convention of the overnight assumption is used to separate plant costs from financing costs, which can be more variable and highly affected by time. The overnight capital cost is not an estimate of total construction costs because it does not take into account interest during construction. However, financial models and integrated resource plan analysis use this estimate to compare the economic feasibility of building different plants because it is a way to separate the financing costs from the plant costs.

Capital costs for each technology were extensively researched by Deloitte. A range of costs was derived from this research, and the most relevant cost was input into the model. Capital-cost decline rates were also applied when research demonstrated it to be relevant. For instance, solar PV prices have fallen significantly over the past several years and are expected to continue to decline for the next few years. Consequently, declines in capital cost over time have been included in the model for relevant technologies.

5.4.1.3. Operating and maintenance (O&M) cost estimates

The model includes both fixed and variable O&M costs. The O&M costs were extensively researched by Deloitte. A range of costs was derived from this research, and the most relevant cost was used in the model. Refer to section 4.1.2 of the main report.

5.4.1.4. Taxes and other investment parameters

The model assumes that any additional capacity built in BC is financed by BC Hydro. As a result, Income Tax Rate is assumed to be 0% since BC Hydro does not pay a corporate income tax rate, and only pays taxes through grants in lieu and school taxes (which are deemed to be immaterial). Property Tax is assumed to be 0% since it is deemed to be immaterial. Insurance Rate is assumed to be 0% since it is deemed to be immaterial.

All new projects are assumed to be 100% debt financed, with a weighted cost of debt of 4.06% in 2018 and 4.13% for 2019. The source for the weighted cost of debt is BC Hydro's F17-F19 RRA, Exhibit B-1-1, Appendix A, Schedule 8.0, Line 59. We assume the 2019 weighted cost of debt for each year between 2020 and 2036.

The model does not account for BC Hydro's treatment of corporate revenue and net income in the modeling of project economics.

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5.4.1.5. Currency and exchange rates

The currency used in the model is the Canadian dollar (CAD). It assumes an exchange rate of 0.75 CAD/USD when applicable[168].

5.4.2. Emissions restrictions

5.4.2.1. Clean Energy Act restrictions

The Clean Energy Act, introduced in spring 2010, sets forth British Columbia's energy objectives. One of these objectives includes generating "at least 93% of the electricity in British Columbia from clean or renewable resources." Clean energy is defined as "biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource". This model assumes that natural gas and cogeneration plants are not clean, and therefore, may not contribute more than 7% of total electricity generated in any given year. The model assumes 0 direct GHG emissions for biomass, biogas, geothermal heat, hydro, MSW, solar, and wind given the BC Government's definition of clean energy[169].

5.4.2.2. Carbon price

British Columbia introduced a revenue-neutral carbon tax on the purchase and use of fuels in 2008. The BC carbon tax is currently CAD$30 per tonne. The federal government outlined a benchmark for carbon pricing that reflects an increase to CAD$50 per tonne in 2022. The NDP's platform indicates that it intends to meet the federally mandated CAD$50/tonne carbon price by 2022 over three years starting in 2020 ($6, $7, $7/tonne).[170] As such, the model assumes a carbon price of $30 per tonne from 2018-2019, rising to $36 per tonne in 2020, $43 per tonne in 2021, and $50 per tonne in 2022. The model assumes that the tax remains $50 per tonne throughout the rest of the forecast (2022-2036). The model also assumes that this tax is applied only to natural gas and cogeneration[171].

5.4.2.3. Imports/exports

Imports/exports are modeled using power price schedules for interconnected external. The external market prices used in the scenario are based on projections from Deloitte MarketPoint's 2016 North American Gas & Power Reference Case for the Alberta and Mid-Columbia (Mid-C) markets. Relative price differences and transfer capability and costs influence the extent of imports and exports, but we assume a similar level of GHG intensity (10 tonnes CO2e/GWh) for any imports into BC.

5.4.2.4. Carbon cap

The provincial government's Order-in-Council (OIC) asked that alternatives to Site C construction be considered which would offer energy while maintaining or reducing the 2016/2017 GHG emission levels. Our

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[168] BC Ministry of Finance; Budget and Fiscal Plan 2017/18 – 2019/20; Exchange rate outlook (pg. 91); http://bcbudget.gov.bc.ca/2017/bfp/2017_Budget_and_Fiscal_Plan.pdf

[169] In this model, all sources of energy are deemed "clean" with the exception of natural gas and cogeneration. Consequently, natural gas and cogeneration are the only resources in the model that are (1) subject to the carbon tax, (2) may only account for 7% of generation in any given year, and (3) may not produce so much energy as to increase the carbon intensity above the 2016/17 level of 10 tonnes/GWh in any given year. Certain portions of MSW may not be considered clean, for instance tires and peat when combusted to produce energy. Conversely, cogeneration may be considered clean in some circumstances such as when biomass is the primary source of energy generation. For simplicity, this model assumes that MSW is clean and cogeneration is not clean due to the use of natural gas-fired generation at many existing cogeneration plants in BC.

[170] BC NDP Platform; Climate Action; https://www.bcndp.ca/files/Clean-Growth-Climate-Action.pdf

[171] Ibid.

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interpretation of this direction is on an intensity rather than absolute basis. The model constrained the annual average carbon intensity to no higher than 10 tonnes/GWh for the duration of the forecast (2018-2036).[172]

5.4.3. EPA renewals

BC Hydro's 2013 IRP states, "For planning purposes, BC Hydro now estimates that 50% of the bioenergy EPAs will be renewed, about 75% of the small hydroelectric EPAs that are up for renewal in the next five years will be renewed, and all remaining EPAs will be renewed." In line with this statement, Deloitte assumed that 50% of all biomass contracts and 25% of all non-storage hydroelectric contracts would retire between 2013-2018. All other contracts are assumed to be renewed in the model.

For those EPAs that are allowed to expire (without renewal), the associated energy and capacity are removed from the model at contract expiration. In reality, some may be re-negotiated at a favorable cost and if modelled as another supply-side resource, it would likely be cheaper than greenfield opportunities.

BC Hydro's Standing Offer Program (SOP) is not explicitly represented in modeling. While the Clean Energy Act requires BC Hydro to offer the SOP, it does not require specific volumes. It also represents a risk of double-counting the resources already in the model assumed under the EPA.

5.4.4. Self-sufficiency

The Clean Energy Act sets forth BC's energy objectives. One of these objectives includes achieving "electricity self-sufficiency." We interpreted this requirement as the need for BC Hydro to hold, each year, the rights to an amount of electricity that meets the electricity supply obligation within the Province. We recognize that an exemption from this requirement can be granted with authorization from the Lieutenant Governor in Council. In the model, we assumed that BC Hydro is allowed to import energy during the year as long as it is not a net importer for each year.

Total annual imports in the model were limited to total annual exports that same year. In other words, in the model, British Columbia may import electricity during some periods but is a net exporter of electricity on average every year.

5.4.5. Resource technology capacity constraints

As mentioned in section 4.3.3, ten different generation technologies and two types of storage were included in the MarketBuilder model. However, only three of these technologies proved economic over the next 18 years, given current assumptions on existing supply, load, and imports and exports. However, since it is unrealistic to assume that any technology, regardless of its economics, could construct an infinite amount of capacity in British Columbia, certain assumptions were made regarding the amount of each technology that could be built in the province.

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[172] A carbon intensity of 10 tCO2e/GWh reflects an average of BC Hydro's reported GHG intensities for total electricity generation over the past two reported years (2014 and 2015). This was the most recent data available at the time of the assessment. Refer to https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/ghg-intensities-2007-2015.pdf. The estimate of 10 tCO2e/GWh also reflects the average over the last five reported years (2011-2015).

