Site C Inquiry

Submission to the BC Utilities Commission

August 2017

Dr. Karen Bakker

Program on Water Governance, University of British Columbia

www.watergovernance.ca

This document was prepared in August 2017 as a submission to the BC Utilities Commission Inquiry Respecting Site C.

This submission includes two expert reports published by the University of British Columbia's Program on Water Governance (www.watergovernance.ca), which is co-hosted by UBC's Department for Geography and Institute for Resources, Environment, and Sustainability. Dr. Karen Bakker, Professor and Canada Research Chair at the University of British Columbia, is the Co-Director of the Program.

The Program on Water Governance has previously published five reports on Site C (watergovernance.ca/projects/sitec/). Two of these reports are highly relevant to the BCUC Inquiry, and are provided as attachments:

- **Report: Reassessing the Need for Site C.** This report, published in April 2017, is attached as Appendix A to this submission. The report was independently reviewed by: Ian Goodman (President, The Goodman Group); Dr. Norman Mousseau (Professor, Université de Montréal and Director, Trottier Energy Institute); and Dr. Mark Winfield (Professor and Co-Chair, Sustainable Energy Institute, York University).

- **Report: Comparative Assessment of Greenhouse Gas Emissions of Site C versus Alternatives.** This report on Greenhouse Gas Emissions (July 2016) is attached as Appendix B. This report was independently reviewed by: Dr. Arthur Fredeen (UNBC), Dr. Normand Mousseau (Université de Montreal), and Philip Raphals (Helios Centre, Montreal).

The three other reports address important issues (First Nations; environmental effects; regulatory issues) that are relevant to Site C Project. These can be found on the Program's website, as noted above.

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Sincerely,

Dr. Karen Bakker

[redacted]

Reassessing the Need for Site C

Richard Hendriks

Philip Raphals

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April 2017

Reviewers:

This report was independently reviewed by:

Ian Goodman (President, The Goodman Group)

Dr. Normand Mousseau (Professor, Université de Montréal and Director, Trottier Energy Institute)

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EXECUTIVE SUMMARY

The Government of British Columbia and its wholly owned utility, BC Hydro, have embarked on an $8.3 billion large-scale hydroelectric project at Site C on the Peace River in northeastern British Columbia. The Project is currently in the early stages of construction with a scheduled commissioning date of 2024.

The purpose of this Report is to provide deeper insight to government, policy-makers, and the general public regarding the economics of the Site C Project.[1] The Report addresses whether the Site C Project is past the "point of no return" from an economic perspective.

The Report incorporates into our analysis several key changed circumstances since the initial comparison of the Site C Project with the alternatives was performed by BC Hydro in 2013. These include: a decline in the cost of the alternative resources to the Site C Project (including wind); a substantial reduction in BC Hydro's forecasted need for electricity in 2024 and beyond; and an increase in the cost of the Site C Project.

Our analysis: We analyze whether it would be economically preferable to a) complete, b) cancel or c) suspend the Project. We examine these three options in the context of different forecasts for electricity requirements, possible cost overruns in the Site C Project, different levels of conservation and efficiency, and a range of electricity prices in the electricity export markets. We also consider whether cancelling the Site C Project is preferable to suspending the Project. Our analysis considers that BC Hydro will have spent $1.87 billion as of June 30, 2017, and that cancelling or suspending the Project will entail additional construction cancellation, demobilization, and suspension costs.

Our findings are: 1) The decision to approve the Site C Project in 2014 will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued at that time. 2) Our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions. 3) Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. Both cancelling and suspending are preferable to continuing with the Site C Project.

Our recommendation is: Suspend the Site C Project, and refer the Project to the BC Utilities Commission for a full review.

[1] The Program on Water Governance at the University of British Columbia has previously published several reports on the Site C Project: http://watergovernance.ca/projects/sitec/

ABOUT THE AUTHORS

Dr. Karen Bakker is Professor, Canada Research Chair, and Founding Director of the Program on Water Governance at the University of British Columbia (www.watergovernance.ca). The author of over 100 academic publications on water-related issues, Dr. Bakker has acted as an advisor and consultant to national and international organizations in North America, Europe, and southeast Asia for the past two decades.

Richard Hendriks is the director of Camerado Energy Consulting, an Ontario-based firm providing environmental assessment, energy planning, policy analysis, and research services to clients across Canada. For the past two decades, he has been engaged in the planning and assessment of several large-scale hydroelectric developments, and provided testimony before regulatory bodies concerning their economic viability, environmental effects, socio-economic impacts and implications for Indigenous rights.

Philip Raphals is cofounder and executive director of the Helios Centre, a non-profit energy research and consulting group based in Montreal. Over the last 25 years, he has written extensively on issues related to hydropower and competitive energy markets, and has appeared many times as an expert witness before energy and environmental regulators in several provinces.

Dr. Karen Bakker acknowledges support from the Social Sciences and Humanities Research Council of Canada, and from the University of British Columbia. The authors are solely responsible for the report's contents. The report does not reflect the views of the University of British Columbia or of the funder.

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1. Introduction and Summary

1.1 Introduction

This report is part of an initiative of the Program on Water Governance at the University of British Columbia.

The Program on Water Governance (watergovernance.ca) conducts interdisciplinary research on water sustainability, and makes this research available to the public. In addition to our academic publications, we publish briefing notes and reports, with the goal of fostering dialogue on water policy with communities and decision-makers.

This report follows on prior work produced by the Program on Water Governance in relation to the Site C Project. This prior work includes four reports (available at watergovernance.ca/projects/sitec/), which address gaps in the review process for Site C:

- Briefing Note Report #1 – First Nations and Site C
- Briefing Note Report #2 – Assessing Alternatives to Site C (Environmental Effects Comparison)
- Briefing Note Report #3 – The Regulatory Process for the Site C Project
- Briefing Note Report #4 – Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives

The purpose of this fifth report is to provide deeper insight to government, policy makers and the general public regarding the development of the Site C Project, an $8.335 billion large-scale hydroelectric project on the Peace River in northeastern British Columbia. Specifically, the report considers the factors that led to the construction of the Site C Project, the factors that have changed since it was approved, and the merits of the following options:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant.

1.2 Methods and Sources

This Report relies primarily on information made public by BC Hydro, including its 2013 Integrated Resource Plan (IRP) and its 2016 Revenue Requirements Application (RRA) currently under review by the BC Utilities Commission.[2]

Scenario analysis was performed through an Excel-based model constructed by the authors. All tables and charts not otherwise identified have been produced by the authors themselves, using this model.

Like any analysis looking 20 years into the future, the forecasts underlying these analyses are highly uncertain. Except otherwise noted, the forecasts used are the most recent forecasts made public by BC Hydro. In most cases, we have used low-mid-high scenarios to explore the implications of these uncertainties.

The Report goes to considerable lengths to explain the inputs and assumptions used in its models. We welcome feedback on our methods, inputs and assumptions.

1.3 Summary

Section 2 explores the historical and regulatory context justifying the decision to proceed with the Site C Project, and provides background for the sections that follow. In December 2014, the Provincial Government justified the significant adverse environmental effects of the Site C Project on the premise — which this Report demonstrates to be incorrect — that the Project would deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives.

Section 3 analyzes the evolution, since Site C was approved, of BC Hydro's forecasts of British Columbia's future electricity needs. This section demonstrates that BC Hydro's 2012 Load Forecast has collapsed. As a result, completing the Site C Project in F2024 would result in a large energy surplus that would last almost a decade — or more, if load growth is lower than forecast by BC Hydro.

Our analysis finds that the decision to build Site C was based on a strikingly high load forecast made by BC Hydro in 2013, which was (a) notably higher than similar estimates made before or since (on the order of 8,000 GWh/year) and (b) largely excluded the potential for energy conservation. BC Hydro's current forecasts are much lower, and indicate that Site C will produce surplus electricity that will have to be sold at a loss for many years after commissioning.

Section 3 also analyzes BC Hydro's load forecasting history over the past three decades, and finds that 85% of the load forecast data points prepared by BC Hydro since Site C was first proposed (in the 1980s) have been overestimates. The report also discusses the reasons why a high-load scenario now appears exceedingly unlikely, due to (a) continuing delays to several mining, LNG, and oil and gas projects; (b) fewer new mining and oil and gas projects because of low commodity prices; (c) lower than expected housing starts; (d) lower residential and commercial demand; (e) somewhat

[2] As part of the regulatory review process for setting rates, BC Hydro released information to the BC Utilities Commission in 2016 and 2017. The documents are available on the BC Hydro website and on the BCUC website (See "British Columbia Hydro and Power Authority ~ F2017 to F2019 Revenue Requirements Application ~ Project No. 3698869" at: http://www.bcuc.com/ApplicationView.aspx?ApplicationId=533).

higher electricity prices; and (f) the ongoing effects of energy conservation and demand management. Moreover, our research shows that "electrification" of the economy will increase demand but not to justify Site C on the current timeline. BC Hydro's own forecasts indicate that electricity demand from electrification will be relatively modest into the 2030s.

Section 4 investigates the costs of continuing to develop the Site C Project to completion as scheduled, including an analysis of the risks and implications of cost overruns. Although the Site C Project so far remains on budget, we summarize the prior experience of BC Hydro and other Crown corporations, which suggests that cost overruns in large-scale hydroelectric and transmission projects are common and potentially substantial. Section 4 also analyzes the economic implications of proceeding with the construction of the Site C Project under BC Hydro's current load forecast, by calculating the losses resulting from exporting the energy surplus at prices far below the cost of production. Over the years of expected surplus, the total export losses are projected to be almost $950 million for the mid-load scenario. Under BC Hydro's low-load forecast, the cumulative losses would be on the order of $2.7 billion by 2036 and would continue to increase thereafter.

The additional cost of GHG emissions is also presented in Section 4.[3] BC Hydro includes the cost of construction phase GHG emissions in its estimate of the cost of the Site C Project, but not those of the operations phase emissions. Using the price of $50/tonne in 2022 announced by the Government of Canada, we estimate the cost associated with GHG emissions from the Site C reservoir to peak at about $32 million per year in 2026, and to total approximately $166 million (in real 2016 $).

Under these circumstances, the question arises: Should construction of the Site C Project be suspended or cancelled? To answer this question, the final three sections of the report assess and compare the financial implications of the following three options, using June 30, 2017 as the decision date:

a) Continue with construction of the Site C Project to completion as scheduled;
b) Cancel the Site C project in order to develop alternative resources; or
c) Suspend the Site C project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant.

Section 5 analyzes the costs of cancelling or suspending the Site C Project. BC Hydro will have incurred on the order of $1.87 billion in sunk costs to develop the Site C Project by June 30, 2017. The analysis considers these sunk costs as well as costs related to contract cancellation and demobilization, and potential site maintenance while the project is in suspension. Alternative resources considered include energy- and capacity-focused demand-side management, as well as supply-side energy and capacity resources.

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[3] In a previous study, we explored in detail the expected GHG emissions of the Site C Project. Report available at: https://watergovernance.ca/projects/sitec/report-4-site-c-comparative-ghg-analysis/

Section 5 also documents the fact that BC Hydro is dramatically reducing energy conservation (Demand Side Management (DSM)) program spending now and into the future, despite the fact that this is one of the cheapest options available to the utility. Specifically, Site C electricity costs are about three times as much as DSM costs.

Section 6 explores whether or not, and under what conditions, cancelling or suspending the Site C Project would be the least-cost solution going forward. The section begins with a review of the analysis of alternatives undertaken by BC Hydro in its 2013 IRP. Since the time of that analysis, several circumstances have changed. In addition to the collapse in BC Hydro's load forecast, the cost of the Site C Project has increased $435 million, and the cost of wind resources has declined by about 20% and is projected to decline a further 20% by 2030.

The first analysis evaluates whether the decision in December 2014 to proceed with the Site C Project, with the benefit of over two years' hindsight, was optimal. This analysis demonstrates that, if the clock could be turned back to December 2014, a Final Investment Decision not to proceed with the Site C Project would have resulted in savings of $1.4 to $1.7 billion.

The subsequent analyses examine the economic implications of continuing, cancelling or suspending the construction of the Site C Project under a number of different scenarios. The findings indicate that cancelling the Site C Project and continuing down an alternative path would save ratepayers $520 to $800 million, depending on the load forecast. In the event that the Site C Project incurs a 25% cost overrun, cancelling the Project would save ratepayers on the order of $1.2 to 1.5 billion, again depending on the load forecast scenario.

The analysis also tests the effects of lower and higher export market prices. If export market prices follow a low scenario, savings from cancelling the Project would increase to $540 to $990 million dollars, depending on the load forecast. With higher than expected market prices, the range of savings from cancelling the Project would fall to $500 to $600 million dollars.

The final analysis considers the implications of suspending as opposed to cancelling the Site C Project, leaving open the possibility of resuming construction if circumstances warrant. Regardless of BC Hydro's current forecasts of load growth, suspending the Site C Project would save ratepayers $800 to $870 million, depending on the load forecast, compared to completing the Site C Project in F2024. The analysis concludes that suspending the Site C Project is preferable to cancelling the Site C Project, with a potential benefit of up to $350 million dollars.

In summary, our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions, despite the fact that BC Hydro will have incurred on the order of $1.87 billion in costs. Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. All alternative scenarios considered have very low greenhouse gas emissions. Both cancelling and suspending are preferable to continuing with the Site C Project.

2. Justification for the Site C Project

2.1 Historical, regulatory and policy context

2.1.1 *Two Rivers Policy*

The Site C Project follows from a policy first formulated in British Columbia in the 1950s. The *Two Rivers Policy* called for large-scale hydroelectric development on both the Peace River and Columbia River systems. The result was the development on the Peace River of two projects: the Bennett Dam, including the GM Shrum Generating Station and the Williston Reservoir in 1968, and the Peace Canyon Dam, including the Dinosaur Reservoir, in 1980.

In the early 1980s, BC Hydro applied to the BC Utilities Commission (BCUC) for review of its proposed third project on the Peace River, the Site C Project. The Commission was tasked with reviewing the project's justification, design, impacts and other relevant matters, and recommending whether and under what conditions an approval should be granted.[4]

Upon review, the Commission raised a number of "major issues" with respect to the demand forecasts prepared by BC Hydro, as detailed in its report, including:

- forecast methodology;
- the role and forecast of key underlying variables;
- specific factors such as industrial sector growth, technological change, interfuel substitution, conservation and self-generation; and
- prospects and potential in the export market.[5]

The issues raised by the Commission remain central to the current evaluation of BC Hydro's forecasted requirements for electrical energy[6] and capacity,[7] and the suitability of the Site C Project for meeting those requirements.

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[4] British Columbia Utilities Commission. 1983. Site C Report: Report & Recommendations to the Lieutenant Governor-in-Council, p.1. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf)

[5] British Columbia Utilities Commission. 1983. Site C Report: Report & Recommendations to the Lieutenant Governor-in-Council, p.57. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf)

[6] "Energy" means the amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

[7] "Capacity" means the power produced or demanded at a particular time, usually measured in kilowatts (kW) or megawatts (MW).

2.1.2 *Clean Energy Act*

BC Energy Objectives

The *Clean Energy Act* (2010) sets out the framework for assessing the need for electricity to be provided by BC Hydro, and for evaluating the alternatives to meeting that need by establishing energy objectives for British Columbia. These energy objectives include the following:

- to achieve electricity self-sufficiency;
- to take demand-side measures and to conserve energy, including BC Hydro reducing its expected increase in demand for electricity by the year 2020 (F2021)[8] by at least 66%;
- to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship,[9] from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
- to ensure that BC Hydro's rates remain among the most competitive of rates charged by public utilities in North America;
- to reduce BC greenhouse gas emissions as determined under the *Greenhouse Gas Reduction Targets Act*;
- to encourage communities to reduce greenhouse gas emissions and use energy efficiently;
- to reduce waste by encouraging the use of waste heat, biogas and biomass; and
- to achieve British Columbia’s energy objectives without the use of nuclear power.

In essence, the *Clean Energy Act* sets a course for reducing greenhouse gas emissions through energy conservation, energy efficiency, and generation of clean (i.e. low-carbon) electricity. It also imposes severe limitations on electricity imports through the self-sufficiency requirement, which includes prohibition on the use of the Canadian Entitlement under the Columbia River Treaty, and prohibits the use of nuclear power. Though not listed among its objectives, the *Act* also prohibits the development of eleven other potential large-scale hydroelectric projects in the Province.[10]

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[8] BC Hydro conducts its planning on the basis of its fiscal year, which begins on April 1 and ends on March 31. So, for example, the calendar year 2020 is equivalent to the fiscal year 2021, abbreviated as F2021.

[9] As per British Columbia’s Energy Objectives Regulation (B.C. Reg. 234/2012). (Accessed 17 April 2017 at: https://www.canlii.org/en/bc/laws/regu/bc-reg-234-2012/latest/bc-reg-234-2012.html)

[10] *Clean Energy Act*, SBC 2010, c 22, Schedule 2 Prohibited Projects.

Importantly, the *Clean Energy Act* also sets the objective of maintaining competitively priced electricity, which therefore prioritizes the development of the lowest-cost low-carbon electricity resources. For example, where conservation and energy efficiency (i.e. "demand-side management" or "DSM") are lower cost, they would take priority over the development of clean or renewable energy, including hydroelectric projects like Site C, wind, biomass, solar and geothermal (i.e. "supply-side resources").

Integrated Resource Plan

In addition to establishing energy objectives, the *Clean Energy Act* also requires BC Hydro to submit, every five years, an integrated resource plan that includes:

- a description of BC Hydro's energy and capacity forecasts; and
- a description of what BC Hydro plans to do to achieve electricity self-sufficiency and to respond to British Columbia's other energy objectives.

BC Hydro prepared and submitted its 2013 IRP in response to these requirements, and the Lieutenant Governor in Council approved the Plan with some modifications on November 25, 2013. The findings and recommendations of the 2013 IRP were used to support the joint federal-provincial environmental assessment of the Site C Project (conducted by the Joint Review Panel or JRP).[11]

BC Hydro has recently initiated planning and consultation for the 2018 IRP, which is scheduled to be completed by November 2018.

BCUC exemptions[12]

The *Clean Energy Act* exempts several projects, including the Site C Project, from Sections 45 to 47 of the *Utilities Commission Act (UCA)*, removing the requirement for a Certificate of Public Convenience and Necessity (CPCN). By exempting the Project from the need to obtain a CPCN, the *Clean Energy Act* eliminated the process through which the Commission normally reviews the economic and technical justification of a project.

Despite this exemption, the Provincial Cabinet does have further discretion to refer the Site C Project to the Commission in order to address matters that Cabinet considers appropriate, pursuant to Section 5 of the *UCA*.[13]

Referring large-scale projects such as the Site C Project to the Commission for advice or recommendations, as opposed to binding decisions, formed a key conclusion of the independent review of the BCUC initiated by the Minister of Energy in November

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[11] See BC Hydro. November 2013. Integrated Resource Plan, Chapter 9 Recommended Actions. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf)

[12] See also UBC Program on Water Governance. 2016. Briefing Note #3: The Regulatory Process for the Site C Project, S.3.2.4, (Available at: www.waterpartners.ca/projects/sitec)

[13] *Utilities Commission Act*, RSBC 1996, c 473.

2013.[14] This review, completed before the final decision to proceed with the Site C Project, reiterated on several occasions the benefits of referring large-scale projects to the BCUC for review and recommendations.

> This provides the benefit of a public process and independent verification of projects and plans but reserves the final decision on plans and projects that have broader public interest criteria to be decided by elected officials.
>
> Broader use of section 5 is similar to the approach taken by the Federal government in its recent amendments to the *National Energy Board Act.* These amendments redefined the role of the Board, which is now mandated not to decide on applications for pipeline certificates, but to instead make a recommendation to the Federal Cabinet.[15,16]

2.1.3 Climate Leadership Plan

Released in August 2016, following approval of the Site C Project, the Climate Leadership Plan sets out a number of actions designed to support BC's climate change policy objectives. These actions include:

- supply 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed;
- electrification of natural gas production, processing and transmission, all currently fuelled by natural gas and diesel fuel, to reduce greenhouse gas emissions;
- expanding the mandate of BC Hydro's DSM programs to include investments that increase efficiency and reduce GHG emissions;
- expanding the Clean Energy Vehicle Program; and
- amending the energy efficiency standards regulation.

These actions will have implications for future requirements for low-carbon electricity that were not contemplated at the time of the decision to proceed with the Site C Project in 2014. They are therefore relevant to any determination of whether to continue the Site C Project to completion as scheduled, cancel the project, or suspend the project leaving open the possibility of resuming the project if future circumstances warrant.

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[14] BCUC Review Task Force. 2014. Independent Review of the British Columbia Utilities Commission Final Report, p.39. (Accessed 17 April 2017 at: http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bcuc_review_final_report_nov_14_final.pdf)

[15] BCUC Review Task Force. 2014. Independent Review of the British Columbia Utilities Commission Final Report, p.39. (Accessed 17 April 2017 at: http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bcuc_review_final_report_nov_14_final.pdf)

[16] Unless stated otherwise, all underlining of quotations in this report is emphasis added by this report's authors.

2.1.4 Environmental assessment

In August 2011, the provincial and federal governments commenced environmental assessment of the Site C Project pursuant to the BC *Environmental Assessment Act* and the *Canadian Environmental Assessment Act, 2012 (CEAA)*. To avoid duplication of effort, the two levels of government collaborated in the development of a Joint Review Panel Agreement,[17] establishing an independent three-person Joint Review Panel (JRP) to review and report to the Ministers respecting the matters detailed in the JRP Terms of Reference and the Environmental Impact Statement (EIS) Guidelines, incorporated into the Agreement.

The EIS Guidelines for the conduct of the environmental assessment required that the EIS:

- provide the fundamental rationale for proceeding with the development at this time within the relevant legal and policy context;
- describe the functionally different ways to meet the need for the Project;
- contain an analysis of technically and economically feasible alternatives to the Project; and
- complete that analysis to a level of detail sufficient to compare the proposed project with its alternatives.[18]

In its submissions before the JRP, BC Hydro stated that **the purpose of the Site C Project is to cost-effectively meet BC Hydro's forecasted need for energy and capacity**.[19] Thus, the forecasting of those needs and the cost-effectiveness of the alternatives was a key consideration during the review.

BC Hydro also presented information during the environmental assessment concerning the GHG emissions from the Site C Project. These emissions from both construction and operations total 5.5 MT CO_2e by 2034, 6.0 MT CO_2e by 2054, and 6.8 MT by 2124, 100 years following commissioning.[20]

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[17] The Minister of the Environment, Canada – The Minister of Environment, British Columbia. February 2012. Agreement to Conduct a Cooperative Environmental Assessment, including the Establishment of a Joint Review Panel, of the Site C Clean Energy Project, (Accessed 17 April 2017 at https://www.ceaa.gc.ca/050/documents/54272/54272E.pdf)

[18] BC Environmental Assessment Office – Canadian Environmental Assessment Agency. 2012. Site C Clean Energy Project Environmental Impact Statement Guidelines, pp.15-16. (Accessed 17 April 2017 at http://www.ceaa-acee.gc.ca/050/documents/p63919/81197E.pdf)

[19] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement, Volume 1 – Section 5: Need for, Purpose of, and Alternatives to the Project, p.5-22, lines 22-23. (Accessed 17 April 2017 at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328).

[20] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 2: Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd., Table 9.9, Table 9.11, Table C-4. (Accessed 17 April 2017 at: http://www.ceaa-acee.gc.ca/050/documents_staticpost/63919/85328/Vol2_Appendix_S.pdf).

On a per unit energy basis the Site C Project delivers both energy and capacity with very low GHG emissions, which is a key advantage of the Project. But these emissions are not zero, and other alternatives also deliver energy and capacity with very low GHG emissions.[21]

The JRP concluded in its final report issued in May 2014 that the Site C Project would likely result in an unprecedented number of significant adverse environmental effects, including in relation to First Nation use of lands and resources for fishing, hunting and trapping.[22] A determination of significant adverse environmental effects is uncommon, and has occurred for only 12 of over 120 major projects assessed since the coming into force of the *CEAA* in 1995, as summarized below in Table 1. As this table illustrates, the number of significant adverse environmental effects determined by the JRP is far beyond that determined for any other project ever assessed under the *CEAA*.

The numerous adverse environmental effects of the Site C Project represent a key disadvantage of the Project. While the alternatives to the Site C Project would also have environmental effects, it is very unlikely that any of these effects would be significant.[23]

The JRP also reached conclusions and made recommendations to the Ministers respecting several matters concerning the need for the Site C Project, most importantly that BC Hydro had not fully demonstrated the need for the Project on the proposed timetable, namely for an in-service date of F2024. As a result of this and other conclusions, the JRP recommended referral of key matters to the BC Utilities Commission for further review, including the costs of the Site C Project, the load forecast, long-term electricity prices, and the demand-side management plan.[24]

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[21] For a comparison of the GHG emissions of the Site C Project and these alternatives, see: Hendriks, R.M. July 2016. Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. UBC Program on Water Governance. (Available at: www.waterpartners.ca/projects/sitec)

[22] Site C Joint Review Panel. May 2014. Report of the Joint Review Panel: Site C Clean Energy Project BC Hydro, pp.310-323. (CEAR #63919-2771). (Accessed 17 April 2017 at: https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf)

[23] For a comparison of the environmental effects of the Site C Project and these alternatives, see: UBC Program on Water Governance. 2016. Briefing Note #2: Assessing Alternatives to Site C: Environmental Effects Comparison, (Available at www.waterpartners.ca/projects/sitec)

[24] Site C Joint Review Panel. May 2014. Report of the Joint Review Panel: Site C Clean Energy Project BC Hydro, p.323-325. (Accessed 17 April 2017 at: https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf)

Table 1: Significant adverse environmental effects under the *CEAA*[25]

Project	Number of Significant Effects
Site C Clean Energy Project	20
New Prosperity Gold and Copper Mine Project	5
Lower Churchill Hydroelectric Generation Project	5
Jackpine [Oilsands] Mine Expansion Project	5
Pacific Northwest LNG[26]	3
Encana Shallow Gas Infill Development Project	2
Cheviot Coal Project	2
Kemess North	2
Northern Gateway Project	1
White Pines Quarry	1
LNG Canada	1
Labrador-Island Transmission Link	1

2.2 Approval of the Site C Project

2.2.1 Environmental assessment decisions

In October 2014, following a period for review and consultation on the final report issued by the JRP, both the provincial and federal governments issued their environmental assessment decisions.

In its decision, the Government of Canada agreed that the Site C Project was likely to cause significant adverse environmental effects under *CEAA 2012*, but that these significant adverse environmental effects were justified in the circumstances.[27] In making these determinations, the federal government provided no information respecting the framework for its justification process, no description of the contextual circumstances, no responses to the recommendations from the JRP, and no reasons for its decision.

The Provincial Government, through the BC Environmental Assessment Office (EAO) issued an Environmental Assessment Certificate to BC Hydro in relation to the Site C Project in October 2014. This approval was accompanied by a response from the Executive Director of the EAO to the recommendations of the JRP. With respect to the

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[25] For details concerning the nature of the significant adverse environmental effects, see: UBC Program on Water Governance. 2016. Briefing Note #2: Assessing Alternatives to Site C: Environmental Effects Comparison, Table 2.1 and Table 2.2. (Available at www.waterpartners.ca/projects/sitec)

[26] For details concerning the significant adverse environmental effects see: Canadian Environmental Assessment Agency. September 2016. Pacific Northwest LNG Project Environmental Assessment Report, p.189. (Accessed 17 April 2017 at: https://www.ceaa.gc.ca/050/documents/p80032/115668E.pdf)

[27] PC 2014-1105. (Accessed 17 April 2017 at: http://www.pco-bcp.gc.ca/oic-ddc.asp)

JRP recommendations to refer key matters to the BC Utilities Commission for further review, the EAO did not accept them, deeming these matters to be "outside of the scope of the Panel's mandate".[28] No further action has been taken to date by the Provincial Government in relation to these recommendations.

2.2.2 Final Investment Decision (FID)

As the sole shareholder and owner of BC Hydro, the Provincial Government had the responsibility for deciding whether or not to initiate the Site C Project. In announcing its decision to authorize development of the Site C Project in December 2014, the Province stated that:

> …[Site C would] provide British Columbia with the most affordable, reliable clean power for over 100 years.[29]

This observation provides insight into the process used by the Provincial Government in making the decision to proceed with the Site C Project in the face of the Project's many significant adverse environmental effects, and implications for First Nations rights.[30] More recently, the Provincial Minister of Energy and Mines stated the following:

> The [Site C] hydroelectric project will deliver the lowest-cost, cleanest power available," the minister said, although he conceded it would have adverse environmental impacts … .[31]

As noted above in Section 2.1.4, the JRP concluded that the Site C Project would likely result in an unprecedented number of significant adverse environmental effects, including in relation to First Nation use of lands and resources for fishing, hunting and trapping. Thus the **significant adverse environmental effects of the Site C Project were justified by government based on the premise that the Project will deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives**.

The following sections of this report explore these claims in the context of the information publicly available at the time the decision was made to proceed with the Site C Project, as well as information that has become available since that time.

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[28] BC EAO. 2014. EAO Executive Director's Response to the Joint Review Panel Report for BC Hydro's Site C Clean Energy Project, pp.14-15. (Accessed 17 April 2017 at: https://projects.eao.gov.bc.ca/p/site-c-clean-energy/docs)

[29] Government of British Columbia. December 16, 2014. "Site C to provide more than 100 years of affordable, reliable clean power". (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

[30] UBC Program on Water Governance. 2016. Briefing Note #1: First Nations and Site C. (Available at: www.waterpartners.ca/projects/sitec)

[31] "Ottawa pushes ahead with Site C dam amid opposition from academics," Globe & Mail, May 24, 2016. (Accessed 17 April 2017 at: http://www.theglobeandmail.com/news/british-columbia/royal-society-of-canada-academics-call-on-ottawa-to-halt-site-c-project/article30127279/)

3. Revisiting future electricity needs

3.1 Evolution of future electricity requirements

This Section 3 focuses on the evolution of BC Hydro's future domestic electricity requirements, which are a key consideration in evaluating the need for the Site C Project. Section 3.2 extensively reviews BC Hydro's historical load forecasts, recently filed with the BCUC, demonstrating the utility's consistent overestimating of actual future requirements. Section 3.3 explores the dramatic decline in BC Hydro's most recent 2016 Load Forecast compared to the 2012 Load Forecast used to justify the Site C Project. Section 3.4 explores the potential that low-carbon electrification, as a means to reduce greenhouse gas emissions, could advance requirements for electricity. A summary of the findings is provided in Section 3.5.

Throughout its planning, assessment and promotional documentation, BC Hydro framed the need for the Site C Project as follows:

> Site C is required to meet the long-term energy and capacity needs of BC Hydro's residential, commercial and industrial customers. BC Hydro forecasts that the province's electricity needs will grow by approximately 40 per cent over the next 20 years, not accounting for savings that can be achieved through conservation and efficiency measures.[32]

The purpose of the Site C Project, as proposed by BC Hydro, is to meet British Columbia's domestic electricity requirements. The Site C Project is not an export project designed to meet requirements of other jurisdictions in the United States or Canada.

The justification for proceeding with the Site C Project at this time hinges on BC Hydro's forecast that the province's electricity needs will grow by 40% over the next 20 years. Importantly, this is before accounting for energy savings from conservation and efficiency (i.e. DSM). After accounting for DSM, BC Hydro's most recent forecast projects that electricity needs will grow by 30%,[33] meaning that BC Hydro is projecting that DSM will play only a modest role in reducing future electricity requirements. This is surprising since BC Hydro currently projects that DSM will meet more than 100% of the utility's needs to F2021, even if the utility were to immediately and entirely discontinue future spending on DSM programs.[34] This issue of the fate of DSM is considered in

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[32] BC Hydro. 2016. Site C Clean Energy Project – About Site C: Project Need. (Accessed 17 April 2017 at: https://www.sitecproject.com/why-site-c/project-need)

[33] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. F2016 – 57,310 GWh/year and F2036 – 74,348 GWh/year. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document)

[34] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 10-5. BC Hydro would still rely only on DSM savings from codes, standards and rate impacts. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

greater detail in section 5.3.1. Here, the first task is to consider the accuracy of BC Hydro's historical forecasts.

3.2 BC Hydro's historical load forecasts of domestic requirements

3.2.1 The factors affecting load forecasting

BC Hydro's future domestic requirements for electrical energy and capacity are inherently uncertain. The rate of growth (stagnation or contraction) in these requirements can be influenced by multiple, highly variable factors, including the following:

- rates of economic and income growth;
- population growth and residential sector consumption growth;
- commercial sector growth;
- industrial sector growth;
- shifts in the economy towards services, which generally consume less energy;
- the cost of energy from alternative energy sources, including the influence of carbon pricing, and cross-price elasticity effects on electricity demand;
- the price of electricity and own-price elasticity effects on electricity demand;
- the use of on-site electricity or alternative energy supply resources that reduce requirements for electricity from the interconnected grid;
- demand-side management, including technological evolution and costs; and
- the extent of low-carbon electrification to reduce greenhouse gas emissions.

Considering these multiple highly variable factors, no forecast will be entirely accurate at projecting requirements, particularly many years into the future. Forecasts that are too low may result in energy or capacity shortfalls that trigger additional costs to import or operate more costly generation during peak demand periods or, in extreme circumstances, have implications for system reliability. However, forecasts that are too high may result in advancing supply-side resources prior to actual needs, resulting in additional and unnecessary costs to ratepayers when surplus energy must be sold at prices below the costs of production.

Utilities rightly treat these risks asymmetrically, since underestimating future requirements involves a risk to reliability that overestimating does not. Thus, BC Hydro builds a number of additional factors into its energy and capacity forecasting, including the following:

- a capacity reserve equal to 14% of supply;
- the potential for additional market reliance;

- the potential to make use of energy and capacity from the Canadian Entitlement under the Columbia River Treaty;[35]
- the potential for capacity-focused DSM and additional load-shedding; and
- planned renewal of only 50% of biomass EPAs and 75% of run-of-river hydroelectric EPAs.

These measures are designed to address this asymmetry of risk. However, it is not good utility practice to overforecast in order to reduce these risks. Indeed, in the JRP hearings for the Site C Project, BC Hydro declared that good forecasting entails predictions that are wrong as much in one direction as in the other.

> [BC Hydro Manager of Market Forecasting]: One of the key principles of the forecast is that we try not to bias it. So it's a P50 forecast. That's what we endeavour for. So, hopefully, my legacy will be that 20 years from now… that 50 percent of the time, my forecasts would have been too high and 50 percent too low, so with no intention of bias.[36]

However, a review of past BC Hydro load forecasts demonstrates that this has not been the case.

3.2.2 "Optimistic" load forecasting

In response to recent BCUC concerns respecting whether this pattern "is an indication of a statistical bias, accurate forecasting issues and/or a random occurrence",[37] BC Hydro recently filed its load forecasts from 1964 to 2016 with the Commission, along with data showing actual electrical energy requirements over that same period.[38]

Since 1981, BC Hydro has prepared 36 load forecasts, including a total of 553 data point estimates of future energy requirements in specific future years. If BC Hydro's approach were statistically unbiased, then half of these projections would be overestimates and half underestimates. BC Hydro's data reveal, though, that **85%** of these data point projections were overestimates. **Since Site C was initially proposed in the early 1980s, BC Hydro's load forecasts have consistently overstated future growth in electricity requirements.**

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[35] See Section 5.4.2 below.

[36] Canadian Environmental Assessment Agency and BC Environmental Assessment Office. January 23, 2014. In the Matter of the Joint Review Panel Established to Review the Site C Clean Energy Project Proposed by British Columbia Hydro and Power Authority. Proceedings at Hearing, Volume 28, p.22-23. (Accessed 17 April 2017 at http://www.ceaa-acee.gc.ca/050/documents/p63919/98182E.pdf.)

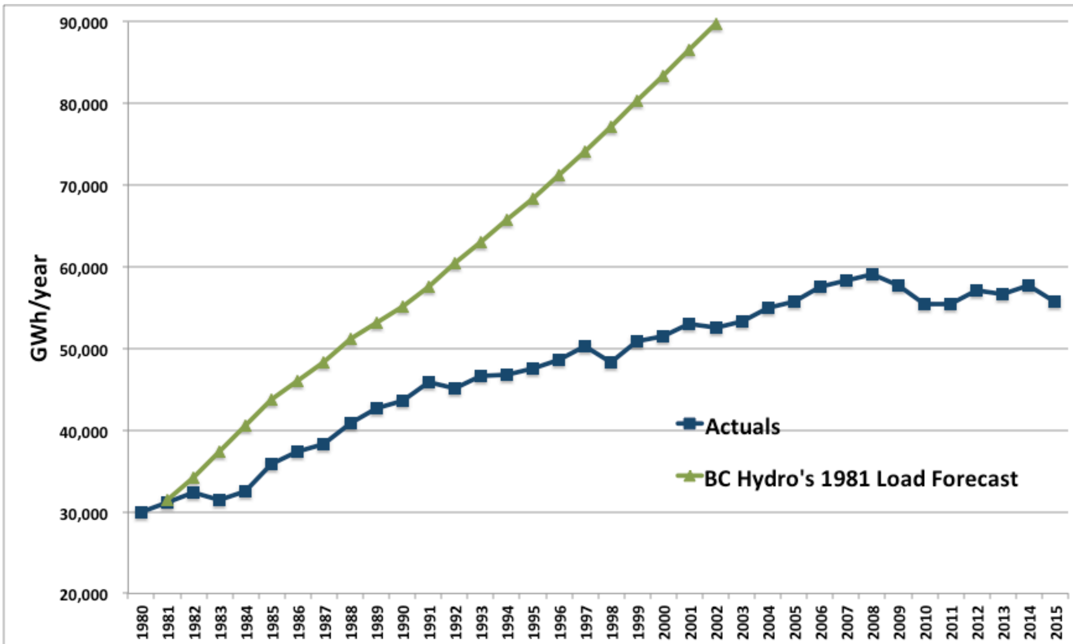
[37] BC Hydro. November 21, 2016. F2017 to F2019 Revenue Requirements Application, Response to Information Request BCUC 1.4.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[38] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

Since 1992, when BC Hydro began producing annual forecasts, **89.5%** of the utility's mid-load projections were overestimates. These estimates in fact could be better described as a high-load forecast, defined as a forecast that is expected to exceed actual future requirements 90% of the time.[39]

In its submissions to the BCUC in support of the Site C Project in 1981, **BC Hydro's "probable" or "mid-load" forecast predicted that system-wide energy demand would increase from 31,450 GWh/year in F1981 to 90,000 GWh by F2002**, net of conservation.[40] This load forecast is presented in Figure 1 below.

Figure 1: BC Hydro's F1981 Load Forecast (after DSM)[41]



The overestimation of future requirements is dramatic. In fact, even the 60,500 GWh forecast for F1992, when BC Hydro proposed to commission the Site C Project, has yet to be reached twenty-five years later. In BC Hydro's most-recent forecast contained in its 2016 RRA, the utility forecasts that integrated system requirements net of planned

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[39] Or to state this another way, the high-load forecast has a probability of being exceeded by actual requirements 10% of the time.

[40] British Columbia Utilities Commission. 1983. Site C Report: Report & Recommendations to the Lieutenant Governor-in-Council, p.76. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf)

[41] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

DSM are now expected not to exceed this value until F2023,[42] or more than thirty years later than initially forecast in 1981.

The Commission concluded at that time that: “Hydro’s ‘probable’ load forecast should be considered as optimistic”[43] and recommended that the provincial Cabinet:

> …defer issuing an Energy Project Certificate for Site C until an acceptable load forecast demonstrates that construction of Site C must begin immediately in order to avoid supply deficiencies, and a comparison of alternative system plans demonstrates that Site C is the best project to meet the anticipated shortfalls.[44]

As discussed below, BC Hydro’s tendency toward overly “optimistic” load forecasts has continued to the present.

3.2.3 F1992 to F2008 load forecasts

In 1992, BC Hydro began its current practice of producing 20-year forecasts of future energy requirements. Figure 2 illustrates BC Hydro’s forecasts of future energy requirements after DSM against actual requirements for the F1992 through F1999 and F2000 through F2008 periods, respectively.

The forecasts from F1992 through F1999 all overstated actual requirements from F2001 through F2008 (the dark “Actuals” line), and drastically overstated actuals for the period since the 2008-2009 recession. The F1992 through F1995 load forecasts all overstate demand 20 years later by on the order of 11,000 to 18,000 GWh/year. With respect to current requirements, in its 2016 RRA, BC Hydro reported total gross system requirements after DSM of 55,674 GWh in F2016,[45] meaning that the utility’s forecasts from 1996 through 1999 overstated current requirements by 14,000 to 18,000 GWh/year. This is about three times the average annual generation of the Site C Project (5,100 GWh/year).

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[42] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

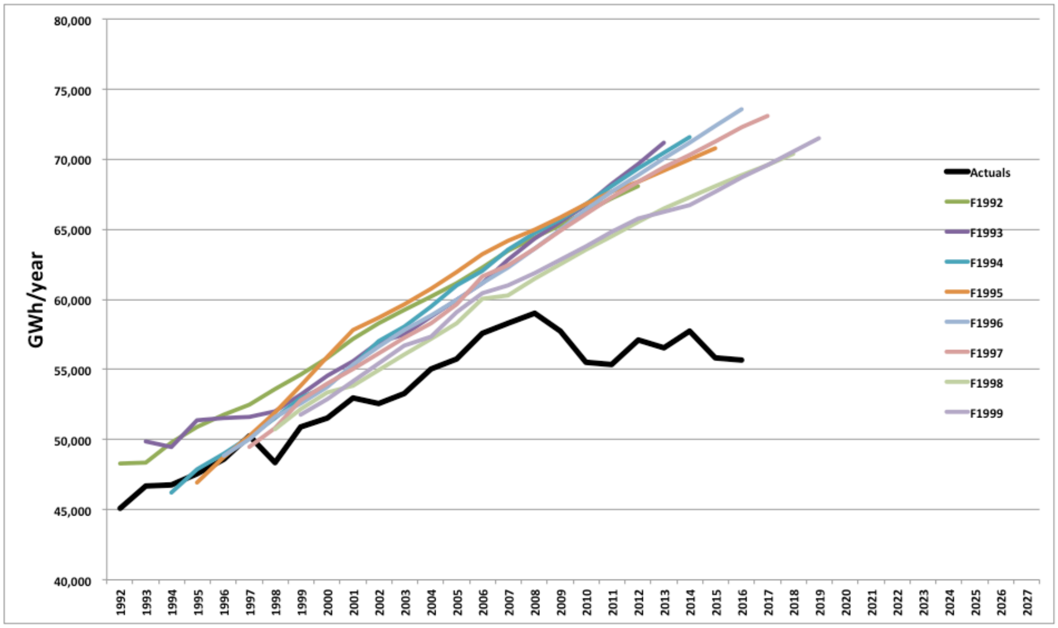
[43] British Columbia Utilities Commission. 1983. Site C Report: Report & Recommendations to the Lieutenant Governor-in-Council, p.85. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf)

[44] British Columbia Utilities Commission. 1983. Site C Report: Report & Recommendations to the Lieutenant Governor-in-Council, p.23. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/19830500%20Report%20and%20Recommendations%20to%20the%20Lieutenant%20Governor%20in%20Council%20-%20BCH.pdf)

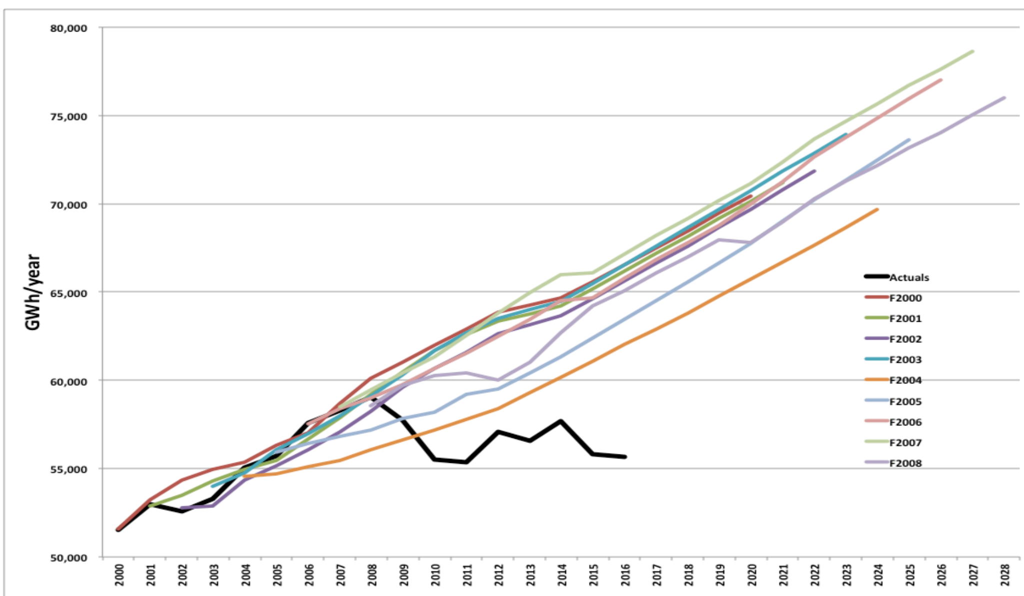
[45] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.1-6. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

Figure 2: BC Hydro forecasts of total gross requirements[46], after DSM

a) F1992 to F1999



b) F2000 to F2008



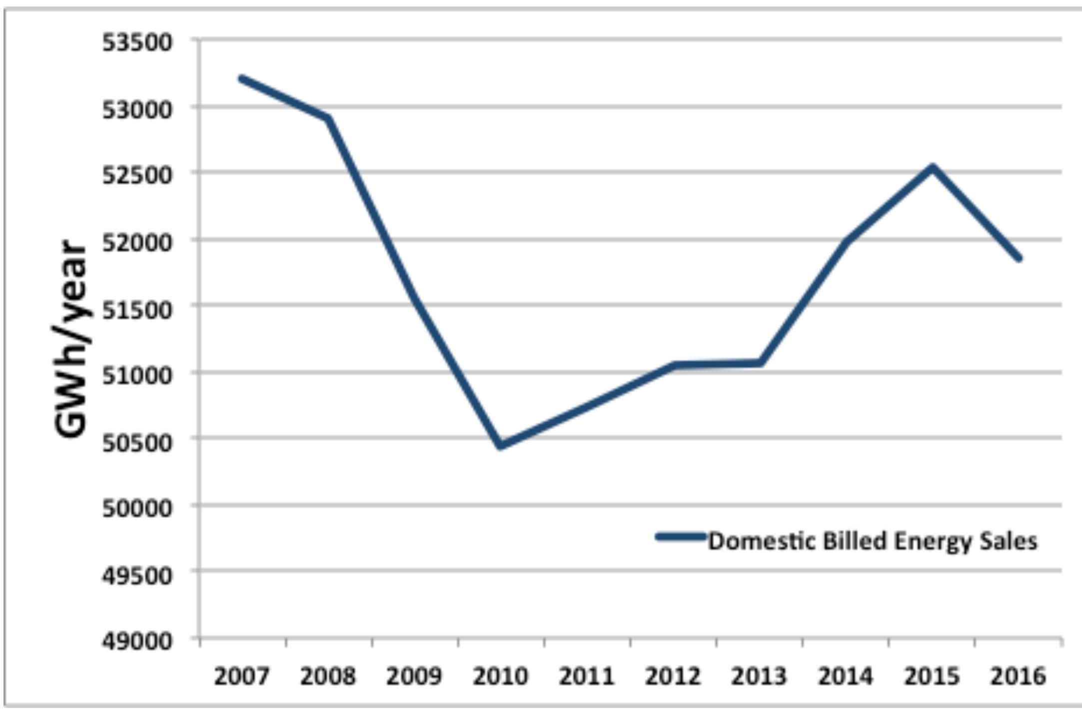
[46] Total gross system requirements include: sales to the residential, commercial and industrial customer classes plus sales to other utilities, and adjusted for system line losses. To determine gross energy requirements for only the integrated system, sales and line losses to all non-integrated areas are excluded.

BC Hydro's projections from F2000 to F2005 were more consistent with actual requirements, but only within the first few years of the forecast period. None of the forecasts appears to have contemplated the potential for a recession in the 20-year forecast period. This despite the acknowledgement by BC Hydro that there have been six recessionary periods, or about one per decade, for the period of readily available data dating to 1964.[47] The forecasts from F2000 through F2008 overstate current requirements by 6,500 to 11,500 GWh/year (one to two times the annual generation of the Site C Project).

3.2.4 F2009 to F2016 load forecasts

In its responses filed for the 2016 RRA, BC Hydro notes that since F2010: "total domestic temperature adjusted billed sales has increased in total by 1,421 GWh or 2.8 percent".[48] While this is true, it fails to acknowledge the overall decline in the years 2007 to 2016, as illustrated in Figure 3.

Figure 3: Total domestic temperature adjusted billed sales – F2007 to F2016



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47 BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEBC 2.133.4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

48 BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEBC 2.133.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

Furthermore, this is not indicative of a longer-term growth trend; particularly since temperature adjusted billed sales in F2016 were actually lower than they were in F2014. The evidence is insufficient to draw conclusions about the average rate of growth (stagnation or contraction) going forward from the 2008-2009 recession.

Figure 3 **demonstrates that actual domestic billed energy sales in F2016 were 51,861 GWh/year, less than they were a decade earlier**.[49,50] Indeed, domestic energy sales are now projected by BC Hydro not to exceed those of F2007 until at least F2020 under its mid-load forecast.[51] The stability in BC Hydro's domestic energy sales[52] over the past decade is presented in Figure 4, which illustrates that domestic energy sales have remained between 48,000 and 52,000 GWh/year since F2004.

Though BC Hydro's load forecasts have consistently anticipated growth in its domestic energy requirements, that growth has not materialized, which explains the recent comments of the Minister of Energy and Mines, Bill Bennett.

> British Columbia's electricity requirements this year are the same as they were eight years ago, a trend that means new clean-energy capacity is not a priority.[53]

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[49] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[50] The difference of 10,159 GWh between the total domestic energy sales before DSM of 62,987 GWh in F2017 and the actual domestic sales now projected to be 51,860 GWh in F2017 illustrates the substantial role that DSM plays in meeting BC Hydro's domestic requirements.

[51] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[52] Domestic energy sales include residential, light industrial and commercial, large industrial and here excludes "other energy sales". Since 2012, BC Hydro began to include surplus energy sales in "other energy sales", and removing this category allows comparisons across the entire 20-year period, and more accurately reflects the evolution of domestic requirements over time.

[53] "B.C. Energy Minister says clean power projects aren't the priority", Globe and Mail, February 29, 2016. (Accessed 17 April 17 at: http://www.theglobeandmail.com/news/british-columbia/bc-energy-minister-says-clean-power-projects-arent-the-priority/article28961898/)

Figure 4: BC Hydro domestic energy sales – F1995 to F2016[54]

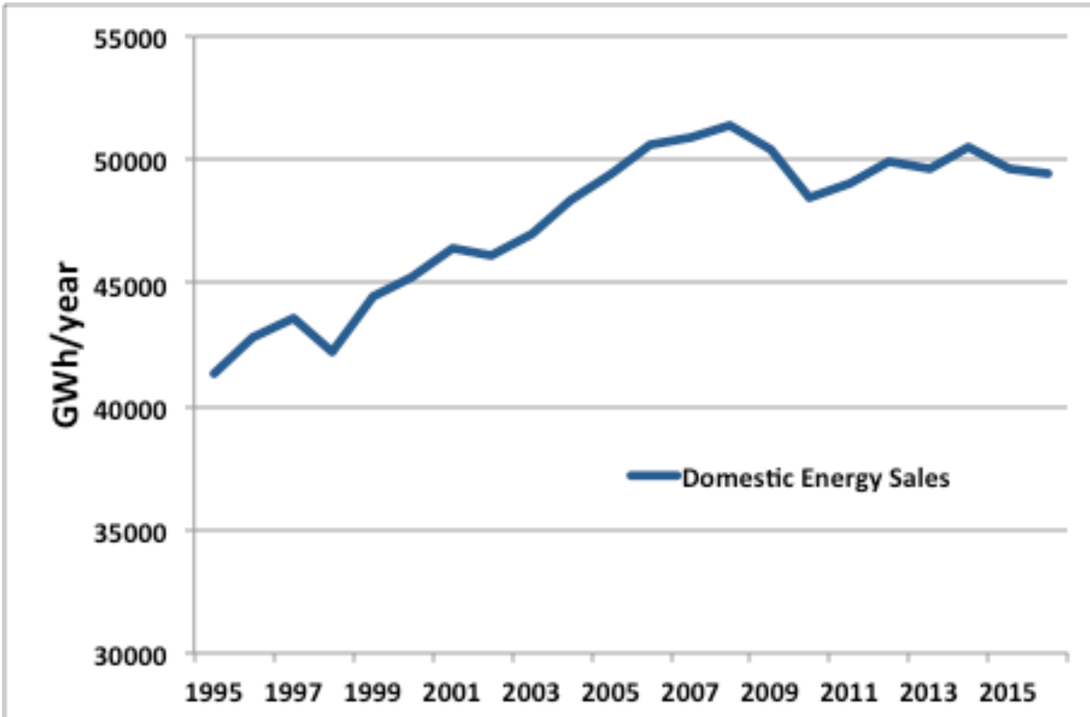

Figure 5a) presents BC Hydro's forecasts for the five years following the 2008-2009 recession. As with prior forecasts, these forecasts also predicted future requirements that are higher than actuals. However, the variability in the forecasts increased substantially over prior forecasts. **The pattern in the variability of these forecasts raises potentially disturbing questions.**

Comparing the charts in Figure 2 to Figure 5a) illustrates this unusual pattern. In Figure 2, the long-term predicted energy requirements vary between forecasts on the order of 6,000 GWh/year, while in Figure 5a) they vary by more than 15,000 GWh/year.

Figure 5a) illustrates that, from 2009 through 2013, BC Hydro's load forecast increased markedly. Using forecast loads for F2024 as an index, the load forecast increased by about 3,000 GWh/year in 2010 and 2011, by 5,000 GWh/year in 2012, and by 8,000 GWh/year in 2013. **The forecasts of energy requirements in F2024, when the Site C Project is due to be commissioned, vary from 60,592 GWh/year in the F2009 Load Forecast to 78,134 GWh/year in the F2013 Load Forecast, a difference of nearly 18,000 GWh/year – more than three times the annual generation of Site C**.

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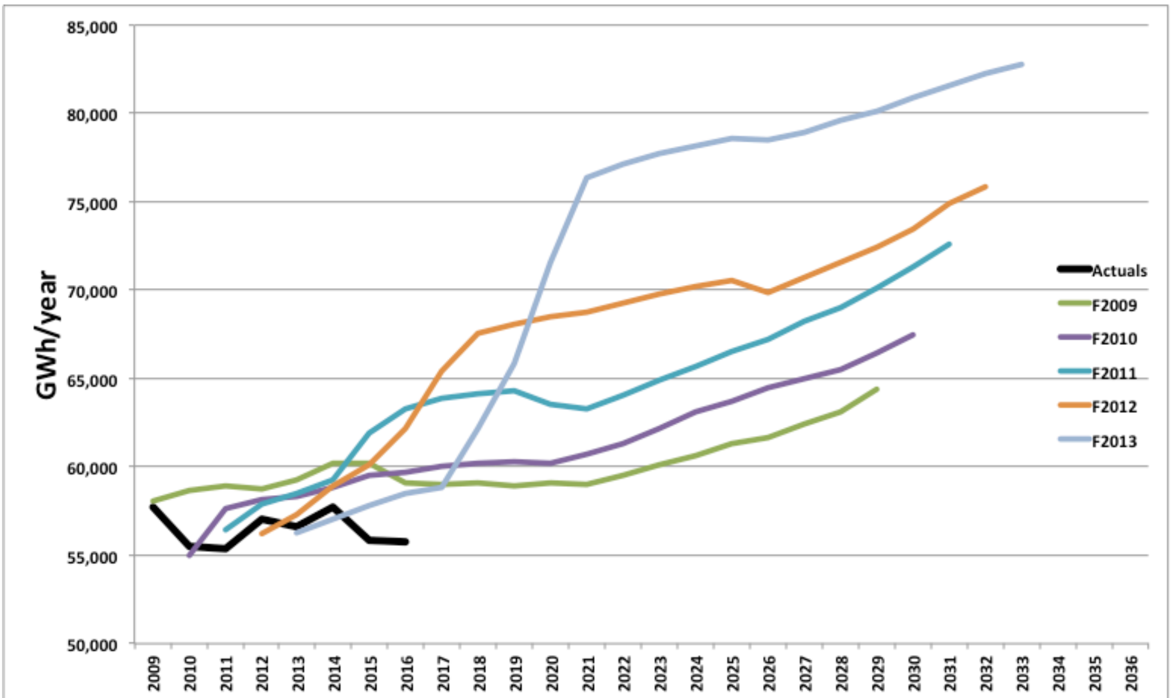
[54] BC Hydro. Annual Reports. (Accessed 17 April 2017 at: https://www.bchydro.com/about/accountability_reports/financial_reports/annual_reports.html)

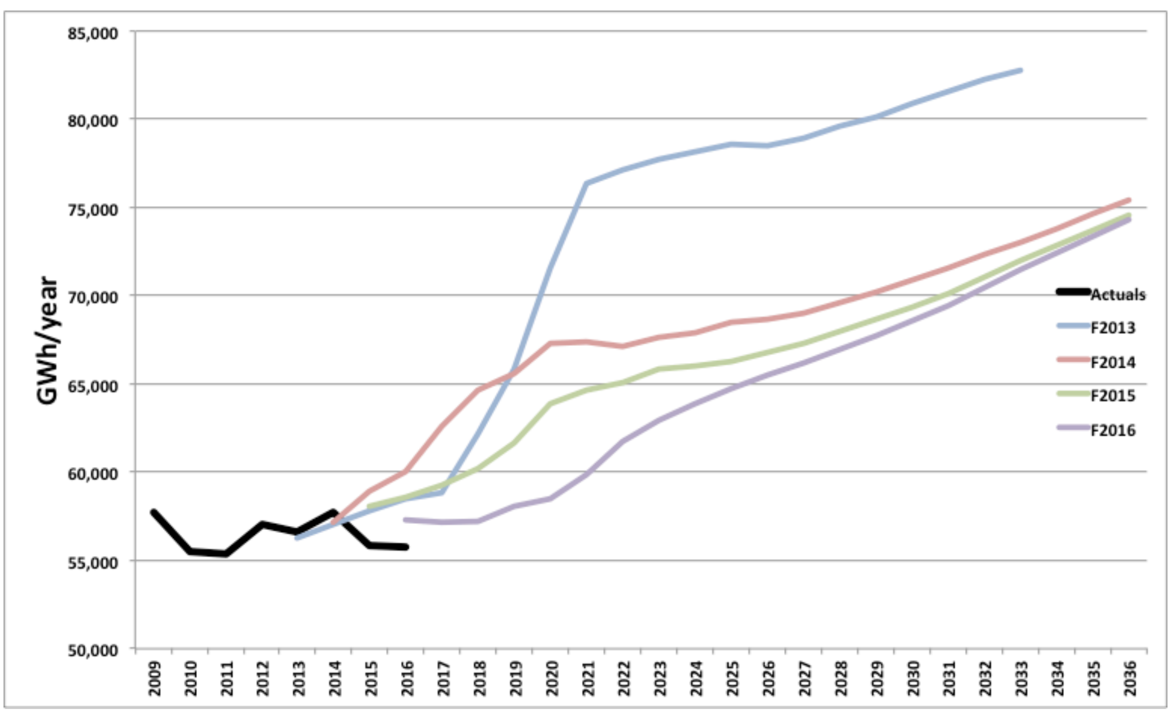
Figure 5b) presents BC Hydro's forecasts for the years 2013-2016. It shows that BC Hydro's load forecast for F2024 fell just as quickly as it had increased – by 8,000 GWh/year in 2014, and by another 2,000 GWh/year in each of 2015 and 2016.

