bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

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

September 8, 2017

BCUC INQUIRY RESPECTING SITE C A-9

Sent via eFile

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

In accordance with Order G-120-17, in which the British Columbia Utilities Commission (Commission) stated that it has engaged the consulting firm Deloitte LLP to produce independent reports on the questions posed in section 3(b) of the terms of reference in Order in Council (OIC) No. 244, please find attached the following Deloitte LLP independent report: Site C – Alternative Resource Options and Load Forecast Assessment.

The Commission will consider the information contained in the Deloitte LLP independent report, as well as the information provided by BC Hydro in its August 30, 2017 submission, and the submissions of data and analysis from members of the public, when preparing its preliminary report due September 20, 2017.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

Deloitte.

British Columbia Utilities Commission

Site C - Alternative Resource Options and Load Forecast Assessment

British Columbia Utilities Commission

September 8, 2017

Deloitte LLP.
2800-1055 Dunsmuir St.
Four Bentall Centre
Vancouver, BC, V7X 1P4
Canada

Tel.: 604 640-3236
Fax: 604 685 0395
www.deloitte.ca

September 8, 2017

David Morton
Chair and Chief Executive Officer
British Columbia Utilities Commission
900 Howe Street, Suite 410
Vancouver, BC
V6Z 2N3

Site C – Alternative Resource Options and Load Forecast Assessment

Dear Mr. Morton,

Deloitte LLP (Deloitte) is pleased to submit this report as part of the British Columbia Utilities Commission (BCUC or the Commission) inquiry respecting the Site C Clean Energy Project (Site C project or the Project). This engagement has been performed in accordance with the consulting services agreement between Deloitte and BCUC, dated August 30, 2017.

The objective of the engagement is to provide an independent review of the Project to assist BCUC answer four questions of the inquiry:

1. Is the Project currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?
2. What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024?
3. What are the costs to ratepayers of terminating the Site C project?
4. What, if any, other portfolio of commercially feasible generating projects and demand-side, management initiatives could provide similar benefits to ratepayers at a similar or lower, unit energy cost as the Site C Project?

The scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report entitled Site C Construction Review covers the response to the first three questions.

We would like to express our appreciation for the cooperation and assistance provided by BCUC, and BC Hydro during this review.

Yours sincerely,

Deloitte LLP

Deloitte LLP

Table of contents

1. Executive summary 1

2. Glossary 7

3. Introduction 8

4. Assessment of alternative sources of energy and capacity 13

5. Assessment of Load Forecast Model 60

Appendix A – Load Forecast Model Inputs 83

Appendix B – List of BC Hydro documents reviewed 85

Appendix C – Interviewees 91

Appendix D – Confidentiality agreement 92

Appendix E – Modeling alternative supply-side sources of energy and capacity (MarketBuilder model) 95

Appendix F - Assessment of alternative supply-side sources of energy and capacity – external research 114

1. Executive summary

In December 2014, the BC Hydro and Power Authority (BC Hydro or the Authority) Site C Clean Energy Project (the Site C Project or the Project) received approval from the Government of the Province of British Columbia (the Province) to proceed with construction. Construction of the Project began in July 2015 and was expected to be in service in November 2024. At the time of the Project's approval, BC Hydro estimated its cost at $8.775 billion, which included a capital-cost estimate of $8.335 billion, plus a $440 million project reserve held by the Treasury Board.

The British Columbia Utilities Commission (BCUC or the Commission) has engaged Deloitte LLP (Deloitte) to provide an independent review of the Site C Project as part of its inquiry into the Project. Deloitte has conducted site visits, interviewed senior management and the Project team, and reviewed project documentation and data provided by BC Hydro and BCUC.

The objective of the engagement is to provide an independent review of the Project to assist BCUC answer four questions of the inquiry:

1. Is the Project currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?
2. What are the costs to ratepayers of suspending the Site C Project, while maintaining the option to resume construction until 2024?
3. What are the costs to ratepayers of terminating the Site C Project?
4. What, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits to ratepayers at similar or lower unit energy cost as the Site C Project?

The scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report covers the response to the first three questions.

1.1. Alternative supply-side sources of energy and capacity to replace that due to be provided by Site C

The assessment of alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C is based on a review and analysis of public and confidential data provided by BC Hydro; independent, external research; interviews with BC Hydro's Integrated Resource Planning (IRP) and Demand Side Management (DSM) teams, and interviews with several independent subject-matter professionals.

On the basis of this information, BCUC has requested an assessment of the following alternative sources of energy and capacity:

- Alternative sources of energy and capacity, including storage options;
- Expansion potential of current BC Hydro facilities; and
- Opportunities to increase demand-side management (DSM). Note that DSM is considered an alternative resource option in that it serves to meet future demand through energy conservation and efficiency.

The results of this high level assessment are used as inputs into the modelling of an alternative portfolio of sources of energy and capacity to meet demand (load) without generation provided by Site C. The modeling is completed using MarketBuilder, an energy-modeling and economic-forecast-modeling platform by Deloitte MarketPoint (herein referred to as the MarketBuilder model). The results of this alternative portfolio are summarized in Appendix E.

1.1.1. Approach

Our approach to the assessment of alternative sources of energy and capacity, including storage options, followed BCUC guidance to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[1];
- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted in the existing regulatory environment in BC;
- Benefits: Our assessment reviewed the firming, shaping, and grid-reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity: Our assessment reviewed the current range of capital costs, and the operations and maintenance (O&M) costs associated with the technology, as well as a cost outlook for the future.

Our approach to the assessment of the expansion potential of current BC Hydro facilities was based on the review of the 2013 Integrated Resource Plan (IRP), Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA), and the individual Facility Asset Plans for each facility. The purpose of our review was to identify additional capacity and associated capital costs. In identifying additional capacity, we have used current capacity as the basis for calculating additional capacity. As such, for facilities that have been derated, the derated capacity value is used as the basis and for facilities that are out of service current production is assumed to be zero. In identifying values for additional capacity and associated capital costs, we have relied on values identified by BC Hydro in the Facility Asset Plans and the RRA. Our analysis identified assets which have potential for expansion; however, we have not conducted a cost benefit analysis on each of these expansion options.

As we noted above, our purpose in assessing BC Hydro's DSM initiatives was to identify opportunities to increase energy and capacity savings. DSM is considered an alternative resource option in that it serves to meet future demand through energy conservation and efficiency. BC Hydro considers two types of DSM measures, energy focused and capacity focused. Energy-focused DSM includes measures to conserve energy, and promote energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to delivery capacity savings during peak load periods. Both are included in the scope of this assessment.

1.1.2. Findings

Based on the results of our high-level assessment, the following sources of generation and storage were included in the model to assess alternative sources of energy and capacity to replace that due to be provided by Site C: Onshore Wind, Offshore Wind, Utility-Scale Solar PV, Geothermal, Natural gas (SCGT and CCGTs), Run-of-river hydroelectricity, Biomass (wood-based), Biogas, Biomass (municipal solid waste), Cogeneration, Pumped storage and Battery storage. Nuclear was not included in the alternative-generation portfolio modeling, given that it is not aligned with the energy objectives of the Clean Energy Act. Tidal and Wave were not included in the alternative-generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[1] It is unrealistic to assume that any technology could provide an infinite amount of capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.

The assessment of current BC Hydro facilities identified several assets with expansion potential. The total additional capacity identified ranges from 600MW to 1000 MW. The types of expansion opportunities are as follows:

- Where there is an empty bay at an generating station which can be utilized to add a generating unit;
- Where the generating station can be replaced/refurbished to add capacity through enhanced efficiency and/or reinstate nameplate capacity;
- Where a generating facility can be added to an asset where there is no current power generation;
- Where individual components of the generating station can be refurbished/replaced to add capacity through enhanced efficiency; or
- Where additional untapped flow is available.

The assessment of DSM initiatives identified additional opportunities to increase energy and capacity savings. BC Hydro's current DSM option, referred to as the moderated DSM Option 2 from the F17-F19 RRA DSM Plan, was selected for the alternative portfolio. An additional DSM option with the potential for higher energy and capacity savings is also described in this report.

1.1.3. Modeling alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C (Appendix E)

The provincial government's Order-in-Council (OIC) asks the question: "Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?"

The results contained in Appendix E offer findings to help inform BCUC's assessment of this question.

The MarketBuilder model was used to generated a portfolio of alternative-generation projects that:

- Meet the energy objectives set out in the Clean Energy Act
- Contain commercially feasible generating projects
- Contain achievable DSM initiatives
- Consider firming/shaping and reliability of the grid
- Maintain the 2016/17 GHG emission levels

The costs and value of the generated portfolio are detailed in the findings section of Appendix E.

Deloitte considers this scenario to be a base case for informing BCUC's assessment of this case vis-à-vis the Site C scenario. Running additional scenarios would offer more insights. For example, it could be of interest to BCUC to consider the following:

- Applying the alternative load forecast developed by Deloitte to replace that provided by BC Hydro;
- Applying an increased level of DSM above what BC Hydro is currently doing (e.g., using BC Hydro's Option 3 DSM);
- Running a 'suspension scenario' to assess the need for alternative supply if Site C is suspended until a specified timeframe;
- Examining the impact of certain decisions or variable combinations (e.g., incorporating the Columbia River Treaty Entitlement if the requirements for 'self-sufficiency' are relaxed, or running various price forecasts, assuming that Burrard Thermal is restarted).

Given the inherent uncertainty of any projection, additional scenarios and analysis could be used to better quantify the sensitivity of the base scenario findings to changes in the assumptions. Additionally, while project

cost and performance (e.g., capacity factor) inputs are reasonable for the various technologies in the alternative-supply portfolio, any particular project will have different costs and performance driven by specific needs, even if such values fall within the expected range. Scenarios probing different cost or performance assumptions for technologies can also evaluate how alternate portfolios may perform under different circumstances.

1.2 BC Hydro's load forecast model

1.2.1 Approach

BC Hydro's load forecast model ("the Forecast Model") published in July 2016, provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. Our approach to the assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other, major utilities in Canada; and interviews with several subject-matter professionals. Importantly, Deloitte has not accessed BC Hydro's Forecast Model directly. As such, this assessment cannot independently validate the information received regarding it, nor project the exact impacts on projected load requirements from changing model inputs. On the basis of information provided, this assessment provides estimates of the direction and order-of-magnitude impacts resulting from changes to several key model inputs.

1.2.2 Findings

BC Hydro uses two distinct models to forecast future demand for load and capacity. To produce its baseline mid forecast, BC Hydro uses an additive, statistically adjusted end use (SAE) approach. It consists of 12 sub models broken down by region and customer segment, as well as separate models for the light-manufacturing sector, FortisBC's expected load, a projection of heavy-industrial load for major customers, and a projection of 'all other' load requirements (e.g., streetlights and irrigation). Separate from the mid forecast, BC Hydro produces high and low-load requirement forecasts. These are the outcome of Monte Carlo simulations that model uncertainty with respect to consumers' responsiveness to future rate increases, the magnitude of these increases, and future provincial economic growth, among other variables. The inputs driving the Monte Carlo simulation are fewer and, in some cases, different from the inputs driving the mid forecast. Due to assumptions relating to demand-side management (DSM), the mid-point of the high and low-load requirements is different from (higher than) BC Hydro's mid forecast.

The assessment of the Forecast Model focused on three aspects: historical performance of model outputs vis-à-vis actuals, inputs to the model, and the model's functional form and statistical features.

In terms of historical performance, the analysis finds that, across model vintages going back to 1964, the model has more frequently overestimated load than underestimated it; of the 647 forecasted points, 500 (77%) were overestimates. Forecasts have performed better in the short run than the long run. While forecast methodology has changed over time, the magnitude of overestimation does not appear to have decreased; in fact, in the first fully forecasted year and the fifth forecasted year, the magnitude of overestimation appears to have increased.

The industrial component of the model, which is responsible for 29% of total sales on average between fiscal 2000 and 2017, has been the largest contributor to overestimation. In forecast models from fiscal 2008 to 2016, large industrial sales are overestimated by an average of 7% of actuals in the first fully forecasted year, and by an average of 21% of actuals in the eighth forecasted year. Interviews with two other Canadian utilities reveal that one of them has tended to overestimate load over time, and that the heavy industrial sector has been the most challenging to estimate accurately.

The residential and light industrial components have performed closer to actuals over both the short and long term. Using forecast models from F2008 to F2016, residential sales are overestimated by an average of 0.2% of actuals in the first fully forecasted year, and underestimated by 4% of actuals in the eighth forecasted year.

Commercial and light industrial sales are overestimated by an average of 1% of actuals in the first fully forecasted year, and by 4% of actuals in the eighth forecasted year.

In terms of inputs, the assessment finds that the types of variables included in the Forecast model appear reasonable, based on consultations with the two other Canadian utilities and several subject-matter professionals. The forecasts for employment, population, and housing starts that BC Hydro uses as inputs, which come from Robert Fairholm Economic Consulting, appear in line with projections published by independent third parties.

With respect to GDP and disposable income growth, the input forecasts appear higher than alternative forecasts after the first 5 years. For instance, in the 2016 load forecast, real GDP growth is assumed to average 2.3% in the first five years (i.e., based on the BC Ministry of Finance's forecast), before increasing to 3.5% over the next five years (based on Robert Fairholm Economic Consulting projections). By comparison, the 2016 Conference Board of Canada forecast projects that real GDP will grow by 2.6% on average between 2016 and 2020, before slowing to an average of 2.3% between 2021 and 2025. Beyond 2025, the two forecasts exhibit similar trends. The mid-forecast model does not explicitly incorporate recessionary periods, even though it is likely that such periods will occur over a 21-year horizon, based on the historical record.

Two assumptions regarding specific LNG projects, Pacific NorthWest LNG (now cancelled) and LNG Canada (final investment decision deferred), appear optimistic assumes that the Forecast model that both will be built. It should be pointed out that the project cancellation and deferral decisions were made after the 2016 Load Forecast was released. The impact of those assumptions is magnified via the indirect link to load requirements in the oil and gas industry (i.e. to supply the LNG projects), as well as the GDP forecast, which also assumes that these projects will proceed.

The assumption of a constant price elasticity of demand across time horizons and customer segments appears to be an oversimplification; as well, the exact elasticity value (-0.05) is lower than several alternative estimates. This leads to a lower impact on load from projected, future rate increases. The impact of using different price elasticities of demand cannot be reliably established without direct testing of the model. Also of note is that the model assumes there will be no future rate increases for the period F2025 to F2036.

A number of potential disrupting trends exist with respect to electricity demand, including improvements in technology for renewable energies such as solar power, the increased use of electric vehicles, decentralized power grids, the Internet of Things, fuel-switching, climate change, and co-generation, among others. Of those, BC Hydro explicitly models future use of electric vehicles. The assessment included an analysis of BC Hydro's assumptions regarding electric vehicle use, the potential impact from solar photovoltaic technology in a residential context, and fuel-switching (i.e., from gas to electric and vice versa). BC Hydro's assumptions regarding electric vehicle use appear conservative compared with public commitments from the federal government. Using an alternative assumption that electric vehicles will account for 30% of all new cars sold in 2030 (compared to BC Hydro's 22%), we can see that load demand from electric vehicles increases by approximately 115 to 125 GWh in 2026 and 680 to 690 GWh in 2036.

The current state of residential solar PV and residential heat and hot water switching were also reviewed as part of this report. These potential disruptors are not currently incorporated in BC Hydro's forecast. This assessment finds that the use of solar PV is currently limited, accounting for approximately 0.002% of residential load demand in F2016. The current payback period for solar PVs in BC is estimated to be 23 years. While costs could decrease going forward and induce further uptake, this assessment has not attempted to model such a scenario.

In terms of fuel switching, the current annual cost of an electric furnace to heat an average detached home is estimated to be over $800 higher than using natural gas, even when comparing the most efficient electricity option to the least efficient gas option. While there are indications that potential future policies will incentivize

a shift from natural gas to electricity, this assessment has not attempted to model the potential for fuel switching to alter future electricity needs.

As part of this assessment, we illustrate the impact on the 2016 load forecast by making several plausible changes to the input assumptions. These include adopting an alternative GDP forecast sourced from the Conference Board of Canada, removing the assumptions that Pacific NorthWest LNG (now cancelled) and LNG Canada (final investment decision deferred) will proceed, increasing the adoption of electric vehicles in line with federal commitments, and assuming a more intensive DSM approach (Option 3 as reported by BC Hydro in the 2013 Integrated Resource Plan).

By F2026, the alternative set of assumptions could result in a reduction of the load forecast in the range of 6,000 to 6,150 GWh, and a reduction in peak capacity in the range of 1,140 to 1,160 GWh. By 2036, the corresponding impacts are a reduction in load forecast of 5,950 to 6,100 GWh, and a reduction in peak capacity forecast of 1,110 to 1,130 GWh. These projections should be considered as indicative only, as BC Hydro's mid forecast has been adjusted after the fact rather than conducting a complete rerun of the models that produced the original forecast.

While this assessment has not included direct testing of the model, it does find that with some exceptions, BC Hydro's methodology is consistent with the practices of other North American utilities. An opportunity may exist to strengthen the reliability of the forecast by employing an econometric approach that models short-term forecasts on the basis of past actual loads. The potential for correlation across the various independent components of the mid-forecast should be tested to minimize risks of suboptimal forecast results.

2. Glossary

Acronym/Abbreviation	Terminology
ACEEE	American Council for an Energy-Efficient Economy
Advisor	Deloitte LLP and affiliated entities
BC Hydro	BC Hydro and Power Authority
BCUC	British Columbia Utilities Commission
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CO2	Carbon dioxide
CO2e	Carbon dioxide equivalent
CVR	Conservation voltage reduction
Deloitte	Deloitte LLP and affiliated entities
DSM	Demand Side Management
g	Grams
GHG	Greenhouse gas
IRP	Integrated Resource Plan
kW	Kilowatt
kW-yr	Kilowatt year
LNG	Liquefied natural gas
Forecast Model	BC Hydro's load and capacity forecasting models
MarketBuilder	An energy and economic modeling and forecasting platform used by Deloitte MarketPoint
MW	Megawatt
MWh	Megawatt hour
PV	Photovoltaic
SAE	Statistically adjusted enduse
SCGT	Single cycle gas turbine
The Authority	BC Hydro and Power Authority
The Commission	British Columbia Utilities Commission
The Project	Site C Clean Energy Project
Var	Volt-ampere reactive
VVO	Voltage and Var optimization

3. Introduction

3.1. Scope of the Review

On August 2, 2017, the Province of British Columbia directed the British Columbia Utilities Commission (BCUC, or the Commission) to conduct a review of certain aspects of the Site C Clean Energy Project (the Site C project, or the Project), under section 5 of the Utilities Commission Act (UCA). Specifically, the Commission has been asked the following:

1. After the Commission has made an assessment of BC Hydro's (the Authority) expenditures on the Site C project to date, is the Commission of the view that the Authority is, respecting the Project, currently on time and within the proposed budget of $8.335 billion (which excludes the $440 million project reserve established and held by the province)?
2. What are the costs to ratepayers of suspending the Site C project, while maintaining the option to resume construction until 2024, and what are the potential mechanisms to recover those costs?
3. What are the costs to ratepayers of terminating the Site C project, and what are the potential mechanisms to recover those costs?
4. Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C Project?

The scope of this report covers the last (fourth) question, and provides an assessment of BC Hydro's Load Forecast Model released in July 2016. A separate report entitled Site C Construction Review covers the response to the first three questions.

3.2. Approach

Deloitte's review comprises a high-level assessment of:

1. Alternative supply-side sources of energy and capacity to replace those due to be provided by Site C.
2. BC Hydro's load-forecasting model, with a focus on the version of the forecast published in July 2016 and provided by BC Hydro.

Each assessment required a distinct approach, summarized below.

3.2.1. Assessment of alternative supply-side sources of energy and capacity to replace those to be provided by Site C

Our approach to the assessment of alternative sources of energy and capacity, including storage options, followed BCUC guidance to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[2];

[2] It is unrealistic to assume that any technology could provide an infinite amount of capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.

- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted by the existing regulatory environment in BC:
- Benefits: Our assessment reviewed the firming, shaping, and grid reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity: Our assessment reviewed the current range of capital costs and the operations and maintenance (O&M) costs associated with the technology, as well as a cost outlook for the future.

Our approach to the assessment of the expansion potential of current BC Hydro facilities was based on the review of the 2013 Integrated Resource Plan (IRP), Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA) and the individual Facility Asset Plans for each facility. The focus of our review was to identify additional capacity and associated capital costs. In identifying additional capacity, we have used current capacity as the basis for calculating additional capacity. As such, for facilities that have been derated, the derated capacity value is used as the basis; for facilities that are no longer in service, current production is assumed to be zero. In identifying values for additional capacity and associated capital costs, we have relied on values identified by BC Hydro in the Facility Asset Plans and the F17-F19 RRA. Our analysis identified assets where there is potential for expansion; however, we have not conducted a cost benefit analysis on each of these expansion options.

Our approach to the assessment of BC Hydro's demand-side management (DSM) initiatives focused on identifying opportunities to increase energy and capacity savings. DSM is considered an alternative resource option, in that it serves to meet future demand through energy conservation and efficiency. BC Hydro considers two types of DSM measures: energy focused and capacity focused. Energy-focused DSM includes measures to conserve energy and promote energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to deliver capacity savings during peak load periods. Both are included in the scope of this assessment.

The results of this high-level assessment were used as inputs for modelling an alternative portfolio of sources of energy and capacity to meet demand (load), without generation provided by Site C (herein referred to as MarketBuilder model). The results of this alternative portfolio are summarized in Appendix E. The general approach to building the MarketBuilder model was to apply BC Hydro's load forecast, and consider what additional generation (not relying on Site C) is required to meet the forecast at the lowest potential cost, within a specific greenhouse gas emissions cap, and specific assumptions and constraints, which are detailed in Appendix E.

3.2.2. Assessment of BC Hydro's load forecast model

BC Hydro's load-forecast model ("the Forecast Model") published in July 2016, provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. Our approach to the assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other major utilities in Canada; and interviews with several subject matter professionals. Based on information obtained from these sources, we assessed the impact of changing several assumptions on load and capacity. Importantly, Deloitte has not accessed BC Hydro's Forecast Model directly. As such, this assessment cannot independently validate the information received regarding it, nor project the exact impacts on projected load requirements from changing model inputs. This assessment should be considered as indicative of the direction and approximate magnitude of the impacts only.

3.3. About Deloitte

Deloitte LLP is Canada's leading professional services firm, providing a full range of consulting, assurance and advisory, financial advisory, enterprise risk, and tax services to clients in all sectors of the Canadian economy through more than 8,800 people in more than 55 locations across the country. Deloitte has been in business in Canada for over 150 years. During this tenure, our clients have relied on Deloitte and its predecessor

organizations for solutions to their ever-changing needs. We are a national and global leader today because we have earned our clients' trust and exceeded their expectations throughout our history. As one of the world's leading professional services firm, Deloitte LLP Canada can, when needed, call on our over 57,000 professionals serving 100 countries. This report was created primarily by a team of professionals from three different practice area: Deloitte's Sustainability and Climate Change practice; Deloitte Economics; and Deloitte MarketPoint.

3.3.1. Deloittes' Sustainability and Climate Change

Deloitte has Canada's largest Sustainability and Climate Change (S&CC) practice among the "Big 4" professional services firms. For more than 20 years, our team has been supporting organizations in every aspect of sustainability.

In Canada, our S&CC team has advised governments, global and national companies, and development agencies on climate change issues and strategies to meet regional, national, and international needs and to deploy innovative de-carbonization strategies that respond to the future low-carbon reality. We have also concluded a series of studies designed to define and characterize the Clean Technology Sector across jurisdictions in Canada and globally. Through these experiences, we have developed a broad understanding of the key challenges and opportunities in the Clean Technology Sector, as well as insights into what other jurisdictions around the world are doing to address them.

Our S&CC practice has deep experience serving the power and utilities industry with 15+ clients across British Columbia, Alberta, Saskatchewan and Ontario.

3.3.2. Deloitte Economics

Deloitte Economics is a team of economists and public policy specialists, who use economic, econometric, statistical and financial expertise to help address the business and policy challenges facing our clients. We advise both public sector and private sector organizations in Canada on a range of areas including: economic development strategy; socio-economic impact analysis; and competition and market analysis. Drawing on the depth of industry knowledge from across Deloitte's global network, we develop rigorous solutions based on the practical application of economic and policy analysis.

3.3.3. Deloitte MarketPoint

Deloitte MarketPoint is a leading provider of economic modeling solutions that are used to analyze energy resource economics, assess market fundamentals, and provide strategic insight for the global power, oil, and gas markets for clients ranging from public and private utilities to project developers to end-users to financial and government institutions.

Our subject matter specialists, many of whom have in excess of twenty years of energy experience, develop Reference Case outlooks and provide custom analysis to support advisory clients and help them better understand changing energy market fundamentals, asset valuation and asset development, risks to strategic plans, disruption in the marketplace, and the impact of new and potential regulations.

Leveraging MarketBuilder, a proprietary economic modeling platform with over 30 years of continuous development and application, Deloitte MarketPoint has developed energy market models and approaches to quantify energy market reactions under various scenarios. The cross-commodity capability of MarketBuilder allows for the seamless integration of energy commodities as well as other related attributes such as emissions limits and renewable energy credits or requirements. As a result, clients benefit from analysis that is comprehensive and consistent. The US Department of Energy utilized MarketBuilder and the MarketPoint team to evaluate the impact of a carbon policy on shifts in generation mix and required power plant and gas pipeline infrastructure development as part of the Quadrennial Energy Review.

3.4. Assumptions and Limitations

This report has been prepared pursuant to the following general assumptions and general limiting conditions:

1. The analyses, advice, recommendations, opinions, or conclusions contained herein are valid only as of the indicated date and only for the indicated purpose.
2. The analyses, advice, recommendations, opinions, or conclusions contained herein are for the exclusive use of BCUC for the sole and specific purposes noted herein and may not be used for any other purpose by BCUC or any other party. Furthermore, the analyses, advice, recommendations, opinions, or conclusions are not intended by the author and should not be construed by the reader to be investment advice in any manner whatsoever. The analyses, advice, recommendations, opinions, or conclusions represent the considered opinion of Deloitte LLP ("Advisor"), and are based on information furnished to it by the client, its representatives, and other sources.
3. Possession of this report, or a copy thereof, does not carry with it the right of publication or distribution to, or use by, any third party. Any third party that uses the information contained herein does so at its sole risk and agrees to hold Advisor, its subcontractors, and their respective personnel harmless from any claims resulting from use by any other third party. Access by any third party does not create privity between Advisor and any third party.
4. No item in this report shall be changed by anyone other than Advisor, and Advisor shall have no responsibility for unauthorized changes.
5. Neither Advisor nor its personnel, by reason of this engagement, is required to give testimony, or to be in attendance in court unless arrangements have been previously made in writing.
6. The Advisor conducted interviews with BC Hydro and have assumed that the information gathered in such interviews is accurate and complete.
7. Financial information provided to us in the course of this engagement by BC Hydro has been accepted without any verification as fully and correctly reflecting the business conditions and operating results of the relevant assets, properties, or businesses for the respective periods, except as specifically noted herein. We have not audited, reviewed, or compiled any financial information provided to us and, accordingly, we express no audit opinion or any other form of assurance regarding such information.
8. If prospective financial information provided by the client or its representatives has been used in this analysis, we have not examined or compiled the prospective financial information and, therefore do not express an audit opinion or any other form of assurance on the prospective financial information or the related assumptions. Events and circumstances frequently do not occur as expected, and there will usually be differences between prospective financial information and actual results, and those differences may be material.
9. The Advisor do not provide assurance on the achievability of any forecasted results contained herein because events and circumstances frequently do not occur as expected, differences between actual and expected results may be material, and achievement of the forecasted results is dependent on actions, plans, and assumptions of management.
10. The Advisor believes the information obtained from public sources or furnished to us by other sources is reliable. However, we issue no warranty or other form of assurance regarding the accuracy of such information.
11. The Advisor is not an environmental consultant or auditor, and it takes no responsibility for any actual or potential environmental liabilities. Any person entitled to rely on this report wishing to know whether such liabilities exist, or the scope and their effect on the value of any subject asset, property, or business interest, is encouraged to obtain a professional environmental assessment. Advisor does not conduct or provide environmental assessments and has not performed one in the course of this engagement.

Note: Additional limitations are provided in section 4.3 specifically related to the assessment of opportunities to increase DSM.

3.5. Project Description

The Site C project is the third dam and hydroelectric generating station on the Peace River in northeast BC. It is part of BC Hydro's overall program to invest in and renew the Province's electricity system. The Project

would provide approximately 1,100 megawatts of capacity, and produce about 5,100 gigawatt-hours of energy per year.

In December 2014, the Project received approval from the Government of the Province of British Columbia to proceed to construction. Construction of the project began in July 2015 and is expected to be completed in 2024.

4. Assessment of alternative sources of energy and capacity

This section provides an assessment of alternative, supply-side sources of energy and capacity to replace those due to be provided by Site C. This assessment has been utilized to determine which sources of alternative generation to include in the modeling of a single, alternative-generation portfolio that could replace the energy and capacity of Site C.

4.1. Introduction

We have been asked by BCUC to assess the following supply-side sources of alternative energy and capacity:

Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
1. Onshore wind	Wind power refers to the conversion of kinetic energy from moving air into electricity. Modern utility-scale wind turbines are horizontal axis machines with three rotor blades. The blades convert the linear motion of the wind into rotational energy that then is used to drive a generator. Onshore wind generation facilities are placed on land.
2. Offshore wind	Wind power refers to the conversion of kinetic energy from moving air into electricity. Offshore wind- generation facilities can be placed on the substrate in water, either in the ocean or possibly in lakes. This source of alternative energy considers the potential to generate electricity with offshore wind turbines located in ocean substrate depths of up to 40 m.
3. Utility-scale solar photovoltaic (PV)	Solar power is obtained by converting energy from sunlight into electricity; it can be manufactured directly using photovoltaic cells (crystalline silicon or thin film). which have the ability to modularly increase the size of the solar-power installation over time, thereby managing capital investment risk. This alternative considers commercial installations on the utility side of the meter, with commercial-scale solar installations sized at 5 MW.
4. Geothermal	Geothermal energy systems draw on natural heat from within the Earth's crust to drive conventional power- generation technologies. The primary source of geothermal energy is radioactive decay occurring deep within the Earth, supplemented by residual heat from the Earth's formation, and heat generated by its gravitational forces pulling dense materials into its core. This source of alternative energy focuses on geothermal electricity generated from conventional resources, in the form of steam or, hot water using flash or binary technologies.
5. Natural gas – simple-cycle gas turbine (SCGT) and combined-cycle gas turbine (CCGT)	Natural gas-fired units generate electricity using the heat released by the combustion of natural gas.

[3] All definitions, with the exception of nuclear, are from the BC Hydro 2013 Integrated Resource Plan; Chapter 3 – Resource Options. The definition for Nuclear is from the U.S. Energy Information Administration www.eia.gov/tools/glossary

Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
	Combined cycle gas turbines or CCGTs are an energy and capacity resource. CCGTs use the combination of combustion and steam turbines to generate electricity. Exhaust gases from a combustion turbine flow to a heat-recovery, steam generator that produces steam to power a steam turbine, resulting in higher efficiencies than those achievable by operating the combustion or steam turbines individually. CCGTs have a relatively high efficiency in converting fuel to electricity in comparison to other thermal generation. Simple-cycle gas turbines or SCGTs are a capacity resource. SCGTs are stand-alone generating plants that use combustion gases to propel a turbine, similar to a jet engine connected to an electrical generator. SCGTs are less efficient than CCGTs in converting fuel to electricity.
6. Run-of-river hydroelectricity	A run-of-river hydro-generation facility diverts a portion of natural stream flows and uses the natural drop in elevation of a river to generate electricity. A weir (i.e., a structure smaller than a dam used for storage hydro) is required to divert flows into the penstocks that lead to the power-generation facilities. A run-of-river project either has no storage, or a limited amount of storage, in which case the storage reservoir is referred to as pondage.
7. Tidal	Tidal energy refers to the kinetic energy available in the flow of water driven by the rotation of the Earth in the gravitational fields of the sun and the moon. Tidal energy can be captured in two different ways – tidal barrages and tidal current systems. Tidal barrage is not considered a viable prospect in BC. Review for this source of alternative energy in BC focuses exclusively on tidal current systems.
8. Wave	Wave energy is generated by winds blowing over the surface of the ocean. Because ocean waves are a product of the interactions among variable local winds, occasional storms and the effects of distant sea conditions, wave energy is a complex and variable phenomenon.
9. Nuclear	Electricity generated by the use of the thermal energy released from the fission of nuclear fuel in a reactor.
10. Biomass (wood-based)	Wood-based biomass electricity is generated from the combustion or gasification of organic materials as fuels. The potential of wood-based biomass considers the following categories of fuels: Standing timber (including pine beetle-killed wood) Roadside wood waste (wood already harvested, but left in the forest or road side, some are pine beetle-killed wood) Sawmill wood waste
11. Biogas	Landfill gas (primarily methane) is created when organic waste in a municipal solid waste landfill decomposes under anaerobic conditions. Landfill gas can be captured, converted, and used as an energy source to help prevent methane from migrating into the atmosphere and contributing to global climate change. Technologies for producing electricity from landfill gas include internal combustion engines, gas turbines and microturbines.
12. Biomass (municipal solid waste)	Municipal solid waste (MSW) biomass refers to the conversion of municipal solid waste into a usable form of energy, such as electricity. Conventional combustion and gasification are the most commonly used MSW technologies.
13. Cogeneration	Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power generation and a low-pressure steam/thermal 'host' to use the excess

Sources of energy	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options[3]
	heat produced from the generating process. Steam/thermal hosts may include industries and institutions that need heat such as pulp mills, greenhouses, or hospitals. This alternative energy considers generation of electricity using the heat released by the combustion of natural gas.

BCUC also asked us to assess the following storage options to assist with grid balancing, reliability and supporting renewables integration.

Storage options	BC Hydro's definition per BC Hydro 2013 Integrated Resource Plan. Chapter 3 – Resource Options
14. Pumped storage	Pumped storage (PS) units use electricity from the grid, typically during light load hours, to pump water from a lower-elevation reservoir to an upper- elevation reservoir. The water is then released during peak demand hours to generate electricity. Reversible turbine/generator assemblies or separate pumps and turbines are used in PS facilities.
15. Battery storage	Batteries come in different chemistries that generally fall into two distinct categories: solid state and flow. Solid state batteries are contained, do not require pumps or other moving parts, and rely on the closure of a conducting loop to allow a flow of electrons that either charge or discharge the battery. Flow batteries rely on chemicals that are pumped through a membrane and require periodic refreshing. This storage option focuses on solid state battery technologies that are available, and include Sodium Sulphur (NaS), Lithium ion (Li-ion), Advanced Lead Acid and Metal Air.

BCUC has asked us to identify the following characteristics for each of the technologies:

- Commercial feasibility: Our assessment reviewed whether the source of generation or storage is commercially offered in BC and/or other comparable jurisdictions[4];
- Regulatory limitations: Our assessment reviewed whether the source of generation or storage has been barred and/or is restricted in the existing regulatory environment in BC:
- Benefits: Our assessment reviewed the firming, shaping, and grid reliability characteristics of the technology, as well as the direct greenhouse gas (GHG) emissions;
- Costs to provide energy and capacity5: Our assessment reviewed the current Capital Costs and the Operations & Maintenance (O&M) Costs associated with the technology, as well as a cost outlook for the future. All costs are expressed in Canadian dollars.

[4] It is unrealistic to assume that any technology could provide an infinite amount of energy or capacity in British Columbia. Therefore, certain assumptions were made regarding the amount of each technology that could be built in the province. Refer to Appendix F for detailed assumptions regarding constraints applied.
[5] Exchange rate of $1USD=$0.75 has been used to convert costs from USD to CAD where relevant. Reference for exchange rate: BCUC IR 1.154.8. Exhibit B-9.

4.1.1. Summary of our assessment

The following sections summarize the results of our research and assessment for the energy sources and storage options.

4.1.1.1. Onshore Wind[6]

Assessment characteristic	Summary of assessment
Commercial feasibility	Onshore wind is deemed commercially feasible in BC, as demonstrated by the existing onshore wind farms.
Regulatory limitations	The development of onshore wind resources is not barred.
Firming/shaping/storage	Wind provides no traditional firming or shaping capability. It is a non-dispatchable, intermittent resource.

[6] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 4, Table 4-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf;
Zero Emission Energy Developments Inc. website. http://zeroemissiondevelopments.com/zed-projects/;
EnergyBC Electricity Generating Stations in British Columbia Map. http://www.energybc.ca/electricitymap.html;
Boralex Moose Lake Wind Project website. http://www.boralex.com/projects/mooselake;
Meikle Wind project website. http://meiklewind.com/;
Canadian Wind Energy Association website. http://canwea.ca/wind-energy/installed-capacity/;
Canadian Wind Energy Association (CanWEA) Pan-Canadian Wind Integration Study (PCWIS). http://canwea.ca/wind-integration-study/wind-data/;
GE Renewable Energy website. https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines;
MIT Technology Review Wind Turbines, Battery Included, Can Keep Power Supplies Stable. https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/;
EPRI Wind Power Integration: Energy Storage for Firming and Shaping. https://www.epri.com/#/pages/product/000000000001008388/;
Hydro-Québec website - Combining Wind and Water. http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook;
NEB Canada's Renewable Power Landscape - Energy Market Analysis 2016. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2016cndrnwblpwr/index-eng.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Hydro-Québec website - Combining Wind and Water. http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html;
IESO 2015 Year-End Data: Electricity Production, Consumption, Price and Dispatch Data. http://www.ieso.ca/corporate-ieso/media/year-end-data/2015;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Hatch Wind Data Study Update Report for BC Hydro. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf;
Alberta Electric System Operator (AESO) 2017 Long-term Outlook and data file. https://www.aeso.ca/grid/forecasting/;
IEA Wind Annual Report for 2015. https://www.ieawind.org/annual_reports_PDF/2015/2015%20IEA%20Wind%20AR_small.pdf;
REN 21 Renewable 2017 Global Status Report. http://www.ren21.net/gsr-2017/chapters/chapter_02/chapter_02/#wind-power-markets;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
Wind Power Monthly website - Turbine advances cut O&M costs. http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

Grid reliability (e.g., dispatchability)	Wind is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, there is an opportunity to leverage hydroelectric resource as a storage medium to balance intermittency in wind power.
Direct GHG emissions	Direct GHG emissions from onshore wind generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for onshore wind range from $1,600 to $3,200/kW, and fixed O&M costs range from $70 to $110/kW-yr.
Future costs	Capital costs for wind are expected to fall by 10-12% per MW in the next 10-20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.2. Offshore Wind[8]

Assessment characteristic	Summary of assessment
Commercial feasibility	Offshore wind is used commercially in other jurisdictions, but has not yet been proven to be commercially feasible in BC.
Regulatory limitations	The development of offshore wind is not barred.
Firming/shaping/storage	Wind provides no traditional firming or shaping capability. It is a non-dispatchable, intermittent resource.
Grid reliability (e.g., dispatchability)	Wind is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, there is opportunity to leverage hydroelectric resources as a storage medium to balance the intermittency of wind power.