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5.4.5.1. Geothermal capacity constraints

Document research was conducted and several studies were analyzed to determine the potential of geothermal in BC[173, 174, 175]. 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 looking at potential 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. We assumed approximately 250 MW of potential capacity are available at the reference capital cost of $7,300/kW. This was included in the model. Further, the studies showed that additional capacity would likely be available, though perhaps at a higher cost. The model assumes another 750 MW is potentially available at $8,800/kW.

While geothermal energy is a proven technology across much of the world, including nearby California, no geothermal energy generation currently exists in British Columbia. The nature of geothermal energy gives it a unique development timeline, different from any other technology analyzed in this model. Development of geothermal energy requires preliminary surveys, exploration, test drilling, field development, and power plant construction. Test drilling is required to validate the geothermal resource and can be capital intensive. Consequently, while geothermal is forecast to be economic in BC, the development of this resource could be slower than projected if difficulties securing financing for test drilling are realized.

5.4.5.2. Onshore wind capacity constraints

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[176, 177]. 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 was 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 to 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

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[173] Canadian Geothermal Energy Association, Canadian National Geothermal Database and Provincial Resource Estimate Maps. http://www.cangea.ca/bc-geothermal-resource-estimate-maps.html

[174] Kerr Wood Leidal Associates Ltd. And GeothermEx, Economic Viability of Selected Geothermal Resources in British Columbia (Selected Sites in BC), November 2015, Updated October 2016. http://www.geosciencebc.com/s/Report2015-11.asp

[175] Geological Survey of Canada, Geothermal Energy Resource Potential of Canada, 2012. http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf

[176] Garrad Hassan, Assessment of the Energy Potential and Estimated Costs of Wind Energy in British Columbia, Feb 2008. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/rou_wind_garrad_hassan_report.pdf

[177] Canadian Wind Energy Association (CanWEA) and GE Energy Consulting, Pan-Canadian Wind Integration Study, Oct 2016. http://canwea.ca/wind-integration-study/full-report/

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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% more than the reference price.

5.4.5.3. Biogas capacity constraints

In the model, biogas refers to landfill gas and is therefore limited by the amount of landfill gas available in British Columbia. Based on current biogas performance and current landfill sizes, it was assumed that a maximum of 14 MW of additional biogas capacity could be added in the province. It was further assumed that only 8 MW would be available at the reference capital cost of $3,600/kW. The other 6 MW was available for approximately 10% more than the reference cost due to size and need for gas collection and transport to generator.

5.4.6. Reserve margin

Reserve margin measures the available capacity above the capacity needed to meet normal peak demand levels. A reserve margin of 14% was required in the model, in line with current requirements at BC Hydro.

5.4.7. Resource availability

Availability, as it exists in the model, represents the percentage of installed capacity that can be expected to generate electricity in each time period in the model. For a natural gas unit, the availability may be as high as 92%, with the other 8% assumed to be for maintenance or forced outages. For solar PV, the availability may only average 20% due to weather variability, and because the sun does not shine 24 hours a day, 365 days a year. The availability will change by time of day (generates more during the day) and by time of year (days are longer in the summer). This has been captured in the model. Availability was derived from historical performance whenever possible (including BC Hydro's hydro assets, solar EPAs, and wind EPAs)[178]. When historical actuals were not available, document research was conducted and industry norms were used[179].

5.5. Findings

Findings are provided for the single scenario modeled as part of this assessment. MarketBuilder model outputs are presented below and include the following information:

- Year: The year in which the alternative resource is selected by the MarketBuilder model.
- Alternative resources selected: The alternative resources (supply-side sources of energy and capacity) selected by the MarketBuilder model.
- Generation: Total energy generated by alternative resource (MWh).
- Capacity: Total installed capacity by alternative resource (MW).
- Costs: Capital and O&M costs by alternative resource (mn $CAD).
- Price of energy: Average price of energy provided by the portfolio ($CAD/MWh).
- GHG emissions: Total annual GHG emissions generated by the portfolio (tCO_2e).

MarketBuilder portfolio run results for the base scenario are described in the following sections according to the categories below:

- Generation
- Capacity
- Costs

[178] As provided by BC Hydro.
[179] Sources detailed in section 4.1 of the main report were referred to.

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- GHG emissions

5.5.1. Generation

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)
- BC Hydro hydroelectric facilities (new endogenous)[180]
- Biogas (new)
- Geothermal (new)
- Onshore wind – Vancouver Island (new)

Total energy generation is forecast to rise from 67 million MWh in 2018 to 79 million MWh in 2036, as the province remains a net exporter while meeting internal demand that rises from 57 million MWh to nearly 74 million MWh over the same period. The majority of this energy will continue to be generated by existing and committed BC Hydro assets. However, the total share of electricity being generated by these existing and committed BC Hydro assets will fall from about 70% in 2018 to approximately 62% in 2036 as new generation comes online to meet increasing demand. Most EPAs are assumed to renew. Consequently, generation from EPAs fall only slightly through the forecast. New generation is expected to account for about 13% of generation by 2036, from a combination of new geothermal, biogas, onshore wind, and hydro expansions.

The generation mix in British Columbia is expected to change over the forecast horizon, as new sources of generation are added. Total hydro generation in the province (from existing units, committed units, new units, and EPAs) is forecast to grow ~6% in absolute terms over the forecast horizon. Hydroelectric market share is forecast to drop slightly form 91% to 81% by 2036, but it is expected to remain the dominant source of power in the province. Generation from biogas and onshore wind increase as incremental capacity is added. Geothermal is the largest source of new generation, accounting for about 10% of total generation by 2036.

[180] While 16 potential hydro expansion projects were included the model, only six of those projects were determined to be economic given current assumptions. These projects were GM Shrum, Ladore, Seven Mile, Shuswap, Wahleach, and Whatshan. Together these projects contributed an additional 317 MW of capacity to the portfolio through 2028.

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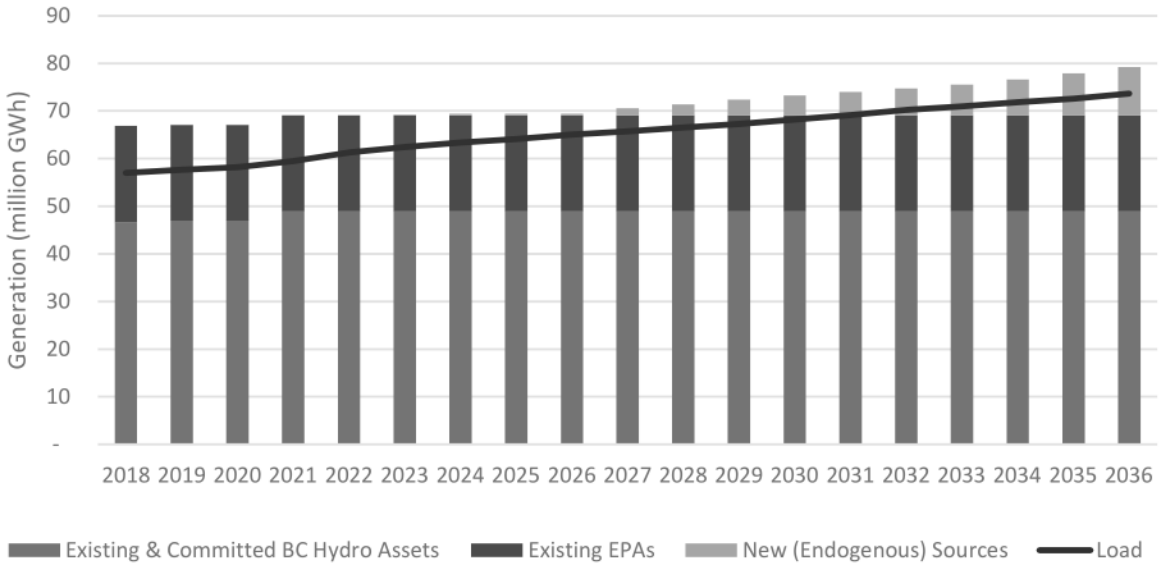