Figure 5: BC Hydro forecasts of total gross requirements after DSM

a) F2009 to F2013



b) F2013 to F2016



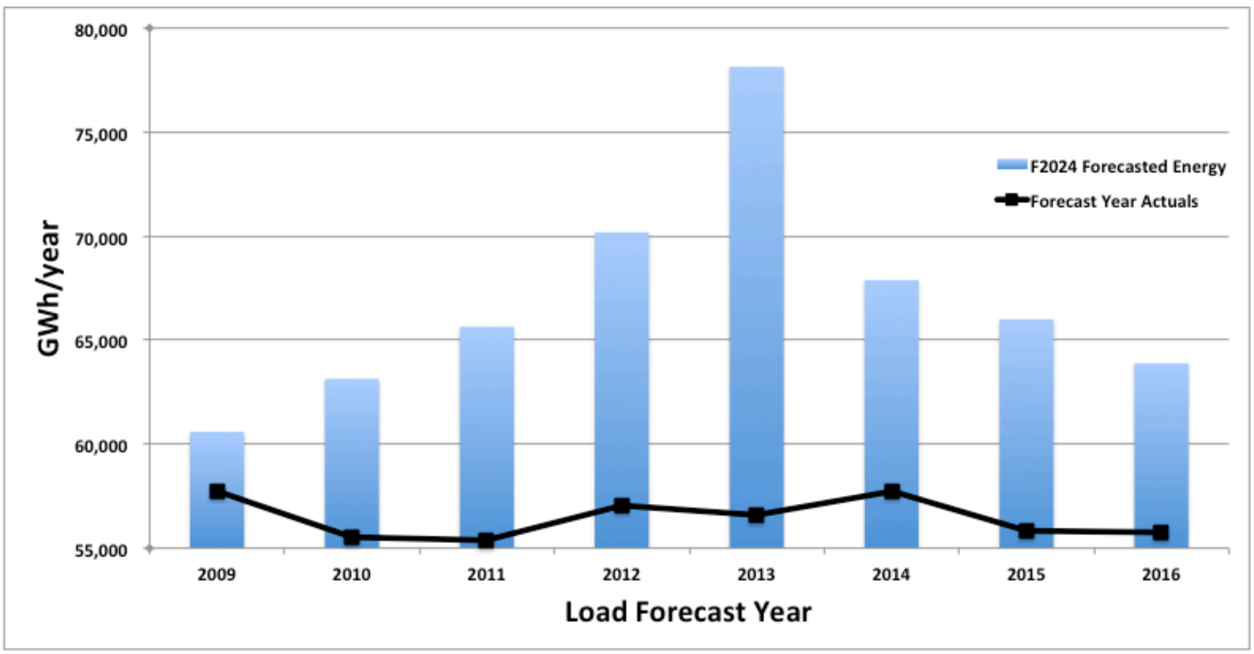
This pattern in the load forecasts for F2024 can be seen in Figure 6. In F2009, prior to the decision on the part of the Provincial Government and BC Hydro to commence the environmental assessment of the Site C Project,[55] the forecasted requirements for F2024 were barely higher than actuals in F2009. There was no forecasted load growth that would justify developing the Site C Project.

Following the decision in 2010 to proceed with the environmental assessment of the Site C Project, the forecasted requirements for F2024 increased dramatically by 18,000 GWh/year leading up to the decision to approve the Project.

Then, following the approval in F2014, the load forecasts steadily declined with projections for requirements in F2024 nearly 15,000 GWh/year lower in the F2016 Load Forecast than they were just three years earlier.

These changes in the load forecast were not reflected by any change in the actual loads, which remained flat through this entire period. This collapse in BC Hydro's load forecast is considered further below in Section 3.3.

Figure 6: Forecasted total gross requirements (after DSM) in F2024



[55] BC Hydro. January 2013. Site C Clean Energy Project Environmental Impact Statement – Volume 1: Introduction, Project Planning, and Description – Section 3: Project Overview, p.3-1. (Accessed 17 April 17 at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328)

This pattern could be seen as a reflection of the substantially increased level of uncertainty in future requirements, and of the challenges that BC Hydro is having modeling that uncertainty. **However, the pattern also raises questions about whether BC Hydro's load forecasting was strategically optimistic in order to support a favourable decision by government to develop the Site C Project.**

3.2.5 Load forecasting summary

Since the F1981 Load Forecast prepared by BC Hydro to support the development of the Site C Project, the utility has prepared a total of 35 load forecasts of 10 years or longer. Figure 7 compares BC Hydro's forecasts against actuals 10 years later.

As illustrated in this figure, BC Hydro's forecasters have overestimated 10-year future requirements on all but 3 of 25 occasions, and for 19 years in a row. On average, BC Hydro's load forecasts overestimate actual requirements 10 years later by 9.1%. For the most recent 19 load forecasts for which 10-year comparisons can be made, this overestimation rises to an average of 9.7% above actuals, or 5,443 GWh/year.[56]

Figure 7: BC Hydro load forecasting overestimates – 10 years after forecast[57]

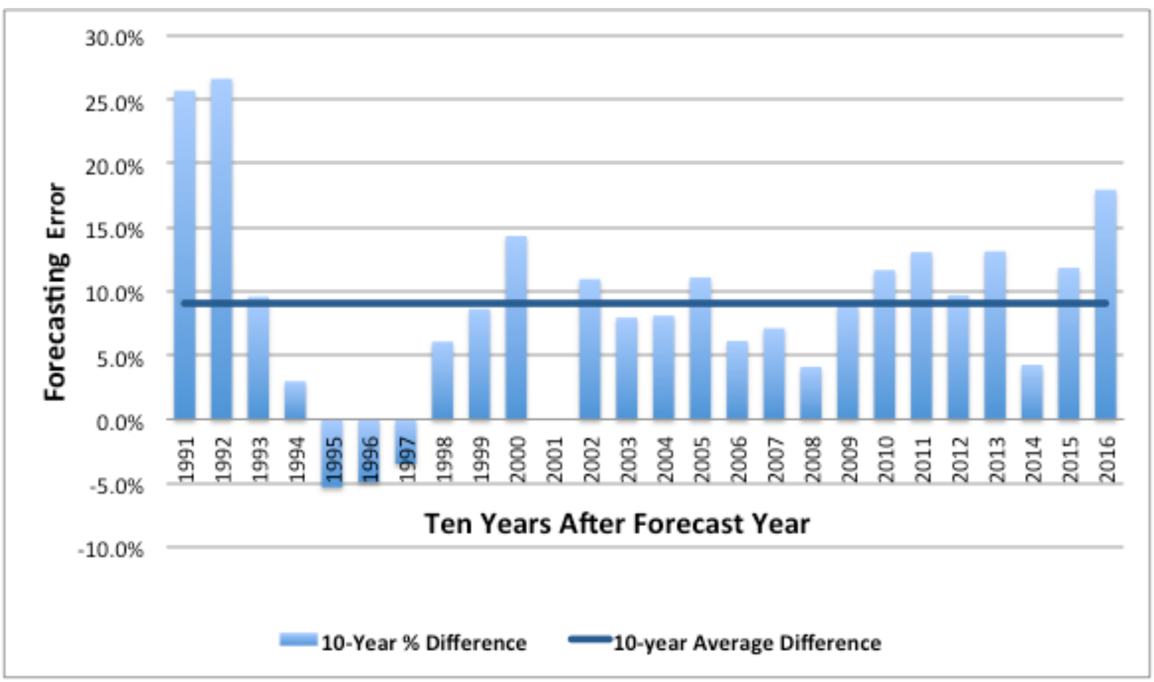
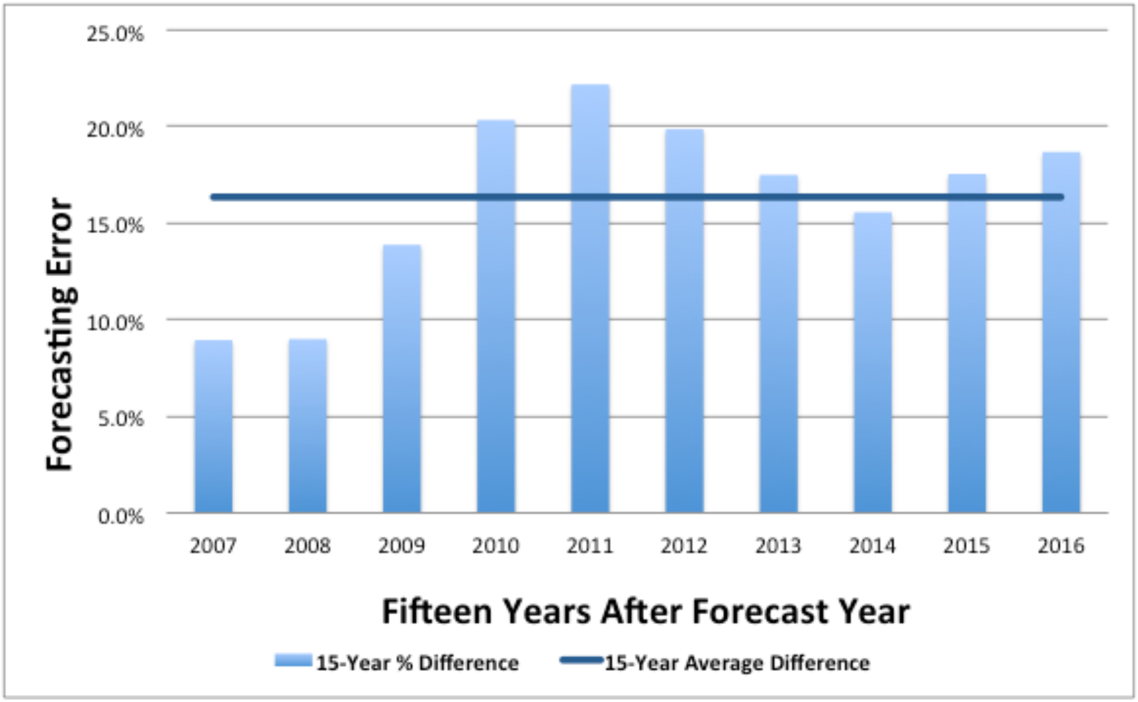


Figure 8 compares BC Hydro's forecasts against actuals 15 years later. All of these forecasts substantially overestimated future requirements 15 years later, on average by more than 15% or 9,254 GWh/year.

[56] Not shown in Figure 7.

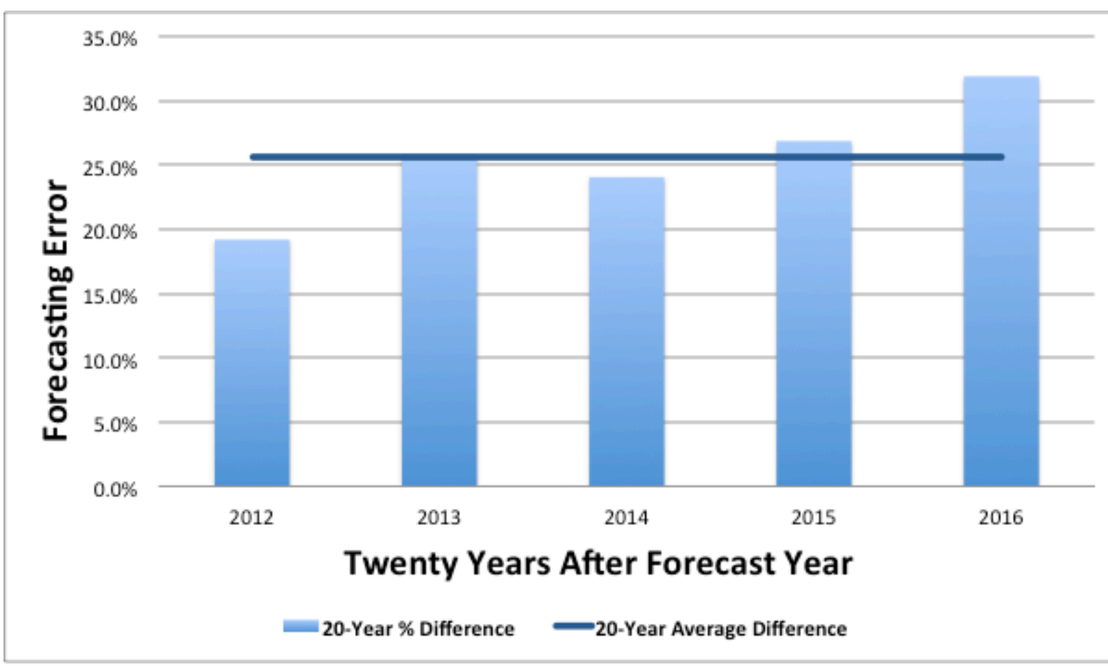
[57] A load forecast was not available for F1991, and so no comparison 10 years later could be made.

Figure 8: BC Hydro load forecasting overestimates – 15 years after forecast



Similarly, Figure 9 compares BC Hydro's forecasts against actuals 20 years later. Once again, all five of BC Hydro's 20-year forecasts exceed actual requirements 20 years later by an average of more than 25% or 14,445 GWh/year.

Figure 9: BC Hydro load forecasting overestimates – 20 years after forecast



The previous three figures illustrate that **as time passes, BC Hydro's forecasts become more and more inaccurate.** During the environmental assessment hearings for the Site C Project, two factors affecting the load forecast were considered at some length: the price elasticity of demand for electricity and the role of the 2008-2009 recession.

Price elasticity is the degree to which consumers reduce electricity consumption in response to increasing price.[58] BC Hydro uses a value of -.05 to reflect rate-increase induced savings over the short and long-term for all customer classes.[59] This value is far lower than the average values cited in the regional studies summarized in Table 2.

Table 2: Price elasticity of electricity demand – literature values

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

As shown in the table, price elasticity varies substantially across regions, though overall values are quite consistent between the studies.[63] BC Hydro's determination of price elasticity is at the very low end of the short-run elasticity determined in the studies reviewed. This is relevant considering the substantial real increase in electricity rates in the 10-Year Rates Plan —on the order of 19% real (46% nominal).[64] Given these significant rate increases to come, BC Hydro's low estimate of price elasticity may lead it to overestimate future requirements.

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[58] This is distinct from the effect of rates specifically designed to reduce consumption (e.g. the residential inclining block rate) and the effect of DSM programs, codes and standards.

[59] BC Hydro. December 9, 2013. Site C Clean Energy Project. Undertaking No.1. (Accessed 17 April 17 at: http://www.ceaa-acee.gc.ca/050/documents/p63919/97058E.pdf). This means that, for every 1% increase in price, consumption is expected to decline by 0.05%.

[60] A. Paul, E. Myers, and Palmer, K. 2009. "A Partial Adjustment Model of US Electricity Demand by Region, Season and Sector," Resources for the Future Discussion Paper, Table 5. (Accessed 17 April 2017 at: https://pdfs.semanticscholar.org/4856/f3c12e88737afb0b70f0eab3cd1c126f19a6.pdf)

[61] Bracketed values indicate ranges across different regions.

[62] Bernstein, M.A. and Griffin, J. 2005. Regional Differences in the Price-Elasticity of Demand for Energy. Prepared for the National Renewable Energy Laboratory. Bernstein, M.A. and Griffin, J. 2005. Regional Differences in the Price-Elasticity of Demand for Energy. Prepared for the National Renewable Energy Laboratory. (Accessed 17 April 2017 at: http://www.nrel.gov/docs/fy06osti/39512.pdf)

[63] Some variability is expected given regional differences in infrastructure, consumer preferences, local economic activity, and seasonality, among other factors.

[64] Government of BC. November 26, 2013. 10 Year Plan for BC Hydro, p.32. Available at: https://news.gov.bc.ca/stories/10-year-plan

Importantly, the studies show that long-run price elasticity is much higher than short-run elasticity in all three sectors. This suggests that over the longer-term, consumers are much more responsive to changes in electricity prices, opting to consume less electricity through conservation, fuel switching and equipment replacement.

With respect to the 2008-2009 recession, it appears that BC Hydro's testimony in the environmental assessment hearings exaggerated the role of the recession with regard to the accuracy of its load forecasting, when it said:

> So I would suggest the 2008/2009 recession, and how it persisted for many years, in an almost unexpected fashion, caught every forecaster by surprise whether it be the Forecasting Council of BC, who we get advice from, or the banks. It was really an unprecedented event in terms of the duration of it. … And I think for the first time we're starting to see some stability in terms of recovery. And so we do have modest load growth considered in our forecast .... .[65]

The 2008-2009 recession may explain, in part, BC Hydro's substantial overestimates of future energy requirements in the years thereafter, as shown in Figure 9. However, it cannot explain the overestimates in the years prior to the recession, as shown in Figure 7 and Figure 8. Nor can it explain the overestimate of requirements in load forecasts made since the recession, including those used to support launching the Site C Project. Was BC Hydro's expected "modest load growth" since the 2008-2009 recession, noted above, also "optimistic"? Events since the 2013 IRP, described in the following section, suggest that it was.

A detailed exploration of the multiple and highly variable factors listed in Section 3.2.1 that could more fully explain BC Hydro's consistent overestimation of actual requirements over the past 35 years is beyond the scope of this report. Those factors are best investigated by the BC Utilities Commission, which has the capacity to review them through a rigorous public process accessible to interveners and experts.

3.3 Collapse of BC Hydro's 2012 Load Forecast

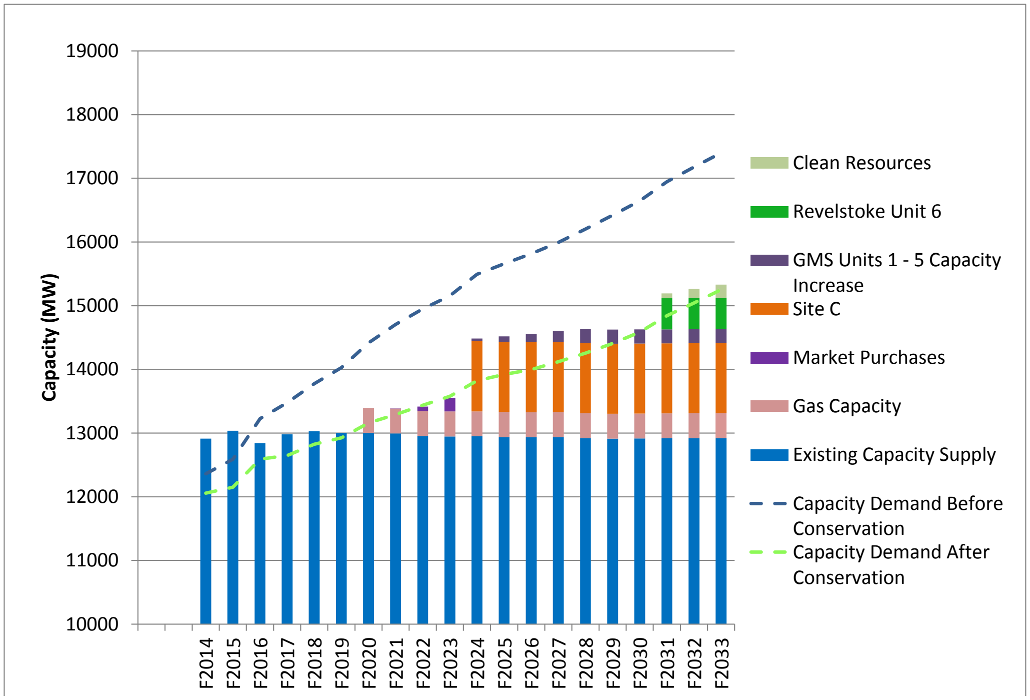
3.3.1 BC Hydro's 2013 IRP

BC Hydro's 2012 Load Forecast forms the basis for the 2013 IRP, which was accepted by the Provincial Government and used to support the approval of the Site C Project. In that planning process, BC Hydro prepared load-resource balances for energy and capacity reflecting the differences between supply and demand, before and after DSM. These "LRBs", as presented in the final November 2013 IRP, are shown in Figure 10.

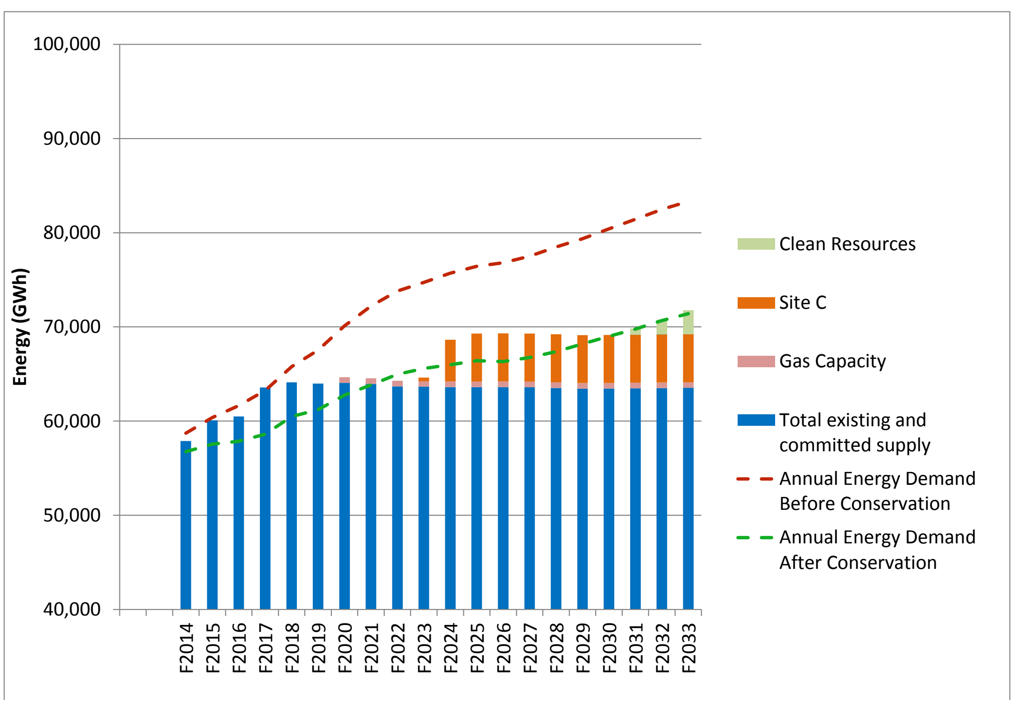
[65] Canadian Environmental Assessment Agency. 2013. In the Matter of the Joint Review Panel Established to Review the Site C Clean Energy Project Proposed by the British Columbia Hydro and Power Authority. Proceedings at Hearing December 9, 2013, Volume 1, p.165. (Accessed 17 April 17 at: http://www.ceaa-acee.gc.ca/050/documents/p63919/96844E.pdf)

Figure 10: 2013 IRP base resource plans with expected LNG

a) Capacity



b) Energy



The charts illustrate that, in the 2013 base resource plan[66] under the "Expected LNG" scenario,[67] BC Hydro saw the need for new resources as follows:

- Before DSM:
  - additional capacity resources would be required in F2016
  - additional energy resources would be required in F2017
- After DSM:
  - additional capacity resources would be required in F2019
  - additional energy resources would be required in F2022

On the basis of these forecast requirements, the Site C Project was planned for addition to the supply mix in F2024. Considering that capacity resources were anticipated to be required by F2019, the capacity load-resource balance also reflects BC Hydro's intention (at that time) to develop 400 MW of simple-cycle gas turbines (SCGTs) beginning in F2020, in order to supply expected additional liquefied natural gas (LNG) electric load requirements, and to make use of market purchases (or capacity from the Columbia River Treaty Entitlement) as "bridging resources" prior to the Site C Project coming into service.

The charts also illustrate that, in the absence of DSM, BC Hydro predicted (in 2013) both a capacity and an energy shortage by F2016, indicating the pivotal role that DSM plays in meeting requirements. These anticipated shortages did not materialize, as there has been no net increase in demand since 2007.[68] In other words, BC Hydro's additional domestic needs since 2008 have been met entirely with DSM.

3.3.2 BC Hydro's 2016 Revenue Requirements Application

On July 28, 2016, BC Hydro filed its Fiscal 2017 to Fiscal 2019 Revenue Requirements Application with the BC Utilities Commission. This Application provides the first meaningful update of BC Hydro's forecasted energy and capacity requirements since the 2013 IRP.

BC Hydro's updated load-resource balances, reflecting the differences between supply and demand, before and after DSM, are shown in Figure 11.[69] These charts indicate

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[66] The base resource plan is the "mid-level forecast" for the purposes of the Electricity Self-Sufficiency Regulation, BC Reg. 315/2010.

[67] BC Hydro estimated that future requirements of the LNG industry could range from 800 to 6,600 GWh/year of energy and 100 to 800 MW of capacity, with an Expected LNG load of 3,000 GWh/year and 360 MW by F2022.

[68] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 10-5. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[69] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

that, in the base resource plan,[70] BC Hydro saw the need (in 2016) for new resources as follows:

- Before DSM:
  - additional capacity resources would be required in F2020
  - additional energy resources would be required in F2022[71]
- After DSM:
  - additional capacity resources would be required in F2023
  - additional energy resources would be required in F2025[72]

The updated LRBs display a substantial deferral of the need for new resources, compared to the 2013 IRP. Table 3 summarizes the changes in BC Hydro's forecasts of its electricity requirements over the three-year period between the 2013 IRP and the 2016 RRA. **The table demonstrates that, in every case, the need date has shifted several years into the future since the 2013 IRP.**

Table 3: Deferred domestic electricity requirements

	Need Date		Time Deferred
	2013 IRP	2016 RRA	(Years)
Capacity (before DSM)	F2016	F2020	4
Capacity (after DSM)	F2019	F2023	4
Energy (before DSM)	F2017	F2022	5
Energy (after DSM)	F2022	F2025	3

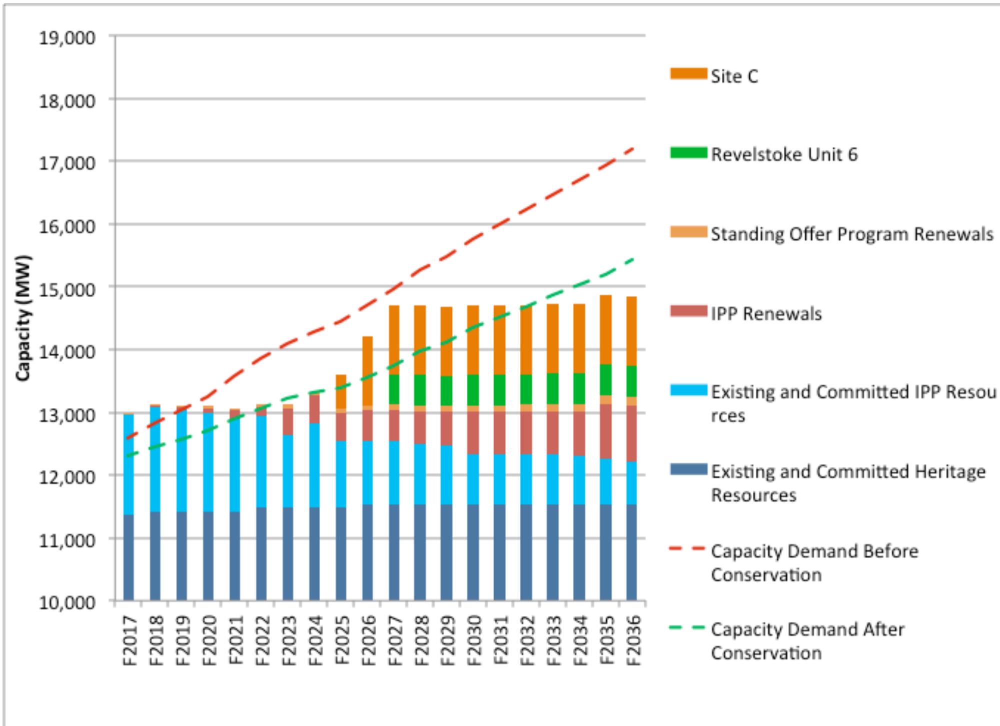
[70] The base resource plan in the 2016 RRA includes the expected LNG of 2,848 GWh/year and 361 MW.

[71] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-28. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

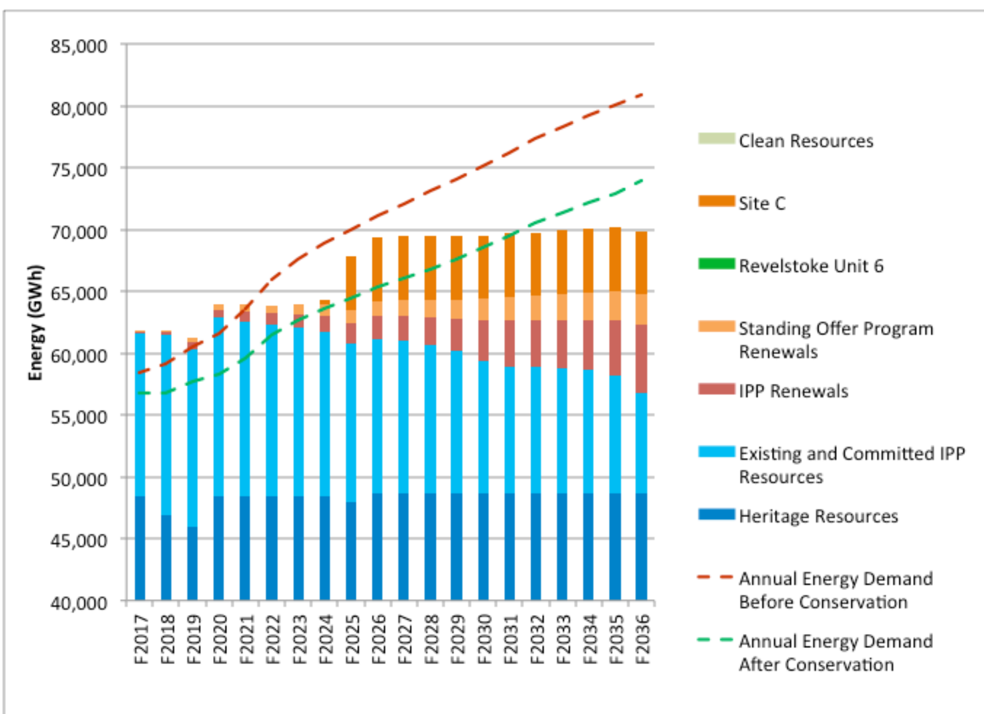
[72] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

Figure 11: 2016 RRA unbalanced base resource plans with expected LNG

a) Capacity

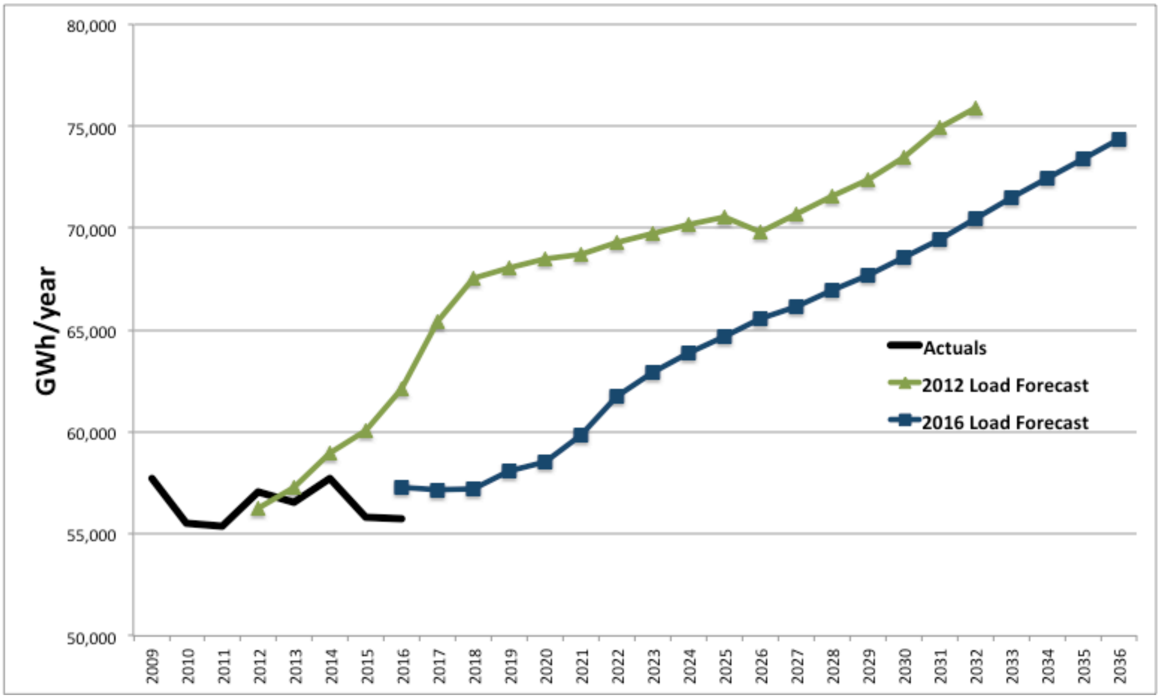


b) Energy



The differences between the two load forecasts are shown more clearly in Figure 12. 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.

Figure 12: 2012 Load Forecast versus 2016 Load Forecast, after DSM[73]



Throughout the 20-year forecasting period, the difference is on the order of 5,000 GWh/year of energy. **In other words, in the four years since the 2012 Load Forecast, a "requirement" for energy equivalent to the Site C Project has disappeared from BC Hydro's 2016 Load Forecast**. The expectation in the 2012 Load Forecast that energy requirements after DSM would reach 70,000 GWh/year by F2024, when Site C would be commissioned, is now expected in the 2016 Load Forecast not to occur until F2032, eight years later.

As also shown in Figure 12, **actual requirements in F2016 are 6,500 GWh/year less than predicted just four years earlier in F2012. This illustrates that BC Hydro's mid-load forecasts continue to substantially overestimate actual future requirements.**

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[73] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

3.3.3 Implications of overestimating requirements

As shown above in Table 3, the requirement for energy (after DSM, including expected loads from LNG) has been deferred from F2022 to F2025, which is after the F2024 in-service date for the Site C Project. **This means that, based on BC Hydro's mid-load forecast in the 2016 RRA, energy from the Site C Project will be entirely surplus when the Project comes on-line beginning in December 2023**.[74] In the event that load growth continues to underperform BC Hydro's load forecasts, the dates of requirements for capacity and energy after DSM could be deferred much later.

In other words, the current situation facing BC Hydro is very different from the one evaluated in the 2013 IRP, upon which was based the decision to proceed with the Site C Project with a planned completion date of F2024.

The potential for load to be higher than the mid-load forecast is modeled by BC Hydro in its "large gap" scenario. This scenario is based on higher than expected demand combined with lower DSM delivery and lower than anticipated load carrying capacity of clean resources (i.e. low hydroelectric reservoir inflows, less wind, etc.).[75] Under such a scenario, the need for new capacity advances from F2023 to F2019 and bridging resources (potentially including simple-cycle gas turbines, imports, or short-term use of the Canadian Entitlement under the Columbia River Treaty) would be advanced until the Site C Project entered operations. However, a high-load scenario now appears exceedingly unlikely, considering continuing delays and uncertainties related to several mining, LNG, and oil and gas projects, reduced potential new mining and oil and gas loads resulting from low commodity prices, and lower than expected housing starts and hence lower residential and commercial demand for electricity.[76]

BC Hydro also considers the potential for load to be much lower than the mid-load forecast, which BC Hydro models in its "small gap scenario". In this scenario, **the energy from the Site C Project (if commissioned in F2024 as currently planned) would be entirely surplus until F2036, and so would inevitably remain substantially surplus well beyond the end of the 20-year planning period.** The implications of the prolonged energy surplus that would be created by developing the Site C Project under the low-load forecast are discussed further below in Section 4.4.2.

Since the release of BC Hydro's 2016 Load Forecast, the Provincial Government released the BC Climate Leadership Plan that proposes several measures to increase the demand for low-carbon electricity as a strategy for reducing greenhouse gas emissions. These measures are considered in the following section.

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[74] As seen below, 80% of the energy from Site C is expected to be surplus in F2025.

[75] The 2016 RRA does not provide a breakdown of these different factors. For the purposes of the modelling in Section 6, the entire variance between the mid-gap and the large- and small-gap scenarios has been attributed to the corresponding load forecasts.

[76] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-33. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

3.4 Low-carbon electrification

Low-carbon electrification involves switching from high-carbon energy sources to low-carbon electricity, and is viewed as essential to achieving meaningful greenhouse gas emission reductions in Canada and around the world.

> Fuel switching to decarbonized electricity is the single most significant pathway toward achieving deep emissions reduction globally. It allows demand sectors to reduce their end-use emissions by switching from refined petroleum products, natural gas and other fossil fuels to clean electricity.[77]

Examples of low-carbon electrification include replacing gasoline or diesel transportation vehicles with electric vehicles, switching from natural gas space heating to electric heating (including heat pumps), and switching industrial processes away from fossil fuels to low-carbon electrical processes. The use of electricity in British Columbia to power the compression loads of liquefied natural gas (LNG) export facilities is another example of low-carbon electrification, as is the electrification of upstream natural gas facilities.

Low-carbon electrification has the potential to increase future domestic electricity requirements in British Columbia, beyond BC Hydro's mid-load forecast. This section explores this potential in the context of several studies of low-carbon electrification conducted nationally and provincially, including by BC Hydro.

3.4.1 Low-carbon electrification in Canada

The Government of Canada's recent climate change mitigation strategy concludes, on the basis of published, unpublished and internal analyses, that substantial quantities of large-scale hydroelectric generation, including potentially in British Columbia, are necessary for deep reductions in Canada's greenhouse gas emissions by mid-century.[78]

Table 4 illustrates the key findings of two of the analyses relied on by the Government of Canada in reaching its conclusions, namely the Deep Decarbonization Pathways Project (DDPP) and the Trottier Energy Futures Project (TEFP). The DDPP modeled scenarios based emission reductions on the order of 90%, while the TEFP modeled scenarios resulting in emission reductions of about 60%.[79]

The table presents the key determinations of both of these analyses for each of the reference (business as usual) and primary low-carbon scenarios in terms of future carbon emissions, electricity requirements, and hydroelectric development in 2050.

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[77] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada ['*Deep Decarbonisation Pathways Project*'], p.24. (Accessed 17 April 2017 at http://deepdecarbonization.org/)

[78] Government of Canada. 2016. Canada's Mid-Century Long-Term Low-Greenhouse Gas Development Strategy, Figure 2. (Accessed 17 April 2017 at http://unfccc.int/files/focus/long-term_strategies/application/pdf/canadas_mid-century_long-term_strategy.pdf)

[79] Both studies focused on energy-related emissions, omitting land-based emissions (e.g. agriculture, forestry).

Table 4: Analyses of low-carbon electrification in Canada

Parameter	DDPP		TEFP	
	Reference[80]	Low-carbon[81]	Reference[82]	Low-carbon[83]
Baseline CO_2e emissions[84] (MT)	552	552	501	501
2050 CO_2e emissions[85] (MT)	666	59	754	171
Δ 2050 CO_2e emissions over reference		-607		-583
CO_2e emissions change	**+21%**	**-89%**	**+50%**	**-66%**
Baseline electricity production (TWh/y)	600	600	700	700
2050 electricity production (TWh/y)	900	1400	950	2250
Total electricity change (TWh/y)	300	800	250	1550
Total electricity change	**+50%**	**+133%**	**+36%**	**+221%**
Baseline hydroelectric production (TWh/y)	360	360	340	340
2050 hydroelectric production (TWh/y)		800	510	800
Total hydroelectric change (TWh/y)		440	170	460
Total hydroelectric change		**+122%**	**+50%**	**+135%**

As shown, the DDPP predicts an increase of 800 TWh/year in electricity generation by 2050, of which 440 TWh/year is projected to be new large-scale hydroelectric. The TEFP predicts an increase of 1550 TWh/year by 2050, of which 460 TWh/year is projected to be new large-scale hydroelectric.[86] For context, this is equivalent to developing ninety (90) Site C Projects in Canada by 2050.

Notwithstanding their differences, **both studies find that meaningful reductions in greenhouse gas emissions over the reference case are accompanied by substantial increases in electricity requirements, which would be met mainly by an unprecedented build out in large-scale hydroelectric development across Canada**.

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[80] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada [‘*Deep Decarbonisation Pathways Project*’], pp.3, 12, 15. (Accessed 17 April 2017 at http://deepdecarbonization.org/)

[81] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada [‘*Deep Decarbonisation Pathways Project*’], pp.3, 42, 43. (Accessed 17 April 2017 at http://deepdecarbonization.org/

[82] Trottier Energy Futures Project. April 2016. Canada’s Challenge & Opportunity: Transformations for major reductions in GHG emissions, Figs. 24, 51, 56, 79. (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/)

[83] Trottier Energy Futures Project. April 2016. Canada’s Challenge & Opportunity: Transformations for major reductions in GHG emissions, Figs. 24, 56, 59, 79. (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/)

[84] *DDPP* uses 2015 and *TEFP* uses 2013 as the baseline dates.

[85] Emissions from combustion, excludes land-use emissions.

[86] Small-scale, run-of-river hydroelectric is not considered to be competitive against other resource options.

These studies suggest that, in a low-carbon future, the Site C Project would inevitably be needed even if BC Hydro has overestimated needs in the short- to medium-term. To explore this proposition, it is worth examining some of the key assumptions in the two studies, including in relation to projections of total electricity requirements, as well as hydroelectric requirements.

Gross domestic product (GDP)

Both the DDPP and the TEFP anticipate the Canadian economy will double in size by 2050, at an annualized growth rate of about 2%.[87,88,89] The federal Department of Finance has projected long-term real economic growth to be on the order of 1.7% between 2016 and 2055.[90] **Lower economic growth would very likely result in slower growth of emissions, lower electricity requirements, and overall less investment in low-carbon electricity to 2050.**

Oil production and electricity requirements in Alberta

The DDPP models three different oil prices ($40, $80 and $114),[91] while the TEFP uses a much higher range of $131.50 to $140.[92] As summarized below in Table 5, assumptions about oil prices result in quite different long-term economic futures for the Alberta oil economy. Oil production declines modestly under mid oil prices to 3.1 Mbbl/day from 4.3 Mbbl/day in the reference case, increases considerably to 7.5 Mbbl/day under high oil prices and declines substantially to 0.85 Mbbl/day under low oil prices.

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[87] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada [‘*Deep Decarbonisation Pathways Project*’], p.*22.* (Accessed 17 April 2017 at http://deepdecarbonization.org/)

[88] Trottier Energy Futures Project. April 2016. Canada’s Challenge & Opportunity: Transformations for major reductions in GHG emissions, Figure 11. (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/)

[89] Trottier Energy Futures Project. April 2016. Canada’s Challenge & Opportunity: Transformations for major reductions in GHG emissions,, p.42 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/)

[90] Government of Canada, Department of Finance. 2016. Update of Long-Term Economic and Fiscal Projections, p.6.

[91] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada [‘*Deep Decarbonisation Pathways Project*’], *p.21.* (Accessed 17 April 2017 at http://deepdecarbonization.org/)

[92] Trottier Energy Futures Project. April 2016. Canada’s Challenge & Opportunity: Transformations for major reductions in GHG emissions, Table 46 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/)

Table 5: Effects of oil prices in 2050 – DDPP analysis[93]

Parameter	Reference	Low Oil Price	Mid Oil Price	High Oil Price
Oil prices in 2050 ($/bbl)	80	40	80	114
Production in 2050 (Mbbl/day)	4.3	0.85	3.1	7.5
Alberta GDP changes in 2050 (2015=1)	1.71	1.20	1.34	1.71
British Columbia GDP changes in 2050 (2015=1)	2.42	2.17	2.14	2.10
Canadian GDP changes in 2050 (2015=1)	2.15	1.98	2.01	1.99

The Alberta Electricity System Operator forecasts requirements for electricity in that province to increase 11 TWh/year in its low-load forecast and 21 TWh/year in its high-load forecast by 2024 when the Site C Project would come on-line.[94] These are substantial increases in requirements, even under the low-load scenario. **Low-carbon electrification of the oilsands and growth in Alberta's electricity requirements more generally could drive a need for imports of energy and capacity from British Columbia beyond that contemplated in BC Hydro's recent 2016 Load Forecast.**

The Canadian Energy Research Institute (CERI) recently evaluated several large-scale hydroelectric alternatives, including the Site C Project, for directly meeting the electricity needs of the oilsands through the development of addition transmission infrastructure. The CERI study also evaluated improvements to the existing transmission intertie between BC and Alberta,[95] which could allow for additional transfers of electricity from BC to Alberta in order to meet some of the electricity needs of the oilsands.

The study found that energy from the Site C Project, including the addition of a dedicated 600-km transmission line, is the most expensive at over $140/MWh, and is therefore not considered cost effective.[96]

This compares to the BC intertie option at about $80/MWh. The expansion of the BC-Alberta intertie could allow for increased sales of BC Hydro's surplus energy, including surplus energy that would be created by the Site C Project. BC hydro currently forecasts an export market price at the BC-US border of $38.10/MWh in F2025 in current dollars (see Table 13, below). This is considerably higher than current market prices in Alberta, which were $18/MWh in 2016 and averaged $32/MWh over the previous three years,

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[93] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada ['*Deep Decarbonisation Pathways Project*'], *p.21 - 23.* (Accessed 17 April 2017 at http://deepdecarbonization.org/)*,*

[94] Alberta Electric System Operator. 2016. AESO 2016 Long-term Outlook, date file. (Accessed 17 April 2017 at: https://www.aeso.ca/grid/forecasting/)

[95] AESO. January 2015. Intertie Restoration Project: AESO – BCH Joint Planning Study. These improvements to the intertie would allow the rated capacity for imports into Alberta to be increased by 400 MW, from the current 800 MW import capability to 1200 MW.

[96] Canadian Energy Research Institute. 2016. An Assessment of Hydroelectric Power Options to Satisfy Oil Sands Electricity Demand, p.32. (Accessed 17 April 2017 at: http://www.ceri.ca/publications-oil/) The Slave River Hydro Project was estimated at $110/MWh, with imports from new hydroelectric development in Manitoba at $125/MWh.

while on-peak prices in 2016 were just under $20/MWh.[97] While the power pool price in Alberta will continue to evolve, current prices do not suggest the development of a higher-priced market in Alberta for export of surplus energy from Site C. This would explain why BC Hydro did not analyze the future Alberta market potential in the 2013 IRP.

Alberta recently initiated its Renewable Electricity Program, which requires that all projects must be based in Alberta to be eligible for support under the program, which therefore precludes subsidies to imports from BC. In the absence of a change in the program rules, or another arrangement that would allow for surplus energy from the Site C Project to access higher prices, the Alberta market does not appear to offer higher prices than those determined by BC Hydro for markets to the south.

Finally, Alberta also recently announced the formation of a capacity market,[98] beginning in 2021. BC Hydro could bid surplus capacity from the Site C Project into this market for the years when capacity is surplus following the scheduled commissioning of the Project beginning in F2024, subject to transmission capacity. Whether the Alberta capacity market will offer higher prices than the $37/kW-year for surplus capacity used by BC Hydro,[99] cannot be determined at this time. In the event that further review of the Site C Project is undertaken by the BCUC, the value of future capacity should be investigated.

Electricity prices

The DDPP does not provide any information about future electricity prices or the effect of future price increases on electricity demand. In the TEFP, the marginal cost of electricity increases substantially from $0.05/kWh in the reference scenario to $0.08/kWh in the low-carbon scenario by 2025 and then stays nearly $0.03 (or 60%) higher until 2050.[100] This is a substantial increase in electricity costs, yet no information is provided respecting what effect higher prices may have on future electricity demand.

Increases in electricity costs are material since the price elasticity of demand for electricity becomes more elastic over time.[101,102] The result of a long-term 60% increase

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[97] AESO. February 2017. AESO 2016 Annual Market Statistics. (Accessed 17 April 2017 at https://www.aeso.ca/market/market-and-system-reporting/annual-market-statistic-reports/) All prices in $2016 CAD.

[98] A "capacity market" ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted requirements some time in the future. By matching energy supply with future energy demand, a capacity market creates long-term price signals to attract needed investments in generation infrastructure to assure adequate power supplies.

[99] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.15.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[100] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, Figure 78 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/).

[101] See Table 2, above, and A. Paul, E. Myers, and Palmer, K. 2009. "A Partial Adjustment Model of US Electricity Demand by Region, Season and Sector," Resources for the Future Discussion Paper, Table 5. (Accessed 17 April

in the real cost of electricity is that consumers are much less likely to fuel switch to electricity, more likely to adopt energy-efficient electricity alternatives, or consume less electricity. This could also include decisions by industrial customers to close production facilities or to relocate, removing substantial load from the integrated system. **The lack of analytical detail respecting the effect of electricity demand elasticity in the DDPP and TEFP raises concerns that the actual electricity requirements in 2050 may be much lower than estimated**.

Demand-side management

The DDPP and the TEFP models both apply demand-side measures across the economy. Indeed, the DDPP notes that "energy efficiency everywhere" provides 100 MT of emission reductions by 2050, a substantial reduction.[103] In both studies, numerous graphs and pages are dedicated to explaining the specifics of the contributions from supply-side electricity resources, yet no analyses regarding the contributions of different demand-side measures are provided. There is also no discussion of the comparative cost-effectiveness of DSM. **The lack of fundamental information concerning the role of DSM in either the DDPP or TEFP raises a concern about disproportionate emphasis in favour of supply-side solutions to decarbonizing the Canadian economy. As a result, actual electricity requirements in 2050 may be much lower than suggested.**

Distributed generation

The TEFP does not include any contribution from distributed generation to 2050, based on the report's conclusion that extensive large-scale hydroelectric generation represents the least-cost path, and would render future distributed generation uncompetitive indefinitely. The study later acknowledges that limitations in time and available funding did not allow full exploration of distributed generation.[104] **The omission of distributed generation from the analysis represents a major shortcoming in the TEFP, calling into question the findings with respect to future electricity requirements that would be met by large-scale hydroelectric development.**

2017 at: http://www.rff.org/research/publications/partial-adjustment-model-us-electricity-demandby-region-season-and-sector).

[102] Ryan, D. and Razek, N.A. 2012. The Likely Effect of Carbon Pricing on Energy Consumption in Canada, Figure 2. Calgary: Sustainable Prosperity Institute. (Accessed 17 April 2017 http://institut.intelliprosperite.ca/sites/default/files/likely-effect-carbon-pricing-energy-consumption-canada.pdf)

[103] SDSN and IDDRI. 2015. Pathways to deep decarbonisation in Canada ['*Deep Decarbonisation Pathways Project*'], Figure 9. (Accessed 17 April 2017 at http://deepdecarbonization.org/),

[104] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, p. 289 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/). "The elements of this include, as examples, energy management/conservation systems in commercial developments, distributed energy, district energy for hot water and steam production, waste conservation, waste to energy, solar electricity supply from residential and commercial buildings, geothermal and air source heat pumps, passive solar thermal systems, thermal energy storage, and smart energy management systems."

Nuclear

The DDPP assumes that no new nuclear resources will be developed in Canada. The TEFP models the effect of no new nuclear generation and finds that in BC, in the absence of new nuclear, some new hydroelectric is developed and some pumped storage hydroelectric with additional energy resources (i.e. wind).[105] In all other provincial jurisdictions, the TEFP determines that nuclear is replaced with pumped storage hydroelectric and additional energy resources. **This illustrates that a key trade-off in a low-carbon, low-nuclear future is between large-scale hydroelectric and a combination of energy storage with additional renewable energy resources.** Thus, the assumptions about the cost of these resources – solar PV, wind, pumped storage hydroelectric and large-scale hydroelectric – are key to forecasting which supply-side resources are likely to meet future electricity requirements.

Solar PV

The DDPP develops 60 TWh/year (or 4% of total requirements) of solar PV by 2050, but provides no cost information that would allow an assessment of the report's findings. The TEFP develops essentially no solar PV in any of its scenarios, and all scenarios present less solar PV in 2050 than in 2012. **The finding in the TEFP of less generation from solar PV in Canada in 2050 than today is not credible**. As discussed in Section 5.4.1, further declines in the cost of energy from solar PV are expected to make utility-scale solar competitive with wind in many parts of Canada by 2030, increasing the role of utility-scale PV in meeting electricity requirements to 2050.

Wind

The DDPP develops 200 TWh/year of wind energy (or 14% of total requirements) by 2050, but provides no cost information on wind resources that would allow an assessment of wind energy's contribution to meeting electricity requirements. The TEFP develops 550 TWh of wind energy (or 24% of total requirements) by 2050, despite the fact that the TEFP presumes no declines in the real costs of wind over the study period. **The assumption in the TEFP that real wind costs remain unchanged between 2012 and 2050 is without merit**. Section 5.4.1 below, discusses recent declines in the cost of energy from wind, which have been on the order of 20% in the past 4 years, and the extent of projected future cost declines. **Further cost declines in wind energy alter the balance of future low-carbon electricity resources towards combinations of energy storage and wind, and away from conventional large-scale hydroelectric resources.**

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[105] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, Figure 119 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/).

Pumped storage hydroelectric and capacity upgrades

The DDPP contains no analysis of pumped storage hydroelectric or capacity upgrades at existing hydroelectric facilities. **The omission of any electricity capacity analysis in the DDPP raises questions about the completeness, accuracy and conclusions of the study**. The TEFP includes consideration of pumped storage hydroelectric, but acknowledges that the analysis entirely omitted inclusion of potential capacity upgrades at existing hydroelectric facilities. **The omission in the TEFP of the potential for capacity upgrades at existing hydroelectric facilities substantially overstates the need for large-scale hydroelectric development**.[106]

Large-scale hydroelectric

The proposed increases in hydroelectric generation of 440 TWh/year (~72,000 MW) in the DDPP and 460 TWh/year (~75,000 MW)[107] in the TEFP by 2050 would represent a doubling – in 30 years – of Canadian hydroelectric capacity that took over a century to develop. The total capacity of large-scale hydroelectric additions between 2000 and 2015 was on the order of 6,000 MW.[108] **The proposals in the DDPP and TEFP would represent a more than six-fold increase in the rate of large-scale hydroelectric development over the period 2020 to 2050, compared to the past 15 years**.

The DDPP provides no cost information on large-scale hydroelectric development. The TEFP indicates investment costs for new large-scale hydroelectric development of $4,988/kW in lower-cost jurisdictions to $7,481/kW in higher-cost jurisdictions.[109]

The current cost estimate of the 1100-MW Site C Project is 8.335 billion or $7,557/kW, presuming that the Project is completed on budget, which is well above the TEFP cost estimates for a lower-cost jurisdiction. As discussed further in Section 4.3.1, the actual costs of the 695-MW Keeyask Project are now estimated at $8.7 billion, or $12,518/kW, while the costs of the 824-MW Muskrat Falls Project inclusive of transmission now total $11.7 billion, or $14,200/kW. In short, **the estimates of hydroelectric development costs used in the TEFP substantially understate actual large-scale hydroelectric development costs of resources currently under construction in Canada**.

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[106] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, p. 288 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/).

[107] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, p. 182,184 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/).

[108] Facilities larger than 100 MW in capacity.

[109] Trottier Energy Futures Project. April 2016. Canada's Challenge & Opportunity: Transformations for major reductions in GHG emissions, Table 17 (Accessed 17 April 2017 at http://www.davidsuzuki.org/publications/reports/2016/canadas-challenge-and-opportunity-transformations-for-major-reductions-in-ghg-em/).Lower-cost jurisdictions include: BC, Manitoba, Quebec and LabradorLower-cost jurisdictions include: BC, Manitoba, Quebec and Labrador.

With respect to the location, technical feasibility and economic viability of the proposed large-scale hydroelectric facilities, the TEFP appears to rely on the summary findings of a single report that was prepared for the Canadian Hydropower Association (CHA) in 2006.[110] Despite requests from the Program on Water Governance, the CHA refuses to make the full report available for public review and scrutiny. While it is unclear whether the DDPP also relies on the CHA report, other analyses,[111] including the Government of Canada's recently released climate change strategy rely on the summary findings of the same report.

The CHA is an advocate for additional hydroelectric development in Canada. **The reliance by the Government of Canada, in formulating federal climate change policy, on unpublished and unreviewable research produced by the CHA concerning the feasibility of additional large-scale hydroelectric potential in Canada is concerning**. The reliance on these private models and databases also greatly limits the possibility of assessing the validity of the hypotheses and conclusions.

3.4.2 Low-carbon electrification in BC

In addition to national analyses of the effects of low-carbon electrification on electricity requirements, additional estimates have been made of potential requirements in BC.