[8] NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
IEA Wind Annual Report for 2015. https://www.ieawind.org/annual_reports_PDF/2015/2015%20IEA%20Wind%20AR_small.pdf;
NaiKun Wind Energy Group Inc. – Benefits of the project. http://naikun.ca/the-project/project-benefits/;
NY Times – America's First Offshore Wind Farm Spins to Life. https://www.nytimes.com/2016/12/14/science/wind-power-block-island.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Nova Scotia Power - Capacity Value of Wind Assumptions and Planning Reserve Margin; http://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf;
GE Renewable Energy website. https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines;
MIT Technology Review Wind Turbines, Battery Included, Can Keep Power Supplies Stable. https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Hydro-Québec website - Combining Wind and Water. http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html;
NREL Energy Analysis of Offshore Systems. https://www.nrel.gov/wind/offshore-energy-analysis.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
REN 21 Renewable 2017 Global Status Report. http://www.ren21.net/gsr-2017/chapters/chapter_02/chapter_02/#wind-power-markets;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf;
IRENA The Power to Change: Solar and Wind Cost Reduction Potential to 2025. http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf;
NREL Distributed Generation Renewable Energy Estimate of Costs. https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
IRENA Innovation Outlook: Offshore Wind. http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=2742;
Wind Power Monthly website - Turbine advances cut O&M costs. http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

Direct GHG emissions	Direct GHG emissions from onshore wind generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for offshore wind resources in BC range from $2,700 to $8,700/kW, with fixed O&M costs of $240/kW-yr.
Future costs	Capital costs and O&M costs for offshore wind are both expected to fall by about 20-25% in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.3. Utility-Scale Solar PV[9]

Assessment characteristic	Summary of assessment
Commercial feasibility	Solar PV is commercially feasible in Canada. While the vast majority of installations are located in Ontario, there is a demonstrated example in BC.
Regulatory limitations	The development of Utility-Scale Solar PV is not barred.
Firming/shaping/storage	Solar power provides no firming or shaping capability. It is a non- dispatchable, intermittent resource.
Grid reliability (e.g., dispatchability)	Solar is not dispatchable by itself. However, it can be paired with battery storage to provide dispatchability. In addition, it has

[9] Sunmine website. http://www.sunmine.ca/;
Compass Renewable Energy Consulting Inc. British Columbia Solar Market Update 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf;
CanSIA Solar PV Overview of Solar Electricity Supply Chain in Canada. http://www.cansia.ca/solar-pv.html;
Compass Renewable Energy Consulting Inc. British Columbia Solar Market Update 2015. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf;
Prepared for Natural Resources Canada by Power Advisory LLC. Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Services. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf;
California ISO, First Solar, and NREL Using Renewables to Operate a Low Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant. https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
IESO Large Renewable Procurement (Independent Electricity System Operator). http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx;
US Department of Energy website, Energy Department Announces More than 90% Achievement of 2020 SunShot Goal, Sets Sights on 2030 Affordability Targets. https://energy.gov/eere/articles/energy-department-announces-more-90-achievement-2020-sunshot-goal-sets-sights-2030;
Navigant Marginal cost of wind and solar PV electricity generation. http://www.ieso.ca/-/media/files/ieso/document-library/engage/fpr/fpr-20150625-navigant.pdf?la=en;
NREL Distributed Generation Renewable Energy Estimate of Costs. https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf;
IRENA The Power to Change: Solar and Wind Cost Reduction Potential to 2025. http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf;
NREL Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections. http://www.nrel.gov/docs/fy15osti/64898.pdf;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/;
NREL U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016. https://www.nrel.gov/docs/fy16osti/67142.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

	been shown to provide frequency response and voltage support with appropriate controls.
Direct GHG emissions	Direct GHG emissions from utility-scale solar PV generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for utility-scale solar PV range from $2,300 to $3,500/kW, and fixed O&M costs range from $30 to $35/kW-yr.
Future costs	Solar PV capital costs have been dropping in recent years and are expected to continue to drop by 35- 60% in the next 10 years. For the purposes of modeling, a conservative estimate of a 35% drop is assumed.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative-generation portfolio modeling.

4.1.1.4. Geothermal[10]

Assessment characteristic	Summary of assessment
Commercial feasibility	Geothermal is used commercially in other jurisdictions but not in BC. There is potential for it to be commercially feasible in BC in the next 15 years.
Regulatory limitations	The development of geothermal resources is not barred.
Firming/shaping/storage	Geothermal power can provide firming and shaping capability due its ability to be dispatched.
Grid reliability (e.g., dispatchability)	Geothermal energy is dispatchable and provides baseload power to the grid.
Direct GHG emissions	Direct GHG emissions from geothermal generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated geothermal capital costs range from $6,000 to $8,700/kW (dependent partially on size), and O&M costs range from $20 to $30/MWh.
Future costs	Capital costs associated with geothermal are expected to fall slowly, at about 0.5% per year through the forecast period as the technology matures.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative-generation portfolio modeling.

[10] Geoscience BC Section B Roadmap for Development of Geothermal Direct-use Projects in British Columbia, Canada. http://www.geosciencebc.com/i/project_data/GBCReport2016-07/GBC%20Report%202016-07_Section%20B_Roadmap.pdf;
Natural Resources Canada Geothermal Energy Resource Potential of Canada. http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf;
Clean Energy BC - Geothermal Power. https://www.cleanenergybc.org/about/clean-energy-sectors/geothermal;
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Geothermal Energy. http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch04.pdf.
FortisBC - Supply side resource options. https://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecResourcePlanning/Documents/2_Supply-Side_Resource_Options.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

4.1.1.5. Natural gas (SCGT and CCGT)[11]

Assessment characteristic	Summary of assessment
Commercial feasibility	Natural gas (SCGT and CCGT) generation is commercially feasible in BC and Canada, as demonstrated by existing plants.
Regulatory limitations	The development of natural gas generation is not barred; however, there are regulatory limitations to the development of natural gas generation resources due to the percentage of clean electricity generation required in BC, as per the Clean Energy Act.
Firming/shaping/storage	Natural gas generation provides traditional firming and shaping capability. SCGTs are generally better suited for firming/shaping than CCGTs, given typically better ramping responsiveness.
Grid reliability (e.g., dispatchability)	Natural gas generation is dispatchable.
Direct GHG emissions	Direct GHG emissions from natural gas generation are assumed to be approximately 520 to 632 g CO2e/kWh for existing SCGTs in BC and 364 to 375 g CO2e/kWh for CCGTs.
Current costs	Estimated costs related to natural gas generating technologies are: CCGT: capital costs of $1,200 to $2,500/kW, annual fixed O&M costs of $15 to $25/kW-year, and variable O&M costs of $5 to $10/MWh. SCGT: capital costs of $1,000 to $2,000/kW, annual fixed O&M costs of $10 to $25/kW-year, and variable O&M costs of $5 to $15/MWh.
Future costs	Capital costs associated with natural gas generation are not expected to decline significantly in the future. Applying a carbon price would increase operating costs.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

[11] FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook.
Alberta Electric System Operator (AESO) 2017 Long-term Outlook and data file. https://www.aeso.ca/grid/forecasting/;
Government of British Columbia Consolidated B.C. Emissions Report Summaries for 2015. http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg;
FortisBC heat content values. https://www.fortisbc.com/NaturalGas/Business/PriceAndMarketInformation/Pages/Heat-content-values.aspx;
Environment and Climate Change Canada National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

4.1.1.6. Run-of-river hydroelectricity[12]

Assessment characteristic	Summary of assessment
Commercial feasibility	Run-of-river hydroelectricity is commercially feasible in BC (subject to seasonal river flows), as demonstrated by existing projects.
Regulatory limitations	The development of Run-of-river hydroelectricity is not barred.
Firming/shaping/storage	Run-of-river hydro power is a non-dispatchable, intermittent resource and therefore does not normally provide firming or shaping capabilities. However, run-of-river hydro with pondage can provide dispatchable baseload with firming and shaping capabilities.
Grid reliability (e.g., dispatchability)	Run-of-river hydro power with pondage can provide dispatchable baseload.
Direct GHG emissions	Direct GHG emissions from run-of-river hydroelectricity generation is assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated run-of-river hydro costs vary greatly, between $2,700/kW to more than $8,000/kW depending on the remoteness of the area, with estimated fixed O&M costs of $40/kW-yr.
Future costs	Capital costs associated with run-of river projects are not expected to change significantly in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

[12] Kerr Wood Leidal Run of River report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-run-of-river-report-20150710-kwl.pdf;
Clean Energy BC - Run of River Hydro in BC. https://www.cleanenergybc.org/about/clean-energy-sectors/run-of-river.
Devlin Gailus Barristers and Solicitors A Review of Environmental Regulation of Run of River Power Projects in British Columbia. http://www.dgwlaw.ca/wp-content/uploads/2014/12/Testing_the_Waters_April_2010.pdf;
Pacific Salmon Foundation Potential impacts of run of the river power hydro projects on salmonids. https://www.psf.ca/sites/default/files/ROR_Report.pdf.
IRENA Renewable energy technologies: Cost Analysis Series. https://hub.globalccsinstitute.com/sites/default/files/publications/138178/hydropower.pdf.
BC Hydro Electricity Supply Options- Chapter 3. https://www.bchydro.com/energy-in-bc/planning-for-our-future/electricity-supply-options.html.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Energy BC - Run of River Power. http://www.energybc.ca/runofriver.html#section16;
Natural Resources Canada Emerging Hydropower Technologies R&D in Canada - A Strategy for 2007-2011. http://www.nrcan.gc.ca/energy/publications/sciences-technology/renewable/small-hydropower/6489;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

4.1.1.7. Tidal[13]

Assessment characteristic	Summary of assessment
Commercial feasibility	While tidal-power technology is currently being tested in BC, there is currently not enough information to determine if this technology is commercially feasible in BC.
Regulatory limitations	The development of tidal-power generation is not barred.
Firming/shaping/storage	Tidal power is not dispatchable and does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Tidal energy is not dispatchable, but can be highly predictable and reliable.
Direct GHG emissions	Direct GHG emissions from tidal electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for tidal energy vary significantly from $8,000 to $21,000/kW. However, due to the high costs associated with the engineering of these projects, as well as the costs of transmission to bring this power to market, this technology is likely cost prohibitive at this time.
Future costs	There are no projected future costs for tidal power in BC readily available; however, it is estimated in other jurisdictions that the cost of this technology could fall by approximately 25% by 2040.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[13] Energy BC website - Tidal Power. http://www.energybc.ca/tidal.html;
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Government of BC Clean Energy Production in B.C., an Inter-Agency Guidebook for Project Development. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf.
International Renewable Energy Agency: Tidal Energy Technology Debrief. Brief #3. http://www.irena.org/DocumentDownloads/Publications/Tidal_Energy_V4_WEB.pdf.
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
World Energy Council 2013 - Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf.
Government of Nova Scotia - Nova Scotia Electricity System Review. Summary Report- Emerging Technology and Market Trend Studies. https://energy.novascotia.ca/sites/default/files/files/NS%20Electricity%20System%20Review%20Summary%20Report%20June%202014.pdf
Carbon Trust - Future Marine Energy. Results of the Marine Energy Challenge: Cost competitiveness and growth of wave and tidal stream energy. http://ec.europa.eu/ourcoast/download.cfm?fileID=967.

4.1.1.8. Wave[14]

Assessment characteristic	Summary of assessment
Commercial feasibility	Based on the current available information, there is insufficient research and data available to support wave energy as a commercially feasible source of alternative energy for BC.
Regulatory limitations	The development of wave generation is not barred.
Firming/shaping/storage	Wave power is not dispatchable, and does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Wave energy is not dispatchable, but it is highly predictable and reliable.
Direct GHG emissions	Direct GHG emissions from wave electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	The range of capital costs varies significantly ($7,300 to $21,000/kW) due to the early stage of its development, and the varying size and development of commercial-scale installations. Due to the lack of sufficient data on the successful implementation and resourcing in BC, it is unlikely that this option is feasible at this time.
Future costs	The cost per kWh in other jurisdictions is predicted to fall by approximately 50-70% by 2040, as the technology is further developed.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, as the costs in BC are not mature enough to be assessed for commercial feasibility.

[14] Natural Resources Canada. The Atlas of Canada - Clean Energy Resources and Projects (CERP). http://atlas.gc.ca/cerp-rpep/en/;
Natural Resources Canada - West Coast Wave Initiative. http://www.nrcan.gc.ca/energy/funding/current-funding-programs/eii/16092;
Government of BC Clean Energy Production in B.C., an Inter-Agency Guidebook for Project Development. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf.
Kim et al. Catching the Right Wave: Evaluating Wave Energy Resources and Potential Compatibility with Existing Marine and Coastal Uses. http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0047598.
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Ocean Energy. http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch06.pdf.
World Energy Council 2013 - Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Government of Nova Scotia - Nova Scotia Renewable Energy Strategy. https://energy.novascotia.ca/sites/default/files/Nova-Scotia-Marine-Renewable-Energy-Strategy-May-2012.pdf.
Ernst & Young Cost of and financial support for wave, tidal stream, and tidal range generation in the UK. A report for the Department of Energy and Climate Change and the Scottish Government. http://webarchive.nationalarchives.gov.uk/20121205081857/http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20mix/renewable%20energy/explained/wave_tidal/798-cost-of-and-finacial-support-for-wave-tidal-strea.pdf;
Government of Nova Scotia Nova Scotia Electricity System Review. Summary Report- Emerging Technology and Market Trend Studies. https://energy.novascotia.ca/sites/default/files/files/NS%20Electricity%20System%20Review%20Summary%20Report%20June%202014.pdf

4.1.1.9. Nuclear[15]

Assessment characteristic	Summary of assessment
Commercial feasibility	Nuclear power is commercially feasible in Canada, as demonstrated by existing plants.
Regulatory limitations	Nuclear power is not aligned with the energy objectives of the Clean Energy Act, such that the BC government will not accept nuclear power as an option for meeting BC's energy needs. Unless there are changes to these regulatory limitations, this is not deemed to be a viable option.
Firming/shaping/storage	Nuclear power provides baseload power to the grid. It is neither dispatchable nor non-dispatchable. It does not provide a firming or shaping capability.
Grid reliability (e.g., dispatchability)	Nuclear power provides baseload power to the grid. It is neither dispatchable or non-dispatchable.
Direct GHG emissions	Direct GHG emissions from nuclear electricity generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for nuclear range from about $8,000 to $10,700/kW, with fixed O&M costs around $120/kW-yr.
Future costs	The capital costs associated with nuclear power generation are not expected to change considerably over the next 20 years.
Inclusion in the alternative generation portfolio model	No – it is not included in the alternative generation portfolio modeling, given that it is not aligned with the energy objectives of the Clean Energy Act.

[15] Nuclear Energy Institute - World Nuclear Generation and Capacity. http://www.world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx;
World Energy Council Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Nuclear Energy Institute - World Statistics: Nuclear Energy Around the World (Nuclear Energy Institute). https://www.nei.org/Knowledge-Center/Nuclear-Statistics/World-Statistics.
Government of BC - The BC Energy Plan. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf.
Natural Resources Canada Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Service. Energy and Mines Ministers' Conference. http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
Chu and Majumdar. Opportunities and challenges for a sustainable energy future. http://www.indiaenvironmentportal.org.in/files/file/sustainable%20energy.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
Ontario Energy Board - Ontario Energy Board Regulated Price Plan. https://www.oeb.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_May2016.pdf;
NEB Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040. https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf.

4.1.1.10. Biomass (wood-based)[16]

Assessment characteristic	Summary of assessment
Commercial feasibility	Wood-based biomass power generation is commercially proven in BC and Canada, although its financial viability depends on the source of biomass fuel.
Regulatory limitations	The development of biomass is not barred.
Firming/shaping/storage	Wood-based biomass can provide baseload power to the grid with firming and shaping capability. The biomass feedstock can also be stored to optimize power output
Grid reliability (e.g., dispatchability)	Wood-based biomass can provide baseload power to the grid. Steam-based plants using solid biomass can be ramped-up, but without the flexible peaking capability of other resources such as natural gas.
Direct GHG emissions	Direct GHG emissions from wood-based biomass generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for biomass generation range from $4,400 to $7,700/kW in BC, depending on the type of generation technology used. Fixed operating costs may range from $40 to $160/kW-year. Variable O&M costs range from $5 to $20/MWh. Fuel costs (including the costs to source and transport wood-based biomass) would vary depending on the distance from the source.
Future costs	Capital costs for biomass are not expected to fall significantly (less than 10%) in the next 10- 20 years.

[16] NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 4, Table 4-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Lessons Learned from Existing Biomass Power Plants. https://books.google.ca/books?id=55IGWS1C0Q4C&pg=PA105&lpg=PA105&dq=peaking+biomass+plant&source=bl&ots=YBOPQ-wfZG&sig=MmV1zRzB7i23oFs2pwjhUgZI48g&hl=zh-TW&sa=X&ved=0ahUKEwjW7via--HVAhUi5YMKHaFdCRIQ6AEIYDAK#v=onepage&q=peaking%20biomass%20plant&f=false;
IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook.
Energy Storage Association website - Flexible Peaking Resource. http://energystorage.org/energy-storage/technology-applications/flexible-peaking-resource;
AMEC Bioenergy Projects Technology Review for BC Hydro. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-20150722-amec-foster-wheeler.pdf.
Government of BC - B.C. Rural Development Progress Report. http://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/doing-business/rural-development/rural_dividend_progress_report_oct_2016.pdf;
Alaska Highway News website Kwadacha First Nation seeks to build biomass plant. http://www.alaskahighwaynews.ca/regional-news/kwadacha-first-nation-seeks-to-build-biomass-plant-1.2185149;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

Assessment characteristic	Summary of assessment
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.11. Biogas[17]

Assessment characteristic	Summary of assessment
Commercial feasibility	Biogas is commercially proven in BC and Canada.
Regulatory limitations	The development of biogas is not barred.
Firming/shaping/storage	Biogas can provide baseload power to the grid. It is neither dispatchable or non-dispatchable (i.e., it can be ramped-up over time, but not quickly enough to smooth out intra-day changes). It does not provide a shaping capability; however, the energy can be stored to enable smoothing of output.
Grid reliability (e.g., dispatchability)	Biogas power can provide baseload power to the grid. It can ramp-up slowly if LFG is stored; however, the ramp-up is slow (similar to coal and nuclear) so it cannot be dispatched to smooth intra-day changes.

[17] IESO Ontario Planning Outlook. http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook;
Natural Resources Canada - Map of Clean Energy Resources and Projects (CERP) in Canada. http://atlas.gc.ca/cerp-rpep/en/;
Metro Vancouver website - Annacis Island (Delta). http://www.metrovancouver.org/services/liquid-waste/treatment/treatment-plants/annacis-island/Pages/default.aspx;
Village Farms International, Inc. Management's Discussion and Analysis Year Ended December 31, 2016. http://villagefarms.com/wp-content/uploads/2017/04/4Q-2016-VFF-MDA-final.pdf;
Government of BC Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization. http://www.cscd.gov.bc.ca/lgd/infra/library/IRR_Landfill_Gas_Capture_Case_Study.pdf.
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
Suncurrent website - Biogas Utilization Electrical Generation website. http://suncurrent.co/biogas-utilization/electrical-generation/;
Suncurrent website - Suncurrent Biogas Utilization Storage website. http://suncurrent.co/biogas-utilization/storage/.
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2014. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2014hartland-gasmonitoring.pdf?sfvrsn=1f1d5dca_8;
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2015. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2015-hartlandlandfillgasmonitoringannualreport.pdf?sfvrsn=76572bca_12;
Capital Regional District, Hartland Landfill – Landfill Gas Monitoring Annual Report 2013. https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2013-hartland-landfill---landfill-gas-monitoring-annual-report-(appendix-b).pdf?sfvrsn=c6bc71ca_6;
Government of British Columbia Consolidated B.C. Emissions Report Summaries for 2015. http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg;
Metro Vancouver, Greater Vancouver Regional District Utilities Committee Meeting Agenda. http://www.metrovancouver.org/boards/Utilities/UC-Jun_15_2017-Agenda_Revised.pdf;
Metro Vancouver's Climate Actions 2016. http://www.metrovancouver.org/boards/ClimateAction/CAC-Jul_5_2017-Agenda_Revised.pdf;
City of Vancouver Administrative Report - Vancouver Landfill: Landfill Gas Projects. http://council.vancouver.ca/020205/a6.htm;
City of Vancouver Administrative Report - Vancouver Landfill: Selection of a Design-Build Contractor for Expanded Landfill Gas Control System Project. http://council.vancouver.ca/000328/a12.htm;
City Farmer website- Vancouver Landfill: Landfill Gas Collection and Utilization Project. http://cityfarmer.org/LandfillGas.html;
Village Farms International, Inc. Management's Discussion and Analysis Year Ended December 31, 2016. http://villagefarms.com/wp-content/uploads/2017/04/4Q-2016-VFF-MDA-final.pdf;
Government of BC Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization. http://www.cscd.gov.bc.ca/lgd/infra/library/IRR_Landfill_Gas_Capture_Case_Study.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

Assessment characteristic	Summary of assessment
Direct GHG emissions	Direct GHG emissions from wood-based biomass generation are assumed to be negligible (0 g CO2e/kWh).
Current costs	Estimated capital costs for biogas generation range from $2,400/kW to $4,400/kW in BC. O&M costs range from $140/kW-yr to $280/kW-yr. However, some of these O&M costs could offset landfill operating costs.
Future costs	Capital costs for biogas are not expected to fall significantly (less than 10%) in the next 10- 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.12. Biomass (municipal solid waste)[18]

Assessment characteristic	Summary of assessment
Commercial feasibility	Biomass - Municipal Solid Waste (MSW) is a commercially proven resource option, with one Waste to Energy (WTE) facility located in Metro Vancouver.
Regulatory limitations	The development of biomass is not barred.
Firming/shaping/storage	Waste to energy is dispatchable and can be used for firming and shaping.
Grid reliability (e.g., dispatchability)	Waste to energy can provide base load generation and is dispatchable.
Direct GHG emissions	Direct GHG emissions from MSW generation are assumed to be negligible (0 g CO2e/kWh).

[18] BioCAP Canada An Inventory of the Bioenergy Potential of British Columbia. http://cesarnet.ca/biocap-archive/images/pdfs/BC_Inventory_Final-06Nov15.pdf;
Government of BC, An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in British Columbia for First Nations, Small Communities, Municipalities and Industry. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc_bioenergy_primer.pdf;
Clean Energy BC website – Biomass. https://www.cleanenergybc.org/about/clean-energy-sectors/biomass;
Metro Vancouver, Generating Energy from Waste - Metro Vancouver's Waste-to-Energy Facility. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/WTEFactSheet.pdf;
Metro Vancouver, Management of MSW in Metro Vancouver. A comparative analysis of options of management of waste after recycling. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/SDD_3_AECOM_FULL_REPORT.pdf.
Natural Resources Canada website - Map of Clean Energy Resources and Projects (CERP) in Canada. http://atlas.gc.ca/cerp-rpep/en/;
Metro Vancouver, Management of MSW in Metro Vancouver. A comparative analysis of options of management of waste after recycling. http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/SDD_3_AECOM_FULL_REPORT.pdf;
BC Hydro Generating Renewable Electricity with Distributed Generation; A Self-assessment Toolkit for BC Local Governments. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2012q4/self-assessment_toolkit_form_oct2012_ar.pdf.
FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf;
Industrial Forestry Service Ltd. Wood Based Biomass in British Columbia and its Potential for New Electricity Generation. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-201507-industrial-forestry-service.pdf;
World Energy Council: Waste to Energy 2016. https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_Waste_to_Energy_2016.pdf;
IEA World Energy Outlook Investment Costs website. http://www.worldenergyoutlook.org/weomodel/investmentcosts/.

Assessment characteristic	Summary of assessment
Current costs	Estimated capital costs for energy from MSW range from $6,700 to $8,000/kW, with O&M costs of $130/kW-yr. In addition, since generation of electricity from MSW achieves two purposes (waste disposal and electricity generation), the allocation of costs between the dual purposes can affect the economics of generation.
Future costs	Capital costs for MSW/WTE are not expected to fall significantly in the next 10- 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.13. Cogeneration[19]

Assessment characteristic	Summary of assessment
Commercial feasibility	Cogeneration is commercially feasibile, and has been proven globally and in Canada.
Regulatory limitations	The development of cogeneration facilities is not barred.
Firming/shaping/storage	Cogen may be dispatchable, though its host use may prevent or limit the flexibility. In general, cogeneration is not used for firming, shaping, or storing electricity.
Grid reliability (e.g., dispatchability)	Cogen, like other types of distributed energy, produces and consumes power onsite, however, excess can be sold on to the grid. Electricity from cogeneration may be dispatchable, but host use may prevent or limit flexibility.
Direct GHG emissions	Direct GHG emissions from cogeneration are assumed to be approximately 300 g CO2e/kWh, depending on the technology.
Current costs	Estimated capital costs for cogeneration are approximately $1,300 to $5,000/kW, with O&M costs of $15 to $20/kW-yr. In addition, since cogeneration achieves two purposes (heat and electricity production), the allocation of costs between the dual purposes can affect the economics of electricity generation.

[19] Canadian Consulting Engineer Nanaimo sewage plant generates 2000 MW annually. http://www.canadianconsultingengineer.com/water-wastewater/nanaimo-sewage-plant-generates-2000-mw-annually/1001923726/;
British Columbia: Ministry of Agriculture, Regulating combined heat and power generation at greenhouses in the ALR. http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/agriculture-and-seafood/agricultural-land-and-environment/strengthening-farming/local-government-bylaw-standards/combined-heat-and-power-generation/chp_discussion_paper_-_may_2013.pdf.
Doluweera et al. Evaluating the role of cogeneration for carbon management in Alberta. https://scholar.harvard.edu/files/davidkeith/files/149.doluweera.etal_.evalrolecongeneration.e.pdf;
World Energy Outlook Projected Costs of Generating Electricity (2010). http://www.worldenergyoutlook.org/media/weowebsite/energymodel/ProjectedCostsofGeneratingElectricity2010.pdf;
Science Integrity Network Greenhouse gas emissions associated with various methods of power generation in Ontario. http://www.opg.com/darlington-refurbishment/Documents/IntrinsikReport_GHG_OntarioPower.pdf;
IEA Executive Summary. http://www.iea.org/textbase/npsum/ElecCostSUM.pdf;
NSW Government Office of Environment & Heritage: Energy Saver Cogeneration feasibility guide. http://www.environment.nsw.gov.au/resources/business/140685-cogeneration-feasibility-guide.pdf;
Center for Climate and Energy Solutions Cogeneration/Combined heat and Power. https://www.c2es.org/technology/factsheet/CogenerationCHP;
IEA Energy Technology Network: Energy Technology Systems Analysis Programme; https://iea-etsap.org/E-TechDS/HIGHLIGHTS%20PDF/E04-CHP-GS-gct_ADfinal%201.pdf;
EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
BVG Associates and KIC InnoEnergy, Future Energy Costs: Coal and Gas Technologies. http://www.innoenergy.com/wp-content/uploads/2016/09/CleanCoal_BF.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
Bloomberg New Energy Outlook 2017 Executive Summary. https://www.bloomberg.com/company/new-energy-outlook/EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

Future costs	Costs, particularly O&M costs, for cogeneration are expected to fall by approximately 10% in the next 10 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.14. Pumped storage[20]

Assessment characteristic	Summary of assessment
Commercial feasibility	Pumped storage is a commercially proven capacity resource option; however, it has not been implemented in BC.
Regulatory limitations	The development of pumped storage is not barred.
Firming/shaping/storage	Pumped storage provides a number of benefits, including storage, shaping, and firming.
Grid reliability (e.g., dispatchability)	Pumped storage is not an energy resource, but is a good capacity resource. It is a non-intermittent, dispatchable resource. Pumped storage can complement the intermittent nature of some renewables, firming these resources to ensure stable grid operation and reliable supply.
Direct GHG emissions	Direct GHG emissions from pumped-storage operations are assumed to be negligible (0 g CO2e/kWh).

[20] BC Hydro 2013 Resource Options Report Update - Lower Mainland/Vancouver Island Pumped Storage Report and North Coast Pumped Storage Report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a30-nov-2013-irp-appx-3a-30.pdf;
FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf.
IRENA Renewable Energy Integration in Power Grids Technology Brief. https://www.researchgate.net/profile/GL_Kulcinski/publication/223663980_Life_cycle_energy_requirements_and_greenhouse_gas_emissions_from_large_scale_energy_storage_systems/links/0c960526ec0ab00722000000.pdf;
IRENA Renewable Energy Technologies: Cost Analysis Series. https://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf;
Energy Storage Association website Pumped Hydroelectric Storage. http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage.
NEB Canada's Adoption of Renewable Power Sources Energy Market Analysis. http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html;
Environment and Climate Change Canada. National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada. https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1.
BC Hydro 2013 Resource Options Report Update - Mica Pumped Storage Report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a31-nov-2013-irp-appx-3a-31.pdf;
Northwest Hydroelectric Association Valuing Pumped Storage: Debunking Myths, Creating Tools. http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/2%20-%20Rick%20Miller.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf;
World Energy Council Cost of Energy Technologies. https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf;
Black & Veatch for PacifiCorp Bulk Storage Study for the 2017 Integrated Resource Plan. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf;
Lazard Levelized Cost of Energy Analysis 10.0. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/;
EIA Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017. https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.

Current costs	Research suggests that capital costs for pumped storage are highly variable, ranging from $1,600 to $7,300/kW, with O&M costs of 1-2% of capital costs.
Future costs	Capital costs for pumped-storage projects are not expected to change significantly in the next 20 years.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.1.15. Battery storage[21]

Assessment characteristic	Summary of assessment
Commercial feasibility	Battery storage as not a commercially feasible technology at the present time. However, there is increasing evidence that energy storage will eventually mature into a commercially viable, grid-scale resource over the time of the forecast to 2040.
Regulatory limitations	The development of battery storage is not barred.
Firming/shaping/storage	Battery storage provides a number of benefits, including storage, shaping, and firming.
Grid reliability (e.g., dispatchability)	Battery storage is not an energy resource but rather a mechanism for storage, and a good capacity resource. It is a non-intermittent, dispatchable resource. Battery storage can complement the intermittent nature of some renewables, firming these resources to ensure stable grid operation and a reliable supply.
Direct GHG emissions	Direct GHG emissions from battery storage are assumed to be negligible (0 g CO2e/kWh). Relevant GHG emissions should reflect the electricity-generation sources.

[21] FortisBC Inc. 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan). https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf;
Avista 2015 Electric Integrated Resource Plan Technical Advisory Committee Meeting No. 1 Presentation. https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/appendix-a-final.pdf?la=en;
The Climate Examiner Energy storage expanding and going mainstream. http://theclimateexaminer.ca/2015/03/12/energy-storage-expanding-going-mainstream/
Utility Dive 10 trends shaping the electric utility industry in 2017. http://www.utilitydive.com/news/10-trends-shaping-the-electric-utility-industry-in-2017/434541/;
Puget Sound Energy Puget Sound Energy 2015 IRP, Appendix L: Electric Energy Storage. https://pse.com/aboutpse/EnergySupply/Documents/DRAFT_IRP_2015_AppL.pdf;
California Energy Storage Alliance California Adopts Historic Energy Storage Targets. http://www.prnewswire.com/news-releases/california-adopts-historic-energy-storage-targets-228251181.html.
Deloitte Energy storage: Tracking the technologies that will transform the power sector. https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-energy-storage-tracking-technologies-transform-power-sector.pdf.
Scientific American, Study Indicates Bulk Energy Storage Would Increase Total U.S. Electricity System Emissions. https://blogs.scientificamerican.com/plugged-in/study-indicates-bulk-energy-storage-would-increase-total-u-s-electricity-system-emissions/.
Lazard's levelised cost of storage - version 2.0. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf;
Western Electric Coordinating Council Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies. https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf.
Utility Dive McKinsey: Cheaper batteries present imminent threat of load defection for utilities. http://www.utilitydive.com/news/mckinsey-cheaper-batteries-present-imminent-threat-of-load-defection-for-u/446193/;
World Energy Resources E-storage: Shifting from cost to value 2016. https://www.worldenergy.org/publications/2016/e-storage-shifting-from-cost-to-value-2016/;
PacifiCorp Battery Energy Storage Study for the 2017 IRP. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf;
E3 Review of Capital Costs for Generation Technologies. https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf;
ESMAP and IFC Energy Storage Trends and Opportunities in Emerging Markets. https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStorage-report.pdf?MOD=AJPERES;
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives. https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf;
Portland General Electric 2016 IRP. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en;
NW Council Seventh Power Plan. https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf;
PacifiCorp 2017 IRP. https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf;
Idaho Power 2017 IRP. https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf.

Current costs	Research suggests that capital costs for utility-scale batteries are highly variable (particularly by technology and size), ranging from $2,000 to $6,000/kW, with O&M costs of 1-2% of capital costs.
Future costs	Capital costs associated with battery storage are conservatively estimated to fall 50% by 2040.
Inclusion in the alternative generation portfolio model	Yes – it is included in the alternative generation portfolio modeling.

4.1.2. Implications for MarketBuilder portfolio modelling

Based on the assessment detailed above, as well as Deloitte's experience and professional judgment, the following alternative resource options and associated inputs will be included in the MarketBuilder model. The reason for their inclusion is to assess alternative sources of energy and capacity to replace those expected to be provided by Site C:

Table 1: Alternative resource options – MarketBuilder model inputs22

Alternative resources	Reference Capital cost ($CAD/kW)	O&M cost ($CAD/MWh)23	Direct GHG emissions (g CO2e/kWh)24	Capacity factor (%)
Onshore wind	2,400	33	0	30
Offshore wind	5,700	78	0	35
Utility-scale solar PV	2,900	18	0	20
Geothermal	7,300	25	0	92
Natural gas (SCGT)	1,300	12	580	92
Natural gas (CCGT)	1,700	9	370	92
Run-of-river hydroelectricity	5,300	49	0	36
Biomass (wood-based)	5,300	32	0	85
Biogas	3,600	32	0	66
Biomass (MSW)	7,300	27	0[25]	76
Cogeneration	3,000	10	300[26]	68
Pumped storage	3,300	13	0	n/a
Battery storage	2,500	24	0	n/a

[22] Detailed assumptions related to MarketBuilder portfolio modeling are included in Appendix F.
[23] O&M costs (fixed and variable depending on the resource) have been converted to a common unit of $CAD/MWh for input into the MarketBuilder model.
[24] The Clean Energy Act defines a "clean or renewable resource" as biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource. These alternative resource options are assumed to have zero direct GHG emissions.
[25] Estimated emissions from biomass – MSW (see section 4.1.1.12) are assumed to be zero based on the Clean Energy Act definition of biomass as "clean or renewable resource". While the non-biogenic component of MSW is not considered a "clean or renewable resource", this component can vary significantly. The overall impact on the modeling is not considered to be significant.
[26] Cogeneration is assumed to be natural gas fired (see section 4.1.1.13).

4.2. Assessment of the expansion potential of current BC Hydro facilities

4.2.1. Introduction

As one of the options for identifying alternative sources of electrical capacity we reviewed current BC Hydro hydroelectric facilities to determine if there are opportunities to expand current capacity.

To determine this expansion potential we reviewed the IRP, RRA and the individual Facility Asset Plans for each facility. The focus or our review was to identify additional capacity and associated capital costs. In identifying additional capacity we have used current capacity as the basis on which the additional capacity is calculated. As such, for facilities that have been derated, the derated capacity value is used as the basis and for facilities that are out of service, current production is assumed to be zero. In identifying values for additional capacity and associated capital costs we have relied on values identified in BC Hydro's Facility Asset Plans and the RRA. Our analysis identified assets where there is potential for expansion. We have not conducted a cost benefit analysis on each of these expansion options.

4.2.2. Summary of our assessment

We noted that there are several assets with expansion potential. The expansion potential relates to one of the following types of opportunities:

- Where there is an empty bay at an existing generating station which can be utilized to add a generating unit;
- Where the generating station can be replaced/refurbished to add capacity through enhanced efficiency and/or reinstate nameplate capacity;
- Where a generating facility can be added to an asset where there is no current power generation;
- Where individual components of the generating station can be refurbished/replaced to add capacity through enhanced efficiency; or
- Where additional untapped flow is available to add generating capacity.

4.2.3. Implications for MarketBuilder portfolio modelling

The additional capacities identified for each expansion project range from 2MW to 500MW in size. The total additional capacity identified ranges from 600MW to 1000 MW.The tables below list the specific facilities which, as we noted, have expansion potential.

Additional capacity identified by BC Hydro as planned/committed[27]:

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
1	Revelstoke	Revelstoke Install Unit 6	The scope of the Revelstoke Unit 6 project is to install a 500 MW unit in the existing empty Unit 6 bay. In addition, there is a transmission requirement for an additional series capacitor station on the transmission line	500	591-328	RRA Appendix J

[27] All committed BC Hydro expansion is included in the model as firm supply (exogenous variable).