Figure 1: Cumulative energy generation by existing, committed, and new sources by year (2018-2036)

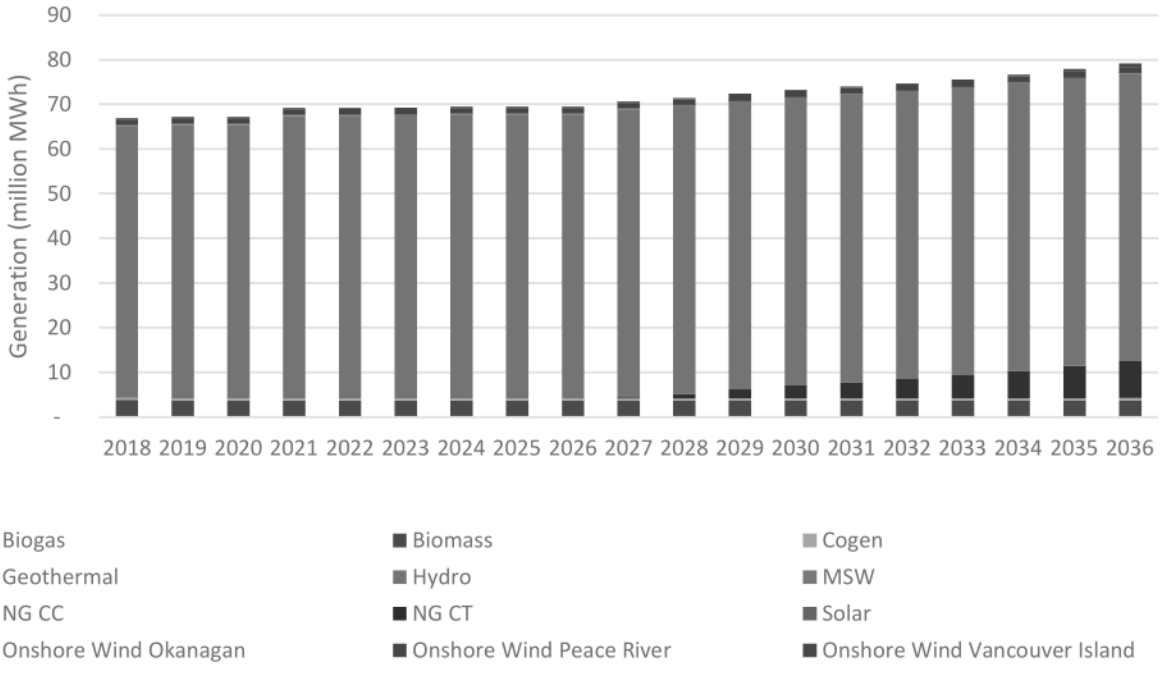

Figure 2: Cumulative energy generation by resource type by year (2018-2036) for all resources (existing, committed and new endogenous)

Total energy generation from the portfolio reaches 79 million MWh by 2036.

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5.5.2. Capacity

The portfolio selected by the MarketBuilder model includes 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 2014 respectively. Capacity from biomass decreases in 2018 and 2019 due to the expiration of existing EPAs that are assumed to not be renewed.

Figure 3 below shows cumulative, installed capacity by technology resource. However, dependable capacity would be substantially lower since resources such as wind, solar, and hydro do not normally operate at 100% of installed capacity.

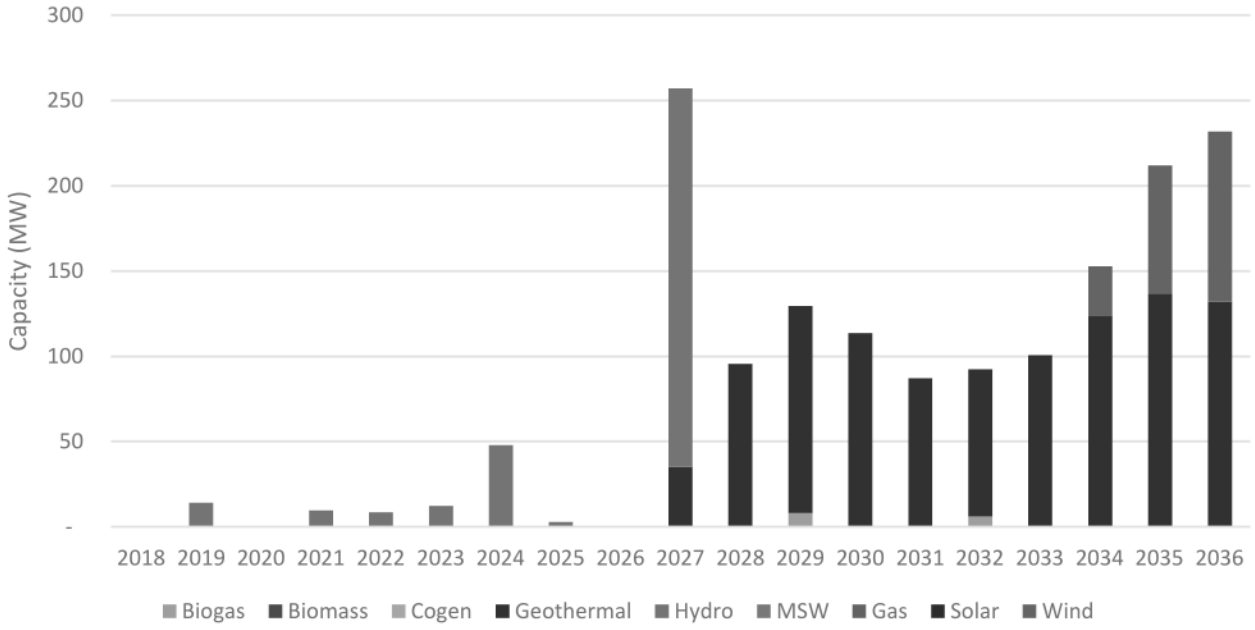

Figure 3: New endogenous capacity by alternative resource type by year (2018-2036)