BC Hydro's electrification potential study

The 2013 IRP contained a study of electrification potential (the "MKJA study"),[112] the key findings of which were as follows:

- Electrification occurs across the economy in response to climate policy, particularly in the natural gas sector in the early years;
- Deep reductions in British Columbia's GHG emissions result in substantially more electricity demand;
- Under all GHG price scenarios, the increase in electricity demand is not significant until the 2030s, due to the limitations of capital stock turnover, relatively low GHG prices, and low natural gas prices;
- Low natural gas prices constrain electrification while high natural gas prices increase electrification;

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[110] EEM. 2006. Study of hydropower potential in Canada. Study conducted for the Canadian Hydropower Association. Summary. (Accessed 17 April 2017 at: https://canadahydro.ca/resources/)

[111] See e.g. Global Forest Watch Canada. 2012. Hydropower Developments in Canada: Number, Size and Jurisdictional and Ecological Distribution (Accessed 17 April 17 at: http://www.globalforestwatch.ca/publications/20120118AB);
Sustainable Dialogues Canada. 2015 Acting on Climate Change: Solutions from Canadian Scholars. (Accessed 17 April 17 at: http://www.sustainablecanadadialogues.ca/en/scd/endorsement)

[112] BC Hydro. 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

- Electric vehicle penetration is relatively low, even under the high GHG price scenario, due to the high capital costs of vehicle batteries.[113]

The assumptions used in the MKJA study were largely matched to those used by BC Hydro in the 2013 IRP. The reference scenario used in the MKJA study is somewhat lower than BC Hydro's 2010 Load Forecast,[114] which for the years 2022 to 2030 is almost identical to BC Hydro's 2016 Load Forecast.[115] Two key inputs into the model include the following:[116]

- GHG prices – low, medium and high scenarios resulting in prices (in 2005 CAD) in 2050 of $30/t, $150/t and $275/t, respectively; and
- Natural gas prices - low, medium and high scenarios resulting in prices (in 2005 CAD) in 2050 of $7/GJ, $12/GJ and $19/GJ, respectively.

Unlike the DDPP and TEFP, the MKJA study does not determine specific portfolios of resources for meeting future electricity requirements. The analysis includes only technologically proven resources (primarily small hydro, wind, the Site C Project and hydroelectric pumped storage), and excludes uncertain resources (e.g. tidal and geothermal).

As shown in Table 6, and based on BC Hydro's domestic billed sales of about 50 TWh/year in 2010, the increase in electricity requirements including electrification could range from 31% to 69% by 2030 and from 49% to 120% by 2050. Under medium GHG and medium natural gas prices, the increases are 45% by 2030 and 86% by 2050. The MKJA study also conducted a sensitivity analysis that concluded that lower-cost electric vehicle batteries increase electrification by an additional 15 TWh/year.[117] **Taken together, these findings suggest that deep reductions in British Columbia's GHG emissions result in substantially more electricity demand.**

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[113] BC Hydro. November 2013. Integrated Resource Plan, Chapter 6 Resource Planning Analysis, p.6-107. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0006-nov-2013-irp-chap-6.pdf)

[114] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.29. The difference is 4,400 GWh/year lower in the MKJA Study by 2030 due to a greater rate of energy efficiency improvements compared to BC Hydro's 2010 Load Forecast. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

[115] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. The difference is about 1,000 GWh/year between the forecasts over that period. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

[116] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., pp.18-22. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

[117] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.44. Medium natural gas and medium GHG price scenario. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

The MKJA study presents three potential scenarios for each of future GHG prices and future natural gas prices. As evident in Table 6, higher GHG prices and natural gas prices result in increased requirements for electricity:

- Under scenarios with low GHG prices and low natural gas prices, there is essentially no increase in electricity requirements over the reference scenario, even by 2050; and
- Under scenarios with high GHG prices and high natural gas prices, the projected increases in electricity requirements rise to around 100% by 2050, or double the rate of growth under the reference scenario (i.e. 56%).

Table 6: Electrification effects on energy demand, after DSM (TWh/year)[118]

GHG Price Scenario	Natural Gas Price Scenario	2010	2030		2050	
		TWh/year	TWh/year	% change	TWh/year	% change
Low	Low	51	67	31%	76	49%
	Medium	51	70	37%	82	61%
	High	51	77	51%	91	78%
Medium	Low	51	70	37%	88	73%
	Medium	**51**	**74**	**45%**	**95**	**86%**
	High	51	80	57%	102	100%
High	Low	51	76	49%	101	98%
	Medium	51	80	57%	106	108%
	High	51	86	69%	112	120%
Reference (TWh/year)		**50**	**67**	**34%**	**78**	**56%**

These projected increases in requirements under the "high-high" scenario (i.e. 120%) are somewhat lower than those determined in the DDPP (133%) and much lower than those in the TEFP (221%), recognizing the different geographical coverage of the studies. The overall emission reductions by 2050 with high GHG and high natural gas prices are on the order of 58 MT CO_2e/year over the reference case, or 66%, with emissions reductions much more sensitive to GHG prices than to natural gas prices. [119]

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[118] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.42. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

[119] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., pp.31. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

Notwithstanding the potential for electrification to contribute to substantial increases in electricity requirements, several factors influencing the analysis in the MKJA study have evolved since the study was completed, including the following:

- GHG prices – with the recent announcement by the Government of Canada of a carbon price of $50 (nominal) by 2022,[120] this is tracking below the medium and near to the low scenario used in the MKJA study; [121]
- Natural gas prices – natural gas prices have trended much lower than projected, and in 2016 averaged just 3.22 $/GJ,[122] which is substantially lower than even the low price forecast of 5.36 $/GJ for 2016 used in the MKJA study;[123] and
- Information in Table 7 below, derived from BC Hydro's 2016 RRA, suggests that electrification in the transportation sector would require less than 1,000 GWh/year by 2030, much less than anticipated in the MKJA study. This updated forecast of electricity demand from electric vehicles is already reflected in BC Hydro's base resource plans (i.e. using the mid-load forecast) in the 2016 RRA.

Table 7: 2016 RRA electric vehicle energy requirements[124]

	F2017	F2019	F2022	F2027	F2036
Energy (GWh/year)	<50	<50	70	430	1,760
# Electric vehicles	6,000	11,000	30,000	164,000	580,000
# Total vehicles[125,126]	3,653,371	3,744,149	3,876,475	4,089,611	4,419,474
% of fleet	0.16	0.29	0.77	4.01	13.12

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[120] Government of Canada. October 3, 2016. "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution. (Accessed 17 April 2017 at: http://news.gc.ca/web/article-en.do?nid=1132149)

[121] BC Hydro. 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.22. Converted to 2016 CAD. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

[122] U.S. EIA. Henry Hub Natural Gas Spot Price. (Accessed 17 April 17 at: https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm)

[123] BC Hydro. 2013. Integrated Resource Plan, Appendix 6C Electrification Potential Review, prepared by MKJA MK Jaccard and Associates Inc., p.22. Converted to 2016 CAD. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600c-nov-2013-irp-appx-6c.pdf)

[124] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-15. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[125] Statistics Canada. 2016. Motor vehicle registrations, by province and territory. CANSIM, table 405-0004. (Accessed 17 April 17 at: http://www5.statcan.gc.ca/cansim/a26?lang=eng&id=4050004)

[126] # Total vehicles assumed to be a constant ratio of the provincial population. See BC Stats. 2016. British Columbia Population Projection 16/07. Available at: http://www.bcstats.gov.bc.ca/StatisticsBySubject/Demography/PopulationProjections.aspx

The reference scenario used in the MKJA study shows an increase in energy demand of 17 TWh/year (17,000 GWh/year) between 2010 and 2030. To date, as shown above in Figure 4, there has been no growth in domestic electricity requirements since 2010. This historic pattern is not necessarily a reflection of future rates of growth, particularly if electrification is to contribute to achieving British Columbia's climate change objectives. However, the relatively low GHG prices, much lower than anticipated natural gas prices, and low uptake of electric vehicles combine to suggest that substantial growth in electricity requirements from electrification is not on the horizon without additional significant policy intervention.

In order to capture the potential for electricity load growth to be higher than anticipated, BC Hydro's large-gap scenario, which contemplates additional energy requirements of 7 TWh/year (before DSM) by 2030 is considered in the comparative analysis of continuing, cancelling or suspending the Site C Project presented in Section 6.3.

In summary, based on the MKJA study, deep reductions in British Columbia's GHG emissions would result in substantially more electricity demand. However, the extent of this increase in demand and its timing remain highly uncertain. Updating the electrification analysis as part of the 2018 IRP or as part of a referral of the Site C Project to the BCUC should be considered a priority.

Electrification of LNG

BC Hydro also included in its 2016 RRA, the energy and capacity requirements of LNG export facilities for which BC Hydro has received electricity service requests.[127] This "Expected LNG" load includes requirements from expansion of the FortisBC Tilbury Island LNG facility, Woodfibre LNG, and LNG Canada. These requirements total 2,848 GWh/year of energy and 361 MW of capacity,[128] which is similar to the 3,000 GWh/year of energy and 360 MW of capacity included in the 2013 IRP "Expected LNG" scenario.

In the 2013 IRP, base resource plans were developed for both Expected LNG and No LNG scenarios. In the 2016 RRA, only the Expected LNG scenario is considered, despite the fact that only Woodfibre LNG has made a final investment decision.[129] However, Woodfibre LNG has not yet executed an electricity supply agreement,[130] nor

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[127] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, section 3.2.1.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[128] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[129] Woodfibre LNG. November 2016. Parent Company Authorizes Woodfibre LNG to Proceed with Project. Available at: http://www.woodfibrelng.ca/parent-company-authorizes-woodfibre-lng-to-proceed-with-project/.

[130] BC Hydro. November 21, 2016. F2017 to F2019 Revenue Requirements Application, Response to Information Request BCUC 1.73. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

secured binding LNG supply contracts.[131] BC Hydro's approach therefore overlooks the possibility that not all of the LNG projects will be developed.

Since the release of the 2016 RRA, Pacific Northwest LNG (which was not included in the Expected LNG scenario) received conditional environmental assessment approval from the federal government. That conditional approval included a hard cap on annual greenhouse gas emissions from the project. In addition, the Canadian Environmental Assessment Agency concluded that using electricity from the BC Hydro grid to meet the 215 MW (~1,800 GWh/year) of non-compression loads at the project site would be technically feasible.[132] No public indication has been given as to whether Pacific Northwest LNG intends to make a service request to BC Hydro for meeting its non-compression loads.

The potential energy and capacity requirements of these four LNG facilities are summarized in Table 8 below.

Table 8: Potential LNG energy and capacity requirements

	Woodfibre LNG[133]	LNG Canada[134]	Tilbury Island LNG	Pacific Northwest LNG
Non-compression load	Grid	Grid	Grid	TBD[135]
Compression load	Grid	Self	Grid	Self
Electricity service request	Yes	Yes	Yes	No
Capacity (MW)	185	157	19	215
Energy (GWh/year) (est.)	1,300	1,400	148	1,800
Final investment decision	Yes	No	No	No

Currently, the Domestic Long-Term Sales Contracts Regulation[136] stipulates the LNG electricity rate for each year from 2015 to 2023. The LNG rate energy charge will be the greater of the energy charges set out in Table 9 below and the energy charges set out in Rate Schedule 1823, as amended from time to time.

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[131] "Woodfibre announces major supply agreement with Chinese Gas Company" in Business in Vancouver, May 12, 2016. Available at: https://www.biv.com/article/2016/5/woodfibre-announces-major-supply-agreement-chinese/.

[132] Canadian Environmental Assessment Agency. 2016. Pacific Northwest LNG Project Environmental Assessment Report, p.42 (Accessed 17 April 2017 at: https://www.ceaa.gc.ca/050/documents/p80032/115668E.pdf)

[133] Woodfibre LNG. 2015. Application for an Environmental Assessment Certificate, Comments #1401 – 1500, Table 15 of 17, p.59. (Accessed 17 April 2017 at https://www.woodfibrelng.ca/wp-content/uploads/2017/02/Application-for-an-Amendment-to-Environmental-Assessment-Certificate-January-2017.pdf)

[134] LNG Canada. 2013. Project Description: LNG Canada Project, p.18. (Accessed 17 April 2017 at: http://www.ceaa.gc.ca/050/document-eng.cfm?document=87575)

[135] Energy and capacity requirements presume grid supply for non-compression loads.

[136] B.C. Reg. 201/2014. (Accessed 17 April 17 at: http://www.bclaws.ca/civix/document/id/complete/statreg/201_2014)

As part of the Climate Leadership Plan, Government and BC Hydro announced a new eDrive rate to encourage LNG proponents to use electricity for their natural gas compression (i.e. liquefaction) needs.[137] The rate applies to the total load of the facility and is only available to proponents that use electricity for both their ancillary and compression power needs and connect at transmission voltage.

Table 9 compares the two rates (not including the demand charge), with the eDrive rate increasing at the rates stipulated in the 10 Year Rates Plan until F2019, and at a rate of 2.6% for each of the years 2020 to 2023,[138] consistent with the rates proposed in BC Hydro's 2016 RRA. The eDrive rate will have the same energy charges as Rate Schedule 1823, the existing transmission service rate. The LNG and eDrive rates also have the same demand charge as Rate Schedule 1823.[139]

Table 9: Comparison of LNG, eDrive and industrial rates

Calendar Year	LNG rate energy charge[140]	eDrive energy charge (equivalent to Rate Schedule 1823B)		Rate Schedule 1823A[141]
		Tier 1	Tier 2	
	($/MWh)	($/MWh)	($/MWh)	($/MWh)
2017	76.85	39.81	89.2	44.75
2018	78.39	41.21	92.32	46.32
2019	79.96	42.44	95.09	47.71
2020	81.56	43.54	97.56	48.95
2021	83.19	44.68	100.1	50.22
2022	84.85	47.03	105.37	51.52
2023	86.55	48.25	108.11	52.86

Woodfibre LNG and Tilbury Island LNG already plan to use electricity for their compression loads, and this is included in the requirements in Table 8. As for Pacific Northwest LNG and LNG Canada, BC Hydro notes that a fully electric two-train LNG facility producing 12 million tonnes per year of LNG would require 500-600MW, or 4,000-5,000 GWh/year of electricity.[142] With respect to Pacific Northwest LNG, BC

[137] BC Hydro. November 4, 2016. News Release: New eDrive electricity rate for LNG facilities. Available at: https://www.bchydro.com/news/press_centre/news_releases/2016/new-edrive-electricity-rate-for-lng-facilities.html.

[138] The LNG rate is specified to 2023 and remains constant after this date.

[139] See: BC Hydro Transmission Service Rates. Available at: https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/transmission_rate.html. 1823A is a flat rate rate, and 1823B is a tiered rate with Tier 2 designed to encourage conservation.

[140] The LNG energy charge rates are based on a calendar year and are effective January 1 of each year.

[141] Rate Schedule 1823A rates are set on a fiscal year basis and are effective April 1 each year.

[142] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC IR 2.197.3 Attachment 1. Briefing Note – Low-Carbon Electrification Potential. (Accessed

Hydro has indicated that the available transfer capacity on the transmission line servicing the Prince Rupert Port lands is limited to not more than 250 MW.[143] LNG customers on the eDrive Rate are required to contribute the full cost of transmission system connection as well as any upgrades required to serve their facilities, as set out in electricity supply and load interconnection agreements with BC Hydro.[144] **As such, electrification of compression loads at the Pacific Northwest LNG facility is not currently feasible, and cannot become feasible unless Pacific Northwest LNG were to pay the full cost of necessary transmission system upgrades.** To date, neither LNG Canada nor Pacific Northwest LNG has indicated an intention to use electricity for their compression loads.

BC Climate Leadership Plan

The Climate Leadership Plan sets out a number of actions, designed to support BC's climate change policy objectives:

- supply 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed;
- electrification of natural gas production, processing and transmission, all currently fuelled by natural gas and diesel fuel, to reduce greenhouse gas emissions;
- expanding the mandate of BC Hydro's DSM programs to include investments that increase efficiency and reduce GHG emissions;
- expanding the Clean Energy Vehicle Program; and
- amending the energy efficiency standards regulation.

In response to the Climate Leadership Plan, BC Hydro prepared a preliminary briefing note exploring the potential implications of low-carbon electrification for electricity requirements. The briefing note contains the following key messages:

> - The full impact of these policy developments on the extent and timing of electrification is highly uncertain, and will be evaluated in detail in preparation for the 2018 Integrated Resource Plan (IRP). This will include a new load forecast.
>
> - Although the extent of electrification is uncertain, the directional impact is clear, and a number of studies and analyses provide an indication of the potential for increased low-carbon electrification in BC.

17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

[143] Canadian Environmental Assessment Agency. September 2016. Pacific Northwest LNG Project, p.42. (Accessed 17 April 2017 at: https://www.ceaa.gc.ca/050/documents/p80032/115668E.pdf)

[144] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.7.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

- Some of the most significant near-term (pre-2030) potential for electrification is in the natural gas sector, and BC Hydro is working with government and stakeholders to explore program initiatives in this area.

- BC Hydro is also exploring electrification opportunities in other sectors, including residential, commercial, other industrial (mining) and transportation (vehicles, ports and airports).

- If low-carbon electrification programs proceed, BC Hydro anticipates that electrification loads could exceed what is currently estimated in the load forecast and will be able to reflect that in future load forecasts.[145]

BC Hydro also noted that the potential combined effect of the transportation, efficiency and electrification measures contained in the Climate Leadership Plan could increase electricity requirements by up to 6,500 to 7,000 GWh/year by 2030. This remains consistent with the analysis in the 2013 IRP, which envisioned an increase of up to 7,000 GWh/year over baseline in the medium scenario, as shown in Table 6.

The briefing note also emphasizes that BC Hydro's 2016 Load Forecast already includes a significant amount of electrification, particularly related to LNG (2,848 GWh/year by F2024), natural gas production, processing and transmission (3,507 GWh/year by F2030),[146] and the requirements related to electric vehicles summarized in Table 7. The Climate Leadership Plan is considered in greater detail below in Section 5.4.2 dealing with capacity resources, particularly simple cycle gas turbines and pumped storage hydroelectric.

Vancouver Renewable City Strategy

In its briefing note, BC Hydro also explored the potential implications of the Vancouver Renewable City Strategy. The primary objectives of this Strategy are to derive 100% of the energy used in Vancouver from renewable sources, and to reduce greenhouse gas emissions by at least 80% below 2007 levels, both by 2050. The Strategy does not include specific policies designed to achieve these ambitious goals, which are yet to be developed.

The main contributor to emissions reduction in the Strategy is energy conservation, which contrasts with BC Hydro's current approach to developing the Site C Project while moderating spending on DSM into the foreseeable future. The Strategy targets reducing total energy use by 35%, even with an allowance for economic and demographic

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[145] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC IR 2.197.3 Attachment 1. Briefing Note – Low-Carbon Electrification Potential, p.1. Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

[146] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC IR 2.197.3 Attachment 1. Briefing Note – Low-Carbon Electrification Potential, p.11. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

growth. This amounts to an increase in electricity requirements of only 1,111 GWh/year by 2050, or about 20% above current levels.[147]

Considering the lack of specific policy in relation to the targets in the Strategy, there are significant uncertainties that may increase the City's future requirements for electricity. These include the extent of development of neighbourhood renewable energy systems, and the contributions of biofuels and biomethane. In the Strategy, these resources collectively provide about 15 million GJ/year of energy or about 40% of total energy requirements in 2050. If these resources were unavailable or not cost-effective, then reliance on electricity from BC Hydro would be higher.

A recent review[148] of the sufficiency of the Strategy's policy initiatives evaluated several scenarios, including:

- the current policy scenario;
- a Strategy scenario, including policies adopted to date in relation to the Strategy; and
- a 100% renewable energy scenario consisting of policies in the Strategy scenario with additional policies designed to get closer to the two primary objectives of the Strategy.

The review is limited to the residential, commercial, light industrial and transportation sectors, and does not address the heavy industrial sector.

One of the additional assumptions in the review is that large supplies of renewable natural gas (RNG) will **not** be available to the Vancouver region at a cost that is competitive with renewable electricity for building end uses, or for district heating. This is a key assumption that limits the use of renewable natural gas to a few niche applications, and perhaps a few high-density locations suitable for district heating. The review also reaches the conclusion, assessed further in Section 5.4.3 below, that solar PV will not become cost-effective in Vancouver by 2050 compared to electricity generated by BC Hydro.

The findings of the review with respect to electricity use under the three scenarios are summarized in Table 10.

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[147] City of Vancouver. 2015. Renewable City Strategy 2015-2050, p.36. (Accessed 17 April 17 at: http://vancouver.ca/files/cov/renewable-city-strategy-booklet-2015.pdf)

[148] Zuehlke, B., Jaccard, M. and R. Murphy. 2017. Can Cities Really Make a Difference?: Case Study of Vancouver's Renewable City Strategy. (Accessed 17 April 2017 at http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017)

Table 10: Vancouver potential future electricity requirements (GWh/year)[149]

	Residential Buildings		Commercial Buildings		Transport		Total		Growth
	2015	2050	2015	2050	2015	2050	2015	2050	2015 to 2050
Current Policies	1,667	2,857	3,056	3,667	0	0	4,722	6,524	38.2%
Strategy Policies	1,667	3,095	3,056	3,544	0	0	4,722	6,640	40.6%
100% Renewables	1,667	4,286	3,056	4,156	0	556	4,722	8,997	90.5%

Under current policies, electricity growth over the 35-year period from 2015 to 2050 across the residential, commercial and transportation sectors was projected to be on the order of 38%. Under the Strategy scenario, the review finds that electricity growth is 40% over the 35-year period or double the 20% increase determined in the Strategy. The 40% growth rate is more consistent with the rate of increase in BC Hydro's 2016 Load Forecast, which projects 20% load growth (net of DSM) system-wide by 2030.[150] Under the policies designed to achieve 100% renewables, the review predicts that electricity consumption will nearly double, growing by 90%.

In summary, similar to the province-wide analyses conducted by BC Hydro in the 2013 IRP, projections of electricity load growth for the City of Vancouver vary widely in a low-carbon future. These estimates range from 20% to 90% between 2015 and 2050 depending on a myriad of factors, including:

- the extent and success of DSM;
- the relative costs of DSM, distributed generation, renewable natural gas, and electricity from BC Hydro; and
- the force and effect of regional, provincial and national policies.

As the review of the Vancouver Renewable City Strategy notes, the additional policies designed to meet the objectives of the Strategy largely involve fuel switching from fossils fuels to electricity, and depend on assumptions about the future cost and availability of RNG for which the research acknowledges there are "substantial uncertainties".[151]

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[149] Zuehlke, B., Jaccard, M. and R. Murphy. 2017. Can Cities Really Make a Difference?: Case Study of Vancouver's Renewable City Strategy, Figures 4, 7, and 12. Converted from TJ/year (Accessed 17 April 2017 at http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017)

[150] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

[151] Zuehlke, B., Jaccard, M. and R. Murphy. 2017. Can Cities Really Make a Difference?: Case Study of Vancouver's Renewable City Strategy, p.26. (Accessed 17 April 2017 at http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017)

3.4.3 Implications of low-carbon electrification

In summary, the direction of electricity requirements resulting from electrification is clear — they will increase.

The increases in electricity requirements in the DDPP and TEFP, which are on the order of 130% and 220% above current requirements by 2050, are not defensible based on the information provided in these analyses.

In its 2013 IRP electrification analysis, BC Hydro projected that requirements for additional electricity inclusive of low-carbon electrification could increase between 49% and 120% by 2050, depending on future natural gas and GHG prices. Since that time, however, there have been no increases in electricity requirements.

The Vancouver Renewable City Strategy predicts that its total electricity requirements, inclusive of low-carbon electrification, will grow only 20% by 2050. However, a critical review of the Strategy, making different policy assumptions found that electricity requirements would need to increase on the order of 90% to achieve the objectives of the Strategy.

Though available information indicates that the effects of electrification on BC Hydro's load forecast are likely to be significant, the timing and extent of those increases remains remain highly uncertain.

The preponderance of information points to a significant effect from electrification beginning not sooner than the 2030s. The possible exception concerns the electrification of natural gas production, processing, transmission and liquefaction, which is currently underway and already included in BC Hydro's 2016 Load Forecast.

The 2018 IRP or a referral of the Site C Project for review by the BCUC would provide the opportunity for BC Hydro to review the full impact of policy developments on the extent and timing of electrification, and to prepare a new load forecast.

3.5 Summary

The justification for proceeding with the Site C Project at this time hinges on BC Hydro's forecast that the province's electricity needs will grow by 40% over the next 20 years. Importantly, this is before accounting for energy savings from conservation and efficiency (i.e. DSM). After accounting for DSM, BC Hydro's most recent forecast projects that electricity needs will grow by 30%,[152] meaning that BC Hydro is projecting that DSM will play only a modest role in reducing future electricity requirements.

Since Site C was initially proposed in the early 1980s, BC Hydro's load forecasts have consistently overstated future growth in electricity requirements. As demonstrated in

[152] BC Hydro. January 23, 2017. F2017 to F2019 Revenue Requirements Application, Response to Information Request CEC 2.135.1. F2016 – 57,310 GWh/year and F2036 – 74,348 GWh/year. (Accessed 17 April 1-2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf -- See data in spreadsheet attachment within the pdf document).

Section 3.2.5, BC Hydro's forecasters have overestimated 10-year, 15-year and 20-year future requirements consistently for the past several decades. The risk is the development of additional higher-cost supply-side resources producing large amounts of surplus energy that must be sold into export markets at a considerable loss.

With the collapse of BC Hydro's 2012 Load Forecast, energy from the Site C Project will be surplus when the Project comes on-line – even with the inclusion of "Expected LNG" load, a large portion of which remains uncertain. While additional load from electrification may help to mitigate the losses associated with this energy surplus, these additional requirements remain highly uncertain and may not be material until well into the 2030s.

As a result of these ongoing and future energy surpluses, the question facing BC Hydro is no longer whether to proceed as soon as possible with a resource portfolio containing the Site C Project or an alternative portfolio containing other supply-side resources, as analyzed in the 2013 IRP.

The decision now facing BC Hydro is whether to:

a) **continue with construction of the Site C Project to completion as scheduled;**
b) **cancel the Site C Project in order to develop alternative resources; or**
c) **suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant**.

These alternatives are discussed further below in Sections 4 and 5, respectively.

4. Option: Continue development of the Site C Project

4.1 Introduction

As indicated in Section 3.5, the decision now facing BC Hydro is whether to:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant.

This section explores the costs and risks of continuing with the Site C Project to completion as scheduled. Section 4.2 discusses the costs of the Site C Project, including costs incurred to date. Section 4.2.4 explores the costs related to the GHG emissions from the Site C Project. The potential for and implications of cost overruns in the development of the Site C Project is discussed in Section 4.3. This is followed by a discussion in Section 4.4 of the losses due to the energy surplus that would be created by the Site C Project. Section 4.5 summarizes the findings associated with the option of continuing the Site C Project to completion as scheduled.

4.2 Site C Project costs

4.2.1 Initial project cost estimates

In terms of project costs, the Site C Project budget summary is provided in Table 11.

Table 11: Site C Project budget summary[153]

Description	Capital Amount (Nominal $ million)
Dam, Power Facilities and Associated Structures	4,120
Offsite Works, Management and Services	1,575
Total Direct Construction Cost	**5,695**
Indirect Costs	1,235
Total Construction and Development Cost	**6,930**
Interest During Construction	1,405
Project Cost, before Treasury Board Reserve	**8,335**
Treasury Board Reserve	440
Total Project Cost	**8,775**

[153] BC Hydro. 2016. Site C Clean Energy Project: Annual Progress Report No.1 July 2015 to September 2016, Table 13. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/annual-progress-report-no1-20150701-20160930.pdf)

The total capital cost of the Site C Project, including interest during construction is estimated at $8.335 billion (nominal[154]), excluding the $440 million Treasury Board reserve. This represents about a 5% increase to the capital cost estimate of $7.9 billion used to evaluate the Site C Project against the alternatives in the 2013 IRP and in the environmental assessment.[155]

These capital costs would translate into a series of annual costs to be paid by ratepayers following commissioning of the Project. BC Hydro reported this annual cost to be about $510 million (nominal) over a 70-year period following commissioning.[156] Though the BC Utilities Commission would ultimately determine the annual amounts to be paid by ratepayers and the term for those payments, this annual cost allows for annual and net present value comparisons of costs between the Site C Project and alternative demand-side and supply-side resources that could be used to meet BC Hydro's electricity requirements. Any costs of the Site C Project that are not transferred to ratepayers would be covered by taxpayers (as shareholders of BC Hydro), whether as direct costs or as foregone dividends.

4.2.2 Cost to ratepayers: 10 Year Rates Plan

In December 2014, at the time of the decision to proceed with the Site C Project, the Provincial Government explained the cost to ratepayers of energy from Site C as a result of the Government's 10 Year Rates Plan for BC Hydro.[157] Under the Plan, the amount of net income that BC Hydro is required to earn each year will be tied to inflation from F2018 until F2024 and, during that period, will no longer increase when new assets are added to the system. Under the Plan, new assets will be financed at a cost approximating the cost of debt, as opposed to being financed based on a weighted average cost of debt and equity, which reflects the higher risk associated with an equity investment.

In a backgrounder entitled "Comparing the Options",[158] 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-

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154 As of the commissioning date.

155 BC Hydro. January 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 1: Introduction, Project Planning, and Description. Section 5: Need for, Purpose of, and Alternative to the Project, p.5-40. (Accessed 17 April 2017 at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328)

156 Government of British Columbia and BC Hydro. "Site C to provide more than 100 years of affordable, reliable clean power." Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

157 Government of British Columbia. November 26, 2013. 10 Year Plan for BC Hydro, p.31. (Accessed 17 April 2017 at: https://news.gov.bc.ca/stories/10-year-plan)

158 Government of British Columbia and BC Hydro. "Site C to provide more than 100 years of affordable, reliable clean power". Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

$88/MWh. (The $2.50/MWh range reflects the $440 million Treasury Board reserve, which may not be fully required.)

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. BC Hydro makes clear in its 2016 RRA that "the 10 Year Rates Plan did not include the Site C Clean Energy Project" and that it "has not yet determined how it will have the impact of the Site C Clean Energy Project come into rates."[159] The current government has not committed to continue the Plan after it expires and, even if it did make such a commitment, it cannot bind future governments. Moreover, there is no guarantee that future governments will maintain the 10 Year Plan to its scheduled conclusion.

There is thus no reason to assume that the 10 Year Rates Plan will affect the financing of the Site C Project. Furthermore, even if the Plan were extended to include the Site C Project, the difference in cost would consist of monies that would otherwise be paid as dividends to the Provincial Government as the sole owner of BC Hydro. This would not affect the actual costs of the Project, but only the allocation of those costs between ratepayer and taxpayer.

4.2.3 Costs incurred to date

From F2007 until the third quarter of F2015, BC Hydro incurred costs in relation to planning and development of the Site C Project and deferred these costs into a regulatory account. In its responses to information requests filed during the 2016 RRA, BC Hydro confirmed that the deferral account for the Site C Project stands at $453 million at the end of F2017 (March 31, 2017).[160] In its most recent 2017/18 to 2019/20 Service Plan, BC Hydro reported total capital expenditures of $1,268 million to the end of F2017.[161]

By the end of F2018, BC Hydro budgets total capital expenditures of $1,844 million and total deferred costs of $472 million, for a total of $2,316 million.[162] Prorating these amounts, anticipated capital expenditures would total $1,412 million and deferred costs $458 million, for a total of $1.87 billion by June 30, 2017. Looked at another way,

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[159] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request AMPC 1.1.5. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[160] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request FortisBC 1.2.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

[161] BC Hydro. February 2017. 2017/18 – 2019/20. Service Plan, p.16. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/BCHydro-Service-Plan-2017-18-2019-20.pdf)

[162] BC Hydro and Power Authority. 2016. 2016/17 to 2018/19 Service Plan, p.16. (Accessed 17 April 17 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/service-plans/bchydro-service-plan-2016-17-2018-19.pdf)

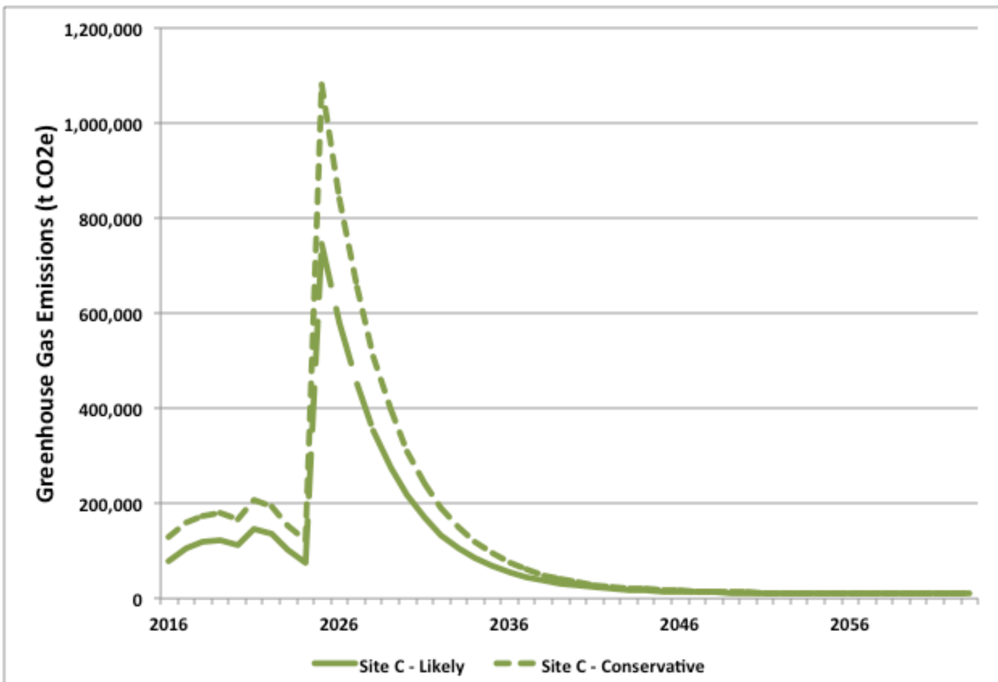
disregarding sunk costs, as of June 30, 2017 the cost of completing the Site C Project will be $6.465 billion (~80% of the original budget).

These costs are used in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.2.4 Greenhouse gas emissions from the Site C Project

In a previous study, one of this report's authors explored in detail the expected GHG emissions of the Site C Project.[163] Figure 13 presents BC Hydro's "likely" and "conservative" estimates of annual greenhouse gas emissions that the Site C Project would produce, where emissions prior to F2024 reflect construction-related emissions and emissions following F2024 indicate operating emissions. Figure 14 presents the cumulative GHG emissions of the Site C Project over the first forty years of operations.

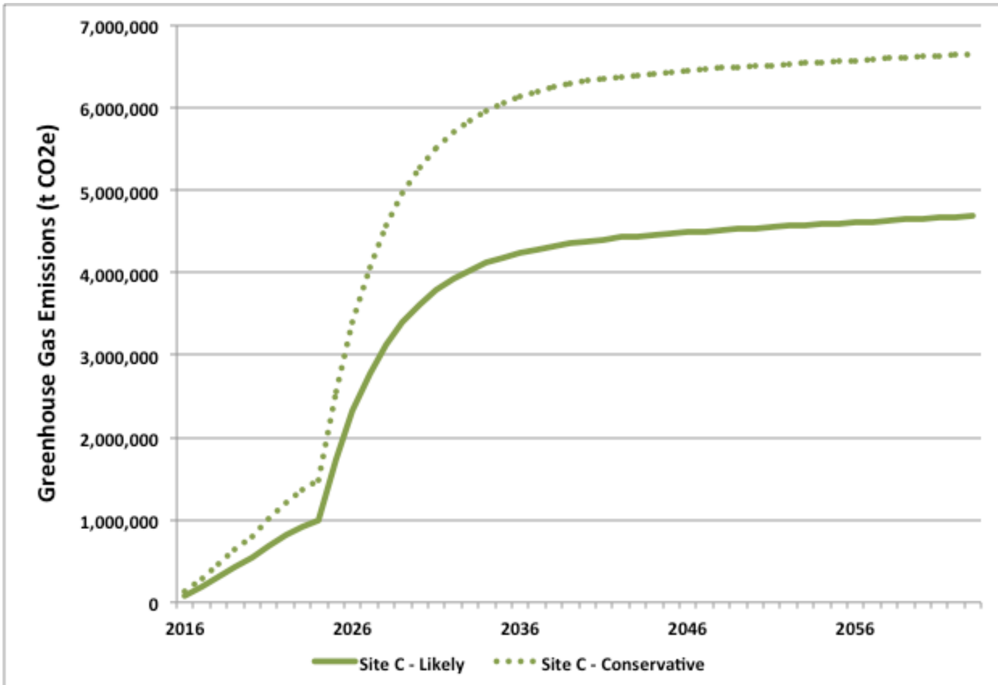
Figure 13: Annual GHG emissions of the Site C Project[164]



[163] Hendriks, R.M. July 2016. Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. Available at: www.waterpartners.ca/projects/sitec

[164] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 2 Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd., Table C-4 and Table C-6. (Accessed 17 April 2017 at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328)

Figure 14: Cumulative GHG emissions of the Site C Project[165]



The cost of construction phase GHG emissions are implicitly included in the construction costs of the Site C Project to the extent that the existing carbon tax of $30/tonne of GHG emissions applies to fuel, materials and equipment. However, GHG emissions from the operations phase were not included in the cost estimate. Using the price of $50/tonne in 2022 announced by the Government of Canada,[166] and assuming that this price will increase with inflation, we estimate the cost associated with GHG emissions from the Site C reservoir to be as indicated in Figure 15. These costs are included in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

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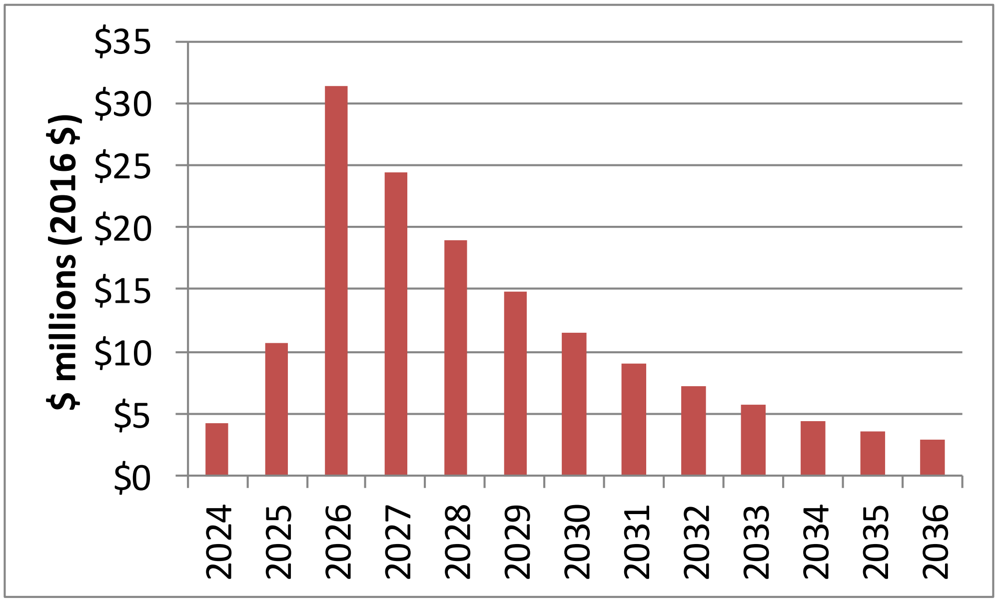
[165] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement. Volume 2 Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd., Table C-4 and Table C-6. (Accessed 17 April 2017 at: http://www.ceaa-acee.gc.ca/050/document-eng.cfm?document=85328)

[166] Government of Canada. October 3, 2016. "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution. (Accessed 17 April 2017 at: http://news.gc.ca/web/article-en.do?nid=1132149)

Figure 15: Costs associated with GHG emissions of the Site C Project



4.3 Site C Project cost uncertainties

4.3.1 Potential for cost overruns

BC Hydro's recent annual and quarterly progress reports also provide updates on the progress of construction of the Site C Project. As noted in the F2017 first quarter progress report, several key milestones were delayed by several months, including in relation to the main civil works. BC Hydro notes that the overall progression of work remains on track to achieve the scheduled in-service dates, but that the success of re-sequencing of work to address delays over the fall and winter "is not yet determined".[167] BC Hydro also notes that: "Any cost impacts to BC Hydro associated with rescheduling activities can be managed from existing contingency budgets."[168]

Several other factors outlined in the Annual Progress Report could potentially contribute to cost overruns in relation to the Site C Project, including the following:

- First Nations opposition;
- Ongoing litigation;
- Permitting delays;

[167] BC Hydro. 2016. Quarterly Progress Report No. 4 F2017 First Quarter April 2016 to June 2016, p.2. (Accessed 17 April 17 https://www.sitecproject.com/sites/default/files/sitec-q-progress-report4-f2017-q1-201604-201606_0.pdf)

[168] BC Hydro. 2016. Quarterly Progress Report No. 5 F2017 Second Quarter July 2016 to September 2016, p.2. (Accessed 17 April 17 at: https://www.sitecproject.com/sites/default/files/quarterly-progress-report-no5-f2017-q2-july-september-2016.pdf)

- Labour costs or instability;
- Material and equipment costs;
- Construction execution;
- Exchange rates;
- Interest rates; and
- Tax rates.

In addition to the above are geotechnical risks, which BC Hydro notes include unexpected shears encountered during construction, deeper than expected relaxation joints, bedding planes worse than expected, larger than expected deterioration of shale bedrock once exposed during construction, and rock rebound/swell. The tension crack that formed recently along the north bank is an example of a geotechnical risk faced by the Project.[169] These geotechnical risks represent one of the more significant threats to the schedule and costs of the Project at this stage, since they will only be more fully understood as major excavation and tunnelling continues in 2017.[170]

To the extent that the Site C Project is delayed or incurs unanticipated costs that exceed contingencies, construction costs and debt servicing costs will increase. As of December 31, 2016, $285 million of a total available contingency of $1.04 billion had been expended.[171]

Internationally, large hydro projects tend to exceed initial project budgets by an average of 27%.[172] Outside of Quebec, where large-scale hydro development is more frequent, costs of large-scale, greenfield hydroelectric and transmission developments in Canada follow a similar pattern, as illustrated in Table 12.

[169] CBC. February 24, 2017. 'Tension crack' interrupts Site C dam construction. Available at: http://www.cbc.ca/news/canada/british-columbia/site-c-dam-officials-halt-road-work-over-large-tension-crack-1.3998157.

[170] BC Hydro. 2016. Quarterly Progress Report No. 5 F2017 Second Quarter July 2016 to September 2016, p.34. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/quarterly-progress-report-no5-f2017-q2-july-september-2016.pdf)

[171] BC Hydro. 2017. Quarterly Progress Report No. 3 F2017 Third Quarter October 2016 to December 2016, p.30. (Accessed 17 April 2017 at: (Access 17 April 17 at: https://www.sitecproject.com/sites/default/files/bcuc-quarterly-progress-report-q4-jan-mar-2016.pdf)

[172] Ansar, Atif, et al. "Should we build more large dams? The actual costs of hydropower megaproject development." *Energy Policy* 69 (2014): 43-56.

Table 12: 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	BC Hydro	230 kV	$222M	$296M	$74M	+33%	Operating

173 Nalcor Energy. June 24, 2016. Muskrat Falls Project Update Technical Briefing, p.3. (Accessed 17 April 2017 at: http://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/News-Conference-Presentation_MF-Project-Update_Web_24Jun2016.pdf)

174 Daily Commercial News. December 28, 2016. Muskrat Falls hydro project costs rise again. (Acceced 17 April 17 at: http://dailycommercialnews.com/Projects/News/2016/12/Muskrat-Falls-hydro-project-costs-rise-again-1020762W/)

175 Manitoba CEC. 2004. Report on Public Hearings Wuskwatim Generation and Transmission Projects, p.39. (Accessed 17 April 2017 at: (Accessed 17 April 17 at: http://www.cecmanitoba.ca/resource/reports/Commissioned-Reports-2004-2005-Wuskwatim_Generation_Transmission_Projects_Full_Report.pdf)

176 Wuskwatim Power Limited Partnership. About the Wuskwatim Generating Station. (Accessed 17 April 17 at http://www.wuskwatim.ca/project.html)

177 Manitoba Hydro. August 2013. Need for and Alternatives to Business Case. Executive Summary, p.4. (Accessed 17 April 2017 at: http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/nfat_business_case__1_executive_summary.pdf)

178 Boston Consulting Group. Bipole II, Keeyask and Tie-Line Review, p.37. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

179 "Keeyask dam cost estimate balloons by $2.2B" CBC News. (Accessed 17 April 17: http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-keeyask-dam-cost-electricity-pc-government-1.4013521)

180 Nalcor Energy. 2016. Muskrat Falls Project Update Technical Briefing June 24, 2016, p.3. Accessed 17 April 2017 at: (https://muskratfalls.nalcorenergy.com/wp-content/uploads/2013/03/News-Release_MF-Project-Update_24Jun2016.pdf)

181 Manitoba Hydro. 2011. Bipole III Environmental Impact Statement Filed. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/NewsReleases/GetDetail?hdnAct=E&hdnTXT=%27Bipole%20III%20Environmental%20Impact%20Statement%20Filed%27)

182 Boston Consulting Group. Bipole III, Keeyask and Tie-Line Review, p.37. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

Transmission Project[183,184]							
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

BC Hydro has not developed a large-scale greenfield hydroelectric project since the Revelstoke Generating Station commissioned in 1984, but it has developed large-scale greenfield transmission projects. The weighted cost overrun for BC Hydro's three most recent large-scale greenfield transmission projects was on the order of 43%.

Overall, BC Hydro reports that from F2012 to F2016, it completed 563 capital projects at an overall cost of $6.49 billion, or 0.18% under budget.[189] Considering that this value includes the projects in the above table, it would appear that BC Hydro's performance on smaller-scale and brownfield projects has been far superior to its performance on larger-scale, greenfield projects.

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[183] BC Utilities Commission. 2012. In the Matter of British Columbia Hydro and Power Authority Certification of Public Convenience and Necessity for the Dawson Creek / Chetwynd Area Transmission Project, p.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2013/DOC_34487_04-08-2013_BCH_PUBLIC_G-144-12_Directive_2a.pdf)

[184] BC Hydro. 2016. British Columbia Hydro and Power Authority. 2015/16 Annual Service Plan Report, p.89. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf)

[185] BCTC. 2008. BCTC Interior to Lower Mainland Transmission Project EAC Application – November 10, 2008, p.4-39.

[186] BC Hydro. 2016. British Columbia Hydro and Power Authority. 2015/16 Annual Service Plan Report, p.89. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf)

[187] BC EAO. 2011. Northwest Transmission Line Project Assessment Report, p.21

[188] BC Hydro. 2015. British Columbia Hydro and Power Authority. 2014/15 Annual Report, p.92. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2015.pdf)

[189] BC Hydro. 2016. British Columbia Hydro and Power Authority. 2015/16 Annual Service Plan Report, p.6. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf)

4.3.2 Quantifying potential cost overruns

The potential for Site C Project cost overruns is relevant to the decision to continue, cancel or suspend the Project. Considering that the Project remains in the early stages of construction, with about 80% of project costs yet to be incurred, the extent of eventual cost overruns, if any, cannot be fully determined at this point.

For every 10% that the Site C Project is over budget, total costs increase on the order of $800 million (nominal). For example, a cost overrun of 23% (on par with that for the Interior to Lower Mainland Transmission Line) would amount to $1.9 billion, or more than what has been expended on the project to date. A cost overrun of 43%, consistent with BC Hydro's performance on its most recent three large-scale transmission lines, would see a cost overrun of $3.6 billion for a total cost on the order of $11.9 billion.

A cost overrun of 43% or $3.6 billion on the Site C Project may appear excessive or unreasonable, but not when viewed in the context of similar projects:

- the Muskrat Falls Project (76% cost overrun) and the Keeyask Hydroelectric Project (40% cost overrun) make a 43% cost overrun at Site C appear not exceptional;
- the Muskrat Falls + Labrador Island Transmission (combined cost overrun $3.4 billion or 62%) and the Keeyask + Bipole III (combined cost overrun $4.6 billion or 48%) also make a $3.6 billion cost overrun at Site C appear not unreasonable.

This does not mean that the Site C Project will necessarily incur a cost overrun. Rather, 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. However, the full extent of any cost overruns will not be known until the Project is further advanced. The potential for cost overruns adds an additional element of risk to the development of the Site C Project that is addressed further in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.4 Losses due to the Site C Project energy surplus

Based on the load resource balances presented by BC Hydro in the 2016 RRA,[190] the Site C Project is now forecast to create an energy surplus that would last for a period of about 8 years following commissioning in F2024. This energy surplus creates additional costs that may not be immediately obvious.

A capital-intensive project like Site C is financed much like a mortgage -- there is a fixed amount to be paid each year to cover the debt and the return on BC Hydro's equity investment. The annual amount of these combined costs is divided by the number of

[190] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

kWh produced each year to give the unit cost that must be recovered through electricity sales.

When the energy is sold to regulated consumers, their rates are set high enough to cover this cost. However, when the energy is exported, it is the export market that sets the sales price. When the sales price is not sufficient to cover the unit costs, then the shortfall must be made up either by regulated ratepayers through increased rates, or by taxpayers through reduced dividends (or cash injections to BC Hydro).

Because current and foreseeable market prices are far below the unit cost of Site C energy, any energy surplus will inevitably create losses of this type. The ultimate size and duration of the surplus cannot be known with certainty until years following the commissioning of the Site C Project, but can be estimated based on BC Hydro's 2016 Load Forecast.

4.4.1 Projected surplus under the mid-load forecast scenario

BC Hydro's 2016 RRA mid-load forecast indicates that the Site C Project will be entirely surplus to domestic requirements when it comes on-line in F2024. Concerns about the implications of this energy surplus were raised by the JRP, which wrote in its final report:

> BC Hydro's outlook is that the market prices it would achieve through the forecast period would average only $35/MWh, radically less than the marginal cost of production and delivery (about $94/MWh[[191]])[at that time; now $85 to $88/MWh[192]]. Site C would be a large, sudden addition to supply. BC Hydro projects losing $800 million [nominal] in the first 4 years of operation. These losses would come home to B.C. ratepayers in one way or another.[193]

BC Hydro now anticipates that when the Project comes on line, an energy surplus would persist for 7 years under its mid-load scenario.[194] Though surplus energy would need to be sold on export markets, in the 2013 IRP BC Hydro made clear its perspective on the prospects for export sales of clean energy:

> Since the enactment of the *CEA*, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency

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[191] The current estimate is about $85 to $88/MWh.

[192] Government of British Columbia and BC Hydro. "Site C to provide more than 100 years of affordable, reliable clean power". Backgrounder: Comparing the Options. See also, Section 4.2.2, above. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

[193] Site C Joint Review Panel. 2014. Report of the Joint Review Panel: Site C Clean Energy Project BC Hydro, p.298. Site C Joint Review Panel. 2014. Report of the Joint Review Panel: Site C Clean Energy Project BC Hydro, p.298. (Accessed 17 April 2017 at: https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf)

[194] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

> requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term.[195]

More recently, in its 2016 Revenue Requirements Application (RRA), BC Hydro reiterated this perspective: prospects are poor for potential export markets for renewable electricity generated in British Columbia.[196]

In its 2013 IRP, BC Hydro presented forecasts for future export market prices for sales of electricity into the U.S. market at the international border. Additional price forecasts were also considered by varying the expected price of electricity in the export markets, GHG prices and natural gas prices (the price-setting fuel in the US Northwest). BC Hydro updated these price forecasts in its 2016 RRA, as illustrated in Table 13.

The prices in this table reflect a single price forecast. 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. The 2013 IRP used an exchange rate of 0.9693 USD/CAD, which is much higher than today's rates, or the average long-term exchange rate of 0.82 USD/CAD used in Table 13. Failing to capture the uncertainty associated with future exchange rate variations, natural gas prices and other variables understates the financial risks associated with the Project.

These price forecasts make possible the development of an initial estimate of the potential losses from the Site C Project that would result from having to sell surplus energy on export markets. As shown in Table 14, in this price scenario and based on BC Hydro's mid-load forecast, the resulting losses rise to $235 million in F2026 before eventually receding to $0 by F2032.

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195 BC Hydro. November 2013. BC Hydro Integrated Resource Plan, Chapter 5 – Planning Environment, p.5-51. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0005-nov-2013-irp-chap-5.pdf)

196 BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.2-19. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

Table 13: B.C. electricity export sales market prices[197,198]

Year	Mid-C Market Prices[199]	Exchange rate	Mid-C Market Prices	Wheeling/loss Adjuster	B.C. Border Sell Price - Calendar Year	B.C. Border Sell Price - Fiscal Year
	$2016 USD/MWh	(USD/CAD)	$2016 CAD/MWh	$2016 CAD/MWh	$2016 CAD/MWh	$2016 CAD/MWh
2017	23.2	0.78	29.74	6.3	23.44	
2018	24.1	0.8	30.13	6.3	23.83	23.54
2019	27.2	0.82	33.17	6.3	26.87	24.59
2020	30.2	0.82	36.83	6.3	30.53	27.79
2021	32.5	0.82	39.63	6.3	33.33	31.23
2022	33.7	0.82	41.10	6.3	34.80	33.70
2023	35.0	0.82	42.68	6.3	36.38	35.19
2024	35.4	0.82	43.17	6.3	36.87	36.50
2025	36.2	0.82	44.15	6.3	37.85	37.11
2026	37.2	0.82	45.37	6.3	39.07	38.15
2027	38.1	0.82	46.46	6.3	40.16	39.34
2028	38.6	0.82	47.07	6.3	40.77	40.32
2029	39.9	0.82	48.66	6.3	42.36	41.17
2030	41.4	0.82	50.49	6.3	44.19	42.82
2031	43.0	0.82	52.44	6.3	46.14	44.68
2032	43.8	0.82	53.41	6.3	47.11	46.38
2033	44.7	0.82	54.51	6.3	48.21	47.39
2034	45.6	0.82	55.63	6.3	49.33	48.49
2035	46.6	0.82	56.78	6.3	50.48	49.62
2036	47.5	0.82	57.94	6.3	51.64	50.77
2037	48.5	0.82	59.13	6.3	52.83	51.94

197 BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.310.1. BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.310.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

198 The export market prices are determined from Mid Columbia (Mid-C) market prices, converted to Canadian dollars, adjusted for transmission wheeling costs and line losses, and converted to BC Hydro's fiscal years.

199 "Mid-C" refers to the Mid-Columbia electricity hub, a reference location for electricity prices in the United States Northwest, the market region into which electricity from the Site C Project would be exported.

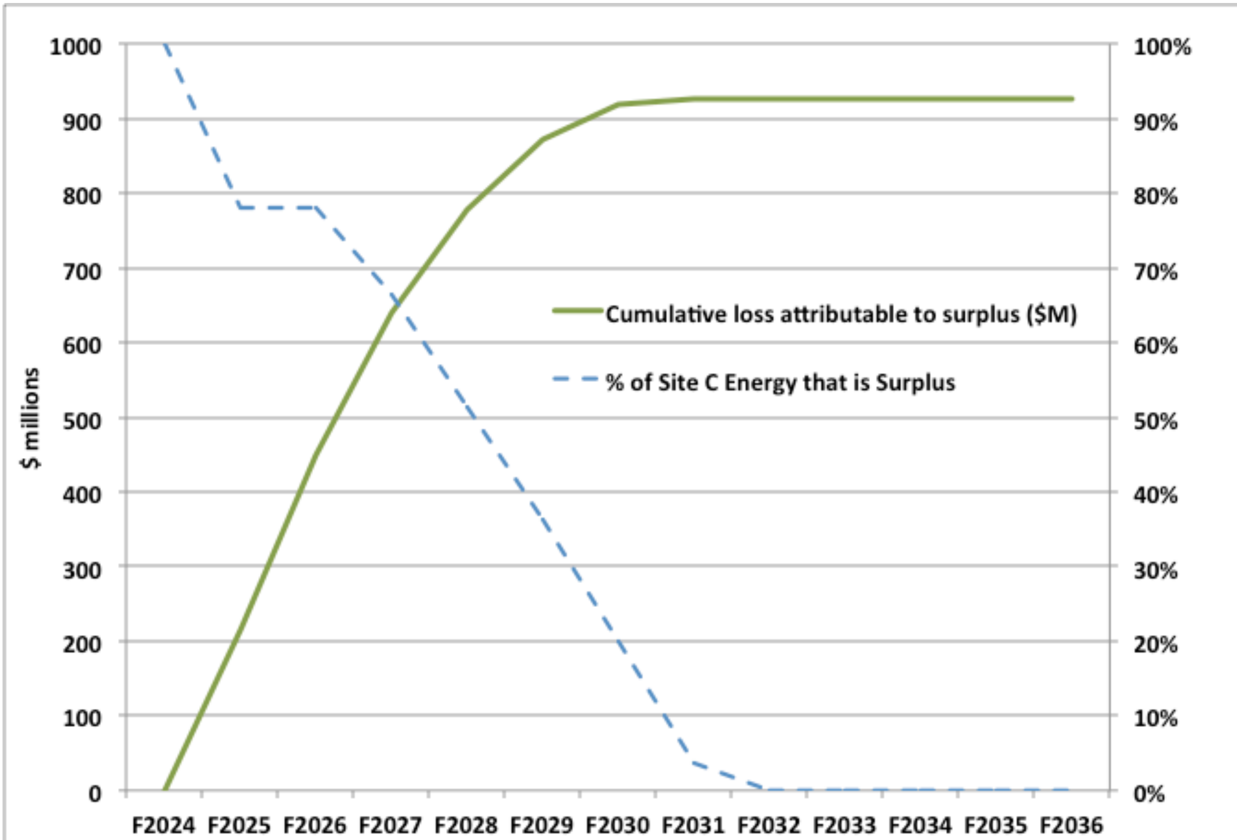
Table 14: Implications of the Site C energy surplus

Year	Site C Energy	B. C. Energy Surplus	Site C Energy used in BC	Site C Energy sold as surplus	% of Site C Energy that is Surplus	B.C. Border Sell Price
	(GWh)	(GWh)	(GWh)	(GWh)		(CA$2016/MWh)
	A	B	C = A - B	D = A - C	E = B / A	F
2024	388	720	0	388	100%	36.5
2025	4,435	3,459	976	3,459	78%	37.1
2026	5,100	3,976	1,124	3,976	78%	38.2
2027	5,100	3,395	1,705	3,395	67%	39.3
2028	5,100	2,621	2,479	2,621	51%	40.3
2029	5,100	1,845	3,255	1,845	36%	41.2
2030	5,100	1,014	4,086	1,014	20%	42.8
2031	5,100	187	4,913	187	4%	44.7
2032	5,100	-	5,100	-	0%	46.4
2033	5,100	-	5,100	-	0%	47.4
2034	5,100	-	5,100	-	0%	48.5
2035	5,100	-	5,100	-	0%	49.6
2036	5,100	-	5,100	-	0%	50.8
Year	Site C Energy Surplus Revenues ($M)	Site C Annual Cost ($M)[200]	Site C Costs Net of Sales Revenues	Costs attributable to surplus	Annual loss attributable to surplus	Cumulative loss attributable to surplus ($M)
	(CA$2016 M)	(CA$2016 M)	(CA$2016 M)	(CA$2016 M)	(CA$2016 M)	(CA$2016 M)
	G = D * F	H	I = H - G	J = E * H	K = J - G	L = K cum
2024	14.16	0	0	0	0	0
2025	128	440	311	343	214	214
2026	152	496	344	386	235	449
2027	134	486	352	323	190	639
2028	106	476	371	245	139	778
2029	76	467	391	169	93	871
2030	43	458	414	91	48	919
2031	8	449	441	16	8	927
2032	0	440	440	0	0	927
2033	0	431	431	0	0	927
2034	0	423	423	0	0	927
2035	0	415	415	0	0	927
2036	0	407	407	0	0	927

[200] These values represent the fixed nominal-dollar cost of the Site C Project, expressed in constant 2016$.