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			from Vaseux to Nicola and some enhancements within existing substations.			
2	John Hart	John Hart Generating Station Replacement	The purpose of the project is to replace the existing John Hart Generating Station. The existing six unit, 121 MW generating station, located on Vancouver Island near the community of Campbell River, has been in operation since 1947. The age and condition of the John Hart facility indicate the need for significant capital investment in the powerhouse and penstocks to ensure reliable generation from the facility in the long term and to mitigate seismic and environmental risks. The John Hart Replacement Project includes: replacement of the existing powerhouse with a new three-unit 132.2 MW powerhouse with integrated flow bypass capability. The new facility will provide an additional 11.2 MW dependable capacity (from 121 MW to 132.2 MW) and approximately 10 per cent additional Resource Smart energy from the same amount of water.	11.2	1092.9	RRA Appendix J
3	Ruskin	Ruskin Dam Safety and Powerhouse Upgrade	The Project includes the replacement of parts of the seismically deficient Ruskin Dam and the rehabilitation/replacement of the 105 MW Ruskin Powerhouse, including generating equipment brought into service between 1930 and 1950, and associated substation.	9	718.1	RRA Appendix J Ruskin Public Report #10
4	Clowhom	Clowhom Rehabilitate Generating Station	The purpose of this project is to rehabilitate the Clowhom Generating Station to enable it to provide reliable, dependable energy and capacity.	0	90.9	RRA Appendix I Cost from FAP
5	Cheakamus	Cheakamus Units 1 and 2 Generator Replacement	The purpose of this project is to replace the Cheakamus generators which are in Poor condition. There is also an	40	73.4	Cost from RRA Appendix J,

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			opportunity to uprate the generators to achieve increased dependable capacity and energy.			capacity from FAP
6	Bridge river	Bridge River 2 Upgrade Units 5 and 6	The purpose of this project is to restore the reliability of the Unit 5 and 6 generators and their ancillary systems, as well as the reliability of other major components (governors, exciters and circuit breakers). The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.	54	83.3-52.5	Cost from RRA, capacity from RRA final arguments
7	Bridge river[28]	Bridge River 1 Upgrade Unit 4 Generator and Governor	This project will restore the capacity and reliability of the Unit 4 generator and governor. The project also presents an opportunity to increase the capacity of the generators to achieve incremental dependable capacity and energy.	18	35.6	Cost and capacity from FAP
8	Bridge river[29]	Bridge River 2 Upgrade Units 7 and 8	The purpose of this project is to restore the reliability of the Unit 7 and 8 generators and their ancillary systems, as well as the reliability of other major components such as the circuit breakers. The project also presents an opportunity to uprate the generators to achieve incremental dependable capacity and energy.	37	53.7	Cost and capacity from FAP

[28] It is assumed that the project will restore nameplate capacity and increase capacity by 15.38% in line with Bridge River 2 Unit 5 and 6 (Unit 4 capacity 50MW derated to 40MW. Refurbished back to capacity of 10MW).
[29] It is assumed that the project will restore nameplate capacity and increase capacity by 15.38% in line with Bridge River 2 Unit 5 and 6 (Unit 7 and 8 capacity 65MW. Unit 8 derated to 48MW).

Additional capacity identified by Deloitte to further expand existing BC Hydro facilities[30]:

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
9	Seven mile	Seven Mile Overhaul Units 1 to 3 Turbines	The purpose of this project is to overhaul Units 1 to 3 turbines in order to provide continued reliable service. The overhaul would address known issues such as cavitation repair to the runner and erosion repairs on the runner band seal. There is also an opportunity for a 2-3% efficiency gain by replacement of the runners with a new modern design.	32	100	RRA Appendix I & J; Additional Capacity from IRP table 3-25 page 3-70.
10	Alouette[31]	Redevelopment of the Alouette powerhouse	The purpose of the project is to redevelop the powerhouse. Efficiencies associated with new generating equipment would marginally improve the installed capacity of a like-for-like redeveloped 9 MW facility to approximately 9.7 MW based on the same unit parameters. If the powerhouse were to be redeveloped to utilize the Power Tunnel capacity of 57 cms, Alouette could attain an installed capacity of 21 MW. This would be approximately 8 MW - 18 MW of Winter Dependable Capacity.	9.7	100	BCUC IR 1.74.1 Attachment 1 Facility Asset Plan July 2013
				21	160	
11	Duncan[32]	Installation of generating facilities at Duncan Dam.	The purpose of the project is to install a generating facility. There are no power generation facilities at Duncan Dam currently. A two unit Vertical Axial type Kaplan option was found to be the most economical. The approach included a 22 MW small hydro generating plant, installation of a new sub-station at the dam site. Would not generate from mid-January to June due to operating limits of the units (based on reservoir head and	22	250	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan 2016

[30] The additional potential is included in the model as a supply option (endogenous variable).
[31] It is assumed that all capacity generated from the project will be in addition to current capacity. Alouette Generating Station has been out of service since February 2010.
[32] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			flow discharges). The levelized cost of energy was estimated to be $114/MWh.			
12	Elko[33]	Installation of an additional powerhouse	The purpose of the project is to install an additional generating facility. Previous Resource Smart studies identified the potential for adding additional capacity at Elko. This would be achieved by means of an additional powerhouse. A 20 MW additional unit in a standalone powerhouse was considered the most attractive alternative. It is recommended that a study be conducted as prior to the next major capital investment to evaluate this opportunity.	20	225	BCUC IR 1.74.1 Attachment 2 - Facility Asset Plan September 2013
13	Falls river[34]	Redevelopment of the Falls river powerhouse	The purpose of the project is to redevelop the powerhouse. Prior studies have assessed the likely re-development potential of Falls River to lie somewhere between 16 MW (9 incremental) and 25 MW (18 incremental). Based on historical inflows it is expected that the full MW rating would contribute to winter generating capacity for the region. Regional load forecasts developed by BC Hydro Energy Planning support the long-term strategy to increase generating capacity for the region.	9 18	165 260	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan April 2015
14	Ash River[35]	Refurbish of the Ash river powerhouse	The purpose of the project is to refurbish the powerhouse. Generating capability could be increased by replacing existing components in order to increase unit efficiency and make use of the additional	8	57	100 Site C Review - Deloitte Questions - August 2017 - Attachment

[33] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).
[34] Redeveloped capacities are assumed to be net of current capacity (i.e., 16MW and 25 MW minus 7MW) as the facility is currently generating power. The cost of redeveloping a powerhouse is assumed to be similar on a KW basis to that identified in the Alouette FAP of $10.3M/MW ($100M/9.7 MW).
[35] A project increase in capacity from derated value is assumed (from 25MW to 33MW). The cost of refurbishment is assumed to be the sum of 3 projects in the FAP Capital Plan (Generator $40M, Governor $6M, Turbine $11M). Unit Capacity of 28MW derated to 25MW.

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			available water. The new exciter and transformer have been sized to accommodate uprating of the unit to 33MW.			- Facility Asset Plan January 2016
15	Ash River[36]	Additional Generating Unit	The purpose of the project is to install an additional generating facility. There is an opportunity to increase the generating capacity at Ash River by tapping off the existing steel penstock and adding a new generating unit beside the existing facility. This is expected to provide an additional 9MW of capacity and 36GWh per year of energy. Any future upgrades to the water passage (such as replacement of the wood stave penstock) should consider sizing/selection to allow for future increased generation capacity. This may require a modification to BC Hydro's Water License.	9	101	
16	GM Shrum	U1-U5 Capacity Increase[37]	The purpose of the project is to enhance the capacity of the powerhouse. Units 1-5 capacity would increase to a dependable capacity of up to 220 MW.	220	71	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan November 2015
		Install 2 New Generating Units[38]	The purpose of the project is to install 2 new generating units. A resource opportunity had been identified in the 1970's to potentially add two new generating units in the low level outlets. This was predicated on a future diversion of water into the Williston Reservoir (The McGregor Diversion). There is no opportunity in the foreseeable future for this additional resource, and if one arises in the future, any new	TBD	TBD	

[36] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW).
[37] Capacity increase identified in IRP section 3 (pg. 69). Cost identified in FAP capital plan.
[38] Potential opportunity identified in FAP; no additional information provided.

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
			units would require a separate, new water passage.			
17	Ladore[39]	Additional Generating Unit	The purpose of the project is to install an additional generating unit. Ladore was designed for the potential installation of three generating units. Two units have been installed but there is an unused penstock available for a third unit.	9	11	BCUC IR 1.86.6 Attachment 1 - Facility Asset Plan October 2015
18	Seton[40]	Unit upgrade	The purpose of the project is to upgrade the existing unit. The current maximum generating capacity is 48MW with upgrade this will be 50MW.	2	20	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan September 2013
19	Shuswap[41]	Refurbishment of generating unit	The purpose of the project is to refurbish unit 1. Unit 1 is currently out of service due to the poor condition of multiple components and triggered by the generator phase-to-phase fault. Linked to the unit condition is the poor condition of the woodstave penstock.	3	6	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan August 2014
20	Strathcona[42]	Additional Generating Unit	The purpose of the project is to install an additional generating unit. The Strathcona Facility was designed for the potential installation of three generating units. Two units have been installed but there is an empty bay available for the installation of a third unit.	31.3	37	BCUC IR 1.87.6 Attachment 1 - Facility Asset Plan February 2014

[39] The cost of adding a unit is assumed to be similar on a kW basis to that identified in the RRA for the Revelstoke addition of $1.18M/MW ($591M/500 MW).
[40] Assumed project increase in capacity from current capacity value (from 48MW to 50MW).
[41] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Ash River FAP of $1.84M/MW ($61M/33 MW).
[42] The cost of adding a unit is assumed to be similar on a kW basis to that identified in the RRA for the Revelstoke addition of $1.18M/MW ($591M/500 MW).

#	Facility Name	Project Name	Project Description	Additional Capacity (MW)	Project Cost ($M)	Source
21	Wahleach[43]	Turbine Replacement	The purpose of the project is to install a new turbine. Given the very high pressure head at Wahleach (620 m at full reservoir), the water energy at the plant is very efficient and highly valuable. Thus, there is an opportunity to replace the turbine and increase the unit flexibility to produce up to 75 MW.	14	5.8	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan March 2016
22	Whatshan	Transformer replacement	The purpose of the project is to replace a transformer. Whatshan's maximum rated capacity of 55 MW is currently limited by the old transformer which was recently replaced with a new 65 MVA unit. The unit generator has an overload rating of 64 MVA and the turbine has a maximum nameplate capacity of 59.7 MW. Therefore, there is potential to increase the maximum rated capacity of the unit.	4.7	3.6	100 Site C Review - Deloitte Questions - August 2017 - Attachment - Facility Asset Plan January 2017
23	Puntledge[44]	Additional Generating Unit	Puntledge additional unit (Puntledge River, Vancouver Island)	10	115	IRP Chapter 3 table 3-25
24	Lajoie[45]	Additional Generating Unit	Lajoie additional unit (Bridge River/Fraser River area)	30	340	IRP Chapter 3 table 3-25

The potential of expansion of BC Hydro current BC Hydro facilities is included in the MarketBuilder model as follows:

- All existing BC Hydro generation capacity is included in the model as firm supply (exogenous variable).
- All planned/committed BC Hydro expansion is included in the model as firm supply (exogenous variable).
- Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

[43] Assumed project increase in capacity from current (from 61MW to 75MW).
[44] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW). This expansion potential is identified in the IRP but not in the FAP.
[45] The cost of developing a powerhouse is assumed to be similar on a kW basis to that identified in the Strathcona FAP of $11.25M/MW ($720M/64 MW). This expansion potential is identified in the IRP but not in the FAP.

The potential for expanding BC Hydro's existing facilities is included in MarketBuilder as follows:

- All existing BC Hydro generation capacity is included in the model as firm supply (exogenous variable).
- All committed BC Hydro expansion is included in the model as firm supply (exogenous variable).
- Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

4.3. Assessment of the opportunities to increase demand-side management

4.3.1. Introduction

As part of the assessment of alternative sources of energy and capacity to replace those due to be provided by Site C, Deloitte was asked by BCUC to assess BC Hydro's demand-side management (DSM) initiatives. The purpose is to identify opportunities to increase energy and capacity savings. DSM is considered an alternative-resource option in that it serves to meet future demand through energy conservation and efficiency.

BC Hydro considers two types of DSM measures: energy focused and capacity focused. Energy-focused DSM includes measures aimed at conserving energy and promoting energy efficiency to meet customer demand (which also includes associated capacity savings). Capacity-focused DSM measures are designed to deliver capacity savings during peak load periods. Both are included in the scope of this assessment and described in more detail below.

4.3.2. Additional limitations

This section of the report has been prepared pursuant to the following additional assumptions and limiting conditions:

1. The Advisor does not assess the cost-effectiveness of BC Hydro's DSM scenarios (as defined in the 2013 IRP, F17-F19 RRA, or otherwise) or the specific measures included therein beyond the publically available analysis previously conducted by BC Hydro. It reflects assumptions at that time.
2. The Advisor does not assess the performance, cost effectiveness, or other characteristics of DSM programs or initiatives offered by other utilities and used as examples.
3. Information related to BC Hydro's DSM initiatives provided to The Advisor have been accepted without any verification as fully and correctly reflecting the business conditions and results for the respective periods. The Advisor has not audited, reviewed, or compiled any information provided and, accordingly, expresses no audit opinion or any other form of assurance regarding such information.
4. The Advisor does not provide assurance on the achievability of any forecasted DSM results contained herein. This is for several reasons: events and circumstances frequently do not occur as expected; differences between actual and expected results may be material, and achievement of the forecasted results is dependent on actions, plans, and assumptions of management.

4.3.3. Summary of assessment

4.3.3.1. Current DSM Plan – base case used in MarketBuilder modeling

In the 2013 Integrated Resource Plan (IRP), BC Hydro describes five options for energy-focused DSM that also provide capacity savings (summarized in Table 2). While all of the options were determined to be cost effective according to the Total Resource Cost (TRC) and Utility Cost (UC) tests[46], BC Hydro determined DSM Option 2 to be the most cost-effective target at the time.

[46] The TRC test measures the overall economic efficiency of a DSM initiative from a resource options perspective based on its total cost including both customer participant and the public utility's costs. The UC measures the costs of the DSM initiative from the utility's perspective, excluding any costs of the participant. The benefits are similar to the TRC utility benefits (avoided supply costs and capacity). The UC test result indicates the change in total utility bills (revenue requirements) due to DSM). For the TRC and UC tests, the long-run marginal cost of electricity from the 2013 IRP ($85/MWh) was used to compare DSM investments against other options. In addition, BC Hydro added an extra UC test screening filter using the B.C.-border sell price forecast (approximately $36/MWh) to prioritize DSM investments. Any DSM initiative that did not pass the TRC test (at long-run marginal cost) and did not pass the UC test at the value of $36/MWh was investigated for

Table 2: Summary of DSM Options in 2013 IRP

DSM Option	Description	Energy savings by F2021 (GWh/yr)	Capacity savings by F2021 (MW)	Total Resource Cost ($/MWh)	Utility Cost ($/MWh)
Option 1	A scaling back of the current DSM activities to generally meet 66% of the load growth.	6,100	1,200	32	18
Option 2	An update of BC Hydro's current DSM Plan with a balanced offering of codes and standards, conservation rate structures, and programs.	7,800	1,400	32	18
Option 3	Expands programs to the limit of cost-effectiveness. Keeps codes and standards and conservation rate structures the same as in Option 2.	8,300	1,500	35	22
Option 4	Builds upon Option 3 and expands the codes and standards and conservation rate structure tools.	9,500	1,500	47	30
Option 5	Reflects an aggressive effort to change market parameters and societal norms and patterns in order to save electricity.	9,600	1,600	49	29

Subsequent to the 2013 IRP, the Fiscal 2017 to Fiscal 2019 Revenue Requirements Application (F17-F19 RRA) proposed an update to Option 2. This was done to further moderate the strategy for DSM investments, given the reduction in the rate of growth of demand for electricity and reduced need for additional resources[47]. Table 3 below compares BC Hydro's F17-F19 DSM expenditure schedule to that in the 2013 IRP. The "moderated" Option 2 described in the current F17-F19 DSM Plan is projected to achieve 5,300 GWh/yr in energy savings by 2021[48].

modifications to pass these tests, with the exception of the DSM initiatives required by the Demand-Side Measures Regulation.

[47] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

[48] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1. 168.1. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf. Savings are cumulative (risk adjusted with losses) with Fiscal 2013 start year for comparability with 2013 IRP data.

Table 3: Comparison of expenditures in BC Hydro 2013 IRP Option 2 and F17-F19 RRA DSM Plan[49]

	BC Hydro 2013 IRP F17-F19 ($m)	DSM expenditure schedule F17-F19 ($m)	Variance ($ m)	Variance %
Codes and Standards	18.5	14.5	(4)	(22%)
Rate Structures	6.6	3.5	(3.1)	(47%)
Programs:				
Residential	55.6	37.9	(17.7)	(32%)
Commercial	132.5	99.4	(33.1)	(25%)
Industrial	139.3	82.9	(56.4)	(40%)
Thermo-Mechanical Pulp	0	55.8	55.8	n/a
Total	**327.3**	**276**	**(51.3)**	**(16%)**
Supporting Initiatives	61.2	42.4	(18.8)	(31%)
Total before capacity DSM	413.6	336.4	(77.2)	(19%)
Capacity focused DSM	0	38.6	38.6	n/a
Total	**413.6**	**375**	**(38.6)**	**(9%)**

The moderated selected the moderated DSM Option 2 from the F17-F19 RRA was selected as the base case for portfolio modelling because it represents BC Hydro's current proposed DSM portfolio.

While the decision to moderate DSM spending in the F17-F19 RRA was supported by the Minister of Energy and Mines[50], it was also criticized by a number of third parties for curtailing cost-effective DSM[51,52]. Given these assertions, and the fact that BC Hydro has significantly curtailed its DSM initiatives over the past several years, an additional assessment was conducted to identify a DSM option with the potential for higher energy and capacity savings.

4.3.3.2. Assessment of alternate DSM scenarios with higher energy and capacity savings

In order to select an alternate DSM scenario with higher energy and capacity savings than the base case, Deloitte reviewed the options proposed by BC Hydro in its 2013 IRP to determine which could represent a realistic estimate of the DSM energy and capacity savings achievable by BC Hydro.

It is important to recognize that each of the DSM options outlined in the 2013 IRP was created as a specific portfolio with a suite of measures (e.g., programs, codes and standards, conservation rate structures) to achieve a particular path of energy savings over time. As a result, the suite of measures included in each option may no longer reflect the current market situation and specific DSM opportunities. For the purpose of

[49] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1.168.3. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[50] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix BB. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[51] BCSEA Final Argument. http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf
[52] CEC Final Argument. http://www.bcuc.com/Documents/Arguments/2017/DOC_49470_06-13-2017-CEC-Final-Argument.pdf

this assessment, we considered the options as energy savings targets, and did not assess the feasibility or cost-effectiveness of each measure within the portfolio of options.

Based on a review of the five DSM options against the criteria below, Option 3 was selected as the alternate scenario. While DSM Options 1 to 5 were all considered to be cost effective at the time of the 2013 IRP, and to contribute towards energy and capacity savings beyond the current state, Options 1 to 3 were the only options considered to be technically feasible. DSM Options 4 and 5 were determined to require significant government intervention, including changes to policies, codes and standards that are outside of the control of the utility.

The criteria used to select the alternate DSM option included the following:

- DSM performance of BC Hydro against peer utilities in North America
- Technical feasibility of BC Hydro achieving the target defined in the option
- Cost-effectiveness of achieving the option (at time of 2013 IRP)

The results from the assessment are summarized below:

DSM performance – BC Hydro's current performance on energy savings as a percentage of revenue is below industry average as compared to U.S. utilities. BC Hydro's overall energy savings from DSM programs as a percentage of retail sales was 0.6% for the period 2014-2016[53]. The 2017 American Council for an Energy Efficient Economy (ACEEE) benchmarking report of U.S. utilities estimates an average of 0.9% savings can be achieved, with leaders demonstrating savings of 1.5% to 2.9[54]. While numerous jurisdictional variances such as climate, political, and socioeconomic factors make direct comparisons difficult, this illustrates that BC Hydro's energy-savings performance is below the industry average. This trend suggests that BC Hydro could take a more aggressive approach to DSM by implementing any of the five options to close the gap in energy-savings performance with other comparable utilities.

Technical feasibility of achieving efforts by BC Hydro – A review of considerations under Options 1 to 3 suggest the implementation of options is technically feasible. However, BC Hydro describes Options 4 and 5 as "not technically viable options for prudent utility planning." These options include significant government intervention in policies, codes and standards, and in some cases, considerable technological innovation and adoption. For example, DSM Option 5 considers changes to building codes, which would require residential and commercial buildings to reach net-zero electricity by FY2032. These substantial shifts in technology adoption are not considered achievable within the proposed timeframes. Therefore, it is assumed that only Options 1-3 are technically achievable for the purpose of utility planning. Option 3 was described by BC Hydro in the 2013 IRP as the "greatest level of DSM program savings currently considered deliverable"[55].

Cost effectiveness – While all options considered by BC Hydro in the 2013 IRP were considered cost-effective, DSM Options 1 to 3 were estimated to come in at a lower TRC and UC than DSM Options 4 and 5. While further analysis needs to be done to evaluate the current costs of each option, Options 4 and 5 had an estimated utility cost of $30/MWh and $29/MWh respectively, as compared to Option 3 with a cost of $22/MWh. A study of the total cost savings for utility energy efficiency programs in the U.S. concluded that the weighted average cost of electricity saved from utility energy efficiency programs from 2009 to 2013 was

[53] BC Hydro Final Argument. 415. http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
[54] 2017 ACEEE scorecard.
[55] BC Hydro 2013 Integrated Resource Plan. Chapter 4 – Resource Planning Analysis. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf

$US23/MWh[56]. Therefore, it is assumed that DSM Option 3 is consistent with DSM opportunities implemented across utilities in the US, and is more cost effective than Options 4 and 5.

4.3.3.3. Opportunities to achieve or exceed Option 3

Quantifying and modeling the potential energy and capacity savings associated with new DSM portfolios or specific measures were beyond the scope of the assessment. However, a number of observations were identified that support the assessment that there is significant potential for BC Hydro to increase its DSM savings beyond its current portfolio to at least those represented by DSM Option 3. These observations are summarized in the following section.

a) Energy-Focused Demand Side Management

Expenditure on energy-focused DSM

BC Hydro's total DSM spending as a percentage of revenue was 2.3% for the period 2014-2016[57]. The 2017 ACEEE benchmarking report of U.S. utilities estimates an average of 2.7%, with leaders (the top five by ranking) demonstrating expenditures of 4.8-11.7% of revenue[58]. This illustrates that BC Hydro's DSM expenditures are somewhat below the industry average.

A comparison conducted by BC Hydro between its sectoral DSM program spend/results and the results of a 2014 Lawrence Berkeley study[59] demonstrate that BC Hydro's residential program spending in particular is significantly below other jurisdictions (see Table 4).

Table 4: Comparison of expenditures by BC Hydro vs. other jurisdictions[60]

	DSM Expenditures		
	Other jurisdictions	**BC Hydro F2014-16**	**BC Hydro F2017-19**
Residential	29%	11%	9%
Low Income	6%	2%	3%
Commercial and Industrial	61%	71%	75%
Cross sectorial	4%	16%	13%

While BC Hydro's FY17-19 DSM Plan did increase spending in some areas (e.g., the industrial thermo-mechanical pulp program, which was not included in the 2013 IRP), there are several notable areas where expenditures on energy-focused DSM decreased:

[56] Berkeley Lab – The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf
[57] Calculated based on actual DSM results included in Exhibit B-9 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf and revenues from BC Hydro annual reports.
[58] 2017 ACEEE scorecard. It is important to note that some states have implemented energy efficiency spending caps for utilities that limit cost-effective energy savings opportunities.
[59] The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs. Ernest Orlando Lawrence Berkeley National Laboratory, 2014. http://utilityscalesolar.lbl.gov/sites/all/files/lbnl-6595e.pdf
[60] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1.168.3. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

- Residential programs – decrease in spending of $17.7 million (-33%)
- Commercial programs – decrease in spending of $33.1 million (-25%)
- Supporting initiatives – decrease in spending of $18.8 million (-31%)

Overall, BC Hydro's energy-focused DSM expenditures proposed in the FY17-19 DSM Plan have decreased by 32% relative to the 2013 IRP (not including capacity-focused pilot spending and the Thermo-Mechanical Pulp program[61], which were not included in the 2013 IRP). Including the Thermo-Mechanical Pulp program, expenditures have decreased by 19% (see Table 3).

Evaluation of energy-focused DSM

Over the long-term, BC Hydro's forecasted, incremental DSM energy savings from the F17-F19 RRA DSM Plan level off (post-2021) and begin to decline, dropping below zero by 2036[62]. In discussion with BC Hydro, management noted that their projections simplify over the long-term due to the uncertainty involved. However, there are examples of other utilities taking a different approach to forecasting long-term energy savings.

For example, in its Long-Term Energy Plan, Ontario's Independent Electricity System Operator (IESO) includes estimates for the energy savings from future programs, codes and standards, in addition to currently planned measures. According to IESO, "To achieve the longer-term target, it is assumed that conservation programs will continue to be made available to customers after the Conservation First Framework ends. The focus and design of future programs will be determined based on future sector and market conditions and on the experience gained in the current framework"[63].

An additional opportunity for BC Hydro to increase forecasted energy savings from DSM could exist through changes in the approach used to estimate energy savings from codes and standards. Subsection 4(1.4) of the Demand-Side Measures Regulation permits the BCUC to attribute a portion of the avoided energy and capacity costs that will result from a code or standard to a demand-side measure that will increase the use of a "regulated item"[64]. However, as outlined in Chapter 10 of the RRA, BC Hydro has not included the attribution of savings from codes and standards in calculating the cost tests to assess the feasibility of DSM programs[65].

BC Hydro acknowledges that the attribution of codes and standards savings would result in improved cost effectiveness test results for some DSM programs. However, it argues that it would present practical challenges and, given that the programs included in the DSM Plan did not require the attribution of savings from codes and standards to pass the cost tests, it is not worth the time, effort, and cost[66].

---

[61] Expenditures for the Thermo-Mechanical Pulp program are shown separately from other industrial program spending, because the costs of this program are covered by the Direction to the British Columbia Utilities Commission Respecting the Authority's TMP Program (B.C. Reg. 139/2015).
[62] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 3, Table 3-8. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[63] Ontario Planning Outlook, IESO, 2016. http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/ontario-planning-outlook-september2016.pdf?la=en
[64] Demand-Side Measures Regulation. 2008. http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section4
[65] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[66] Letter dated November 21, 2016 – BC Hydro Submitting Responses to Interveners Information Request No. 1 (Exhibit B-10). http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf

Despite this, it is possible that this lack of attribution could result in BC Hydro scaling back or eliminating a DSM program that might otherwise have been maintained. For example, in the F17-F19 DSM Plan BC Hydro eliminated the residential New Home Program on the basis of cost-effectiveness, shifting its focus instead to codes and standards.

Specific opportunities to increase energy-focused DMS

The 2017 ACEEE report identifies the breadth and types of efficiency programs (e.g., small business, low income, multifamily) as "essential determinants of utility energy efficiency capability and performance." It notes a number of emerging program areas that reflect new trends and opportunities in the industry[67]. While some of these are already being pursued by BC Hydro, many are not.

Table 5: BC Hydro's pursuance of emerging programs (as defined by ACEEE)

Emerging area	Description	Status at BC Hydro
Advanced space-heating heat pumps	Programs that encourage the adoption of cold- or warm-climate heat pumps with a Heating Seasonal Performance Factor (HSPF) above 10. To receive credit, utilities must provide extra incentives for advanced heat pumps relative to those provided for moderate-efficiency heat pumps.	• BC Hydro does offer incentives for heat pumps through its Home Energy Retrofit Offer program[68], but it does not appear to be pursuing programs that specifically encourage the adoption of heat pumps with HSPF above 10 at this time[69].
Commercial and industrial geo-targeting	Energy efficiency programs that target businesses in specific geographic locations that will yield high savings. Does not include geo-targeted marketing efforts or comparative business energy report programs.	• BC Hydro does not appear to be pursuing this at this time.
Conservation voltage reduction (CVR), or volt/ volt-ampere reactive (Var) optimization (VVO)	Voltage-reduction systems to improve the efficiency of a utility's transmission and distribution system, whether explicitly included in the utility's energy efficiency portfolio or not.	• BC Hydro is pursuing Var and Voltage Optimization energy reductions; however, this is not currently classified as a DSM measure[70].
Energy use feedback to consumers in real time	Programs that allow consumers to better understand their behavior and react to their energy usage to increase savings. Includes programs that provide feedback in near real time.	• BC Hydro does not appear to be pursuing this at this time. An Energy Insights program aimed at providing proactive information to customers about energy consumption has been deferred[71].
Heat pump water heaters	Programs to improve the efficiency of water heating systems, either stand-	• BC Hydro does not offer a heat –pump, water heater program at this time;

[67] ACEEE 2017 scorecard
[68] BC Hydro – Home renovation rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
[69] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 186.2 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[70] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 3. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[71] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 114.9. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

Emerging area	Description	Status at BC Hydro
	alone or included as part of another program.	however, it does have a technical trial in the marketplace and will be investigating the potential for a program offer[72].
High-efficiency ceiling fans	Efforts to promote the installation of high-efficiency ceiling fans, either stand-alone or included as a part of another program.	• BC Hydro does not appear to be pursuing this at this time. However, it does offer incentives for bathroom ventilation fans through its Home Energy Retrofit Offer program[73],
High-efficiency consumer electronics (residential)	Efforts to promote the purchase and use of high-efficiency consumer electronics, including through rebates, midstream and upstream programs, and the use of smart strips with consumer electronics.	• BC Hydro supports product and equipment standards (including residential electronics) and offers rebates on consumer electronics through the Retail program[74]. However, funding for this program was reduced by 35% in the F17-F19 DSM Plan.
High-efficiency residential clothes dryers	Programs offering rebates for high-efficiency clothes dryers, or participation in the Super-Efficient Dryers Initiative. Does not include advocacy for dryer efficiency standards.	• BC Hydro does provide appliance rebates through its Retail program (seasonal only)[75]. However, funding for this program was reduced by 35% in the F17-F19 DSM Plan[76].
Midstream and upstream programs	Programs to transform the market for energy-efficient products by targeting midstream and/or upstream retailers and partners to improve choices and reduce costs for consumers. Includes midstream and upstream lighting and appliance programs. Midstream and upstream programs are scored separately.	• BC Hydro does support market transformation through its Commercial and Residential Sector Enabling Initiatives[77].
Quality HVAC installation	Programs to improve and ensure the quality installation of HVAC equipment.	• BC Hydro does not appear to be pursuing this at this time[78].
Reduction of plug and other miscellaneous load in commercial buildings	Programs that aim to reduce plug or other loads in commercial buildings, including midstream and upstream programs.	• BC Hydro does provide support for strategic energy management in commercial buildings through its Leaders in Energy Management – Commercial program (though not targeted to the

[72] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 186.2 http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[73] BC Hydro – Home renovation rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
[74] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[75] BC Hydro – Appliance Rebates. https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/appliance-rebates.html?WT.mc_id=F18_spring_appliances_bchpromos
[76] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 184.6. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[77] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[78] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 184.2. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf

Emerging area	Description	Status at BC Hydro
		reduction of plug and other, miscellaneous load)[79].
Residential geo-targeting	Energy efficiency programs that target residents in specific geographic locations that will yield high or particularly valuable savings. Does not include geo-targeted marketing efforts or comparative home energy reports.	• BC Hydro does not appear to be pursuing this at this time. BC Hydro's DSM programs are province-wide offerings[80].
Residential learning thermostats	Programs to boost savings for consumers by increasing energy-efficient behaviors through smart thermostats. Includes learning thermostats, Wi-Fi enabled thermostats, and other smart-thermostat programs.	• BC Hydro does not offer programs to increase energy-efficient behaviors through smart thermostats at this time. It is in the early stages of researching demand-response programs, including programmable, communicating thermostats and other connected home technologies[81].
Zero net energy buildings	Developing zero net energy buildings through codes and standards or other methods. Does not include programs or participation in zero net energy forums or coalitions.	• BC Hydro is actively focused on building codes. However, it has cancelled the New Home Program encouraging builders and developers to build energy-efficient homes[82].

b) Capacity-Focused Demand Side Management

Capacity savings from capacity-focused DSM are currently not quantified in BC Hydro's DSM plan projections. BC Hydro proposes to spend $38.6 M on capacity-focused DSM pilots over F2017-F2019 which, according to the F17-F19 RRA, are aimed at determining the dependability of targeted capacity savings for inclusion in BC Hydro's future integrated resource planning[83].

BC Hydro's 2010 Resource Options Report describes three options for capacity focused DSM[84]:

[79] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Appendix V. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[80] Letter dated January 23, 2017 - BC Hydro Submitting Responses to Intervener Information Request No. 2. 37.2. http://www.bcuc.com/Documents/Proceedings/2017/DOC_48632_B-15_BCH-Response-Intervener-IR-No2.pdf
[81] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[82] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[83] BC Hydro Fiscal 2017 to Fiscal 2019 Revenue Requirements Application. Chapter 10. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
[84] BC Hydro 2010 Resource Options Report. https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a01-nov-2013-irp-appx-3a-1.pdf

- Time-based rates that encourage and reward customers for shifting their electricity consumption to off-peak periods. Both Time-of-Use (TOU) rates and Dynamic Pricing (DP), such as critical peak pricing (CPP) and peak time rebate (PTR), are rate structures that could accomplish this objective.
- Capacity-focused programs that consist of a suite of programs that target capacity savings in all three customer sectors. They are designed to provide capacity savings that can be dispatched under utility control.
- Industrial load curtailment that targets large customers who agree to curtail load on short notice in return for a financial payment.

In the 2013 IRP, BC Hydro states that "since then, in accordance with government policy, BC Hydro has no plans to implement Time-Based Rates to address capacity requirements for residential and commercial customers." Nonetheless, 76% of the utilities surveyed in the ACEEE 2017 benchmarking report use Time-Based Rates[85].

Although BC Hydro has yet to quantify the potential savings from capacity-focused pilot programs, limited results to date demonstrate that these programs may provide a cost- effective source of new capacity. BC Hydro provided the following examples of incentives paid to customers through capacity-focused DSM pilots[86]:

- Residential hot water trial: The residential demand response pilot project focused on managing electric water-heating loads using wireless load control relays, and an alternative three-element water heater that typically operates at a lower demand than standard water heaters. BC Hydro offered customers $40/year (the $/kW-year will be determined after evaluating results for the three-year period ending March 2017).
- Commercial and industrial demand response trials: The commercial and industrial demand response pilot initiatives offer customers $0.25/kW-year through a manual-call, demand-response program where participants select their own actions for implementation (e.g., refrigeration, lighting, heating, ventilation).
- Industrial load curtailment pilot: The load curtailment program targets large industrial customers, offering them $75/kW-yr for up to 28 days of 16 hour per day curtailment (448 hours).

BC Hydro estimates the long run marginal cost for capacity to be $50/kW-yr to $55kW-yr (fiscal 2013 $) based on Revelstoke 6; however, it notes that this is a unique low-cost capacity option and is only available for approximately 500 MW. The next clean- generation capacity option is estimated to be pumped storage facilities (estimated at $200/kW-yr including the impact of energy losses in the pump generation cycle)[87].

While BC Hydro's capacity-focused projects are still in the pilot stage, there are numerous examples of utilities already successfully implementing and realizing savings from capacity-focused DSM programs, including:

Hydro Quebec

- Interruptible electricity options for large-power customers – Hydro-Québec Distribution can ask large-power customers that have signed up for the interruptible electricity option to reduce their power demand in return for financial compensation. Since 2006, the division has been offering a similar option to medium-power customers. The Electricity Supply Plan 2008–2017 provides for the renewal of these options, yielding an expected contribution of 1,000 MW[88].

---

[85] ACEEE 2017 scorecard
[86] Letter dated May 11, 2017 –BC Hydro Submitting Responses to Commission IRs on Rebuttal Evidence (Exhibit B-21). http://www.bcuc.com/Documents/Proceedings/2017/DOC_49232_B-21_BCH-Responses-BCUC-IR-No1.pdf
[87] Letter dated November 21, 2016 – BC Hydro Submitting Responses to BCUC Information Request No. 1. 168.1. http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
[88] Hydro Quebec Strategic Plan 2009-2013. http://www.hydroquebec.com/publications/en/docs/strategic-plan/plan-strategique-2009-2013.pdf

- Residential dual energy – A dual-energy heating system lowers the demand for power in peak periods, which are generally winter cold spells. This gives Hydro-Québec some leeway concerning the amount of electricity it has available to meet Québec customers' greatest demand for power at those times, and makes it easier to balance high electricity demand with availability[89]. This rate option provides for a 640-MW decrease in peak power requirements[90].

Manitoba Hydro[91]

- Bioenergy optimization programs – Launched in 2008, this program encourages customers to install, operate, and maintain customer-sited, load-displacement generation systems that employ heat and CHP applications fueled by renewable energy. The program is expected to achieve 12.2 MW of capacity savings and 32.5 GWh of energy savings in 2016/2017.
- Load-displacement program – Launched in 2014, this program encourages industrial and municipal customers to install, operate, and maintain customer-sited, load- displacement generation systems that employ combined heat and power (CHP) technologies relying on waste and by-product streams or locally available, low-cost sources of renewable energy. The program is expected to achieve 12.4 MW of capacity savings and 91.9 GWh of energy savings in 2016/2017.
- Curtailable rate program – This program allows qualifying customers to receive a monthly credit on load, which can be curtailed on notice from Manitoba Hydro. With 55 customers, this program is expected to achieve 159.5 MW of capacity savings in 2016/2017.
- Arizona Public Service Company (APS)[92]
- APS peak solutions program – A commercial and industrial demand response program utilizing direct load control and manual load reduction. This program is available for the summer months between 12pm and 7pm, and anticipated a 2016 weekday load reduction of approximately 25 MW.
- Residential battery storage program – The Arizona Corporation Commission has ordered APS to spend up to US$4 million to develop a residential, battery-storage program to facilitate energy-storage technologies through demand response or load management, allowing customers to lower energy use during times of peak demand[93]. While this is only a pilot program, it reflects the dramatic advancements in battery storage and surge in current utility-scale, battery project.

4.3.4. Implications for the MarketBuilder portfolio modeling

BC Hydro's current DSM Plan (i.e., "moderated Option 2/"mid DSM") was included in the MarketBuilder modeling.

It should be noted that running additional scenarios would offer more insights, for example, by applying Option 3 from the 2013 IRP, in order to consider a higher level of DSM energy and capacity savings.

---

[89] Hydro Quebec – Residential Dual Energy. http://www.hydroquebec.com/residential/customer-space/account-and-billing/understanding-bill/residential-rates/rate-dt.html
[90] Hydro Quebec 2014-2023 Supply Plan Integrated System.
[91] Manitoba Hydro 2016/2017 Demand Side Management Plan. https://www.hydro.mb.ca/corporate/pdfs/demand_side_management_plan.pdf
[92] APS 2016 Demand Side Management Implementation Plan. http://images.edocket.azcc.gov/docketpdf/0000162231.pdf
[93] Arizona Corporation Commission – Commission Approves Energy Efficiency Programs that Save APS Customers Money. http://azcc.gov/Divisions/Administration/news/2016Releases/7-13-2016%20Commission%20Approves%20Energy%20Efficiency%20Programs.pdf

5. Assessment of Load Forecast Model

This section provides an assessment of BC Hydro's load-forecast model published in July 2016 ("the Forecast Model"), which provides low, mid, and high projections for electricity load and capacity requirements in BC until F2036. The assessment is based on a review and analysis of public and confidential data provided by BC Hydro; interviews with BC Hydro's forecasting team; interviews with the forecasting teams of two other major utilities in Canada; and interviews with several subject matter professionals. Importantly, Deloitte has not accessed BC Hydro's model directly. As such, this assessment cannot independently validate the information received regarding the model, nor the exact impacts on the forecast from changing model inputs. On the basis of information provided, this assessment provides estimates of the direction and an order-of- magnitude calculation of impacts resulting from changes to several model inputs.