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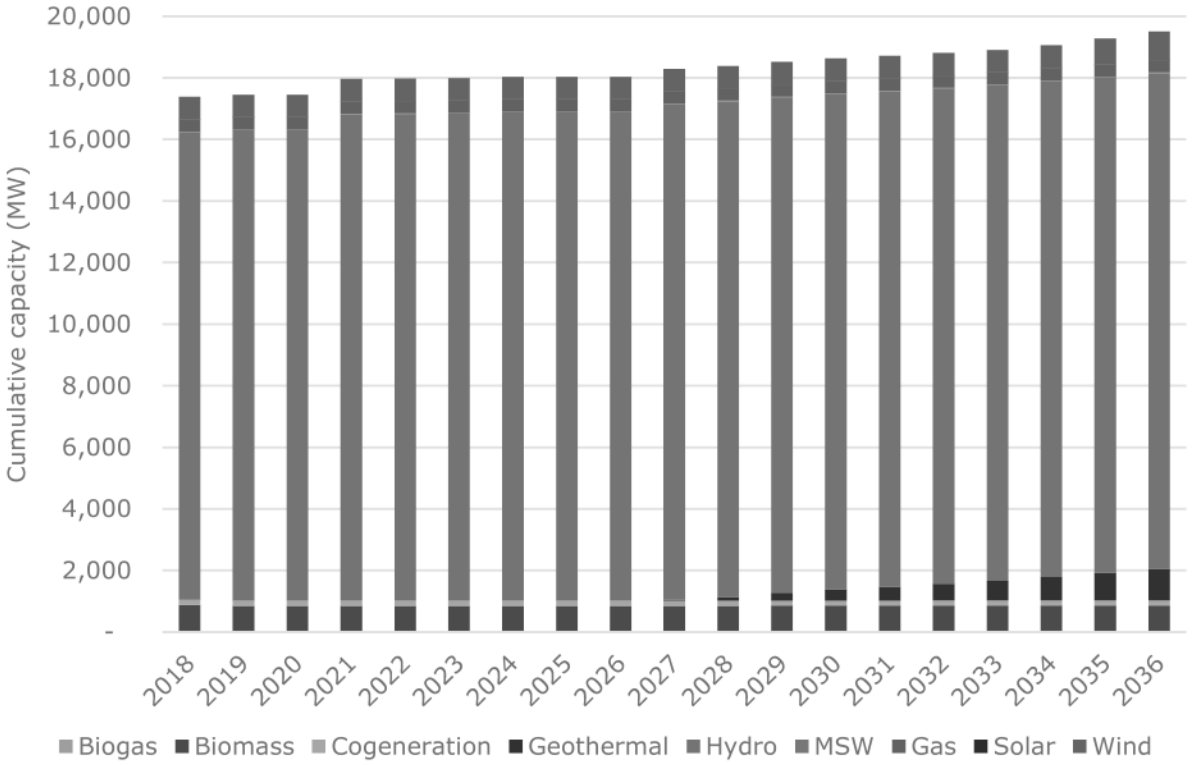

Figure 4: Cumulative installed capacity by resource type by year (2018-2036) for all resources (existing, committed, and new endogenous)

Total installed and contractual capacity from the portfolio reaches 19,506 MW by 2036.

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5.5.3. Costs

Since additions of new generating resources are sometimes lumpy, capital cost requirements associated with these additions are not necessarily a constant or smoothly increasing value. Earlier years can maintain lower capital costs for new generation, since there is potential to increase utilization of existing assets. Table 1 below summarizes capital costs of incremental capacity from alternative resources. These capital costs are only for those endogenous expansions found to be economic in the modeling. Therefore, the costs of exogenous expansions are considered sunk costs and excluded from the costs in the table. 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.

Table 1: Capital costs (mn $CAD) by alternative resource type by year (2018-2036)

Year	Biogas	Biomass	Cogen-eration	Geo-thermal	Hydro	MSW	Gas	Solar	Wind	Total
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	6	-	-	-	-	6
2020	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	37	-	-	-	-	37
2022	-	-	-	-	33	-	-	-	-	33
2023	-	-	-	-	39	-	-	-	-	39
2024	-	-	-	-	48	-	-	-	-	48
2025	-	-	-	-	0	-	-	-	-	0
2026	-	-	-	-	0	-	-	-	-	0
2027	-	-	-	183	72	-	-	-	-	255
2028	-	-	-	496	0	-	-	-	-	496
2029	21	-	-	627	-	-	-	-	-	647
2030	-	-	-	583	-	-	-	-	-	583
2031	-	-	-	445	-	-	-	-	-	445
2032	17	-	-	484	-	-	-	-	-	501
2033	0	-	-	605	-	-	-	-	-	605
2034	-	-	-	750	-	-	-	-	46	796
2035	-	-	-	826	-	-	-	-	120	946
2036	-	-	-	792	-	-	-	-	159	951

Table 2: O&M costs (mn $CAD) for new endogenous by resource type by year (2018-2036)

	Biogas New	Geothermal New	Hydro Expansions New	Onshore Wind Vancouver Island New	Total
2018	-	-	-	-	-
2019	-	-	0	-	0

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	Biogas New	Geothermal New	Hydro Expansions New	Onshore Wind Vancouver Island New	Total
2020	-	-	0	-	0
2021	-	-	1	-	1
2022	-	-	1	-	1
2023	-	-	1	-	1
2024	-	-	3	-	3
2025	-	-	3	-	3
2026	-	-	3	-	3
2027	-	5	10	-	15
2028	-	19	10	-	30
2029	1	37	10	-	49
2030	1	54	10	-	65
2031	1	67	10	-	78
2032	2	80	10	-	92
2033	2	95	10	-	107
2034	2	113	10	2	127
2035	2	133	10	7	152
2036	2	152	10	13	178

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In modeling the BC system, the supply of energy from the suite of available sources including existing and contracted supply, committed supply additions, and endogenously selected economic additions, is dispatched to meet the forecasted load of the demand side. Interchange subject to transfer limits with external markets can also participate in the supply/demand balance when economically appropriate.

Among the results of this process is the implied market- clearing price of energy. This price of energy may be considered the price to be paid by any incremental demand in that period or the price received for any incremental supply. These prices represent wholesale prices rather than retail rates.

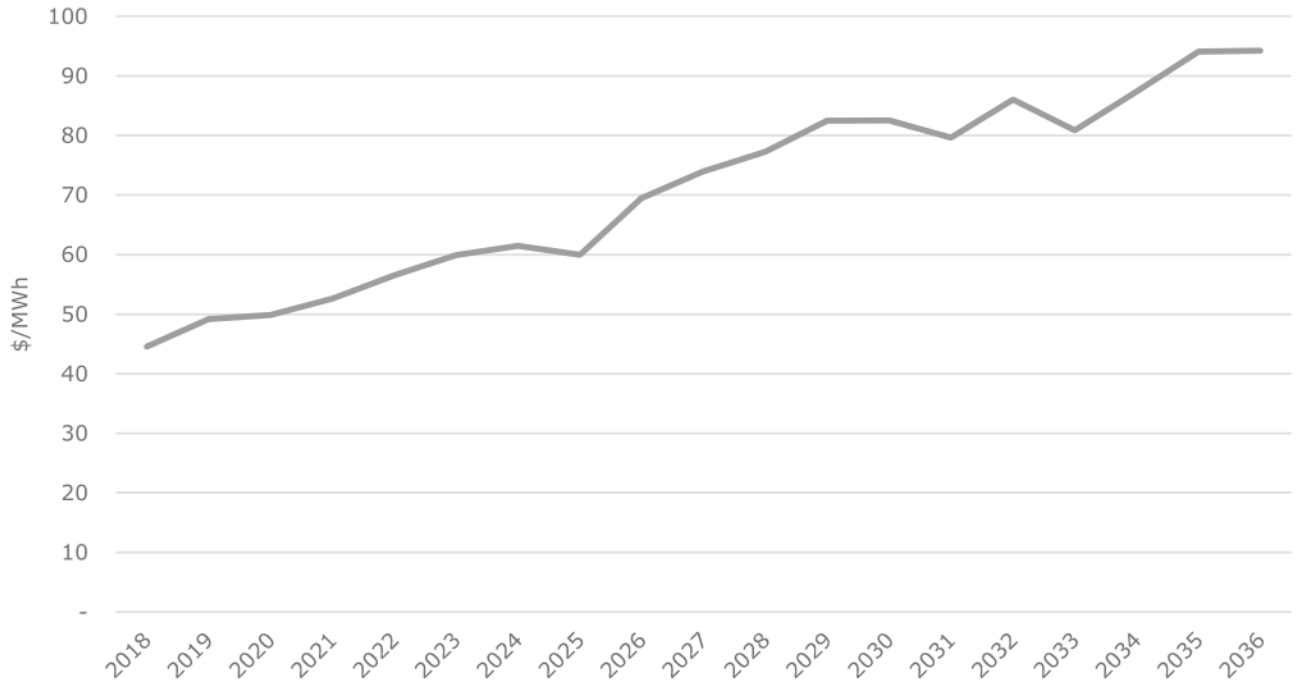

Figure 5: Price of energy in BC by year (2018-2036)

The annual average price of energy in BC rises from $45/MWh in 2018 to $94/MWh in 2036. This, like any other projection, is a function of assumptions, and the realized future may differ from the projection. Comparison with other projections can be helpful in interpreting any particular result, but care must to taken to understand that assumptions, as well as approaches, methodologies, and other differences, can account for wide variation among forecasts.