The findings in Table 14 are presented graphically in Figure 16 below. The solid green line illustrates the cumulative cost of the energy surplus. The dashed blue line shows the percent of Site C energy that is surplus each year.[201] As the percentage of Site C that is surplus declines to zero, the cumulative losses due to the surplus level off at the value of $927 million shown in F2036 in Table 14.

Figure 16: Losses due to the Site C Project energy surplus (mid-load forecast)



In summary, the losses due to the energy surplus created when the Site C Project is commissioned are an important consideration in evaluating the relative risks and costs of the Project. These losses do not appear in BC Hydro's determination of project costs summarized in Section 4.2.1, yet they are material to comparing the Project against the available alternatives, which can be developed modularly so as not to create a similar energy surplus. The extent of these losses depends not only on market prices, exchange rates and natural gas prices but also on the accuracy of BC Hydro's load

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[201] Table 14 and Figure 16 omit the small amount of energy to be produced by Site C in F2024, which is expected to be 100% surplus to BC requirements.

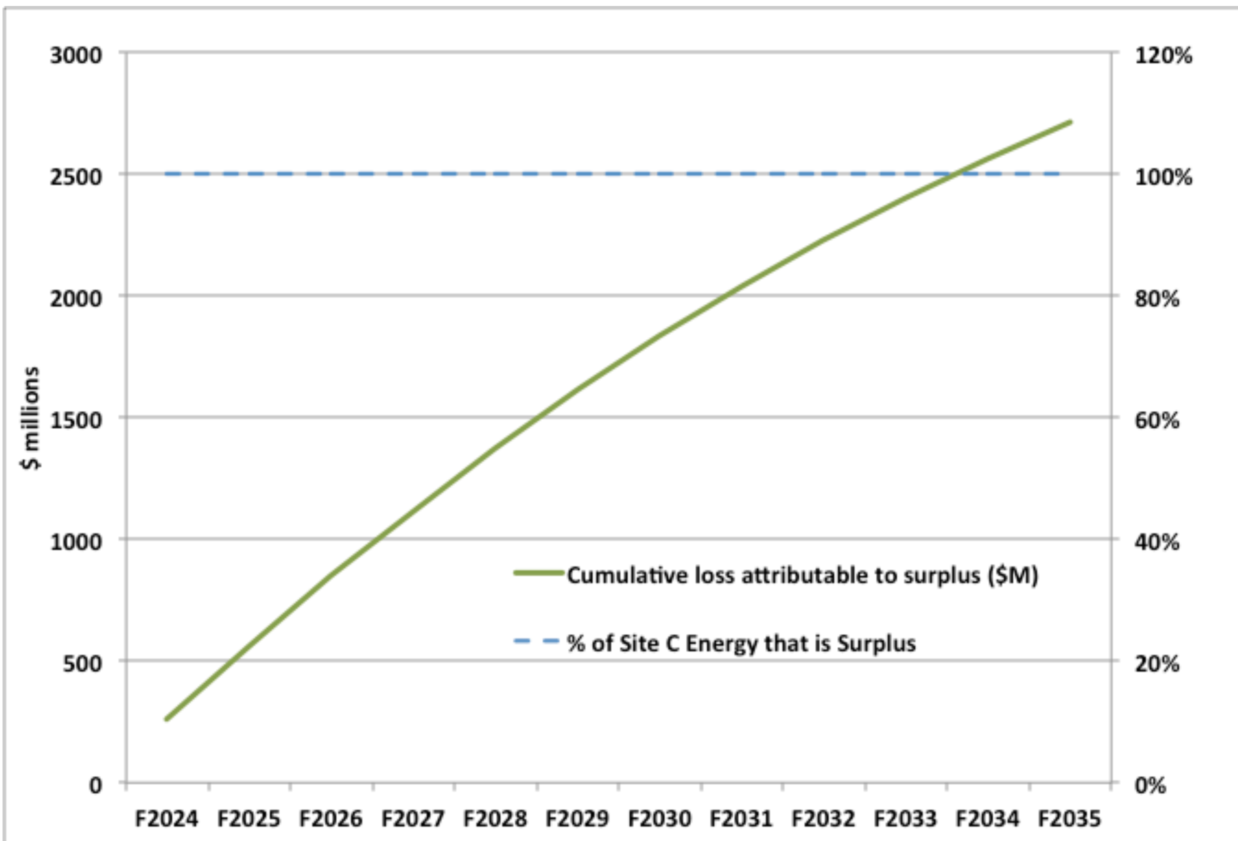
forecasts. Additional scenarios are developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

4.4.2 Potential surplus under the high-load and low-load forecast scenarios

In the event that the need for energy grows faster than anticipated, the losses resulting from the Site C Project surplus will be less than the $927 million illustrated above. For example, under BC Hydro's high-load scenario, the rapid growth in energy requirements would reduce the surplus to three years, and the resulting losses to just $279 million.

Considering that BC Hydro's mid-load forecasts have consistently overstated actual future demand, there remains a very real possibility that the surplus created by the Site C Project will persist longer than anticipated. Under the low-load scenario contained in the 2016 RRA, Site C is 100% surplus until F2036, and the costs to ratepayers by that time are on the order of $2.7 billion, with additional costs thereafter (Figure 17).

Figure 17: Losses due to the Site C Project energy surplus (low-load forecast)



As long as the energy from Site C is entirely surplus, the losses borne by ratepayers will be on average $225 million per year, declining from $300 million in F2026 to $150 million in F2036 as the annual cost of Site C in real dollars declines and market prices increase.

4.5 Summary

The key observations respecting the costs of continuing with development of the Site C Project are as follows:

- The current projected capital cost of the Site C Project, excluding the $440 million Treasury Board reserve, is $8.335 billion, which is about 5% higher than the $7.9 billion used to evaluate the Site C Project against the alternatives in the 2013 IRP;
- BC Hydro will have expended $458 million in deferred costs and $1,412 million in capital costs for a total of $1,870 million by June 30, 2017;
- Following the first year of construction, the Site C Project has experienced some delays, but BC Hydro anticipates that any cost impacts associated with rescheduling activities can be managed from existing contingency budgets totaling $1.04 billion, from which $285 million had been expended (as of December 31, 2016);
- In the event that the Site C Project has a cost overrun of 43% comparable to BC Hydro's most recent three greenfield transmission projects, the cost of the Site C Project would rise by $3.6 billion to a total of $11.9 billion;
- The cumulative losses resulting from the surplus created by the Site C Project under BC Hydro's mid-load forecast and the market price forecast in the 2016 RRA are on the order of $950 million; and
- Under BC Hydro's low-load forecast, the cumulative losses resulting from the Site C energy surplus would be on the order of $2.7 billion by F2036 and would continue to increase thereafter.

5. Options: cancel the Site C Project, or suspend the Site C Project

5.1 Introduction

Pursuant to Section 3.5, BC Hydro now has the following three options:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant.

This Section 5 begins with an analysis in Section 5.2 of costs associated with cancelling or suspending the Site C Project. The costs to cancel include addressing sunk costs to date and costs related to contract cancellation and demobilization. The costs to suspend also include addressing sunk costs to date, contract cancellation and demobilization. Suspension also includes costs to maintain the site in suspension, and to remobilize to the site in the event that circumstances warrant resuming the Site C Project at a future date.

Section 5.3 evaluates the demand-side resources (i.e. DSM) that would need to be developed in the event that Site C is cancelled or suspended. Similarly, Section 5.4 evaluates the supply-side resource (i.e. wind, natural gas, etc.) that would need to be developed in the event that Site C is cancelled or suspended. Section 5.5 summarizes the findings.

5.2 Site C Project cancellation and suspension costs

5.2.1 Sunk costs

Any potential decision to cancel or suspend the Site C Project must take into consideration costs already spent in developing the Project. As these sunk costs increase, the opportunity to pursue an alternative path fades. As indicated in Section 4.2.3, total expenditures to the end of June 30, 2017 were projected to be $1.87 billion, leaving $6.465 billion to be spent. Therefore, development of an alternative portfolio of resources must be evaluated against a suspended Site C Project that can be realized at an additional cost of just $6.465 billion, plus remobilization costs, and not the full project cost of $8.335 billion.

In the event that the Site C Project is cancelled, these sunk costs will need to be repaid. It is presumed that these costs are repaid over a 70-year period, similar to the repayment of the Site C Project if it were developed to completion. Suspension of the Site C Project must consider the cost to carry these sunk costs until a decision is made to either continue or cancel the Project.

5.2.2 Cancellation costs

The cancellation of the Site C Project would entail contractual costs (e.g. contract breakage, remediation), including demobilization costs, which must also be considered.

The magnitude of these costs would depend on the terms of any contracts signed to date, information that has not been publicly divulged. However, the value of the major contracts executed to date is provided in BC Hydro's most recent project progress update, and shown in Table 15. The total value of minor contracts (valued at less than $10 million) was not provided by BC Hydro.

Table 15: Major Site C Project contracts awarded (to December 2016)[202]

Work Package	Contract Value ($M)	Current Status
Site Preparation: North Bank	60	Executed July 2015, and includes amendments to December 2016
Worker Accommodation	465	Executed September 2015
Main Civil Works	1,750	Executed December 2015
Turbine-Generator	464	Executed March 2016
TOTAL	**2,739**	

Cancellation of the Site C Project would entail costs for demobilization. These costs would include:

- Removing equipment, personnel and materials from the site;
- Securing quarries and borrow areas and allowing them to flood in accordance with permit conditions;
- Stabilizing any rock or overburden stockpiles in accordance with permit conditions;
- Removing any fuels, chemicals and explosives from the site; and
- Securing mechanical, hydraulic and electrical systems.

A recent review of Manitoba Hydro's 695 MW Keeyask Project on the Nelson River in northern Manitoba indicated that $2.5 billion, or 39% of project development costs of $6.5 billion, had been spent as of September 2016.[203] Cancelling that project at that stage would have triggered on the order of $1.3 billion in contract cancellation costs.[204] The Site C Project will have expended approximately $1.412 billion in capital costs

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[202] BC Hydro. 2016. Site C Clean Energy Project: Annual Progress 6 October 2016 to December 2016, Table 9. (Accessed 17 April 2017 at: https://www.sitecproject.com/sites/default/files/quarterly-process-report-no6-f2017-q3-october-december-2016.pdf)

[203] Boston Consulting Group. Bipole II, Keeyask and Tie-Line Review, p.36. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

[204] Boston Consulting Group. Bipole II, Keeyask and Tie-Line Review, p.37. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

(excluding deferred costs) by June 30, 2017, with more than $2.730 billion contracted. Based on the proportions in the Keeyask Project review, cancellation costs for the Site C Project as of June 30, 2017 are estimated to be on the order of $600 million to $900 million, including demobilization costs. For the purposes of the analysis in Section 6.3, an amount of $750 million for contractual and demobilization costs is estimated.

The Site C Project has faced considerable First Nation and public opposition, as well as ongoing litigation.[205] The potential for disruption of construction or revocation of permits issued to allow the Project to proceed suggests that BC Hydro would have exercised caution before entering into construction contracts to ensure that the interests of ratepayers were protected in the event of disruption or cancellation.

However, the extent to which BC Hydro was successful in negotiating cancellation or suspension clauses into these contracts cannot be determined, since contractual arrangements with the many contractors working on the Site C Project are confidential. Without access to the Site C construction contracts, the contract cancellation costs represent a significant unknown cost in evaluating the options to continue, cancel or suspend the Site C Project.

Typically, the BCUC would have access to these contracts were the Commission to review the Site C Project. In the event that the Site C Project is referred to the BCUC for further review, these cancellation costs should be further evaluated.

5.2.3 Suspension costs

Contract cancellation and demobilization costs are presumed for the purposes of the analysis in this report not to apply to a suspended Site C Project. To the extent that the Project is suspended for an extended period of time, it is quite likely that contract cancellation costs will be triggered. Considering the significant uncertainty respecting the magnitude of these costs, the details of any payments to contractors in a suspension period are for further consideration in the event that the Site C Project is referred for further review to the BC Utilities Commission.

Following demobilization of non-essential equipment and materials, additional ongoing costs would be incurred for maintenance and monitoring if the Site C Project is suspended but not cancelled. These costs could include the following:

- Securing the site from visitors for protection of the public through the provision of fencing or other measures;
- Maintaining the site in a secure condition through provision of continuous security;
- Periodically inspecting any rock or overburden stockpiles;

[205] BC Hydro. 2017. Quarterly Progress Report No. 6 F2017 Third Quarter October 2016 to December 2016, pp.5-7. (Accessed 17 April 17 at: https://www.sitecproject.com/sites/default/files/quarterly-process-report-no6-f2017-q3-october-december-2016.pdf)

- Securing and maintaining all facilities to remain on-site during suspension; and
- Continuing with environmental monitoring programs in accordance with permit conditions.

No large-scale hydroelectric projects are currently in a state of suspended construction in Canada. The costs to suspend the Site C Project are therefore estimated to be on the order of $15 million per year based on the annual site maintenance costs at a large and currently suspended mine site.[206] In the event that the Site C Project is referred to the BCUC for further review, these suspension costs should be further evaluated.

5.2.4 Remobilization and continuation costs

Costs to remobilize the construction site following a suspension of the Site C Project would likely be similar to costs to initially mobilize to the site in the summer and fall of 2015 (i.e. Q2 and Q3 of F2016). However, these costs were not specifically reported by BC Hydro. In its quarterly progress report for the third quarter of F2016 ending December 31, 2015, BC Hydro reported actual project costs to that date of $694 million.[207] These costs would include deferred costs incurred prior to mobilization, which were $432 million as of that date.[208] This suggests that about $270 million was expended during the first five months on-site, which provides an initial order of magnitude estimate of site mobilization costs. Not all of these costs would have been related to mobilization, and remobilization is likely to be somewhat less costly than mobilization. An estimated amount of $200 million (or about 3% of initial construction costs) is added to the remaining cost of $6.465 billion following suspension, for a total of $6.665 billion to resume the development of the Site C Project if circumstances warrant at some future date.

5.2.5 Summary of costs related to cancellation or suspension

The following table summarizes the costs related to cancellation and suspension, respectively. These costs are integrated into the analysis in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

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[206] Potash Corp. January 19, 2016. News Release: PotashCorp to Suspend New Brunswick Potash Operations. “The Picadilly mine will be placed in care-and-maintenance mode at an estimated annual cost of $20 million in 2016 and $15 million in subsequent years.” (Accessed 17 April 2017 at: http://www.potashcorp.com/news/2112/)

[207] BC Hydro. 2017. Quarterly Progress Report No. 2 F2016 Third Quarter October 2015 to December 2015, p.23. (Accessed 17 April 17 at: https://www.sitecproject.com/sites/default/files/2016_03_11_BCH_SC_RPT_02_PUB.pdf)

[208] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request FortisBC 1.2.1. Reports $419 million to March 31, 2015 and $436 million to March 31, 2016. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

Table 16: 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

5.3 Evaluating demand-side resources

Following cancellation or suspension of the Site C Project, it would be necessary for BC Hydro to advance other resources in order to meet future requirements for energy or capacity. Any future scenarios involving a cancelled or suspended Site C Project would require additional investment in demand-side measures beyond that currently contemplated by BC Hydro, and in advance of higher-cost supply-side resources.

The *Clean Energy Act* defines 'demand-side measure' (DSM) to mean:

> "a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency; (b) to reduce the energy demand a public utility must serve; or (c) to shift the use of energy to periods of lower demand … but does not include (d) a rate, measure, action or program the main purpose of which is to encourage a switch from the use of one kind of energy to another such that the switch would increase greenhouse gas emissions in British Columbia, or (e) any rate, measure, action or program prescribed."[209]

BC Hydro develops and implements two forms of DSM: energy-focused DSM and capacity-focused DSM. The former involves measures designed to conserve energy, promote energy efficiency and reduce customer energy demand. Capacity-focused measures target additional capacity savings during BC Hydro's peak load periods. These two forms of DSM are discussed below.

5.3.1 Energy-focused demand-side management

Since the 2013 IRP, BC Hydro has made a number of decisions that have resulted in a considerable reduction in the role that DSM plays in meeting requirements for energy and capacity. These decisions have had implications for the need to advance higher-cost supply-side resources, including the Site C Project.

[209] *Clean Energy Act*, SBC 2010, c 22

The state of DSM

BC Hydro relies on three general approaches to energy-focused DSM:

- *Codes and standards*: public policy instruments enacted by governments to influence energy efficiency (e.g. building codes, appliance standards, local government zoning);
- *Conservation rate structures*: inclining block (stepped) rate structures (for residential, commercial and industrial customers) designed to reduce electricity consumption; and
- *Programs*: designed to support codes and standards and rate structures, as well as to address the remaining barriers to energy efficiency and conservation after codes and standards and rate structures, thereby capturing additional conservation potential.[210]

Historically, these demand-side resources have focused on reducing energy needs, though they also provide capacity savings. BC Hydro's 2013 IRP identified DSM options that targeted increasing energy and associated capacity savings by F2021. Each of these options is described briefly below.

Table 17: Energy-focused DSM Options[211]

DSM Option	Energy Savings by F2021 (GWh/year)	Capacity Savings by F2021 (MW)	Description
Option 1	6,100	1,200	Minimum required to meet the *Clean Energy Act* objective of reducing BC Hydro's "expected increase in demand for electricity by the year 2020 by at least 66%"
Option 2	7,800	1,400	The DSM Target used in the 2013 IRP
Option 3	8,300	1,500	Targets additional electricity savings beyond Option 2 by expanding program efforts, while keeping codes and standards and conservation rate structures unchanged
Option 4	9,500	1,500	Based on new or more aggressive conservation rate structures, and significant government regulation in the form of codes and standards
Option 5	9,600	1,600	Creates a future where most buildings are net-zero consumers of electricity with some buildings being net contributors of electricity back to the grid

[210] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 Resource Options, Section 3.3. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

[211] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 Resource Options, Section 3.3.1. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

BC Hydro selected Option 2 as its DSM Target for use in the 2013 IRP, despite the fact that Option 3 represented (in 2013) the "greatest level of DSM program savings currently considered deliverable".[212] BC Hydro determined that the additional cost to the utility to implement DSM Option 3 as opposed to DSM Option 2 was on the order of $50 million per year.[213]

The decision not to proceed with DSM Option 3 was the result of BC Hydro's ongoing energy surplus, which the utility believed at that time would be short-lived, and the utility's desire to reduce near-term costs. Indeed, BC Hydro recommended in the 2013 IRP to moderate (i.e. reduce) program spending for DSM Option 2 in the near term (F2014 through F2016), in order to reduce costs further without compromising the ability to ramp up to the DSM Target seven years later, in F2021.[214]

Since the approval of the 2013 IRP, it is now clear that the energy surplus will continue well into the future, meaning that a return to DSM Option 2 would exacerbate the surplus. In the 2016 RRA, BC Hydro confirmed that it is proposing to further extend the "moderation" of DSM program spending through F2017 – F2019.[215] Moreover, this moderation strategy is being extended as an assumption for F2020 and beyond, pending further review as part of the 2018 IRP.[216]

The consequences of these successive moderations to DSM spending are not immaterial for the need to develop new, and costlier, supply-side resources, including the Site C Project. During the proceedings for its 2016 RRA, and in response to an information request seeking to understand the implications of further moderation of DSM, BC Hydro filed information updating DSM Option 2. This information reflected a similar level of activity as the DSM plan included in the 2013 IRP, but incorporated changes from new market information, including "lower than planned savings from conservation rates, increased savings from codes and standards, and changes to

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[212] BC Hydro. November 2013. Integrated Resource Plan, Chapter 4 Resource Planning Analysis Framework, p. 4-18. (Accessed 17 April 17 at: 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)

[213] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 Resource Options, Figure 3-4. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

[214] BC Hydro. November 2013. Integrated Resource Plan, Chapter 4 Resource Planning Analysis Framework, p. 4-22. (Accessed 17 April 17 at: 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)

[215] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-34. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[216] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-34. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

programs based on more up to date market information."[217] This information makes it possible to assess the energy and capacity savings of DSM Option 2 if it were not moderated beyond F2016 as currently proposed by BC Hydro.

As Figure 18 illustrates, initially selecting DSM Option 3 would have provided more than 10,000 GWh/year of energy and more than 1800 MW of capacity savings by F2024.[218] The decision in the 2013 IRP to proceed with DSM Option 2 reduced those savings to under 9000 GWh/year and 1600 MW.[219] The further decision to moderate DSM Option 2 during the F2014 to F2016 period reduced those savings further to 8400 GWh/year and less than 1500 MW,[220] and now the proposal in the 2016 RRA to further moderate DSM would reduce those savings to about 6700 GWh/year and 1200 MW.[221]

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. This is more than 50% of the Site C Project at 5,100 GWh/year of energy and 1100 MW of capacity.

In short, BC Hydro is abandoning Recommended Action #1 of the 2013 IRP consisting of a DSM Target of 7,800 GWh/year by F2021 with associated capacity savings of 1400 MW. The utility's most recent proposal would have DSM reduce its expected increase in demand by 76% between F2008 and F2021,[222] which still exceeds the minimum of at least 66%, as required by the *Clean Energy Act*.[223] However, the recent plan significantly reduces the contribution under DSM Option 2, which in the mid-load

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[217] BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.2.9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[218] BC Hydro. November 2013. Integrated Resource Plan, Figure 3-1 and Figure 3-2.

[219] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.168.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[220] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.2.9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[221] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.168.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

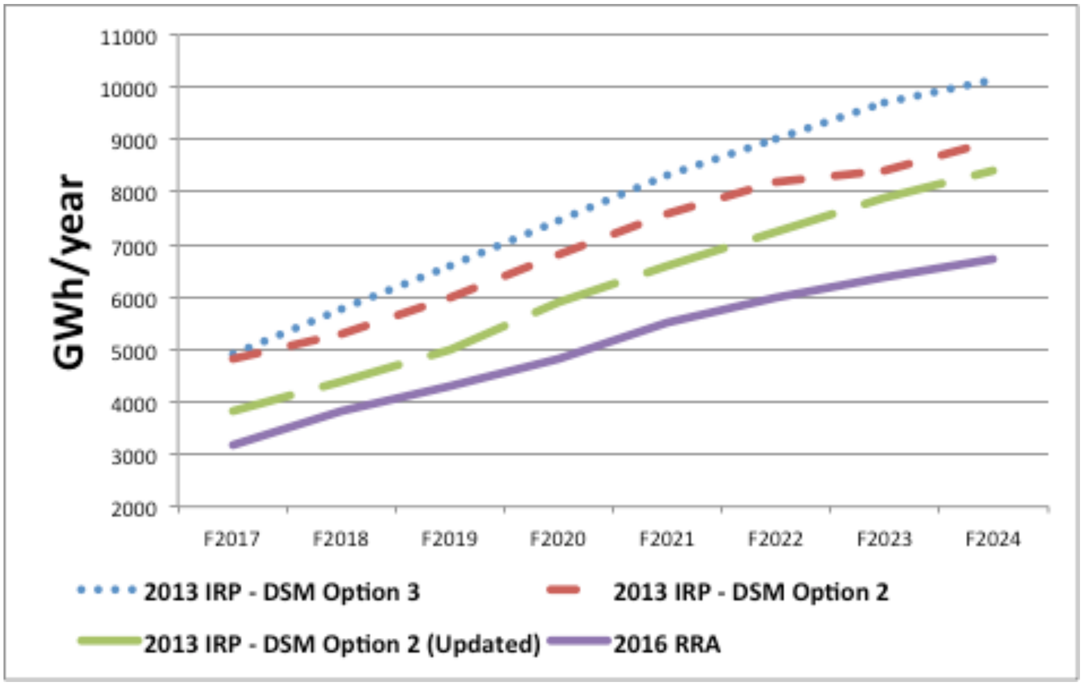
[222] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 10-6. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[223] Subsection 2(b) of the Clean Energy Act "to take demand-side measures and to conserve energy, including the objective of [BC Hydro] reducing its expected increase in demand for electricity by year 2020 [by year fiscal 2021 from fiscal 2008] by at least 66 per cent".

forecast would see DSM meeting 85% of new requirements (with LNG)[224], or 116% of new requirements (without LNG).[225]

Figure 18: DSM options available to BC Hydro since the 2013 IRP

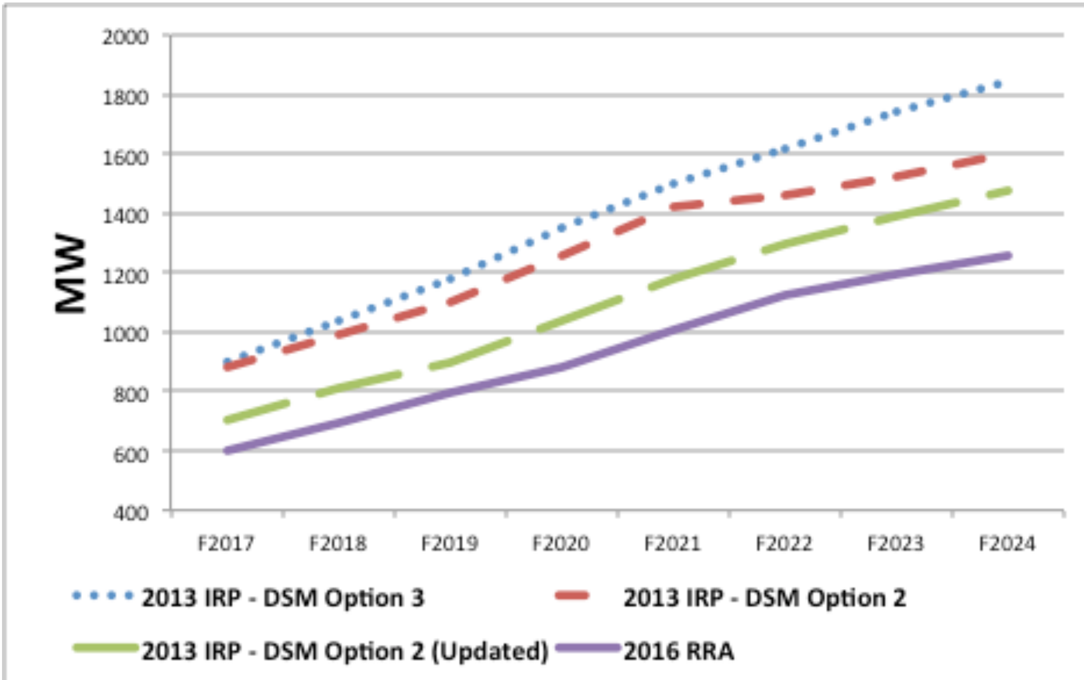
a) Energy-focused DSM energy savings



[224] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 10-6. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[225] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 10-5. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

b) Energy-focused DSM capacity savings



Based on the 2016 Load Forecast, had DSM Option 3 been pursued from F2014 to F2024, this would have had the effect of delaying the need for new energy resources by five years, from F2025 to F2030. Additional savings from DSM Option 3 after F2024 would only further delay the need for new resources beyond F2030.

The costs of DSM

As noted above, BC Hydro reduces its near-term costs by reducing its commitment to DSM program spending, with the cost savings between DSM Option 3 and DSM Option 2 on the order of $50 million/year. BC Hydro reported further expected cost savings of about $100 million per year to continue the moderation of DSM Option 2 as contemplated in the 2016 RRA.[226] 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.

Relative to all of BC Hydro's supply-side resources, including the Site C Project, BC Hydro's DSM programs are very cost-effective. This cost-effectiveness is determined in accordance with the Utility Cost (UC)[227] and the Total Resource Cost

[226] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCOAPO 2.95.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

[227] The UC measures the costs of the DSM initiative from the utility's perspective, excluding any costs of the participant, and indicate the change in total utility bills (revenue requirements) due to DSM.

(TRC)[228] tests, and evaluated by the BC Utilities Commission in accordance with the Demand-side Measures Regulation.[229]

The 2013 IRP reported that the unit energy cost for DSM Option 2 from the TRC perspective was $32/MWh while that from for the UC perspective was $18/MWh.[230] In the 2016 RRA, BC Hydro reported DSM Option 2 total resource cost of $46/MWh and utility cost of $29/MWh, respectively.[231] The utility cost of DSM programs under BC Hydro's proposed revised DSM Plan is $22/MWh.[232] These costs reflect the weighted average of many demand-side measures. They compare to the levelized cost of energy from the Site C Project of $85 to $88/MWh, as discussed further in Section 4.2.2,[233] and the current long-run marginal cost of energy from clean resources (i.e. wind) of $100/MWh.[234]

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. [235]

As it did in the 2013 IRP, BC Hydro provides a rationale for extending the moderation of DSM beyond F2016 based on a desire to lower near-term costs:

> BC Hydro notes that it did not select an alternative with higher expenditure levels because, in part, it would increase rates relative to the proposed Demand-Side

[228] The TRC measures the overall economic efficiency of a DSM initiative from a resources options perspective, including both participant and utility costs. The BCUC has determined that individual DSM programs should be assessed to determine if they pass a TRC cost/benefit ratio of 1.0, and any programs not exceeding this ratio must be justified.

[229] B.C. Reg 326/2008. The Demand-Side Measures Regulation also guides the BCUC's determination of cost effectiveness by providing modifications to the TRC test that the Commission must follow when assessing DSM expenditures.

[230] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 Resource Options, p.3-27. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

[231] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.2.9 Attachment 1, Table 10. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

[232] BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.25.4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[233] See Section 4.2.2, above.

[234] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-46. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[235] BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request BCUC 1.170.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

> Management Plan. This upward pressure on rates would challenge BC Hydro's ability to meet the targets under the 2013 10 Year Rates Plan.[236]

It is important to provide some context respecting the confluence of events that have lead BC Hydro to conclude that it is necessary to continue to moderate spending on lower cost DSM, while at the same time advancing the much higher-cost Site C Project.

First, the Provincial Government approved the Site C Project in the context of the 2012 and 2013 Load Forecasts. As illustrated in Figure 6, these forecasts predicted energy requirements in F2024 that exceed those now predicted in the 2016 Load Forecast by 6,290 GWh/year and 14,244 GWh/year, respectively. For context, the Site C Project would produce 5,100 GWh/year.

Secondly, with this collapse in BC Hydro's load forecast, the utility is now forecasting $3.5 billion less revenue than when the 10-Year Rates Plan was announced. The only way to recoup those lost revenues is to increase rates.[237] However, the 10-Year Rates Plan imposes a freeze on rate increases until F2019, at levels much lower than BC Hydro's actual revenue requirements in the period F2017 to F2019 with the shortfalls to be deferred to future rate increases in the period F2020 to F2024.[238]

Moreover, the updated load resource balance contained in the 2016 RRA now predicts that the energy surplus will extend to F2025, beyond the scheduled in-service date for the Site C Project. As such, additional savings from DSM would only exacerbate the costly Site C energy surplus. Thus, in order to prevent even higher future increases in rates and to mitigate the losses due to the Site C Project energy surplus, BC Hydro must moderate spending on lower cost DSM in hopes that consumers will consume more.

In summary, BC Hydro finds it preferable to curtail DSM. The utility is taking this action in order to reduce near-term losses from its ongoing energy surplus and future losses from surpluses that the Site C Project would create if commissioned as planned in F2024. This action is being taken despite the fact that DSM delivers electricity at a fraction of the cost of electricity from the Site C Project.

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[236] BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request BCUC 1.67.4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

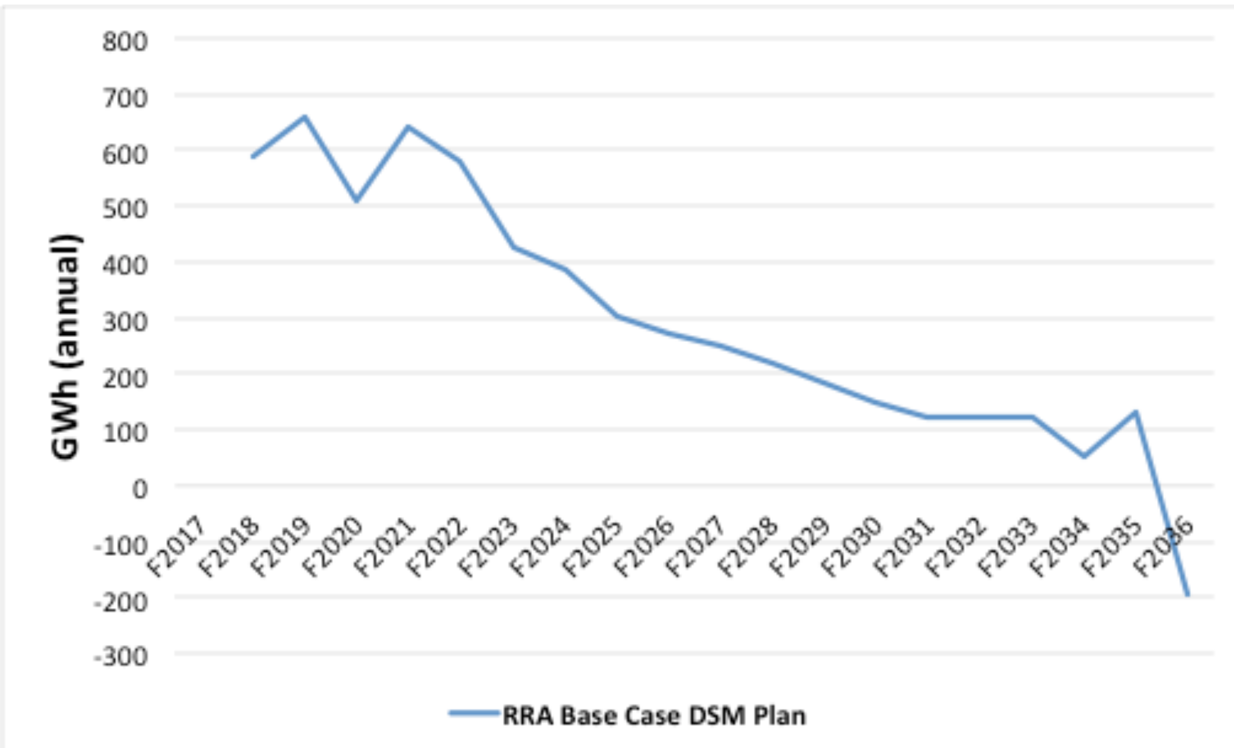
[237] BC Hydro. July 28, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, p.1-1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[238] BC Hydro. July 28, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Figure 1-1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

BC Hydro's long-term DSM plan

In evaluating the long-term utility of its DSM programs, BC Hydro assumes that average DSM persistence is about 19 years,[239] depending on the program and the technology employed. At the end of this period, since the savings are no longer incremental to what would have otherwise occurred, they are removed from the DSM plan. However, 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.

Figure 19: 2016 RRA DSM Plan – annual incremental energy[240]



The approach taken by BC Hydro can be contrasted with that taken by the Ontario IESO. Figure 20 illustrates the anticipated savings from DSM programs, codes and standards in Ontario over the same 20-year planning period as BC Hydro's 2016 RRA.

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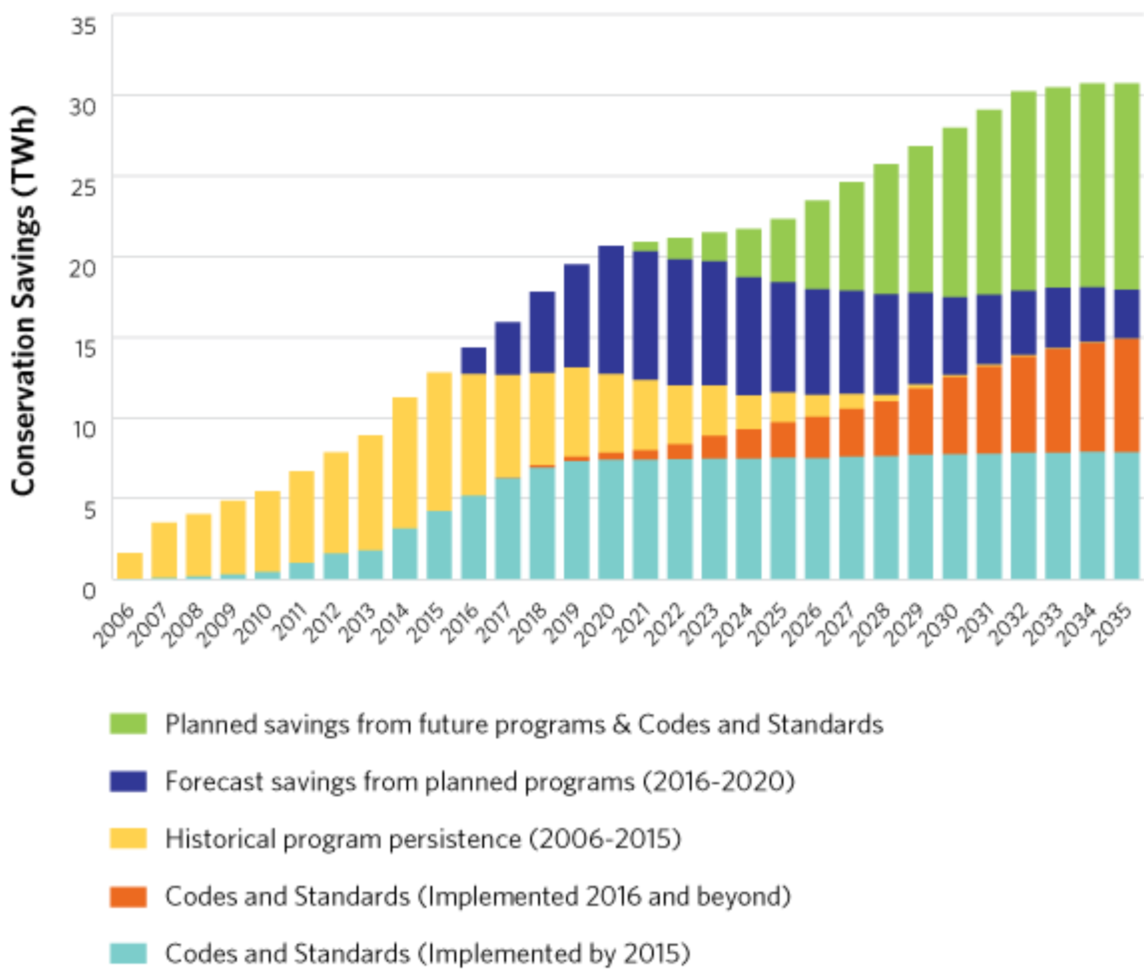
[239] BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request BCUC 1.170.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[240] Derived from BC Hydro. July 28, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Table 3-8. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

BC Hydro includes only what the IESO refers to as "historic program persistence" (yellow bars) and "forecast savings from planned programs" (blue bars). BC Hydro presumes that the additional savings from "codes and standards implemented by 2015" (turquoise bars) will decay to zero over the 20-year period, while the IESO sees these savings persisting to the end of the period. Most importantly, BC Hydro includes no savings from future programs, codes and standards (the green and red bars) that the Ontario IESO notes form the vast majority of DSM savings by the end of the planning period.

Figure 20: Ontario IESO conservation achievement and outlook[241]



[241] IESO. 2016. Ontario Planning Outlook: A technical report on the electricity system prepared by the IESO, Figure 11. (Accessed 17 April 2017 at: http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook)

BC Hydro's position that no new additional demand-side measures will be developed following F2021 to replace and improve upon existing measures is not credible. LED lights, time-of-use prices, load curtailment, programmable thermostats, community energy planning, micro-grids, real-time data analytics, smart meters, and direct load control are just a few of the many electricity management innovations of recent years. There is no reason to believe that human inventiveness will suddenly come to an end in 2020. The following expert testimony before the Manitoba Public Utilities Board speaks to this issue:

> The challenge of DSM for planning purposes, then, becomes the challenge of predicting innovations: we know they will happen, but we don't know exactly how or how much. Yet the reverse is true too: we know that a static view – one in which future DSM savings are limited to the savings opportunities available today – is wholly inappropriate for a long-term planning horizon, much less one covering the coming 20 years.[242]

The conclusion in the 2016 RRA that DSM will cease to make any new contributions to meeting BC Hydro's needs beyond F2021, and any contributions at all beyond F2036, implies abandoning the *Clean Energy Act* Objective 2(b) without any public policy acknowledgement or debate.

The *Clean Energy Act*, in section 2(b), sets what appeared at the time to be an ambitious objective of meeting 66% of BC Hydro's demand growth with DSM, until the year 2020 – but was silent about the longer-term future.

While, strictly speaking, there is no requirement for BC Hydro to develop new DSM measures beyond 2020 (F2021), there is also no reason to believe that the intent of the *Clean Energy Act* was to aggressively ramp down DSM after that date. Moreover, in the current context of low load growth, there is potential for cost-effective DSM to meet much more than 66% of new demand going forward, as it has for the past decade. **When a decision has been taken in the face of stagnant load growth to advance a large and costly supply-side resource such as the Site C Project, the only way to make that resource continue to appear necessary and cost-effective is by curtailing investment in lower-cost DSM.**

The next time that BC Hydro's DSM plans will be subject to review will be as part of its 2018 IRP, and government expects BC Hydro to establish a new DSM Target at that time.[243] In the event that the utility continues with the development of the Site C Project, the DSM Target will depend largely on minimizing the energy surplus at the time of

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[242] Dunsky, P. et al. February 3, 2014. The Role and Value of Demand-side Management in Manitoba Hydro's Resource Planning Process. Submitted to the Manitoba Public Utilities Board at the request of Consumers Association of Canada (Manitoba) and Green Action Centre, at p.35. (Accessed 17 April 2017 at: http://www.pubmanitoba.ca/v1/nfat/pdf/demand_side_management_dunsky.pdf)

[243] BC Hydro. July 28, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Appendix BB. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

commissioning of Site C in F2024. **Cancelling or suspending the Site C Project would allow BC Hydro to take fuller advantage of the very cost-effective DSM available to the utility.**

Barring a change in policy or legislation, the 2018 IRP will not be reviewed or approved by the BC Utilities Commission, and so will very likely avoid rigorous, independent third-party assessment. Furthermore, as we approach 2020, the contradiction between the letter and the spirit of the *Clean Energy Act* with regard to DSM will become ever more flagrant. Given the ramping down of DSM by BC Hydro since the approval of the 2013 IRP, and the arrival of the large Site C surplus in just a few years, it is likely that DSM will all but disappear from the 2018 IRP.

5.3.2 Capacity-focused demand-side management

In recent years, as a result of a forecasted need for capacity resources in advance of energy resources, BC Hydro has paid increasing attention to DSM measures designed specifically to reduce capacity needs.

In its 2013 IRP, BC Hydro identified two types of capacity-focused DSM with substantial potential:[244]

- 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.

As a result, the potential for capacity-focused DSM savings identified in the IRP totalled 575 MW. **However, for planning purposes in its 2013 IRP, BC Hydro entirely disallowed capacity-focused DSM as an available resource, assuming it would deliver zero (0) MW over the next 20 years.** In order to further investigate the potential of capacity-focused DSM, BC Hydro made Recommended Action #2 in the 2013 IRP:

> Implement a voluntary industrial load curtailment program from F2015 to F2018 to determine how much capacity savings can be acquired and relied upon over the long term. Pilot voluntary capacity-focused programs (direct load control) for

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[244] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 – Resource Options, p.3-22. In its 2012 Draft IRP, BC Hydro had also proposed a third option, time-of-use (TOU) rates, but it abandoned this approach – at the same time as it launched a system-wide smart-meter program, which for the first time made broad-based TOU rates a realistic option. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

> residential, commercial and industrial customers over two years, starting in F2015.[245]

In its 2015 Rate Design Application (RDA), filed with the BC Utilities Commission less than a year following the decision to proceed with the Site C Project, BC Hydro stated the following:

> In BC Hydro's view, load curtailment potentially offers a better avenue [than time of use pricing (TOU)] to avoid costly generation capacity resource additions because it is targeted at capacity, is more reliable (particular with aspects of demand control), and in contrast to TOU, load curtailment is dispatchable.[246]

In other words, BC Hydro acknowledged in the 2015 RDA what it neglected to acknowledge a short time before in the 2013 IRP, namely the substantial benefits of load curtailment for reducing capacity requirements. The utility now also acknowledges that compared to supply-side capacity resources, capacity-focused demand-side management is lower cost and can be developed in smaller increments, has the advantage of shorter lead times and could also relieve local constraints (e.g. regional transmission and/or distribution).[247]

Since the 2013 IRP, BC Hydro has further advanced its investigation of capacity focused DSM in the form of load curtailment[248] and demand response,[249] providing additional evidence of the potential efficacy of these approaches for meeting capacity requirements.

Regarding load curtailment, BC Hydro issued a request for proposals in the fall of 2015, in response to which eligible customers proposed amounts of load they were capable of curtailing, to a maximum total requirement of 100 megawatts for up to 36 days per year in aggregate. BC Hydro selected interested proponents, prorating the expected number of curtailment days to a contracted total of 126 MW for 28 days.[250] Participants were given day-ahead notice to curtail their load for up to 16 hours per day, up to six consecutive days per week from November 2015 through April 2016. A second Request

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[245] BC Hydro. November 2013. Integrated Resource Plan, Chapter 9 Recommended Actions, p.9-20. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf)

[246] BC Hydro. 2015. 2015 Rate Design Application. Appendix C-5A, p.107. (Accessed 17 April 2017 at: https://www.bchydro.com/about/planning_regulatory/2015-rate-design.html)

[247] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.317.2. BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.310.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

[248] BC Hydro. 2015. Load Curtailment Pilot. Available at: https://www.bchydro.com/powersmart/business/load-curtailment-pilot.html.

[249] BC Hydro. 2015. Load Management Demonstration Project. Avaiable at: https://www.bchydro.com/powersmart/business/load-management.html

[250] For a description of BC Hydro's load curtailment and demand response programs, see: BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.10-7. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

for Proposals was released in October 2016 for year two of the pilot based on the results of the first year.

With respect to demand response, BC Hydro is conducting a demonstration pilot using wireless load control relays on residential water heaters. BC Hydro is also engaged in researching several other demand response programs. The impacts of these programs, and others under investigation, on demand and participants are yet to be determined.[251] **The contribution of capacity-focused DSM now appears to be much larger than the 0 MW presumed in the 2013 IRP**.

In its 2015 RDA, BC Hydro also noted the following:

> …<u>There is an opportunity to reduce the amount of gas-fired generation that might be required through the development of load curtailment</u>.[252]

This reference to utilizing capacity-focused DSM to reduce the amount of gas-fired generation that might be required in the future is consistent with the direction in the Climate Leadership Plan to move towards 100% clean or renewable electricity. Deferring the need for new gas-fired capacity resources through the use of capacity-focused DSM is a cost-effective approach for BC Hydro compared to the alternative clean and renewable resources available to the utility.

In terms of potential costs, BC Hydro has indicated for its pilot load curtailment program that it is seeking a mix of products with payments summarized in the following table.

Table 18: BC Hydro pilot load curtailment program capacity and payments[253]

Number of MW	Duration	Number of Days	Total Hours	Incentive per MW
60	16 hours/day	36	576	$75,000
40	8 hours/day	36	288	$37,500
80	4 hours/day	36	144	$18,750

Based on Table 18, the average weighted unit capacity contracted payment to participants in BC Hydro's load curtailment program is $75/kW-year. BC Hydro's initial estimate was $57/kW-year, based on the 126 MW contracted in year one of the pilot. That estimate was for up to 28 days of 16 hour/day curtailment (448 hours). Actual costs in the first year of the pilot program were $49/kW-year, lower than the contracted

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[251] For a complete list, see: BC Hydro. November 21, 2016. Fiscal 2017 to 2019 Revenue Requirements Application, Response to Information Request 1.183.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[252] BC Hydro. 2015. 2015 Rate Design Application. Appendix C-5A, p.107. (Accessed 17 April 2017 at: https://www.bchydro.com/about/planning_regulatory/2015-rate-design.html)

[253] BC Hydro. 2016. Load Curtailment Pilot FAQ. Available at: https://www.bchydro.com/powersmart/business/load-curtailment-pilot/faq.html.

capacity value because customers curtailed more than the amount contracted.[254] The unit capacity costs of capacity-focused DSM are very competitive compared to other capacity alternatives investigated by BC Hydro. The unit capacity cost of natural gas capacity is $115/kW-year, [255] while the cost of pumped storage hydroelectric is $199/kW-year, [256] taking into account energy costs, network integration and transmission losses related to these resources.

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. It is 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. The potential of capacity-focused DSM is included in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

5.4 Evaluating supply-side resources

In addition to considerable additional energy and capacity available from DSM, BC Hydro also has available to it large quantities of competitively priced and low-emission energy and capacity supply-side resources. In the event that the Site C Project is cancelled or suspended, and despite the contributions from DSM, BC Hydro will eventually need to advance some of these supply-side resources in order to meet future forecasted requirements for energy and capacity.

5.4.1 Energy resources

In its 2013 IRP, BC Hydro evaluated a broad range of potential supply-side energy and capacity resources for inclusion in its resource portfolios. This evaluation considered the technical, financial, environmental and economic development attributes of these resources. Table 19 summarizes the technical and financial attributes of some of these renewable resources, as determined by BC Hydro in its 2013 IRP.

Since the time of the 2013 IRP, some of the resources listed in Table 19 have seen substantial declines in unit energy costs as a result of technological, operational and other advances. In particular, on-shore wind resource costs have declined markedly and their costs are anticipated to continue to decline for the foreseeable future. In addition, utility scale solar PV costs have declined dramatically over the past several years, and

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[254] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.318.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

[255] BC Hydro. July 2016. BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p. 3-50.

[256] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.81.3. Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

anticipated future declines could position solar PV as a competitive source of renewable energy available to BC Hydro before the end of the planning period in F2036.

Table 19: 2013 IRP renewable resource technical and financial attributes

Supply-side Resource	Dependable Generating Capacity (MW)	Total Energy (GWh/year)	Firm Energy (GWh/year)	UEC at POI[257] ($2013/MWh)	Adjusted Firm UEC[258] ($2013/MWh)
Wood-based Biomass	1,226	9,772	9,772	122 – 276	132-306
Biogas	16	134	134	59 – 154	56 – 156
MSW Biomass	50	425	425	85 – 184	83 – 204
Onshore Wind	4,271	46,165	46,165	90 – 309	115 – 365
Offshore Wind	3,819	56,700	56,700	166 – 605	182 – 681
Geothermal	780	5,992	5,992	91 - 573	90 – 593
Run-of-river Hydro	1,149	31,880	24,543	93 – 500	143 – 1,170
Site C	1,100	5,100	4,700	83	88
Solar	12	57	57	266 – 746	341 – 954

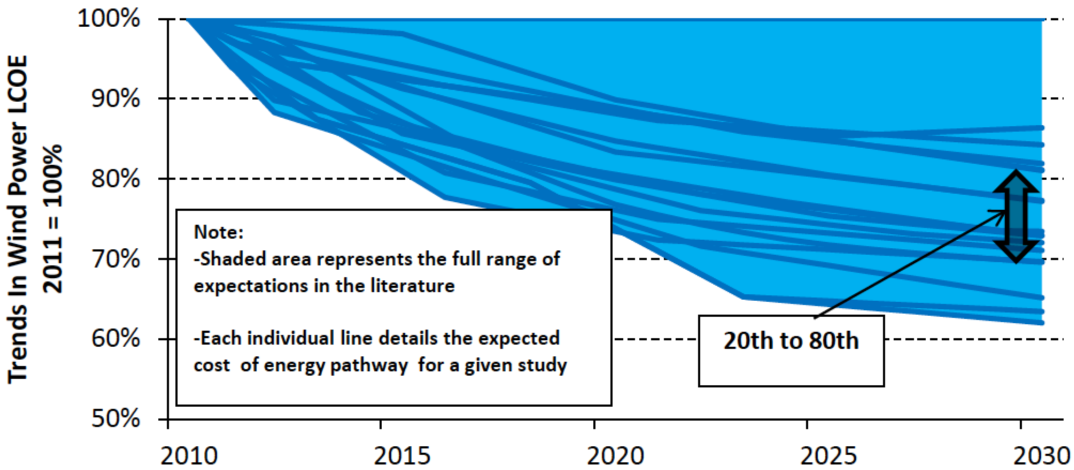
On-shore wind

In the Resource Options Report that forms an appendix to the 2013 IRP, BC Hydro assumed there would be no further declines in real wind costs before F2041, and that the real costs of energy from wind generation would remain equivalent to what they were in F2012. Figure 21 illustrates 18 different projections made in 2011 of the future levelized cost of energy from wind generation.

[257] Unit energy cost at the point of interconnection to the integrated transmission system.

[258] The costs of resources delivered to the Lower Mainland, including: network upgrades costs; a wind integration cost of $10/MWh; a freshet firm energy adjustment; and a capacity credit of $50/kW-year based on the cost of Revelstoke Unit 6 applied to a resource option that can provide dependable capacity. Values are calculated using a 7% real discount rate for all resources, except the Site C Project calculated at a 5% real discount rate.

Figure 21: Range of wind levelized energy cost projections[259]



The position taken by BC Hydro in its 2013 IRP reflects the single outlier in the graph, namely the *uppermost* horizontal blue line indicating that the cost of wind energy in 2030 would be 100% of its cost in 2011 (i.e. F2012), according to which there would be no future declines in the real cost of wind energy. However, all other industry observers consulted, including the US Department of Energy and the US Energy Information Administration, believed that wind costs would decline by somewhere between 15% and 40% in real terms by 2030, due to technology improvements and other cost reductions. To date, as detailed below, the declines in levelized costs have been on the order of 20%, following closely to the *lowermost* blue line in Figure 21.

BC Hydro now acknowledges that wind energy costs have declined,[260] contradicting the position the utility took in the 2013 IRP. The 2016 RRA now estimates the adjusted unit energy cost of wind at $100/MWh (fiscal 2015$), reflecting a 20% decline in wind costs since the 2013 IRP.[261] These are adjusted unit energy costs that include the cost of transmission losses to deliver energy to the Lower Mainland, network upgrade costs, wind integration costs, among other adjustments.[262] Unadjusted unit energy costs at the point of interconnection would be lower, on the order of $80/MWh. Wind costs are

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[259] National Renewable Energy Laboratory. May 2012. IEA Wind Task 26: The Past and Future Cost of Wind Energy, p.26. (Accessed 17 April 2017 at: https://www.ieawind.org/index_page_postings/WP2_task26.pdf)

[260] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.1-27. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[261] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-46. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[262] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.171.1.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

marginally higher in BC compared to other jurisdictions due to difficult terrain, mobilization, turbine delivery, and suitable transmission proximity, among other factors.

In its most recent resource options update report, BC Hydro updates its assumptions and methodologies for estimating the unit energy cost of wind,[263] including:

- 3 MW turbine size (previously 2.3 MW in Class II wind sites)[264]
- 100 m hub height (previously 80 m)
- 25 year project life (previously 20 years)
- updated capital, operations and maintenance costs

This update is summarized in Figure 22 below, which illustrates that BC Hydro has on the order of 10,000 GWh/year of energy (~3,000 MW of capacity) from onshore wind at less than $100/MWh (7% discount rate), and 6,000 GWh/year of energy (~1800 MW of capacity) at less than $80/MWh (5% discount rate).

In terms of future wind resource costs, BC Hydro believes that the long-term adjusted unit energy costs of onshore wind will continue to remain unchanged at approximately $100/MWh beyond F2030.[265] The utility is taking the same perspective it took during the 2013 IRP – the cost of energy from wind resources never declines. On the other hand, Bloomberg New Energy Finance, in its New Energy Outlook 2016, projects that the cost of onshore wind would drop 41% by 2040.[266] For its part, IRENA projects that the global weighted average levelized cost of energy from wind could fall 26% by 2025.[267] In a recent elicitation survey of 163 of the world's foremost wind experts, these experts anticipate a 24% reduction in the levelized cost of energy from onshore wind by 2030 and a 35% reduction by 2050.[268]

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[263] BC Hydro. October 2016. Resource Options Update Results Summary, p.23. (Accessed 17 April 2017 at: 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)

[264] GEC. 2009. BC Hydro Wind Data Study, p.33. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf)

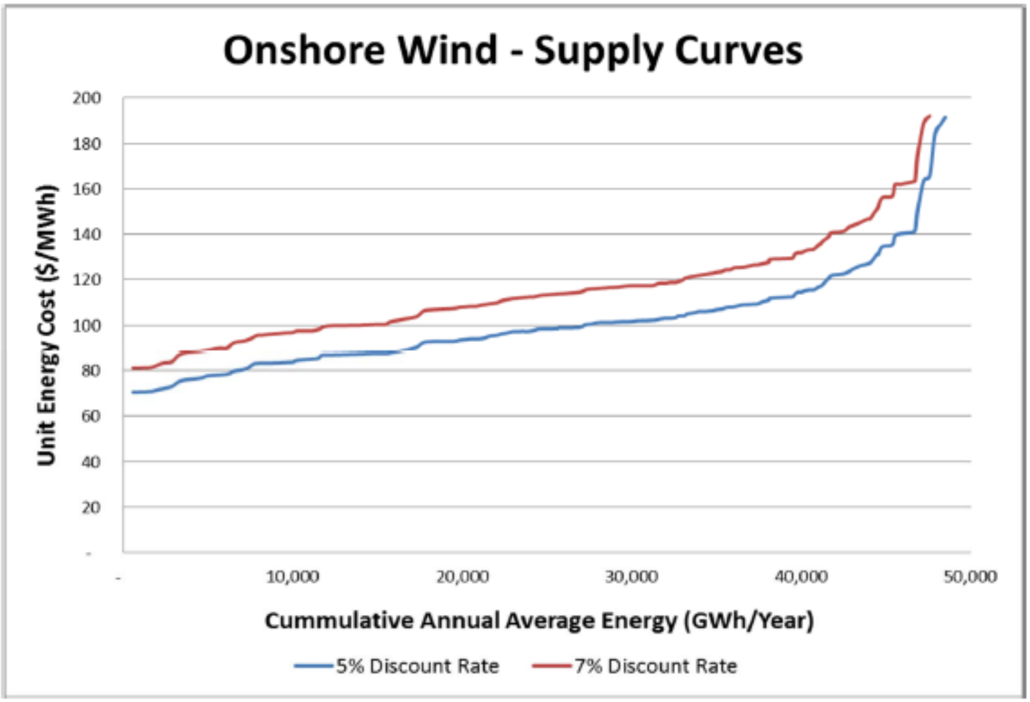
[265] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.170.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[266] Bloomberg New Energy Finance. June 2016. New Energy Outlook 2016 Executive Summary. (Accessed 17 April 2017 at: https://www.bloomberg.com/company/new-energy-outlook/)

[267] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.67. (Accessed 17 April 2017 at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf)

[268] Wiser, R. et al. 2016. Expert elicitation survey on future wind energy costs. *Nature Energy*, Article 16135, p.4.