5.1. Description of the Load Forecast Model

BC Hydro forecasts future load and capacity requirements using two distinct methodologies. First, to produce its mid forecast, BC Hydro uses an additive, statistically adjusted end use (SAE) model, which technically consists of 12 sub models broken down by region and customer segment. In addition to the 12 SAE models, BC Hydro produces a linear regression for the light manufacturing sector, a model of FortisBC's expected load based on its cost of purchasing energy from markets, and two projections. The first projection, of heavy industrial load, consists of an assessment of load requirements for roughly 180 major clients, plus 20 to 30 prospective ones. It includes assumptions regarding the prospects of major capital projects, such as liquefied natural gas (LNG) plants, advancing to the construction phase. The second, which consists of 'all other' load requirements (e.g., streetlights and irrigation), is both small and more straightforward to estimate, as it has historically remained relatively stable compared with other market segments.

In addition to the mid forecast, BC Hydro produces high and low load requirement forecasts. These are the outcome of Monte Carlo simulations that model uncertainty with respect to consumers' responsiveness to future rate increases, the magnitude of future rate increases, and future provincial economic growth, among other variables. The inputs driving the Monte Carlo simulation are fewer and in some cases. different from the inputs driving the mid forecast. We understand that BC Hydro ensures that data that is common to the two models is consistent.

While these modeling approaches involve a high degree of complexity, they appear generally in line with the practices of other utilities, with some exceptions (see section 5.6). Potential risks and alternatives to these approaches are explored.

The mid, high and low forecasts are produced both before and after accounting for demand-side management (DSM) initiatives. These initiatives, which are designed to improve efficiency, and thus mitigate the need for major capital projects to increase electricity supply, are assumed to provide increased load and capacity savings over time. The gross forecasts prepared for each of the customer segments (e.g., residential) are then lowered by either a mid or low DSM factor, producing forecasts of net (or actual) future electricity requirements.[94]

[94] High DSM does not feature in either the Monte Carlo simulations or the mid forecast.

Interpreting the SAE and Monte Carlo models together can be conceptually challenging, as assumptions relating to DSM differ; as a result, the mid forecast of actual requirements is closer to the low projection than the high projection. In fact, while the Monte Carlo simulations are used to produce high and low pre-DSM forecasts that have equal probabilities of occurring (Figure 1), the DSM adjustment that is made to these forecasts is smaller than in the mid SAE forecast. As a result, the average of the high and low forecasts tends to be greater than the mid forecast produced by the SAE model (Figure 2). BC Hydro's rationale for applying low DSM to the low forecast is that it is unrealistic to assume that if electricity requirements were growing slowly, a mid- or high-DSM policy would be pursued. Presumably, however, this same reasoning would see high DSM applied to the high forecast, since mitigating demand growth would be comparatively more important—and cost effective—in an environment where load requirements are growing rapidly.

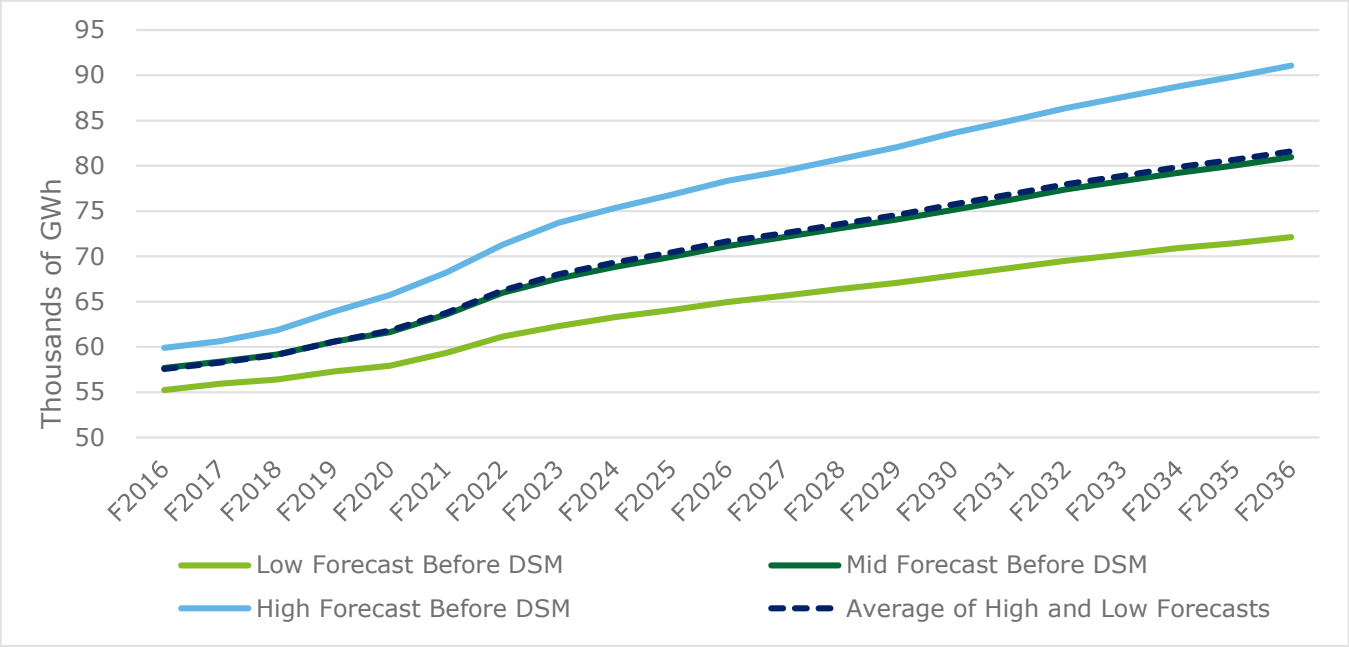


Figure 1: Total Integrated Gross Requirement Forecasts before DSM

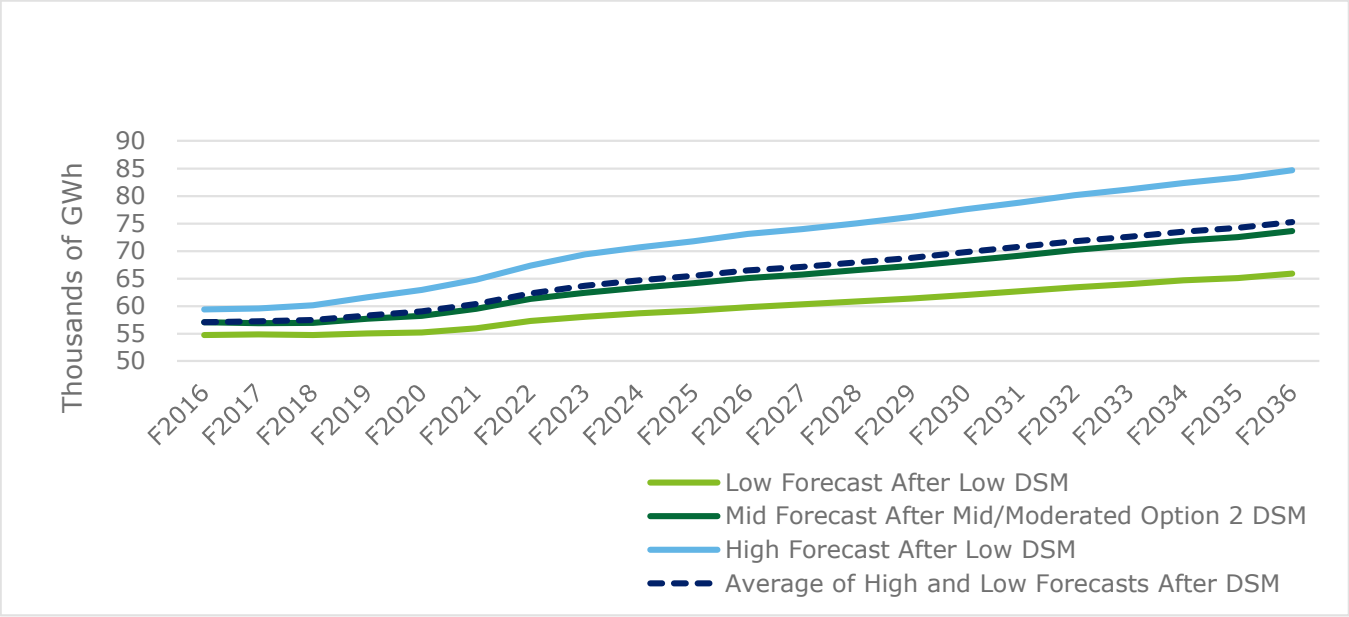


Figure 2: Total Integrated Gross Requirement Forecasts after DSM

5.2. Historical Model Performance

Forecasting several years or decades into the future is a difficult task that is prone to error regardless of the scenario being examined. This challenge is particularly hard in an electricity-demand context, where actual demand is driven by a large number of variables, some of which can change rapidly, such as advancement in energy efficiency, fluctuations in commodity prices, weather variability, and others. Nevertheless, forecast models should be routinely compared to actuals, and recalibrated to ensure that they do not result in systematic overestimation or underestimation. A high-performing forecast model is one that produces estimates relatively close to actuals, and results in relatively equal instances of overestimation and underestimation.

The analysis in this section uses BC Hydro's forecasts of total, gross load requirements after DSM. DSM cannot be measured with a high degree of accuracy as it is difficult to determine whether electricity consumers changed their level of demand as a result of DSM or for other reasons. Actual electricity demand measured by BC Hydro is by definition demand after DSM. When comparing actual demand to forecasted demand after DSM, some of the deviance from forecasted demand could be the result of a larger/smaller size of DSM compared with BC Hydro's expectations.

BC Hydro has run a load forecast model every year from fiscal 1964 onwards. Each model forecasts loads between five and twenty years into the future, as well as current fiscal year requirements. For all models between fiscal 1964 and 2016, there were 647 point estimates that can be compared to actual load demand. Of the 647 forecasted points, 500 (77%) were overestimates, with this being especially common since the global financial crisis (Figure 3). We explore the model's performance overtime and across customer segments below.

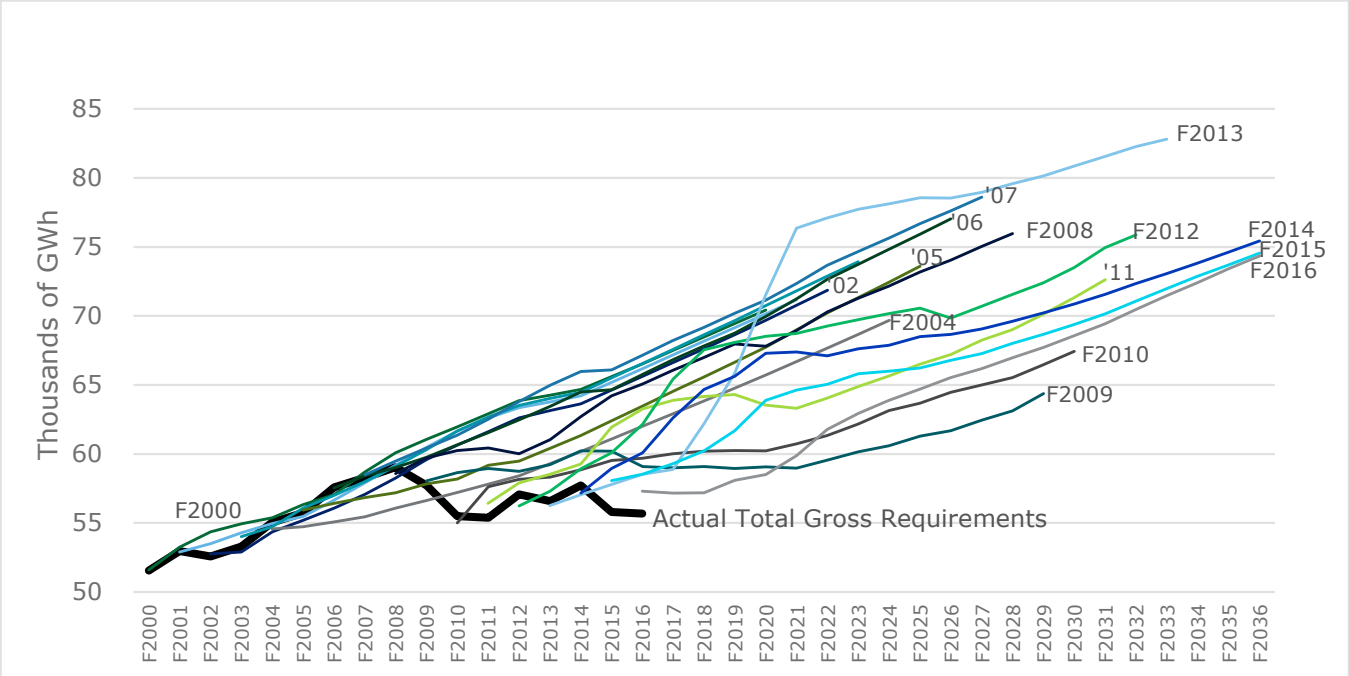


Figure 3: Total Gross Requirement Forecast Models Between 2000 and 2016 (with DSM

BC Hydro's load forecasts have performed better in the short-run compared with the long-run. Averaging over all point estimates from models starting in fiscal 1964 shows that forecasts in the first full year were overestimated on average by 1.7% of actual loads. Five-year forecasts were overestimated on average by 4.5% of actual loads, 10-year forecasts were overestimated on average by 12.2% of actual loads, 15-year forecasts were overestimated on average by 18.0% of actual loads, and 20-year forecasts were overestimated on average by 30.8% of actual loads.

BC Hydro's load forecast methodology has changed several times since its first forecast in fiscal 1964. However, the magnitude of overestimation has not decreased over the 10-year and 15-year horizons, but has increased somewhat for the first fully forecasted year and over a 5-year horizon.[95]

- The average forecast in the first fully forecasted year[96] was overestimated by 0.9% of actual load for models run between fiscal 1986 and 1995, 0.7% for models between fiscal 1996 and 2005, and 2.7% for models between fiscal 2006 and 2015 (Figure 4).[97]

[95] Data provided in document B-15, BC Hydro Submitting Responses to Intervener Information Request No. 2.
[96] We have used the second forecasted data point (first fully forecasted year) as BC Hydro forecasts the fiscal year during which the model is produced. That is, the first forecasted data point is load in fiscal 1980 for the model vintage completed in fiscal 1980.
[97] Three 10-year periods were analyzed going back from 2015, the last date a comparison can be made between the first fully forecasted year and actuals.

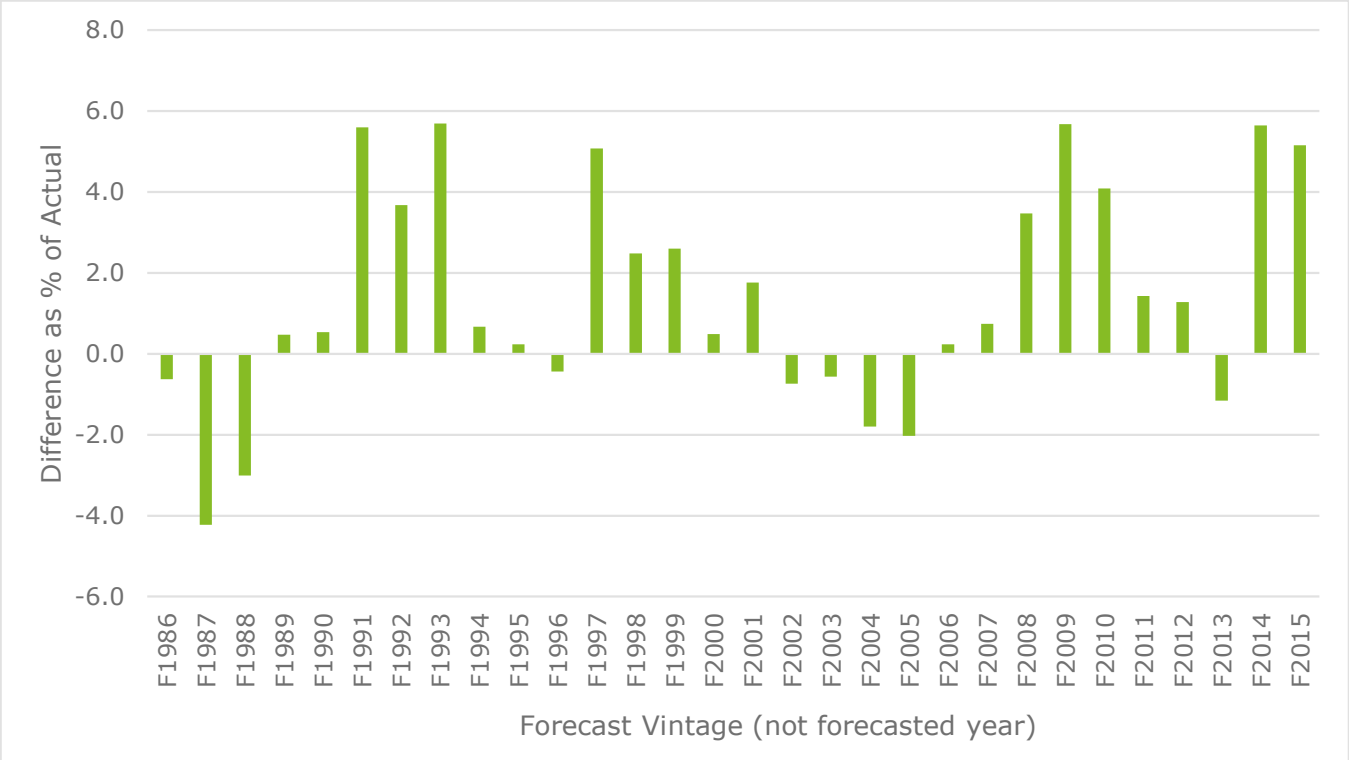


Figure 4: Difference Between First Fully Forecasted Year and Actual Total Gross Requirements (with DSM)

- The average 5-year-out forecast overestimation was 0.1% of actual load for models ran between 1983 and 1992, 3.2% for models between 1993 and 2002, and 5.1% for models between 2003 and 2012 (Figure 5).[98]

[98] Three 10-year periods were analyzed going back from 2012, the last date for which a five-year comparison can be made.

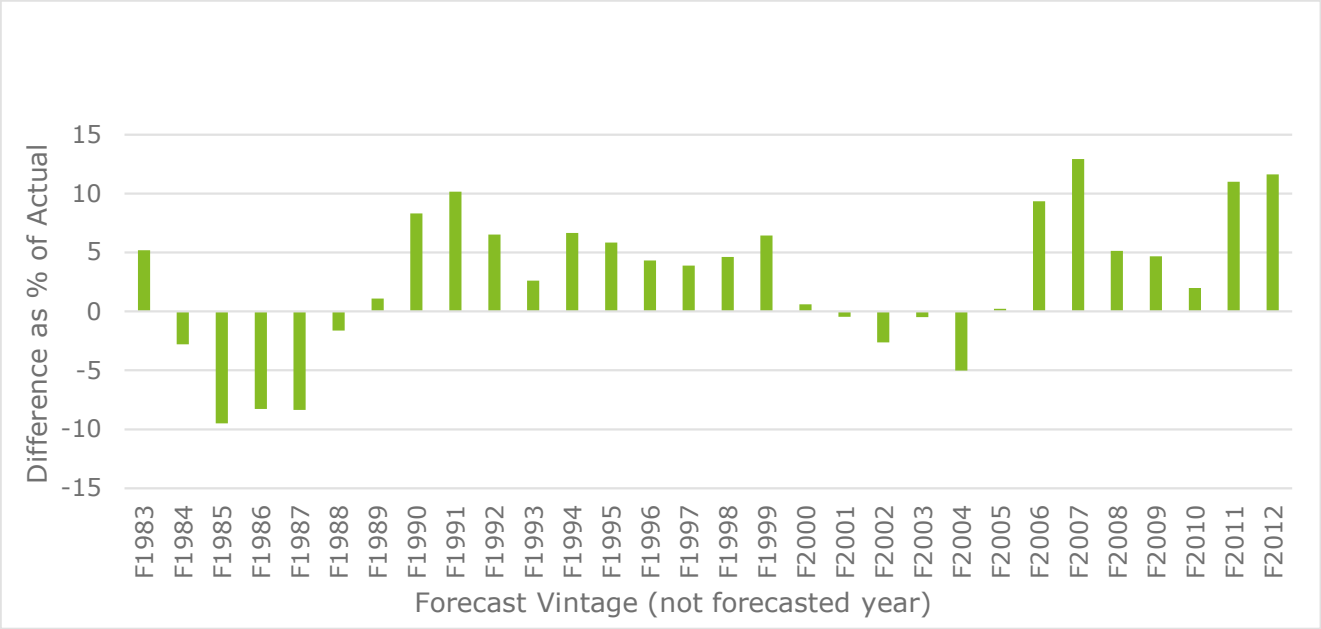
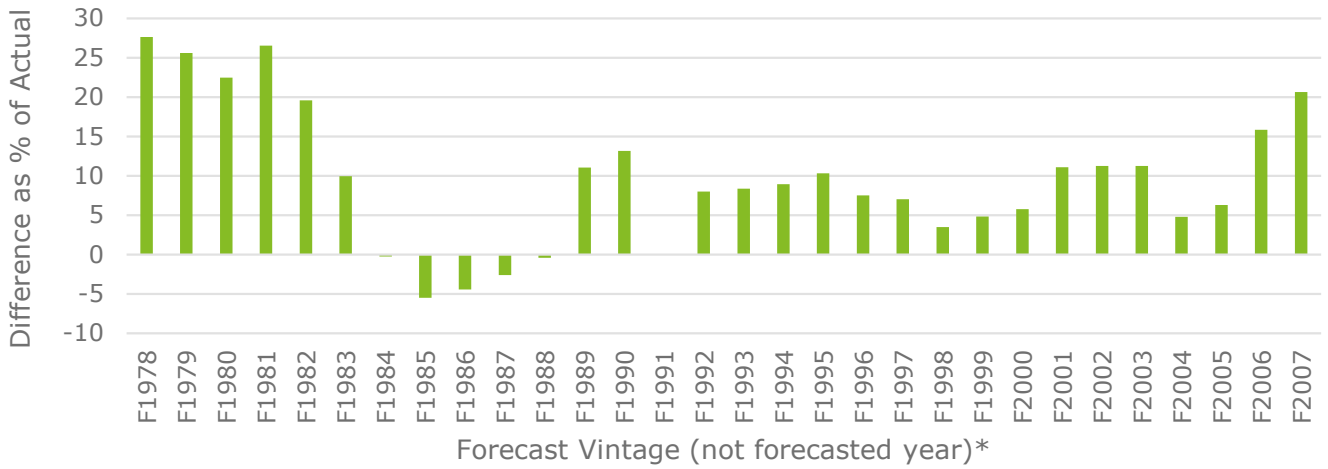


Figure 5: Difference Between 5-Year Forecast and Actual Total Gross Requirement (with DSM)

- The average 10-year-out forecast overestimation was 11.9% of actual load for models ran between 1978 and 1987, 8.2% for models between 1988 and 1997, and 9.5% for models between 1998 and 2007 (Figure 6).[99]

[99] Three 10-year periods were analyzed going back from 2007, the last date a 10-year comparison can be made.



*The 1991 forecast model only forecasted 9-years, so there is no data point for this year.

Figure 6: Difference Between 10-Year Forecast and Actual Total Gross Requirement (with DSM)

- The average 15-year-out forecast overestimation was 14.5% of actual load for models ran between 1993 and 1997, and was 15.7% for models between 1998 and 2002 (Figure 7).[100]

[100] Two 5-year periods were analyzed going back from 2002, the last date a 15-year comparison can be made.

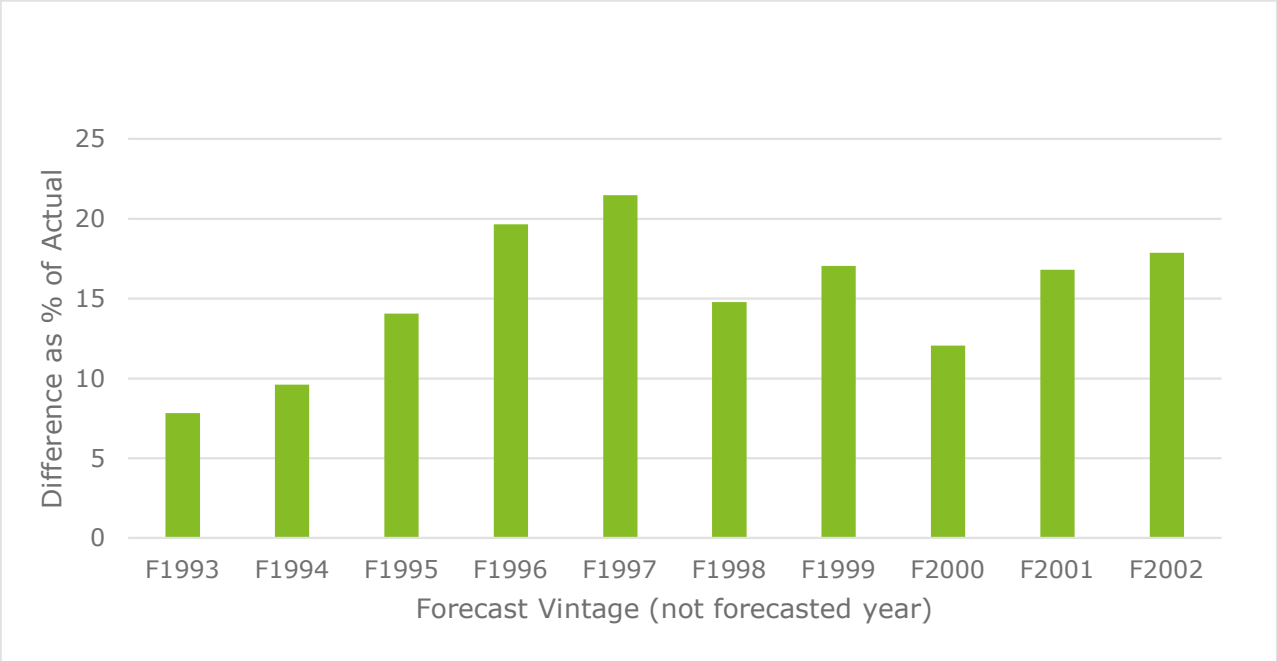


Figure 7: Difference Between 15-Year Forecast and Actual Total Gross Requirement (with DSM)

The large, industrial component of the model is the largest contributor to the deviation from actuals in both the short and long term. This component is responsible for 29% of total sales[101] on average between fiscal 2000 and 2017.

- Using forecast models from fiscal 2008 to 2016, large, industrial sales are overestimated by an average of 954 GWh (or 9% of actuals) in the first fully forecasted year.[102]
- Large industrial sales were overestimated by an average of 2,664 GWh (or 19% of actuals) in the fifth forecasted year.[103]
- Large industrial sales are overestimated by an average of 2,796 GWh (or 21% of actuals) in the eighth forecasted year (Figure 8).[104]

[101] Share of total sales, not total gross requirement. Total sales do not included system losses.
[102] The first forecasted year is completed the same year that the forecast is completed. For example, the first forecasted year in the fiscal 2008 forecast is also fiscal 2008. Forecasts for models before fiscal 2014 were completed in December of the fiscal year, meaning that much of the year had already happened. The first fully forecasted year is technically the second year of the forecast.
[103] Fifth forecasted year was used as a reference between the short (first fully forecasted year) and longer term (eighth year) estimations.
[104] The eighth forecasted year was chosen as actual data ends in fiscal 2017 and we are using model vintages that start forecasting in fiscal 2008. As such, we take the average of 8-year forecasts for three model vintages (model fiscal 2008, 2009, and 2010). Using longer time horizons would decrease the number of model vintages used to compare the deviance from actuals.

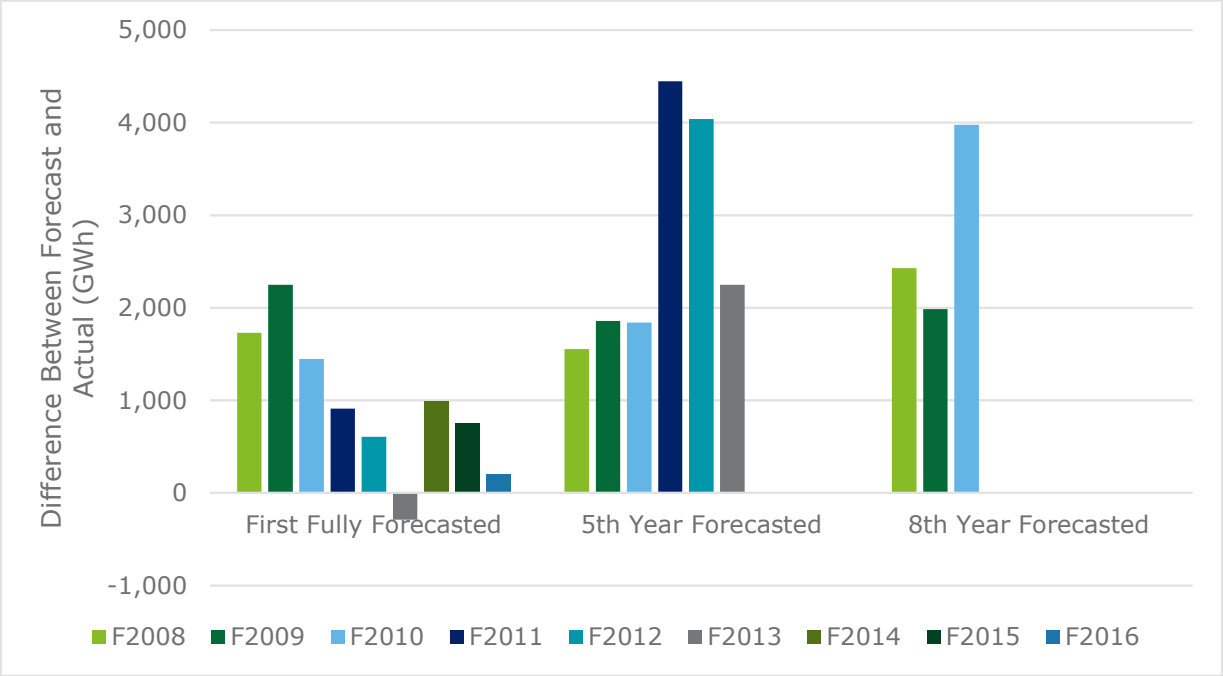


Figure 8: Large Industrial Sector - Difference Between Forecasted and Actual Sales

On average, residential sales account for 33% of total sales between fiscal 2000 and 2017. Forecasts of residential sales are close to actuals in both the short and long run.

- Using forecast models from fiscal 2008 to 2016, residential sales are overestimated by an average 28 GWh (or 0% of actuals) in the first fully forecasted year.
- In the fifth forecasted year, residential sales were underestimated by an average of 347 GWh (or 2% of actuals).
- Residential sales are underestimated by an average of 667 GWh (or 4% of actuals) in the eighth forecasted year.

Commercial and light, industrial sales account for 35% of total sales on average between fiscal 2000 and 2017. Forecasts of this component of the model are close to actuals in both the short and long run.

- Using forecast models from fiscal 2008 to 2016, commercial and light industrial sales are overestimated by an average of 149 GWh (or 1% of actuals) in the first fully forecasted year.
- In the fifth forecasted year, commercial and light industrial sales were overestimated by 191 GWh (or 1% of actuals).
- Commercial and light industrial sales are underestimated by an average of 751 GWh (or 4% of actuals) in the eighth forecasted year.

It should be noted that the challenge in estimating electricity demand accurately is not unique to BC Hydro. Deloitte interviews with two other Canadian utilities revealed that at least one has tended to overestimate load over time. Moreover, as with BC Hydro, this utility reported that the heavy industrial sector was most likely to be overestimated.

5.3. Model Inputs

Appendix A reports the key variables for all SAE models and the Monte Carlo simulations. These include macro-economic indicators, demographic variables, weather-related variables, as well as variables specific to individual customer segments, such as the number of accounts. Based on consultations with two other

Canadian utilities and several, independent industry subject-matter experts, the key variables included in the models appear reasonable.

The inputs to the 2016 forecast come from five main sources: the BC Ministry of Finance, the U.S. Energy Information Administration, Environment Canada, Robert Fairholm Economic Consulting (RFEC), and BC Hydro itself, which produces calculations based on past load requirements and develops assumptions around future capital projects. To inform its model assumptions, particularly with respect to heavy industrial projects, BC Hydro reports that it reviews a wide array of market data, from sources such as IHS Global Insight, Bloomberg, Wood Mackenzie and PIRA Energy, and engages outside consultants, such as PwC.

5.3.1. Macro-economic inputs

BC Hydro uses a number of macro-economic variables as inputs to their model, such as growth in GDP, employment, population, retail sales, disposable income, and housing starts.

The forecasts for employment, population, and housing starts that BC Hydro uses as inputs in the forecast model appear in line with projections published by Statistics Canada[105] and the Conference Board of Canada.[106]

With respect to GDP, while BC Hydro uses the BC Ministry of Finance's real GDP forecast as an input for the first five years of its load forecast, the values incorporated in the model appear higher than the Conference Board of Canada's in the years that follow. For instance, in calculating its 2016 load forecast, real GDP growth is assumed to average 2.3% in the first five years (i.e., based on the BC Ministry of Finance's forecast), before increasing to 3.5% over the next five years (based on the RFEC projections).[107] By comparison, the 2016 Conference Board of Canada forecast projects that real GDP will grow by 2.6% on average between 2016 and 2020, before slowing to an average of 2.3% between 2021 and 2025. By 2025, the RFEC forecast projects that BC's economy will be 6% larger in real terms (Figure 9). After 2025, the two forecasts exhibit similar trends.

[105] Statistics Canada (2015). *Population Projections for Canada (2013 to 2063), Provinces and Territories (2013 to 2038).* Accessed on August 29, 2017 at: http://www.statcan.gc.ca/pub/91-520-x/91-520-x2014001-eng.pdf
[106] Conference Board of Canada (2016). *Provincial Outlook 2016: Long-Term Economic Forecast.* Accessed on August 29, 2017 at: http://www.conferenceboard.ca/temp/09ed73c5-c0a5-4714-82ae-80d72b70d0fd/8004_po_longterm_2016_rpt_bc.pdf
[107] Refers to the arithmetic average of annual growth rates provided by BC Hydro.

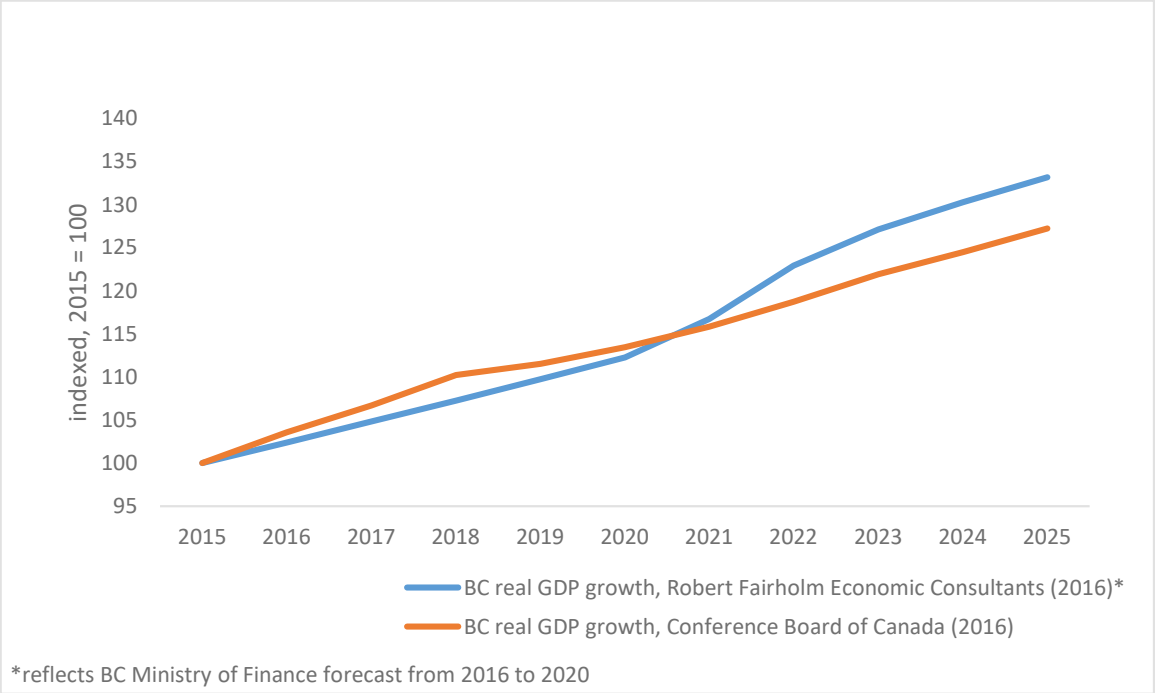


Figure 9: BC's projected economic growth based on RFEC and Conference Board of Canada 2016 forecasts

This assessment does not examine which of the two GDP forecasts is more likely to be accurate, as analyzing the RFEC and Conference Board of Canada's forecast models is beyond its scope. However, we note that the RFEC GDP forecast which BC Hydro uses is itself based on assumptions BC Hydro provides to RFEC regarding future, heavy industrial developments. On one hand, this ensures that the GDP projections RFEC provides are consistent with the assumptions of the load forecast (e.g., in terms of the number of LNG projects that are likely to be developed). On the other hand, it also means that if BC Hydro's assumptions of the likelihood of large projects going forward prove to be incorrect, the impact on the load forecast is magnified via the effect on GDP growth, which affects multiple components of the forecast model.

The Conference Board of Canada does not publish specific assumptions around the timing and prospects of LNG projects. However, RFEC provided BC Hydro with a set of alternate GDP assumptions under the assumption that no LNG projects in BC are built over the forecast horizon. We note that this forecast resembles the Conference Board of Canada's 2016 forecast much more closely: by 2025 (i.e., F2026), it projects BC's economy as being just 1% larger (Figure 10).