FortisBC published a set of three cases with price projections for the Mid-C market through 2035 as part of their 2016 Long Term Electric Resource Plan (LTERP)[181]. Prices for the Mid-C market assumed in this scenario are generally between the "High" and "Base" cases of the LTERP.

[181] FortisBC released the 2016 Long Term Resource Plan dated November 30, 2016. The document was obtained via the link: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf

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The price of energy in the BC system is not necessarily equal to the price in external markets such as Mid-C. There is some linkage between the markets via interchange, though costs to transfer energy will result in price differences remaining between the systems even while transfers are economic.

The value of capacity in BC in this scenario starts at $33/kW-yr in 2019 and levels out at $285/kW-yr in 2028. When there is a large surplus of capacity, capacity value is low or even zero. Capacity gains value when the reserve margin declines toward or below the target. As load increases, reserve margins naturally decline if the existing supply portfolio remains unchanged. The value of capacity is affected by factors such as the reserve margin, as well as the cost of new capacity. The cost of new capacity can vary year to year depending on availability of options as well as the underlying costs of deploying those options.

In estimating the value of capacity, the cost of new, capacity along with the need for additional capacity, was considered. The potential cost decline for certain technologies was included in the cost analysis. For example, solar panels have declined in cost in the past and are expected to continue to decline. The cost of solar assumed that each year reflects such a decline. The availability to generate at peak demand is also considered, so intermittent sources like solar or wind are affected by this more than dispatchable sources like natural gas turbines. The lowest-cost, new resource in a given year is used to determine the value of capacity.

In some years, lower cost projects are available, such as a hydroelectric expansion to an existing facility. This can result in a lower value of capacity, since the contribution to new capacity can come from a relatively lower-cost option. After such an option is built, however, it is no longer available to add to overall capacity. Therefore, the value of capacity may rise as other, higher-cost options must be considered. The value of capacity may again decline if another lower-cost option not previously available is possible. This may be due to timing on when projects can be constructed.

Some projects are relatively large, and their addition creates a greater contribution to reserve margin and a resulting drop in the value of capacity. Increasing load may cause a higher value for capacity in subsequent years.

With the availability and timing of new capacity options, along with an evolving supply/demand balance, the exact value of capacity can vary. The range of values should provide a guide to the overall values possible, but the estimated value in a specific future year should be taken in the context of the overall analysis. In the earlier years of the study, the lower-capacity values should indicate that there exist options to provide capacity at that cost. The higher values point to the potential cost if those options were not available at that time. The reader should consider the timing of these project options in light of the value of capacity. It would be incorrect to take the lowest cost option and apply that value across the horizon, since that resource cannot possibly add incremental capacity in every year of the horizon. It would also be incorrect to exclude that lower value altogether.

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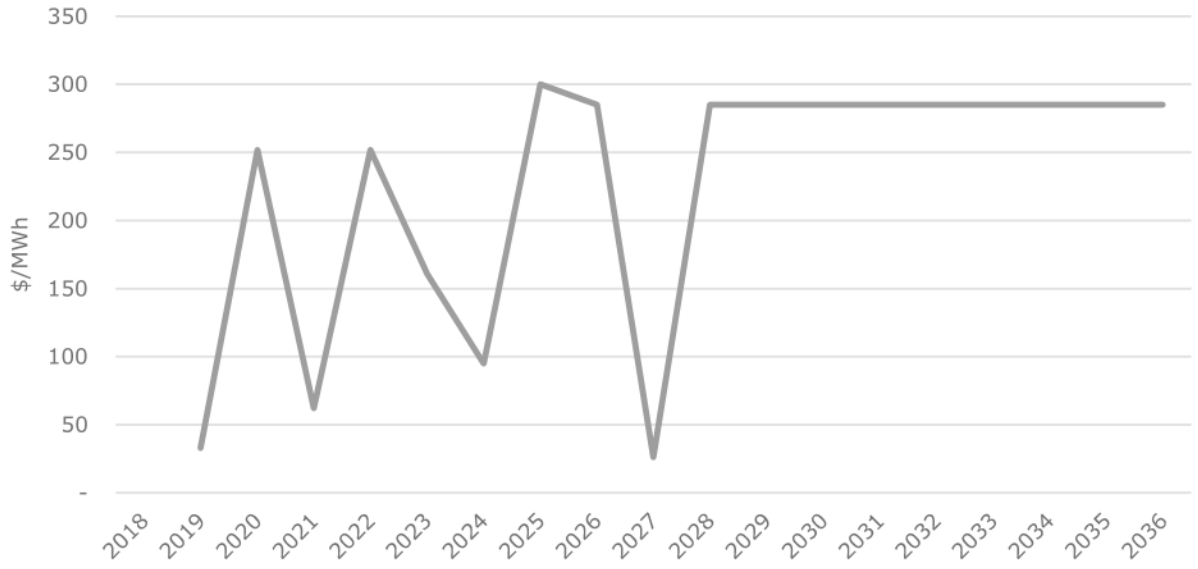

Figure 6: Value of capacity in BC by year (2018-2036)

5.5.4. GHG emissions

Emissions from the portfolio are assumed to be generated by just two of the resource categories: cogeneration and natural gas. Among the scenario assumptions is the constraint that GHG emissions should be limited to an intensity of 10 tCO_2e per gigawatt-hour. As a result, total GHG emissions can increase on a mass basis, as long as total load and generation increases. With the underlying growth in load and generation along with adherence to the GHG intensity limit, total GHG emissions rise from 564,013 tCO_2e in 2018 to 728,874 tCO_2e in 2036.