Figure 22: BC Hydro wind supply curves and unit energy costs[269]



Based on these projections, a further decline of 25% in the levelized cost of energy from wind resources by 2030 is conservative. Considering the information presented by BC Hydro in Figure 22, this would result in about 10,000 GWh/year of energy (~3,000 MW of capacity) at less than $75/MWh at a 7% discount rate, and 6,000 GWh/year of energy (~1800 MW of capacity) at less than $60/MWh at a 5% discount rate. By the late 2020s, it is conservatively anticipated that wind resources can be contracted by BC Hydro at an adjusted unit energy cost of $80/MWh to the end of the planning period in F2036.

Solar photovoltaic (PV)

In the 2013 IRP, BC Hydro determined the unit energy cost for a 5 MW utility-scale solar PV system to be $266/MWh for the East Kootenay Region, with costs approximately 5% to 20% higher in the Peace River, Central Interior and Kelly/Nicola regions.[270]

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[269] BC Hydro. October 2016. Resource Options Update Results Summary, p.23. (Accessed 17 April 2017 at: 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)

[270] BC Hydro. November 2013. Integrated Resource Plan Appendix 3A-1 2013 Resource Options Report Update, p.173. (Accessed 17 April 2017 at: 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)

In its recent resource options update, BC Hydro revised its estimates of unit energy costs for 13 hypothetical 5 MW utility-scale solar projects located at various locations throughout the Province. The utility's assumptions and methodologies for estimating the unit energy cost of utility-scale solar, include:

- Project life of 25 years, with a 4 year lead time
- Single axis tracking
- Capacity factor range: 17% to 20%
- $US 1.88/$W_{DC}$ installed

The findings of the update indicate unit energy costs at the point of interconnection for the East Kootenay region of $145/MWh (5% discount rate) and $171/MWh (7% discount rate), with costs in the Kelowna, Peace and Kelly-Nicola regions 5% to 20% higher. [271]

In Ontario, the IESO recently completed a competitive procurement of utility-scale solar PV projects ranging in size from 1.375 MW to 54 MW, of which the lowest cost was $141.50/MWh.[272] Solar insolation in Kelowna, Kamloops and Cranbrook is very similar to that in Kingston, Toronto and Hamilton.[273] While there are variations between jurisdictions in labour, regulatory and other costs, this provides some additional evidence that the UEC for utility-scale solar PV in British Columbia is currently on the order of $150/MWh in the most cost-effective regions.

With respect to future utility-scale solar PV costs, NREL noted in 2015 that: "analysts project that from 2014-2020, system prices will fall…26% – 36% for utility-scale systems."[274] The US Department of Energy recently announced its objective of lowering the average levelized cost of energy from utility-scale solar in the United States from $US70/MWh in 2016 to $US30/MWh by 2030, a decline of nearly 60%.[275] Bloomberg New Energy Finance, in its New Energy Outlook 2016 foresees declines of 60% in utility-scale solar PV prices by 2040.[276] IRENA projects that the global weighted

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[271] BC Hydro. October 2016. Resource Options Update Results Summary, p.38. (Accessed 17 April 2017 at: 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)

[272] IESO Large Renewable Procurement. Available at : http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx.

[273] Natural Resources Canada. 2016. Photovoltaic and solar resource maps. Available at: https://www.nrcan.gc.ca/18366.

[274] U.S. Department of Energy. 2015. Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. *2015 Edition*, p.15. For the year 2014. (Accessed 17 April 2017 at: http://www.nrel.gov/docs/fy15osti/64898.pdf)

[275] US DOE. November 14, 2016. Energy Department Announces more than 90% Achievement of 2020 SunShot Goals, Sets Sights on 2030 Affordability Targets, p.2. (Accessed 17 April 2017 at: https://energy.gov/eere/articles/energy-department-announces-more-90-achievement-2020-sunshot-goal-sets-sights-2030)

[276] Bloomberg New Energy Finance. June 2016. New Energy Outlook 2016 Executive Summary. (Accessed 17 April 2017 at: https://www.bloomberg.com/company/new-energy-outlook/)

average levelized cost of energy from utility-scale solar PV could decline by 59% by 2025.[277]

Based on these projections, utility-scale solar PV unit energy costs are set to decline dramatically from current levels. A 60% decline would see unit energy costs drop to $60/MWh in the most cost effective locations in British Columbia and below $80/MWh throughout large areas of the Province within the next 10 to 20 years.

However, these unit energy costs must be adjusted to include the cost of transmission losses to deliver energy to the Lower Mainland, network upgrade costs, and integration costs, among other adjustments. BC Hydro has not provided updated adjusted UECs for utility-scale solar PV since the 2013 IRP. As shown in Table 19, BC Hydro's estimated the adjustment to be as low as $75/MWh (i.e. $341 – $266/MWh), which compares to $25/MWh for onshore wind (i.e. $115 - $90/MWh). Presuming similar transmission losses and network upgrade costs to integrate wind and solar, the $50/MWh difference requires further explanation. This could be an additional matter for consideration by the BCUC in the event that the Site C Project is referred to the Commission for further review.

Nonetheless, the development of solar resources is not essential to alternative portfolios to the Site C Project; alternative portfolios can instead rely upon the large volumes of low-cost wind energy that is available to BC Hydro. However, to the extent that utility-scale solar PV can provide energy at adjusted unit energy costs lower than that of wind resources, this would further lower the cost of the alternative portfolios that do not contain the Site C Project.[278]

5.4.2 Capacity resources

The 2013 IRP also evaluated resources designed specifically to meet capacity requirements. The following table summarizes some of the capacity resources considered by BC Hydro in terms of their unit capacity cost (UCC) at the point of interconnection.

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[277] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.49. (Accessed 17 April 2017 at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf)

[278] Comparative evaluation of solar and wind resources must also consider night-time vs. day-time generation, seasonal generation, electric load carrying capacity, and other factors.

Table 20: 2013 IRP capacity resource technical and financial attributes

Capacity Resource	Dependable Generating Capacity	UCC at POI
	(MW)	($2013/kW-year)
Revelstoke 6 Capacity Upgrade	488	50
Pumped storage hydroelectric - various	1,000	120
Pumped storage hydroelectric – Mica	465	100
Natural Gas SCGT – Kelly Nicola	101	84

Capacity upgrades

With the completion of the capacity upgrades at GM Shrum in 2015, capacity upgrades at Revelstoke 6 are now BC Hydro's lowest cost available capacity resource. BC Hydro is currently undertaking work to advance the Revelstoke 6 project to the environmental assessment stage,[279] for an earliest possible in-service date of F2022.[280] As a result, it is presumed that this project is developed during the 20-year planning period under all future scenarios. BC Hydro has limited capacity upgrade options following Revelstoke 6.

Pumped storage hydroelectric

With respect to pumped storage, BC Hydro recently provided its perspective on the development of this resource:

> Revelstoke Unit 6 is a unique low cost capacity option (estimated at $57/kW-yr fiscal 2015$) for BC Hydro available for approximately 500 MW. Beyond that and considering the 100 per cent clean policy from the Climate Leadership Plan which requires new acquisition in the integrated system to be from clean or renewable resources, the next clean generation capacity option would generally be pumped storage facilities which is a step increase in cost (estimated at $199/kW-year fiscal 2015$ including the cost of energy losses in the pump-generation cycle). BC Hydro has estimated the time to commit to and have a pumped storage facility constructed to be about 8 to 10 years.[281]

[279] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.2-3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[280] BC Hydro. November 21, 2016. F2017 to F2019 Revenue Requirements Application, Response to Information Request BCUC 1.81.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

[281] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.81.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

In its 2013 IRP, BC Hydro identified pumped storage as a potentially useful capacity resource that can respond quickly to variations in system demand. The IRP identified more than 5,000 MW of its lowest-cost pumped storage hydro near to the load centre in the Lower Mainland.[282]

Of the identified potential sites, a pumped storage facility at the existing Mica generating station was the only facility with seasonal shaping capability (the ability to store water for months, not only hours or days), allowing BC Hydro to better manage its oversupply during the spring freshet. However, pumped storage at Mica need not be limited to seasonal operation, and may also be used to meet weekly or daily capacity requirements.[283] The total dependable generating capacity of a pumped storage facility at the Mica generating station is 465 MW.[284]

The Mica site has an updated estimated UCC at the point of interconnection of $109/kW-year (F2015$).[285] Since the site has been investigated only to a pre-feasibility level, this cost estimate has considerable uncertainty.[286] In addition, pumped storage hydroelectric is a net user of energy, with efficiency on the order of 70%. This UCC therefore needs to be adjusted to account for these energy inputs as well as for line losses associated with delivering capacity to the main load center in the Lower Mainland. As noted above, BC Hydro recently indicated that its adjusted UCC for pumped storage is $199/KW-year, so this cost is taken as the adjusted UCC for pumped storage at Mica.

The estimates of UCCs at other pumped storage facilities are based only on preliminary surveys and have greater uncertainty in terms of costs and feasibility than a facility at Mica. Given the preliminary nature of these cost estimates, pumped storage hydroelectric, other than at the Mica Generating Station, is not considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

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[282] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 – Resource Options, p.3-66. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

[283] Hatch. 2010. BC Hydro Pumped Storage at Mica Generating Station Preliminary Cost Estimate, p.2. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/ror/appx_10b_pumped_storage_mica_preliminary_cost_estimate.pdf)

[284] BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 – Resource Options, p.3-65. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

[285] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCOAPA 1.64.1. Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[286] BC Hydro. November 2013. Integrated Resource Plan, Appendix 3A-1 2013 Resource Options Report Update, p.139. (Accessed 17 April 2017 at: 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)

Simple cycle gas turbines

Simple cycle gas turbines (SCGTs) are stand-alone natural gas generating stations that are capable of ramping quickly to meet varying loads, and of providing firm energy and dependable capacity. SCGTs have been an integral part of BC Hydro's planning process.

Fore example, BC Hydro's 2013 IRP base resource plan scheduled 400 MW of gas-fired generation by F2020 to meet expected LNG load. The utility's contingency resource plan also foresaw the addition of 400 MW of SCGTs by F2020 to meet expected LNG, as well as additional SCGTs to meet capacity shortfalls beyond Site C and Revelstoke 6 up to the 93% constraint in the *Clean Energy Act*.[287] **BC Hydro's contingency scenario in the 2013 IRP included 2,058 MW of SCGTs by F2033**.[288]

The 2016 RRA updated the unit capacity cost of an SCGT at the point of interconnection at Kelly-Nicola to $79/kW-year. To make the unit capacity costs of an SCGT comparable with other options, the unit capacity costs were adjusted to $115/kW-year,[289] to reflect delivery to the Lower Mainland, to account for energy costs and to include a cost of $30/tonne of CO_2e emissions.[290] The analysis in Section 6.3 concerning whether to continue, cancel or suspend the Site C Project, uses a capacity cost of $84/kWh plus an energy cost, based on the actual amounts generated and the gas price forecasts presented in the IRP.

However, SCGTs also produce greenhouse gas emissions, and the *Clean Energy Act* constrains the potential role of natural gas-fired generation through the following objectives:

- to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship,[291] from clean or renewable resources and to build the infrastructure necessary to transmit that electricity
- to reduce BC greenhouse gas emissions as determined under the *Greenhouse Gas Reduction Targets Act*

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287 BC Hydro. November 2013. Integrated Resource Plan, Appendix 9A Load-Resource Balances, p.9A-2. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0900a-nov-2013-irp-appx-9a.pdf)

288 BC Hydro. November 2013. Integrated Resource Plan, Appendix 9A Load-Resource Balances, p.9A-20. Contingency Resource Plan with LNG. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0900a-nov-2013-irp-appx-9a.pdf)

289 BC Hydro. July 28, 2016. BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p. 3-50. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

290 BC Hydro. November 2013. Integrated Resource Plan, Chapter 3 – Resource Options, p.3-71. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

291 As per British Columbia's Energy Objectives Regulation (B.C. Reg. 234/2012).

More recently, with the release of the Climate Leadership Plan, the Province has signalled its intention to obtain "100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed." In a recent submission to the BCUC, BC Hydro provide insight into its understanding of this policy:

> BC Hydro notes that the Climate Leadership Plan requires 100 per cent clean resources for new greenfield sites in the integrated system unless there is reliability or cost concern. Exceptions on the basis of reliability or cost concerns could be granted through an Integrated Resource Plan. If we encounter a large shortfall of capacity and do not have enough lead time to build new clean generation resources, temporary market reliance and the use of gas resources may need to be considered.

This perspective suggests that BC Hydro continues to be willing to consider the use of SCGTs in those situations where capacity requirements are higher than anticipated, such as in its high-load forecast. How BC Hydro would operate any SCGTs to meet those requirements, considering the constraints in the *Clean Energy Act* and the Climate Leadership Plan, is less clear.

In the 2013 IRP, BC Hydro presumed that these facilities would operate with an 18% capacity factor, or 1577 hours per year. The effect of this assumption is not inconsequential, as the GHG emissions of SCGTs depend upon both their hours of service and on the frequency of start-ups and shutdowns.

In response to information requests during the 2016 RRA concerning its load curtailment pilot programs, BC Hydro provides insight into how it determines this 18% capacity factor for SCGTs.

> We periodically assess system need and have determined that, with the current system and load characteristics, the ability for a load curtailment program to curtail 16-hour peak/day for up to 36 days (totaling 576 hours) anytime over the winter and shoulder months (October through March) would give BC Hydro sufficient capacity and reliability to defer generation capacity and would be assigned a value at 85 per cent of generation capacity annual fixed cost. An additional ability to curtail four peak hours /day over the remaining months would be assigned the remaining 15 per cent of generation value.[292]

Given the requirements of the *Clean Energy Act*, the quantity (i.e. in MW) of natural gas capacity that BC Hydro could rely upon is substantially reduced by operating the SCGTs with an 18% capacity factor.

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[292] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCOAPO 2.203.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf)

It appears that BC Hydro is presuming that supply-side capacity resources (i.e. not capacity-focused DSM), developed on its integrated system would need to be available to meet the usual requirements of a peaking plant, namely the winter peak capacity requirements totalling 576 hours, but would also be called upon to operate for four hours almost every other day of the year that is not a holiday or a Sunday (approximately 1000 hours). The use of SCGTs in this manner such that their capacity factor would be 18% is unusual.[293]

Indeed, the U.S. Energy Information Administration recently reported that the average annual capacity factor, for each of the past 8 years, of all SCGTs in operation in the United States ranged from 4.5% to 6.7%.[294] In the case of BC Hydro, though the SCGTs would be available to operate for the 576 hours of the winter peaking season, they would operate somewhat less often as not all days during a winter peak would require 16 hours of peaking capacity. To meet winter peaking requirements only, any SCGTs are presumed to operate for 5% of the time, or 436 hours per year.

For the purposes of the analysis in Section 6.3, evaluating the options of continuing, cancelling or suspending the Site C Project, 18% capacity factors for SCGTs are used in the resource portfolios with the Site C Project, in accordance with BC Hydro's preferred approach. A 5% capacity factor for SCGTs is used in the portfolios without the Site C Project, limiting the use of the SCGTs to meeting winter peaking requirements. The upcoming 2018 IRP process provides an opportunity for BC Hydro to further consider the use of SCGTs in its integrated grid.

For context, as shown above in Figure 14, the 5 MT of CO_2e emissions from the first 30 years of operations of the Site C Project (i.e. F2024 to F2054), the typical lifespan of an SCGT,[295] is equivalent to operating about 800 MW of SCGTs for 436 hours per year (5.0% of the time) to meet BC Hydro's winter peak capacity requirements. Similarly, the nearly 6 MT of CO_2e emissions from the Site C Project during the first 100 years of operations is equivalent to operating about 290 MW of SCGTs to meet BC Hydro's peaking requirements over that 100 year period.

SCGTs are low capital cost facilities, normally acquired on an as-required basis with an economic life of 30 years. Even if BC Hydro eventually requires some SCGTs, there is a reasonable likelihood that they would be replaced by cost-effective and lower emitting storage before the end of their useful life. Modular energy storage technologies (including lithium-ion batteries, flow batteries, flywheels and other technologies) are evolving and declining rapidly in cost. As these storage technologies also provide

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[293] U.S. EIA. October 1, 2013. Today in Energy: Natural gas-fired combustion turbines are generally used to meet peak electricity load. (Accessed 17 April 17 at: https://www.eia.gov/todayinenergy/detail.php?id=13191)

[294] U.S. EIA. 2016. Electric Power Monthly. Table 6.7.A Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels. Available at: http://www.eia.gov/electricity/monthly/.

[295] BC Hydro. November 2013. Integrated Resource Plan, Appendix 3A-4 2013 Resource Options Report Update Resource Options Database (RODAT) Summary Sheets, p.476. Emissions factor of 477 tCO_2e/GWh. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a04-nov-2013-irp-appx-3a-4.pdf)

reliable capacity, it is to be expected that they will gradually replace SCGTs when the economics so allow. Indeed, it is quite likely that, by the time the SCGTs included in these plans are actually necessary, it will be economic to acquire storage instead.

For simplicity, the resource portfolios in Section 6.3 to assess whether it is preferable to continue, cancel or suspend the Site C Project model SCGTs as the last-resort modular capacity resource. However, considering the policy direction provided in the Climate Leadership Plan, it is unlikely that they will actually be required. These issues are explored further in Section 6.3.

Canadian Entitlement under the Columbia River Treaty

In addition to the energy and capacity resources considered by BC Hydro, the Canadian Entitlement (CE) under the Columbia River Treaty is also potentially available to BC Hydro. Owned by the Province of B.C. and marketed on its behalf by Powerex at Mid-C market prices similar to those shown in Table 13, the Canadian Entitlement is available at a fraction of the cost of energy and capacity from the Site C Project.

Under the Treaty, additional energy and capacity are available to downstream hydroelectric facilities located in the U.S. as a result of reservoirs located in British Columbia. Varying from year to year, in F2014 the CE consisted of 1,330 MW of hydroelectric capacity and 4,425 GWh of energy. These amounts represent “half of the extra power capability at generation facilities in the U.S. that results from the improved water regulation made available by the Columbia River Treaty.” [296] They also represent energy and capacity on par with that provided by the Site C Project, at much lower cost.

However, **BC Hydro cannot plan to use the Canadian Entitlement under the Columbia River Treaty because of the self-sufficiency requirement set out in s. 6(2) of the *Clean Energy Act*, which requires that BC Hydro plan to meet all energy needs with in-province generation.**

As a result, this hydropower cannot be relied upon by BC Hydro for long-term planning purposes. Thus, it cannot be used to displace far more expensive resources, such as Site C or pumped storage hydro. It should be noted that Section 6(3) of the *Clean Energy Act* does allow the government to authorize BC Hydro by regulation to enter into electricity import contracts otherwise barred under Section 6(2) of the *Act*.

> Subsection 6(3) of the CEA provides an exception to the self-sufficiency requirement found in subsection 6(2). The [Lieutenant Governor in Council] LGIC

[296] BC Hydro. 2014. BC Hydro Annual Report 2014, p.8. BC Hydro. 2014. BC Hydro Annual Report 2014, p.8. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2014.pdf)

> may by regulation authorize BC Hydro to enter into contracts for purposes of not meeting the self-sufficiency requirement.[297]

In the 2013 IRP, BC Hydro had to assume that the self-sufficiency criterion would remain unchanged throughout its planning period. The JRP reviewing the Site C Project faced a similar constraint. **However, the Government of British Columbia is not so constrained, given its executive power to allow exemptions to the self-sufficiency requirement**.

The comments of the Joint Review Panel for the Site C Project raised questions as to whether or not this criterion is in the public interest of British Columbians:

> Taken literally, this [self-sufficiency requirement of the *CEA*] means a B.C. disconnected to the outside world, a vision of autarchy truly strange for a province that relies on trade, and a long way from its recent history. (It could also explain the neglect of geothermal opportunities.)
>
> Minor relaxations could mean being connected for reliability or for diversity exchange, which are current practices apparently not condoned by the regulation, or for multi-year balance, all of which seem consistent with the intent if not the drafting of the regulation. …[298]

The BC Ministry of Energy's Industrial Energy Policy Review raised the same issue in its Final Report:

> As BC Hydro's surplus diminishes, Government should consider whether a requirement for self-sufficiency is consistent with a long-run approach to least cost electricity prices.[299]

The Ministry's formal response suggested that it is open to reviewing this restraint in the future:

> BC Hydro is currently in surplus. While not under consideration at this time, this recommendation could be considered as energy forecasts change.[300]

Once Site C is commissioned, B.C. Hydro will face energy surpluses into the 2030s and potentially much longer. The economic benefit that would flow from the repatriation of the Canadian Entitlement under the Columbia River Treaty would be lost. Powerex

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[297] BC Hydro. November 2013. Integrated Resource Plan, Chapter 9 Recommended Actions, p.9-39. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf)

[298] Site C Joint Review Panel. May 2014. Report of the Joint Review Panel Site C Clean Energy Project BC Hydro, at pp.304-305. (Accessed 17 April 2017 at: https://www.ceaa-acee.gc.ca/050/documents/p63919/99173E.pdf)

[299] IEPR Task Force. October 31, 2013. Industrial Energy Policy Task Force Review. Final Report, p.18. (Accessed 17 April 2017 at: http://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/electricity/electricity-business/industrial-electricity-policy-review)

[300] Government of British Columbia. November 2013. Backgrounder: Industrial Electricity Policy Review Background Report. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

would also continue to be in the disadvantageous position of selling the Canadian Entitlement at extremely low market prices.

The self-sufficiency requirement was apparently designed in large part to make it impossible to circumvent BC's clean energy legislation by importing high-GHG power. The Canadian Entitlement, however, consists of hydropower, the environmental costs of which are already borne by British Columbians. Adopting a regulation allowing the import of the Canadian Entitlement could not be seen as compromising BC's climate policies or its goal of energy self-sufficiency.

However, as a result of the self-sufficiency regulation, the Canadian Entitlement is not considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

5.4.3 BC Hydro purchases of energy and capacity

The opportunity to purchase renewable energy and to renew existing electricity purchase agreements represent additional opportunities to reduce the need for energy and capacity resources delivered by BC Hydro, including from the Site C Project. Whether these opportunities are realized depends on the evolution of the price of energy from these renewables, electricity rates, and BC Hydro's requirements for energy and capacity. BC Hydro's current net metering program, standard offer program and existing energy purchase agreements are discussed below.

Net metering

BC Hydro currently offers net metering service to residential and general service customers who generate electricity from clean or renewable resources[301] to serve all or a portion of their electricity requirements. Eligible generating facilities must have a nameplate capacity of less than 100 kW. According to BC Hydro, more than 95% of the 900 customers in the net metering program generate energy using solar PV.[302]

BC Hydro does not publish estimates of the cost of energy generated from solar PV facilities less than 100 kW in size. The current rates offered for the Ontario IESO feed-in tariff program are used to estimate the current cost of energy from solar PV in the more cost-effective locations in BC. These rates are summarized in Table 21.

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[301] Includes: biogas, biomass, geothermal heat, hydro, solar, ocean, wind or another clean or renewable energy source.

[302] BC Hydro Net Metering Program. Available at: http://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html?WT.mc_id=rd_netmetering

Table 21: IESO and BC Hydro price schedules for solar PV

Solar PV Type	Project Size	IESO Feed-in Tariff Rate ($/MWh) [303]	BC Hydro Rate Schedule	BC Hydro Rate ($/MWh)[304]
Rooftop	≤ 6 kW	311	Residential	137
	> 6 kW ≤ 10 kW	288	Small General Service	123
	> 10 kW ≤ 100 kW	223	Medium General Service	75
Non-Rooftop (Ground mount)	≤ 10 kW	210	Small General Service	123
	> 10 kW ≤ 500 kW	192	Medium General Service	75

As shown in the table, current PV costs, as reflected in the prices paid under the Ontario IESO feed-in tariff program, currently exceed the comparable BC Hydro rates paid by consumers for electricity. Thus, there is limited incentive to offset consumption through net metering. Where energy generated exceeds energy consumed, BC Hydro is deemed to have purchased that energy at the net metering rate, currently $99.90/MWh,[305] which is also well below the cost to generate energy from solar PV.

As with utility-scale solar PV, residential solar PV costs are expected to continue to decline for the foreseeable future. In 2015, the NREL noted that: “analysts project that from 2014-2020, system prices will fall 16% – 33% for residential systems.”[306] The US Department of Energy recently announced its objective of lowering the average levelized cost of energy from residential solar in the United States from US$180/MWh in 2016 to US$50/MWh by 2030, a decline of more than 70%.[307]

As solar panel costs decline, the total installed cost of solar PV systems becomes weighted towards balance of system costs.[308] These costs now typically account for

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[303] IESO. 2017. FIT/microFIT Price Schedule (January 1, 2017). (Accessed 17 April 2017 at: http://www.ieso.ca/en/sector-participants/ieso-news/2016/09/fit-microfit-price-schedule-for-2017-now-available)

[304] Includes 5% rate rider for all rate classes, and goods and services tax.

[305] BC Hydro. August 2015. Rate Schedule 1289 – Net Metering Service. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/schedule-1289-net-metering-service.pdf)

[306] U.S. Department of Energy. 2015. Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. *2015 Edition*, p.30. (Accessed 17 April 2017 at: http://www.nrel.gov/docs/fy15osti/64898.pdf)

[307] US Department of Energy. November 14, 2016. Energy Department Announces more than 90% Achievement of 2020 SunShot Goals, Sets Sights on 2030 Affordability Targets, p.2. (Accessed 17 April 2017 at: https://energy.gov/eere/articles/energy-department-announces-more-90-achievement-2020-sunshot-goal-sets-sights-2030)

[308] Balance of system costs include those related to grid connection, racking and mounting, electrical installation, inspection, financing and permitting.

more than 70% of total system costs and are much more variable and dependent on local policies and conditions.[309]

Figure 23 illustrates residential solar cost declines of 40%, 50% and 60% to 2030 for the more cost-competitive regions of British Columbia. These cost declines are compared to Tier 2 residential rates[310] increasing according to the 10 Year Rates Plan to F2019 and then either 1%, 0.6% or 0% real rate increases thereafter. In the 60% decline scenario, residential solar reaches parity in the cost effective regions of the province by 2025 regardless of rate increases, but in the case of a 40% decline does not reach parity until 2040, even under the high rate increase scenario.

Presuming the 60% price decline scenario is realized, this would apply only to certain regions of the province where solar is most cost effective, which excludes the Lower Mainland. These regions account for not more than 20% of the provincial population,[311] and would amount to about 400,000 residential customers by 2025.[312] Of these, only a portion would have suitable solar exposure and be in a position to purchase a 4 kW to 6 kW residential PV system. Installation by 2.5% (10,000) of these customers (0.5% of all residential customers) of an average 5-KW solar system producing 1200 kWh/kW annually would amount to 60 GWh/year (50 MW installed capacity) in offset generation annually beginning in 2025.

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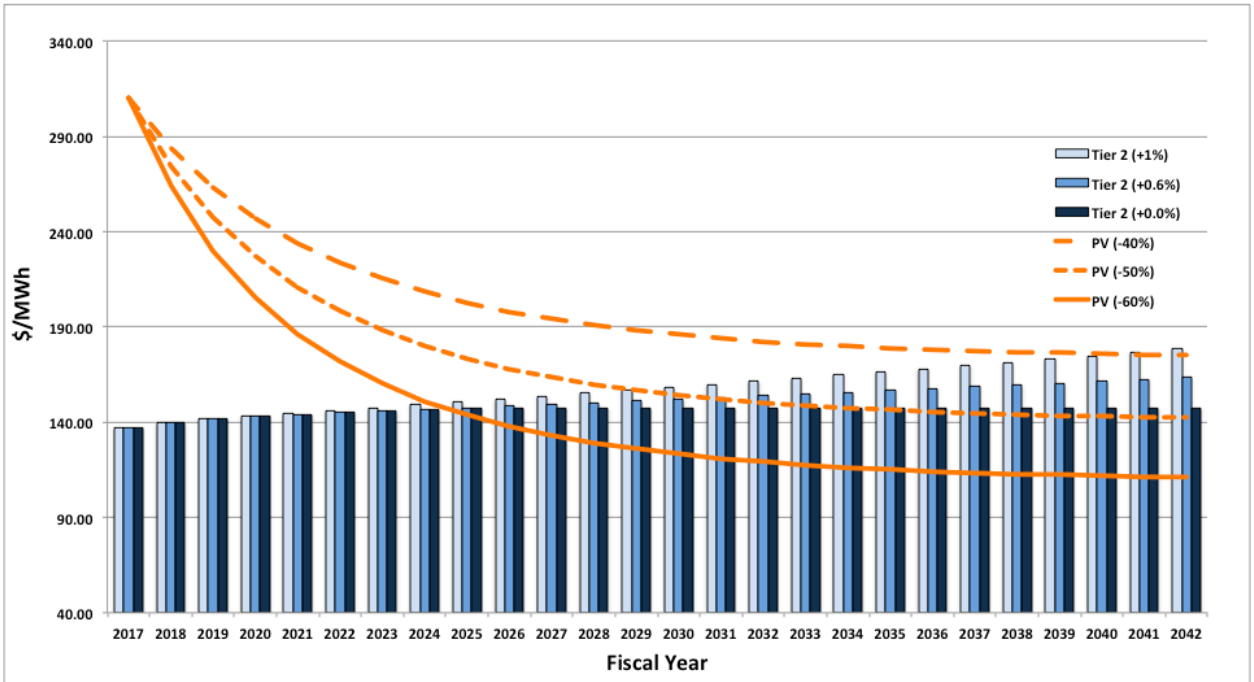
[309] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.31. (Accessed 17 April 2017 at: http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf)

[310] Tier 2 residential rates, which apply after the first 1350 kWh used every two months (8100 kWh/year), are used to reflect the likelihood that those with sufficient rooftop space for solar PV likely consume more than the average of 11,000 kWh/year.

[311] BC Stats. January 2017. 2016 Sub-Provincial Population Estimates. Higher solar potential regions include: Central Kootenay, Central Okanagan, Columbia-Shuswap, East Kootenay, Kootenay-Boundary, North Okanagan, Okanagan-Similkameen, Peace River, Thompson-Nicola. (Accessed 17 April 2017: http://www2.gov.bc.ca/gov/content/data/statistics/people-population-community/population/population-projections)

[312] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.4.4. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

Figure 23: Residential solar PV (<6 kW) vs. Tier 2 residential rates



In the case of commercial customers, BC Hydro has three commercial rate classes and some of these customers have the potential to install a more cost-effective ground-mounted solar PV system. Figure 24 illustrates commercial solar cost declines of 40%, 50% and 60% to 2030. These cost declines are compared to small general service rates for rooftop solar, and medium general service rates for ground mount solar, increasing according to the 10 Year Rates Plan to F2019 and then 1%, 0.6% or 0% real increases thereafter. In the case of a 60% cost decline, commercial solar reaches parity by the mid- to late-2020s regardless of rate increases, but in the case of a 40% decline does not reach parity, even under the high rate increase scenario.

Presuming the 60% price decline scenario is realized, this again would apply only to certain regions of the province where solar is most cost effective. These regions are presumed to account for not more than 20% of the ~250,000 commercial customers by 2025.[313] Of these, only a portion would have suitable solar exposure, and high initial capital costs would be expected to somewhat constrain investment, even at 60% lower cost. These customers consume on average about 85 MWh per year, and would not be expected to install systems larger than their consumption if they are participating in a net metering program. Installation by 2.5% (1,250) of these customers (0.5% of all

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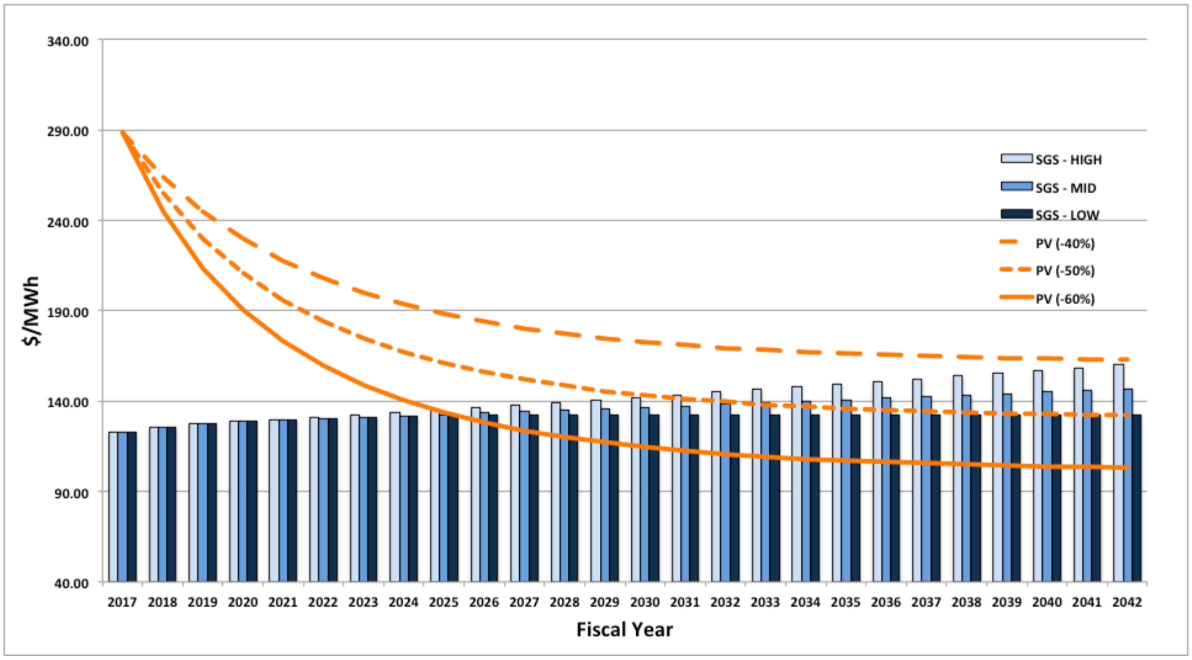
[313] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to BCUC Information Request 1.4.4. Including customers of FortisBC. Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

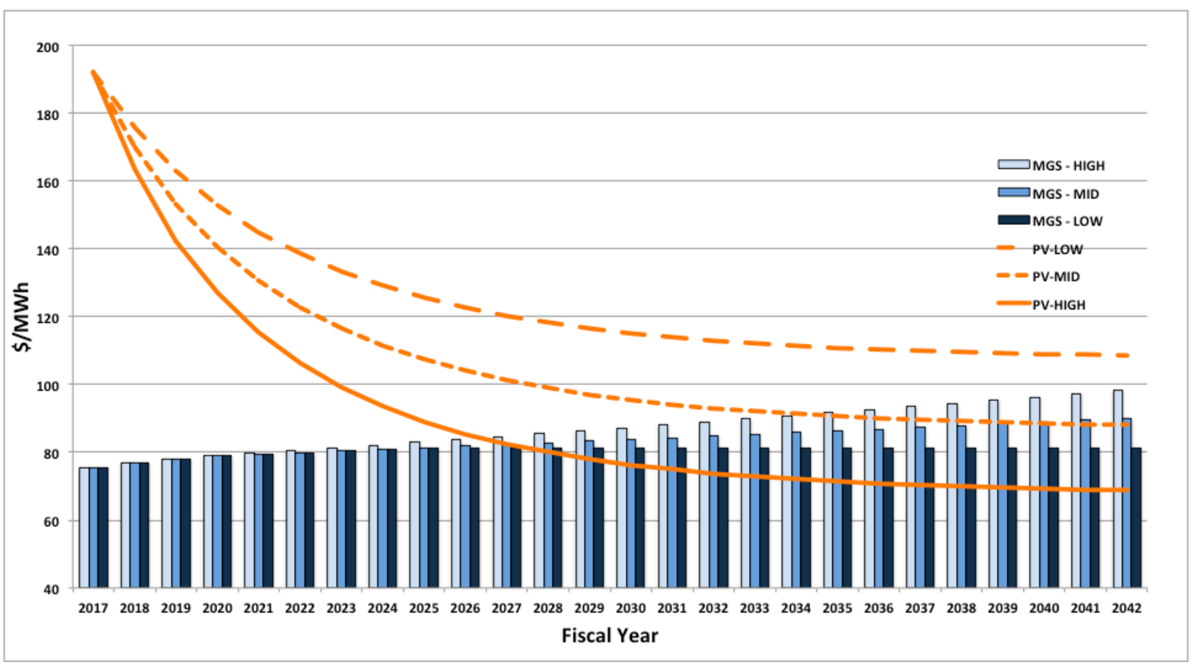
commercial customers) of an average 50-KW solar system producing 1200 kWh/kW, or 60 MWh/year, would amount to 75 GWh/year (62.5 MW installed capacity) in offset generation annually beginning in 2025.

Figure 24: Commercial solar PV vs. general service rates

a) Rooftop solar PV (> 10 kW ≤ 100 kW) vs. small general service rates



b) Ground-mount solar PV (> 10 kW ≤ 100 kW) vs. medium general service rates



In a future scenario where the costs of energy from solar PV continue to decline by 60% or more from today, then total annual incremental generation could be on the order of 135 GWh/year (or 112.5 MW of installed capacity) beginning as early as 2025. For context, Ontario's Feed-in Tariff program developed about 325 MW per year of installed solar generation capacity beginning in 2011.[314]

Considering the substantial declines in costs that remain to occur, and that even with a 60% decline in costs distributed solar PV will remain uneconomic in much of the Province, energy delivery from distributed solar PV is likely to remain modest throughout the 20-year planning period.

Standing Offer Program

BC Hydro established the Standing Offer Program (SOP) in 2008, and is required to maintain the program pursuant to subsection 15(2) of the *Clean Energy Act*. The purpose of the SOP is to encourage the development of small-scale clean or renewable generation projects (> 100 kW ≤ 15 MW), and to streamline the process for these small developers. BC Hydro also offers a Micro-SOP for projects > 100 kW ≤ 1 MW for First Nation and community developers.

As of the end of F2017, BC Hydro had signed contracts for 176.8 MW and 648.6 GWh/year under the SOP.[315] In its 2016 RRA, the utility forecasted 4 MW of dependable capacity and 62 GWh/year of annual energy from the SOP as of F2017, with a gradual increase to 145 MW and 2,045 GWh/year by F2036.[316] The 2013 IRP introduced an annual incremental energy volume target of 150 GWh/year. The information in the 2016 RRA indicates an expected annual increase of about 8 MW of dependable capacity and 110 GWh/year of energy, which allows for attrition from the 150 GWh/year target.[317]

The current prices offered under the SOP range from $102.06 MWh/year in the Peace Region to $111.56 MWh/year in the Lower Mainland.[318] However, in February 2016, BC Hydro announced that, along with the Government of B.C. and Clean Energy BC, it is reviewing these prices and future requirements under the SOP. The basis for this review is the declining cost of renewables and current system requirements for capacity over energy.

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[314] IESO. 2017. Ontario Energy Report Q4 2016, p.5. (Accessed 17 April 17 at: https://www.ontarioenergyreport.ca)

[315] BC Hydro SOP: Current Applications. Available at: https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/current-applications.html

[316] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[317] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[318] BC Hydro. April 2016. Standing Offer Program: Program Rules, Version 3.2, p.10.

> Utilities along the Pacific Northwest, including BC Hydro, have an oversupply of energy during the late spring and early summer period (May through to July). We're also expecting to be in need of new capacity resources in the near and long-term.
>
> We need to focus on acquiring electricity that better fits the needs of the system. For example, dependable capacity is becoming increasingly more important than energy in the mid to long term. As such, we'll be looking at how to encourage the development of resources that can provide dependable capacity.[319]

This review and "optimization" of the SOP is in many respects the outcome of the decision to proceed with the Site C Project, which will result in extension of the ongoing energy surplus beyond 2030. Much like the decision to curtail spending on DSM programs, BC Hydro retains considerable discretion to expand or moderate purchases under the SOP, even where those resources might deliver energy and capacity at costs at or below the costs of energy and capacity from the Site C Project, or might avoid the energy surplus created by Site C.

Electricity Purchase Agreement (EPA) Renewals

In the 2016 RRA, BC Hydro forecasted 9 MW of dependable capacity and 61 GWh/year of annual energy from EPA renewals in F2017, gradually increasing to 901 MW and 5,515 GWh/year by F2036.[320] While these are substantial quantities, they do not represent all the potential dependable capacity and annual energy available to BC Hydro through EPA renewals over the planning period.

In the 2013 IRP, BC Hydro reduced spending on EPAs with Independent Power Producers. Spending reductions were the result of the ongoing energy surplus, and BC Hydro's desire to reduce short-term costs. BC Hydro identified three potential approaches to cost reductions:

- For projects not yet in operation, defer the commercial operation date, downsize the capacity or terminate the EPA;
- Do not sign any new EPAs; and
- Renew fewer EPAs where contracts are expiring.

In its 2016 RRA, BC Hydro confirmed that it has reached agreements to terminate 14 EPAs, downsize and defer two EPAs, and defer delivery of energy from an additional 11 EPAs. The net result was reductions of 435 MW in nameplate capacity and 1,890 GWh/year of energy through downsizing and terminations, as well as deferral of 2,050 GWh/year from F2015 to F2018. Consistent with the Clean Energy Strategy in the 2013

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[319] BC Hydro SOP: About SOP Optimization. Available at https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/standing_offer_program/sop-optimization-process/about.html.

[320] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8 and Table 3-9. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

IRP, BC Hydro is not proposing to enter into any new EPAs, with the exception of EPAs entered into under the SOP.[321]

BC Hydro pursues EPA renewals on a cost-of-service basis, and also considers past performance, certainty of continued operation, and system support characteristics.[322] As noted in the 2016 RRA, renewal of EPAs with existing facilities has the long-term benefit of delaying future greenfield resources. In addition, BC Hydro notes the following:

> Due to the fact that Electricity Purchase Agreement renewals are related to existing projects for which the IPPs' initial capital investment has been fully or largely recovered during the term of the initial Electricity Purchase Agreement, BC Hydro expects to be able to negotiate a lower energy price than the initial Electricity Purchase Agreement. Since the 2013 Integrated Resource Plan, BC Hydro has carried out further analysis of the expected cost of service for existing projects. BC Hydro currently estimates that the renewal volumes in the plan can be acquired at or below $85/MWh (fiscal 2013$) although the relationship between price, volume, contract terms and other non-energy benefits has yet to be established through bilateral negotiations.[323]

This suggests that, from a levelized cost of energy perspective, planned EPA renewals are on par with the Site C Project. However, this ignores the potential that the EPAs could be renewed on an as-required basis, avoiding the costly energy surplus that would be created by the Site C Project. It is also unclear to what extent this levelized cost is inclusive of capacity benefits or costs related to these renewals, a key consideration given BC Hydro's need for capacity resources over energy resources.

The potential to renew biomass EPAs is limited by the sustainability and proximity of biomass fuel supply. As a result, BC Hydro assumes renewal of 50% of the energy and capacity from biomass EPAs due to expire prior to the end of the 10 Year Rates Plan, in F2024.[324] BC Hydro estimates the average cost of bioenergy EPA renewals to be on the order of $95/MWh,[325] which is somewhat higher than the cost of energy from the Site C Project, at $85 to $88/MWh. This suggests that a higher EPA renewal rate for biomass EPAs offers marginal, if any, cost savings compared to the Site C Project.

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[321] BC Hydro. November 2013. Integrated Resource Plan, Chapter 9 Recommended Actions, p.9-45. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0009-nov-2013-irp-chap-9.pdf)

[322] BC Hydro. September 24, 2015. 2015 Rate Design Application, p.2-50. (Accessed 17 April 2017 at: https://www.bchydro.com/about/planning_regulatory/2015-rate-design.html)

[323] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-43. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[324] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-43. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[325] BC Hydro. September 24, 2015. 2015 Rate Design Application, p.2-50. (Accessed 17 April 2017 at: https://www.bchydro.com/about/planning_regulatory/2015-rate-design.html)

In the case of run-of-river hydroelectric EPA renewals, BC Hydro assumes renewal of 75% of these EPAs due to expire prior to the end of the 10 Year Rates Plan, in F2024.[326] This appears to be a change from the 2013 IRP, which assumed that 75% of these EPAs expiring before F2018 would be renewed, and 100% thereafter.[327] BC Hydro has estimated the average cost of EPA renewals to be on the order of $70/MWh,[328] which is materially lower than the cost of energy from the Site C Project.

The remaining 25% of run-of-river hydroelectric EPAs not planned for renewal by BC Hydro may represent an additional low-cost resource available to BC Hydro that is not being fully utilized. This cannot be determined without detailed cost information respecting these EPA renewals. Unfortunately, this information is treated as confidential and not divulged by BC Hydro.

Implications and opportunities

Contracting additional resources through net metering, the SOP, and renewing additional EPAs include some cost-effective opportunities that could reduce the need for additional energy and capacity delivered by BC Hydro, including from the Site C Project.

As distributed renewable forms of generation become more cost effective, they will be increasingly used for self-generation, with a commensurate effect on BC Hydro's requirements for energy and capacity. The timing of this effect depends largely on the extent of cost declines in these resources, but also on future rate increases.

If the Site C Project is developed, and these additional resources do become more cost effective, this could increase and/or prolong the Site C Project energy surplus. BC Hydro and the Provincial Government have several options that could reduce contributions from these resources, even if these additional resources could otherwise provide energy and capacity at lower costs than the Site C Project:

- lower the rates paid, impose additional charges, implement aggregate caps, impose minimum project sizes, or otherwise change the rules to limit contributions under the net metering program, or eliminate the program entirely;
- lower the rates paid, further reduce the aggregate energy contribution, or impose technology or electricity service restrictions (e.g. tender only capacity resources) under the SOP, or eliminate the SOP entirely; and

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[326] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, p.3-43. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[327] BC Hydro. November 2013. Integrated Resource Plan, Chapter 4 Resource Planning Analysis Framework, p.4-15. (Accessed 17 April 17 at: 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)

[328] BC Hydro. September 24, 2015. 2015 Rate Design Application, p.2-50. (Accessed 17 April 2017 at: https://www.bchydro.com/about/planning_regulatory/2015-rate-design.html)

- opt not to renew a larger portion of EPAs up for renewal, and delay procurement of new renewable resources indefinitely.

These actions may seem extreme, but many are already being implemented or considered for implementation by BC Hydro in the face of its ongoing energy surplus. The potential actions in relation to the net metering program are strategies already employed in other jurisdictions in the face of increasing contributions from solar PV.[329]

Whether these actions represent a least-cost approach to meeting energy and capacity requirements compared to developing the Site C Project cannot be determined without additional information. In particular, a detailed review of the costs of EPA renewals would require access to renewal contracts, which remain confidential. **In the event that the Site C Project is reviewed before the BCUC, it will be important to thoroughly review the long-term potential for energy and capacity to be contracted through net metering, the Standing Offer Program, and energy purchase agreements.**

5.5 Summary

To summarize, the relevant costs to evaluating continuing, cancelling or suspending the Site C Project are as follows:

- Total expenditures on the Site C Project as of June 30, 2017 are projected to be 1.87 billion, leaving $6.465 billion to be spent;
- Contractual and demobilization costs are estimated at $750 million;
- Costs to maintain the Site C Project in suspension are estimated at $15 million per year;
- Costs to remobilize to continue with the development of the Site C Project are estimated at $200 million, which added to the remaining cost of $6.465 billion results in a cost of $6.665 billion to resume the development of the Site C Project if circumstances warrant in the future;
- 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;
- The unit energy cost of energy-focused DSM from the utility cost perspective is on the order of $29/MWh, which compares to $85 to $88/MWh for the Site C Project at the time of the final investment decision;
- BC Hydro is cancelling or scaling back many DSM programs that have utility costs well below the unit energy costs of the Site C Project, at $85 to $88/MWh;
- A total of 126 MW of capacity-focused DSM has been demonstrated in BC Hydro's pilot programs to date, and an estimated 500 MW of capacity-focused DSM is considered to be feasible by F2030;

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[329] NC Clean Energy Technology Centre. 2016. The 50 States of Solar. (Accessed 17 April 2017 at: https://nccleantech.ncsu.edu/the-50-states-of-solar-report-2016-annual-review-and-q4-update/)

- The cost of capacity-focused DSM is estimated to be on the order of $50/kW-year based on BC Hydro's pilot programs to date;
- The unit energy cost of on-shore wind resources has decline by 20% since the 2013 IRP and is conservatively projected to decline by another 20% by F2030, resulting in adjusted unit energy costs of $80/MWh by the late 2020s to the end of the planning period in F2036;
- The unit energy cost of utility-scale solar PV is expected to continue to decline on the order of 40% to 60%, resulting in levelized (unadjusted) unit energy costs at or lower than $80/MWh by the end of the planning period in F2036;
- Considering the CO_2e emissions of the Site C Project, BC Hydro could develop up to 290 MW of SCGTs operated for a 100-year period to meet winter peak capacity requirements without exceeding the CO_2e emissions of Site C; and
- Distributed generation could make the Site C Project less cost-effective by expanding the energy surplus created by the Project; as a result it is reasonable to expect that BC Hydro will continue to moderate and potentially eliminate the net metering program and SOP, and choose to renew fewer EPAs.

These findings are considered in the scenarios developed in Section 6.3 assessing the conditions under which it is preferable to continue, cancel or suspend the Site C Project.

6. Re-evaluating the Site C Project against the alternatives

6.1 Comparing the alternatives

This Section 6 compares the present value costs of different combinations of demand-side and supply-side resources, including the Site C Project, for meeting BC Hydro's needs for energy and capacity. In particular, this section reviews the merits of the following options:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of resuming the Site C Project if circumstances warrant.

In December 2014, the Provincial Government justified the significant adverse environmental effects of the Site C Project on the premise that the project will deliver energy and capacity at lower GHG emissions and lower costs than the available alternatives. However, as summarized earlier in this report, circumstances have changed and new information has become available since the decision to approve the Site C Project.

Specifically, as demonstrated in this report, BC Hydro's 2012 Load Forecast has collapsed (Section 3.3). As a result, the Site C Project will create a large energy surplus resulting in significant losses (Section 4.4.1), which could be much larger if load growth is lower than forecasted by BC Hydro (Section 4.4.2). It should be noted that BC Hydro has consistently overestimated future requirements for energy (Section 3.2). Though the Site C Project so far remains on budget, the prior experience of BC Hydro and other Crown corporations suggests that cost overruns in large-scale hydroelectric and transmission projects are common (Section 4.3.1) and potentially substantial (Section 4.3.2).

In addition, BC Hydro is dramatically reducing DSM program spending now and into the future, despite the very low costs of energy and capacity from DSM (Section 5.3.1). At the same time, the costs of energy from alternative supply-side resources, particularly wind, have declined substantially since the decision to proceed with the Site C Project, and are forecast to continue to decline in the coming years (Section 5.4.1).

However, the Site C Project also provides dependable capacity in addition to energy. In the absence of the Site C Project, in order to meet its needs for dependable capacity, BC Hydro could develop additional capacity-focused DSM (Section 5.3.2) or a 465 MW pumped storage hydroelectric facility at the Mica Generating Station (Section 5.4.2). It also could operate up to 800 MW of SCGTs for 30 years, or up to 290 MW for 100 years without exceeding the greenhouse gas emissions from the operations of the Site C Project over those respective periods (Section 5.4.2).

BC Hydro will have incurred on the order of $1.87 billion in sunk costs to develop the Site C Project by June 30, 2017 (Section 5.2.1). Cancelling the Site C Project must consider these sunk costs as well as costs related to contract cancellation and demobilization (Section 5.2.2). Suspending the Site C Project must consider the costs to carry the sunk costs until a decision is made to continue or cancel the Site C Project (Section 5.2.1), as well as the costs to maintain the project site while in suspension (Section 5.2.3).

Despite these costs, cancelling or suspending the Site C Project could still be the least-cost solution going forward. This Section 6 explores whether or not this is the case, and under what conditions. The section begins with a review of the analysis of alternatives undertaken by BC Hydro in its 2013 IRP (Section 6.2). This is followed by a detailed assessment of the conditions under which it would be preferable to continue, cancel or suspend the Site C Project (Section 6.3). Section 6.4 provides a summary of the model results, while Section 6.5 contemplates additional analyses that could be considered in the event that the Site C Project is referred to the BCUC. The section concludes with a summary of its findings (Section 6.6).

6.2 BC Hydro's analysis of alternatives

The 2013 IRP and the environmental impact statement prepared for the Site C Project make clear that BC Hydro carries out two distinct types of resource analysis for comparing alternatives for meeting the requirements for energy and capacity: a block analysis, and a portfolio analysis.

6.2.1 Block analysis

The block analysis compares the Site C Project to similarly sized blocks of energy and capacity from other sources, and calculates the adjusted unit energy costs for each. The approach has some value for comparing the environmental and socio-economic attributes of different development paths; it allows for direct comparisons in terms of adverse environmental effects,[330] GHG emissions,[331] employment and macroeconomic indicators.[332] **But as an approach for comparing the economic attributes of the available alternatives for meeting the energy and capacity requirements of BC Hydro, the block analysis used in the 2013 IRP is fundamentally flawed. In forcing the alternative portfolios to reproduce the energy surplus that the Site C Project would create, it masks the resulting losses**.

In its 2013 IRP, BC Hydro compared the adjusted unit energy costs of three blocks of resources designed to provide the same amounts of energy and capacity as the Site C Project (5100 GWh/year and 1100 MW).

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[330] UBC Program on Water Governance. 2016. Briefing Note #2: Assessing Alternatives to Site C: Environmental Effects Comparison. Available at: www.waterpartners.ca/projects/sitec

[331] Hendriks, R.M. July 2016. Comparative Analysis of Greenhouse Gas Emissions of Site C versus Alternatives. Available at: www.waterpartners.ca/projects/sitec

[332] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement Executive Summary, p.9. (Accessed 17 April 17 at: http://www.ceaa-acee.gc.ca/050/documents_staticpost/63919/85328/Executive_Summary.pdf)

Table 22: 2013 IRP block analysis – adjusted unit energy costs[333,334]

Blocks	Clean		Clean + Thermal #1		Clean + Thermal #2		Site C	
	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy
Supply-side Resources	**MW**	**GWh/year**	**MW**	**GWh/year**	**MW**	**GWh/year**	**MW**	**GWh/year**
Site C							1100	5100
GM Shrum	220	0			220			
Revelstoke 6	488	26	488	26	488	26		
Municipal Solid Waste	36	312	36	312	36	312		
Natural Gas (SCGT)			588	924	392	616		
Pumped Storage	500	-364						
Wind		5126		3839		4148		
Totals	1244	5100	1112	5101	1136	5102	1100	5100
Adjusted UEC ($/MWh)	**153**		**128**		**130**		**94**	

The Government of British Columbia, in its Final Investment Decision (FID) for the Site C Project also placed substantial emphasis on the comparison of adjusted unit energy costs between the available alternatives, despite the limitations of this approach.

> When considering the impact on ratepayers, the costs of delivering the electricity must be accounted for. In addition, as IPPs are intermittent, the cost of backing them up with firm energy sources (e.g., natural gas) must be included. Also, IPPs do not have the same ability to store energy and take advantage of high prices on the export market, which reduces trade revenues.
>
> Accounting for all of these factors, the final cost to ratepayers is $64 to $67 / MWh[335] for Site C and $110 to $130 / MWh for IPPs.[336]

The intermittency of renewable energy resources and the cost to provide dependable capacity (i.e. "backing them up") are realities that must be considered in a comparative analysis of the alternatives and the Site C Project. These realities are considered in the analysis detailed below in Section 6.3. However, while the BC Government FID notes some potential disadvantages of the alternatives in comparison with the Site C Project, it fails to mention several factors pointing in the opposite direction.

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[333] BC Hydro. November 2013. Integrated Resource Plan, Chapter 6 Resource Planning Analysis, pp.6-34 to 6-39. Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0006-nov-2013-irp-chap-6.pdf)

[334] The unit energy costs are based on the firm energy provided, with adjustments made to reflect delivery costs to the Lower Mainland, wind integration costs (where applicable), soft costs and time of delivery of the energy. Capacity costs are added to resource options that do not have dependable capacity. For example, the unit energy cost (excluding sunk cost) of the Site C Project is adjusted for delivery to the Lower Mainland before taking into account a capacity credit. The corresponding adjusted UEC after a capacity credit at the time of the 2013 IRP was $83/MWh.

[335] This unit energy cost presumes that the Site C Project is financed in accordance with the 10 Year Rates Plan. See Section 4.2.2.

[336] Government of British Columbia and BC Hydro. Site C to provide more than 100 years of affordable, reliable clean power. Backgrounder: Comparing the Options. (Accessed 17 April 2017 at https://news.gov.bc.ca/stories/site-c-to-provide-more-than-100-years-of-affordable-reliable-clean-power)

First, the quoted unit energy cost of the Site C Project is based on the 10 Year Rates Plan. The actual unit energy cost of the Site C Project as announced in the FID is $85 to $88/MWh. As discussed in Section 4.2.2 above, there is no reason to believe that the Plan, which expires in March 2024, would affect the regulatory treatment of the Site C Project. The 10 Year Rates Plan does not include the Site C Project, and the BC Utilities Commission has yet to determine how the Project will impact rates. The current government has not committed to continue the Plan after it expires and, even if it did make such a commitment, it cannot bind future governments. Moreover, there is no guarantee that future governments will maintain the 10 Year Rates Plan to its scheduled conclusion.