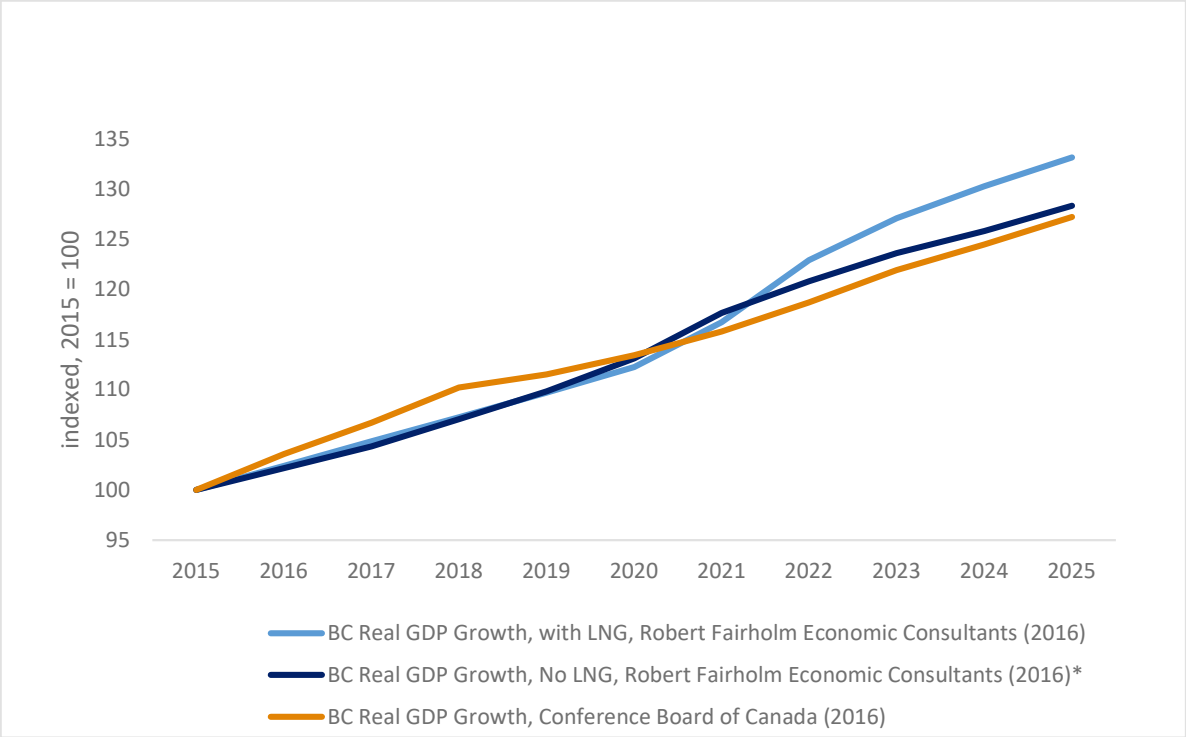


Figure 10: BC's Projected Real GDP Growth, with and without LNG

To assess the sensitivity of the model to a different GDP forecast, rough projections can be done on the basis of the GDP elasticities published by BC Hydro from the Monte Carlo simulation.[108] While these elasticities are not derived from the mid-forecast model itself, it should be noted that the pre-DSM Monte Carlo simulations produce comparable mid-points to the mid-forecast. Nonetheless, the projections derived with regards to load and capacity should be considered approximate, and indicative of magnitude and direction only. BC Hydro publishes elasticities for the residential, commercial and light industrial sectors, but not for the heavy industrial segment, as its load requirements are forecast via a separate process. Based on the published BC Hydro elasticities, and using the Conference Board of Canada's 2016 forecast instead of the RFEC figures, we find that residential load requirements would be 3.8% lower by F2026, while those for the commercial and light industrial sector would fall by 3.6%. These reductions do not include the heavy industrial sector, which accounts for a quarter to a third of overall load.

[108] See BC Hydro's 2012 report titled "Electric Load Forecast: Fiscal 2013 to 2033".

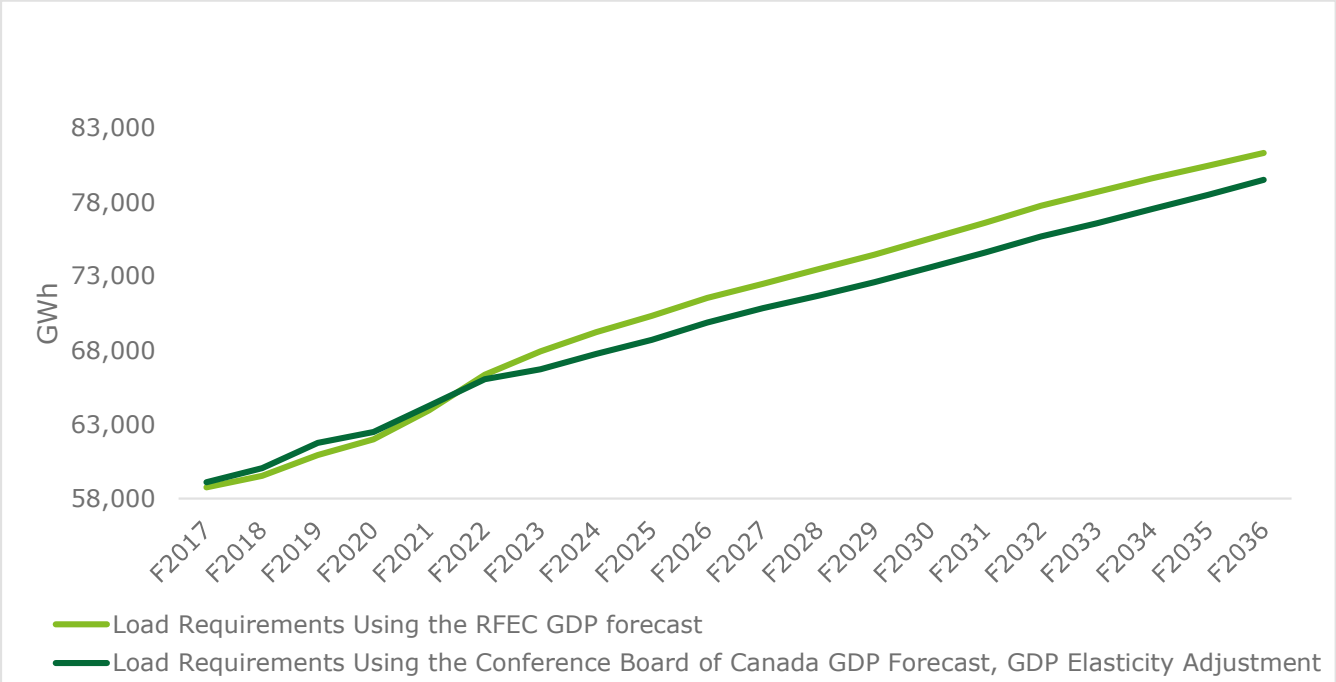


Figure 11: Mid forecast using the RFEC and Conference Board of Canada GDP projections

Using the same approach and GDP elasticities, this exercise was extended to the capacity forecasts. Using the published BC Hydro GDP elasticities and the Conference Board of Canada's 2016 forecast instead of the RFEC figures, by F2026 total peak demand is lower by 3.3% to 3.4% (Figure 12).

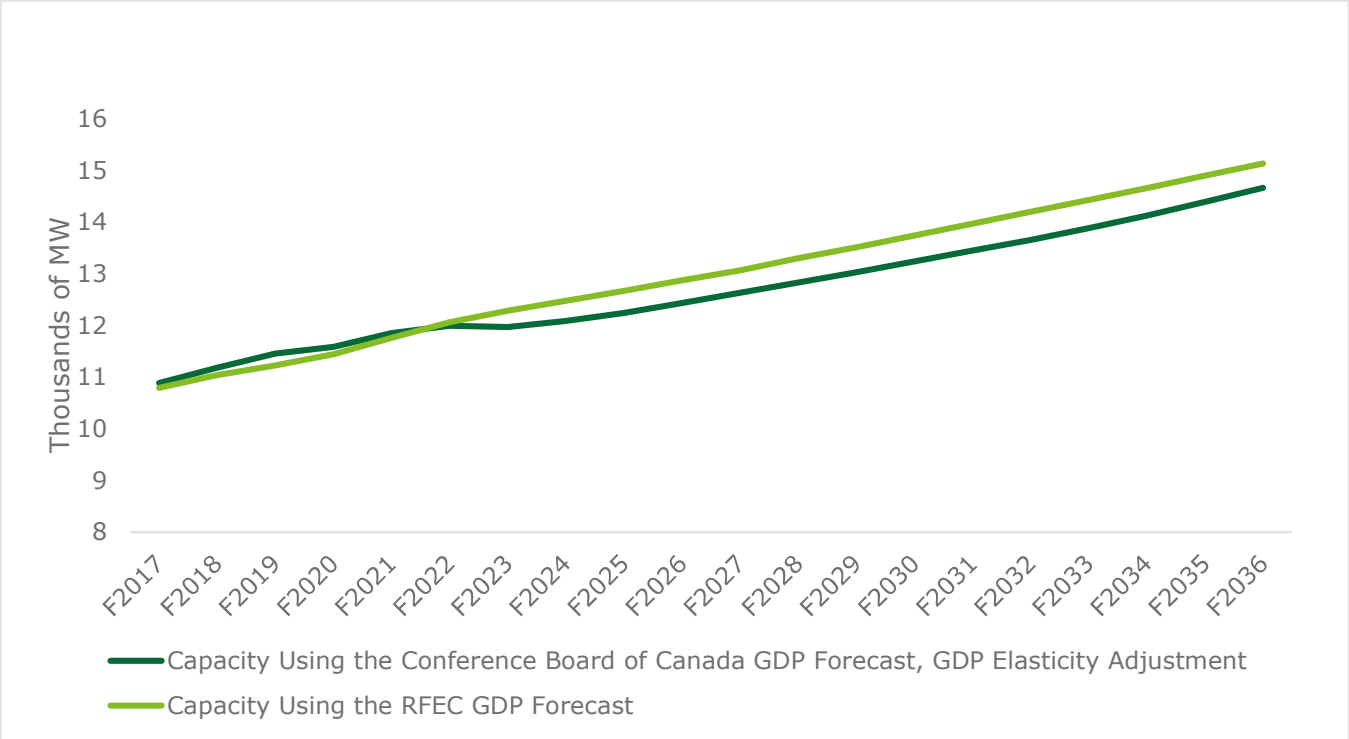


Figure 12: Capacity Forecast Before DSM using the Conference Board of Canada GDP Projection

It should be noted that BC Hydro's mid forecast does not explicitly account for recessionary periods, which may have a larger impact on load requirements than on long-run GDP growth, based on the experience of the 2008 financial crisis.[109,110] While it is not possible to confidently predict when recessions will occur, nor their magnitude, historical analysis shows that over the past 35 years (since provincial GDP records began), BC has seen two recessions, defined as two consecutive quarters of negative growth, and four periods in which annual growth was below 1%.[111] Thus we find it reasonable to assume that there will be at least one recession over the horizon of the 2016 load forecast. However, this assessment does not attempt to model such an adjustment.

Similar to GDP, the RFEC forecast for disposable income growth—which is a driver of residential load in the SAE model—appears higher than the Conference Board of Canada's, particularly in years six to 10 of the forecast. It should be noted that precise comparisons are difficult, however, as the Conference Board of Canada publishes a nominal disposable income growth forecast, while RFEC publishes these figures in inflation-adjusted terms.

[109] Recessionary periods are nonetheless accounted for in the form of lower GDP growth—without accounting for any disproportionate impacts on load—in the Monte Carlo simulations.
[110] In past periods of economic contraction, such as the early 1980s and 1990s, the relationship between recessions and slower load growth is less pronounced; nonetheless, following the economic downturn in the early 1990s, average load expansion slowed by roughly half compared with the 1980s.
[111] Some of the latter could have been recessionary periods as well, but we cannot ascertain whether this is the case as quarterly GDP data is not reported.

5.3.2. Bottom-up Inputs

In addition to the SAE model, which is used for the residential, commercial and light industrial sectors, BC Hydro projects load for the heavy industrial sector by assessing roughly 180 accounts in mining, forestry, and oil and gas, as well as 20 to 30 prospective large accounts relating to proposed projects in these sectors. In some cases, BC Hydro's assumptions regarding the prospects of proposed major industrial developments appear above consensus. For instance, a May 2017 presentation prepared by BC Hydro indicates that the forecast for BC LNG over the 2024 to 2035 period is more optimistic than reference forecasts prepared by Bloomberg, Wood Mackenzie, ABB Power and PIRA Energy.

The 2016 forecast assumes that four LNG projects will go ahead with certainty: FortisBC Tilbury LNG (currently under construction), Woodfibre LNG (expected to begin construction in 2018), LNG Canada (final investment decision deferred), and Pacific NorthWest LNG (cancelled in July 2017). In the high and low forecasts, BC Hydro applies a probability assessment on when, but not if, these projects will come online. Of the four proposals, the latter two account for over 90% of total combined capital spending.

BC Hydro reports that the direct impact of the cancellation of the $36 billion Pacific NorthWest LNG plant (including related upstream O&G activity) on the load and capacity forecasts is limited. The indirect impacts associated with the project's cancellation, for which roughly $11 billion of the total of $36 billion was already spent, are likely to be more significant with respect to GDP as it relates to the 2016 load forecast. In particular, the project was expected to generate up to 4,500 construction jobs (0.2% of BC's total current employment) and more than $1 billion annually in federal, provincial and municipal government revenues (0.4% of BC's GDP).[112] Thus, the project's cancellation likely represents a material downwards shift in the GDP outlook relative to the 2016 baseline forecast.

We find the assumption that LNG Canada will proceed with certainty to be overly optimistic. LNG Canada has officially deferred their final investment decision, and its prospects of being built are unclear.

Section 5.5 of this report provides alternative load and capacity projections, which exclude the direct and indirect load and capacity requirements of LNG Canada and Pacific NorthWest LNG.

5.3.3. Price Elasticity

BC Hydro reports that it accounts for price elasticity of demand (i.e., the reduction in load requirements that results from higher electricity prices) in two ways. First, it applies a constant, own-price demand elasticity of -0.05 to the residential, commercial, light industrial and transmission segments (i.e., BC Hydro assumes that every 1% increase in price reduces load in these categories by 0.05%). Second, the load forecast includes assumptions related to demand-side management (DSM) pricing initiatives. While not normally considered as a price elasticity, these initiatives are conceptually similar, in that they project a reduction in load or capacity requirements from different price structures.

It appears that BC Hydro's assumed price elasticity may be an oversimplification in three respects. First, ignoring any DSM impacts, its magnitude of -0.05 is smaller, in absolute terms (i.e., less negative), than those in some empirical studies (e.g., Alberini and Filippini 2011 and Espey and Espey 2004).[113] While location is relevant, these studies suggest that price elasticities for electricity can be at least -0.08 in the short run, and

---

[112] http://www.pacificnorthwestlng.com/media/PNW%20Backgrounder_V%2030%200.pdf

[113] See Alberini and Filippini (2011). "Response of Residential Electricity Demand to Price: The Effect of Measurement Error". *Journal of Energy Economics.* 33: 889-895 and Espey and Espey (2004). "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities". *Journal of Agricultural and Applied Economics.* 36,1(April 2004):65-81 .

at least -0.45 in the long run. Second, BC Hydro assumes that short-run and long-run elasticities are identical; the same empirical research shows that long-run price elasticities of electricity demand are larger, in absolute terms, than short-run elasticities, as consumers may respond only gradually to higher prices (e.g., by investing in energy-efficient lighting and appliances). Third, BC Hydro assumes that price elasticity of demand is constant across sectors. Some independent studies have found that commercial and industrial consumers exhibit more price elastic demand than residential consumers (e.g., Griffin and Arent 2006).

Based on interviews with two other major utilities in Canada, we understand that one uses price elasticities for different customer segments, as well as short- and long-term horizons. In the case of the commercial and industrial sectors, the price elasticities used are considerably greater, in absolute terms, at -0.16 in the short run and -0.27 in the long run.

BC Hydro assumes rate increases will not occur between F2025 and F2036. Thus, even if electricity demand is assumed to be more price elastic, there will likely be no change to the load forecast over that period as the change in price is assumed to be zero. Rate increases introduced between F2025 and F2036 would lower the 2016 load forecast. This assessment does not attempt to model this impact.

5.3.4. Policy Variables

BC Hydro reports that their model does not incorporate any future policy-related assumptions or projections with regards to climate change action or electrification. We find this to be a conservative approach in the current environment. A potential future regulatory or policy push towards electrification and green-house gas emission reduction constitutes an upside risk to the forecast (i.e., the current forecast would be an underestimate, all else being equal). For an assessment of BC Hydro's approach to electric vehicle adoption, please refer to section 5.4.1 below.

5.4. Potential Future Disruptors

A number of trends could potentially disrupt electricity demand in the future. Examples of these disruptors include improvements in technology for renewable energies such as solar power, the increased use of electric vehicles, decentralized power grids, the Internet of Things, fuel-switching, climate change, and co-generation. Of these potential disruptions, BC Hydro explicitly models electric vehicles use in its forecasts. Within the context of this study, we examined three specific potential disruptors: electric vehicles, solar photovoltaic technology in a residential context, and fuel switching (i.e., from gas to electric and vice versa).

5.4.1. Electric Vehicles Use

In 2016, there were roughly 5,400 electric vehicles (EVs) on the road in BC; new EV sales accounted for approximately 1% of all new vehicle sales in the province.[114] In absolute terms, BC lags Quebec and Ontario in EV use, as the 2016 stock of EVs was 13,500 and 9,200 in these provinces, respectively.[115] On a per capita basis, BC is the second-largest provincial user of EVs.[116] The potential increase in EV use could impact electricity demand in BC.

BC Hydro currently incorporates potential EV growth in its load demand forecast using a vehicle stock turnover model. Load demand growth from EVs depends on the increase in BC's driving population, capital and

[114] http://www.fleetcarma.com/ev-sales-canada-2016-final/
[115] Ibid.
[116] Using fleetcarma data on EVs in each province and provincial population from Statistics Canada.

operating costs of EVs versus internal combustion engines, and variables impacting the uptake of EVs (e.g., policy support and customer awareness).

Within its model, BC Hydro makes some key assumptions about the use of EVs that impact load demand. BC Hydro assumes the energy efficiency of EVs is 0.20 KWh/km.[117] Of EV models offered in Canada in 2017, energy efficiencies of battery-electric vehicles (BEVs) range from 0.168 KWh/km to 0.244 KWh/km[118], meaning that BC Hydro's efficiency assumption is consistent with current EV models available to consumers. BC Hydro uses a distribution of annual kilometers driven per vehicle, the mean of which is 13,318 kms. This is consistent with other estimates in the literature.[119] As well, EV market share is constrained in the short run by model availability, relative costs, and limited awareness of consumers. BC Hydro relaxes these restraints over the model time horizon.

In its reference case[120], BC Hydro's estimated EV market share is relatively conservative (lower) compared with policy goals set by the federal government and other estimates of EV growth. Specifically, BC Hydro estimates that roughly 22% of all new vehicles sold will be electric in 2030 while the federal government has recently pledged support to reach an EV share of 30% of all new vehicles sold by the same year.[121] With increased supply and demand side incentives, Wolinetz & Axsen (2017) estimates that EVs could account for between 38% and 49% of new vehicle sales in BC by 2030. BC Hydro's assumptions are also conservative compared to Quebec's goal of having EVs account for 20% of <u>all</u> vehicles (not just new sales) by 2030.[122]

To understand the sensitivity of the forecasts with regards to a change in electric vehicle assumptions, we modelled a scenario where electric vehicles account for 30% of new sales in BC by 2030, consistent with recent federal government's commitments.[123] None of BC Hydro's assumptions beyond the assumption of EV share of new vehicles were changed in the new scenario. Using the assumption that EVs will account for 30% of new vehicle sales in 2030, the estimated load demand in 2026 increases from 323 GWh in BC Hydro's scenario to 440 to 450 GWh. This 115 to 125 GWh increase is equivalent to less than 1% of actual residential sales in fiscal 2016.[124] By 2036[125], the difference in load demand expands to 680 to 690 GWh or just under 4% of actual residential sales in fiscal 2016. Using BC Hydro's fiscal 2016 residential demand forecast, the increase in GWh from our scenario is equivalent to roughly 0.6% of residential demand in 2026, and roughly 2.9% of residential demand in 2036. On the capacity side, this new assumption amounts to roughly an additional 30 to 40 MW in 2026 and 245 to 255 MW by 2036.

---

[117] Electric Load Forecast. 2012. BC Hydro. pg. 95.
[118] http://oee.nrcan.gc.ca/transportation/tools/fuelratings/atv-2017.cfm
[119] Wolinetz & Axsen (2017) use an average of 16,000 kms. driven annually in modeling fuel costs by class of vehicle (electric versus internal combustion engine), but they note that drivers have heterogeneous driving patterns highlighting the importance of using a range of driving distances. BC Hydro's EV model uses a distribution of annual kms driven as part of their model to estimate EV market share, where the mean is 13,318 kms.
[120] BC Hydro also estimates a high case for EVs. The reference case is incorporated in its mid forecast, which is used for planning purposes.
[121] This includes battery-electric, plug-in hybrid electric and fuel-cell electric vehicles. https://www.iea.org/media/topics/transport/CampaignDocumentFinal_rev_SENER.pdf
[122] https://politiqueenergetique.gouv.qc.ca/wp-content/uploads/Energy-Policy-2030.pdf
[123] Focusing on the share of new vehicles sold ignores the possibility that consumers import used vehicles, which would also increase the stock of EVs in BC. While this might occur because of cost advantages, it is not possible to accurately capture in this analysis as data on this is not tracked consistently.
[124] BC Hydro adds 75% of the load demand from EVs to their residential load forecast and 25% to their commercial and light industrial forecast. We compare our results to the residential load for simplicity.
[125] 2036 is the end of BC Hydro's forecast.

5.4.2. Solar Photovoltaic Panels

The use of solar photovoltaic (PV) by residential customers is another potential electricity demand disruptor. Residential use of solar PV for electricity could reduce the demand for hydroelectricity. Growth projections for residential solar PV are not explicitly included in BC Hydro's 2016 load forecast.

As with EVs, projections regarding solar PVs are sensitive to electricity rates, policy, and the costs of solar PV equipment. A benchmarking study by the Berkeley Lab finds that, in the absence of incentive programs to drive adoption, the use of solar PV is highly sensitive to the relative costs of solar versus hydroelectricity.[126] A report by Sunmetrix shows that there are only three main incentive programs for solar PVs in BC: a one-time cash incentive of $250 in Nanaimo, a provincial sales tax exemption for solar PV panels and related equipment, and BC Hydro's own net metering program.[127]

BC Hydro's net metering program allows consumers to sell surplus energy generated from solar PVs back to BC Hydro. Furthermore, it allows customers to lease solar PV equipment. However, only one customer has used this leasing option since the program started and only five customers contacted BC Hydro to inquire about leasing equipment between fiscal 2014 and 2016.[128] As such, it seems the current policy incentives in BC are not driving mass consumer uptake and that the economics of solar PV compared to hydro are what would drive uptake going forward in the absence of further policy incentives.

The cost of solar PV includes the costs of solar panels, installing equipment, installation labor, and balance-of-system equipment[129]. BC Hydro's online solar PV calculator estimates the current cost of residential solar PV to be $3.6/Watt.[130] Similarly, the U.S. National Renewable Energy Laboratory estimates the cost of residential solar PV to be roughly $3.9/Watt on average in the U.S.

Under current prices of solar PVs, BC Hydro estimates the payback period for residential solar PV to be 23 years.[131] This is based on an assumed $14,500 for 4KW of installed panels, and the assumption that the retail rate of electricity is 14.2c/KWh, which is the tier two BC Hydro rate (12.87c/KWh), plus 5% from the rate rider program,[132] and 5% GST.[133] According to EnergySage (supported by the U.S. Department of Energy), the payback period in California and Arizona is approximately 6.4 and 7.6 years, respectively.[134] Solar penetration in these states was roughly 7.2% and 5.8% in 2016, much higher than the use of solar in BC that year.[135] The payback period is a function of both unit costs, retail electricity rates, and solar potential, so comparisons are only used as an estimate to show the payback period in states where residential solar use is much higher.

---

[126] https://emp.lbl.gov/sites/all/files/lbnl-1006047.pdf

[127] http://sunmetrix.com/solar-tax-credits-incentives-and-solar-rebates-canada/british-columbia/

[128] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/20170426-BCH-Rate-Schedule-1289-Net-Metering-Eval-RPT-4.pdf

[129] Includes equipment required to run panels, such as inverters and wiring.

[130] Based on the assumption that a 4KW system (reasonable size for residential generation) costs roughly $14,500. https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html?WT.mc_id=rd_netmetering

[131] This does not include forecasted retail rate increases. If retail rates increase, the payback period for solar PV would decrease. https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html?WT.mc_id=rd_netmetering

[132] The Rate Rider covers additional and unpredictable energy costs resulting from, for example, low water inflows or higher-than-forecast market prices.

[133] If tier one rates were used instead of tier two rates, the payback period would increase. https://www.bchydro.com/accounts-billing/rates-energy-use/electricity-rates/residential-rates.html

[134] https://www.energysage.com/data/#intel-4

[135] https://www.ohmhomenow.com/2016-solar-penetration-state/

In addition to solar's long payback period, the use of solar PV by BC Hydro's customers is currently limited. In fiscal 2016, customers under BC Hydro's net metering system installed approximately 3,250 kW of solar PV capacity, generated from just over 600 projects.[136] BC Hydro assumes that a 4KW solar panel generates 0.0044GWh/year. Therefore the estimated load generation from solar PV was approximately 3.6 GWh in fiscal 2016. This is equivalent to roughly 0.02% of residential load for that year. Even if residential load did not grow at all between now and 2030, solar PV gigawatt-hour production would have to increase at an average annual rate of 32% to reach 1% of residential sales by 2030. This is equivalent to a 50-times increase in current load generated by solar PVs. In its seventh power plan, the Northwest Power and Conservation Council estimated that solar PV uptake will increase 15 times at most between 2013 and 2035.[137] The Berkeley Lab estimated that solar PV use would increase 6 times between 2015 and 2040.[138]

Despite long payback periods and low levels of current use, the cost of solar PVs is likely to come down further, and potentially increase uptake going forward. However, it is not clear when this will materialize. Solar PV installation costs have already decreased over time; the Berkley Lab estimates that median installed prices of U.S. solar PVs decreased at an average annual rate of 13% to 18% between 2009 and 2014, and that these decreases continued into 2015.[139] Going forward, the Northwest Conservation and Electric Power Plan (NCEPP) estimates solar PV costs will decrease by 53% between 2012 and 2030.[140]

In summary, the payback period for residential solar PV is still high, and current use is low. While costs could decrease going forward and induce further uptake, this assessment has not attempted to model such a scenario.

5.4.3. Heat and Hot Water Fuel Switching

Fuel switching occurs when energy consumers switch from electricity to gas or oil fuel sources and vice versa. Consumer behaviour may change because of government policy objectives to shift energy use to renewable sources, cost considerations of gas compared to electricity, or personal preferences for greener energy use.

Many factors determine the cost of using a heat pump compared to a gas furnace, including the size of a house, and how well it is insulated. For smaller, well-insulated houses or apartments, using a heat pump could indeed be more cost effective.[141] However, analysis conducted by Fortis BC found that the annual costs of heating a typical, detached home using natural gas are over $800 lower than using electricity, even when the least efficient natural gas furnaces are compared to the most efficient electric heating options.[142] Given this cost differential, the higher fixed cost of installing electric heating is likely to prevent consumers from switching from natural gas to electric heating for some time, assuming that natural gas prices remain low, and absent strong incentives introduced by policy.

There is some evidence that future policy could try to incentivize a shift from natural gas to electricity. For example:

---

[136] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/20170426-BCH-Rate-Schedule-1289-Net-Metering-Eval-RPT-4.pdf
[137] https://www.nwcouncil.org/media/7149913/7thplanfinal_appdixe_dforecast.pdf
[138] https://emp.lbl.gov/sites/all/files/lbnl-1006983.pdf
[139] https://energy.gov/sites/prod/files/2015/08/f25/LBNL%20Tracking%20the%20Sun%20August%202015.pdf
[140] https://www.nwcouncil.org/media/7149931/7thplanfinal_chap07_demandforecast.pdf
[141] http://www.pembina.org/pub/bc-heating-costs
[142] As noted in response to BCUC IR 1.4.1.

- BC's Climate Leadership Plan states[143]: "To advance efficient electrification we are taking action by working with BC Hydro to expand the mandate of its DSM programs to include investments that increase efficiency and reduce GHG emissions."
  - The March 2017 Order in Council 101 enables BC Hydro to pursue cost-effective electrification; Order in Council 100 allows these costs to be charged to the DSM Regulatory Account.[144]
- The City of Vancouver's Green Building Rezoning Policy (in-force May 2017), requires new building developers who are seeking rezoning to meet emissions targets of a 50% decrease in greenhouse gas emissions. Developers can meet these targets in a number of ways, one of which might be to use electric water and space heating instead of natural gas.[145]

A study by Simon Fraser University found that, with strong policy support, residential and commercial buildings may rely almost exclusively on electricity by 2050.[146]

In summary, given current policies and cost differential between gas and electricity, a mass shift from gas to electric heating is unlikely. While there are indications a policy shift may be forthcoming in the future, this assessment has not attempted to model such a scenario.

5.5. An Alternative Scenario

In this section, we illustrate the combined impact of several, alternative input assumptions on the fiscal 2016 load-and-capacity forecast. The results should be considered as indicative only, as BC Hydro's mid forecast has been adjusted after the fact, as opposed to conducting a complete re-run of the models that have produced the forecast. For illustrative purposes, the following changes in assumptions are made:

GDP – the alternative scenario replaces BC Hydro's 2016 GDP forecast with the 2016 Conference Board of Canada long-term BC forecast.[147] To simulate the effect on load and capacity of this change, the alternative projection uses GDP elasticities published by BC Hydro from the Monte Carlo simulation. While these elasticities are not derived from the mid-forecast model itself, it should be noted that the pre-DSM Monte Carlo simulations produce comparable mid-points to the mid-forecast. Nonetheless, the projections derived with regards to load and capacity should be considered approximate and indicative of magnitude and direction only.

LNG – the alternative forecast excludes the impacts on load and capacities from the Pacific NorthWest LNG project (now cancelled) and LNG Canada (final investment decision deferred). The forecast excludes both the direct impact as well as the indirect impact from the oil and gas-extraction activity associated with the projects. However, the forecast does not include impacts on GDP. This is done to avoid double counting the reduction of GDP from adopting the Conference Board of Canada's GDP numbers, as assumptions around LNG projects are unclear. This represents a conservative approach to the LNG adjustment.

Electric Vehicles Use – the alternative forecast assumes a higher adoption curve of electric vehicles in BC than BC Hydro's forecast, consistent with federal public commitments that 30% of new vehicles sold by 2030 will be electric. All other BC Hydro assumptions regarding electric vehicle use are preserved.

---

[143] https://climate.gov.bc.ca/app/uploads/sites/13/2016/10/4030_CLP_Booklet_web.pdf, p. 28.
[144] BCH RRA, Exhibit B-18, p. 1.
[145] http://vancouver.ca/news-calendar/city-response-to-bc-liberal-statement-on-natural-gas.aspx
[146] http://rem-main.rem.sfu.ca/papers/jaccard/ZuehlkeJaccardMurphy-Vancouver_Renewables_Report-March%202017
[147] Conference Board of Canada (2016). *Provincial Outlook 2016: Long-Term Economic Forecast.* Accessed August 29, 2017 at: http://www.conferenceboard.ca/temp/09ed73c5-c0a5-4714-82ae-80d72b70d0fd/8004_po_longterm_2016_rpt_bc.pdf

Demand Side Management (DSM) – to illustrate the impact of a more intensive DSM program, the alternative forecast assumes Option 3 DSM savings as projected by BC Hydro in the 2013 Integrated Resource Plan, as opposed to the Moderated Option 2 DSM savings incorporated in the 2016 load forecast. In the 2013 Integrated Resource Plan, BC Hydro notes that DSM Option 3 "features increased program activities and expenditures to target the greatest level of DSM program savings currently considered deliverable".[148] It should also be noted that the 2013 Integrated Resource Plan featured 2 higher DSM Options (4 and 5), which BC Hydro deemed unfeasible at the time.

5.5.1. Summary of Impacts on Load and Capacity

The analysis finds that by F2026, the alternative set of assumptions could result in a reduction of the load forecast in the range of 6,000 to 6,150 GWh, and a reduction in peak capacity in the range of 1,140 to 1,160 MW. By F2036, the corresponding impacts are a reduction in load forecast in the range of 5,950 to 6,100 GWh, and a reduction in peak capacity forecast in the range of 1,110 to 1,130 MW. Figures 13 to 16 summarize the impact on load and capacity before and after applying the DSM adjustment.

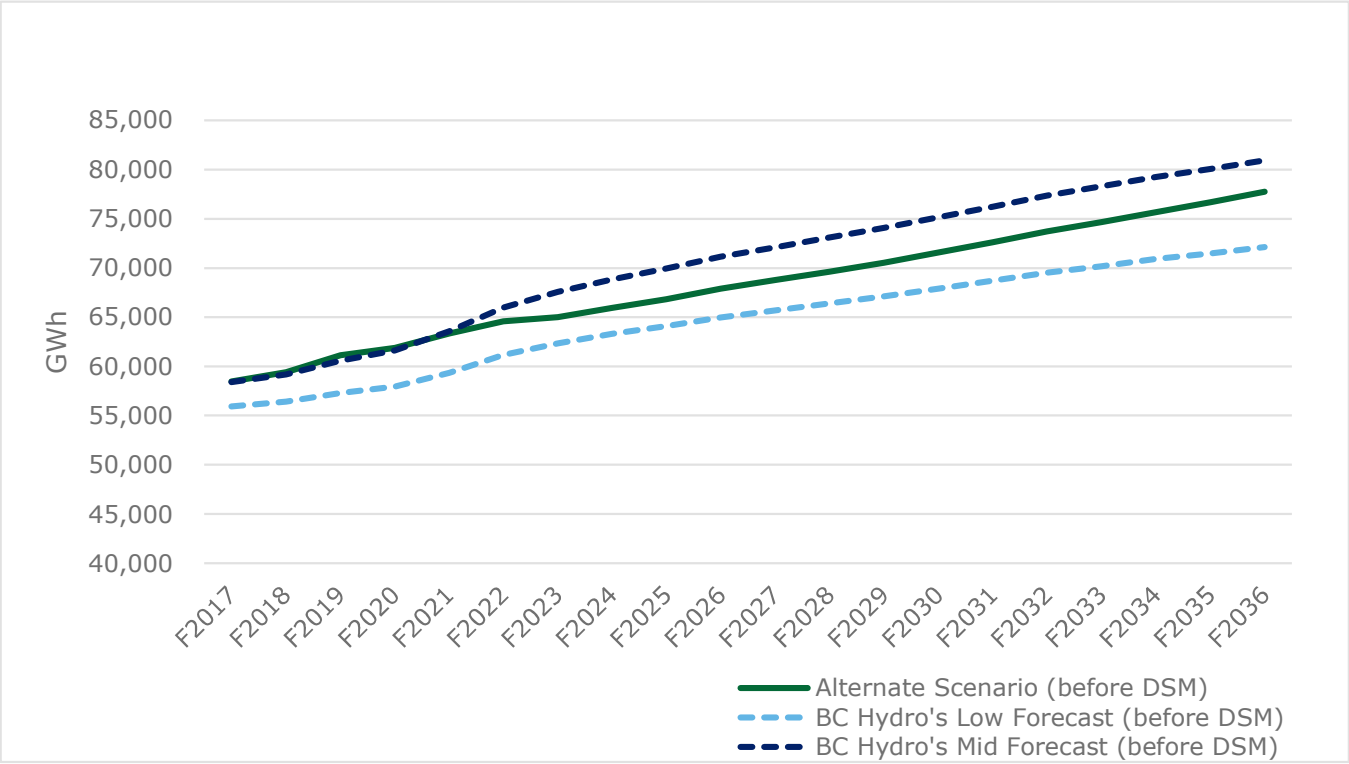


Figure 13: Load Forecasts Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario

[148] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0004-nov-2013-irp-chap-4.pdf

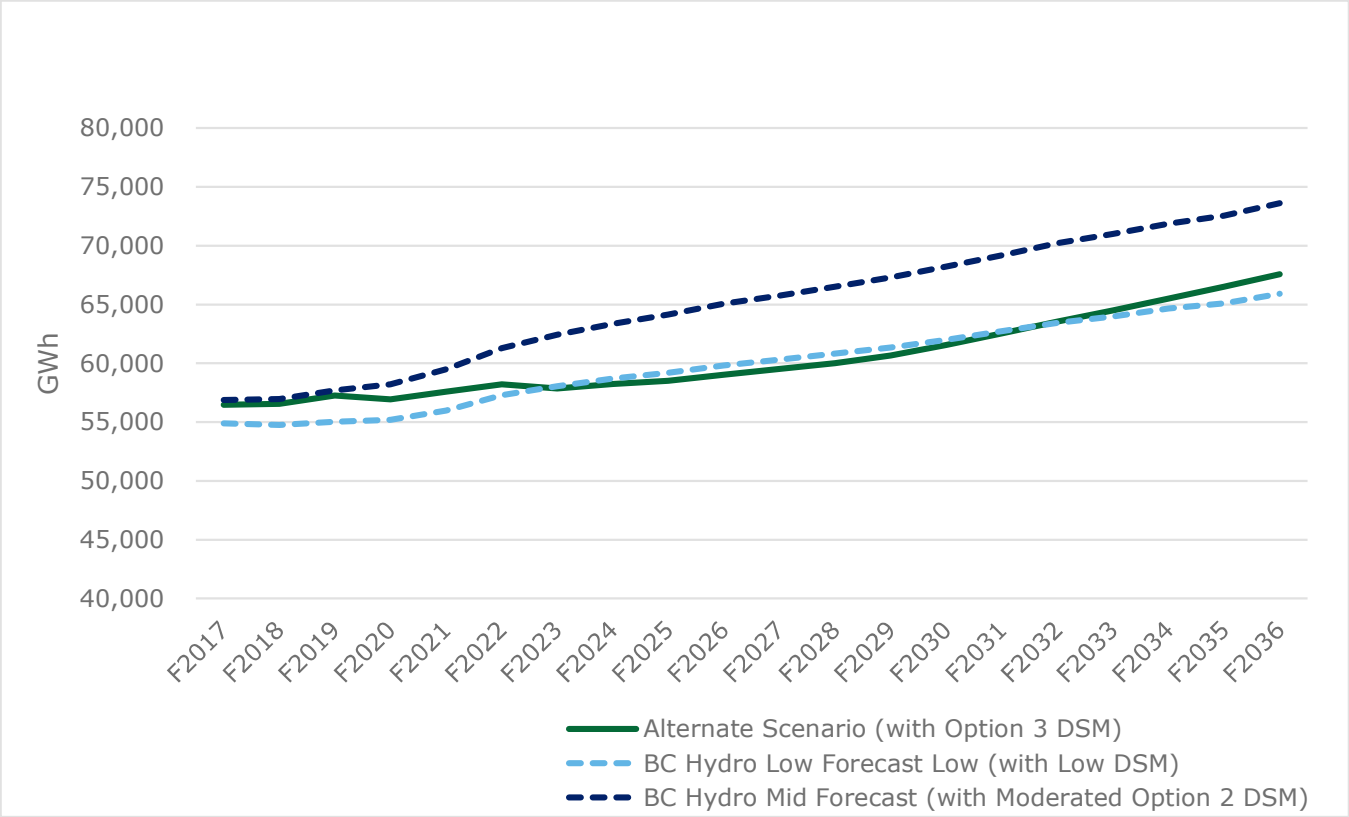


Figure 14: Load Forecasts After DSM - BC Hydro Mid and Low Compared with Alternate Scenario