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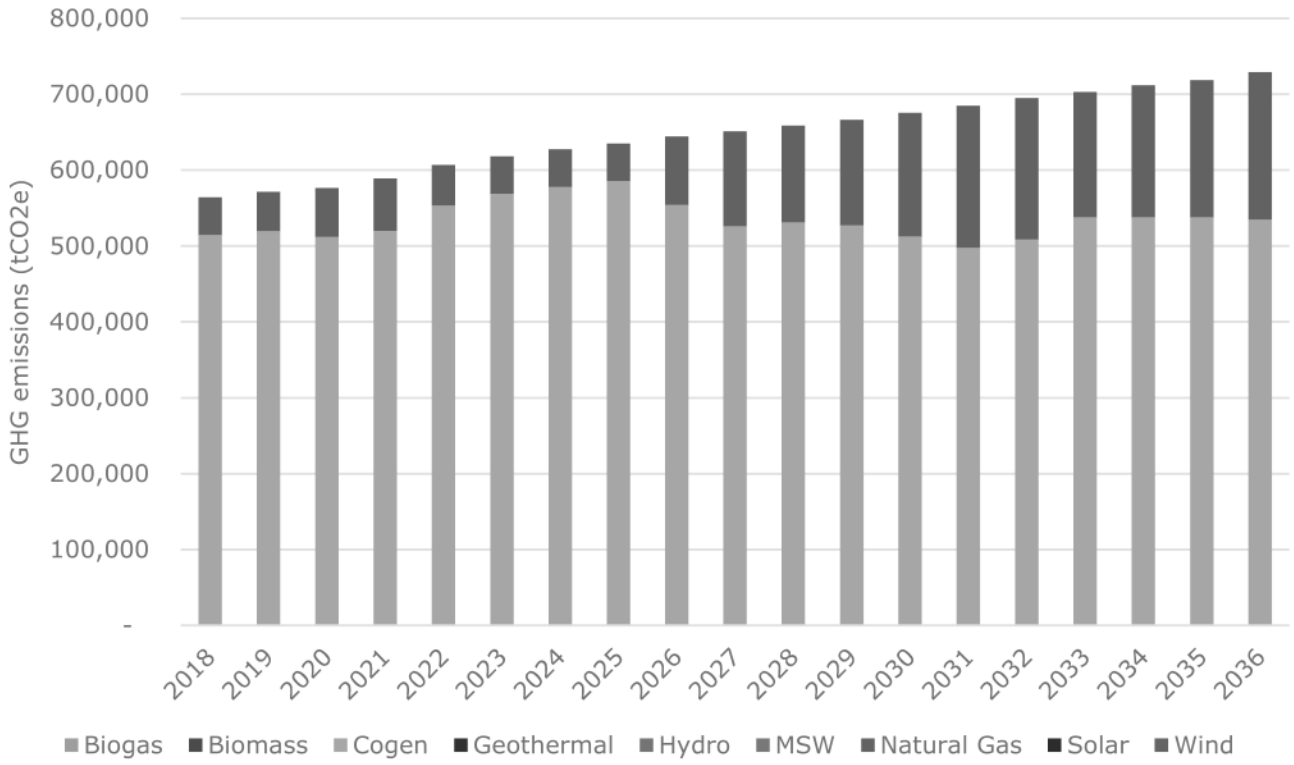

Figure 7: GHG emissions (tCO_2e) by alternative resource type by year (2018-2036)

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5.5.5. Conclusion

The provincial government's Order-in-Council asks the question: "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 findings contained herein offer findings to help inform BCUC's assessment of this OIC question.

We generated a portfolio of alternative-generation projects that:

- Meet the energy objectives set out in the Clean Energy Act;
- Contain commercially feasible generating projects;
- Contain achievable DSM initiatives;
- Consider firming/shaping and reliability of the grid;
- And maintain the 2016/17 greenhouse gas emission.

The costs, and value of the generated portfolio, are detailed in the findings section above.

It is noteworthy that we consider this scenario to be a base case for BCUC's consideration to inform the assessment, vis-à-vis the Site C scenario. Running additional scenarios would offer more insights. For example, it could be of interest to BCUC to consider the following:

- Applying the load forecast developed by Deloitte to replace that provided by BC Hydro;
- Applying increased level of DSM opportunities above what BC Hydro is currently provifing (e.g. using BC Hydro's Option 3 DSM, referred to in section 4.3 of the main report);
- Running a 'suspension scenario' to assess the need for alternative supply if Site C is suspended until a specified timeframe;
- And examining the impact of certain decisions or variable combinations (e.g. incorporating the Columbia River Treaty Entitlement if the requirements of 'self-sufficiency' is relaxed, running various price forecasts, assuming that Burrard Thermal is restarted, etc.)

Given the inherent uncertainty of projections, additional scenarios and analysis could be used to better quantify the sensitivity of the base scenario findings to changes in the assumptions. Additionally, while project cost and performance (e.g. capacity factor) inputs are reasonable for the various technologies in the alternative supply portfolio, any particular project will have different costs and performance driven by specific project needs, even if such values fall within the expected range. Scenarios probing different cost or performance assumptions for technologies can also evaluate how alternate portfolios may perform under different circumstances.

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Appendix F - Assessment of alternative supply-side sources of energy and capacity – external research

Document name	Author	Date	Source
Canada's Renewable Power Landscape - Energy Market Analysis 2016	National Energy Board	October 2016	http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2016cndrnwblpwr/index-eng.html
Canada's Adoption of Renewable Power Sources Energy Market Analysis	National Energy Board	October 2016	http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html
FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)	FortisBC	November 30, 2016	https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf
Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies	Western Electric Coordinating Council	March 2014	https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
Capital Cost Estimates for Utility Scale Electricity Generating Plants	EIA	November 2016	https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
Life Cycle Greenhouse Gas Emissions: Natural Gas and Power Production	NREL	June 15, 2015	https://www.eia.gov/conference/2015/pdf/presentations/skone.pdf
Distributed Generation Renewable Energy Estimate of Costs	NREL	February 2016	https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html
Annex II: Methodology. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation	IPCC	2011	http://www.ipcc-wg3.de/report/IPCC_SRREN_Annex_II.pdf
U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016	NREL	September 2016	https://www.nrel.gov/docs/fy16osti/67142.pdf

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Document name	Author	Date	Source
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives	Puget Sound Energy	2015	https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf
Portland General Electric 2016 IRP (PGE)	Portland General Electric	November 2016	https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en
NW Council Seventh Power Plan	NW Council	February 25, 2016	https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf
PacifiCorp 2017 IRP	PacifiCorp	April 4, 2017	https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf
Idaho Power 2017 IRP	Idaho Power	June 2017	https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf
Lazard's Levelized Cost of Energy Analysis - Version 10.0	Lazard	December 2016	https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
IESO Ontario Planning Outlook	IESO	September 2016	http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook
BC Hydro Wind Data Study Report	BC Hydro	May 1, 2009	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.pdf
BC Hydro Wind Data Study Update Report	BC Hydro	September 24, 2009	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #1 Handout	BC Hydro	September 12, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting1-20140912-handout.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #1 Handout	BC Hydro	September 12, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting1-20140912-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #2 Presentation	BC Hydro	December 15, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-

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Document name	Author	Date	Source
			characterization-wind-meeting2-20141215-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #2 notes	BC Hydro	December 15, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting2-20141215-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #3 Presentation	BC Hydro	May 5, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150505-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #3 note	BC Hydro	May 5, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150505-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #4 Presentation	BC Hydro	June 3, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting4-20150603-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #4 notes	BC Hydro	June 3, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150603-summary-notes.pdf
EnergyBC Electricity Generating Stations in British Columbia Map	Energy BC	Accessed 08/16/2017	http://www.energybc.ca/electricitymap.html
Zero Emission Energy Developments Inc. website	Zero Emission Energy Developments Inc.	Accessed 08/16/2017	http://zeroemissiondevelopments.com/zed-projects/
Boralex Moose Lake Wind Project website	Boralex	Accessed 08/16/2017	http://www.boralex.com/projects/mooselake

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Document name	Author	Date	Source
Meikle Wind project website	Meikle Wind	Accessed 08/16/2017	http://meiklewind.com/
Canadian Wind Energy Association website	CanWEA	Accessed 08/16/2017	http://canwea.ca/wind-energy/installed-capacity/
Canadian Wind Energy Association (CanWEA) Pan-Canadian Wind Integration Study (PCWIS)	CanWEA	Accessed 08/16/2017	http://canwea.ca/wind-integration-study/wind-data/
GE Renewable Energy website	GE	Accessed 08/16/2017	https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines
Wind Turbines, Battery Included, Can Keep Power Supplies Stable	MIT Technology Review	Accessed 08/16/2017	https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/
Wind Power Integration: Energy Storage for Firming and Shaping	EPRI	Accessed 08/16/2017	https://www.epri.com/#/pages/product/000000000001008388/
Hydro-Québec website - Combining Wind and Water	Hydro Quebec	Accessed 08/16/2017	http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html
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Energy Storage Trends and Opportunities in Emerging Markets	ESMAP and IFC	2017	https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStorage-report.pdf?MOD=AJPERES
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Cost of Energy Technologies	World Energy Council	2013	https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf
Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Service. Energy and Mines Ministers' Conference.	Natural Resources Canada	August 2017	http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf
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Geothermal FAQs	US Department of Energy	Accessed 8/17/2017	https://energy.gov/eere/geothermal/geothermal-faqs
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s.12; s.13; s.14

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s.79

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Withheld pursuant to/removed as

s.12

Site C Review – Summary and Milestones – Oct. 5, 2017

Executive Summary:

The BCUC is currently in the process of collecting information in order to provide advice to Government on whether completing, suspending or terminating the Site C project is the lowest cost option for BC Hydro ratepayers.