Secondly, as discussed in Section 4.4, if commissioned as planned in F2024, the Site C Project would result in very large energy surpluses, especially in low-load scenarios. The revenues from exporting those surpluses are far less than the annual costs of the Site C Project. The total losses would be on the order of $950 million in the mid-load scenario and exceed $2.7 billion in the low-load scenario.

In addition, considering the collapse of BC Hydro's load forecast discussed in Section 3.3 and the very low utility cost of additional demand-side management discussed in Section 5.3, pursuing an alternative path has substantial advantages over proceeding with the Site C Project. These advantages go entirely unmentioned in the FID comparison, and include the following:

- **Deferral of costs**. Costs deferred are, to a large extent, costs avoided. In the current low load growth context, and in the absence of proceeding with the Site C Project, BC Hydro would be positioned to defer the development of supply-side resources in favour of lower-cost DSM. This reality contrasts with the situation described in Section 5.3.1, where the decision to proceed with the Site C Project has encouraged the utility to further reduce spending on lower-cost DSM programs in order to limit the future losses from the surplus created by the Site C Project.
- **Modularity and flexibility**. The alternatives to the Site C Project consist of resources that are generally much smaller in size. Development of these resources can occur on a modular basis, only as required to meet load growth, avoiding the losses associated with an energy surplus. In terms of capacity resources, this modularity is more limited beyond capacity-focused DSM and the relatively low-cost Revelstoke 6, as BC Hydro must either choose to develop simple-cycle gas turbines or larger-scale and higher-cost pumped storage hydroelectric. However, the longer these additions can be deferred, the greater the likelihood that low-cost modular storage options will become available.
- **Declining costs**. As noted in Section 5.4.1, the costs of wind and utility-scale solar resources continue to decline dramatically, with numerous projections suggesting that wind power will be available by the late 2020s in BC at adjusted unit energy costs less than $80/MWh.
- **Technology improvements**. By allowing the deferral of resources until they are required, the alternative portfolios can take full advantage of future improvements in demand-side management, generation and energy storage technologies.

- **Cost overruns**. As discussed in Section 4.3.1, based on the history of large-scale greenfield hydroelectric generation (and transmission) projects developed by BC Hydro and other utilities across Canada, the Site C Project is at risk of substantial cost overruns. The alternative resources that are substitutes for Site C could largely be contracted through independent power producers, transferring the risk of cost overruns to developers and away from ratepayers.

In summary, the block analysis compares four resource portfolios. Site C unavoidably creates an expensive surplus. The other three portfolios are arbitrarily structured to recreate the same costly surplus. The Site C Project is then shown to be superior on the basis of a comparison of adjusted unit energy costs. This ignores the fact that, in reality, none of the alternative portfolios would create the same costly surplus as the Site C Project. **For this reason, the output of the block analysis, a series of adjusted unit energy costs, is not sufficiently informative for comparing the economic attributes of the alternatives.**

6.2.2 Portfolio analysis

In order to address the shortcomings of the block analysis, BC Hydro also made use of a portfolio analysis in its 2013 IRP. This analysis was carried out using a series of modeling tools, including System Optimizer, a deterministic optimization model that produces an optimal sequence of generation and transmission resource expansions for a predefined scenario by selecting from the stack of available resources. The model minimizes the present value (PV) of the net cost of meeting a forecast of energy and capacity requirements under average water conditions.

In addition to ensuring that all portfolios satisfy good utility practice, System Optimizer also operates under the constraints imposed by the *Clean Energy Act*, including:

- to achieve electricity self-sufficiency;
- to take demand-side measures to reduce BC Hydro's expected increase in demand for electricity by the year 2020 (F2021) by at least 66%; and
- to generate at least 93% of the electricity in British Columbia from clean or renewable resources.

The modeling of the alternative portfolios in the 2013 IRP was performed in 2013 real (constant) Canadian dollars for the period F2017 through F2041. The modeling for the 2016 RRA was performed in 2016 real (constant) Canadian dollars for the period F2017 through F2036. These analyses were based on the following assumptions:[337]

- **Inflation rate**. An annual inflation rate of 2% was used in both the 2013 IRP and the 2016 RRA for conversion between real and nominal dollars.

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[337] As summarized from BC Hydro. November 2013. Integrated Resource Plan, Chapter 4, section 4.4. (Accessed 17 April 17 at: 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)

- **Cost of capital**. The cost of capital used is the weighted average cost of debt and equity. BC Hydro's weighted average cost of capital (WACC) used in the 2013 IRP and 2016 RRA was 5% real. BC Hydro uses a WACC of 7% real for independent power producers (IPPs).[338]
- **Discount rate**. BC Hydro uses 5% and 7% discount rates to calculate levelized unit costs (UECs and UCCs) for BC Hydro and IPP resources, respectively. BC Hydro's discount rate is used to calculate the portfolio present values since the analysis is from the utility's perspective.
- **Exchange rate**. The USD to CAD exchange rate used in the 2013 IRP was 0.9693 USD/CAD, reflecting the strength of the Canadian dollar at that time. The exchange rate used in the 2016 RRA increases gradually to 0.82 USD/CAD, and remains at that level until F2036.[339]
- **Load resource balances (LRBs)**. The LRBs form the base assumption for resource requirements in the IRP portfolio analysis. The LRBs for the 2013 IRP reflect the 2012 Load Forecast and are presented in this report as Figure 10. The LRBs for the 2016 RRA are current to May 2016 and are presented as Figure 11.
- **Market prices**. Costs and revenues of each portfolio are affected by market price assumptions for natural gas, GHGs, electricity and renewable energy credits. The electricity market price assumptions used in the 2016 RRA are presented in Table 13.
- **Resource options**. Chapter 3 of the 2013 IRP contains an extensive list of resource options, and those not eliminated on the basis of cost, policy or other reasons are made available to System Optimizer. A number of generic costs are added to the costs of some resources, including a soft cost adder,[340] a wind integration cost adder[341] and a network upgrade cost adder.[342]

The objectives of the *Clean Energy Act*, discussed in Section 2.1.2, include that BC Hydro's rates "remain among the most competitive of rates charged by public utilities in North America."[343] As such, the comparative present value costs of the portfolios are

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[338] BC Hydro's recent Resource Options Update presents unit energy costs for energy produced by IPPs using both 5% and 7%.

[339] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 8-6. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

[340] This is applied to generic resource options or specific projects that do not have discrete cost estimates which specifically include costs related to mitigation, First Nations, public engagement regulatory review costs. BC Hydro adds 5% to the cost of these resources based on prior experience.

[341] Wind integration is highly variable resulting in the need for additional highly responsive generation capacity reserves on the electric system to maintain system reliability and security. Also, the natural variability in wind power generation results in the need to set aside system flexibility to address the potential for wind generation to either under- or over-generate. A wind integration cost adder of $10/MWh is used in the 2013 IRP analysis.

[342] This cost adder reflects costs borne by BC Hydro when interconnecting resource options to the bulk transmission system and is added to all resource options except those that have such costs explicitly included in their cost estimates.

[343] *Clean Energy Act*, SBC 2010, c22, s.2(f).

very relevant to the evaluation of the alternatives for meeting energy and capacity requirements.

In its portfolio analysis, BC Hydro models more than sixty different portfolios, of which four portfolios compose its base case:

- A Clean portfolio, without the Site C Project, consisting entirely of resources that meet the definition of clean energy in the *Clean Energy Act*;[344]
- A Clean portfolio, with the Site C Project, consisting entirely of resources that meet the definition of clean energy in the *Clean Energy Act*;
- A Clean + Thermal portfolio, without the Site C Project, consisting mostly of resources that meet the definition of clean energy in the *Clean Energy Act*, but including simple cycle gas turbines for capacity up to the limits in the *Clean Energy Act*; and
- A Clean + Thermal portfolio, with the Site C Project, consisting mostly of resources that meet the definition of clean energy in the *Clean Energy Act*, but including simple cycle gas turbines for capacity up to the limits in the *Clean Energy Act*;

The following table illustrates the present value (PV) cost differences determined by BC Hydro in its 2013 IRP, for commissioning the Site C Project as planned in F2024. This table shows that the benefit of the Site C Project in a Clean portfolio was determined to be $630 million, while the benefit in a Clean + Thermal portfolio was determined to be just $150 million.

Table 23: Portfolio present value base case analysis for Site C (in F2024)[345]

Portfolio Type	PV costs of Portfolios without Site C (M$)	PV costs of Portfolios with Site C (M$)	PV Difference (M$) (Portfolio without Site C minus Portfolio with Site C)
Clean	6,766	6,138	630
Clean + Thermal	6,030	5,883	150

The $630 million benefit of the Site C Project in the Clean portfolio is largely the result of the relatively high cost of pumped storage hydroelectricity. In the absence of Site C and simple cycle gas turbines (SCGTs), pumped storage hydroelectric meets the bulk of BC Hydro's capacity needs in the Clean portfolio without Site C. Pumped storage

[344] *Clean Energy Act*, SBC 2010, c22, s.1(1). **"clean or renewable resource"** means biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource.

[345] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6A Portfolio Results, p.6A-36. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600a-nov-2013-irp-appx-6a.pdf)

hydroelectric and SCGTs provide most of the capacity in the Clean + Thermal portfolio without Site C.

As noted in Section 3.4.2 dealing with low-carbon electrification in BC, the Province's Climate Leadership Plan calls for the adoption of 100% clean or renewable electricity, with allowances to address reliability or costs. [346] Due to the high costs of pumped storage hydroelectric, and the lack of another "clean" capacity resource that can provide sufficient capacity at a competitive cost,[347] creation of clean portfolios is considered to be required only in the low-load and mid-load forecasts. The high-load forecast scenarios are considered to raise "concerns regarding reliability or costs" specified in the Climate Leadership Plan, which concerns would justify the development of some natural gas generation for capacity purposes.

Since the time of the 2013 IRP, several circumstances have changed, calling into question the determination that a portfolio with the Site C Project has a lower present value cost compared to an alternative portfolio without the Project:

- **Increased cost of the Site C Project**. At the time of the FID for the Site C Project, the cost of the Site C Project increased from $7.9 billion (nominal) to $8.335 billion (nominal), or $435 million, with a treasury board reserve of an additional $440 million.
- **Reduction in wind costs**. As noted in Section 5.4.1, the unit energy costs of wind resources have declined by about 20% since the 2013 IRP from $125/MWh to $100/MWh. The decline in wind costs disproportionately benefits the portfolios without the Site C Project on the order of $700 million in direct capital cost reductions.[348,349]
- **Future declines in wind costs**. Also noted in Section 5.4.1, the unit energy cost of wind resources is conservatively expected to decline from current levels by a further 20% by 2030 when these resources would be required in the portfolios without the Site C Project. This would be an additional benefit to the portfolios without the Site C Project on the order of $600 million in direct costs.
- **Collapse in the load forecast**. The collapse in BC Hydro's load forecast discussed in Section 3.3 combined with the pending addition of the Site C Project have encouraged BC Hydro to further reduce investment in lower-cost DSM

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[346] Government of British Columbia. August 2016. Climate Leadership Plan, p.28. (Accessed 17 April 2017 at: https://climate.gov.bc.ca/)

[347] While other potential clean capacity resources, such as lithium-ion batteries, continue to decline in cost, and may become cost-effective by the end of the planning period in F2036, analysis of these potential resources was outside the scope of this report.

[348] BC Hydro. 2013. Integrated Resource Plan Appendix 6A Portfolio Results. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600a-nov-2013-irp-appx-6a.pdf)

[349] BC Hydro. 2013. Integrated Resource Plan Appendix 3A-4 2013 Resource Options Report Update Resource Options Database (RODAT) Summary Sheets. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a04-nov-2013-irp-appx-3a-4.pdf)

programs. However, the collapse in the load forecast can also be seen to open up an opportunity to meet the need for energy and capacity by more aggressively pursuing DSM, and allowing wind and utility-scale solar PV costs to decline further. However, this opportunity is only available by cancelling or suspending the Site C Project.

These factors suggest that the present value cost benefits of proceeding with the Site C Project that were determined in the 2013 IRP have not materialized as predicted. As detailed below, updated alternative portfolios, with costs continuing to decline, are now hundreds of millions of dollars less costly than portfolios with the Site C Project, even when sunk costs and cancellation costs are taken into account.

6.3 Updated analysis of alternatives

The purpose of this updated alternatives analysis was to reconsider the need for the Site C Project. This analysis compares portfolios for meeting BC Hydro's requirements for energy and capacity in the context of the changed circumstances since the 2013 IRP, as outlined in Section 6.2.2.

The first analysis evaluates whether the decision in December 2014 to proceed with the Site C Project, with the benefit of over two years' hindsight, was optimal. This analysis, set out in detail in Section 6.3.4, was conducted for all of BC Hydro's future load forecast scenarios – the mid-load, low-load and high-load – as derived from its 2016 RRA. **As will become apparent, this analysis demonstrates that if the clock could be turned back to December 2014, a Final Investment Decision not to proceed with the Site C Project would have resulted in savings of $1.4 to $1.7 billion, depending on the future load forecast scenario.**

Since that decision was made, however, BC Hydro has spent about $1.87 billion on the Site C Project, and has committed several hundred million more. We estimate that, if the Site C Project were cancelled on June 30, 2017, the total cost to be written off would be on the order of $2.62 billion. In effect, then, the additional cost to complete the Site C Project today is much lower than the cost considered in December 2014. Section 6.3.5 compares the cost of completing the Site C Project against the costs of alternate pathways for meeting energy and capacity requirements, adding the cancellation (or suspension) costs of the Site C Project to all alternative portfolios.

Finally, the analysis explores the implications of several additional scenarios. The first of these considers the implications of a 25% cost overrun for the Site C Project, consistent with the many precedents around the world, across Canada and in recent large-scale BC Hydro projects (Section 6.3.6). The subsequent additional analysis considers the effects of low export market prices (Section 6.3.7), and high market prices (Section 6.3.8), which would increase or decrease, respectively, the losses associated with the energy surplus created by the Site C Project. The following analysis combines the effect of a 25% cost overrun in the Site C Project along with low export market prices (Section 6.3.9). The final analysis (Section 6.3.10) considers the option of suspending, but not cancelling the Site C Project, and resuming development of the Project at a later date if circumstances warrant.

6.3.1 Model design

An Excel-based model was developed to compare the costs of resource portfolios that either continue, cancel or suspend development of the Site C Project. Similar to System Optimizer, this model applies a DSM plan and selects from the available supply-side resources in order to maintain capacity and energy balance, while minimizing present value costs. The model also operates under the constraints imposed by the *Clean Energy Act*, including those related to achieving self-sufficiency and to generating at least 93% of the electricity in British Columbia from clean or renewable resources.[350] The model analyses are conducted in real 2016 Canadian dollars for the period F2017 through F2036.

Inputs

The model assumptions and inputs are the same as those used previously by BC Hydro in its 2013 IRP, with the following variations:

- **Exchange rate**. The analysis uses the exchange rates provides in Table 13 from the 2016 RRA, which increase gradually over the next few years before stabilizing at 0.82 USD/CAD.[351] This represents a marked change from the 2013 IRP, which forecast a constant exchange rate of 0.9693 USD/CAD from F2014 through F2033.
- **Market prices**. The model makes use of the market price assumptions used in the 2016 RRA and presented in Table 13.
- **Capacity costs:** The model relies on the levelized resource unit capacity costs (UCCs) determined by BC Hydro for capacity resources ($84/kW-year for SCGTs plus energy costs,[352] $199/kW-year for pumped storage hydroelectric at Mica,[353] and $100/kW-year for market purchases). It also attributes capacity sales

[350] While the *Clean Energy Act* obligation to meet 66% of load growth through DSM is of little relevance, since it is inoperative after 2020, the Option 2 variant described below has a similar, though smaller, effect.

[351] BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.310.1. BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 2.310.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

[352] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.15.1. $79/kW-year adjusted for delivery to the Lower Mainland, presuming 6% losses, with energy costs added separately to reflect actual energy production. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[353] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCUC 1.81.3. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf)

revenues of $37/kW-year for surplus capacity,[354] applied to surpluses greater than 250 MW.

- **Energy costs**: The model relies on the levelized resource unit energy costs (UECs) determined 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 2020s, as discussed in Section 5.4.1. Energy costs for gas used by SCGTs or, in the high-load scenario CCGTs, is calculated based on the natural gas price forecasts in the 2013 IRP. Energy costs for pumped storage are dealt with as energy requirements in the model, to be met by the available energy resources in the resource stack.
- **Site C Project**: The energy from the Site C Project is presumed to be available in accordance with the load resource balance presented in the 2016 RRA,[355] with 550 MW of capacity available in F2025 and the full 1100 MW by F2026. A small amount of energy (388 GWh) from Site C is available in F2024, 87% of full output in F2025, and full output starting in F2026.

The model evaluates the relative present value cost of meeting future energy and capacity requirements under a number of different scenarios created by adjusting input variables as summarized in Table 24.

The model calculates the present value of the year-by-year costs for resources that are added to the base case, as discussed below in Section 6.3.2, net of revenues from export of surplus energy and capacity. Costs of elements that remain unchanged from the base case scenario are not included in the analysis. Thus, the costs reported below in relation to the various scenarios are only meaningful in comparison to one another, and are **not** comparable to the total portfolio costs presented above in Table 23.

[354] BC Hydro. November 21, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to Information Request BCSEA 1.15.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf)

[355] BC Hydro. July 28, 2016. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Table 3-8. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2016/DOC_46852_B-1-1_BCH_RevenueRequirements-App.pdf)

Table 24: Model input variables

Variable	Alternatives	Description
Load forecast	▪ Low ▪ Mid ▪ High	BC Hydro's low, mid and high load forecasts as derived from the small gap[356] and large gap[357] scenarios in its 2016 RRA. The high-load forecast scenario encompasses the potential for additional electricity requirements resulting from low-carbon electrification, as discussed in Section 3.4.2. It reflects additional electricity requirements comparable to the electrification scenario with medium GHG prices and medium natural gas prices shown in Table 6.
Energy-focused DSM	▪ 2016 RRA DSM Plan ▪ 2013 IRP DSM Option 2 updated	BC Hydro's DSM proposal contained in the 2016 RRA in scenarios with the Site C Project. The updated 2013 IRP Option 2, discussed above in Section 5.3.1, in scenarios without the Site C Project.
Capacity-focused DSM	▪ Moderate	Following the recent Climate Leadership Plan, moderate capacity-focused DSM (30 MW in F2018, increasing by 30 MW/year to 570 MW in F2036) at a cost of $50/kW-year, is included in all scenarios, as discussed in Section 5.3.2.
Site C Project	▪ Continuing ▪ Cancelling ▪ Suspending	Continuing with the Site C Project, with costs as described in Section 4.2.1. Cancelling the Site C Project, considering sunk costs of $1.87 billion and $750 million related to contract cancellation and demobilization (5.2.2), amortized over 70 years. Suspending the Site C Project with costs to carry the sunk costs until a decision is made to cancel or complete the Site C Project, as well as suspension costs of $15 million per year to maintain the site (5.2.3) and remobilization costs of $200 million (5.2.4) in the event that circumstances warrant continuing the Site C Project.
Revelstoke 6	▪ All scenarios	Commissioned in order to minimize net present value costs of each scenario, but not prior to F2022.
Mica Pumped Storage	▪ All scenarios	Commissioned in order to minimize net present value costs of each scenario, but not prior to F2025.
Mica 1 to 4 refurbishment	▪ All scenarios	Maintenance outage for five-year period commencing not later than F2024 in all scenarios.
SCGTs	▪ 5% ▪ 18%	A capacity factor of 5% to meet winter peak capacity requirements only, in scenarios without Site C. A capacity factor of 18% to meet winter peak capacity and year-round 4-hour daily peaking requirements in scenarios with Site C.
CCGTs	▪ Only in high-load forecast scenarios	When large amounts of SCGTs are required, it is more cost-effective to develop CCGTs.
Market reliance	▪ All scenarios	Short-term reliance of up to 400 MW of capacity and 1,000 GWh/year of energy, consistent with the approach taken by BC Hydro in the 2013 IRP.

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[356] The Small Gap Scenario is one with the least need for new resources reflecting a low-load forecast combined with low DSM delivery resulting from the fact that a prolonged period of low load growth would likely have BC Hydro scaling back DSM.

[357] The Large Gap Scenario is the one with the greatest need for new resources reflecting a high-load forecast combined with lower DSM delivery.

Market prices	▪ Low ▪ Medium ▪ High	2016 RRA market prices as medium market prices, with low and high market prices derived from the spreads between low, mid and high market price forecasts presented in the 2013 IRP.

Limitations

The model determines the net present value of the differential costs of each scenario by discounting the year-by-year costs to the present. The model uses BC Hydro's discount rate of 5% to calculate the portfolio present values, reflecting that the analysis is conducted from the utility's perspective.

With respect to the discount rates used to calculate the unit costs (UECs and UCCs), the model relies on BC Hydro's use of 5% and 7% for BC Hydro and IPP resources, respectively. In other words, with the exception of wind resources as discussed in Section 5.4.1, the model relies on the adjusted UECs and UCCs developed by BC Hydro.

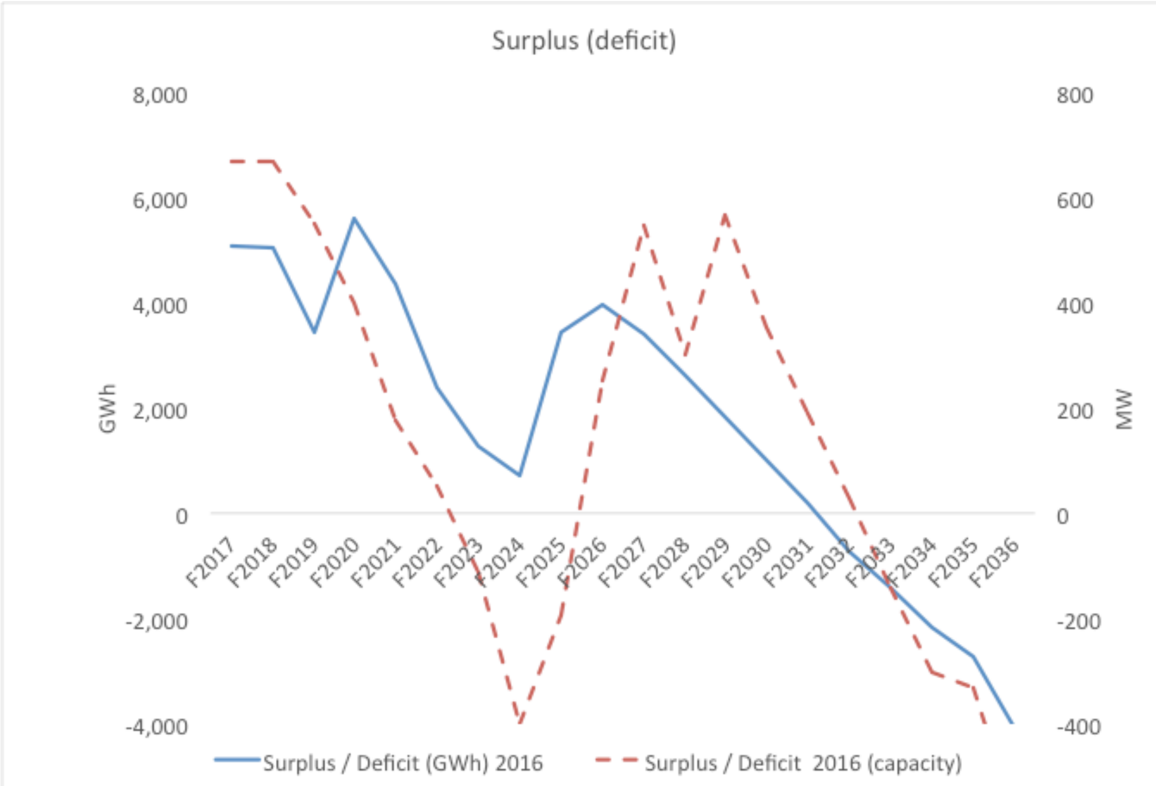
The model evaluates different resource options over a 20-year planning period, as BC Hydro did in its 2013 IRP. However, most of the resources will still be in operation at the end of the planning period. This situation creates the possibility of a computational bias, resulting from the exclusion of "end effects". This is especially true for the Site C Project, which is expected to have an economic life of 70 years, of which only 12 years are included in the analysis period. Since the model reflects the annualized cost and not the total cost of the resources, only those costs incurred in the first twelve years of operations are reflected in the model. The same is true for the additional costs in the "cost overrun" scenario explored later.

While including the end effects for a resource like the Site C Project is straightforward, it would be inappropriate to do so without doing the same for the other resources that will be required in all scenarios with and without Site C after F2036. That would require being able to forecast loads for the same 70-year period. However, forecasting load, prices, technology development, economic conditions and other factors comes with considerable uncertainties. For this reason, BC Hydro limits its load forecasts to 20 years, and so this analysis is limited to the same period.

6.3.2 Scenario A – the 2016 RRA

The most recent information made public by BC Hydro is the 2016 RRA, which presents load forecasts and planned resources through F2036. However, the load resource balances in the 2016 RRA do not include sufficient resources to meet energy and capacity requirements through F2036. Thus, the load resource balances (presented above in Figure 11), referred to here as "Scenario A", contain both energy and capacity shortfalls, particularly in the latter years beyond F2032. In other words, they are not "balanced" to the end of the 20-year planning period, as illustrated more clearly in Figure 25.

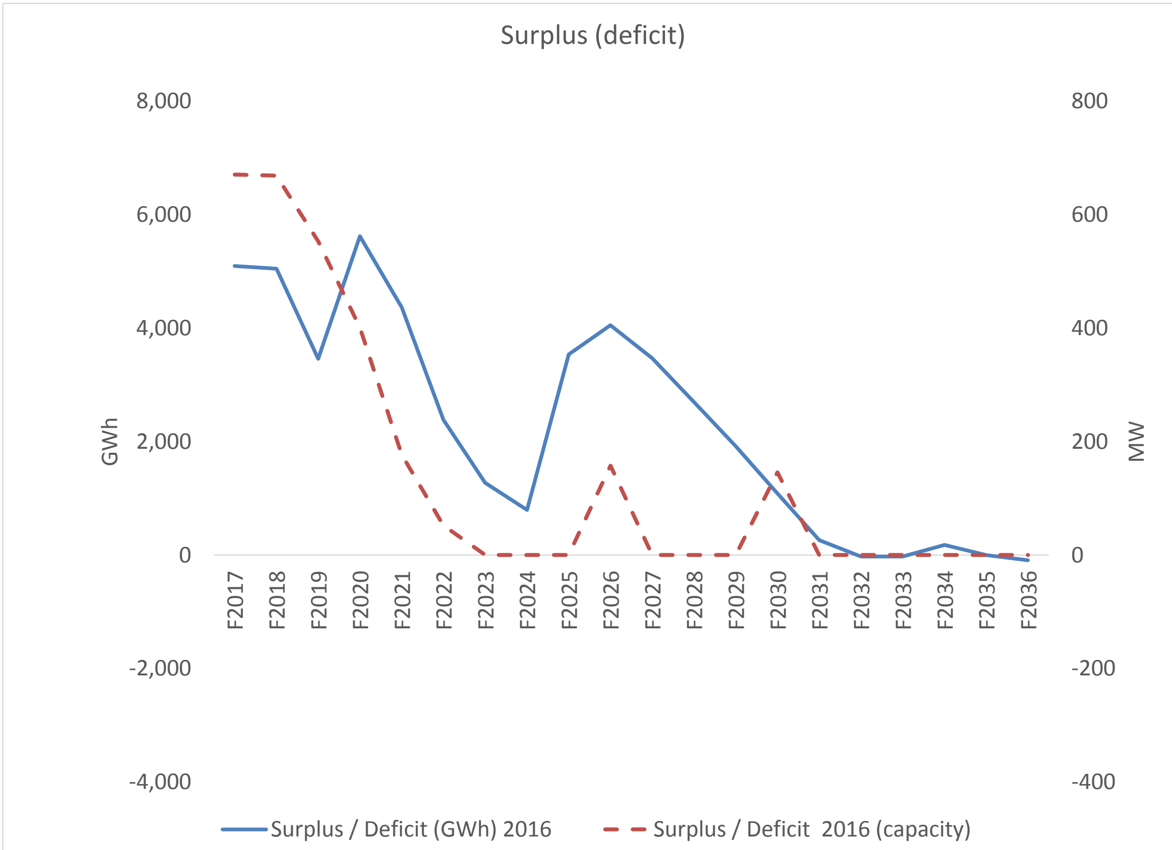
Figure 25: Scenario A – RRA unbalanced (mid-load forecast)



6.3.3 Scenario B – RRA balanced (the base case)

These shortfalls in energy and capacity result from the fact that the 2016 RRA is not a long-term resource planning document but rather a revenue requirements application for the upcoming three-year operating period. In order to compare the present value costs over a 20-year planning period of continuing, cancelling or suspending the Site C Project, it is necessary to first balance the LRBs contained in the 2016 RRA. This is achieved by making use of the most cost-effective available resources, following the approach set out in the 2013 IRP. Clean resources (primarily wind) are used to meet additional energy needs; as capacity needs are limited and late in the planning period, capacity-focused DSM and market reliance (up to 400 MW) are sufficient to meet them. (The in-service date for Revelstoke is also delayed, compared to the RRA, to avoid creating a capacity surplus.) The RRA balanced LRBs are shown below in Figure 26 in the same planning context (mid-load, including Site C), but with the additional resources needed to maintain adequate energy and capacity until F2036. This “balanced RRA” scenario (Scenario B) is used as a reference case in the analyses that follow.

Figure 26: Scenario B – RRA balanced (mid-load forecast)



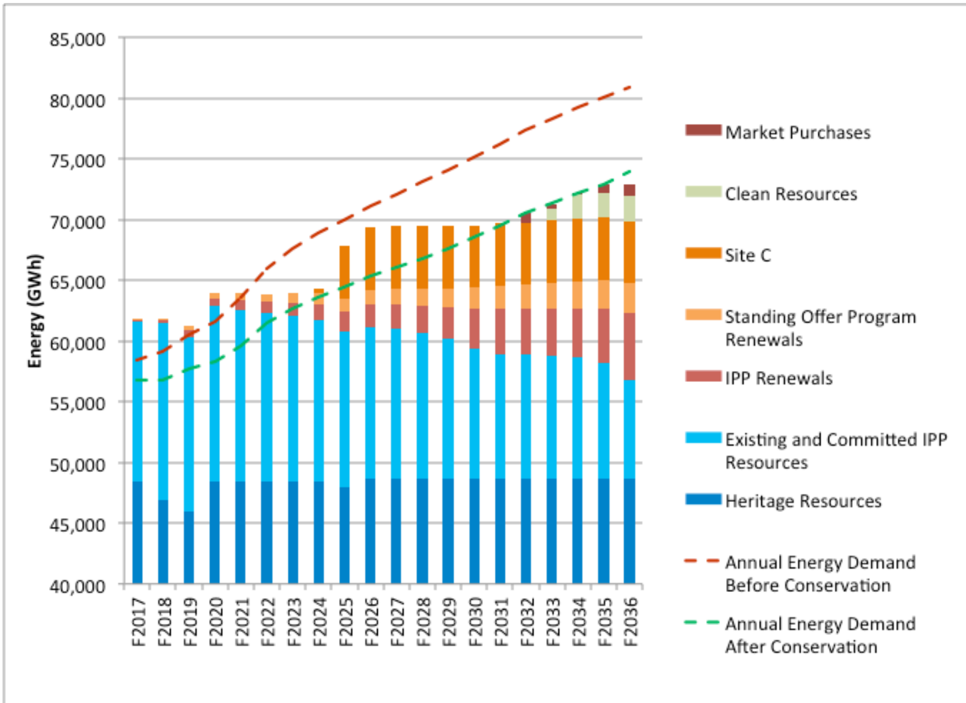
Resource stacks for the mid, low and high load forecast scenarios are presented in Figure 27, Figure 28, and Figure 29. Similar to the 2013 IRP, these balanced 2016 RRA LRBs include expected LNG, with the Site C Project commissioned in F2024. These scenarios for energy and capacity form the "base cases" against which alternative portfolios that involve cancelling or suspending the Site C Project are evaluated. As summarized in Table 25, the base cases are referred to as Scenario B1 for the mid-load forecast, Scenario B2 for the low-load forecast and Scenario B3 for the high-load forecast. They all reflect BC Hydro's decision to commission the first generating unit of the Site C Project in F2024.

Table 25: Scenario B – The base case for continuing with the Site C Project

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
B1	Mid	F2024	Yes	0%	Medium	2016 RRA	Yes
B2	Low	F2024	Yes	0%	Medium	2016 RRA	Yes
B3	High	F2024	Yes	0%	Medium	2016 RRA	Yes

Figure 27: Scenario B1 – Base resource plans with expected LNG (mid-load)

a) Energy



b) Capacity

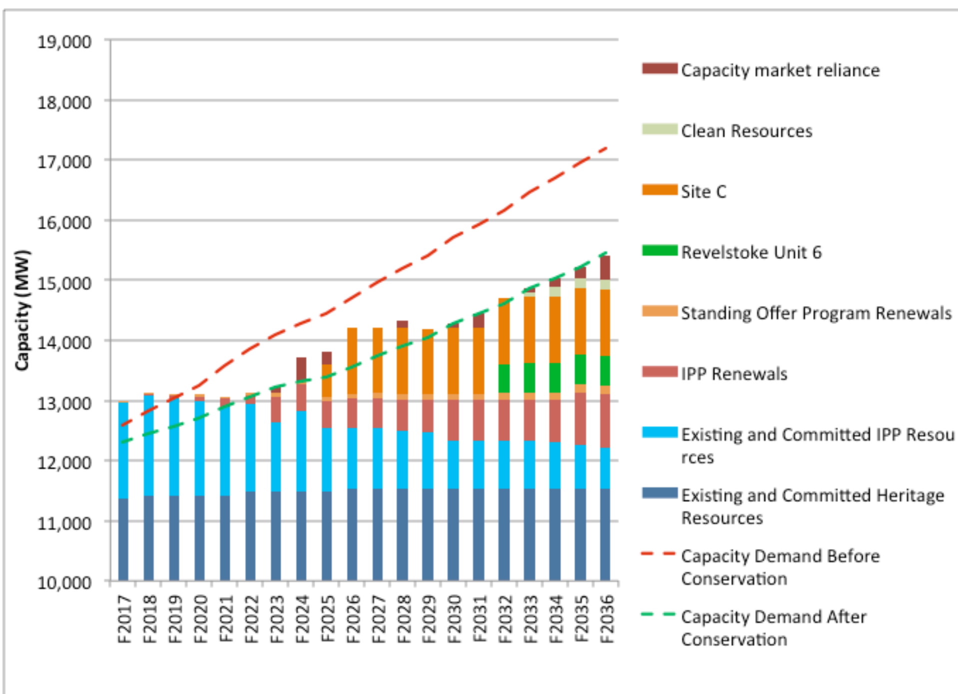
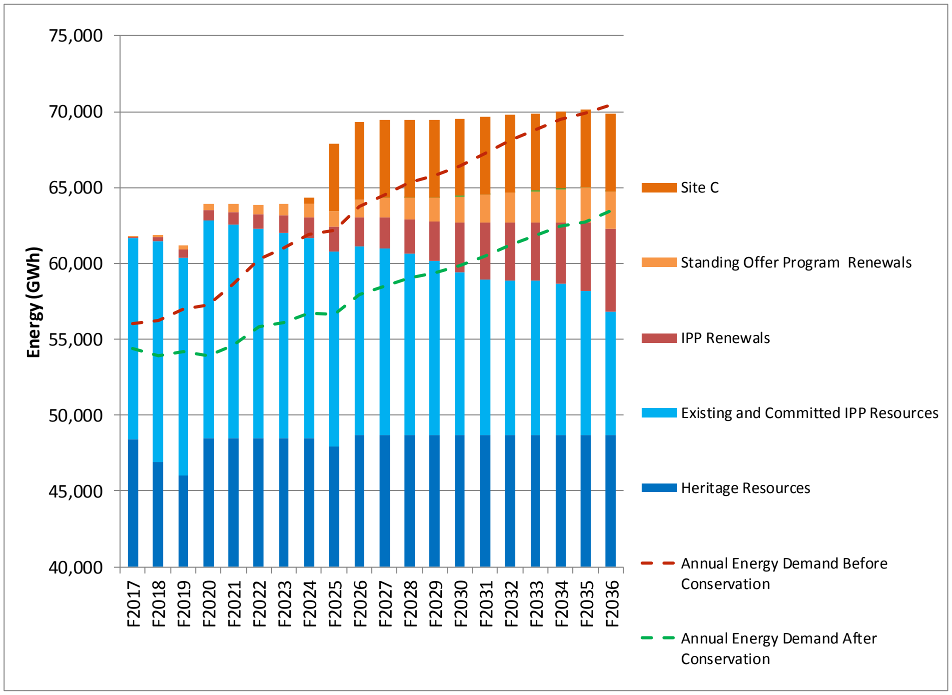


Figure 28: Scenario B2 – Base resource plans with expected LNG (low-load)

a) Energy



b) Capacity

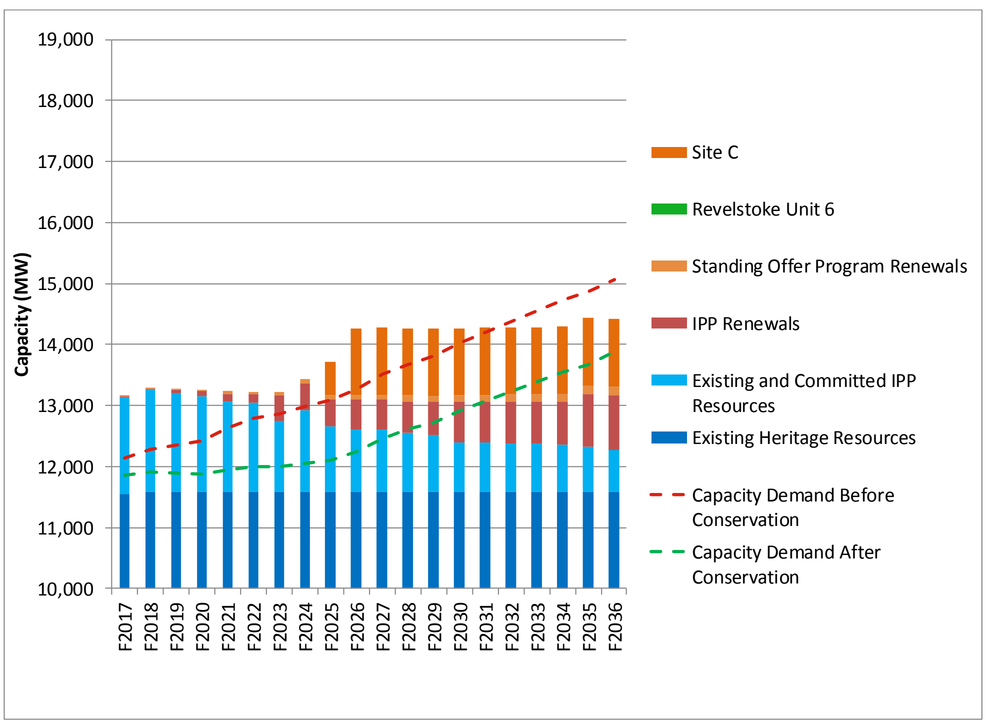
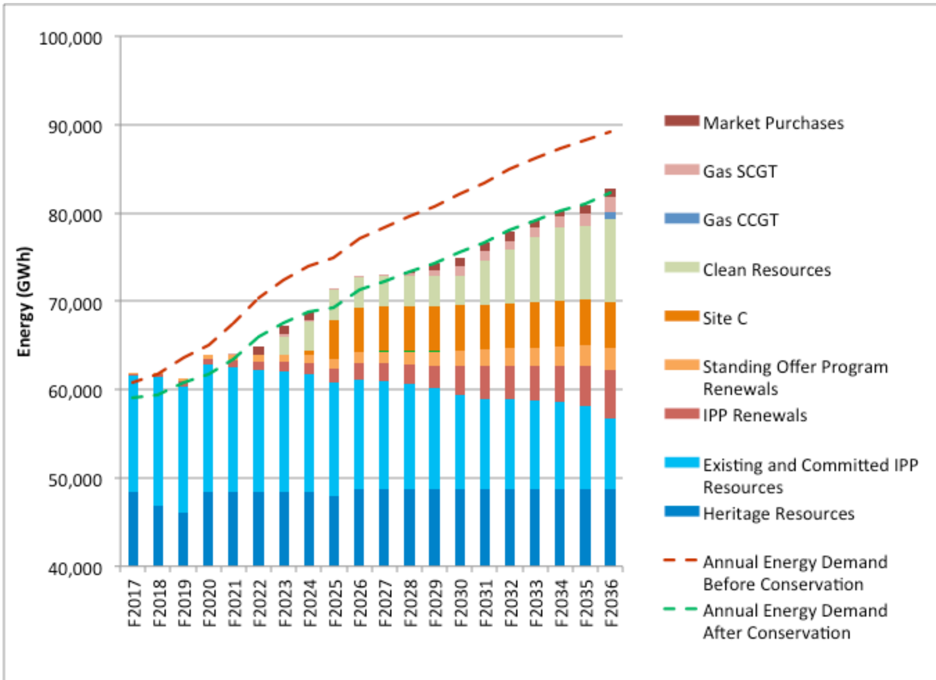
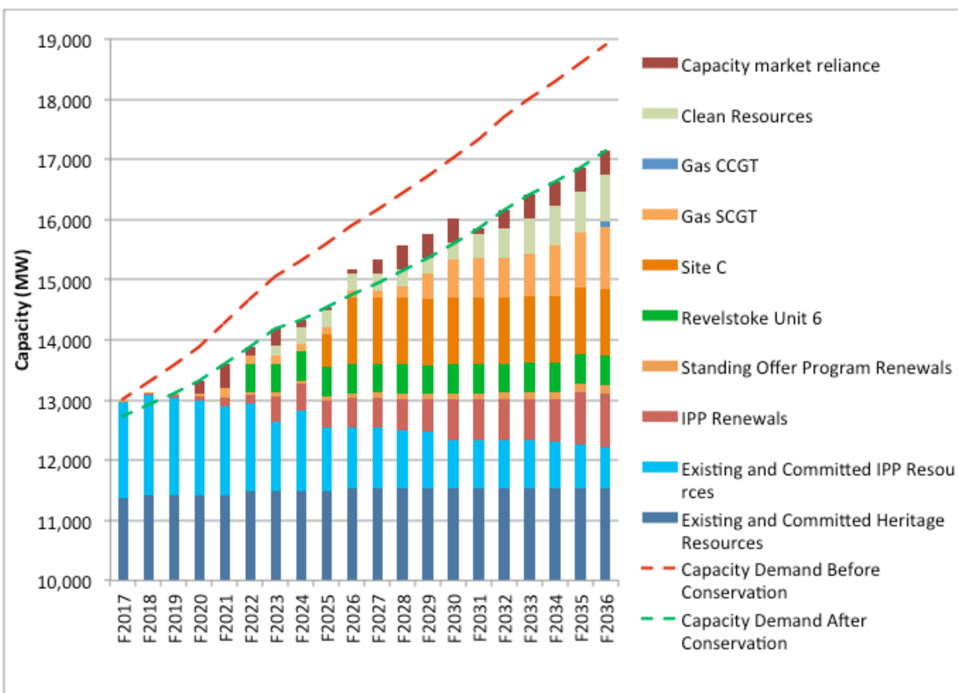


Figure 29: Scenario B3 – Base resource plans with expected LNG (high-load)

a) Energy



b) Capacity



This base case also includes the DSM plan proposed in the 2016 RRA, as well as capacity-focused DSM starting with 30 MW in F2018 and adding another 30 MW each year, ramping up to 570 MW in F2036.

In the 2013 IRP, BC Hydro attributed 0 MW to capacity-focused DSM through the entire planning period. Since that time, the Climate Leadership Plan was released and specifies an objective of supplying 100% of electricity for the integrated grid from clean or renewable sources, except where concerns regarding reliability or costs must be addressed. This policy directs BC Hydro to pursue capacity-focused DSM, since were BC Hydro not to do so, it would either have to develop SCGTs (low cost, but not a clean or renewable resource), or pumped storage hydroelectric (high cost, but a clean and renewable resource). The development of capacity-focused DSM (low cost, and a clean resource) allows BC Hydro to defer that choice between SCGTs and pumped storage hydroelectric for as long as possible.

Were Scenario B to be developed without capacity-focused DSM, it would either be substantially more costly (due to the need to advance pumped storage hydroelectric) or result in much higher GHG emissions (due to the need to advance SCGTs). This would have the effect of penalizing the base case and therefore making the scenarios without the Site C Project appear to have lower relative present value costs, to produce lower GHG emissions, or a combination of both.

6.3.4 Scenario C – No approval of the Site C Project in 2014

This counter-factual “do over” scenario considers the implications of an initial decision by the Provincial Government **not** to approve the Site C Project in December 2014. The parameters of Scenario C are listed in Table 26, and reflect the fact that a decision not to approve the Site C Project would have allowed BC Hydro to now continue with an updated DSM Option 2, and to make greater and earlier use of capacity-focused DSM.

Table 26: Scenario C – No approval of the Site C Project in 2014

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
C1	Mid	Cancel	No	n/a	Medium	Option 2	Yes
C2	Low	Cancel	No	n/a	Medium	Option 2	Yes
C3	High	Cancel	No	n/a	Medium	Option 2	Yes

Scenario C reflects the changed circumstances discussed in Section 6.2.2, assuming that the Provincial Government had not approved the Site C Project in December 2014. These changed circumstances include the increased costs of the Site C Project, a substantial decline in wind costs, and the collapse of BC Hydro’s load forecast. Table 27 compares the present values of Scenario C against those of the base case (Scenario B) for the mid, low and high load forecast scenarios at medium market prices.

Table 27: Cost implications – 2014 approval of the Site C Project (model results)

Load Forecast	Market Price Forecast	PV of Scenario C (without Site C) (M$)	PV of Scenario B (with Site C) (M$)	PV Difference (M$) (Benefit or cost of completing the Site C Project)
Mid	Medium	733	2,259	-1,526
Low	Medium	-3,215	-1,517	-1,698
High	Medium	5,075	6,498	-1,422

Table 27 demonstrates that:

- under the 2016 mid-load forecast, the decision to proceed with the Site C Project will result in additional costs of $1,526 million dollars, compared to a scenario in which the Project had not been approved;
- under the 2016 low-load forecast, ratepayers would have saved nearly $1,700 million dollars had the Site C Project not been approved; and
- under the 2016 high-load forecast, ratepayers would be ahead by $1,422 million had an approval not been granted for Site C.

Regardless of BC Hydro's current forecasts of load growth, it now appears likely that the decision to approve the Site C Project will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued in 2014.

The road not taken: deferring a decision by two years

In its 2013 IRP, BC Hydro compared two different in-service dates for the Site C Project (F2024 and F2026). In the mid-load forecast, BC Hydro found that deferring the Project by two years would reduce costs by about $250 million.[358] In the low-load forecast, all of the scenarios substantially favoured not proceeding with the Site C Project, by at least $700 million, regardless of the Project's in-service date.[359]

As shown above in Figure 7, for many years prior to the decision to approve the Site C Project, BC Hydro consistently overestimated requirements for energy 10 years in the future, by on the order of 5,400 GWh/year. Moreover, the dramatic increases in BC Hydro's load forecasts leading up to the decision to approve the Site C Project, presented in Figure 6, contrast sharply with forecasts only a few years earlier.

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[358] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6A Portfolio Results, p.6A-36. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600a-nov-2013-irp-appx-6a.pdf)

[359] BC Hydro. November 2013. Integrated Resource Plan, Appendix 6A Portfolio Results, p.6A-37. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0600a-nov-2013-irp-appx-6a.pdf)

As illustrated in Figure 12, the mid-load forecast has declined by about 5,000 GWh/year since 2012, and now resembles the low-load forecast of that year. **By relying on BC Hydro's mid-load forecast, and proceeding with the Site C Project as soon as possible in F2024, despite BC Hydro's history of overstating future electricity demand, the Provincial Government chose to ignore the risks of substantial losses that this strategy would lead to under a low-load scenario.**

6.3.5 Scenario D – Cancel the Site C Project

Scenario D considers the implications of cancelling the Site C Project as of June 30, 2017 (i.e. the end of F2017). The parameters of Scenario D are listed in Table 28, reflecting the fact that cancelling the Site C Project would allow BC Hydro to follow an alternative resource path that includes an updated DSM Option 2, capacity-focused DSM and continuing declines in the costs of the alternative resources, particularly wind.

Table 28: Scenario D – Alternative path after cancellation of the Site C Project

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
D1	Mid	Cancel	Yes	n/a	Medium	Option 2	Yes
D2	Low	Cancel	Yes	n/a	Medium	Option 2	Yes
D3	High	Cancel	Yes	n/a	Medium	Option 2	Yes

Cancelling the Site C Project as of June 30, 2017 results in $1.87 billion in sunk costs, along with an estimated $750 million contractual and demobilization costs for a total of $2.62 billion. It is presumed that ratepayers repay these costs over a 70-year period beginning in F2025, which is consistent with the expected term for repayment of the costs of a completed Site C Project. It also allows repayment to begin after the 10 Year Rates Plan ends.

Cancelling the Site C Project thus would result in $135 million in annual debt repayment costs for 70 years. These costs are not immaterial, and, since they increase the costs of all scenarios **without** the Site C Project, they tend to counteract the effects of the declining costs of wind energy and the lower load forecast.

Table 29 presents comparisons between cancelling the Site C Project (Scenario D) and continuing with the Site C Project (Scenario B) in the mid, low and high load forecast scenarios at medium market prices.

Table 29: 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

The findings in this table illustrate that:

- under the 2016 mid-load forecast, it would be $622 million cheaper to proceed down an alternative path by cancelling the Site C Project;
- under the 2016 low-load forecast, ratepayers would be better off by $794 million were the Project to be cancelled; and
- under the 2016 high-load forecast, ratepayers would be better off by $518 million were the Project to be cancelled.

It now appears that cancelling the Site C Project and continuing down an alternative path would save ratepayers on the order of $520 to $800 million, depending on the load forecast.

This means that the Site C Project is not yet "past the point of no return",[360] regardless of the load forecast scenario. The following subsections will test the additional implications of this conclusion, with respect to two possibilities:

- The Site C Project experiences a cost overrun; and
- Market prices are lower or higher than projected.

6.3.6 Scenario E – Cancel the Site C Project with cost overrun

Scenario E builds on the previous one (Scenario D) by comparing cancellation of the Site C Project against completing it, with the Project incurring a substantial cost overrun. This is a plausible scenario,[361] given that many large-scale Canadian hydro projects built in the last 15 years (with the exception of some Hydro-Québec projects) have incurred significant cost overruns, as have many large transmission projects.

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[360] "Getting Site C to point of no return a damning progress report, so far", Vancouver Sun, January 5, 2017. (Accessed 17 April 2017 at: http://vancouversun.com/opinion/columnists/vaughn-palmer-getting-site-c-to-point-of-no-return-a-damning-progress-report-so-far) On January 31, 2016, Premier Christy Clark stated in relation to the Site C Project, "I will get it past the point of no return."

[361] The potential that Site C Project costs come in substantially under budget is not analyzed, as it is not considered plausible.

Table 30 presents the cost overruns of comparable projects in BC and Manitoba. The information in Table 30 was provided above in Section 4.3.1 (Table 12), which also included data on Nalcor Energy projects. The authors view Manitoba Hydro to be the most comparable Canadian utility to BC Hydro, given its recent experience with large-scale hydroelectric and transmission line development. Projects in Manitoba, like the Site C Project, also compete for labour with the fossil fuel industry in Alberta. Hydro Québec has considerably more experience in the past 15 years, having completed several large-scale hydroelectric projects,[362] while Nalcor Energy has considerably less experience, with Muskrat Falls being its first large-scale hydroelectric project since 1985. Nalcor's service area is much more remote and its labour supply less available making it more vulnerable to cost uncertainties.[363] Based on these factors, and global estimates of an average 27% cost overrun,[364] a 25% cost overrun is considered a conservative scenario for the Site C Project.

Table 30: Recent Manitoba Hydro and BC Hydro project cost overruns

Hydro Projects	Proponent	Capacity	Total Cost		Overrun		Status
			Initial	Actual	$	%	
Wuskwatim[365,366]	Manitoba Hydro	200 MW	$0.9B	$1.6B	$0.7B	+78%	Operating
Keeyask[367,368,369]	Manitoba Hydro	695 MW	$6.2B	$8.7B	$2.5B	+40%	~40% constructed
Bipole III[370,371]	Manitoba Hydro	500 kV	$3.3B	$5.4B	$2.1B	+64%	~50%

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362 Hydro Québec. Centrales hydroélectriques. Available at: http://www.hydroquebec.com/production/centrale-hydroelectrique.html. Including: Saint-Margeurite-3 (882 MW), Toulnustous (526 MW), Eastmain-1 (480 MW), Péribonka (385 MW), Eastmain 1-A (768 MW), and Romaine (1550 MW).

363 Newfoundland and Labrador Hydro. Hydroelectric Generating Stations. Available at: https://www.nlhydro.com/operations/hydroelectric-generating-stations/.

364 Ansar, Atif, et al. "Should we build more large dams? The actual costs of hydropower megaproject development." *Energy Policy* 69 (2014): 43-56

365 Manitoba CEC. 2004. Report on Public Hearings Wuskwatim Generation and Transmission Projects, p.39. (Accessed 17 April 2017 at: (Accessed 17 April 17 at: http://www.cecmanitoba.ca/resource/reports/Commissioned-Reports-2004-2005-Wuskwatim_Generation_Transmission_Projects_Full_Report.pdf)

366 Wuskwatim Power Limited Partnership. About the Wuskwatim Generating Station. (Accessed 17 April 17 at http://www.wuskwatim.ca/project.html)

367 Manitoba Hydro. August 2013. Need for and Alternatives to Business Case. Executive Summary, p.4. (Accessed 17 April 2017 at: http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/nfat_business_case__1_executive_summary.pdf)

368 Boston Consulting Group. Bipole II, Keeyask and Tie-Line Review, p.37. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

369 "Keeyask dam cost estimate balloons by $2.2B" CBC News. (Accessed 17 April 17: http://www.cbc.ca/news/canada/manitoba/manitoba-hydro-keeyask-dam-cost-electricity-pc-government-1.4013521)

							constructed
DCAT Project[372,373]	BC Hydro	230 kV	$222M	$296M	$74M	+33%	Operating
ILM Transmission Line[374,375]	BC Hydro	500kV	$602M	$743M	$141M	+23%	Operating
Northwest Transmission Line[376,377]	BC Hydro	287kV	$404M	$716M	$312M	+77%	Operating

The parameters of Scenario E are listed in Table 31, reflecting the Site C Project with a 25% cost overrun, medium market prices and BC Hydro's DSM plan proposed in its 2016 RRA.

Table 31: Scenario E – Site C Project + 25% cost overrun

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
E1	Mid	F2024	Yes	25%	Medium	2016 RRA	Yes
E2	Low	F2024	Yes	25%	Medium	2016 RRA	Yes
E3	High	F2024	Yes	25%	Medium	2016 RRA	Yes

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370 Manitoba Hydro. 2011. Bipole III Environmental Impact Statement Filed. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/NewsReleases/GetDetail?hdnAct=E&hdnTXT=%27Bipole%20III%20Environmental%20Impact%20Statement%20Filed%27)

371 Boston Consulting Group. Bipole III, Keeyask and Tie-Line Review, p.37. (Accessed 17 April 2017 at: https://www.hydro.mb.ca/corporate/news_media/in_the_news/bcg_bipoleIII_keeyask_and_tie_line_review.pdf)

372 BC Utilities Commission. 2012. In the Matter of British Columbia Hydro and Power Authority Certification of Public Convenience and Necessity for the Dawson Creek / Chetwynd Area Transmission Project, p.2. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2013/DOC_34487_04-08-2013_BCH_PUBLIC_G-144-12_Directive_2a.pdf)

373 BC Hydro. 2016. British Columbia Hydro and Power Authority. 2015/16 Annual Service Plan Report, p.89. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf)

374 BCTC. 2008. BCTC Interior to Lower Mainland Transmission Project EAC Application – November 10, 2008, p.4-39.

375 BC Hydro. 2016. British Columbia Hydro and Power Authority. 2015/16 Annual Service Plan Report, p.89. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bchydro-2015-16-annual-service-plan-report.pdf)

376 BC EAO. 2011. Northwest Transmission Line Project Assessment Report, p.21

377 BC Hydro. 2015. British Columbia Hydro and Power Authority. 2014/15 Annual Report, p.92. (Accessed 17 April 2017 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/accountability-reports/financial-reports/annual-reports/bc-hydro-annual-report-2015.pdf)

Table 32 presents comparisons between cancelling the Site C Project (Scenario D) and completing the Site C Project with a 25% cost overrun (Scenario E) in the mid, low and high load forecast scenarios at medium market prices.

Table 32: Cost implications – Site C Project + 25% 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

The findings in this table indicate that a 25% increase in the cost of the Site C Project substantially alters the findings:

- under the 2016 mid-load forecast, it would cost $1,285 million more to continue with the Site C Project that goes over budget by 25% than to cancel the Project and proceed with an alternative portfolio;
- under the 2016 low-load forecast, the benefit to ratepayers of cancelling the Site C Project with a 25% cost overrun totals $1,457 million; and
- under the high-load forecast, the findings indicate that it would be beneficial to ratepayers in the amount of $1,181 million to cancel the Site C Project with a 25% cost overrun.

In the event of a 25% cost overrun, cancelling the Project would save ratepayers on the order of $1.2 to 1.5 billion depending on the load forecast scenario.

A 25% increase in the total Site C Project budget amounts to more than $2 billion (nominal). However, comparing the findings in Table 29 to those in Table 32, the effect on PVs appears to be much smaller, on the order of $700 million (real). This effect results from two factors. First, the cost overrun results in an increase in the future annual costs of the Site C Project that are discounted back to 2016 current dollars. Secondly, since the analysis only extends to F2036, only the first 12 years of the increase in future annual costs (i.e. F2025 through F2036) appear in the calculation. In reality, this increase in Site C annual costs has to be paid for by ratepayers over the 70-year economic life of the Site C Project. Thus, the structure of this analysis tends to understate the impact of a significant cost overrun.