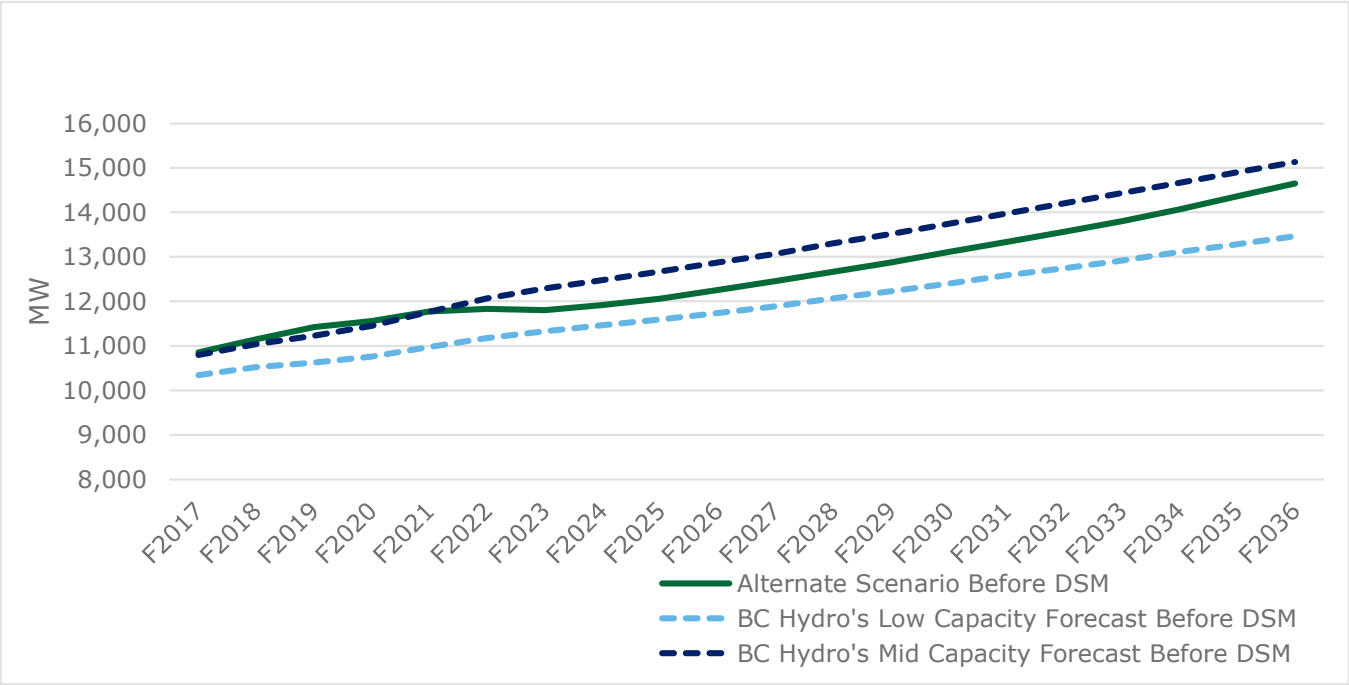


Figure 15: Capacity Forecast Before DSM - BC Hydro Mid and Low Compared with Alternate Scenario

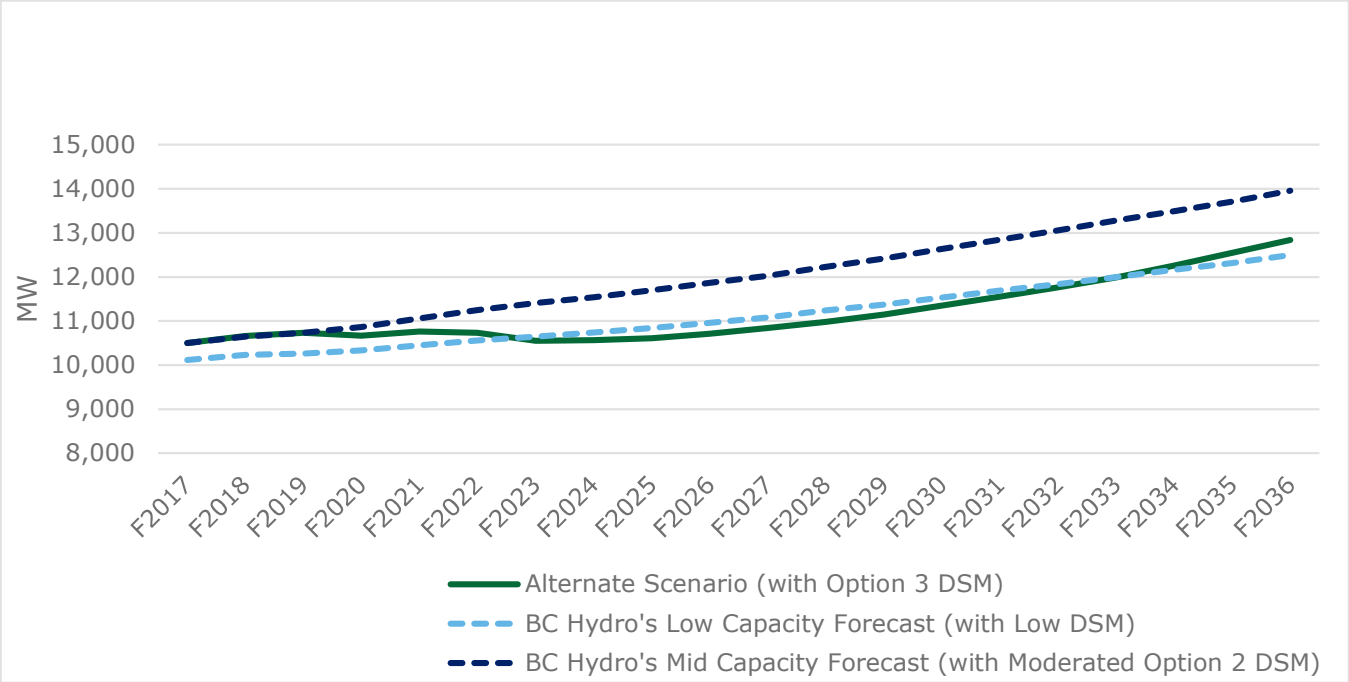


Figure 16: Capacity Forecast After DSM - BC Hydro Mid and Low Compared with Alternate Scenario

5.6. Statistical Considerations

With some exceptions, BC Hydro's approach to forecasting future load requirements appears broadly in line with the practices of utilities elsewhere in North America. For instance, both of the Canadian utilities interviewed reported using an SAE approach, as well as Monte Carlo simulations to model uncertainty. These utilities assessed heavy industrial requirements on a project-by-project basis and noted that this market segment is particularly difficult to forecast as it is more volatile than the residential and commercial sectors. One of the two utilities noted that heavy industrial was particularly sensitive to economic conditions: in the midst of the 2008 financial crisis, it saw heavy industrial requirements collapse, while residential (and, to a lesser extent, commercial) requirements remained comparatively steady.

In contrast to BC Hydro's current approach, the two other Canadian utilities interviewed reported that they had historically used a "top-down" time-series analysis in addition to a "bottom-up" SAE approach. One of the utilities continues to use time series analysis to produce a short-run forecast, and reports that it performs better than the bottom-up SAE approach over a 2-year horizon. From the perspective of mid forecast reliability, this utility also found it could be helpful to analyze time series and SAE regressions simultaneously, as it allowed differences between the two forecasts, if they emerged, to be more thoroughly examined. The other utility interviewed reported that it no longer conducts time-series analysis, as it believed that the speed of technological change meant that the past was no longer a good predictor of the future. While SAE modelling is used by many U.S. utilities, a U.S.-based energy forecasting professional interviewed by Deloitte reported that a top-down approach to load estimation is also common.

While this assessment did not include direct testing of the forecast model, the potential for correlation across the various independent components of the mid-forecast should be examined to make sure risks of suboptimal results are minimized.

Appendix A – Load Forecast Model Inputs

Model/Customer Segment	Key Input Variables	Source
Residential Model (4 models by region)	Historical # of accounts	BCH's data
	Historical use per account	BCH's data
	Housing starts	Robert Fairholm Consulting
	Personal income	Robert Fairholm Consulting
	Heating degree day	Environment Canada
	Cooling degree day	Environment Canada
	End-use saturation rates	BCH's residential end-use survey for historical, U.S. Energy Information Agency for forecasts
	End-use efficiency data	U.S. Energy Information Agency
	Dummy control variables (for certain months/ years)	N/A
Commercial/Light Industrial Model (8 models by region and demand size)	Billing data	BCH's data
	Industrial manufacturing part of total light industrial	B.C. Ministry of Finance (first five years), Robert Fairholm Consulting (beyond five years)
	Industrial production forecast	Consultant wood production for wood part of light industrial distribution
	Commercial GDP output-SAE	Robert Fairholm Consulting
	Employment-SAE	Robert Fairholm Consulting
	Retail sales-SAE	Robert Fairholm Consulting
	Heating degree day	Environment Canada
	Cooling degree day	Environment Canada
	End-use saturation rates for commercial	End-use efficiency data U.S. Energy Information Agency
	End-use efficiency data for commercial	U.S. Energy Information Agency
	Dummy control variables (for certain months/ years)	N/A

Model/Customer Segment	Key Input Variables	Source
Large Industrial (180 accounts)	Billing data	BCH's data
	GDP	B.C. Ministry of Finance and Robert Fairholm Consulting
	Forecasts from consultants	Has been provided in a data appendix
	Information from various reports and Key Account Managers	BCH, compared to other major sources (i.e., Bloomberg)
Other (i.e., street lighting)	Billing data	BCH's data
	Historical # of accounts	BCH's data
	Street lights, bc hydro own use, irrigation	BC Hydro data
	Local conditions in the short-term for NIA	BC Hydro data
	Population forecasts for NIA	BC stats
Other Large Utilites	Sales to Fortis BC	BCH model cost of purchased under tariff rates and costs of electricity purchases to the market
Monte Carlo (for high and low forecast)	GDP (regional)	Robert Fairholm Consulting
	Price of electricity (electricity rates)	BCH
	Weather (heating degree days)	Environment Canada
	GDP elasticity of demand	BCH's assumptions/ research (triangular distribution)
	Rate elasticity of demand	BCH's assumptions/ research (triangular distribution)
	Residual load impacts	BCH's own model
	Electric Vehicles	BCH's own model
	Load forecast DSM/integration overlap with codes and standards	BCH's own model

Appendix B – List of BC Hydro documents reviewed

5.1. Load forecasting:

- PPT titled "BC Hydro Energy Planning 101"
- December 2012 pdf "Electric Load Forecast: Fiscal 2013 to Fiscal 2033"
- PPT titled "A Path to the Long Term Forecast"
- PPT titled "EV Load Forecast Methodology"
- Responses to Deloitte questions #51, #86, #88, #89, #90 (all parts), #91, #92, #140, #141
- Exhibits B-9, B-9-2 and B-10 from BC Hydro's F2017 to F2019 Revenue Requirements Application
- Excel spreadsheet titled "83 to 87Release MID HIGH AND LOW BEFORE AND AFTER DSM"
- Excel spreadsheet titled "CEC_2_135_01_ATT_01" from Exhibit B-15, BC Hydro's response to intervener questions
- Excel spreadsheet titled "126 Site C Review – Deloitte Questions – August 2017 – Load Forecast history since 2007_Attachment" as provided in response to Deloitte's questions #126
- Excel spreadsheet titled "BCH EV Forecast Summary" provided by BC Hydro via email on Thursday August 24, 2017
- All data provided in response to Deloitte's questions #126
- BC Hydro's April 2017 Net Metering Report
- May 2017 BC Hydro PPT titled "Montney Load Forecast Model, Part 2 of 3: Top-down & Alignment Process"
- PDF titled "Site C Historical Savings" sent by BC Hydro on August 25, 2017

5.2. Assessment of alternative sources of energy and capacity

5.2.1. Publically available documentation

Document name	Author	Date	Source
BC Hydro F2017-F2019 Revenue Requirements Application (RRA)	BC Hydro	July 29, 2016	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/f17-f19-rra-20160728.pdf
Arguments and exhibits pertaining to BC Hydro's F2017-F2019 RRA	BCUC	Various	http://www.bcuc.com/ApplicationView.aspx?ApplicationId=533
BC Hydro 2013 Integrated Resource Plan	BC Hydro	November 2013	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/november-2013-irp.html#chapters
BC Hydro 2013 Resource Options Update Report	BC Hydro	November 2013	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/2013-ror-update.html
BC Hydro 2010 Resource Options Report	BC Hydro	February 10, 2012	https://www.bchydro.com/energy-in-bc/planning-for-our-future/irp/current-plan/document-centre/reports/final-ror.html
BC Hydro Resource Options Update Results Summary	BC Hydro	October 2016	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-summary-results-201610.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-9	BC Hydro	November 21, 2016	http://www.bcuc.com/Documents/Proceedings/2016/DOC_48161_B-9_BCH-Responses-to-BCUC-IRs.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-10	BC Hydro	November 21, 2016	http://www.bcuc.com/Documents/Proceedings/2016/DOC_48164_B-10_BCH_Responses-Interveners-IR.pdf
F2017 – F2019 Revenue Requirements Rate Technical Briefing Deck	BC Hydro	Jul. 28, 2016	www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/revenue-requirements/FY17-FY19-rra-application-technical-briefing-deck-20160728.pdf
BC Hydro and Power Authority F2017 to F2019 Revenue Requirements Application and Demand-Side Management Expenditure Schedule Final Submission of B.C. Sustainable Energy Association and Sierra Club B.C.	BCSEA and SCBC	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf

Document name	Author	Date	Source
FISCAL 2017 – FISCAL 2019 REVENUE REQUIREMENTS APPLICATION; Final Submissions of BC Hydro	BC Hydro	May 23, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-21	BC Hydro	May 11, 2017	http://www.bcuc.com/Documents/Proceedings/2017/DOC_49232_B-21_BCH-Responses-BCUC-IR-No1.pdf
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-14	BC Hydro	January 23, 2017	http://www.bcuc.com/Documents/Proceedings/2017/DOC_48630_B-14_BCH-Response-BCUC-IR2.pdf
Demand Side Measures Regulation (B.C. Reg. 326/2008)	Government of BC	November 7, 2008	http://www.bclaws.ca/Recon/document/ID/freeside/10_326_2008#section4
CEC Final Argument	CEC	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49470_06-13-2017-CEC-Final-Argument.pdf
BCSEA Final Argument	BCSEA	June 13, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49469_06-13-2017-BCSEA-Final-Argument.pdf
Manitoba Hydro 2016/2017 Demand Side Management Plan	Manitoba Hydro	March 2016	https://www.hydro.mb.ca/corporate/pdfs/demand_side_management_plan.pdf
Commission Approves Energy Efficiency Programs that Save APS Customers Money	Arizona Corporation Commission	June 15, 2016	http://azcc.gov/Divisions/Administration/news/2016Releases/7-13-2016%20Commission%20Approves%20Energy%20Efficiency%20Programs.pdf
APS 2016 Demand Side Management Plan	APS	June 1, 2015	http://images.edocket.azcc.gov/docketpdf/0000162231.pdf
The Total Cost of Saving Electricity through Utility Customer-Funded Energy Efficiency Programs: Estimates at the National, State, Sector and Program Level	Berkeley Lab	April 2015	https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf
Ontario Planning Outlook	IESO	September 1, 2016	http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/ontario-planning-outlook/ontario-planning-outlook-september2016.pdf
National Grid – Participate in Demand Response, save energy, and receive incentives!	National Grid	Accessed August 27, 2017	https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/connectedsolution-ma-ci-dr-info-flier.pdf
Hydro Quebec Strategic Plan 2009-2013	Hydro Quebec	2009	http://www.hydroquebec.com/publications/en/docs/strategic-plan/plan-strategique-2009-2013.pdf

Document name	Author	Date	Source
Hydro Quebec – Residential Dual Energy	Hydro Quebec	Accessed August 27, 2017	http://www.hydroquebec.com/residential/customer-space/account-and-billing/understanding-bill/residential-rates/rate-dt.html
Hydro Quebec 2014-2023 Supply Plan Integrated System	Hydro Quebec	Accessed August 27, 2017	
BC Hydro – Home renovation rebates	BC Hydro	Accessed August 27, 2017	https://www.bchydro.com/powersmart/residential/savings-and-rebates/current-rebates-buy-backs/home-renovation-rebates.html
BC Hydro Final Argument	BC Hydro	May 23, 2017	http://www.bcuc.com/Documents/Arguments/2017/DOC_49332_05-23-2017_BCHydro-Final-Argument.pdf
The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs	Ernest Orlando Lawrence Berkeley National Laboratory	2014	http://utilityscalesolar.lbl.gov/sites/all/files/lbnl-6595e.pdf

5.2.2. Confidential documentation

Document name	Author	Date	Source
08-18-2017_DSM consolidated issues brief	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
Draft Issues Brief – Chapter 10 – Capacity DSM and Codes and Standards – CPG – R3	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary (no. 2) (final)	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary – (final) V2	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
BCH F2017-F2019 DSM Evidence Summary (no. 1) final	BCUC	Received August 21, 2017	Provided by BCUC; email on August 21, 2017
Imports and Exports by Powerex: B.C. to/from U.S.	NEB	Received August 25, 2017	https://apps.nebone.gc.ca/CommodityStatistics/Statistics.aspx?language=english Provided by Powerex; email on August 25, 2017
Annual volumes of inter-provincial deliveries and receipts of electricity;	Statistics Canada	Received August 25, 2017	http://www5.statcan.gc.ca/cansim/a47 Provided by Powerex; email on August 25, 2017
BC Hydro (Integrated) Hourly Gen Aggregated (MWh) (206-2016)	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017

Document name	Author	Date	Source
IPP Forecast – Installed MW by day	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017
Wind Hourly Generation with Breakout	BC Hydro	Received August 25, 2017	Provided by BC Hydro; email on August 25, 2017
Historical hourly generation for onshore wind; Response to Deloitte Question #134	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly generation for solar; Response to Deloitte Question #133	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly generation for solar; Response to Deloitte Question #133	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical hourly hydro generation; Response to Deloitte Question #132	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
Historical heat rate and hourly generation for natural gas units; Response to Deloitte Question #135	BC Hydro	Received August 23, 2017	Provided by BC Hydro on August 23, 2017
79 Site C Review – Deloitte Questions – August 2017 – Attachment; Market Electricity and Gas Price Forecast Data	BC Hydro		Provided by BC Hydro
BC Hydro F2017-F2019 Revenue Requirements Exhibit B-14-1	BC Hydro	Received August 14, 2017	Provided by BCUC; email on August 14, 2017
RE: Solar price in BC	BCUC	Received August 14, 2017	Provided by BCUC; email on August 14, 2017
ACEEE 2017 scorecard	American Council for an Energy-Efficient Economy	Received August 22, 2017	Provided by BCUC; email on August 22, 2017
ACEEE 2016 scorecard	American Council for an Energy-Efficient Economy	Received August 22, 2017	Provided by BCUC; email on August 22, 2017
DSM background information Aug 22	BCUC	Received August 22, 2017	Provided by BCUC; email on August 22, 2017

Document name	Author	Date	Source
Site C BCUC #175 part 1; Response to Deloitte Question #175	BC Hydro	Received August 28 2017	Provided by, BC Hydro; email on August 28, 2017
Site C BCUC #175 part 2; Response to Deloitte Question #155	BC Hydro	Received August 28 2017	Provided by BC Hydro; email on August 28, 2017
Site C BCUC #175 part 3; Response to Deloitte Question #155	BC Hydro	Received August 28 2017	Provided by BC Hydro; email on August 28, 2017

Appendix C – Interviewees

- Director, Resource Planning, BC Hydro
- Commercial Manager, Site C Project, BC Hydro
- Sr. Manager, Strategic Planning, BC Hydro
- Senior Business Strategic Advisor, Conservation & Energy Management, BC Hydro
- Director, Conservation & Energy Management, BC Hydro
- DSM Planning Manager, BC Hydro

Appendix D – Confidentiality agreement

AGREEMENT ON CONFIDENTIALITY PROTOCOL FOR THE SITE C REVIEW
between
BC HYDRO AND DELOITTE LLP

WHEREAS:

A. The British Columbia Utilities Commission (Commission) has initiated the Site C Inquiry (Inquiry) pursuant to Terms of Reference issued on August 2, 2017 by the Province of British Columbia.

B. The Commission retained Deloitte LLP ("Deloitte") to assist in conducting its Inquiry and provide a report to the Commission. Deloitte has, in turn, subcontracted with consultants to assist in its work.

C. The Parties recognize that the disclosure of BC Hydro's commercially sensitive information could cause harm to BC Hydro, and thus potentially adversely impact BC Hydro's ratepayers.

D. On August 4, 2017 Deloitte and BC Hydro agreed to the attached interim terms (Interim Terms) regarding protection of commercially sensitive documents and information that BC Hydro provides to Deloitte during the course of the review. The Interim Terms contemplated that the Parties would develop and agree on a more formal protocol for the protection and treatment of commercially sensitive information.

E. Also on August 4, 2017, BC Hydro provided Deloitte and the Commission with access to a SharePoint site, on which BC Hydro had posted commercially sensitive documents requested by the Commission and Deloitte. BC Hydro has continued to post documents containing commercially sensitive information on the SharePoint site since that time.

F. The commercially sensitive information includes, but is not limited to, the following categories:

(a) Documents and information related to ongoing or potential claims with contractors working on the Project, for which disclosure to the contractor(s) could compromise BC Hydro's position *vis-a-vis* the contractor(s) and thus harm the interests of BC Hydro and ratepayers;
(b) Information that, if disclosed, would compromise BC Hydro's ability to procure materials and services cost-effectively; and
(c) Customer information.

G. The Parties have developed this Agreement Regarding Confidentiality Protocol (Protocol) to ensure that Deloitte can fulfil its mandate from the Commission, while protecting BC Hydro's commercially sensitive information and documents.

THE PARTIES AGREE AS FOLLOWS:

Confidential Documents and Confidential Information

1. In this Protocol, Confidential Information means:

   (a) documents posted on the confidential SharePoint site; and
   (b) any other information, whether disclosed in writing, orally, or visually, that has been identified by BC Hydro employees, or other representatives, as being commercially sensitive.

Deloitte's Obligation to Maintain Confidentiality Over Confidential Information

2. Deloitte shall hold in confidence, and shall not disclose to any person, any Confidential Information except to the extent that

   (a) the Confidential Information is generally known to the public at the time of disclosure or becomes generally known through no wrongful act on the part of Deloitte;
   (b) the Confidential Information is in Deloitte's possession at the time of disclosure other than as a result of prior disclosure by BC Hydro or a breach of any legal obligation by Deloitte or a third party;
   (c) the Confidential Information becomes known to Deloitte through disclosure by sources other than BC Hydro or those having a duty of confidentiality to BC Hydro; or
   (d) the Commission has determined the Confidential Information should be disclosed publically.

   Deloitte will not make any use of the Confidential Information beyond what is required to fulfil its retainer in this Inquiry.

3. Notwithstanding section 2, Deloitte may provide Confidential Information to:
   (a) the Commission; and
   (b) third parties with whom Deloitte has contracted to perform work on the Inquiry, and who have agreed with BC Hydro to abide by terms equivalent to the Interim Agreement, this Protocol or otherwise acceptable to BC Hydro.

   In the case of both (a) and (b), Deloitte must advise the recipient that the information is Confidential Information.

4. Notwithstanding Section 2 and 3, Deloitte may disclose Confidential Information if Deloitte is compelled to disclose such Confidential Information by an order of a court of competent jurisdiction or a regulatory body, provided that Deloitte provides prompt notice (to the extent permitted by law) to BC Hydro of any proceedings seeking such an

order, so that BC Hydro has the opportunity to make representations to such court or regulatory body regarding the proposed disclosure. If Deloitte is precluded by law from providing the above notice to BC Hydro, and an order is made without notice to BC Hydro, then Deloitte must provide prompt notice of such order to BC Hydro prior to making any disclosure.

5. Deloitte will destroy or return to BC Hydro any written Confidential Information in its possession by December 1, 2017, and provide confirmation of the same to BC Hydro. This Protocol shall apply to all Confidential Information for as long as Deloitte is in possession of Confidential Information. Notwithstanding the foregoing however, Deloitte shall have access to, or maintain copies of, any such Confidential Information as is needed to support its work papers in accordance with applicable professional standards. Such copies will be destroyed promptly following the retention date specified by applicable professional standards.

Inclusion of Confidential Information in Deloitte Report

6. Deloitte may, in its own discretion, refer to or include Confidential Information in its report to the Commission. In that event, Deloitte will submit that Confidential Information to the Commission in a confidential appendix to the report or otherwise identify for the Commission where the Confidential Information appears.

Acknowledgement of Commission's Jurisdiction

7. The Parties anticipate that BC Hydro will, upon request by the Commission, provide an explanation to the Commission as to why BC Hydro considers that the commercially sensitive information referenced in the Deloitte Report should remain confidential. Nothing in this Protocol is intended to fetter the Commission's jurisdiction to determine the treatment of Confidential Information for the purposes of the Inquiry.

The Parties agree the above terms, effective August 27, 2017.

BC Hydro
Per _____
Fred James
Chief Regulatory Officer

Deloitte LLP
Per Deloitte LLP

Appendix E – Modeling alternative supply-side sources of energy and capacity (MarketBuilder model)

5.1. About MarketBuilder and Disclaimer

MarketBuilder, developed by Deloitte MarketPoint, is a fundamentals-based generalized equilibrium model of commodity supply chains. Deloitte MarketPoint has a 30-year history of continuous development and extensive, documented, and broadly applied use of MarketBuilder by industry and government entities. MarketBuilder allows for a combination of variable measurements, such as fuels and electricity along with emissions allowances/credits and variables such as renewable energy credits, if applicable. It has provided the foundational modeling platform for regulatory impact models, fuel procurement planning, market strategy development, and capital investment decisions for utilities, project developers, investors, regulators, and government agencies. Additionally, U.S.-based investor owned utilities have utilized MarketBuilder to support resource plans and similar regulatory filings. MarketBuilder provides flexibility and rigor in endogenous capacity expansion computations as well as natural multi-commodity (e.g., fuels, electricity, emissions) integration in ways and to a degree not generally available in the other platforms.

The results from the MarketBuilder model are solely directional and for informational purposes only. In our assessment, we did not have the benefit of utilizing BC Hydro's IRP model with each existing generation and transmission asset modeled. Where the results of analysis are discussed in this publication, the results are based on the application of economic logic and specific assumptions. These results are not intended to be predictions of events or future outcomes.

Deloitte MarketPoint is not, by means of this publication, rendering accounting, business, financial, investment, legal, tax, or other professional advice or services to any person. This publication is not a substitute for such professional advice or services, nor should it be used as a basis for any decision or action that may affect your business. Before making any decision or taking any action that may affect your business, you should consult a qualified professional advisor. Deloitte MarketPoint shall not be responsible for any loss sustained by any person who uses or relies on this publication.

5.2. Introduction and approach to MarketBuilder modeling

This appendix presents results from the modeling of alternative supply-side sources of energy and capacity to replace that expected to be provided by Site C. The modeling of an alternative supply-side portfolio is completed using MarketBuilder. It is herein referred to as the MarketBuilder model.

The general approach to constructing the MarketBuilder model was to apply BC Hydro's load forecast and consider what additional generation (not relying on Site C) is required to meet the forecast at the lowest potential cost, within a specific greenhouse gas emissions cap, and specific assumptions and constraints, which are detailed below.

In modeling B.C.'s electricity system, Deloitte utilized MarketBuilder to analyze fuel supply (including thermal and renewable sources) which flows into generation units that convert the fuel into electricity that then flows

to demand (electrical load). For example, each generation unit is a node that receives the fuel supply and price (inputs to the node), contains parameters such as heat rate (a measure of conversion efficiency) and capacity, and produces electricity at a price (outputs from the node).

In this modeling exercise, the Deloitte team started with a portfolio that includes:

- BC Hydro's existing generation capacity;
- Committed projects expected to come online in the future:
- Current Energy Purchase Agreements (EPA):
- Expected EPA renewals and expirations[165].

These capacities provided a starting point for the model. Deloitte then considered different potential generation types that are commercially feasible in B.C., including geothermal, wind, solar, and wood-based biomass facilities, in addition to new hydroelectric capacity; it also included the available characteristics of each fuel type. The modeling can be done where capacity is exogenous (i.e. specified externally regardless of economic performance), or endogenous (i.e. determined as a function of the economics and added only when economically supported). Deloitte recommends modeling exogenous capacity additions when utilities can confirm new units with a high degree of certainty, and modeling endogenous capacity additions when they seek to incorporate economic assumptions into modeling the performance of the overall system. Therefore, existing resources including contracted supplies as well as BC Hydro projects underway or otherwise very likely to move forward were modeled as exogenous capacity; potential new sources and alternatives were modeled as endogenous options with their related economic and operating parameters. BC Hydro provided additional and updated cost and performance information based on recent and pending capacity additions to the system[166].

Under this approach, the MarketBuilder model for BC was used to evaluate the economic portfolio of supply-side options to meet forecasted electricity demand in BC without Site C. Existing and expected resources were optimized along with the economic alternative sources required to satisfy the expected growth in demand. The assumptions regarding salient inputs such as the demand forecast, operational and economic parameters, and available alternative sources are described in greater detail in the following sections.

5.3. Scenario parameters

To properly define any modeling study, a large number of parameters must be specified. Long-term studies that involve asset development must particularly contend with the potential for changes and uncertainties in the macro-level environment, as well as shorter-term operational issues. This section describes a number of important scenario parameters used in the analysis. Many can debate alternatives to the assumptions, but for any given scenario, one set must be selected and the others can be reserved for further study. The following parameters were applied in the construction of this portfolio.

10.3.1 Time horizon

The study period is for 18 years, and is based on BC Hydro's fiscal year ending March 31 from 2018 to 2036.

[165] This model does not include BC Hydro's expected capacity reduction of Mica dam's units 1 to 4. This reduction is expected to reduce dependable capacity by 410 MW between F2025 and F2030. This information was not available to Deloitte at the time of the portfolio run.

[166] Data provided by BC Hydro included operating and maintenance costs for their hydroelectric facilities, as well as historical hourly generation data for their hydroelectricity facilities, their hydroelectric EPAs, their solar EPAs, and their wind EPAs. A list of BC Hydro documents reviewed is summarized in Appendix C.

10.3.2 Regulatory Landscape

The scenario assumes the current regulatory landscape, including the requirements of the Clean Energy Act (e.g. need to generate at least 93% of the electricity in BC from clean or renewable resources; the requirement of self-sufficiency applies; Burrard Thermal is barred; nuclear power is not included in modeling as it is not aligned with BC energy objectives). The assumptions below provide additional details.

10.3.3 Load forecast

The portfolio modeling relies on BC Hydro's load forecast published in July 2016. We used the mid-level projections for electricity load and capacity requirements in BC until F2036, after Option 2 Modified DSM has been applied.

10.3.4 Scope of portfolio

An assessment of the following alternative sources of energy and capacity was included in the model:

1. The list of generation alternatives/storage modelled includes:

    - Onshore Wind
    - Offshore Wind
    - Utility-Scale Solar PV
    - Geothermal
    - Natural gas (SCGT and CCGT)
    - Run-of-river hydroelectricity
    - Biomass (wood-based)
    - Biogas (landfill gas)
    - Biomass (municipal solid waste - MSW)
    - Cogeneration
    - Pumped storage
    - Battery storage

2. Expansion potential of current BC Hydro facilities:

    - All existing BC Hydro assets are included in the model as firm supply (exogenous variable).
    - All committed BC Hydro expansion is included in the model as firm supply (exogenous variable)167.
    - All EPAs are included in the model as firm supply (exogenous variable). However, some EPAs are assumed to expire. Details of these expirations are detailed below in the Assumptions (section 3).
    - Deloitte conducted an assessment of the potential to further expand existing BC Hydro facilities. The additional potential is included in the model as a supply option (endogenous variable). It is optimized in the model among all other generation options.

[167] Committed projects included in the model as firm capacity (exogenous) include Revelstoke Unit 6, John Hart, Ruskin, Cheakamus, and Bridge River projects (see Section 4.2.3 in the report for more details on these projects).

- Throughout this report, existing and committed BC Hydro projects will refer to the exogenous variables explained above. New endogenous capacity includes the potential expansion of existing BC Hydro facilities as described above and in section 4.2 of the main report.

3. Demand-side management to account for energy and capacity savings:

- In this portfolio, we apply BC Hydro's mid-load after Option 2 Modified DSM to account for the current energy and capacity savings. Refer to section 4.3 of the main report for an explanation of this DSM option.

5.4. Assumptions

5.4.1. Economic assumptions

5.4.1.1. Cost estimates

The scenario uses constant, current 2017 Canadian dollars over the entire forecast period. Inflation was not included in the analysis.

5.4.1.2. Capital cost estimates

Overnight capital cost is the cost of construction for a power plant, assuming an overnight build period. While plant construction takes time, the convention of the overnight assumption is used to separate plant costs from financing costs, which can be more variable and highly affected by time. The overnight capital cost is not an estimate of total construction costs because it does not take into account interest during construction. However, financial models and integrated resource plan analysis use this estimate to compare the economic feasibility of building different plants because it is a way to separate the financing costs from the plant costs.

Capital costs for each technology were extensively researched by Deloitte. A range of costs was derived from this research, and the most relevant cost was input into the model. Capital-cost decline rates were also applied when research demonstrated it to be relevant. For instance, solar PV prices have fallen significantly over the past several years and are expected to continue to decline for the next few years. Consequently, declines in capital cost over time have been included in the model for relevant technologies.

5.4.1.3. Operating and maintenance (O&M) cost estimates

The model includes both fixed and variable O&M costs. The O&M costs were extensively researched by Deloitte. A range of costs was derived from this research, and the most relevant cost was used in the model. Refer to section 4.1.2 of the main report.

5.4.1.4. Taxes and other investment parameters

The model assumes that any additional capacity built in BC is financed by BC Hydro. As a result, Income Tax Rate is assumed to be 0% since BC Hydro does not pay a corporate income tax rate, and only pays taxes through grants in lieu and school taxes (which are deemed to be immaterial). Property Tax is assumed to be 0% since it is deemed to be immaterial. Insurance Rate is assumed to be 0% since it is deemed to be immaterial.

All new projects are assumed to be 100% debt financed, with a weighted cost of debt of 4.06% in 2018 and 4.13% for 2019. The source for the weighted cost of debt is BC Hydro's F17-F19 RRA, Exhibit B-1-1, Appendix A, Schedule 8.0, Line 59. We assume the 2019 weighted cost of debt for each year between 2020 and 2036.

The model does not account for BC Hydro's treatment of corporate revenue and net income in the modeling of project economics.

5.4.1.5. Currency and exchange rates

The currency used in the model is the Canadian dollar (CAD). It assumes an exchange rate of 0.75 CAD/USD when applicable[168].

5.4.2. Emissions restrictions

5.4.2.1. Clean Energy Act restrictions

The Clean Energy Act, introduced in spring 2010, sets forth British Columbia's energy objectives. One of these objectives includes generating "at least 93% of the electricity in British Columbia from clean or renewable resources." Clean energy is defined as "biomass, biogas, geothermal heat, hydro, solar, ocean, wind or any other prescribed resource". This model assumes that natural gas and cogeneration plants are not clean, and therefore, may not contribute more than 7% of total electricity generated in any given year. The model assumes 0 direct GHG emissions for biomass, biogas, geothermal heat, hydro, MSW, solar, and wind given the BC Government's definition of clean energy[169].

5.4.2.2. Carbon price

British Columbia introduced a revenue-neutral carbon tax on the purchase and use of fuels in 2008. The BC carbon tax is currently CAD$30 per tonne. The federal government outlined a benchmark for carbon pricing that reflects an increase to CAD$50 per tonne in 2022. The NDP's platform indicates that it intends to meet the federally mandated CAD$50/tonne carbon price by 2022 over three years starting in 2020 ($6, $7, $7/tonne).[170] As such, the model assumes a carbon price of $30 per tonne from 2018-2019, rising to $36 per tonne in 2020, $43 per tonne in 2021, and $50 per tonne in 2022. The model assumes that the tax remains $50 per tonne throughout the rest of the forecast (2022-2036). The model also assumes that this tax is applied only to natural gas and cogeneration[171].

5.4.2.3. Imports/exports

Imports/exports are modeled using power price schedules for interconnected external. The external market prices used in the scenario are based on projections from Deloitte MarketPoint's 2016 North American Gas & Power Reference Case for the Alberta and Mid-Columbia (Mid-C) markets. Relative price differences and transfer capability and costs influence the extent of imports and exports, but we assume a similar level of GHG intensity (10 tonnes CO2e/GWh) for any imports into BC.

5.4.2.4. Carbon cap

The provincial government's Order-in-Council (OIC) asked that alternatives to Site C construction be considered which would offer energy while maintaining or reducing the 2016/2017 GHG emission levels. Our

---

[168] BC Ministry of Finance; Budget and Fiscal Plan 2017/18 – 2019/20; Exchange rate outlook (pg. 91); http://bcbudget.gov.bc.ca/2017/bfp/2017_Budget_and_Fiscal_Plan.pdf

[169] In this model, all sources of energy are deemed "clean" with the exception of natural gas and cogeneration. Consequently, natural gas and cogeneration are the only resources in the model that are (1) subject to the carbon tax, (2) may only account for 7% of generation in any given year, and (3) may not produce so much energy as to increase the carbon intensity above the 2016/17 level of 10 tonnes/GWh in any given year. Certain portions of MSW may not be considered clean, for instance tires and peat when combusted to produce energy. Conversely, cogeneration may be considered clean in some circumstances such as when biomass is the primary source of energy generation. For simplicity, this model assumes that MSW is clean and cogeneration is not clean due to the use of natural gas-fired generation at many existing cogeneration plants in BC.