The review was announced and terms of reference released on August 2, 2017. The BCUC was asked to advise Government if the project is currently on time and on budget, what the costs would be to terminate or suspend the project, and whether a portfolio of alternative resources (e.g. wind, geothermal, biomass, pumped storage, solar) could provide similar benefits at the same or lower costs to ratepayers.

The BCUC is controlling the review process. The first phase of the review consisted of fact gathering to inform the preliminary report. Data and analysis relevant to the scope was accepted for consideration up until August 30th. In addition to BC Hydro's submission, the BCUC received submissions from over 150 individuals and organizations. The BCUC also engaged Deloitte LLP, a consulting firm, to produce independent analysis on questions raised in the terms of reference for the review. In their submissions Deloitte and BC Hydro agreed the cost to terminate the project would be about $1.2 billion, and suspending the project about $1.4 billion. This would be in addition to sunk costs which Deloitte estimates will be $2.1 billion by December 31, 2017.

The BCUC released its preliminary report on September 20th. The report was characterized by most as raising more questions than it answered. The BCUC indicated that the project has the potential to be on time and budget, but that there are numerous risks that could delay the project and increase costs. The BCUC noted it was not yet in a position to determine ratepayer impacts and requested that BC Hydro provide a large volume of additional data and analysis to address 73 questions.

In its October 4th response to the questions raised in the preliminary report, BC Hydro indicated that it will not meet one of the key project milestones – that the fall 2019 date to divert the Peace River through bypass tunnels will be delayed by one year. While BC Hydro remains confident that it will still be able to complete the project on schedule in 2024, BC Hydro has calculated that the delay will add $610 million to the $8.335 billion budget for the project, bringing it to $8.945 billion.

Following the release of its preliminary report, the BCUC commenced a series of 11 community input sessions and three First Nations input sessions around the province to gather comment on the preliminary report. The BCUC also continues to accept written submissions. To date, more than 220 individuals and organizations have made written submissions to the BCUC.

BC Hydro will reply to the preliminary report in writing on October 11th. The BCUC will also host technical presentations on October 13th and 14th in Vancouver to hear oral presentations from, and ask questions of, BC Hydro and invited parties. Members of the public are welcome to attend the technical presentation sessions however presentation spots are available and pre-arranged only for the invited speakers.

The BCUC will submit its final report on November 1, 2017, to the Minister of Energy, Mines and Petroleum Resources. The Minister intends public release within a day or two.

Government has separately begun engagement with 11 Treaty 8 First Nations in B.C. and Alberta that are directly affected by Site C. This process is in addition to the sessions the BCUC is doing. The engagement process will provide Treaty 8 First Nations an opportunity to share their views on the BCUC's final report, to provide submissions to Government around any new and incremental impacts to Treaty rights, economic, social cultural, heritage or any other First Nations interests associated with the options of completing, suspending or terminating the Site C project. Ministers Mungall and Fraser will meet with BC Treaty 8 First Nations in Fort St John on November 14 to hear their views directly.

Government will consider the advice from the BCUC, along with other environmental and First Nations considerations, and make a final decision on the future of Site C. The final decision from Government is anticipated in early December.

Milestones:

- **August 2, 2017:** Site C review announced and terms of reference released.
- **August 30:** Deadline for parties to provide written submissions to the BCUC review.
- **Sept. 8:** Deloitte LLP releases its report on Site C for the review. The BCUC engaged Deloitte to produce independent analysis on questions raised in the terms of reference for the review.
- **Sept. 20, 2017:** BCUC releases preliminary report on Site C.
- **Sept. 23 – October 11:** Community Input Sessions (speakers limited to 5 minute presentations):
    - Sept. 23: Vancouver
    - Sept. 24: Kamloops
    - Sept. 25: Kelowna:
    - Sept. 26: Nelson:
    - Sept. 29: Prince George
    - Sept. 30: Hudson's Hope
    - Oct. 1: Fort St. John
    - Oct. 2: Fort St. John
    - Oct. 5: Vancouver
    - Oct. 10: Nanaimo
    - Oct. 11: Victoria
- **Sept. 29 – Oct. 11:** BCUC-hosted First Nations Input Sessions
    - Sept. 29: Prince George

  - Oct. 6: Vancouver
  - Oct. 11: Victoria
- **Oct. 11:** BC Hydro and other parties submit written replies to the BCUC preliminary report
- **Oct. 13-14:** Technical Presentation Sessions to provide invited speakers an opportunity to make an oral presentation to the Panel, and for the BCUC Panel to ask questions of BC Hydro and the other invited speakers. Invited speakers:
  - Clean Energy Association of BC (CEABC)
  - BC Old Age Pensioners Organization (BCOAPO
  - Robert McCullough
  - Allied Hydro Council of BC
  - Marc Eliesen
  - Guy Dauncey
  - Canadian Wind Energy Association (CanWEA)
  - Association of Major Power Consumers (AMPC)
  - Canadian Centre for Policy Alternatives
  - Harry Swain
  - David Vardy
  - Rick Hendriks and Philip Raphals
  - BC Pulp and Paper Coalition
  - BC Sustainable Energy Assn (BCSEA)
  - Commercial Energy Consumers (CEC)
  - Canadian Geothermal Energy Assn (CanGEA)
  - BC Hydro
- **Nov. 1:** BCUC releases its final report to Government and posts on its website.
- **Nov. 13-14:** Minister Mungall and Minister Fraser meet with B.C. Treaty 8 First Nations in Fort St. John to consult on the project before making decision.
- **Nov. 29 [TBC]:** Cabinet consideration of EMPR-recommended option to complete, terminate or suspend the Site C project**.**
- **December:** Public announcement of decision on Site C.

Summary of the BCUC Community Input Sessions on the Site C Inquiry.