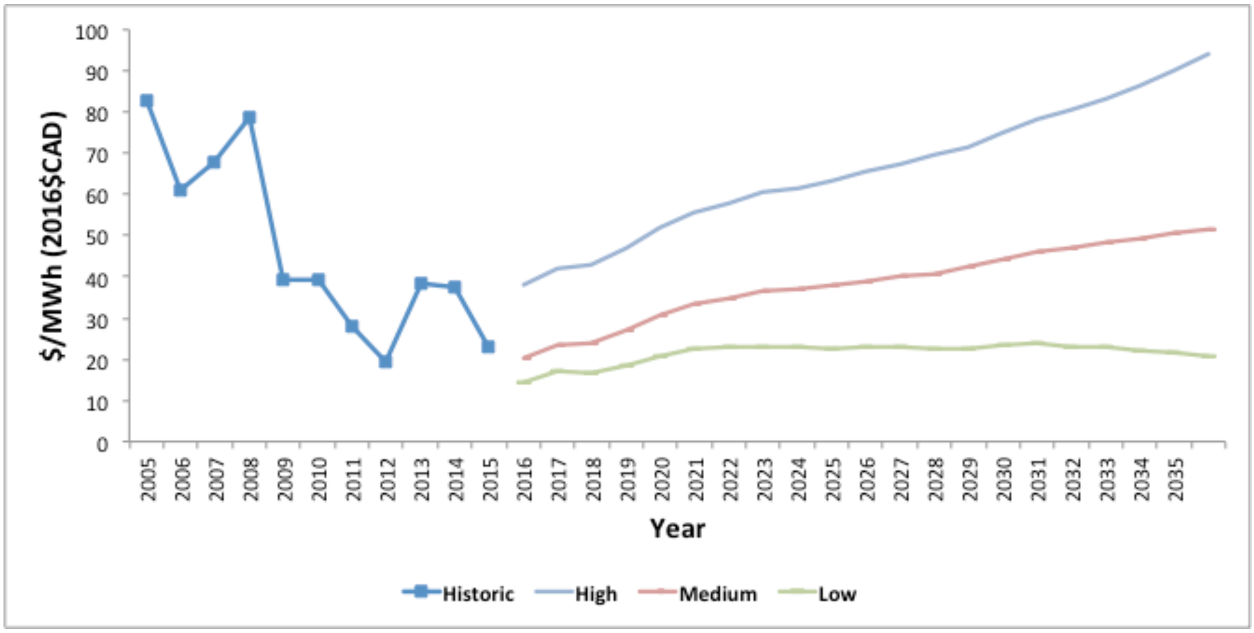
6.3.7 Scenarios F and G – Cancel the Site C Project with low market prices

Scenarios F and G are variants of the comparison between Scenario B (base case) and Scenario D (without Site C), but in a future with low export market prices.

In its 2013 IRP, BC Hydro presented forecasts for future export market prices for sales of electricity into the U.S. market at the international border. Low and high price forecasts were also considered by varying the expected price of electricity in the export markets, GHG prices and natural gas prices (the price-setting fuel in the US Northwest).

BC Hydro updated these price forecasts in its 2016 RRA. Figure 30 presents historical market prices and future export market price scenarios.

Figure 30: Historical export market prices[378] and future scenarios[379]



The parameters of Scenarios F and G are summarized in Table 33.

Table 33: Scenarios F and G – The effect of low market prices

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
F1	Mid	F2024	Yes	0%	Low	2016 RRA	Yes
F2	Low	F2024	Yes	0%	Low	2016 RRA	Yes
F3	High	F2024	Yes	0%	Low	2016 RRA	Yes
G1	Mid	Cancel	Yes	0%	Low	Option 2	Yes
G2	Low	Cancel	Yes	0%	Low	Option 2	Yes
G3	High	Cancel	Yes	0%	Low	Option 2	Yes

378 Northwest Power and Conservation Council. 2016. Seventh Northwest Conservation and Electric Power Plan, Figure 8-1. Historic prices in $2012 US converted to $2016 CAD, and adjusted for wheeling from Mid-C to border by $6.3/MWh. (Accessed 17 April 2017 at: https://www.nwcouncil.org/energy/powerplan/7/home/)

379 BC Hydro. January 23, 2017. Fiscal 2017 to Fiscal 2019 Revenue Requirements Application, Response to IR BCUC 2.310.1. (Accessed 17 April 2017 at: http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf)

Table 34 presents comparisons between cancelling the Site C Project under low market prices (Scenario G) and completing the Site C Project under low market prices (Scenario F) in the mid, low and high load forecast scenarios.

Table 34: 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

These findings indicate that, in the context of low market prices, the benefit of cancelling the Site C Project is increased, compared to that shown in Table 29 regardless of the load forecast. However, the effect of low market prices is not as significant as the effect of a 25% cost overrun:

- under the 2016 mid-load forecast and low market prices, the savings from cancelling the Site C Project would be $689 million, an increase from the $622 million in the context of medium market prices (see Table 29);
- under the 2016 low-load forecast, the benefit to ratepayers of cancelling the Site C Project increases from $794 million with medium market prices to $985 million with low market prices; and
- under the 2016 high-load forecast, the benefit to ratepayers increases from $518 to $536 million.

These increases in the benefits to ratepayers result from the fact that the surplus created by the Site C Project, which would be largest in the low-load forecast and smallest in the high-load forecast, would be sold at lower market prices and yield less revenue. In short, this analysis indicates that:

In a future context of low export market prices, cancelling the Project would save ratepayers on the order of $540 to $990 million dollars.

6.3.8 Scenarios H and I – Cancel the Site C Project with high market prices

Scenarios H and I are variants of the comparison between Scenario B (base case) and Scenario D (without Site C), but in a future where the evolution of US electricity market prices follow the high market export price scenario similar to the one described by BC Hydro in the 2013 IRP, modified to reflect changes in market prices since 2012. The parameters of these scenarios are summarized in Table 35.

Table 35: Scenarios H and I – The effect of high market prices

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
H1	Mid	F2024	Yes	0%	High	2016 RRA	Yes
H2	Low	F2024	Yes	0%	High	2016 RRA	Yes
H3	High	F2024	Yes	0%	High	2016 RRA	Yes
I1	Mid	Cancel	Yes	0%	High	Option 2	Yes
I2	Low	Cancel	Yes	0%	High	Option 2	Yes
I3	High	Cancel	Yes	0%	High	Option 2	Yes

Table 38 presents comparisons between cancelling the Site C Project under high market prices (Scenario H) and completing the Site C Project under high market prices (Scenario I) in the mid, low and high load forecast scenarios.

Table 36: 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

These findings indicate that, in the context of high market prices, the benefit of cancelling the Site C Project decreases compared to that shown in Table 29 regardless of the load forecast. However, the effect of high market prices is not as significant as the effect of a cost overrun:

- under the 2016 mid-load forecast and high market prices, it would be $555 million more expensive to continue than to cancel the Site C Project, a decrease from the $622 million in the context of medium market prices (see Table 29);
- under the low-load forecast, the benefit to ratepayers of cancelling the Site C Project decreases from $794 million with medium market prices to $593 million with high market prices; and
- under the high-load forecast, the benefit to ratepayers decreases from $518 to $503 million.

These decreases in the benefits to ratepayers result from the fact that the surplus created by the Site C Project, which would be largest in the low-load forecast and smallest in the high-load forecast, would be sold at higher market prices and yield more revenue.

In the event of higher than expected market prices, cancelling the Project would save ratepayers on the order of $500 million to $600 million dollars.

6.3.9 Scenario J – Cancel the Site C Project with cost overrun and low market prices

This scenario builds on the previous scenarios, by combining a 25% cost overrun with low market prices. The parameters of this new Scenario J, together with Scenario G from the Section 6.3.7, are summarized in Table 37.

Table 37: Scenario J – Site C Project + 25% cost overrun + low market prices

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
J1	Mid	F2024	Yes	25%	Low	2016 RRA	Yes
J2	Low	F2024	Yes	25%	Low	2016 RRA	Yes
J3	High	F2024	Yes	25%	Low	2016 RRA	Yes
G1	Mid	No	Yes	0%	Low	Option 2	Yes
G2	Low	No	Yes	0%	Low	Option 2	Yes
G3	High	No	Yes	0%	Low	Option 2	Yes

Table 38 presents comparisons between cancelling the Site C Project under low market prices (Scenario G) and completing the Site C Project with a 25% cost overrun and low market prices (Scenario J) in the mid, low and high load forecast scenarios.

Table 38: Cost implications – Site C Project + 25% 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

The findings in Table 38 show that, in the context of a 25% increase in the cost of the Site C Project and low market prices, it would be preferable to cancel the Site C Project. Specifically:

- under the 2016 mid-load forecast, it would be $1,352 million more expensive to continue with the Site C Project;
- under the 2016 low-load forecast, the cost to ratepayers of continuing with the Site C Project would be $1,648 million; and
- under the high-load forecast the cost to ratepayers of continuing with Site C would be $1,199 million.

In the event of a 25% cost overrun in the Site C Project and low market prices, the Site C Project is further from the point of no return. The cost of continuing with the Project ranges from $1.2 billion to $1.65 billion, depending on the load forecast scenario.

A scenario in which both a 25% cost overrun and low market prices occur would be less likely than only one of these scenarios occurring. However, a 25% cost overrun is less than the average cost overrun (43%) of BC Hydro's most recent three large-scale greenfield transmission projects (see Table 31). Market prices at the BC-US border have also hovered below, and sometimes well below, $40/MWh CAD since 2008, as shown in Figure 30.

6.3.10 Scenario K – Suspend the Site C Project

Scenario K considers the implications of suspending as opposed to cancelling the Site C Project as of June 30, 2017 in order to investigate whether there is an optimal time to develop the Project in the next 20 years. The parameters of Scenario K are listed in Table 39, reflecting the fact that suspending the Site C Project would allow BC Hydro to follow an alternative resource path that includes an updated DSM Option 2, capacity-focused DSM and continuing declines in the costs of wind resources. In the event that future circumstances warrant, the Site C Project can then be taken out of suspension and completed.

Table 39: Scenario K – Alternative path following suspension of the Site C Project

Scenario	Load Forecast	Site C	Site C Sunk Costs	Site C Cost Overrun	Market Price Forecast	DSM Option	Capacity-focused DSM
K1	Mid	Suspend	Yes	n/a	Medium	Option 2	Yes
K2	Low	Suspend	Yes	n/a	Medium	Option 2	Yes
K3	High	Suspend	Yes	n/a	Medium	Option 2	Yes

Suspending the Site C Project as of June 30, 2017 results in $1.87 billion in sunk costs. It is presumed that ratepayers repay these costs over a 70-year period beginning in F2025, which is consistent with the expected term for repayment of the costs of the Site C Project, and allows repayment to begin after the 10 Year Rates Plan.

In addition, maintaining a suspended Site C Project in a condition where it might be continued if it becomes cost effective adds an estimated $15 million to the annual carrying costs. The result is a total of $112 million in annual carrying costs for up to 70 years, or as long as the Project remains in suspension. These costs are not immaterial, and, since they increase the costs of all scenarios **without** the Site C Project, they tend to counteract the effects of the declining costs of wind energy and the lower load forecast.

Table 40 presents comparisons between suspending the Site C Project (Scenario J) and continuing with the Site C Project (Scenario B) in the mid, low and high load forecast scenarios at medium market prices. Since suspension carries with it the potential to restart construction of the Site C Project, the optimal date of restarting is also noted in this table.

Table 40: Cost implications – suspending the Site C Project (model results)

Load Forecast	Market Price Forecast	PV of Scenario K (suspended Site C) (M$)	PV of Scenario B (with Site C) (M$)	PV benefit (cost) of completing the Site C Project (M$)	Optimized Date to restart Site C Construction
Mid	Medium	1,392	2,259	-867	2030
Low	Medium	-2,311	-1,517	-794	After 2036
High	Medium	5,633	6,498	-865	2027

The findings in this table illustrate that:

- under the 2016 mid-load forecast, there would be a benefit of $867 million to suspending the Site C Project and completing it for a F2030 in-service date, compared to proceeding with the Site C Project for a F2024 in-service date;
- under the 2016 low-load forecast, there would be a benefit of $794 million to suspending the Site C Project and completing it for an in-service date after F2036, compared to proceeding with the Site C Project for a F2024 in-service date; and
- under the 2016 high-load forecast, there would be a benefit of $865 million to suspending the Site C Project and completing it for a F2027 in-service date compared to proceeding with the Site C Project for a F2024 in-service date;

Regardless of BC Hydro's current forecasts of load growth, suspending the Site C Project in order to develop it at an optimal later date would save ratepayers on the order of $800 to $870 million, depending on the load forecast, compared to completing the Site C Project in F2024.

In addition, it is worth noting that, other than in the low-load forecast, where the Project remains suspended until following F2036, it is preferable to suspend the Site C Project rather than to cancel it. Comparing the findings in Table 40 to those in Table 29, this benefit of suspension over cancellation is $271 million in the mid-load forecast,[380] and $352 million in the high-load forecast.[381] **While these values are not large, they indicate that suspending the Site C Project is preferable to cancelling the Site C Project. However, cancellation and suspension are both superior options to continuing with Site C**.

[380] i.e. -$601M – (-$872M) = $271

[381] i.e. -$534M – (-$876M) = $342

6.4 Summary of model results

Table 41 provides a summary of the resources for each scenario.

Table 41: Summary of resources by model scenario

Load Forecast	Scenario	B	C	D	E	F
Low	Site C start date	F2024	Cancel	Cancel	F2024	F2024
	Wind in F2036 (MW)	0	0	0	0	0
	Avg. new gas generation (GWh/y)	0	0	0	0	0
Medium	Site C start date	F2024	Cancel	Cancel	F2024	F2024
	Wind in F2036 (MW)	715	1181	1181	715	715
	Avg. new gas generation (GWh/y)	0	6	6	0	0
High	Site C start date	F2024	Cancel	Cancel	F2024	F2024
	Wind in F2036 (MW)	2960	3916	3916	2960	2960
	Avg. new gas generation (GWh/y)	690	226	226	690	690
Load Forecast	**Scenario**	**G**	**H**	**I**	**J**	**K**
Low	Site C start date	Cancel	F2024	Cancel	F2024	F2037
	Wind in F2036 (MW)	0	0	0	0	0
	Avg. new gas generation (GWh/y)	0	0	0	0	0
Medium	Site C start date	Cancel	F2024	Cancel	F2024	F2030
	Wind in F2036 (MW)	1181	715	1181	715	0
	Avg. new gas generation (GWh/y)	6	0	6	0	0
High	Site C start date	Cancel	F2024	Cancel	F2024	F2027
	Wind in F2036 (MW)	3916	2960	3916	2960	2120
	Avg. new gas generation (GWh/y)	226	690	226	690	104

B = The base case
C = No approval of the Site C Project in 2014
D = Cancel the Site C Project
E = Cancel the Site C Project with cost overruns
F = The base case with low market prices
G = Cancel the Site C Project with low market prices
H = The base case with high market prices
I = Cancel the Site C Project with high market prices
J = Cancel the Site C Project with low market prices
K = Suspend the Site C Project

Wind development varies substantially under the various scenarios. No new wind resources are developed in the low-load forecast scenarios, as additional DSM or the development of the Site C Project is able to meet requirements for the duration of the planning period. In the medium and high-load forecasts, wind resources are developed in all scenarios except the scenario where the Site C Project is suspended (Scenario K) in the mid-load forecast. In this instance, DSM and other resources meet requirements until the Site C Project comes on-line in F2030.

All alternative scenarios considered have very low greenhouse gas emissions. With respect to natural gas generation resources, no natural gas resources are developed in the low-load forecast scenarios, as DSM meets all additional requirements. In the mid-load forecast, the portfolios without the Site C Project develop SCGTs only in F2036, the last year of the planning period, to meet winter peak requirements. In terms of capacity, 186 MW are developed producing 81 GWh/year of energy. The total annual GHG emissions from the operation of these SCGTs would be about 0.039 Mt CO_2e, for a total of 1.16MT CO_2e emissions over 30 years, or 3.9 MT CO_2e emissions over 100 years. This compares to the operations of the Site C Project, which would produce 5 MT of CO_2e emissions over 30 years, and 6 MT of CO_2e emissions over 100 years.

In the high-load forecast scenarios, considerably more gas is developed in all scenarios, beginning in F2021 in the portfolios without the Site C Project, and in F2029 in the portfolios with the Site C Project. A more rapid introduction and ramp up of capacity-focused DSM could delay the need date for these resources. The average annual generation from SCGTs is higher in the portfolios with the Site C Project than in those without the Site C Project. This is the outcome of BC Hydro's approach to operating SCGTs at 18% capacity factors. By the end of the planning period, the scenarios with the Site C Project develop 1,217 MW of SCGTs while those without the Site C Project develop 1,038 MW.

Though pumped storage hydroelectric generation at the Mica Generating Station was included in the modelling, the facility did not start (DNS) operating in most of the scenarios. Only in the high-load forecast without the Site C Project was this resource selected in F2036. This explains the lower capacity of SCGTs in the portfolios without the Site C Project in the high-load forecast scenario at the end of the planning period. As shown in Table 42 below, the portfolios without the Site C Project all had a cost advantage of more than $500 million over the portfolios with the Site C Project. This cost advantage could be applied to advancing pumped storage to an earlier date in order to further lower GHG emissions.

The percentage of energy coming from non-clean resources remains below the 7% maximum prescribed in the *Clean Energy Act* for all of the forecast scenarios.

6.5 Additional considerations

The modelling exercise described above assessed the relative benefits and costs of continuing, cancelling or suspending the Site C Project under a number of different scenarios. These scenarios included:

- low, mid, and high load forecasts;
- the Site C Project on budget or with a 25% cost overrun;
- low, medium, and high export market prices;
- a combination of a cost overrun and low market prices; and

- suspending the Site C Project in order to resume construction in the future, should circumstances so warrant.

The above scenarios address the most important issues, but are not exhaustive. With additional time and resources, other scenarios could be developed and analyzed to assess additional factors. In the event that the Site C Project is suspended and referred to the BCUC for additional review, additional analyses could consider the following:

- **Wind prices**. This report finds that the adjusted unit energy cost of wind is conservatively anticipated to decline by an additional 20% by 2030. Greater or lesser declines could be assessed to determine the effects on the portfolio costs and benefits.
- **Capital and operating costs**. With the exception of BC Hydro's assumptions regarding the future costs of energy from wind resources, this research has accepted BC Hydro's estimates of the costs to develop and operate various demand-side and supply-side resources. A review and sensitivity analysis of these cost estimates before a public utility board, such as the BCUC, is usual practice prior to approval of a project of the size and significance of the Site C Project. In the event that further review is undertaken by the BCUC, the costs of the demand-side and supply-side resources should receive particular scrutiny.
- **Site C Project cost overruns**. The modelling exercise considers only the potential for a 25% cost overrun, which is consistent with other large-scale hydroelectric development across Canada and around the world. However, some hydroelectric and transmission projects in operations and under construction in Canada, including BC Hydro projects, have had much higher cost overruns. An appropriate time and context to undertake such a review would be in a hearing before the BC Utilities Commission.
- **Storage technologies**. This report was not able to assess the potential implications of significant further declines in the cost of battery and other forms of energy storage. These resources could be added to the resource stack to determine whether they could become cost-effective within the 20-year planning period in order to assess what impact, if any, they would have on the findings.
- **Geothermal**. In its 2013 IRP, BC Hydro estimated that the province has available on the order of 500 MW and 4,000 GWh/year of geothermal resources at a unit energy cost of $100/MWh.[382] Half of this amount is located in the Lower Mainland, the primary load center in the Province. However, due to its high initial capital costs to locate and developed suitable resources, no projects have been developed to date in British Columbia. For these reasons, geothermal resources were not considered in the analysis in this report. Any future analysis should seek to resolve cost uncertainties, and look to other jurisdictions where

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[382] BC Hydro. November 2013. Integrated Resource Plan. Chapter 3 Resource Options, p.3-50. (Accessed 17 April 17 at: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0003-nov-2013-irp-chap-3.pdf)

geothermal resources have been successfully developed. Geothermal could be particularly relevant to a decision to cancel versus suspend the Site C Project if these matters can be resolved in the next few years. In the event that further review of the Site C Project is undertaken by the BCUC, geothermal potential should receive particular attention, as recognized by the JRP in its final report.

- **Financial parameters**. Additional scenarios could theoretically be developed to test the effect of different financial parameters, including discount rates, cost of capital, exchange rates, etc. In general, these parameters are built in to the unit energy costs and unit capacity costs of the various resources used in the analysis, and there may not be sufficient information available on the public record to undertake this kind of financial sensitivity analysis.
- **Macroeconomic issues**. The analysis of alternatives could be broadened to consider key macroeconomic considerations, including employment, government revenue and government debt.
- **Macroenvironmental issues**. The analysis in this report considers the social costs of GHG emissions. However, no costs are allocated with respect to the residual environmental effects of the various alternative portfolios, indirectly assigning zero value to these externalities. In general, this approach tends to favour portfolios with the Site C Project considering the extent of its significant adverse environmental effects and its effects on ecosystem services. While some of these effects are quantifiable (e.g. habitat loss), others are more qualitative (e.g. visual impacts, loss of use).
- **Social issues**. The consequences, in terms of impacts and benefits, of the alternative portfolios for Indigenous, local and provincial populations also merit consideration in a fuller analysis of the alternative portfolios. This could include consideration of local, regional and provincial benefits, impacts on Indigenous peoples and relations with government, as well as the legacy effects of the portfolios for future generations.

6.6 Summary of findings

The modeling exercise investigated the following options:

a) continue with construction of the Site C Project to completion as scheduled;
b) cancel the Site C Project in order to develop alternative resources; or
c) suspend the Site C Project and develop alternative resources as needed, but leave open the possibility of continuing the Site C Project if circumstances warrant.

Each of the scenarios was developed under the constraints imposed by the *Clean Energy Act*, including those related to achieving self-sufficiency and to generating at least 93% of the electricity in British Columbia from clean or renewable resources. The operational GHG emissions of all resources, including the Site C Project were included in the analysis.

Table 42 summarizes the net present value benefit (cost) of continuing with the Site C Project under the various scenarios. **These results indicate that it was not prudent to proceed with the Site C Project, and it remains imprudent to continue with it.**

Regardless of the load forecast scenario, it would be preferable to suspend or cancel the Site C Project. If market prices are lower than anticipated, and particularly if there is a 25% cost overrun, the losses associated with continuing the Site C Project would be much higher.

Table 42: Cost implications – summary of model results ($million)

Load Forecast	No approval of Site C in 2014	Cancel Site C	Cancel Site C with 25% cost overrun	Cancel Site C with low market prices	Cancel Site C with high market prices	Cancel Site C with cost overrun and low market prices	Suspend Site C
	C	D	E	F/G	H/I	J	K
Low	-1,698	-794	-1,457	-985	-593	-1,648	-794
Mid	-1,526	-622	-1,285	-689	-555	-1,352	-867
High	-1,422	-518	-1,181	-536	-503	-1,199	-865

In summary, **our findings are**: 1) The decision to approve the Site C Project in 2014 will cost ratepayers on the order of $1.4 to $1.7 billion dollars more than had an alternative portfolio of resources been pursued at that time. 2) Our analysis indicates that cancelling the Site C Project as of June 30, 2017 would save between $500 million and $1.65 billion, depending on future conditions. 3) Suspending the Site C Project is preferable to cancelling the Project by up to $350 million. Both cancelling and suspending are preferable to continuing with the Site C Project.

Our recommendation is: Suspend the Site C Project, and refer the Project to the BC Utilities Commission for a full review.

ACRONYMS

AESO	Alberta Electric System Operator
BCUC	British Columbia Utilities Commission
CCGT	Combined cycle gas turbine
CE	Canadian Entitlement under the Columbia River Treaty
CEAA	Canadian Environmental Assessment Act
CO_2e	Carbon dioxide-equivalent
DSM	Demand-side management
EIS	Environmental Impact Statement
FID	Final Investment Decision
IPP	Independent Power Producer
IRP	Integrated Resource Plan
JRP	Joint Review Panel
PV	Present value
RDA	Rate Design Application
RRA	Revenue Requirements Application
SCGT	Simple cycle gas turbine
TOU	Time-of-use
TRC	Total resource costs
UC	Utility costs
UCC	Unit Capacity Cost
UEC	Unit energy cost
WACC	Weighted average cost of capital

GLOSSARY[383]

Alberta Electric System Operator As an independent system operator, the AESO leads the operation and planning of Alberta's interconnected power system. AESO also facilitates Alberta's competitive wholesale electricity market.

Base Resource Plan BC Hydro's proposed action plan for meeting its current and future customers' electricity needs on a reliable and cost-effective basis.

Billed Sales The amount of electricity billed. Because bills are produced after the electricity has been delivered, monthly billed sales lag monthly delivery of electricity.

British Columbia Utilities Commission An independent regulatory agency of the provincial government operating under and administering the *Utilities Commission Act*. The BCUC regulates BC Hydro's domestic supply and rates and the safety and reliability of the BC Hydro system, as well as operating, management and administrative costs, and also assesses concerns from ratepayers regarding BC Hydro's service.

Canadian Entitlement The Canadian 50 per cent share of the computed increase in downstream energy and capacity benefits on the Columbia River in the U.S. due to the construction and coordinated operation of Duncan, Keenleyside and Mica storage dams in Canada, as provided for under the Columbia River Treaty (1964).

Capacity The power produced or demanded at a particular time, usually measured in kilowatts (kW) or megawatts (MW).

Capacity Factor The ratio of the average annual power output to the rated power output of electricity generating plants.

Certificate of Public Convenience and Necessity (CPCN) A certificate/permit issued by a public body, such as the B.C. Utilities Commission, that is charged with the supervision of public facilities, e.g., transmission carriers or public utilities. The certificate authorizes the holder of the permit to operate, or construct a public facility (such as a generating plant or transmission facilities) within a particular area. The issuance of the certificate is made after application, notice and hearing.

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[383] Selected definitions obtained or derived from: i) BC Hydro. December 2012. Electric Load Forecast Fiscal 2013 to Fiscal 2033; ii) BC Hydro. November 2013. Integrated Resource Plan Appendix 1A Glossary and Abbreviations.

Clean Energy Act (CEA) The legislation that sets the foundation for electricity self-sufficiency, job creation and reduced greenhouse gas emissions. The *Act* also describes the consideration of investments in clean, renewable energy across the province.

Clean or Renewable Energy Defined by the *Clean Energy Act* as including biomass, biogas, geothermal heat, hydro, solar, ocean, wind or other prescribed resources.

Climate Leadership Plan A policy document produced by the B.C. Government that describes actions that will be undertaken as government moves to its target of reducing greenhouse gas emissions by 33 per cent below 2007 levels by 2020 and 80 per cent by 2050.

CO_2e Carbon dioxide-equivalent. A unit that measures the climate change potential of each of the six greenhouse gases identified in the Kyoto Protocol.

Columbia River Treaty A treaty ratified in 1964 between Canada and the U.S. that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the U.S. for power production and flood control.

Combined Cycle Gas Turbine The combination of combustion and steam turbines to generate electricity from two thermodynamic cycles. Exhaust gases from a combustion turbine flow to a heat recovery steam generator (**HRSG**) that produces steam to power a steam turbine, resulting in higher thermal efficiency than achievable by operating the combustion or steam turbines individually.

Conservation Reducing the level of energy service to reduce energy consumption. For example, turning off unused lights.

Contingency Resource Plan A plan that identifies alternative sources of supply and transmission components that could be required should the Base Resource Plan not materialize as expected.

Dependable Capacity The maximum generator output that can be reliably supplied coincident with the system peak load, taking into account the physical state and availability of the equipment, and on water or fuel constraints.

Demand-side Management (DSM) Activities that occur on the demand side of the revenue meter and are influenced by the utility. DSM activities result in a change in electricity sales. Past DSM savings include incremental load displacement and energy efficiency savings. Note that BC Hydro's historical sales include the impact of DSM savings realized up to that year.

Discount Rate A rate used to determine the present value of cash flows (expenses and revenues) that will occur over a period of time, reflecting the cost of capital.

Dispatchable A resource whose output can be adjusted to meet various conditions including fluctuating customer demand, weather changes, outages, market price changes and non-power considerations.

Distribution Delivery of electricity to retail customers, generally at voltages lower than 69 kV.

Efficiency The effective rate of conservation of a natural resource (e.g., electricity) to usable energy; the effective rate of conversion of electricity to an end use (e.g., heating).

Elasticity The proportionate change in a dependent variable (e.g. electricity consumption) divided by the proportionate change in a specified independent variable (e.g. electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

Electricity Purchase Agreement (EPA) The contract that defines the terms and conditions by which BC Hydro purchases electric energy from Independent Power Producers.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours.

Energy Efficiency (EE) A reduction in energy usage to provide the same level of energy service, such as lighting, cooling or motor torque.

Final Investment Decision (FID) The decision made in December 2014 by the BC Government to approve the Site C Project and proceed with construction.

GHG Emissions Refers to GHG emissions per unit of electrical production, measured in units of tonnes of CO_2e/GWh.

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure.)

Greenhouse Gases (GHG) Greenhouse gas – any of the atmospheric gases that contribute to climate change such as water vapour, methane, or carbon dioxide

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Independent Power Producer (IPP) A non-utility-owned electricity generating facility that produces electricity for sale to utilities or other customers.

Integrated Resource Plan (IRP) The document describing BC Hydro's long term plan to meet customers' needs using existing and new resources and demand-side measures.

Integrated system That portion of the BC Hydro electricity system that is connected as one whole by a high voltage transmission grid.

Integrated system peak includes the peak requirements for BC Hydro's distribution and transmission customers in its service territory; sales to Other Utilities; and system transmission and distribution losses.

Intermittent Resource A source of energy that has varying output due to natural changes, and is not dispatchable; can also be referred to electricity supply that fluctuates or is not available at all times.

Kilowatt (kW) One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Kilowatt-hour (kWh) A measure of electrical energy, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure)

Liquefaction The process by which natural gas is converted to liquid through refrigeration. Liquefaction facilities are important infrastructure in the LNG production and transportation process. Liquefaction reduces the volume by approximately 600 times, making it more economical to transport between continents in specially designed ships.

Liquefied Natural Gas (LNG) is natural gas that has been converted temporarily to liquid form for ease of storage or transport. This process involves refrigeration, and requires no chemical transformations.

Load The total amount of electrical power demanded by the utility's customers at any given time, typically measured in megawatts.

Load Curtailment A reduction in demand as a result of demand-side measures or a decrease in generation output.

Load Displacement Projects that involve the installation of self-generation facilities at customer sites, with the electricity generated being used on-site by the customer, with a resultant decrease in the purchase of electricity from BC Hydro.

Load Forecast The expected load requirements that an electricity system will have to meet in future years.

Load Forecasting The process to determine the expected amount of electricity required to meet customer needs in future

Load-Resource Balance (LRB) The difference between B.C. Hydro's Load Forecast and existing and committed resources available to meet the load.

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure.)

Megawatt-hour (MWh) A measure of electrical energy, equivalent to 1,000 kWh. (See Units of Measure)

Mid-Columbia (Mid-C) Wholesale electricity trading hub located in the U.S. Pacific Northwest.

Natural Conservation The changes in end use efficiency due to stock replacement, energy prices and other factors that are projected to occur in the absence of new and incremental market interventions.

Net Metering A system that allows customers with their own small on-site generation facilities (such as solar panels) to "bank" electricity that they generate in excess of their needs and consume electricity from the grid when they need it.

Net Present Value (NPV) The difference between the present value of benefits and the present value of costs (including capital, operating, maintenance and administration costs) for a given discount rate.

Peak Capacity The maximum amount of electrical power that generating stations can produce in any instant.

Peak Demand/Load The maximum instantaneous demand on a power system. Normally, the maximum hourly demand.

Persistence The timeframe during which demand-side measures produce electricity savings that are attributable to the utility's actions.

Photovoltaic (PV) Direct conversion of light into electricity by semi-conductor diodes called photovoltaic cells, especially using sunlight.

Portfolio A group of individual resource options to be acquired in a sequence over time to fill customers' future electricity needs.

Portfolio Analysis A process of developing and evaluating resource portfolios, each consisting of a combination of supply side and demand-side resources, which meet customers' electricity needs.

Present Value (PV) Today's discounted value of future receipts or expenditures.

Price elasticity of demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Pumped Storage (PS) The use of electricity generated during off-peak hours to pump water from a lower elevation reservoir to a higher reservoir. The stored water is then released during peak demand periods and used to propel a reversible pump/turbine generator before returning to the lower reservoir.

Rate Term used for a utility's unit price of service.

Reliability A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system's ability to respond to transient disturbances in the system.

Resource Option A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand-side measures and transmission facilities.

Revenue Requirements Application (RRA) Application before the B.C. Utilities Commission expected to determine the revenues BC Hydro will need for its operations, to ensure a safe and reliable supply of electricity to its customers.

Run-of-River A hydroelectric facility that operates with no significant storage facilities.

Self-Generation Generation of electricity by an industry or commercial enterprise whose principal product is not electricity. Self-generation can reduce the amount of electricity purchased from the utility, or surplus electricity may be sold to the utility as a supply side resource.

Simple-Cycle Gas Turbine (SCGT) A stand-alone generating plant that uses combustion gases to propel a turbine similar to a jet engine connected to an electrical generator.

Site C Project An 1100 MW, hydroelectric generating station under construction downstream from the existing Williston Reservoir and two existing generating facilities on the Peace River region.

System Optimizer A deterministic optimization model used by BC Hydro that produces an optimal sequence of generation and transmission resource expansions for a predefined scenario by selecting from the stack of available resources.

Total Resource Cost (TRC) Test A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the perspective of all utility customers (also referred to as the All Ratepayers Test). The benefit-cost ratio is calculated as follows:

PV (avoided electric energy costs + avoided electric capacity costs + avoided non-electric fuel costs + customer non-energy benefits/

PV (BC Hydro program costs + BC Hydro allocated supporting initiative costs + customer costs + partner organization program costs)

Transmission The transportation or conveyance of electricity in bulk, usually at voltages over 69 kV.

Unit Capacity Cost (UEC) Present value of the total annual cost of a capacity resource divided by the resource's dependable capacity. It is measured in dollars per kilowatt per year.

Unit Energy Cost (UCC) Present value of the total annual cost of an energy resource divided by the present value of its annual average energy benefit. It is calculated using either a discounted cash flow method or annualized cost method, and is measured in dollars per MWh.

Utility Cost Test A DSM benefit-cost test that indicates the impact of a DSM initiative or portfolio from the utility's perspective. The benefit-cost ratio is calculated as follows:

PV (Avoided electric energy costs + avoided electric capacity costs)/

PV (BC Hydro program costs + BC Hydro incentive costs + BC Hydro allocated supporting initiative costs)

Wheeling The transmission of electric power from one system to another through a third party, usually the owner or operator of the transmission facilities.

Wind Integration Costs Costs that will be incurred by a utility in managing and operating its system to regulate the intermittent variability of generation from wind resources.

ERRATA

With respect to Version 01 of the report "Reconsidering the Need for Site C" issued on April 19, 2017, the authors acknowledge the following errata:

Section 1.3; p.2	Our analysis finds that the decision to build Site C was based on a strikingly high load forecast made by BC Hydro in 2013, which was (a) notably higher than similar estimates made before or since (on the order of ~~5~~8,000 GWh/year) and (b) …
Section 1.3; p.2	Section 3 also analyzes BC Hydro's load forecasting history over the past three decades, and finds that 85% of the ~~26~~ load forecast~~s~~ data points prepared by BC Hydro …
Section 3.2.2; p.15	Since 1981, BC Hydro has prepared 36 load forecasts, including a total of 553 point estimates of future energy requirements in specific future years. If BC Hydro's approach were statistically unbiased, then half of these projections would be overestimates and half underestimates. BC Hydro's data reveal, though, that **85%** of these data point projections were overestimates.
Section 4.5; p.71	…can be managed from existing contingency budgets totaling $1.04 billion, from which $285 million had been expended (as of December 31, 2016);
Section 5.4.1; p.93	In terms of future wind resource costs, BC Hydro believes that the long-term adjusted unit energy costs of onshore wind will …
Section 6.3.7; p.141	However, the effect of low market prices is not as significant as the effect of a 25% cost overrun…
Section 6.3.8; p.142	Table 36: Cost implications – ~~low~~ high market prices (model results)
Section 6.6; p.150	Table 42: Cancel Site C with ~~low~~ high market prices [sixth column]

PROGRAM ON WATER GOVERNANCE

COMPARATIVE ANALYSIS OF GREENHOUSE GAS EMISSIONS OF SITE C versus ALTERNATIVES

July 2016

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This report was authored by Rick Hendriks (Camerado Energy Consulting), an energy consultant with 20 years experience in assessment and analysis of large-scale hydropower projects. The report was overseen by Dr. Karen Bakker (UBC), and independently reviewed by Dr. Arthur Fredeen (UNBC), Dr. Normand Mousseau (Université de Montreal), and Philip Raphals (Helios Centre, Montreal).

1. Summary

What and where is Site C? Site C is a hydroelectric dam on the Peace River currently in the early stages of construction. The site is located in northeastern British Columbia in the Peace Valley near Fort St John. Site C would be downstream from two other dams (including the Bennett Dam, one of the largest earth-filled dams in the world).

What is the key finding of the report? The Site C dam does not deliver energy and capacity at significantly lower greenhouse gas emissions than a fully optimized Alternative Portfolio put forward by BC Hydro (which includes wind energy). The difference in lifecycle GHG emissions, if a difference exists at all, is at most 1% of BC's current emissions.

Why is this finding significant? Site C has more significant adverse environmental effects than any project ever reviewed under the history of the *Canadian Environmental Assessment Act*, including impacts on dozens of species, aquatics, vegetation, wildlife, Aboriginal use of lands and resources, and cultural heritage. The federal and provincial governments stated that the unprecedented level of significant adverse environmental effects from Site C are justifiable, in part, because the project delivers energy and capacity at substantially lower GHG emissions than the available alternatives. Our analysis indicates this is not the case.

How does this add to the analysis in the Joint Review Panel report? The Joint Review Panel (JRP) jointly commissioned by the federal and provincial governments did not analyze GHG emissions in detail. The JRP draws conclusions about the relative GHG emission advantages of the Site C Project without additional analysis beyond that provided by BC Hydro. Our analysis reviews the information presented by BC Hydro to the Joint Review Panel and also presents the findings of additional research concerning the GHG emissions of the Site C Project. The JRP noted in its report that its limited mandate and resources precluded analysis of some key issues. This report thus fills an important gap.

How was the analysis conducted? Optimizing the selection and operation of the resources composing the mostly likely Alternative Portfolio proposed by BC Hydro, the analysis indicates that the environmental assessment process for the Site C Project overlooked opportunities to reduce the average GHG emissions of the Alternative Portfolio from 611 to 68 kt CO_2e/year (a reduction of more than 0.5 Mt CO_2e/year) while maintaining costs. This reduces the average annual GHG emissions reduction benefits achieved by developing the Site C Project, compared to the Alternative Portfolio, to *at most* 0.1 Mt CO_2e/year. This is equivalent to just 0.15% of BC's current emissions.

What about the timing of these emissions? The Site C Project entails the release of at least 4 Mt CO_2e emissions before 2035, as a result of construction-related emissions and the fact that reservoir emissions are concentrated in the early years following inundation. It will be several decades before the GHG emissions of an optimized Alternative Portfolio exceed those of the Site C Project, if ever. An optimized Alternative Portfolio has available to it all of the future technological advances that would allow for additional reductions in potential GHG emissions. This opportunity is unavailable to the Site C Project, since once it is constructed and operating, its GHG emissions are certain to occur. Fully optimizing the Alternative Portfolio would allow its emissions to remain below the emissions of the Site C Project indefinitely.

How do these emissions compare to other projects? The recently-approved Woodfibre LNG facility, even with its relatively low emissions intensity per tonne of LNG, is nearly 10 times the maximum annual GHG emission benefits of Site C compared to the optimized Alternative Portfolio. Were the Pacific Northwest LNG export facility to be approved, its annual emissions would be more than 120 times the maximum GHG emissions benefits of Site C, and would also represent over 95% of British Columbia's 2050 emissions reduction target set out in the *Clean Energy Act*.

What about exporting energy from Site C to Alberta? It has been suggested that additional GHG emissions reductions would result from exporting surplus Site C energy to Alberta. The purpose of the Site C Project, as proposed by BC Hydro, was to meet British Columbia's domestic electricity requirements; Site C was not evaluated in an export context. This report questions the potential for exporting Site C energy to Alberta, as the cost of Site C energy is high compared to other renewables such as wind and solar. Our analysis indicates that these other renewables could be much better alternatives for replacing coal, helping Canada achieve its climate change goals more quickly and affordably, and with much lower overall environment impact compared to Site C.

Need for comprehensive review: The findings of our research reinforce the statements of the Joint Review Panel, which indicated that it had insufficient time and resources to conduct a full assessment of the Site C Project. Our analysis also supports the recommendation of the Joint Review Panel for a more thorough review by the BC Utilities Commission prior to any decision to proceed with development at Site C.

2. Regulatory and policy context

BC Hydro's planning environment in terms of greenhouse gas (GHG) emissions is set out in the requirements of the *Clean Energy Act*, including as follows:

- 2(c) to generate at least 93% of the electricity in British Columbia, other than electricity to serve demand from facilities that liquefy natural gas for export by ship,[1] from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
- 2(f) to ensure the authority's rates remain among the most competitive of rates charged by public utilities in North America;
- 2(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
- 2(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia; and
- 6(2) (b) relying on Burrard Thermal for no energy and no capacity, except as authorized by regulation.

The alternative portfolios developed and assessed by BC Hydro in its 2013 Integrated Resource Plan (IRP) for meeting the requirements for firm energy and dependable capacity all comply with the above requirements, including the requirement that 93% of BC's electricity come from clean resources. As a result, *all* of the alternative portfolios produce low levels of GHG emissions.

In its 2013 IRP, BC Hydro reported the detailed GHG emissions related only to fuel combustion during operations of the Site C Project, while excluding emissions related to its construction and reservoir inundation.[2] As a result, in the IRP, the utility reported GHG emissions of Site C as "no direct emissions".[3] In its Environmental Impact Statement (EIS) for the Site C Project, BC Hydro prepared a more detailed assessment of the GHG emissions for Site C construction and reservoir operations,[4,5] reporting lifecycle emissions of 3.7 to 8.5 Mt CO_2e (see Table 1). It also provided emission rates

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[1] As per British Columbia's Energy Objectives Regulation (B.C. Reg. 234/2012).
[2] BC Hydro. 2013. Integrated Resource Plan ['IRP']. Appendix 3A-4: 2013 Resource Options Report Update Resources Options Database (RODAT) Summary Sheets, p.470.
[3] *Ibid*., Appendix 3A-3: 2013 Resource Options Report Update Environmental Attributes Review and Update, p.60.
[4] BC Hydro. 2013. Site C Clean Energy Project Environmental Impact Statement ['EIS']. Volume 2: Assessment Methodology and Environmental Effects Assessment. Section 15 Greenhouse Gases.
[5] *Ibid*., Volume 2 Appendix S: Site C Clean Energy Project: Greenhouse Gases Technical Report. Prepared for BC Hydro by Stantec Consulting Ltd ['GHG Report'].

for the electricity generation resources used in the alternative portfolios, discussed below.

During the Site C Joint Review Panel (JRP) hearings, minimal attention was paid to the issue of GHG emissions. Over the course of the 25 days of hearings, the JRP dedicated one afternoon session to atmospheric and air quality issues, of which the sub-topic of GHG emissions was one of five sub-topics.[6] No evidence concerning GHG emissions was presented to the Panel during the hearings, other than by BC Hydro. The JRP undertook no independent analysis of the findings of BC Hydro, and solicited no additional evidence through undertakings by BC Hydro or other interveners. Yet, the JRP reached the following conclusion in its final report to the Ministers:

> [Site C] would produce a <u>vastly smaller burden of greenhouse gases than any alternative</u> save nuclear power, which B.C. has prohibited.[7] [emphasis added]

Our analysis, presented below, demonstrates that this finding of the JRP, based as it was on limited evidence was, in fact, unfounded. This uncritical view of the GHG emissions of the Site C Project, as compared to the available alternatives identified by BC Hydro in its 2013 IRP, is shared by many, including the Provincial Minister of Energy and Mines, who recently stated the following:

> "The hydroelectric project will deliver the lowest-cost, cleanest power available," the minister said, although he conceded it would have adverse environmental impacts downstream.[8]

It is this concession by the Minister that reveals the underlying process used by government to justify approving the Site C Project: the significant environmental effects of the Site C Project, which are unprecedented,[9] are justifiable because the project is *presumed* to deliver energy and capacity at lower costs and lower GHG emissions (i.e. the "cleanest") compared to the available alternatives.

The chair of the Joint Review Panel, Dr. Harry Swain, has recently stated that, in his view, this justification test has not been satisfied:

> The environmental and First Nations land rights issues are serious costs that would have to be borne if the [Site C] project goes ahead. You would only want to do that if there were an overwhelming economic case that this was the best and cheapest way, including all external effects, of providing something that the

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[6] Site C Clean Energy Project Joint Review Panel. 2013. Revised Public Hearing Schedule – released December 6, 2013. Available at: http://www.ceaa-acee.gc.ca/050/documents/p63919/96899E.pdf.

[7] Site C Clean Energy Project Joint Review Panel. 2014. Report of the Joint Review Panel Site C Clean Energy Project BC Hydro ['JRP Report'], p. iv.

[8] "Ottawa pushes ahead with Site C dam amid opposition from academics," Globe & Mail, May 24, 2016. Available at: http://www.theglobeandmail.com/news/british-columbia/royal-society-of-canada-academics-call-on-ottawa-to-halt-site-c-project/article30127279/

[9] Briefing Note #2 Assessing Alternatives to Site C: Environmental Effects Comparison. Available at: www.watergovernance.ca.

> provincial economy absolutely required. And I'm saying since you can't pass that test then the rest of it is moot."[10]

This is, indeed, a key issue. This report provides independent comparative analysis of GHG emissions in order to inform this debate.

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[10] Alaska Highway News, « Q&A: Dr. Harry Swain, former Site C panel chair becomes outspoken opponent", July 8, 2016 (http://www.alaskahighwaynews.ca/regional-news/site-c/q-a-dr-harry-swain-former-site-c-panel-chair-becomes-outspoken-opponent-1.2296875).

3. Presentation of estimations of greenhouse gas emissions

3.1 Estimations of greenhouse gas emissions from Site C

As explained in the EIS, the GHG emissions from the Site C Project are not nil, but include construction-related emissions, life-cycle emissions from manufacturing, and reservoir-related emissions.

In preparing its emissions estimate in the EIS, BC Hydro considered both "likely" (lower emission) and "conservative" (higher emission) scenarios.[11] During construction, the conservative scenario assumes 15% greater fuel emissions and greater life-cycle emissions for construction materials than in the likely scenario. For operations, the conservative scenario assumes no storage of carbon and no burial of biomass, while the likely scenario assumes that merchantable timber inundated by the reservoir will be converted entirely into stored carbon (i.e. as building materials for the construction industry) and that 30% of non-merchantable timber cleared from the reservoir would be buried (and therefore indefinitely stored). During the operations phase, both estimates assume that the reservoir emissions occur almost entirely in the early years following inundation, and eventually decline to resemble those prior to reservoir creation.[12] In order to assess the uncertainty of these estimates, BC Hydro also undertook a sensitivity analysis of various input parameters in order to develop "minimum likely" and "maximum conservative" estimates.

The resulting total Site C GHG emissions, including construction-related emissions, for the 108-year construction and operation period are summarized below in Table 1. These data do not tell the full story, however, as Site C's GHG emissions are heavily front-loaded.

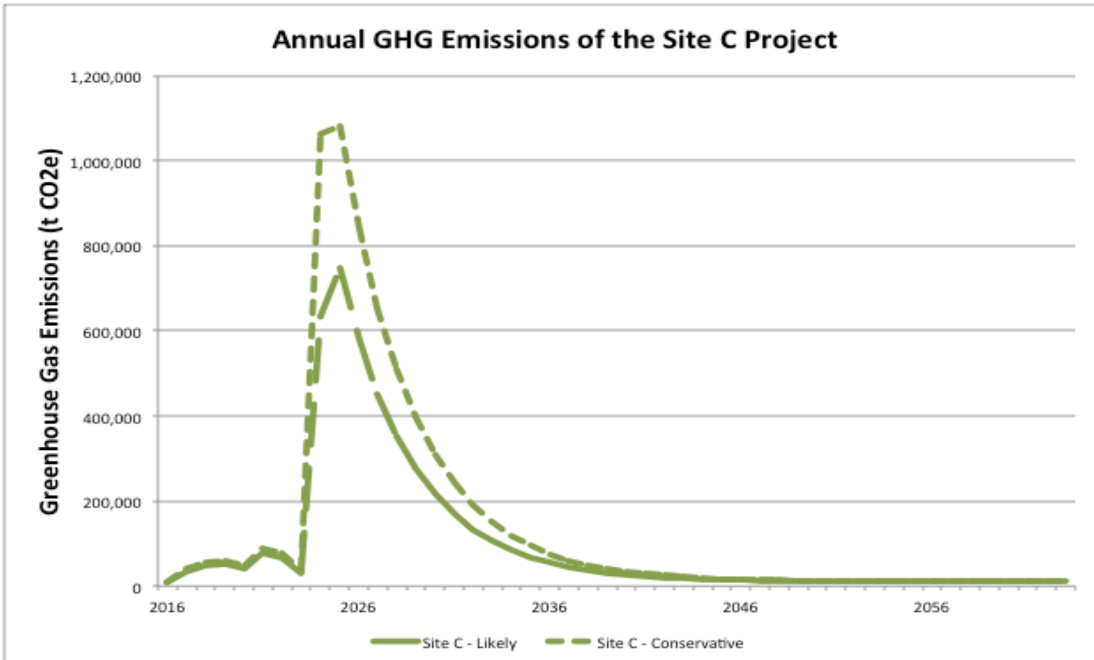
Table 1. Range of Site C Project GHG Cumulative Emissions Estimates[13,14]

	Minimum (kt CO_2e)[15]	Likely (kt CO_2e)	Conservative (kt CO_2e)	Maximum (kt CO_2e)
Operations	2,713	4,344	5,825	6,970
Construction - Materials	628	628	1,060	1,060
Construction - Fuel	363	363	417	417
Construction - Electricity	6	6	7	7
TOTAL	**3,710**	**5,341**	**7,309**	**8,454**
Annual average (over 108 years)	**34.4**	**49.5**	**67.7**	**78.3**

[11] *GHG Report*, *supra* note 5, p.84.
[12] *Ibid.*, p.54.
[13] *Ibid.*, p.92.
[14] *Ibid.*, Table 10.2, p.108.
[15] CO_2 equivalents (CO_2e) calculated on a 100-year global warming potential of 21 for CH_4 and 310 for N_2O.

Figure 1 demonstrates that the Site C Project would produce annual emissions of 500 to 1000 kt/year CO_2e during the period 2024-2030 – a critical period for emissions *reductions* if Canada is to meet its commitments to reduce GHG emissions by 30% below 2005 levels by 2030.[16] As demonstrated below in section 4.5, the Alternative Portfolio avoids this emissions spike.

Figure 1[17]



3.2 Estimations of greenhouse gas emissions from Alternative Portfolios

In its IRP and in its EIS for the Site C Project, BC Hydro compared three alternative portfolios of resources for meeting the needs for electrical energy and dependable capacity in terms of GHG emissions. These portfolios all make up approximately the same 5,100 GWh of annual energy and 1,100 MW of dependable capacity as the Site C Project, as shown in Table 2.

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[16] Government of Canada. Undated. Canada's INDC Submission to the UNFCC. Available at: http://www4.unfccc.int/submissions/indc/Submission%20Pages/submissions.aspx.
[17] *GHG Report*, *supra* note 5, Table C.4 and Table C.6.

Table 2. BC Hydro's Integrated Resource Plan Portfolios[18]

Portfolios	Clean		Clean + Thermal #1		Clean + Thermal #2		Site C	
	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy	Dependable Capacity	Annual Energy
Supply-side Resources	MW	GWh/year	MW	GWh/year	MW	GWh/year	MW	GWh/year
Site C							1100	5100
GM Shrum	220	0			220			
Revelstoke 6	488	26	488	26	488	26		
Municipal Solid Waste	36	312	36	312	36	312		
Natural Gas (SCGT)			588	924	392	616		
Pumped Storage	500	-364						
Wind		5126		3839		4148		
Totals	1244	5100	1112	5101	1136	5102	1100	5100

The resources included in these portfolios consist of available resources for meeting the needs within regulatory, planning and technical constraints, including the provincial energy objectives in the *Clean Energy Act*.

- Clean portfolio – wind resources for energy, additional capacity at Revelstoke 6, capacity upgrades at G.M. Shrum, municipal solid waste generation, and pumped storage hydro
- Clean + Thermal #1 – wind resources for energy, Revelstoke 6, municipal solid waste generation, and natural gas generation (6 simple cycle gas turbines (SCGTs))
- Clean + Thermal #2 – wind resources for energy, Revelstoke 6, G.M. Shrum, municipal solid waste generation and natural gas generation (4 SCGTs)
- The Site C Project for an in-service date of F2024

The objectives of the *Clean Energy Act*, discussed in section 4.1, include that BC Hydro's rates "remain among the most competitive of rates charged by public utilities in North America."[19] As such, the comparative costs of the portfolios are also relevant to the consideration of the justification of environmental effects. The following table illustrates the present value (PV) cost differences determined by BC Hydro in its IRP, for Site C commissioning in F2024.

[18] *IRP*, *supra* note 2, Chapter 6 Resource Planning Analysis, pp.6-37 to 6-39.
[19] *Clean Energy Act*, SBC 2010, c22, s.2(f).

Table 3. Portfolio present value for Site C base case analysis[20]

Portfolio Type	Portfolios without Site C Portfolio PV (M$)	Portfolios with Site C Portfolio PV (M$)	PV Difference (M$) (Portfolio without Site C minus Portfolio with Site C)
Clean	6,766	6,138	630
Clean + Thermal	6,030	5,883	150

Some observations:

- Developing all clean generation without Site C was found to be about $700 million more expensive than similar portfolios with some thermal generation (i.e. natural gas), as a result of the need to advance costly pumped storage hydro;
- The benefit of Site C compared to the clean + thermal alternative was just $150 million, which represented 1.7% of the estimated cost of Site C of $8.8 billion at the time of sanction.

The Clean + Thermal portfolios therefore provide the most likely alternatives to the Site C Project, while still meeting the requirements of the *Clean Energy Act*, including with respect to GHG emissions and competitive electricity rates.

The most recent project cost estimate for Site C is a Class 2 cost estimate as defined by AACE International, which means that the expected accuracy range in the estimate is -5% to +5%.[21,22] The resources composing the Clean + Thermal portfolios are developed to the feasibility level in the case of capacity upgrades at Revelstoke, the pre-feasibility level for wind, MSW generation and natural gas, and the concept level in the case of capacity upgrades at GM Shrum.[23] This is equivalent to a Class 4 cost estimate for the entire portfolio, and therefore has an expected accuracy range of -15% to +20%. In other words, the perceived economic benefit of Site C over the Clean + Thermal Portfolios is less than the margin of error in the Site C cost estimate, and much less than the margin of error in the estimate of the Clean + Thermal Portfolios. This demonstrates the importance of the recommendation by the JRP that the Site C cost estimate be reviewed by the BC Utilities Commission.[24]

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[20] *IRP*, *supra* note 2, Appendix 6A Portfolio Results, p.6A-36.
[21] United States Society on Dams. 2012. Guidelines for Construction Cost Estimating for Dam Engineers and Owners.
[22] AACE International. 2016. Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries, p.3.
[23] *IRP*, *supra* note 2, Appendix 3A-4: 2013 Resource Options Report Update Resources Options Database (RODAT) Summary Sheets.
[24] *JRP Report*, *supra* note 7, p.280.

Of potential concern, in light of the requirements under the *Clean Energy Act*, is that some of the resources in the Clean + Thermal portfolios, including MSW generation and SCGTs, emit carbon dioxide. Though technology for separating CO_2 from facility exhaust is available, it is costly and untested in BC,[25] and it is unlikely that CO_2 removal technology would be employed for an SCGT considering its relatively small size and limited hours of operation. In addition, these combustion resources, as well as wind generation resources, which play a prominent role in the alternative portfolios, also produce life-cycle GHG emissions as a result of construction activities and materials manufacture.

In its IRP, BC Hydro determined GHG emission rates (in CO_2e/GWh) specific to each supply-side resource, based on direct emissions from fuel combustion.[26] These estimates excluded emissions from other phases of the resource life cycle, including construction, land clearing, emissions embedded in materials, etc. BC Hydro noted that these life cycle emissions are "generally small in comparison to emissions from fuel combustion at a power plant".[27] In the EIS, however, BC Hydro also reported figures for life-cycle emissions, including those related to construction and materials. Table 4 below summarizes the direct GHG emissions from fuel combustion and the life cycle GHG emissions for the various alternative resources. It is striking to note that the value provided in the IRP for GHG emissions from MSW is even greater than that from natural gas generation.