[170] BC NDP Platform; Climate Action; https://www.bcndp.ca/files/Clean-Growth-Climate-Action.pdf

[171] Ibid.

interpretation of this direction is on an intensity rather than absolute basis. The model constrained the annual average carbon intensity to no higher than 10 tonnes/GWh for the duration of the forecast (2018-2036).[172]

5.4.3. EPA renewals

BC Hydro's 2013 IRP states, "For planning purposes, BC Hydro now estimates that 50% of the bioenergy EPAs will be renewed, about 75% of the small hydroelectric EPAs that are up for renewal in the next five years will be renewed, and all remaining EPAs will be renewed." In line with this statement, Deloitte assumed that 50% of all biomass contracts and 25% of all non-storage hydroelectric contracts would retire between 2013-2018. All other contracts are assumed to be renewed in the model.

For those EPAs that are allowed to expire (without renewal), the associated energy and capacity are removed from the model at contract expiration. In reality, some may be re-negotiated at a favorable cost and if modelled as another supply-side resource, it would likely be cheaper than greenfield opportunities.

BC Hydro's Standing Offer Program (SOP) is not explicitly represented in modeling. While the Clean Energy Act requires BC Hydro to offer the SOP, it does not require specific volumes. It also represents a risk of double-counting the resources already in the model assumed under the EPA.

5.4.4. Self-sufficiency

The Clean Energy Act sets forth BC's energy objectives. One of these objectives includes achieving "electricity self-sufficiency." We interpreted this requirement as the need for BC Hydro to hold, each year, the rights to an amount of electricity that meets the electricity supply obligation within the Province. We recognize that an exemption from this requirement can be granted with authorization from the Lieutenant Governor in Council. In the model, we assumed that BC Hydro is allowed to import energy during the year as long as it is not a net importer for each year.

Total annual imports in the model were limited to total annual exports that same year. In other words, in the model, British Columbia may import electricity during some periods but is a net exporter of electricity on average every year.

5.4.5. Resource technology capacity constraints

As mentioned in section 4.3.3, ten different generation technologies and two types of storage were included in the MarketBuilder model. However, only three of these technologies proved economic over the next 18 years, given current assumptions on existing supply, load, and imports and exports. However, since it is unrealistic to assume that any technology, regardless of its economics, could construct an infinite amount of capacity in British Columbia, certain assumptions were made regarding the amount of each technology that could be built in the province.

[172] A carbon intensity of 10 tCO2e/GWh reflects an average of BC Hydro's reported GHG intensities for total electricity generation over the past two reported years (2014 and 2015). This was the most recent data available at the time of the assessment. Refer to https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/environment-sustainability/environmental-reports/ghg-intensities-2007-2015.pdf. The estimate of 10 tCO2e/GWh also reflects the average over the last five reported years (2011-2015).

5.4.5.1. Geothermal capacity constraints

Document research was conducted and several studies were analyzed to determine the potential of geothermal in BC[173, 174, 175]. The studies analyzed for this report ranged widely in their assessment of potential geothermal resources in the province, from just 250 MW in specific areas analyzed to more than 6.5 GW of potential capacities looking at potential across the entire province. However, each of these studies did identify several similar areas in BC as having potential capacity, including the Lower Mainland and North Coast. We assumed approximately 250 MW of potential capacity are available at the reference capital cost of $7,300/kW. This was included in the model. Further, the studies showed that additional capacity would likely be available, though perhaps at a higher cost. The model assumes another 750 MW is potentially available at $8,800/kW.

While geothermal energy is a proven technology across much of the world, including nearby California, no geothermal energy generation currently exists in British Columbia. The nature of geothermal energy gives it a unique development timeline, different from any other technology analyzed in this model. Development of geothermal energy requires preliminary surveys, exploration, test drilling, field development, and power plant construction. Test drilling is required to validate the geothermal resource and can be capital intensive. Consequently, while geothermal is forecast to be economic in BC, the development of this resource could be slower than projected if difficulties securing financing for test drilling are realized.

5.4.5.2. Onshore wind capacity constraints

The economics of onshore-wind generation in British Columbia differ greatly by geography due to various factors, including the quality of the wind resource, proximity to dense populations, proximity to transmission lines, and terrain. Document research was conducted and several studies were analyzed[176, 177]. Three transmission regions with high wind potential were included in the model (Vancouver Island, Kelly Nicola, and Peace River), each with its own wind profile and cost profile.

Each of these regions was further refined by capacity constraints. Onshore wind in the Peace River region was determined to have the lowest cost. However, transmission lines between Peace River and the Lower Mainland were expected to become congested if more than about 600 MW of wind capacity was added. Similar analysis was carried out for Kelly Nicola and Vancouver Island. Kelly Nicola benefits from being near to the Lower Mainland and sparsely populated. Consequently, more capacity was available at lower prices compared to Vancouver Island. Vancouver Island had the highest capital cost compared to the other two

---

[173] Canadian Geothermal Energy Association, Canadian National Geothermal Database and Provincial Resource Estimate Maps. http://www.cangea.ca/bc-geothermal-resource-estimate-maps.html

[174] Kerr Wood Leidal Associates Ltd. And GeothermEx, Economic Viability of Selected Geothermal Resources in British Columbia (Selected Sites in BC), November 2015, Updated October 2016. http://www.geosciencebc.com/s/Report2015-11.asp

[175] Geological Survey of Canada, Geothermal Energy Resource Potential of Canada, 2012. http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf

[176] Garrad Hassan, Assessment of the Energy Potential and Estimated Costs of Wind Energy in British Columbia, Feb 2008. https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/rou_wind_garrad_hassan_report.pdf

[177] Canadian Wind Energy Association (CanWEA) and GE Energy Consulting, Pan-Canadian Wind Integration Study, Oct 2016. http://canwea.ca/wind-integration-study/full-report/

regions. However, capacity was limited to 500 MW in the model at the reference price. Another 600 MW was offered at a higher price, approximately 15% more than the reference price.

5.4.5.3. Biogas capacity constraints

In the model, biogas refers to landfill gas and is therefore limited by the amount of landfill gas available in British Columbia. Based on current biogas performance and current landfill sizes, it was assumed that a maximum of 14 MW of additional biogas capacity could be added in the province. It was further assumed that only 8 MW would be available at the reference capital cost of $3,600/kW. The other 6 MW was available for approximately 10% more than the reference cost due to size and need for gas collection and transport to generator.

5.4.6. Reserve margin

Reserve margin measures the available capacity above the capacity needed to meet normal peak demand levels. A reserve margin of 14% was required in the model, in line with current requirements at BC Hydro.

5.4.7. Resource availability

Availability, as it exists in the model, represents the percentage of installed capacity that can be expected to generate electricity in each time period in the model. For a natural gas unit, the availability may be as high as 92%, with the other 8% assumed to be for maintenance or forced outages. For solar PV, the availability may only average 20% due to weather variability, and because the sun does not shine 24 hours a day, 365 days a year. The availability will change by time of day (generates more during the day) and by time of year (days are longer in the summer). This has been captured in the model. Availability was derived from historical performance whenever possible (including BC Hydro's hydro assets, solar EPAs, and wind EPAs)[178]. When historical actuals were not available, document research was conducted and industry norms were used[179].

5.5. Findings

Findings are provided for the single scenario modeled as part of this assessment. MarketBuilder model outputs are presented below and include the following information:

- Year: The year in which the alternative resource is selected by the MarketBuilder model.
- Alternative resources selected: The alternative resources (supply-side sources of energy and capacity) selected by the MarketBuilder model.
- Generation: Total energy generated by alternative resource (MWh).
- Capacity: Total installed capacity by alternative resource (MW).
- Costs: Capital and O&M costs by alternative resource (mn $CAD).
- Price of energy: Average price of energy provided by the portfolio ($CAD/MWh).
- GHG emissions: Total annual GHG emissions generated by the portfolio (tCO_2e).

MarketBuilder portfolio run results for the base scenario are described in the following sections according to the categories below:

- Generation
- Capacity
- Costs

[178] As provided by BC Hydro.
[179] Sources detailed in section 4.1 of the main report were referred to.

- GHG emissions

5.5.1. Generation

The portfolio selected by the MarketBuilder model comprises a range of existing facilities and new alternative resources. These include:

- BC Hydro hydroelectric facilities (existing and committed)
- BC Hydro natural gas facilities – CCGT and SCGT
- EPA contracts (existing and renewals) – biogas, biomass, cogeneration, hydroelectric, MSW, solar, onshore wind (Okanagan and Peace River regions)
- BC Hydro hydroelectric facilities (new endogenous)[180]
- Biogas (new)
- Geothermal (new)
- Onshore wind – Vancouver Island (new)

Total energy generation is forecast to rise from 67 million MWh in 2018 to 79 million MWh in 2036, as the province remains a net exporter while meeting internal demand that rises from 57 million MWh to nearly 74 million MWh over the same period. The majority of this energy will continue to be generated by existing and committed BC Hydro assets. However, the total share of electricity being generated by these existing and committed BC Hydro assets will fall from about 70% in 2018 to approximately 62% in 2036 as new generation comes online to meet increasing demand. Most EPAs are assumed to renew. Consequently, generation from EPAs fall only slightly through the forecast. New generation is expected to account for about 13% of generation by 2036, from a combination of new geothermal, biogas, onshore wind, and hydro expansions.

The generation mix in British Columbia is expected to change over the forecast horizon, as new sources of generation are added. Total hydro generation in the province (from existing units, committed units, new units, and EPAs) is forecast to grow ~6% in absolute terms over the forecast horizon. Hydroelectric market share is forecast to drop slightly form 91% to 81% by 2036, but it is expected to remain the dominant source of power in the province. Generation from biogas and onshore wind increase as incremental capacity is added. Geothermal is the largest source of new generation, accounting for about 10% of total generation by 2036.

[180] While 16 potential hydro expansion projects were included the model, only six of those projects were determined to be economic given current assumptions. These projects were GM Shrum, Ladore, Seven Mile, Shuswap, Wahleach, and Whatshan. Together these projects contributed an additional 317 MW of capacity to the portfolio through 2028.

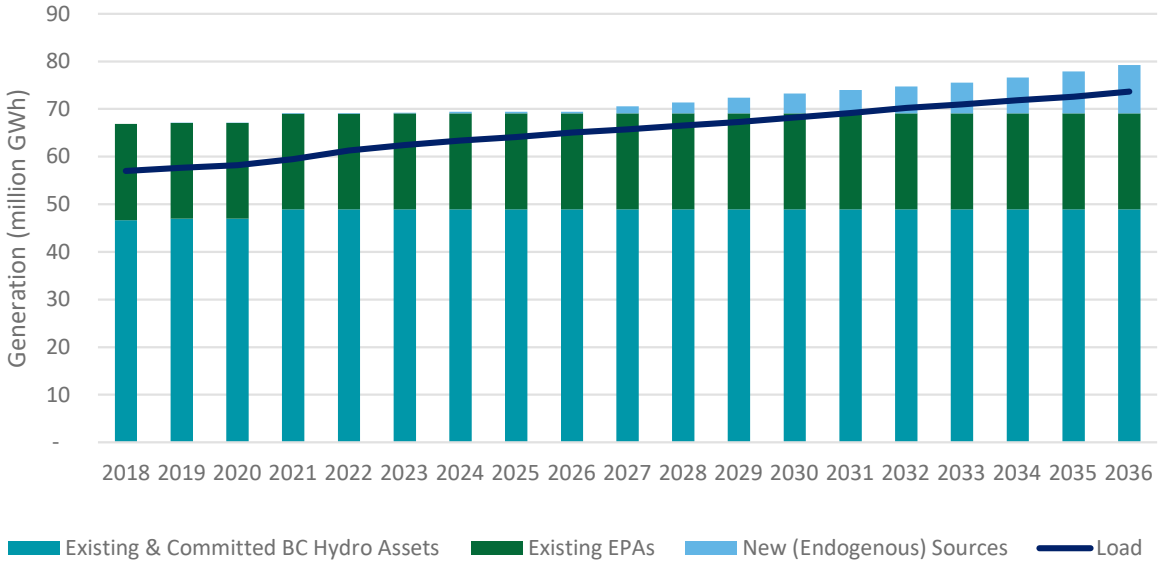


Figure 1: Cumulative energy generation by existing, committed, and new sources by year (2018-2036)

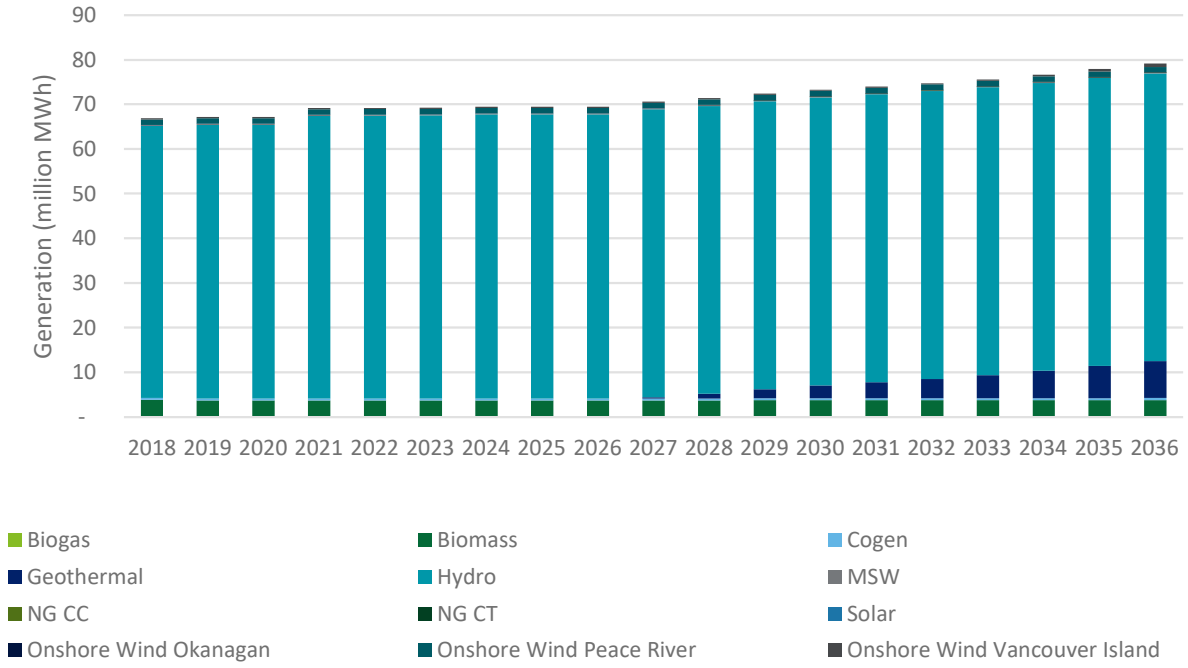


Figure 2: Cumulative energy generation by resource type by year (2018-2036) for all resources (existing, committed and new endogenous)

Total energy generation from the portfolio reaches 79 million MWh by 2036.

5.5.2. Capacity

The portfolio selected by the MarketBuilder model includes new capacity hydroelectric facilities beginning in 2018, with additional geothermal added in 2027. Biogas and wind begin to add capacity later in the planning period, in 2029 and 2014 respectively. Capacity from biomass decreases in 2018 and 2019 due to the expiration of existing EPAs that are assumed to not be renewed.

Figure 3 below shows cumulative, installed capacity by technology resource. However, dependable capacity would be substantially lower since resources such as wind, solar, and hydro do not normally operate at 100% of installed capacity.

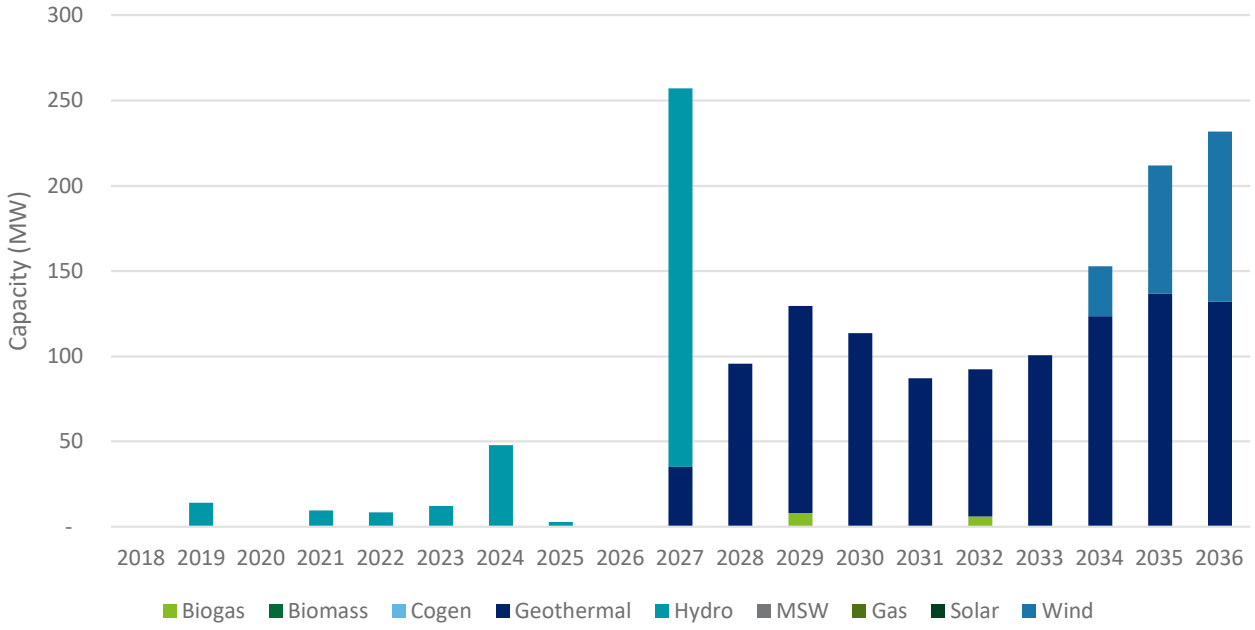


Figure 3: New endogenous capacity by alternative resource type by year (2018-2036)

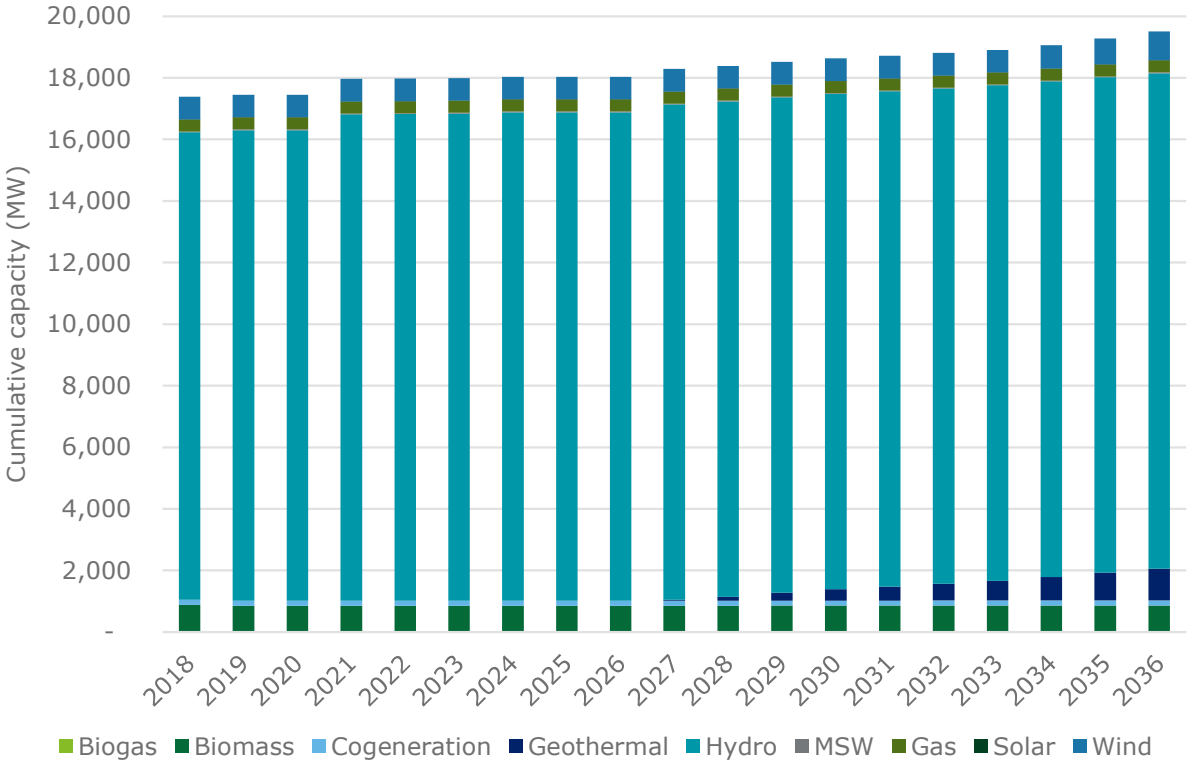


Figure 4: Cumulative installed capacity by resource type by year (2018-2036) for all resources (existing, committed, and new endogenous)

Total installed and contractual capacity from the portfolio reaches 19,506 MW by 2036.

5.5.3. Costs

Since additions of new generating resources are sometimes lumpy, capital cost requirements associated with these additions are not necessarily a constant or smoothly increasing value. Earlier years can maintain lower capital costs for new generation, since there is potential to increase utilization of existing assets. Table 1 below summarizes capital costs of incremental capacity from alternative resources. These capital costs are only for those endogenous expansions found to be economic in the modeling. Therefore, the costs of exogenous expansions are considered sunk costs and excluded from the costs in the table. Total annual capital costs from the development of new biogas, geothermal, hydroelectric, and wind facilities reach $951,484 by 2036, with annual O&M costs of $583,839.

Table 1: Capital costs (mn $CAD) by alternative resource type by year (2018-2036)

Year	Biogas	Biomass	Cogen-eration	Geo-thermal	Hydro	MSW	Gas	Solar	Wind	Total
2018	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	6	-	-	-	-	6
2020	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	37	-	-	-	-	37
2022	-	-	-	-	33	-	-	-	-	33
2023	-	-	-	-	39	-	-	-	-	39
2024	-	-	-	-	48	-	-	-	-	48
2025	-	-	-	-	0	-	-	-	-	0
2026	-	-	-	-	0	-	-	-	-	0
2027	-	-	-	183	72	-	-	-	-	255
2028	-	-	-	496	0	-	-	-	-	496
2029	21	-	-	627	-	-	-	-	-	647
2030	-	-	-	583	-	-	-	-	-	583
2031	-	-	-	445	-	-	-	-	-	445
2032	17	-	-	484	-	-	-	-	-	501
2033	0	-	-	605	-	-	-	-	-	605
2034	-	-	-	750	-	-	-	-	46	796
2035	-	-	-	826	-	-	-	-	120	946
2036	-	-	-	792	-	-	-	-	159	951

Table 2: O&M costs (mn $CAD) for new endogenous by resource type by year (2018-2036)

	Biogas New	Geothermal New	Hydro Expansions New	Onshore Wind Vancouver Island New	Total
2018	-	-	-	-	-
2019	-	-	0	-	0

	Biogas New	Geothermal New	Hydro Expansions New	Onshore Wind Vancouver Island New	Total
2020	-	-	0	-	0
2021	-	-	1	-	1
2022	-	-	1	-	1
2023	-	-	1	-	1
2024	-	-	3	-	3
2025	-	-	3	-	3
2026	-	-	3	-	3
2027	-	5	10	-	15
2028	-	19	10	-	30
2029	1	37	10	-	49
2030	1	54	10	-	65
2031	1	67	10	-	78
2032	2	80	10	-	92
2033	2	95	10	-	107
2034	2	113	10	2	127
2035	2	133	10	7	152
2036	2	152	10	13	178

In modeling the BC system, the supply of energy from the suite of available sources including existing and contracted supply, committed supply additions, and endogenously selected economic additions, is dispatched to meet the forecasted load of the demand side. Interchange subject to transfer limits with external markets can also participate in the supply/demand balance when economically appropriate.

Among the results of this process is the implied market- clearing price of energy. This price of energy may be considered the price to be paid by any incremental demand in that period or the price received for any incremental supply. These prices represent wholesale prices rather than retail rates.

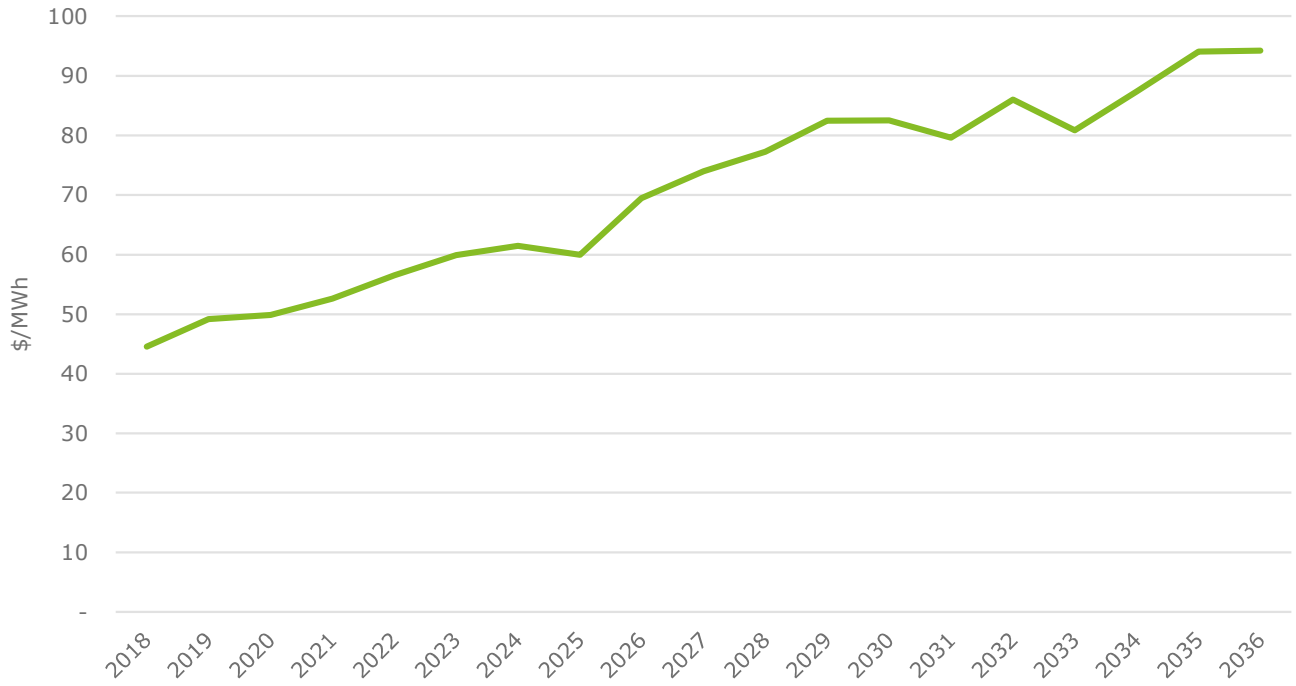


Figure 5: Price of energy in BC by year (2018-2036)

The annual average price of energy in BC rises from $45/MWh in 2018 to $94/MWh in 2036. This, like any other projection, is a function of assumptions, and the realized future may differ from the projection. Comparison with other projections can be helpful in interpreting any particular result, but care must to taken to understand that assumptions, as well as approaches, methodologies, and other differences, can account for wide variation among forecasts.

FortisBC published a set of three cases with price projections for the Mid-C market through 2035 as part of their 2016 Long Term Electric Resource Plan (LTERP)[181]. Prices for the Mid-C market assumed in this scenario are generally between the "High" and "Base" cases of the LTERP.

[181] FortisBC released the 2016 Long Term Resource Plan dated November 30, 2016. The document was obtained via the link: https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf

The price of energy in the BC system is not necessarily equal to the price in external markets such as Mid-C. There is some linkage between the markets via interchange, though costs to transfer energy will result in price differences remaining between the systems even while transfers are economic.

The value of capacity in BC in this scenario starts at $33/kW-yr in 2019 and levels out at $285/kW-yr in 2028. When there is a large surplus of capacity, capacity value is low or even zero. Capacity gains value when the reserve margin declines toward or below the target. As load increases, reserve margins naturally decline if the existing supply portfolio remains unchanged. The value of capacity is affected by factors such as the reserve margin, as well as the cost of new capacity. The cost of new capacity can vary year to year depending on availability of options as well as the underlying costs of deploying those options.

In estimating the value of capacity, the cost of new, capacity along with the need for additional capacity, was considered. The potential cost decline for certain technologies was included in the cost analysis. For example, solar panels have declined in cost in the past and are expected to continue to decline. The cost of solar assumed that each year reflects such a decline. The availability to generate at peak demand is also considered, so intermittent sources like solar or wind are affected by this more than dispatchable sources like natural gas turbines. The lowest-cost, new resource in a given year is used to determine the value of capacity.

In some years, lower cost projects are available, such as a hydroelectric expansion to an existing facility. This can result in a lower value of capacity, since the contribution to new capacity can come from a relatively lower-cost option. After such an option is built, however, it is no longer available to add to overall capacity. Therefore, the value of capacity may rise as other, higher-cost options must be considered. The value of capacity may again decline if another lower-cost option not previously available is possible. This may be due to timing on when projects can be constructed.

Some projects are relatively large, and their addition creates a greater contribution to reserve margin and a resulting drop in the value of capacity. Increasing load may cause a higher value for capacity in subsequent years.

With the availability and timing of new capacity options, along with an evolving supply/demand balance, the exact value of capacity can vary. The range of values should provide a guide to the overall values possible, but the estimated value in a specific future year should be taken in the context of the overall analysis. In the earlier years of the study, the lower-capacity values should indicate that there exist options to provide capacity at that cost. The higher values point to the potential cost if those options were not available at that time. The reader should consider the timing of these project options in light of the value of capacity. It would be incorrect to take the lowest cost option and apply that value across the horizon, since that resource cannot possibly add incremental capacity in every year of the horizon. It would also be incorrect to exclude that lower value altogether.

Figure 6: Value of capacity in BC by year (2018-2036)

5.5.4. GHG emissions

Emissions from the portfolio are assumed to be generated by just two of the resource categories: cogeneration and natural gas. Among the scenario assumptions is the constraint that GHG emissions should be limited to an intensity of 10 tCO_2e per gigawatt-hour. As a result, total GHG emissions can increase on a mass basis, as long as total load and generation increases. With the underlying growth in load and generation along with adherence to the GHG intensity limit, total GHG emissions rise from 564,013 tCO_2e in 2018 to 728,874 tCO_2e in 2036.

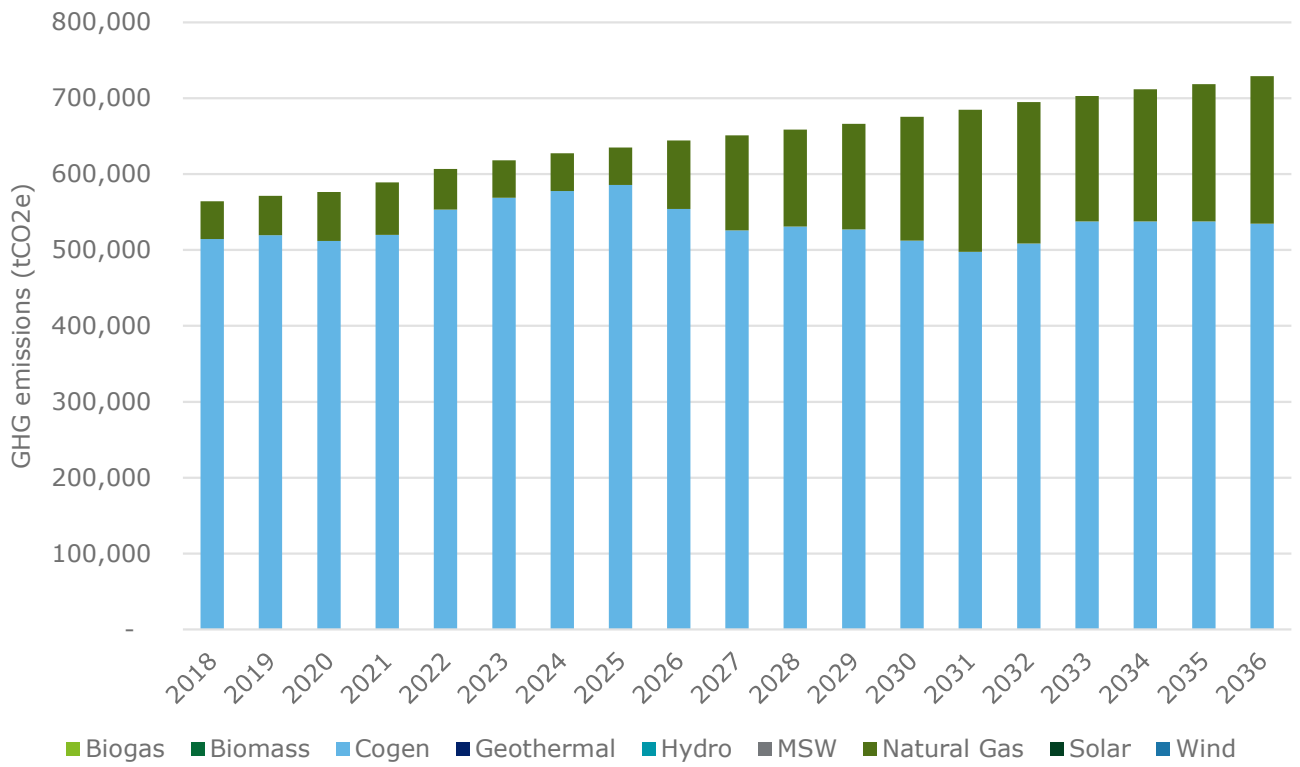


Figure 7: GHG emissions (tCO_2e) by alternative resource type by year (2018-2036)

5.5.5. Conclusion

The provincial government's Order-in-Council asks the question: "Given the energy objectives set out in the Clean Energy Act, what, if any, other portfolio of commercially feasible generating projects and demand-side management initiatives could provide similar benefits (including firming; shaping; storage; grid reliability; and maintenance or reduction of 2016/17 greenhouse gas emission levels) to ratepayers at similar or lower unit energy cost as the Site C project?"

The findings contained herein offer findings to help inform BCUC's assessment of this OIC question.

We generated a portfolio of alternative-generation projects that:

- Meet the energy objectives set out in the Clean Energy Act;
- Contain commercially feasible generating projects;
- Contain achievable DSM initiatives;
- Consider firming/shaping and reliability of the grid;
- And maintain the 2016/17 greenhouse gas emission.

The costs, and value of the generated portfolio, are detailed in the findings section above.

It is noteworthy that we consider this scenario to be a base case for BCUC's consideration to inform the assessment, vis-à-vis the Site C scenario. Running additional scenarios would offer more insights. For example, it could be of interest to BCUC to consider the following:

- Applying the load forecast developed by Deloitte to replace that provided by BC Hydro;
- Applying increased level of DSM opportunities above what BC Hydro is currently provifing (e.g. using BC Hydro's Option 3 DSM, referred to in section 4.3 of the main report);
- Running a 'suspension scenario' to assess the need for alternative supply if Site C is suspended until a specified timeframe;
- And examining the impact of certain decisions or variable combinations (e.g. incorporating the Columbia River Treaty Entitlement if the requirements of 'self-sufficiency' is relaxed, running various price forecasts, assuming that Burrard Thermal is restarted, etc.)

Given the inherent uncertainty of projections, additional scenarios and analysis could be used to better quantify the sensitivity of the base scenario findings to changes in the assumptions. Additionally, while project cost and performance (e.g. capacity factor) inputs are reasonable for the various technologies in the alternative supply portfolio, any particular project will have different costs and performance driven by specific project needs, even if such values fall within the expected range. Scenarios probing different cost or performance assumptions for technologies can also evaluate how alternate portfolios may perform under different circumstances.