Location	Approximate Number of Participants	Number of Speakers	For Site C	Against Site C	Major Themes	Any additional comments
Vancouver (Sept 23)	120	41	3	37	- Several speakers with project economic credentials outlined how they saw the economics as being marginal. -Demand forecast overestimated and reliant on unlikely LNG industry success; -Load shedding (relocation) from major industries likely in face of increased rates; Inadequate project contingencies; -Future cost of power being dependent on low interest rates. -Suggest alternative energy prices dropping, and can meet demand gap incrementally. DSM also mentioned. - Concern over loss of agricultural land. Some suggested that when considering the economics of the project, the scope should be expanded to consider the lost productive output from the flooded land. -Over the long term, with climate change occurring, food imports from California and Mexico will dwindle and we will need to retain any productive capacity to maintain our food security in BC. - A lot of outrage over treatment of FN treaty rights, flooding of burial sites. Concerned that it would be a black mark on our province reputation. - Environmental concerns, about water behind a dam being 'dead water'. -Those in favour of the dam were concerned about the impact of cancelling it on people currently employed; on the message it would send to international investors about projects being cancelled at	- BC Sustainable Energy Association remained neutral but noted the importance of having low-cost clean electricity to electrify the economy. Emphasized importance of using portfolio analysis rather than unit energy comparisons. - A Site C protest was organized outside the venue prior to the hearing, with organizers encouraging people to register and 'flood the hearings'. - Many attendees had t-shirts, placards etc. opposing the project, and applauded those opposing the project. - Participants were grateful to BCUC for holding the session and doing the inquiry - The tone in the room was generally respectful, though the few speakers in favour of the project got a lot of head-shaking from audience members. -Of the three speakers in favour of Site C, one was the Independent Contractors and Business Association of BC, one was a union representative, and one was a private citizen.

					the whim of a changing government; and spoke of the future need for electricity for electric vehicle demand.	
Kamloops (Sept 24)	15	10	1	9	- Participants were supportive of the BCUC holding the input session. - Some speakers noted their disappointment that more people had not shown up to the session. - Several participants were not in favour of Site C because they felt that adequate alternatives are available (i.e. wind, solar, geothermal, tidal) - Some participants noted that the demand for Site C power will not be needed because of increased demand side management and movement of ratepayers towards distributed generation and self-reliance. - Some speakers noted their disapproval with the flooding of agricultural land and the impacts to hunting grounds. - Some speakers noted the negative impacts to Communities and First Nations and that the costs addressing are not being considered in the BCUC's inquiry	- The one speaker in favour of the project suggested that Site C was the cheapest option for new electricity. The speaker noted that they were retired, on a fixed income and wants rates to be affordable. - Chief Patrick Michelle from the Kanaka Bar Band, near Lytton BC, was in attendance and was not in favour of Site C and suggested that alternative sources could be used. - Attendees stayed until the end of the speakers. - No Speakers were in favour of suspending Site C.
Kelowna (Sept 25)	110	29	9	20	- Participants were supportive of the BCUC holding the input session. - The majority of speakers were against Site C being completed - They suggested that there are adequate alternatives available (i.e. wind, solar, geothermal) - Many spoke of the environmental impacts to the Peace River Valley. - Speakers suggested that First Nations have not been consulted appropriately and are concerned about impacts on First Nations communities if Site C is completed. - Many speakers spoke in favour of preserving farmland. - Approximately 20% of speakers were in	- There were several speakers who identified themselves as part of the local chapter of Amnesty International; generally they spoke against Site C because of community and First Nations impacts. - A representative from the BC Fruit Growers Association spoke against Site C to protect farmland. - A representative from the Christian Labour Association of Canada and Construction of Allied Workers Union spoke in favour of Site C going ahead. Site C supports jobs and will support BC electrification with clean energy. - Several attendees were wearing "Stop Site C" shirts. - No Speakers were in favour of suspending

					favour of Site C being completed. All those in support noted that Site C is clean and renewable. Some noted that alternatives have environmental and social impacts too.	Site C. - Attendees stayed until the end of the speakers.
Nelson (Sept 26)	45	19	1	18	- Participants were supportive of the BCUC holding the input session. - The majority of speakers were against Site C being completed. - They suggested that there are adequate alternatives available (i.e. wind, solar, geothermal) - Many spoke of the environmental impacts to the Peace River Valley. - There was concern about impacts on First Nations communities if Site C is completed. - There were some who suggested that the forecasted demand from oil and gas development has been inflated by BC Hydro. - Several speakers spoke of the community impacts from the damming of the Columbia River system in the Kootenay Region, and are not in favour of any more dam development.	- Martin Carver, who was an expert witness called to the Joint Review Panel Site C Environmental Review, spoke of the hidden costs that result from the impacts to the Peace/Athabasca Delta and settling claims brought forward by affected First Nations that live there. He stated that the Environmental Review process in Canada is flawed. -The one speaker that was supportive of Site C was a representative from the Construction and Maintenance and Allied Workers Local 2300, the Kootenay's Carpentry and Construction Union. He spoke of Site C's low carbon benefits and noted that other alternatives are not as beneficial and have social and environmental impacts as well. - No Speakers were in favour of suspending Site C. - Attendees stayed until the end of the speakers.
Prince George (September 29)	100	19	5	14	-Social, cultural and environmental impacts are of great concern. -Future need/demand for electricity from Site C is questionable. - BC Hydro has not done enough to investigate alternative energy sources. - Increased costs to ratepayers are a concern. - For those in support, cancellation of the project will make it look like BC is closed for business.	- Clear from level of applause after each speaker that vast majority of attendees opposed to project. - Support for the project was expressed by a representative of the Independent Contractors and Businesses Association of BC (ICBA) and by a local consulting engineering firm. - Commissioner rebuked one presenter for divulging redacted information from the Deloitte report after warning presenters against disclosure of confidential or personal information.

Hudson's Hope (Sept 30)	60	20	1	19	- Very happy that the BCUC came to Hudson's Hope to hear from the local area residents. -Peace Valley agricultural sector in the area is valuable and can feed 1 million people - There are a number of alternatives to Site C, (wind, solar, geothermal, run of river) that are less expensive and their costs are falling. - Strong distrust of BC Hydro. -	-Very respectful audience - Attendees stayed until the end of the session - Support for the project was based on the cost-effectiveness of Site C and the dispatchability, firming and flexibility of the resource compared to the alternatives
Fort St. John (Oct 1)	100	17	2	15	-Peace Valley agricultural sector is important and can feed up to 1 million people. -Cost-effective alternatives to Site C are available and those costs are falling. -Strong distrust of information provided to local area residents by BC Hydro. -Site C does not respect Treaty 8 rights -	-Unlike the Hudson's Hope session, many participants left following their presentation. -Media in attendance - Support for Site C provided by Richard Neufeld, former Minister of EMPR and now Senator, speaking as a local resident and a Treaty 8 First Nations woman who sees project as beneficial for FN around Jobs, training and business opportunities.

Summary of the BCUC First Nation Input Sessions on the Site C Inquiry

Location	Public Attendees	First Nation presentations	For Site C	Against Site C	Major Themes	Any additional comments
Prince George (September 29)	7	2	1	1	*West Moberly/Prophet River First Nations* - Opposed to Site C - Project is a violation of Treaty 8, which preserves FN hunting and fishing rights. - Cumulative effects from existing dams and various industries are already impacting fish and wildlife that were traditional sources of food. - Support alternative energy	- Both FN presentations included comments from Chief / Councillor, followed by comments from a band lawyer - Formal written submission/arguments were presented to Commission by McLeod Lake

					sources, including solar, wind, geothermal and smaller run of the river projects. - Terminating the project is an opportunity to promote reconciliation. FN's can help with reclamation work. - Project is a violation of UNDRIP, as the FNs in the area haven't given free, informed consent. *McLeod Lake Indian Band* - Supports Site C. - In the 1960's, construction of the W.A.C. Bennett dam ruined the traditional lifestyle of band members. - IBA agreements put in place with BC Hydro and the Crown recognize the impacts of the Bennett dam and present a turning point in the relationship; suspending Site C would unravel those agreements and hamper reconciliation. - Suspending Site C would also be an economic catastrophe for the community. - This Site C review triggers the Crown's duty to consult with FN's. Crown is not currently meeting that obligation. - The Crown can't leave McLeod Lake in worse shape if Site C is ended. If agreements cancelled, land transfers must still go through and Crown must provide further accommodation.	