Table 4. Emissions intensity for alternative generation sources

Electricity Resource	IRP[28] Combustion Emissions (t CO_2e/GWh)	EIS Lifecycle Emissions Range[29] (t CO_2e/GWh)	EIS Lifecycle Emissions Average[30,31] (t CO_2e/GWh)
Diesel	--	555 – 880	717
Municipal Solid Waste (MSW)	694	694[32]	694
Natural Gas (SCGTs)	477	469 – 622	545
Solar Photovoltaic	--	13 – 104	58
Wind	0	7 – 22	14

The GHG emissions from SCGTs depend not only upon their operating hours, but also on the frequency of start-ups and shutdowns. BC Hydro did not present information in

[25] *IRP*, *supra* note 2, Appendix 3A-1: 2013 Resource Options Report Update, p.24.
[26] *IRP*, *supra* note 2, Appendix 3A-4: 2013 Resource Options Report Update Appendix 3.
[27] *Ibid*., Appendix 3A-3: 2013 Resource Options Report Update Appendix 2, p.53.
[28] *Ibid*., Appendix 3A-4: 2013 Resource Options Report Update, Resources Options Database (RODAT) Summary Sheets.
[29] *GHG Report*, *supra* note 5, p.106.
[30] *Ibid*.
[31] Average refers to the 100-year average.
[32] The EIS did not provide additional information, so the IRP values are used.

its EIS or its IRP concerning the frequency of start-ups and shutdowns of the SCGTs proposed for the Alternative Portfolio. In a recent submission to the California Energy Commission in relation to the proposed Alamitos Energy Center, the emissions of SCGTs identical to those proposed by BC Hydro[33] were determined to be 633 t CO_2e /GWh, including start-ups, shutdowns and performance degradation over time.[34]

This value is higher than the 545 t CO_2e /GWh presented by BC Hydro in its EIS and as stated in Table 4 above. This results from the higher frequency of start-ups and shutdowns (500 per year, or 1 per every 4 hours of operations) and different assumptions concerning global warming potential, emission factors, thermal efficiencies, performance degradation and other input variables. For example, presuming that BC Hydro operates the facilities 16-hours per day during the winter cold snaps as proposed, the number of start-ups and shutdowns would be 1 per every 16 hours of operations, far fewer than the 1 per 4 hours of operations used in the analysis of the Alamitos Energy Center.[35] This lower frequency of start-up and shutdown cycles lowers the average GHG emissions found in the case of the Alamitos Energy Center from 633 to 593 t CO_2e /GWh.

Lacking detailed operational information for the SCGTs proposed in the Alternative Portfolio, and the full slate of assumptions underlying BC Hydro's determination of the GHG emissions intensity for SCGTs, the analyses in this briefing note utilize the 545 t CO_2e/GWh presented by BC Hydro in its EIS. Referral of the Site C Project to the BC Utilities Commission would allow for further exploration of these matters.

Table 5 summarizes the GHG emissions for the "Clean + Thermal #2" portfolio in the 2013 IRP (the "Alternative Portfolio"), based on the emissions intensities in Table 4. As Table 5 illustrates, BC Hydro determined the emissions of the Alternative Portfolio to be 511 kt CO_2e/year in its IRP considering only combustion during operations. Considering life-cycle emissions, based on emissions intensities reported in the EIS, this total increases to 611 kt CO_2e/year. For context, a typical natural gas combined cycle generating turbine operating to produce 5,100 GWh/year would emit more than four times as much (2,780 kt CO_2e/year).

Indeed, the Alternative Portfolio produces much lower emissions than an "all gas" alternative to the Site C Project. Nevertheless emissions still exceed those of the Site C Project by about 500 kt or 0.5 Mt CO_2e/year. However, the analyses presented by BC Hydro in the IRP and the EIS did not seek to minimize the GHG emissions in the Alternative Portfolio by optimizing the selection and operation of the available resources. Further optimization is readily available, and the proposed approaches below focus on further lowering the emissions of the Alternative Portfolio without increasing its costs.

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[33] GE Power LMS100 gas turbines.
[34] AES Alamitos Energy , LLC, April 12, 2016. Alamitos Energy Center Supplemental Application for Certification (13-AFC-01) Revised Air Quality, Biological Resources, and Public Health Assessment, Table 5.1B.23. Available at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=13-AFC-01.
[35] *Ibid*.

Table 5. GHG Emissions – Alternative Portfolio

		IRP		EIS	
	Annual Generation[36]	GHG Combustion Emissions Intensity	GHG Combustion Emissions	GHG Lifecycle Emissions Intensity	GHG Lifecycle Emissions
Resources	(GWh/year)	(t CO_2e/GWh)	(kt CO2e/year)	(t CO_2e/GWh)	(kt CO2e/year)
GM Shrum[37]	0	0	0	0	0
Revelstoke 6	26	0	0	0	0
MSW[38]	312	694	217	694	217
Natural Gas	616	477	294	545	336
Wind[39]	4148	0	0	14	58
Totals	**5102**		**511**		**611**

[36] *IRP*, *supra* note 2, Chapter 6 Resource Planning Analysis, Table 6-9, p.6-39.
[37] Lifecycle GHG emissions for capacity upgrades at GM Shrum and Revelstoke 6 are unavailable and presumed to be zero for comparison purposes. Eventual turbine replacement at the Site C Project is also presumed to have no GHG emissions.
[38] Lifecycle GHG emissions for MSW generation other than in relation to combustion are unavailable and presumed to be zero for comparison purposes.
[39] *EIS*, *supra* note 4, Volume 2, Section 15: Greenhouse Gases, Table 15.11 Emissions Intensity – Project Compared with other Generation.

4. Optimizing the resources in the Alternative Portfolio

4.1 Replacing MSW generation with SCGTs and wind

In its analysis, BC Hydro makes use of MSW generation as part of the Alternative Portfolio. MSW generation involves the incineration of municipal solid waste to produce electricity, following pre-processing of waste to remove oversized, non-combustible, hazardous or explosive materials. MSW generation is generally promoted by the province as part of a strategy to manage municipal solid waste in British Columbia.[40]

Though MSW generation is a "clean" resource in the *Clean Energy Act*, it actually produces very high GHG emissions (694 t CO_2e /GWh), on par with diesel generation (717 t CO_2e/GWh). Replacing the MSW generation resource from the Alternative Portfolio with a combination of SCGTs and wind can provide the capacity and energy of MSW generation while producing much lower GHG emissions at comparable cost.[41] More specifically, replacing the 37 MW of dependable capacity and 312 GWh/year of firm energy provided by the MSW generation with additional SCGTs and wind in the Alternative Portfolio reduces its GHG emissions by 182 kt CO_2e/year. This reduction occurs because the emissions intensity of a combination of wind and natural gas is much lower than the emissions intensity of MSW generation.

4.2 Optimizing the operations of simple-cycle gas turbines (SCGTs)

The *Clean Energy Act* establishes that at least 93% of the electricity in British Columbia must come from clean (i.e. non-greenhouse gas emitting) or renewable resources. Currently, high-GHG resources account for some 6% of BC Hydro's electricity supply, leaving a "GHG headroom" of around 500 GWh/year available for non-clean resources.[42] In its IRP, BC Hydro concluded that the best strategy is to reserve the GHG headroom as a capacity and contingency resource, particularly in the event of rapidly increasing electricity requirements resulting from LNG development.[43]

In its analysis, BC Hydro assumes that a typical 100 MW SCGT would produce 154 GWh of energy per year, and associated GHG emissions. This implies that SCGTs, which are acquired as capacity resources for peaking purposes, would operate 18% of the time, or 1577 hours per year. This is the equivalent of operating 16 hours a day, 6 days a week, for four months a year. The effect of this assumption is not inconsequential, as the greater the annual hours of operation, the greater the annual emissions. The GHG emissions of SCGTs depend upon both their hours of service and on the frequency of start-ups and shutdowns.

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[40] BC Energy Mines and Petroleum Resources. Undated. BC Bioenergy Strategy: Growing our Natural Energy Advantage. Available at: http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_bioenergy_strategy.pdf.

[41] For a list of resource costs see: *IRP*, *supra* note 2, Appendix 6A, p. 6A-27.

[42] 3500 GWh/year from Fort Nelson, Prince Rupert, McMahon Cogen and the Island Generation Plant. *IRP*, *supra* note 2, Chapter 6 Resource Planning Analysis, p.6-10.

[43] *Ibid*., p.6-21.

BC Hydro notes that its capacity resources must be available to operate during "a 16-hour block per day for a two week cold snap that can happen at least three times per year anytime during the winter."[44] Typically, cold snaps occur once or twice during the critical winter period between November and February.[45] BC Hydro also clarifies that the heavy load hours during a winter peak exclude Sundays and statutory holidays.[46]

The BC Hydro analysis confuses the hours that the SCGTs need to be *available* to operate (i.e. the daily peak hours during the critical winter period) with the hours that the SCGTs will be *called upon* to operate, which will be much fewer.[47] If there are three two-week cold snaps (or ~35 heavy load days, excluding Sundays and holidays) during the critical winter period, with the SCGTs operating 16 hours each of those days, they would operate for 560 hours per year, for a capacity factor of 6.4% (about a third of the service hours assumed by BC Hydro). This is consistent with the findings of the U.S. Energy Information Administration, which concluded that the average annual capacity factor, for each of the past 8 years, of all SCGTs in operation in the United States ranged from 4.5% to 6.7%.[48] The actual number of hours that BC Hydro would operate any SCGTs during a cold snap would sometimes be less than 16 hours each day, and the average annual number of cold snaps would be fewer than the three assumed in this estimate, based on historical patterns.

In summary, BC Hydro's assumption of a high capacity factor for SCGTs penalizes the Alternative Portfolio by overstating its annual GHG emissions. Assuming operation of the SCGTs at a 5% capacity factor in a manner consistent with industry practice and with the stated frequency and duration of cold snaps, accounting for the reduced energy production from the SCGTs with additional wind resources, and adding in the life-cycle GHG emissions from these wind resources, would reduce GHG emissions in the Alternative Portfolio by 236 kt CO_2e/year.

4.3 Developing capacity-focused DSM to offset or replace SCGTs

While most DSM programs do reduce capacity as well as energy requirements, until recently reducing capacity requirements has not been the primary focus in DSM program design. Programs designed specifically to reduce capacity requirements are referred to as "capacity-focused DSM".

Assumptions made in approving the Site C Project

In the load resource balance presented in its 2013 IRP, BC Hydro identified a need for capacity by F2019, at least five years before a need for energy. In the 2016 load

[44] BC Hydro. 2015. BC Hydro 2015 Rate Design Application ['RDA'], Appendix C-5A, p.96.
[45] BC Ministry of Energy and Mines. 2013. U.S. Benefits from the Columbia River Treaty – Past, Present and Future: A Province of British Columbia Perspective, p.14.
[46] *Ibid*., p.46.
[47] Raphals, P. Need for, Purpose of and Alternatives to the Site C Hydroelectric Project (CEAR #63919-1952), pp.16-18; Raphals, P. January 18, 2014. Response to BC Hydro Rebuttal Evidence (CEAR #63919-2548), pp.14-18.
[48] U.S. EIA. 2016. Electric Power Monthly. Table 6.7.A Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels. Available at: http://www.eia.gov/electricity/monthly/.

resource balance update, the requirement for capacity has shifted to F2020.[49] In response to this future need, and recognizing the prioritization of DSM in the *Clean Energy Act*, BC Hydro identified two types of capacity-focused DSM with substantial potential:[50]

- 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.

As a result, the potential for capacity-focused DSM savings identified in the IRP total 575 MW – over 50% of the capacity of Site C, and over 140% of the capacity of the SCGTs in the Alternative Portfolio. However, noting the uncertainty in the potential quantity of capacity-focused DSM savings actually achievable, BC Hydro elected to "not yet rely on capacity savings from capacity-focused DSM for resource planning purposes." Instead, in the face of this short-term uncertainty respecting the contribution of capacity-focused DSM, BC Hydro assumed that for long-term planning purposes these options would make no contribution to the utility's capacity needs and would deliver **0 MW** over the next 20 years.[51]

The utility recommended further study of capacity-focused DSM as one of the recommendations of the 2013 IRP. As called for in Recommended Action #2, BC Hydro completed a pilot study of automated demand response and direct load control, both effective forms of capacity-focused DSM.[52] The study identified a potential of 53 MW of reliable winter capacity reduction in the Kamloops area alone.[53] This result exceeded by far the 30 MW target set by BC Hydro for this region, which represents approximately 10% of the Provincial industrial electricity demand – implying a province-wide potential on the order of 500 MW. BC Hydro is continuing with these and other pilot programs.[54]

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[49] *RDA*, *supra* note 44, Evidentiary Update on Load Resource Balance and Long Run Marginal Cost, p.13.
[50] *IRP*, *supra* note 2, Chapter 3 Resource Options, p.3-22. In its 2012 Draft IRP, BC Hydro had also proposed a third option, time-of-use (TOU) rates, but it abandoned this approach – at the same time as it launched a province-wide smart-meter program, which for the first time made broad-based TOU rates a realistic option.
[51] Raphals, P. 2013. Need for, Purpose of and Alternatives to the Site C Hydroelectric Project (CEAR #63919-1952), pp.19-26; Raphals, P. January 18, 2014. Response to BC Hydro Rebuttal Evidence, (CEAR #63919-2548), pp. 21-24.
[52] Enbala Power Networks. Undated. Capacity Focused Demand Side Management at BC Hydro: Industrial and Commercial Potential in the Kamloops Region.
[53] The study was based on a 4-hour curtailment period, but BC Hydro also has up to 16-hour requirements to meet shoulder capacity needs.
[54] BC Hydro. 2015. Load Management Demonstration Project. Available at: https://www.bchydro.com/powersmart/business/load-management.html; BC Hydro. 2015. Load Curtailment Pilot. Available at: https://www.bchydro.com/powersmart/business/load-curtailment-pilot.html.

New information since the approval of the Site C Project

Despite its decision not to include any capacity-focused DSM in its 2013 IRP, BC Hydro stated the following in its recently filed 2015 Rate Design Application (RDA):

> In BC Hydro's view, load curtailment potentially offers a better avenue [than time of use pricing (TOU)] to avoid costly generation capacity resource additions because it is targeted at capacity, is more reliable (particular with aspects of demand control), and in contrast to TOU, load curtailment is dispatchable.
>
> …the 2013 IRP identifies that 400 MW of SCGTs would be required by F2020 if LNG projects proceed. There is an opportunity to reduce the amount of gas-fired generation that might be required through the development of load curtailment.[55] [emphasis added]

In other words, BC Hydro now acknowledges the substantial benefits of load curtailment to reduce the 400 MW of SCGTs required in the event that LNG projects proceed, and yet no similar consideration was given in the 2013 IRP to utilizing load curtailment to reduce the 400 MW of SCGTs in the Alternative Portfolio. While the RDA does not yet quantify the magnitude of the capacity reduction resulting from load curtailment, it is clearly anticipated to be **more than the 0 MW presumed in the IRP**.

If capacity-focused DSM had been given appropriate consideration in the 2013 IRP, it would have contributed to deferring for several years the need for the Site C Project, a very costly capacity resource addition.[56] Based on the recent information in the 2016 load resource balance update, over the coming decade each 100 MW of capacity-focused DSM delays the need for new resources by one year in the "Expected LNG" scenario[57] and by more than two years in a scenario where LNG does not materialize.[58]

Experience in neighbouring jurisdictions

In its RDA, BC Hydro also undertook a jurisdictional review of load curtailment programs at winter-peaking Canadian utilities. The review reported that all of these programs were optional, and that most of the programs had maximum curtailment durations of 4 hours.[59] No information concerning success of these Canadian programs was provided in the RDA. In addition, no similar review was undertaken for winter-peaking American utilities, many of which have been employing capacity-focused DSM (also known as "demand response") for many years. According to the US Energy Information

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[55] *RDA*, *supra* note 44, Appendix C-5A, p.107.

[56] In the environmental assessment hearings, unrebutted evidence was presented before the JRP to the effect that, as long as the Site C Project's energy production is surplus to BC's needs, the unit capacity cost of the project is between $150 and $350/kW-year – far more expensive than other capacity resources, including those listed in *IRP*, *supra* note 2, Appendix 6A, p. 6A-27. See Raphals, P. January 18, 2014. Response to BC Hydro Rebuttal Evidence (CEAR #63919-2548), p.9.

[57] BC Hydro estimated that future requirements of the LNG industry could range from 800 to 6,600 GWh/year (100 to 800 MW) with an Expected LNG load of 3,000 GWh/year and 360 MW by F2022.

[58] *RDA*, *supra* note 44, Evidentiary Update on Load Resource Balance and Long Run Marginal Cost, p.13.

[59] *RDA*, *supra* note 44, Appendix C-5A, p.107.

Administration, peak capacity savings (winter and summer) from demand response in the U.S. totalled 12,700 MW in 2014, and these numbers are expected to increase considerably in the coming years.[60] In the PJM Interconnection alone, 2,500 MW of winter demand response was called into action during certain critical hours in January 2014.[61]

Since the approval of the Site C Project in December 2014, the Northwest Power and Conservation Council (NPCC) released its Seventh Northwest Conservation and Electric Power Plan.[62] NPCC issues its 20-year plan every five years for the states of the Pacific Northwest. This region consists of both public and investor-owned utilities that collectively comprise an electrical system that is about three times the size of BC Hydro's integrated system, but is similar in demand profile (winter peaking) and resource mix (substantial hydroelectric resources).

Like BC Hydro, the NPCC assesses demand response primarily for the purpose of reducing peak load and, specifically, for deferring the development of new generation and transmission assets. In relation to winter demand response potential, which is most relevant to BC Hydro, the NPCC identified approximately 3,500 MW of regional winter demand response potential over the 20-year planning period. Nearly 1,500 MW is available at less than $32 per kilowatt of peak capacity per year (kW-year), and an additional 1,200 MW at less than $71 per kW-year.[63] This 2,700 MW represents approximately 6% of winter peak load in the Pacific Northwest. Several utilities in the Pacific Northwest are now implementing winter demand response, including PacifiCorp (149 MW), Portland General Electric (28 MW), and the Bonneville Power Administration (60 MW).[64]

BC Hydro estimated the cost of its capacity-focused DSM programs at $69 per kW-year,[65] similar to that determined by the NPCC for the Pacific Northwest. In BC, 6% of winter peak capacity would be equivalent to about 700 MW of demand response potential. This provides further indication that the magnitude of potential demand response savings is **much greater than the 0 MW presumed in the IRP**.

Integrating capacity-focused DSM in the alternative portfolio

Including the additional capacity from SCGTs used to replace MSW generation noted above in Table 2, the Alternative Portfolio would have 436 MW of SCGTs. Developing about 40% of the 575 MW of potential capacity savings from the capacity-focused DSM measures identified in the IRP would offset half of the SCGT capacity contemplated in

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[60] U.S. Energy Information Administration. 2016. Today in Energy: Demand response saves electricity during times of high demand. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=24872.
[61] FERC. December 2014. Assessment of Demand Response and Advance Metering (staff report), p.12. Available at: http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf.
[62] Northwest Power and Conservation Council. 2016. Seventh Northwest Conservation and Electric Power Plan. Available at: http://www.nwcouncil.org/energy/powerplan/7/plan/.
[63] *Ibid.*, Table 14-2. (values converted to Canadian dollars).
[64] *Ibid*., Table 9-1.
[65] *IRP*, *supra* note 2, Chapter 3 Resource Options, Table 3-6, p.3-28.

the Alternative Portfolio. Developing 80% of the potential capacity savings from these capacity-focused DSM measures (supplemented as required with energy storage, as described below) would offset *all* of the SCGT capacity in the Alternative Portfolio. With SCGTs operated at a 5% capacity factor, these two levels of capacity-focused DSM would result in net annual GHG emissions from the Alternative Portfolio of 119 kt CO_2e/year and 68 kt CO_2e/year, respectively (see Table 6).

Though capacity-focused DSM is reliable and dispatchable, relying on it to replace most or all of the contemplated SCGTs raises complex questions best explored through a review before the BC Utilities Commission. First, though BC Hydro's load curtailment and capacity-focused DSM programs show promise and are anticipated to provide much more than the 0 MW presumed in the IRP, they remain at the pilot phase, with the ultimate effectiveness of the measures to be determined over the next few years. Second, in addition to requiring peak capacity, the BC Hydro system becomes energy constrained in the shoulder hours before and after the peak period on winter days during a cold snap. This means that the capacity resources must at times be available for up to 16-hour periods, which is longer than the 4-hour period typical of load curtailment and capacity-focused DSM programs in other jurisdictions.

These uncertainties may – or may not – limit the extent to which capacity-focused DSM can offset the operation or requirements for SCGTs. If necessary, capacity-focused DSM can also be supplemented with energy storage technologies, which are fast becoming a viable resource in electricity systems across North America. Though costs remain high, they continue to decline rapidly.[66] Ontario recently procured 33.5 MW of energy storage and is proceeding with additional procurement to a total of 50 MW.[67] Of particular interest in the current context, San Diego Gas & Electric recently contracted for both a 20 MW lithium ion battery energy storage facility and 18.5 MW of DSM capacity savings.[68] Considering that the need for SCGTs in the Alternative Portfolio does not arise until F2027, BC Hydro has ten years to benefit from additional declines in the costs of battery and other energy storage, improving the prospects that the Alternative Portfolio could proceed with very limited, if any, use of SCGTs.

4.4 Summary

The above discussion illustrates several approaches available for optimizing the GHG emissions from the Alternative Portfolio. The resulting GHG emissions for each of these approaches are summarized in Table 6, along with the values presented previously in Table 5. This analysis indicates that the environmental assessment process for the Site C Project overlooked opportunities to reduce the lifecycle GHG emissions of the

[66] Bloomberg New Energy Finance. April 14, 2015. Bloomberg New Energy Finance Summit. Presentation by Michael Liebreich. Lithium-Ion Battery Experience Curve ['BNEF'], p.12. Available at: http://about.bnef.com/content/uploads/sites/4/2015/04/Final-keynote_ML.pdf.

[67] IESO. 2016. Energy Storage Procurement. Available at: http://www.ieso.ca/Pages/Participate/Energy-Storage-Procurement/default.aspx.

[68] SDG&E. 2016. SDG&E Adding New Technologies to Harness Clean Energy, Efficiencies. Available at: http://www.sdge.com/newsroom/press-releases/2016-03-31/sdge-adding-new-technologies-harness-clean-energy-efficiencies.

Alternative Portfolio by more than 500 kt CO_2e/year (i.e. from 611 kt CO_2e/year to 68 kt CO_2e/year).

Table 6. Annual GHG Emissions Estimates – Optimized Alternative Portfolio

	IRP	EIS	Optimized Lifecycle Emissions		
Alternative Portfolio	**GHG Combustion Emissions**	**GHG Lifecycle Emissions**	**No MSW, 5% SCGT**	**No MSW, 5% SCGT, DSM for 50% of SCGTs**	**No MSW, 5% SCGT, DSM + storage for all SCGTs**
Resources	**(kt CO_2e/year)**	**(kt CO_2e/year)**	**(kt CO_2e/year)**	**(kt CO_2e/year)**	**(kt CO_2e/year)**
GM Shrum	0	0	0	0	0
Revelstoke 6	0	0	0	0	0
MSW	217	217	0	0	0
Natural Gas (SCGTs)	294	336	102	51	0
Wind	0	58	68	68	68
Totals	**511**	**611**	**171**	**119**	**68**

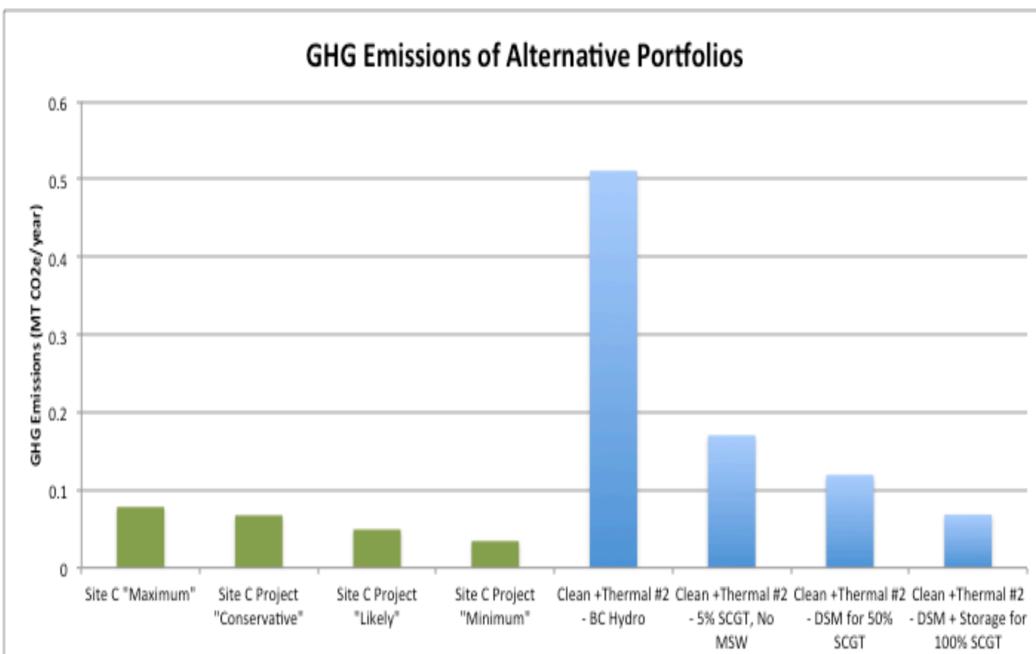
5. Magnitude of the GHG emissions in context

5.1 Magnitude of GHG emissions

Optimizing the Alternative Portfolio, as described in section 4, substantially reduces its GHG emissions. The green bars in Figure 2, below, illustrate the annual average GHG emissions of the Site C Project, based on the estimates summarized in Table 1 above. The tall blue bar represents the GHG emissions of the Alternative Portfolio as developed by BC Hydro; the shorter bars illustrate the optimized approaches to this portfolio, as summarized in Table 6. These optimizations do not include the potential for further future reductions in GHG emissions from the Alternative Portfolio, or potential reductions from export of the Site C Project energy surplus, as discussed below.

As shown in Figure 2, the GHG emissions from the fully optimized Alternative Portfolio are equal to BC Hydro's "conservative" estimate of emissions from the Site C Project, and less than its "maximum" estimate. The GHG emissions reduction benefit of the Site C Project compared to an optimized Alternative Portfolio is *at most* 0.1 Mt CO_2e/year, equivalent to just 0.15% of British Columbia's annual GHG emissions,[69] or 3 days per year of operations of the proposed Pacific Northwest LNG export facility.[70,71]

Figure 2



[69] Government of British Columbia. 2015. Summary of B.C. Greenhouse Gas Emissions: 1990-2013. Available at: http://www2.gov.bc.ca/gov/content/environment/climate-change/reports-data/provincial-ghg-inventory-report-bc-s-pir.

[70] Stantec. 2014. Pacific NW LNG Environmental Impact Statement and Environmental Assessment Certificate Application Section 7: Greenhouse Gas Management, p.7-14.

[71] Environment Canada. 2016. Pacific Northwest Liquefied Natural Gas (LNG) Project Review of Related Upstream Greenhouse Gas (GHG) Emissions Estimates. Available at: http://www.ceaa-acee.gc.ca/050/documents/p80032/104795E.pdf.

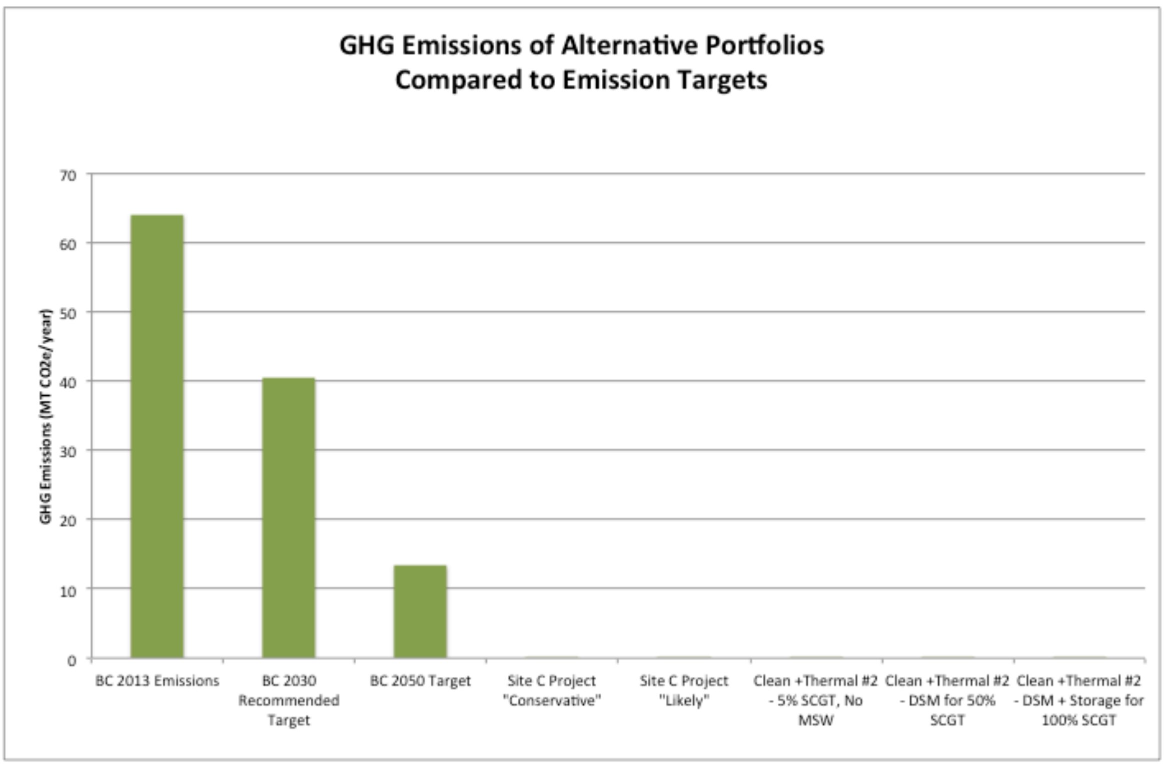
5.2 BC GHG emission reduction targets

In order to place in context any differences between portfolios in terms of GHG emissions, it is instructive to compare them against the current emissions and emission reduction targets for British Columbia, as shown below in Figure 3.

Once viewed at the appropriate scale, the differences between the portfolios are revealed to be extremely small. This disproves the common perception that the Site C Project provides a substantial benefit in terms of GHG emission reductions compared to the available alternatives.

As shown in Figure 2, above, the optimized Alternative Portfolio (0.068 Mt CO_2e/year to 0.171 Mt CO_2e/year), differs from the Site C Project "conservative" scenario (0.068 Mt CO_2e/year) by *at most* 0.1 Mt CO_2e/year. **This difference represents about 0.15% of BC's current emissions**, 0.25% of BC's 2030 target emissions and 0.75% of the BC's 2050 target emissions.

Figure 3

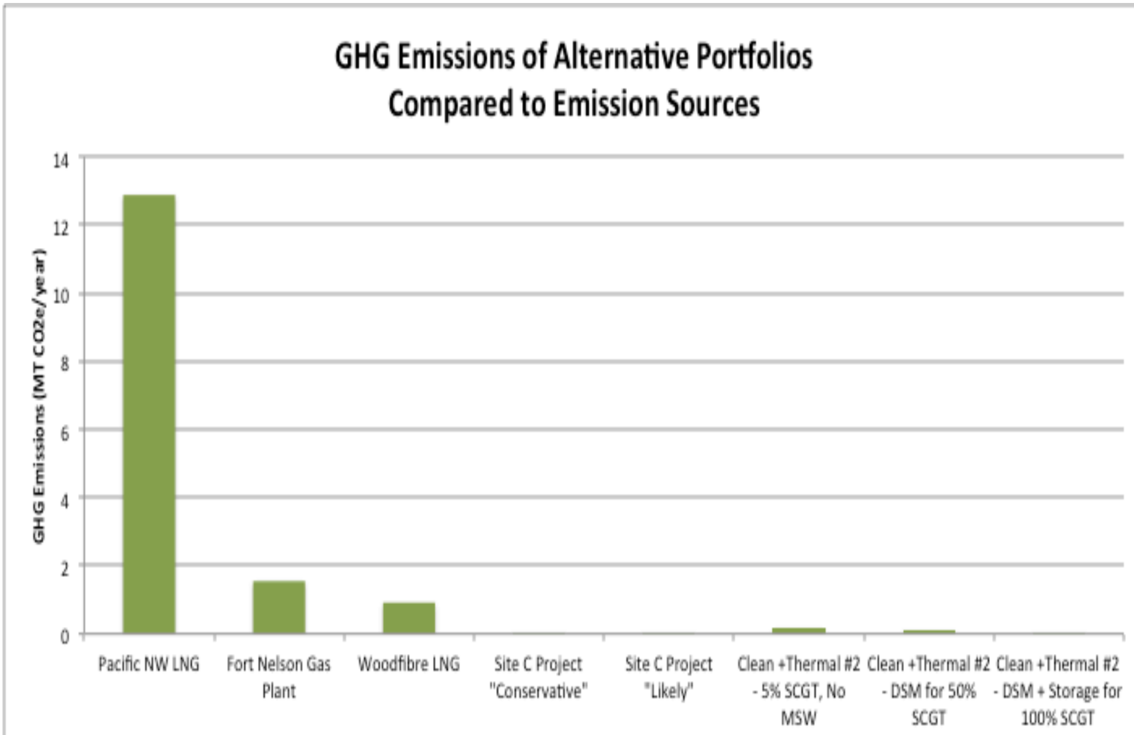


5.3 Other BC GHG emissions

The maximum 0.1 Mt CO_2e/year difference between the Site C Project and the optimized Alternative Portfolio in terms of GHG emissions can also be considered in the context of other existing and potential future emission sources in British Columbia, as shown below in Figure 4.

The potential GHG emission reduction benefits of the Site C Project compared to the optimized Alternative Portfolio, if they exist at all, are about 7% of the annual emissions of the largest existing single emitter in the Province, the Spectra Energy Fort Nelson Gas Plant, as shown in Figure 4. The recently-approved Woodfibre LNG facility, even with its relatively low emissions intensity per tonne of LNG, is nearly 10 times the maximum annual GHG emission benefits of Site C compared to the optimized alternative portfolio. Were the Pacific Northwest LNG export facility to be approved, its annual emissions would be more than 120 times the potential GHG emissions benefits of Site C, and would also represent over 95% of British Columbia's 2050 emissions reduction target set out in the *Clean Energy Act*.

Figure 4[72,73,74,75]



[72] Stantec. 2014. Pacific NW LNG Environmental Impact Statement and Environmental Assessment Certificate Application Section 7: Greenhouse Gas Management, p.7-14.
[73] Environment and Climate Change Canada. 2016. Pacific Northwest Liquefied Natural Gas (LNG) Project Review of Related Upstream Greenhouse Gas (GHG) Emissions Estimates. Available at: http://www.ceaa-acee.gc.ca/050/documents/p80032/104795E.pdf.
[74] Environment Canada. 2014. Greenhouse Gas Emissions Reporting Program Online Data Search – Facility Reported Data.
[75] Environment and Climate Change Canada. February 1, 2016. Woodfibre Liquefied Natural Gas (LNG) Project Review of Related Upstream Greenhouse Gas (GHG) Emission Estimates. Available at: http://www.ceaa-acee.gc.ca/050/documents/p80060/104688E.pdf.

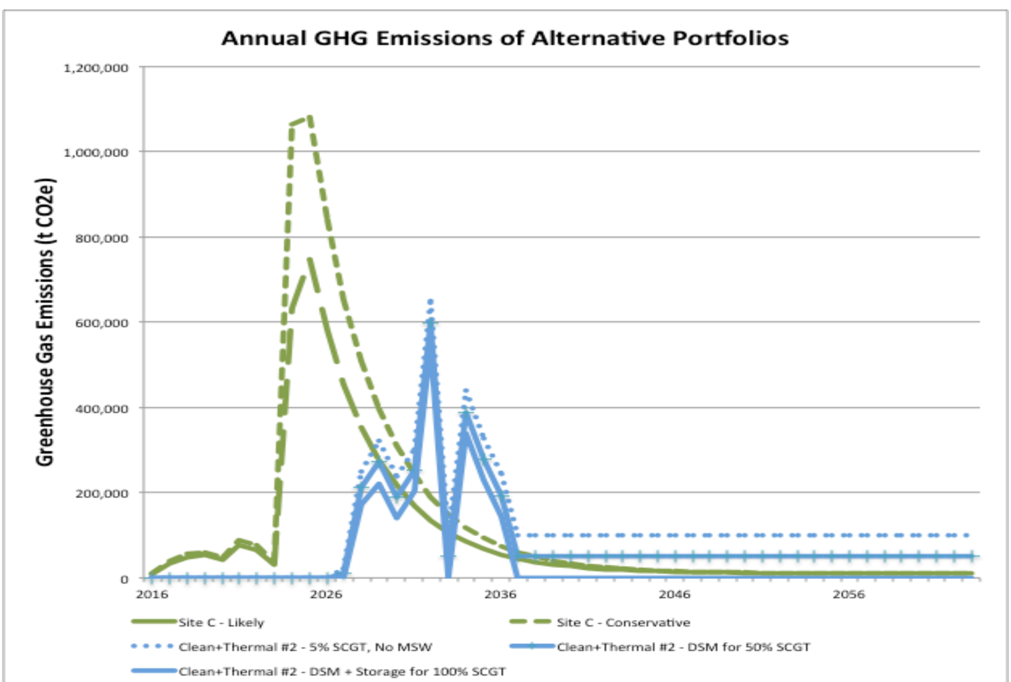
6. Additional considerations for comparing GHG emissions

6.1 Future opportunities for further GHG emission reductions

The GHG emissions analysis presented by BC Hydro in the IRP assumes that the electricity generation resources comprising the Alternative Portfolio will come into service all at once at the same time as the Site C Project. In fact, the resources in the Alternative Portfolio will be brought into service incrementally, only if and when required in response to increases in demand for energy and capacity. This reflects an advantage for the Alternative Portfolio that is not reflected in BC Hydro's analysis.

BC Hydro's presentations of cumulative and annualized GHG emissions both mask the fact that the GHG emissions for the Site C Project commence a full decade earlier than those of the Alternative Portfolio. As shown in Table 1, the GHG emissions of the Site C Project appear modest, but this is the result of the averaging of these emissions over a 108-year period. Site C entails the inevitable and immitigable release of 4 Mt CO_2e emissions or more before 2035, as a result of construction-related emissions and the fact that reservoir emissions are concentrated in the early years following inundation. Figure 5 illustrates this situation, where annual GHG emissions of the Site C Project rise sharply following inundation before declining over the next 20 years.[76] The Alternative Portfolio follows a similar, though smaller, pattern as a result of the development of wind resources over a 10-year period beginning in 2028.

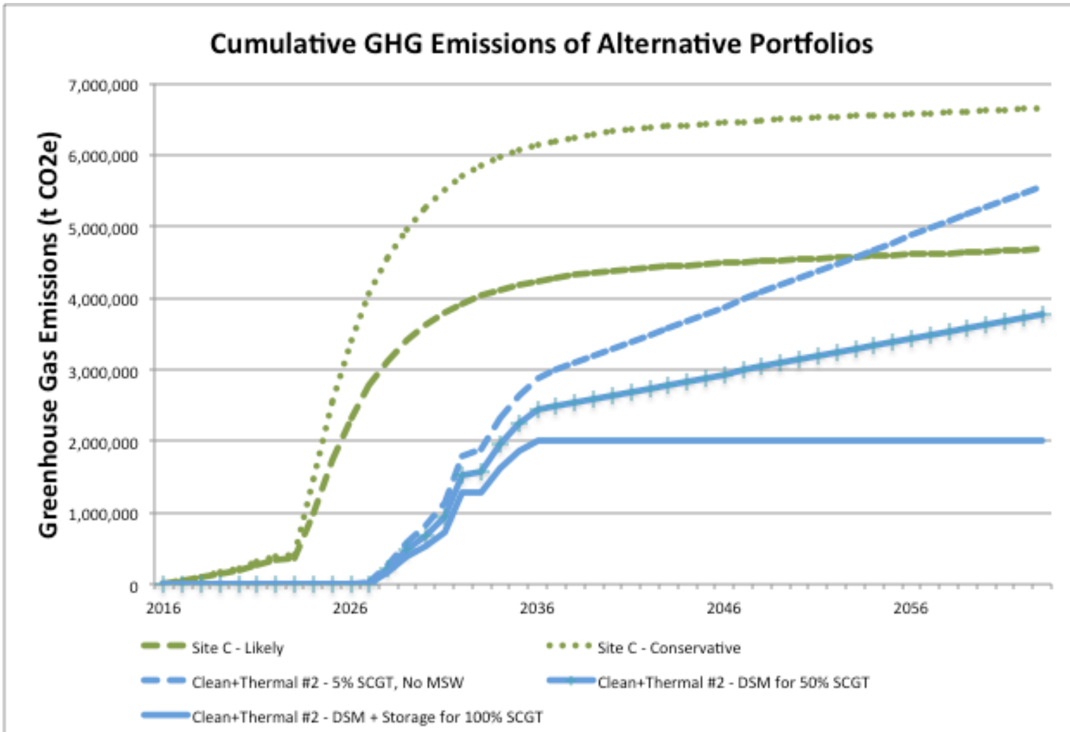
Figure 5.



[76] *GHG Report*, *supra* note 5, Table C.4 and Table C.6.

Figure 6 shows the cumulative GHG emissions of the Site C Project under the "likely" and "conservative" scenarios as well as the emissions of the optimized Alternative Portfolio presented in Table 6, with the resources developed over time based on the most likely resource sequence from the 2013 IRP.[77] As the figure illustrates, **depending on the extent of portfolio optimization, it will be several decades before the GHG emissions of the Alternative Portfolio exceed those of the Site C Project, if ever.**

Figure 6.



This situation arises because the Site C Project entails a relatively large "pulse" of GHG emissions in the early years of operations, while the Alternative Portfolio commences with the development of capacity upgrades at Revelstoke and GM Shrum, which require no additional reservoir creation and result only in minimal GHG emissions associated with equipment manufacture and construction. Natural gas generation would not be required in the Alternative Portfolio until at least 2027, and wind generation until 2028, under the mid-load electricity demand scenario.[78] These dates may be even later as a result of lower than expected demand growth, further delays or cancellations of LNG export facilities, increased self-generation, additional DSM, electricity storage, renewable fuel standards for natural gas, or other factors. An optimized Alternative Portfolio that excludes MSW generation, operates SCGTs only as necessary during

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[77] *IRP*, *supra* note 2, Appendix 6A, p. 6A-27. This resource sequence was used for BC Hydro's present value cost analysis and includes resources developed after the resources contained in the Clean + Thermal #2 portfolio used for GHG emission comparisons.
[78] *Ibid*.

peak demand periods, and avails of contributions from DSM and storage (the lowermost blue line in Figure 5) will remain indefinitely below the cumulative GHG emissions of the Site C Project.

Even if the Alternative Portfolio is initially developed with SCGTs operating at a given capacity factor, over time this capacity factor can be reduced with additional capacity-focused DSM. The SCGTs can also be replaced at the end of their useful life with lower emission technologies, or the GHG emissions intensity of the natural gas can be lowered through a renewable fuel standard. An optimized Alternative Portfolio (the uppermost blue line in Figure 6) that initially avails of no capacity-focused DSM, no lower emission technologies and no renewable fuel standard has nearly 40 years to "bend the curve" below the GHG emissions of the Site C Project.

Beyond 2035, the GHG emissions in the Alternative Portfolio are depicted as changing linearly over time, due to ongoing fuel consumption. This is unlikely to be the case. One of the factors driving the use of SCGTs is their low capital cost, which means that they can be replaced in the future as better technologies arise, without significant capital loss. Furthermore, though these data do not take into account the replacement of wind turbines, with resulting manufacturing emissions, they also do not include the eventual turbine replacement for the Site C Project. Operations and maintenance activities would also contribute modest GHG emissions to both Site C and the Alternative Portfolio. These emissions are minimal or far in the future compared to the emissions from initial project development and inundation at Site C, and compared to initial development of wind resources and operation of SCGTs, if any, in the optimized Alternative Portfolio.

Ten years is a long time in the electricity business. Forty years is a technological eternity. Between 2005 and 2015, the average price of natural gas fell from US$8.69 to US$2.62 per million Btu, a remarkable decline of 70%, as a result of largely unanticipated technological developments.[79] Utility scale solar PV systems declined by that same percentage in just over half that time.[80] Over a forty-year period, the price of silicon crystalline photovoltaic cells has declined by over 99%.[81] An optimized Alternative Portfolio has available to it all of the technological advances of the coming four decades or longer that would allow for additional reductions in potential GHG emissions in order to remain well below the emissions of the Site C Project.

This opportunity for improvement is unavailable to the Site C Project, since once it is constructed and operating, its GHG emissions are certain to occur.

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[79] U.S. EIA. Henry Hub Natural Gas Spot Price (Annual). Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.
[80] U.S. Department of Energy. 2015. Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. 2015 Edition, p.19.
[81] *BNEF*. *supra* note 66.

6.2 GHG emission reductions resulting from potential Site C exports

Site C not assessed for export purposes

The need for the Site C Project was framed by BC Hydro in the context of domestic residential, commercial and industrial electricity requirements. In its IRP, BC Hydro concluded that there were no economically viable export opportunities:

> BC Hydro concludes that, aside from monitoring, there are no actions BC Hydro should be taking because there are no suitable opportunities for the export of electricity from clean or renewable B.C. resources for the foreseeable future.
>
> Consequently, BC Hydro does not perceive, at this time, any value in continuing to investigate and develop potential market opportunities for export sales. …[C]urrent market conditions do not warrant expenditures for export, and no expenditures are planned as part of the Recommended Actions.[82]

The Site C Project was not proposed as an export facility, either to meet the needs of export markets in the United States, or to meet potential future market opportunities that may be available as a result of Alberta's decision to shutter its coal generation by 2030.[83]

> Since the enactment of the CEA, the prospects of export sales of clean or renewable energy in excess of that required to meet B.C. self-sufficiency requirements have diminished considerably. Further, the prospects of such sales are not expected to materially improve over the short to medium term. The reasons include a significant recent increase in renewable energy resources in the WECC [Western Electricity Coordinating Council], the persistence of tax incentives available to U.S. producers, and the enactment of RPS standards in potential markets, particularly California, that exclude many clean or renewable B.C. resources.[84]

In other words, the purpose of the Site C Project, as proposed by BC Hydro, as evaluated in the IRP, and as assessed during the environmental assessment by the JRP was to meet British Columbia's domestic electricity requirements and not those of some other jurisdiction. The Site C Project was not evaluated in the export context.

Potential GHG emission reductions in Alberta

Despite the lack of prior evaluation by BC Hydro, the Provincial government has acknowledged that it is now considering exporting energy and capacity from the Site C

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[82] *IRP*, *supra* note 2, Chapter 5 Planning Environment, pp. 5-53 to 5-54.
[83] Government of Alberta. 2016. Climate Leadership – Ending Coal Pollution. Available at: http://www.alberta.ca/climate-coal-electricity.cfm
[84] *IRP*, *supra* note 2, Chapter 5 Planning Environment, p.5-51.

Project to Alberta.[85] This raises the potential that electricity generated at Site C could reduce GHG emissions from the electricity sector in the neighbouring Province. Whether this occurs would depend on the extent to which electricity from the Site C Project displaces competing electricity generation with a higher or lower GHG emissions intensity.

Alberta has recently indicated that: "By 2030, two-thirds of Alberta's coal generating capacity will be replaced by renewable energy; one-third will be replaced by natural gas."[86] This is an important consideration in evaluating the potential GHG emissions reductions from the Site C Project, namely that coal generation will be replaced in Alberta regardless of whether or not energy or capacity from the Site C project is exported there. **Site C would not necessarily displace coal generation in Alberta. Site C competes with the other forms of generation that will be developed since coal generation can no longer be refurbished or replaced with new coal generation.**

The extent of potential GHG emission reductions resulting from the Site C Project will depend on several factors, including the duration of any export contracts, whether additional transmission can or will be developed to support exports, and how BC Hydro replaces exports beyond the Site C energy surplus. Long-term exports of firm energy and dependable capacity from Site C to Alberta would trigger a requirement for additional dependable capacity resources in BC (and any associated GHG emissions), given BC Hydro's IRP identified a need for capacity by F2019, and the more recent 2016 load resource balance updated that requirement to F2020.

Electricity exported to Alberta during the period when Site C that is surplus to BC Hydro's needs would displace or delay other generation that would otherwise be dispatched or developed. The precise mix of natural gas, wind, hydro, solar, geothermal and biomass that will be developed cannot be known with certainty, but the range of the potential GHG emission reductions during the Site C energy surplus period can be estimated.

Table 7 presents the estimated surplus energy projected for the BC Hydro integrated system in the utility's most recent load resource balance for the years following the commissioning of the Site C Project.[87] It also presents a preliminary estimate of the GHG emission reductions from exporting this surplus to Alberta, based on the assumption that one-third of the replacement energy would otherwise come from natural gas and two-thirds from renewables, as per the Government of Alberta policy objective.

This GHG emission offset of 2.4 Mt CO_2e would lower the cumulative GHG emissions from the Site C Project to a level more similar to that of an optimized Alternative

[85] "Big gambles on big energy projects." Globe & Mail, April 28, 2016. Available at: http://www.theglobeandmail.com/opinion/big-gambles-on-big-energy-projects/article29777411/

[86] Government of Alberta. 2016. Climate Leadership: Ending Coal Pollution. Available at: http://www.alberta.ca/climate-coal-electricity.cfm.

[87] *RDA*, *supra* note 44, Evidentiary Update on Load Resource Balance and Long Run Marginal Cost, p.12.

Portfolio containing at least some capacity-focused DSM (see Figure 6). Whether the Site C Project actually displaces this quantity of GHG emissions depends on the emissions intensity of competing generation resources that would otherwise be developed in Alberta in the period 2024-2030.

Table 7. Site C energy surplus GHG emissions reductions in Alberta

Year	Site C Energy Surplus	Natural Gas		Renewables		Total Emissions Reduction
		Generation	Emissions Intensity	Generation	Emissions Intensity	
	GWh/year	GWh/year	(t CO_2e/GWh)	GWh/year	(t CO_2e/GWh)	(t CO_2e)
2025	3,277	1,092	545	2,185	15	628,092
2026	3,241	1,080	545	2,161	15	621,192
2027	2,711	904	545	1,807	15	519,608
2028	1,866	622	545	1,244	15	357,650
2029	1,082	361	545	721	15	207,383
2030	331	110	545	221	15	63,442
						2,397,367

Evidence from Ontario, which shuttered all of its coal-fired generation over a ten-year period (2005-2014), suggests a potential pattern for development of the alternative resources to coal generation in Alberta. Figure 7 presents the 17,304 MW of transmission-connected[88] and embedded[89] generating capacity contracted by the Ontario Independent Electricity System Operator (IESO) over the period 2004-2016. Combined-cycle, simple-cycle and combined heat and power natural gas facilities account for 36%, which is not dissimilar to the 33% policy objective of the Government of Alberta. This suggests that 2.4 Mt CO_2e is a reasonable estimate of the cumulative emissions that could be displaced by the surplus energy from the Site C Project.

However, the timing of any exports to Alberta is an additional and important consideration, particularly in light of the costs of the low-carbon alternatives that are available in Alberta. To date, there has been no public indication that the Alberta Government or any commercial entity in Alberta would consider paying the actual cost of electricity from the Site C Project, which would also need to include any additional transmission-related costs. In the 2013 IRP, BC Hydro estimated the cost of delivering electricity to the BC lower mainland from Site C at $94/MWh (before capacity benefits),[90] and the cost of delivery to load centers in Alberta would likely be similar, ignoring additional transmission costs. Transmission development in BC or Alberta, and any transmission tariffs in Alberta would add to this cost. As a result, the cost of energy

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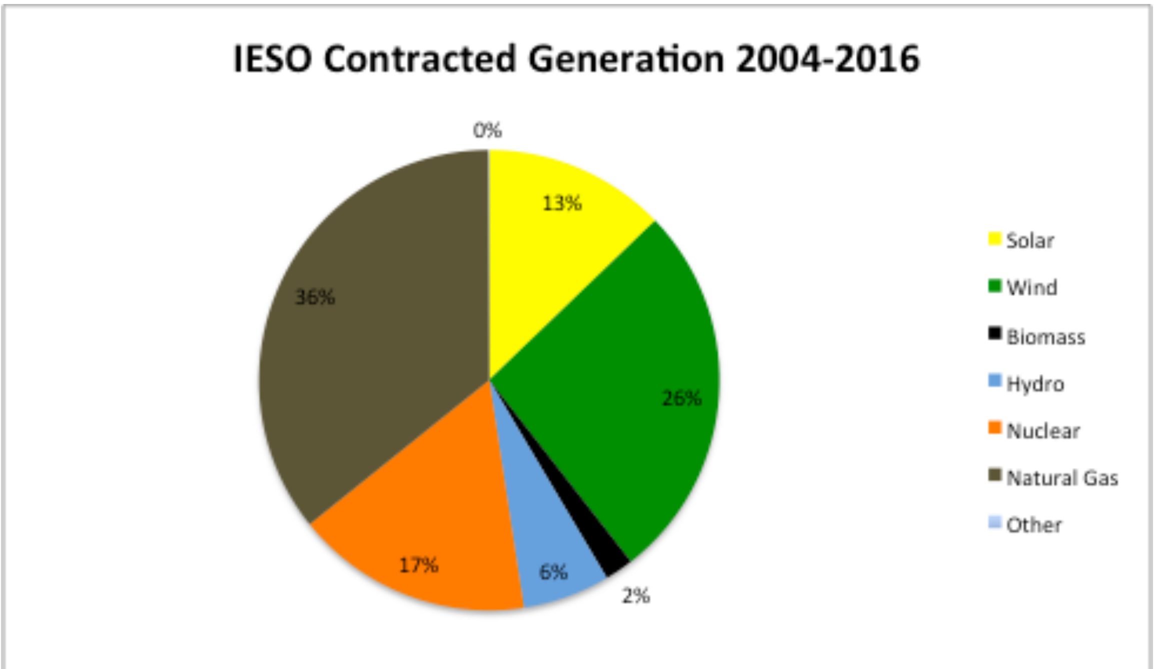
[88] IESO. 2016. New and Retired Generation Since the Market Opened in 2002. Available at: http://www.ieso.ca/Pages/Power-Data/Supply.aspx.
[89] IESO. 2016. Ontario Energy Report Q4 2015, p.4. Available at: http://www.ontarioenergyreport.ca.
[90] *IRP*, *supra* note 2, Chapter 6 Resource Planning Analysis, p.6-28.

from Site C is substantially higher than the regulated rates in Alberta and the wholesale market pool price, both of which are on the order of $35/MWh[91,92] and, importantly, higher than the cost of electricity generated from other alternatives available in Alberta, including natural gas,[93]wind and, potentially by 2024, utility-scale solar PV.

Figure 7



Alberta has superior wind resources to British Columbia and Ontario, where a recent competitive process by the Independent Electricity System Operator (IESO) saw 300 MW contracted at a weighted average price of $86/MWh with a range of about $65 to $105/MWh.[94] The Government of Alberta recently tasked the Alberta Electric System Operator (AESO) with developing a program to bring on new renewable generation capacity to 2030. The program is still under development with contracts to be awarded in 2017, and with first projects in service by 2019.[95] Average prices are therefore not yet known, but would be expected to be lower than in Ontario and on the order of $50 to $80/MWh with the average in the $60 to $70/MWh range.

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[91] Alberta Utilities Commission. May 2016. Monthly Regulated Retail Option Rates. Available at: http://www.auc.ab.ca/utility-sector/rates-and-tariffs/Pages/MonthlyRegulatedRateOptionRates.aspx.
[92] AESO. 2016. AESO 2015 Annual Market Statistics, p.3.
[93] Electricity generated from combined cycle natural gas would be available in Alberta at approximately $60/MWh as it is in BC. See *IRP*, *supra* note 2, Chapter 3 Resource Options, Table 3-17.
[94] Ontario Independent Electricity System Operator. 2016. Large Renewable Procurement. Available at: http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx
[95] Alberta Electricity System Operator. 2016. Renewable Electricity Programs. Available at: http://www.aeso.ca/rep/.

The cost of on-shore wind energy is expected to continue to decline, with the International Renewable Energy Agency (IRENA) recently projecting costs declines of 26% to 2025,[96] and Bloomberg New Energy Finance (BNEF) projecting costs declines of 41% to 2040. The extent to which these declines are realized in Alberta depends on a number of factors including improvements in wind turbine efficiency and design, government policy, and technology adoption. A decline of 26% in the cost of wind energy in Alberta would mean a weighted average price on the order of $45 to $55/MWh in 2025 when energy from Site C would become available. This would be about half the full cost of surplus energy from Site C, presuming no transmission costs or tariffs.

Regarding solar energy, utility-scale solar PV is not currently competitive in Alberta. However, as with wind energy, the Province has superior solar resources to British Columbia and to Ontario, where IESO's competitive process saw 140 MW of utility-scale solar PV contracted at a weighted average price of $157/MWh with a range over $140/MWh to $180/MWh.[97] Considering Alberta's solar insolation advantage over Ontario, and presuming the implementation of appropriate policies and market development, average prices in 2016 would be expected to be on the order of $125 to $150/MWh, in the event that any proponents were to respond to the AESO's upcoming competitive procurement.

Declines in the cost of utility-scale solar PV are also expected to continue in the coming decades. BNEF projects an average cost decline in utility scale solar PV on the order of 60% out to 2040. In its recent analysis, IRENA projected a 59% decline in utility-scale solar PV costs by 2025.[98] Whether these declines are realized in Alberta depends on a number of factors including: continued declines in installed costs, operations and maintenance cost declines, improvements in capacity factors, government policy, and technology adoption. A decline of 40% by 2025, in line with the BNEF projections, would mean a weighted average price on the order of $75 to $90/MWh, while a decline of 60% would see weighted average prices on the order of $50 to $60/MWh just when energy from Site C would become available.

Considering the continued declines in the price of energy from on-shore wind and utility-scale solar PV to well below the cost of delivering energy to Alberta from Site C, it is far from obvious that the Alberta Government or any commercial entity in Alberta would be willing to contract for the delivery of that energy, or to pay for the transmission investments required for that delivery. While Site C potentially has the additional advantage of providing dependable capacity, that advantage must consider the additional costs and environmental effects associated with transmission development, the relatively low costs (but higher GHG emissions) of providing that dependable

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[96] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.67.
[97] Ontario Independent Electricity System Operator. 2016. Large Renewable Procurement. Available at: http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx
[98] International Renewable Energy Agency. June 2016. The Power to Change: Solar and Wind Cost Reduction Potential to 2025, p.49.

capacity in Alberta using combined-cycle natural gas turbines, and the potential that considerable dependable capacity can be provided in Alberta at low costs and low emissions using a combination of SCGTs, capacity-focused DSM (including demand response and direct load control), and other dependable sources of capacity including geothermal and energy storage similar to the optimized Alternative Portfolio developed in this report. There has been no review to date by the BC Utilities Commission or an Alberta regulator of the costs of exporting energy or capacity from the Site C Project to Alberta.