Appendix F - Assessment of alternative supply-side sources of energy and capacity – external research

Document name	Author	Date	Source
Canada's Renewable Power Landscape - Energy Market Analysis 2016	National Energy Board	October 2016	http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2016cndrnwblpwr/index-eng.html
Canada's Adoption of Renewable Power Sources Energy Market Analysis	National Energy Board	October 2016	http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/index-eng.html
FortisBC Inc. (FBC) 2016 Long Term Electric Resource Plan (LTERP) and Long Term Demand Side Management Plan (LT DSM Plan)	FortisBC	November 30, 2016	https://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/161130_FBC_2016_LTERP_LTDSM_Plan.pdf
Capital Cost Review of Generation Technologies: Recommendations for WECC's 10- and 20-Year Studies	Western Electric Coordinating Council	March 2014	https://www.wecc.biz/Reliability/2014_TEPPC_Generation_CapCost_Report_E3.pdf
Capital Cost Estimates for Utility Scale Electricity Generating Plants	EIA	November 2016	https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
Life Cycle Greenhouse Gas Emissions: Natural Gas and Power Production	NREL	June 15, 2015	https://www.eia.gov/conference/2015/pdf/presentations/skone.pdf
Distributed Generation Renewable Energy Estimate of Costs	NREL	February 2016	https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html
Annex II: Methodology. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation	IPCC	2011	http://www.ipcc-wg3.de/report/IPCC_SRREN_Annex_II.pdf
U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016	NREL	September 2016	https://www.nrel.gov/docs/fy16osti/67142.pdf

Document name	Author	Date	Source
Puget Sound Energy 2015 IRP - Electric Resources and Alternatives	Puget Sound Energy	2015	https://pse.com/aboutpse/EnergySupply/Documents/IRP_2015_AppD.pdf
Portland General Electric 2016 IRP (PGE)	Portland General Electric	November 2016	https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en
NW Council Seventh Power Plan	NW Council	February 25, 2016	https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf
PacifiCorp 2017 IRP	PacifiCorp	April 4, 2017	https://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf
Idaho Power 2017 IRP	Idaho Power	June 2017	https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/IRP.pdf
Lazard's Levelized Cost of Energy Analysis - Version 10.0	Lazard	December 2016	https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
IESO Ontario Planning Outlook	IESO	September 2016	http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook
BC Hydro Wind Data Study Report	BC Hydro	May 1, 2009	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.pdf
BC Hydro Wind Data Study Update Report	BC Hydro	September 24, 2009	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2010q3/bc_hydro_wind_data.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #1 Handout	BC Hydro	September 12, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting1-20140912-handout.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #1 Handout	BC Hydro	September 12, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting1-20140912-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #2 Presentation	BC Hydro	December 15, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-

Document name	Author	Date	Source
			characterization-wind-meeting2-20141215-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #2 notes	BC Hydro	December 15, 2014	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting2-20141215-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #3 Presentation	BC Hydro	May 5, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150505-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #3 note	BC Hydro	May 5, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150505-summary-notes.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #4 Presentation	BC Hydro	June 3, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting4-20150603-presentation.pdf
BC Hydro Resource Options Update—Wind Engagement Meeting #4 notes	BC Hydro	June 3, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-engagement-characterization-wind-meeting3-20150603-summary-notes.pdf
EnergyBC Electricity Generating Stations in British Columbia Map	Energy BC	Accessed 08/16/2017	http://www.energybc.ca/electricitymap.html
Zero Emission Energy Developments Inc. website	Zero Emission Energy Developments Inc.	Accessed 08/16/2017	http://zeroemissiondevelopments.com/zed-projects/
Boralex Moose Lake Wind Project website	Boralex	Accessed 08/16/2017	http://www.boralex.com/projects/mooselake

Document name	Author	Date	Source
Meikle Wind project website	Meikle Wind	Accessed 08/16/2017	http://meiklewind.com/
Canadian Wind Energy Association website	CanWEA	Accessed 08/16/2017	http://canwea.ca/wind-energy/installed-capacity/
Canadian Wind Energy Association (CanWEA) Pan-Canadian Wind Integration Study (PCWIS)	CanWEA	Accessed 08/16/2017	http://canwea.ca/wind-integration-study/wind-data/
GE Renewable Energy website	GE	Accessed 08/16/2017	https://www.gerenewableenergy.com/wind-energy/technology/integrated-energy-storage-for-wind-turbines
Wind Turbines, Battery Included, Can Keep Power Supplies Stable	MIT Technology Review	Accessed 08/16/2017	https://www.technologyreview.com/s/514331/wind-turbines-battery-included-can-keep-power-supplies-stable/
Wind Power Integration: Energy Storage for Firming and Shaping	EPRI	Accessed 08/16/2017	https://www.epri.com/#/pages/product/000000000001008388/
Hydro-Québec website - Combining Wind and Water	Hydro Quebec	Accessed 08/16/2017	http://www.hydroquebec.com/learning/eolienne/couplage-hydro-eolien.html
IEA Wind Annual Report for 2015	IEA	Accessed 08/16/2017	https://www.ieawind.org/annual_reports_PDF/2015/2015%20IEA%20Wind%20AR_small.pdf
Renewable 2017 Global Status Report	REN21	Accessed 08/16/2017	http://www.ren21.net/gsr-2017/chapters/chapter_02/chapter_02/#wind-power-markets
Alberta Electric System Operator (AESO) 2017 Long-term Outlook and data file	AESO	July 20, 2017	https://www.aeso.ca/grid/forecasting/
2015 Year-End Data: Electricity Production, Consumption, Price and Dispatch Data	IESO	Accessed 08/16/2017	http://www.ieso.ca/corporate-ieso/media/year-end-data/2015
IEA World Energy Outlook Investment Costs website	IEA	Accessed 08/16/2017	http://www.worldenergyoutlook.org/weomodel/investmentcosts/
Levelized Cost of Energy Analysis 10.0	Lazard	December 15, 2016	https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/
BC Hydro Total Adjusted Firm Energy Price (for first ~5000 GWh)	BC Hydro	Accessed 08/17/2017	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-

Document name	Author	Date	Source
			plans/current-plan/rou-total-adjusted-firm-energy-price.pdf
Ontario Planning Outlook	IESO	September 1, 2016	http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook
Wind LCA Harmonization	NREL	Accessed 08/16/2017	https://www.nrel.gov/docs/fy13osti/57131.pdf
Turbine advances cut O&M costs	Wind Power Monthly	June 1, 2013	http://www.windpowermonthly.com/article/1183992/turbine-advances-cut-o-m-costs
IRENA. The Power to Change: Solar and Wind Cost Reduction Potential to 2025	IRENA	June 2016	http://www.irena.org/DocumentDownloads/Publications/IRENA_Power_to_Change_2016.pdf
IESO Large Renewable Procurement (Independent Electricity System Operator)	IESO	Accessed 08/15/2017	http://www.ieso.ca/Pages/Participate/Generation-Procurement/Large-Renewable-Procurement/default.aspx
Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections	NREL	August 25, 2015	http://www.nrel.gov/docs/fy15osti/64898.pdf
New Energy Outlook 2017 Executive Summary	Bloomberg	June 2016	https://www.bloomberg.com/company/new-energy-outlook/
Generating your own electricity	BC Hydro	Accessed 08/15/2017	https://www.bchydro.com/energy-in-bc/acquiring_power/current_offerings/net_metering.html#stories
Sunmine	Sunmine	Accessed 08/15/2017	http://www.sunmine.ca/
British Columbia Solar Market Update 2015	Compass Renewable Energy Consulting Inc.	June 24, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-solar-report-20150624-compass.pdf
Technology Roadmap – Solar Thermal Electricity 2014 Edition	IEA	September 2014	http://www.iea.org/publications/freepublications/publication/technologyroadmapsolarthermalelectricity_2014edition.pdf
Solar PV Overview of Solar Electricity Supply Chain in Canada	CanSIA	Accessed 08/15/2017	http://www.cansia.ca/solar-pv.html

Document name	Author	Date	Source
Energy Department Announces More than 90% Achievement of 2020 SunShot Goal, Sets Sights on 2030 Affordability Targets	US Department of Energy	November 14, 2016	https://energy.gov/eere/articles/energy-department-announces-more-90-achievement-2020-sunshot-goal-sets-sights-2030
Marginal cost of wind and solar PV electricity generation	Navigant	May 29, 2014	http://www.ieso.ca/-/media/files/ieso/document-library/engage/fpr/fpr-20150625-navigant.pdf?la=en
Distributed Generation Renewable Energy Estimate of Costs	NREL	February 2016	https://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html
Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Services	Prepared for Natural Resources Canada by Power Advisory LLC	August 2017	http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf
Life Cycle Greenhouse Gas Emissions from Solar Photovoltaics	NREL	Accessed 08/16/2017	https://www.nrel.gov/docs/fy13osti/56487.pdf
Using Renewables to Operate a Low Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant	California ISO, First Solar, and NREL	2017	https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf
Section B Roadmap for Development of Geothermal Direct-use Projects in British Columbia, Canada	Geoscience BC	May 5, 2016	http://www.geosciencebc.com/i/project_data/GBCReport2016-07/GBC%20Report%202016-07_Section%20B_Roadmap.pdf
An Assessment of the economic viability of selected Geothermal Resources in BC	Geoscience BC	Nov 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-geothermal-report-20160331-kwl-geothermex.pdf
Geothermal Energy Resource Potential of Canada	Natural Resources Canada	2012	http://publications.gc.ca/collections/collection_2013/rncan-nrcan/M183-2-6914-eng.pdf
Geothermal Power	Clean Energy BC	Accessed 8/16/2017	https://www.cleanenergybc.org/about/clean-energy-sectors/geothermal
FortisBC - Supply side resource options	FortisBC	2016	https://www.fortisbc.com/About/ProjectsPlanning/ElecUtility/ElecResourcePlanning/Documents/2_Supply-Side_Resource_Options.pdf

Document name	Author	Date	Source
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Geothermal Energy	IPCC	Accessed 18/22/2017	http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch04.pdf
2013 Resource Options Report Update - Mica Pumped Storage Report	BC Hydro	November 2013	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a31-nov-2013-irp-appx-3a-31.pdf
2013 Resource Options Report Update - Lower Mainland/Vancouver Island Pumped Storage Report and North Coast Pumped Storage Report.	BC Hydro	2013	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0300a30-nov-2013-irp-appx-3a-30.pdf
Hydropower. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation	IPCC	2011	http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch05.pdf
Levelized cost of energy storage and operational GHG performance. CAES and zero emission storage compared to natural gas peaking plants	Pembina Institute	May 2017	https://www.pembina.org/reports/energy-storage-cost-and-ghg.pdf
Renewable Energy Integration in Power Grids Technology Brief	IRENA	April 2015	https://www.researchgate.net/profile/GL_Kulcinski/publication/223663980_Life_cycle_energy_requirements_and_greenhouse_gas_emissions_from_large_scale_energy_storage_systems/links/0c960526ec0ab00722000000.pdf
Renewable Energy Technologies: Cost Analysis Series.	IRENA	June 2012	https://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf
Valuing Pumped Storage: Debunking Myths, Creating Tools	Northwest Hydroelectric Association	February 18, 2016	http://www.nwhydro.org/wp-content/uploads/events_committees/Docs/2016_Pumped_Storage_Workshop_Presentations/2%20-%20Rick%20Miller.pdf
Pumped Hydroelectric Storage	Energy Storage Association	Accessed 18/17/2017	http://energystorage.org/energy-storage/technologies/pumped-hydroelectric-storage
Lifecycle Assessment for Energy Resource Options in Yukon Territory	Yukon Energy	September 2016	http://resourceplan.yukonenergy.ca/media/site_documents/Appendix_5.1_Greenhouse_Gas_Emissi

Document name	Author	Date	Source
			on_Life_Cycle_Assessment_of_Resource_Options_(ArcticCan_Energy_Services_2016).pdf
Greenhouse Gas Emissions from Energy Systems: Comparison and Overview	IAEA	Accessed 08/25/2017	http://www.iaea.org/inis/collection/NCLCollectionStore/_Public/36/002/36002859.pdf
Bulk Storage Study for the 2017 Integrated Resource Plan	Black & Veatch for PacifiCorp	August 19, 2016	http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/Black_Veatch_PacifiCorp_Bulk_Storage_IRP_Study_Report-final_20160819.pdf
Fort Nelson Generating Station 2002/03 Asset Plan	BC Hydro	July 17, 2002	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/rev_req/rev_reqs_1/19_fort_nelson_generating_station_pdf.pdf
Response for British Columbia Utilities Commission Information Request No. 1.14.4 Dated: 23 January 2004	BCUC	February 20, 2004	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/rev_req/rev_reqs_3/bcuc_1_014_04_pdf.pdf
Canadian Energy Pipeline Association (CEPA) liquids and natural gas pipelines maps	CAPP	Accessed 08/17/2017	http://www.capp.ca/canadian-oil-and-natural-gas/infrastructure-and-transportation/pipelines
Spectra Energy's pipeline system	Spectra Energy	Accessed 08/17/2017	http://www.spectraenergy.com/Operations/Canadian-Natural-Gas-Operations/Western-Canadian-Operations/BC-Pipeline/
FortisBC pipeline system	FortisBC	Accessed 08/17/2017	https://www.fortisbc.com/NaturalGas/Business/TransportationServiceOption/Documents/WINS_FortisBC_Pipeline_System_Map_2593.pdf
A Study on the Efficiency of Alberta's Electrical Supply System	Clean Air Strategic Alliance	October 2004	http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta%27s_Electrical_Supply_System_EEEC-02-04.pdf
Consolidated B.C. Emissions Report Summaries for 2015	Government of British Columbia	Accessed 08/17/2017	http://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg
Fortis BC heat content values	FortisBC	Accessed 08/17/2017	https://www.fortisbc.com/NaturalGas/Business/PriceAndMarketInformation/Pages/Heat-content-values.aspx
National Inventory Report 1990-2015: Greenhouse gas sources and sinks in Canada	Environment and Climate Change Canada	2016	https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1

Document name	Author	Date	Source
Shale Gas Update for GHGenius	Natural Resources Canada	August 31, 2011	https://ghgenius.ca/reports/ShaleGasUpdateFinalReport.pdf
Fact Sheet- Run of River Hydro Power	Clean Energy BC	Accessed 8/16/2017	https://www.cleanenergybc.org/wp-content/uploads/2015/12/CEBC_Run-of-River_Fact_Sheet.pdf
A Review of Environmental Regulation of Run of River Power Projects in British Columbia	Devlin Gailus Barristers and Solicitors	April 2010	http://www.dgwlaw.ca/wp-content/uploads/2014/12/Testing_the_Waters_April_2010.pdf
Analyzing British Columbia Run of river facilities for the California Renewable Portfolio Standard	California Energy Commission	December 2013	http://www.energy.ca.gov/2013publications/CEC-300-2013-011/CEC-300-2013-011-LCD.pdf
Potential impacts of run of the river power hydro projects on salmonids	Pacific Salmon Foundation	Jan 30, 2014	https://www.psf.ca/sites/default/files/ROR_Report.pdf
Canadian Hydropower and the clean power plan	Center for Climate	April 2015	https://www.c2es.org/docUploads/canadian-hydropower-04-2015.pdf
Run of River report	Kerr Wood Leidal	July 10, 2015	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-run-of-river-report-20150710-kwl.pdf
Renewable energy technologies: Cost Analysis Series	IRENA	June 2012	https://hub.globalccsinstitute.com/sites/default/files/publications/138178/hydropower.pdf
Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Services	Natural Resources Canada	August 2017	http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf
Electricity Supply Options	BC Hydro	Accessed: 8/17/2017	https://www.bchydro.com/energy-in-bc/planning-for-our-future/electricity-supply-options.html
Run of River Power	Energy BC	Accessed: 8/17/2017	http://www.energybc.ca/runofriver.html#section16
Run of River Hydro in BC	Clean Energy BC	Accessed 08/17/2017	https://www.cleanenergybc.org/about/clean-energy-sectors/run-of-river
Emerging Hydropower Technologies R&D in Canada - A Strategy for 2007-2011	Natural Resources Canada	Accessed 08/17/2017	http://www.nrcan.gc.ca/energy/publications/sciences-technology/renewable/small-hydropower/6489

Document name	Author	Date	Source
Nanaimo sewage plant generates 2000 MW annually	Canadian Consulting Engineer	Accessed 08/17/2017	http://www.canadianconsultingengineer.com/water-wastewater/nanaimo-sewage-plant-generates-2000-mw-annually/1001923726/
Regulating combined heat and power generation at greenhouses in the ALR	British Columbia: Ministry of Agriculture	Accessed 08/17/2017	http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/agriculture-and-seafood/agricultural-land-and-environment/strengthening-farming/local-government-bylaw-standards/combined-heat-and-power-generation/chp_discussion_paper_-_may_2013.pdf
Evaluating the role of cogeneration for carbon management in Alberta	Doluweera et al.	September 24, 2011	https://scholar.harvard.edu/files/davidkeith/files/149.doluweera.etal_.evalrolecongeneration.e.pdf
IEA Executive Summary	IEA	Accessed 08/18/2017	http://www.iea.org/textbase/npsum/ElecCostSUM.pdf
Energy Saver Cogeneration feasibility guide	NSW Government Office of Environment & Heritage:	Accessed 08/18/2017	http://www.environment.nsw.gov.au/resources/business/140685-cogeneration-feasibility-guide.pdf
Cogeneration/Combined heat and Power	Center for Climate and Energy Solutions	Accessed 08/18/2017	https://www.c2es.org/technology/factsheet/CogenerationCHP
IEA Energy Technology Network: Energy Technology Systems Analysis Programme	IEA	Accessed 08/18/2017	https://iea-etsap.org/E-TechDS/HIGHLIGHTS%20PDF/E04-CHP-GS-gct_ADfinal%201.pdf
Projected Costs of Generating Electricity (2010)	World Energy Outlook	2010	http://www.worldenergyoutlook.org/media/weowebsite/energymodel/ProjectedCostsofGeneratingElectricity2010.pdf
Greenhouse gas emissions associated with various methods of power generation in Ontario	Science Integrity Network	Accessed 08/18/2017	http://www.opg.com/darlington-refurbishment/Documents/IntrinsikReport_GHG_OntarioPower.pdf
Future Energy Costs: Coal and Gas Technologies	BVG Associates and KIC InnoEnergy	2016	http://www.innoenergy.com/wp-content/uploads/2016/09/CleanCoal_BF.pdf
A study on the Efficiency of Alberta's Electrical Supply System. Project # CASA-EEEC-02-04	Clean Air Strategic Alliance	Accessed 08/18/2017	http://www.hme.ca/reports/CASA_Report_--_The_Efficiency_of_Alberta's_Electrical_Supply_System_EEEC-02-04.pdf
GE Power: Combined Heat & Power - What is Cogeneration?	GE Power	Accessed 08/18/2017	https://www.gepower.com/applications/chp

Document name	Author	Date	Source
Combined Heat and Power - Evaluating the benefits of greater global investment	IEA	Accessed 08/18/2017	https://www.iea.org/publications/freepublications/publication/chp_report.pdf
Evaluating the role of cogeneration for carbon management in Alberta	Doluweera et al.	September 24, 2011	https://scholar.harvard.edu/files/davidkeith/files/149.doluweera.etal_.evalrolecongeneration.e.pdf
Biomass	Clean Energy BC	Accessed 08/16/2018	https://www.cleanenergybc.org/about/clean-energy-sectors/biomass
Wood Based Biomass in British Columbia and its Potential for New Electricity Generation	Industrial Forestry Service Ltd.	Accessed 08/17/2018	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-201507-industrial-forestry-service.pdf
Map of Clean Energy Resources and Projects (CERP) in Canada	Natural Resources Canada	Accessed 08/17/2017	http://atlas.gc.ca/cerp-rpep/en/
Annacis Island (Delta)	Metro Vancouver	Accessed 08/17/2018	http://www.metrovancouver.org/services/liquid-waste/treatment/treatment-plants/annacis-island/Pages/default.aspx
Village Farms International, Inc. Management's Discussion and Analysis Year Ended December 31, 2016	Village Farms International, Inc.	March 31, 2017	http://villagefarms.com/wp-content/uploads/2017/04/4Q-2016-VFF-MDA-final.pdf
Integrated Resource Recovery Case Study: Regional District of Nanaimo Landfill Gas Recovery and Utilization	Government of BC	Accessed 08/17/2018	http://www.cscd.gov.bc.ca/lgd/infra/library/IRR_Landfill_Gas_Capture_Case_Study.pdf
Suncurrent Biogas Utilization Electrical Generation website	Suncurrent	Accessed 08/17/2018	http://suncurrent.co/biogas-utilization/electrical-generation/
Suncurrent Biogas Utilization Storage website	Suncurrent	Accessed 08/17/2018	http://suncurrent.co/biogas-utilization/storage/
City of Vancouver Administrative Report - Vancouver Landfill: Landfill Gas Projects	City of Vancouver	Accessed 08/17/2018	http://council.vancouver.ca/020205/a6.htm
City of Vancouver Administrative Report - Vancouver Landfill: Selection of a Design-Build Contractor for Expanded Landfill Gas Control System Project	City of Vancouver	Accessed 08/17/2018	http://council.vancouver.ca/000328/a12.htm

Document name	Author	Date	Source
Vancouver Landfill: Landfill Gas Collection and Utilization Project	City Farmer	Accessed 08/17/2018	http://cityfarmer.org/LandfillGas.html
Technical memo - The 5th Residual Waste Management Memo	Capital Regional District	September 20, 2013	https://www.crd.bc.ca/docs/default-source/recycling-waste-pdf/iswrmp-stage2technicalmemo-residualwastemanagement.pdf?sfvrsn=2
Hartland Landfill – Landfill Gas Monitoring Annual Report 2014	Capital Regional District	October 2015	https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2014hartland-gasmonitoring.pdf?sfvrsn=1f1d5dca_8
Hartland Landfill – Landfill Gas Monitoring Annual Report 2015	Capital Regional District	October 2016	https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2015-hartlandlandfillgasmonitoringannualreport.pdf?sfvrsn=76572bca_12
Hartland Landfill – Landfill Gas Monitoring Annual Report 2013	Capital Regional District	October 2014	https://www.crd.bc.ca/docs/default-source/crd-document-library/annual-reports/environmental-protection/geoenvironmental/hartland-reports/2013-hartland-landfill---landfill-gas-monitoring-annual-report-(appendix-b).pdf?sfvrsn=c6bc71ca_6
Greater Vancouver Regional District Utilities Committee Meeting Agenda	Metro Vancouver	June 15, 2017	http://www.metrovancouver.org/boards/Utilities/UC-Jun_15_2017-Agenda_Revised.pdf
Metro Vancouver's Climate Actions 2016	Metro Vancouver	May 31, 2017	http://www.metrovancouver.org/boards/ClimateAction/CAC-Jul_5_2017-Agenda_Revised.pdf
2006 IPCC Guidelines for National Greenhouse Gas Inventories - Chapter 3: Solid Waste Disposal	IPCC	April 2007	http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html
Vancouver Landfill Gas Heats Greenhouses	City Farmer	Accessed 08/17/2018	http://cityfarmer.org/LandfillGas.html
Caterpillar Gas Generator Set Product Rating Summary	CAT	Accessed 08/17/2018	http://www.cat.com/en_US/products/new/power-systems/electric-power-generation.html
Clean Energy BC: Biomass	Clean Energy BC	Accessed 08/16/2018	https://www.cleanenergybc.org/about/clean-energy-sectors/biomass

Document name	Author	Date	Source
Industrial Forestry Service Ltd.: Wood Based Biomass in British Columbia and its Potential for New Electricity Generation	BC Hydro	Accessed 08/17/2018	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-201507-industrial-forestry-service.pdf
Municipal Solid Waste and its Role in Sustainability	IEA Bioenergy	2003	http://www.ieabioenergy.com/wp-content/uploads/2013/10/165_IEAPositionPaperMSWfinal.pdf
An Inventory of the Bioenergy Potential of British Columbia	BioCAP Canada	Access 08/18/17	http://cesarnet.ca/biocap-archive/images/pdfs/BC_Inventory_Final-06Nov15.pdf
An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in British Columbia for First Nations, Small Communities, Municipalities and Industry	Government of BC	Access 08/18/17	http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc_bioenergy_primer.pdf
Generating Energy from Waste **Metro Vancouver's Waste-to-Energy Facility**	Metro Vancouver	Access 08/18/17	http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/WTEFactSheet.pdf
Management of MSW in Metro Vancouver. A comparative analysis of options of management of waste after recycling.	Metro Vancouver	2009	http://www.metrovancouver.org/services/solid-waste/SolidWastePublications/SDD_3_AECOM_FULL_REPORT.pdf
GENERATING RENEWABLE ELECTRICITY WITH DISTRIBUTED GENERATION: A SELF-ASSESSMENT TOOLKIT FOR B.C. LOCAL GOVERNMENTS	BC Hydro	2012	https://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2012q4/self-assessment_toolkit_form_oct2012_ar.pdf
Metro Vancouver's waste-to-energy facility	Metro Vancouver	Access 08/18/17	http://www.metrovancouver.org/services/solid-waste/about/wte/pages/04.aspx
Biomass for Power Generation	IRENA	2012	https://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-BIOMASS.pdf
Analysis of a Waste-To-Energy Power Plant with CO2 Sequestration	Earth Engineering Center, Columbia University	Access 08/18/17	http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.544.3695&rep=rep1&type=pdf

Document name	Author	Date	Source
Flexible Peaking Resource	Energy Storage Association	Accessed 08/18/2018	http://energystorage.org/energy-storage/technology-applications/flexible-peaking-resource
Lessons Learned from Existing Biomass Power Plants		Accessed 08/18/2018	https://books.google.ca/books?id=55IGWS1C0Q4C&pg=PA105&lpg=PA105&dq=peaking+biomass+plant&source=bl&ots=YBOPQ-wfZG&sig=MmV1zRzB7i23oFs2pwjhUgZI48g&hl=zh-TW&sa=X&ved=0ahUKEwjW7via--HVAhUi5YMKHaFdCRIQ6AEIYDAK#v=onepage&q=peaking%20biomass%20plant&f=false
Bioenergy Projects Technology Review	BC Hydro	Accessed 08/18/2018	https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/rou-characterization-wood-based-biomass-report-20150722-amec-foster-wheeler.pdf
B.C. Rural Development Progress Report	Government of BC	Accessed 08/18/2018	http://www2.gov.bc.ca/assets/gov/business/natural-resource-industries/doing-business/rural-development/rural_dividend_progress_report_oct_2016.pdf
Kwadacha First Nation seeks to build biomass plant	Alaska Highway News	Accessed 08/18/2018	http://www.alaskahighwaynews.ca/regional-news/kwadacha-first-nation-seeks-to-build-biomass-plant-1.2185149
World Energy Resources: Waste to Energy 2016	World Energy Council	2016	https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_Waste_to_Energy_2016.pdf
Evaluation of life cycle greenhouse gas emissions from different biomass feedstock electricity generation systems	Akhil et al.	November 16, 2016	http://www.mdpi.com/2071-1050/8/11/1181/pdf
Air Emissions from MSW Combustion Facilities	EPA	Accessed 08/18/2018	https://archive.epa.gov/epawaste/nonhaz/municipal/web/html/airem.html
Waste Not, Want Not: Analyzing the Economic and Environmental Viability of Waste-to-Energy (WTE) Technology for Site-Specific Optimization of Renewable Energy Options	NREL	February 2013	https://www.nrel.gov/docs/fy13osti/52829.pdf

Document name	Author	Date	Source
World Energy Resources Waste to Energy	World Energy Resources	2016	https://www.worldenergy.org/wp-content/uploads/2017/03/WEResources_Waste_to_Energy_2016.pdf
NaiKun Wind Energy Group Inc. – Benefits of the project	NaiKun Wind Energy Group Inc.	Accessed 08/17/2017	http://naikun.ca/the-project/project-benefits/
America's First Offshore Wind Farm Spins to Life	NY Times	Accessed 08/17/2017	https://www.nytimes.com/2016/12/14/science/wind-power-block-island.html
Innovation Outlook: Offshore Wind	IRENA	Accessed 08/17/2017	http://www.irena.org/menu/index.aspx?mnu=Subcat&PriMenuID=36&CatID=141&SubcatID=2742
Capacity Value of Wind Assumptions and Planning Reserve Margin	Nova Scotia Power	April 23, 2014	http://www.nspower.ca/site/media/Parent/20140423%20Wind%20Capacity%20Value%20Assumptions.pdf
Energy Analysis of Offshore Systems	NREL	Accessed 08/17/2017	https://www.nrel.gov/wind/offshore-energy-analysis.html
Tidal Power, Energy BC	Energy BC	February 2017	http://www.energybc.ca/tidal.html
The Atlas of Canada - Clean Energy Resources and Projects (CERP)	Government of BC	January 2017	http://atlas.gc.ca/cerp-rpep/en/
Ocean and Energy Council: Tidal Energy	Ocean Energy Council	2017	http://www.oceanenergycouncil.com/ocean-energy/tidal-energy/
International Renewable Energy Agency: Tidal Energy Technology Debrief. Brief #3	IRENA	June 2014	http://www.irena.org/DocumentDownloads/Publications/Tidal_Energy_V4_WEB.pdf
Future Marine Energy. Results of the Marine Energy Challenge: Cost competitiveness and growth of wave and tidal stream energy.	Carbon Trust	2006	http://ec.europa.eu/ourcoast/download.cfm?fileID=967
National Energy Board. Canada's Adoption of Renewable Power Sources: Energy Market Analysis.	NEB	May 2017	http://www.neb-one.gc.ca/nrg/sttstc/lctrct/rprt/2017cnddptnrnwblpwr/2017cnddptnrnwblpwr-eng.pdf
Ocean Energy Systems 2015 Report	Ocean Energy Systems	2015	https://report2015.ocean-energy-systems.org/
Tidal Energy Project in the Bay of Fundy	Natural Resources Canada	June 2017	http://www.nrcan.gc.ca/energy/funding/current-funding-programs/cef/4955

Document name	Author	Date	Source
Clean Energy Production in B.C., An Inter-Agency Guidebook for Project Development	Government of BC	April 2016	http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf
World Energy Council 2013 - Cost of Energy Technologies.	World Energy Council	2013	https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf
Nova Scotia Electricity System Review. Summary Report- Emerging Technology and Market Trend Studies.	Government of Nova Scotia	2013	https://energy.novascotia.ca/sites/default/files/files/NS%20Electricity%20System%20Review%20Summary%20Report%20June%202014.pdf
Low-cost solution to the grid reliability problem with 100% penetration of intermittent wind, water, and solar for all purposes	Jacobson et al.	December 2015	http://www.pnas.org/content/112/49/15060.full.pdf
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation (IPCC)	IPCC	2011	http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch06.pdf
World Energy Council 2013 - Cost of Energy Technologies.	World Energy Council	2013	https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf
Seventh Northwest Conservation and Electric Power Plan - Chapter 13: Generating Resources.	Northwest Council	May 2016	https://www.nwcouncil.org/media/7149923/7thplanfinal_chap13_gresources.pdf
Cost of and financial support for wave, tidal stream, and tidal range generation in the UK. A report for the Department of Energy and Climate Change and the Scottish Government.	Ernst & Young	October 2010	http://webarchive.nationalarchives.gov.uk/20121205081857/http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/energy%20mix/renewable%20energy/explained/wave_tidal/798-cost-of-and-finacial-support-for-wave-tidal-strea.pdf
The Atlas of Canada - Clean Energy Resources and Projects (CERP)	Natural Resources Canada	January 2017	http://atlas.gc.ca/cerp-rpep/en/
Clean Energy Production in B.C., An Inter-Agency Guidebook for Project Development	Government of BC	April 2016	http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/natural-resource-use/land-water-use/crown-land/land-use-plans-and-objectives/natural-resource-major-projects/major-projects-office/guidebooks/clean-energy-projects/clean_energy_guidebook.pdf

Document name	Author	Date	Source
Reserve Requirement Impacts of Large-Scale Integration of Wind, Solar, and Ocean Wave Power Generation	Halamay et al.	2010	http://nnmrec.oregonstate.edu/sites/nnmrec.oregonstate.edu/files/northwest-national-marine-renewable-energy-center/PES_GM_2010_HalamayVariability_y09m11d30h13m26_DAH.pdf
Wave Energy. Technology Debrief. IRENA Ocean Energy Technology Brief 4.	IRENA	June 2014	http://www.irena.org/DocumentDownloads/Publications/Wave-Energy_V4_web.pdf
Wave Power	Clean Energy BC	Accessed 08/17/17	https://www.cleanenergybc.org/about/clean-energy-sectors/wave
Catching the Right Wave: Evaluating Wave Energy Resources and Potential Compatibility with Existing Marine and Coastal Uses	Kim et al.	November 7, 2012	http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0047598
Nova Scotia Renewable Energy Strategy.	Government of Nova Scotia	May 2012	https://energy.novascotia.ca/sites/default/files/Nova-Scotia-Marine-Renewable-Energy-Strategy-May-2012.pdf
West Coast Wave Initiative. Natural Resources Canada.	Natural Resources Canada	April 2017	http://www.nrcan.gc.ca/energy/funding/current-funding-programs/eii/16092
IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation: Ocean Energy	IPCC	Accessed 08/22/17	http://www.ipcc-wg3.de/report/IPCC_SRREN_Ch06.pdf
Battery Storage For Renewables: Market Status and Technology Outlook	IRENA	JANUARY 2015	http://www.irena.org/documentdownloads/publications/irena_battery_storage_report_2015.pdf
Avista 2015 Electric Integrated Resource Plan Technical Advisory Committee Meeting No. 1 Presentation (Avista)	Avista	2015	https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/appendix-a-final.pdf?la=en
Energy storage expanding and going mainstream	The Climate Examiner	March 12, 2015	http://theclimateexaminer.ca/2015/03/12/energy-storage-expanding-going-mainstream/
Capital Cost Estimates for Utility Scale Electricity Generating Plants	EIA	November 2016	https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf
Lazard's levelised cost of storage - version 2.0 (Lazard)	Lazard	2016	https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

Document name	Author	Date	Source
10 trends shaping the electric utility industry in 2017	Utility Dive	January 23, 2017	http://www.utilitydive.com/news/10-trends-shaping-the-electric-utility-industry-in-2017/434541/
Puget Sound Energy 2015 IRP, Appendix L: Electric Energy Storage (Puget Sound Energy)	Puget Sound Energy	2015	https://pse.com/aboutpse/EnergySupply/Documents/DRAFT_IRP_2015_AppL.pdf
California Adopts Historic Energy Storage Targets (California Energy Storage Alliance)	California Energy Storage Alliance	October 17, 2013	http://www.prnewswire.com/news-releases/california-adopts-historic-energy-storage-targets-228251181.html
10 trends shaping the electric utility industry in 2017	Utility Dive	January 23, 2017	http://www.utilitydive.com/news/10-trends-shaping-the-electric-utility-industry-in-2017/434541/
McKinsey: Cheaper batteries present imminent threat of load defection for utilities	Utility Dive	June 30, 2017	http://www.utilitydive.com/news/mckinsey-cheaper-batteries-present-imminent-threat-of-load-defection-for-u/446193/
E-storage: Shifting from cost to value 2016	World Energy Resources	January 2016	https://www.worldenergy.org/publications/2016/e-storage-shifting-from-cost-to-value-2016/
Energy storage: Tracking the technologies that will transform the power sector	Deloitte	2015	https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-energy-storage-tracking-technologies-transform-power-sector.pdf
The Life Cycle Energy Consumption and Greenhouse Gas Emissions from Lithium-Ion Batteries. A Study with Focus on Current Technology and Batteries for light-duty vehicle	IVL Swedish Environmental Research Institute	May 2017	http://www.ivl.se/download/18.5922281715bdaebede9559/1496046218976/C243+The+life+cycle+energy+consumption+and+CO2+emissions+from+lithium+ion+batteries+.pdf
GHG Emissions from the Production of Lithium-Ion Batteries for Electric Vehicles in China	Hao et al.	April 4, 2017	https://www.google.ca/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwiDw63VoenVAhUl4oMKHWp0B9sQFggmMAA&url=http%3A%2F%2Fwww.mdpi.com%2F2071-1050%2F9%2F4%2F504%2Fpdf&usg=AFQjCNH77oxNyUgrAe9N97S22HcAut8QjA
Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems	Denholm and Kulcinski	Accessed 08/21/17	https://www.researchgate.net/profile/GL_Kulcinski/publication/223663980_Life_cycle_energy_requirements_and_greenhouse_gas_emissions_from_large_scale_energy_storage_systems/links/0c960526ec0ab00722000000.pdf
Battery Energy Storage Study for the 2017 IRP	PacifiCorp	August 22, 2016	http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2

Document name	Author	Date	Source
			017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf
Review of Capital Costs for Generation Technologies	E3	January 31, 2017	https://www.wecc.biz/Administrative/2017-01-31%20E3%20WECC%20Capital%20Costs%20v1.pdf
Energy Storage Trends and Opportunities in Emerging Markets	ESMAP and IFC	2017	https://www.ifc.org/wps/wcm/connect/ed6f9f7f-f197-4915-8ab6-56b92d50865d/7151-IFC-EnergyStorage-report.pdf?MOD=AJPERES
The BC Energy Plan	Government of BC	Accessed 08/15/17	http://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/bc_energy_plan_2007.pdf
Nuclear Power in the World Today	World Nuclear Association	2016	http://www.world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx
World Nuclear Generation and Capacity	Nuclear Energy Institute	2017	http://www.world-nuclear.org/information-library/current-and-future-generation/nuclear-power-in-the-world-today.aspx
Nuclear Power	Ontario Power Generation	2017	http://www.opg.com/generating-power/nuclear/Pages/nuclear.aspx
The Atlas of Canada - Clean Energy Resources and Projects (CERP)	Natural Resources Canada	January 2017	http://atlas.gc.ca/cerp-rpep/en/
Ontario Energy Board Regulated Price Plan	Ontario Energy Board	May 2016	https://www.oeb.ca/oeb/_Documents/EB-2004-0205/RPP_Price_Report_May2016.pdf
Refurbishment of the Darlington Nuclear Generating Station. An Impact Analysis on Ontario's Economy.	The Conference Board of Canada	November 2015	http://www.opg.com/darlington-refurbishment/Documents/CBCDRP-EconomicAnalysisReportFINAL.pdf
Amended agreement secure Bruce Power's role in Long-Term energy plan	Bruce Power	December 2015	http://www.brucepower.com/amended-agreement-secures-bruce-power-role-in-long-term-energy-plan/
How is it stored today?	Nuclear Waste Management Organization	Accessed 08/15/17	https://www.nwmo.ca/en/Canadas-Plan/Canadas-Used-Nuclear-Fuel/How-Is-It-Stored-Today
Canada's Energy Future 2016 – Energy Supply and Demand Projections to 2040	NEB	2016	https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2016/2016nrgftr-eng.pdf

Document name	Author	Date	Source
Comparison of Lifecycle Greenhouse Gas Emissions of Various Electricity Generation Sources.	World Nuclear Organization	Accessed 08/15/17	http://www.world-nuclear.org/uploadedFiles/org/WNA/Publications/Working_Group_Reports/comparison_of_lifecycle.pdf
2016 OPG Annual Report	Ontario Power Generation	2016	http://www.opg.com/news-and-media/Reports/2016AnnualReport.pdf
Cost of Energy Technologies	World Energy Council	2013	https://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf
Integration of Variable Output Renewable Energy Sources – The Importance of Essential Reliability Service. Energy and Mines Ministers' Conference.	Natural Resources Canada	August 2017	http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/17-0071-Essential-Reliability-Services-access-EN.pdf
Power generation assumptions in the New Policies and 450 Scenarios in the World Energy Outlook 2016	IEA	2016	http://www.worldenergyoutlook.org/media/weowebsite/energymodel/WEO_2016_PG_Assumptions_NPSand450_Scenario.xlsb
Opportunities and challenges for a sustainable energy future.	Chu and Majumdar	August 16, 2012	http://www.indiaenvironmentportal.org.in/files/file/sustainable%20energy.pdf
World Statistics: Nuclear Energy Around the World (Nuclear Energy Institute)	Nuclear Energy Institute	Accessed 08/17/17	https://www.nei.org/Knowledge-Center/Nuclear-Statistics/World-Statistics
GHG from Geothermal Power Production	World Bank	February 2017	https://pangea.stanford.edu/ERE/db/GeoConf/papers/SGW/2017/Fridriksson.pdf
Geothermal FAQs	US Department of Energy	Accessed 8/17/2017	https://energy.gov/eere/geothermal/geothermal-faqs
National Renewable Energy Lab (NREL)	NREL	February 2012	file:///C:/Users/aschristian/Documents/SKELEC/Research/Tech%20Cost/Black_and_Veatch_nrel-cost-report.pdf
Study Indicates Bulk Energy Storage Would Increase Total U.S. Electricity System Emissions	Scientific American	August 17, 2015	https://blogs.scientificamerican.com/plugged-in/study-indicates-bulk-energy-storage-would-increase-total-u-s-electricity-system-emissions/

Deloitte.

www.deloitte.ca

Deloitte, one of Canada's leading professional services firms, provides audit, tax, consulting, and financial advisory services. Deloitte LLP, an Ontario limited liability partnership, is the Canadian member firm of Deloitte Touche Tohmatsu Limited.